Appendix 4-3g
Report of Examination of Mud Conditions
(Agency Information Consultants, Inc., 1988

Appendix 4-3g

Report of Examination of Mud Conditions

(Agency Information Consultants, Inc., 1988)

October 6, 1988

Mr. James Clark
E. I. Du Pont de Nemours and Company, Inc.
P. O. Box 3269, Mail Area 83
Beaumont, Texas 77704

In re: Mud conditions of reentered wells

Dear Sir,

Agency Information Consultants, Inc. (AIC) has researched the files of the Texas Railroad Commission (TRC) to identify oil and gas wells that have been reentered within the past two years. The objective was to identify wells that had been originally drilled and plugged within the past twenty to thirty years to determine the condition of the mud in these wells upon their reentry.

From the Texas Railroad Commission files, AIC identified wells that had "reentry" permits filed in 1987 and 1988. AIC then contacted the operators of these permits to determine if reentry had occurred and to ask the condition of the mud. If a well had been reentered, AIC requested any documentation or verbal comment that might be available as to the condition of the mud. For wells that had been reentered AIC also retrieved the well's original plugging records from the TRC to indicate when and how the well had been plugged.

A summary of AIC's interviews and accompanying well records is found in the attached report entitled "Report of Examination of Mud Conditions.

Sincerely,

Rickye Lennon

Attachment

RLL/rad

REPORT OF
EXAMINATION OF
MUD CONDITIONS

Agency Information Consultants, Inc. (AIC) examined the 1987 & 1988 drilling permit indexes for operators who have filed re-entry permits in the Gulf Coast Area and West Texas. The Texas Railroad Commission files were researched for the wells actually re-entered. The operators were contacted, but many unable to provide information. The operators in the Gulf Coast Area that were able to provide AIC with information found the mud to be hard, but the operators in West Texas found it to be soft. The majority of the operators stated the top of the mud was just below the surface plug, but did not know the exact depth.

AIC contacted Louis A. Newitt, who over the past five years has been re-entering wells in the Gulf Coast Area. The last ten to fifteen wells he has re-entered have had casing left in the hole and both cement and mud were used to plug the wells. Mr. Newitt said from his experience mud sets up like cement and the only way he has been able to tell the difference between the mud and cement is by the color. He also stated mud sets up firm after about five years.

Mr. Pat Ray with Famcor Oil, Inc. was contacted about the Langham Unit #1 in San Jacinto County which was plugged as a dry hole on January 29, 1966 (See Exhibit A-1). Ray could only remember the mud was hard and it took a long time to drill through the plug.

AIC spoke to an engineer with Hughes Texas Petroleum Ltd. in Beeville, Texas. He said the mud in the Gulf Coast Area is usually dehydrated and hard. The top of the mud drops down to approximately one hundred to two hundred feet.

Mr. Jerry Cheatham with Jerry Cheatham Operating Inc. said most of the wells he has re-entered in the Gulf Coast Area have to be conditioned before drilling through the plugs because the mud is so hard and firm. Mr. Cheatham also said the mud was at the surface.

AIC contacted Mr. David Russell with John McGown and he stated "most of the fluid is in suspension. The water is on top with mud particles on the bottom." Mr. Russell also said the top of the mud is usually below the top cement plug.

AIC contacted Enerquest Petroleum, Inc. and was referred to Mr. Ken Patterson about the H. E. Evans #1 in Coleman County which was plugged as a dry hole May 31, 1956 (See Exhibit B-1). Mr. Patterson stated the mud was soft and a little dehydrated, but in good condition. The only plug was a five sack cement plug at the surface and then the hole was full of mud. Mr. Patterson did not know the depth of the top of the mud.

Russ with Harken Production Company in Abilene, Texas was contacted by AIC. He re-entered a dry hole in Taylor County known as the Ella P. Edins #1 (See Exhibit C-1). Russ said cement plugs were found at the surface and at one hundred feet and another one at approximately three thousand feet. The hole was full of mud and the mud was like jello with a grey tint to it. He felt the mud was in good condition at the time the well was re-entered.

AIC spoke with Mr. Jack Fisher about a couple of wells he re-entered in Jones County which were originally plugged in 1960 (See Exhibit D-1). Mr. Fisher said the mud was hard, but he was unable to determine the top of the mud.

Crump Petroleum Corporation was contacted about the re-entering of the T. B. Rutherford #1 in Stonewall County which was plugged April 6, 1955 (See Exhibit E-1). The mud was soft, but he did not know the depth of the top of the mud. The well was plugged with cement and mud.

AIC, also contacted Mr. Greg Norman with Gunn Oil Company about the re-entry of Tom L. Burnett #1 in Foard County which was plugged as a dry hole May 31, 1945 (See Exhibit F-1). Mr. Norman stated the mud was in good condition. The mud weight was 9.7 at the top of the mud. The well had a cement plug at the surface and fifteen hundred feet of surface casing left in the hole.

The following companies which were contacted use state funds to replug old leaking wells in West Texas.

AIC contacted Mr. Lynn Smith with X-Cel Well Service & Drilling about the mud conditions. He said most of the leaking wells he replugs were originally plugged with mud prior to 1940. Mr. Smith was unable to give AIC any additional information.

Battista Drilling was contacted and the wells are usually plugged with mud, pipe, and iron. He said these wells are leaking due to injection pressure. The mud is soft and at the surface. He also stated the top of the mud for wells not leaking is usually at one hundred feet or less in West Texas.

AIC contacted Riffe Drilling Company and the wells they plug are usually flowing salt water and are originally plugged with mud in the 1920's. The top of the mud varies, but it is usually around one hundred feet.

Bill with Yellow Mound Oil Company stated that the majority of wells he replugs were cable tool wells drilled in the 1920's. When replugging the wells he usually finds a mesquite or oak plug with soft mud in the hole.

EXHIBIT A-1

[illegible]
No File No. ..

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

Form 3A
Application
To Plug and
Well Record

FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH
WELL IS LOCATED FIVE FULL DAYS PRIOR TO PLUGGING

Company Viking Drilling Company & Rodney De Lange Address 900 N. E. Loop Expressway San Antonio, Texas 78209

Sec. No. Block No. Survey John Stewart A-58 County San Jacinto

Well No. 1 Name of Lease Langham Unit No. of Acres 640 Elev. 168' Gr.

Name of Field in which well is located Wildcat - Urbana Field Area

Located 2 Miles West Direction from Urbana (Nearest P. O. or Town)

Form 1, "Notice of Intention to Drill," was filed in name of Viking Drilling Company & Rodney De Lange

Drilling Commenced January 8, 19 66, Drilling Completed January 29, 1966

Was this well ever produced Oil? No or Gas? No

Character of Well (Oil, Gas or Dry) Dry Total Depth 10,520'

Date you wish to Plug January 29, 19 66

Name of Party Plugging Well Western Company Address Houston, Texas

Correspondence regarding this well should be sent to: Name W. E. Richards

Address 900 N. E. Loop Expressway, San Antonio, Texas

Initial Production of Gas: Volume (MCF) None 24 Hrs. Pressure lbs. per square inch

Initial Production of Oil: Barrels None

Give notice before Plugging to all available Lease Owners, as required by Rule (10).

When Plugging completed, file final Plugging Report, duly signed and sworn to. All necessary forms will be furnished by the Deputy Supervisor of district in which well is located.

NOTE: If no log available, so state and give all information that can be obtained as to total depth, whether or not cemented, producing formation, water crude, and as near as possible date well was drilled.

General Remarks: Mr. Tyler of your Houston office approved plugging.

FILL OUT PORTION AND AFFIDAVIT ON REVERSE SIDE

RECEIVED
FEB 2 1966
Railroad Commission of Texas
OIL & GAS DIV.
AUSTIN, TEXAS

RECEIVED
Railroad Commission of Texas
OIL & GAS DIVISION
SAN ANTONIO, TEXAS

RECEIVED
R. R. C. OF TEXAS
FEB 7 1966
O. G.
HOUSTON, TEXAS

DR-11

Please Refer to
File No. __

Form 4
Plugging Record

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED

Company Viking Drilling Company & Rodney De Lange Address 900 N. E. Loop Expressway San Antonio, Texas 78209

Sec. No. Block No. Survey John Stewart A-52 County San Jacinto

Well No. 1 Name of Lease Langham Unit No. of Acres 640

Name of Field in which well is located Wildcat - Urbana Field Area Date well was plugged January 29 1966

Form 1 (Notice of Intention to Drill) was Filed in Name of Viking Drilling Company & Rodney DeLange

Character of Well at the time of completion Oil (Initial Production) bbls: Gas (Initial Production) Cu. Ft. Dry X

Amount well producing when plugged Oil 0 bbls. Gas 0 Cu. Ft.. Water 0 bbls

Has this well ever produced oil or gas? No

Total Depth 10,520 feet. Top of each producing sand - feet

Was the well filled with mud-laden fluid, according to regulations of the Railroad Commission? Yes

How was mud applied? Circulated

Were plugs used? Yes If so, show all shoulders left for casing, depth of each, and size of casing, size and kind of plugs used, and depth placed. Also amount of cement and rock. Was well shot? No

80 sacks cement - 1550'-1350' 10 sacks - surface to 45'

Plugged pursuant to conversation with Mr. Tyler on January 29, 1966

SIZE PIPE	PUT IN WELL		PULLED OUT		LEFT IN WELL		PACKERS AND SHOES
	Ft.	In.	Ft.	In.	Ft.	In.	
9-5/8"	1421		0		1421		Guide Shoe & Float Collar

Show depth found and thickness of all water, oil and gas formations None

Have all abandoned wells on this lease been plugged according to Commissions rules? Yes

Manner of confining all oil, gas or water to strata: Mud and cement

The names of adjacent lease, royalty and landowners with their addresses in each
Pan American Petroleum Corporation, P. O. Box 3092, Houston, Texas

RECEIVED
FEB 1 1966
Railroad Commission of Texas
OIL & GAS DIVISION
SAN ANTONIO, TEXAS

Was a time given before plugging to all available adjacent lease owners as required
Yes

I W. E. Richards being first duly sworn on oath, state that I have knowledge of the facts and the matter herein set forth and that the same are true and correct.

Name

Subscribed and sworn to before me this 3rd day of February 19 66

FEB 7 1968

Notary Public County, Texas

RECEIVED
FEB [illegible] 1966
Railroad Commission of Texas
OIL & GAS DIVISION

Correspondence regarding this well should be addressed to
Name Viking Drilling Company Address 900 N. E. Loop Expressway
San Antonio, Texas 78209

DP 11

Form CS-23 (Rev. 4-63) The Western Company

CEMENTING AFFIDAVIT

STATE OF TEXAS
COUNTY OF ____________

I, DELBERT G. KREISS being of lawful age do state that I am employed by The Western Company in the capacity of SERVICE ENGINEER and that on 4 day of JAN. 1966 The Western Company rented equipment and personnel to VIKING DRLG. CO. for the purpose of cementing the SURFACE (prod., prot., surface) string of casing in their well Number 1, LANGHAM GAS UNIT Lease, located in SAN JACINTO County, Texas. Information provided me by the customer, his agent or representative, states that the above string of casing was size 9 5/8 O.D., set in 12 1/4 inch drilled hole, and that casing depth set was 1441 feet.

For this cement job, I mixed the following

220 sacks TRINITY LITE-WATE + 4% GEL. Admix
150 sacks COMMON + 2% CACl2 Admix
________ sacks ____________________ Admix

Based upon the above information, according to my cement tables, I have calculated that the above volume of cement will fill up an annular height of 1968' feet between 9 5/8 casing and 12 1/4 hole.
CEMENT CIRCULATED TO SURFACE
The work performed was done under the direction, supervision and control of the said

J.C. BIRKHAM DRLG CO
customer

Affiant Delbert G. Kreiss
Western Company Employee

STATE OF TEXAS
COUNTY OF ____

BEFORE ME the undersigned authority, on this day personally appeared ____________ known to me to be the person whose name is subscribed to the foregoing, who after being duly sworn upon oath states that to the best of his knowledge and belief the facts as stated above are true and correct.

GIVEN under my hand and seal this FEB 7 1968 day of ____

RECEIVED
Railroad Commission of Texas
OIL & GAS DIVISION
AUSTIN, TEXAS

EXHIBIT B-1

13302

Please Refer
to File No.______

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

Form 2A
Applicatio
To Plug an
Well Recor

FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED FIVE FULL DAYS PRIOR TO PLUGGING

Company Paul C. Teas Address 1328 Republic Bank Bldg. Dallas, Texas

Sec. No. [illegible] Tr. 11 Block No. 1 Survey GH&H RR Co. County Coleman

Well No. 1 Name of Lease H. E. Evans No. of Acres 60 Elev. 1997 KB

Name of Field in which well is located Wildcat

Located 2 Miles SE Direction from Talpa (Nearest P. O. or Town

Form 1, "Notice of Intention to Drill," was filed in name of Paul C. Teas

Drilling Commenced May 21, 1956, Drilling Completed May 31, 1956

Has this well ever produced Oil? No or Gas? No

Character of Well (Oil, Gas or Dry) Dry Total Depth 3547

Date you wish to Plug May 31, 1956.

Name of Party Plugging Well Guffey Drilling Co. Address Dallas, Texas

Correspondence regarding this well should be sent to: Name Paul C. Teas

Address 1328 Republic Bank Bldg., Dallas, Texas

Initial Production of Gas: Volume (MCF) 0 24 hrs. Pressure ______ lbs. per square inc

Initial Production of Oil: Barrels 0

Give notice before Plugging to all available Lease Owners, as required by Rule (10).

When Plugging completed, file final Plugging Report, duly signed and sworn to. All necessary forms will be furnishe by the Deputy Supervisor of district in which well is located.

NOTE: If no log available, so state and give all information that can be obtained as to total depth, whether or not cemented, producing formation, water sands, and as near as possible date well was drilled.

General Remarks: ______

FILL OUT FORMATION AND AFFIDAVIT ON REVERSE SIDE

Posted
[illegible] Map 1203

Please Refer to

File No. ______

Form 4

Plugging Recor

RAILROAD COMMISSION OF TEXAS

OIL AND GAS DIVISION

FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED

Company Paul C. Teas Address 1328 Republic Natl. Bank Bldg. Dallas, Texas

Rec. No. 7, Tr.11 Block No. 1 Survey GH&H RR Co. County Coleman

Well No. 1 Name of Lease H. E. Evans No. of Acres [illegible]

Name of Field in which well is located Wildcat Date well was plugged May 21, 19

Form 1 (*Notice of Intention to Drill*) Was Filed in Name of Paul C. Teas

Character of Well at the time of completion: Oil ______ bbls: (Initial Production) Gas ______ Cu. Ft.; (Initial Production) Dry ✓

Amount well producing when plugged: Oil ______ bbls; Gas ______ Cu. Ft.; Water ______ bbls

Has this well ever produced oil or gas? No

Total Depth 3547 feet. Top of each producing sand None feet

Was the well filled with mud-laden fluid, according to regulations of the Railroad Commission? Yes

How was mud applied? Pump

Were plugs used? No If so, show all shoulders left for casing, depth of each, and size of casing, siz and kind of plugs used, and depth placed. Also amount of cement and rock. Was well shot? No

SIZE PIPE	PUT IN WELL		PULLED OUT		LEFT IN WELL		PACKERS AND SHOES
	Ft.	In.	Ft.	In.	Ft.	In.	
10-3/4	100				100		

Show depth found and thickness of all water, oil and gas formations None

Have all abandoned wells on this lease been plugged according to Commissions rules? Yes

Manner of confining all oil, gas or water to strata: Heavy mud

The names of adjacent lease, royalty and landowners with their addresses in each instance as follows:

Superior Oil Company, Abilene, Texas

Was notice given before plugging to all available adjacent lease owners as required by Rule 10? Yes

I, Wm. B. Duncan, III, being first duly sworn on oath, state that I have knowledge of the fact and the matter herein set forth and that the same are true and correct.

Name Wm B Duncan III, Title Engineer

Subscribed and sworn to before me this 12th day of June, 195

Notary Public Dallas County, Texas

Correspondence regarding this well should be addressed to:

Name Paul C. Teas Address 1328 Republic Bank Bldg.
Dallas 1, Texas

EXHIBIT C-1

43957

Please Refer
to File No.____

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

Form 24
Application
To Plug and
Well Record

FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED FIVE FULL DAYS PRIOR TO PLUGGING

Company Copaz Oil & Gas Corporation Address Box 936, Baird, Texas

Sec. No. 62 Block No. - Survey J.M.Cloud County Taylor

Well No. 1 Name of Lease Ella P.Edins No. of Acres 81.5 Elev. -

Name of Field in which well is located wildcat

Located 3 Miles West Direction from Buffalo Gap (Nearest P. O. or Town)

Form 1, "Notice of Intention to Drill," was filed in name of Copaz Oil & Gas Corporation

Drilling Commenced 5/18, 1961, Drilling Completed 5/22, 1961

Has this well ever produced Oil? no or Gas? no

Character of Well (Oil, Gas or Dry) dry Total Depth 2160

Date you wish to Plug immediately, 19__.

Name of Party Plugging Well J.W.King Drilling Co. Address Abilene, Texas

Correspondence regarding this well should be sent to: Name Copaz Oil & Gas Corporation

Address Box 936, Baird, Texas

Initial Production of Gas: Volume (MCF) - 24 hrs. Pressure - lbs. per square inch

Initial Production of Oil: Barrels -

Give notice before Plugging to all available Lease Owners, as required by Rule (10).

When Plugging completed, file final Plugging Report, duly signed and sworn to. All necessary forms will be furnished by the Deputy Supervisor of district in which well is located.

NOTE: If no log available, so state and give all information that can be obtained to as total depth, whether or not cemented, producing formation, water sands, and as near as possible date well was drilled.

General Remarks:

RECEIVED
MAY 26 1961
Railroad Commission of Texas
OIL & GAS DIVISION
ABILENE, TEXAS

FILL OUT FORMATION AND AFFIDAVIT ON REVERSE SIDE

Dn.

54 0721

Form 4

Plugging Record

Please Refer to

File No. ______

RAILROAD COMMISSION OF TEXAS

OIL AND GAS DIVISION

FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED

Company Copaz Oil & Gas Corporation Address Box 936, Baird, Tex.

Sec. No. 62 Block No. - Survey J.M.Cloud County Taylo.

Well No. 1 Name of Lease Ella P.Edins No. of Acres 51.5

Name of Field in which well is located wildcat Date well was plugged 5/22 19

Form 1 (*Notice of Intention to Drill*) Was Filed in Name of Copaz Oil & Gas Corporation

Character of Well at the time of completion: Oil - bbls: (Initial Production) Gas - Cu. Ft. (Initial Production) Dry yes

Amount well producing when plugged: Oil - bbls: Gas - Cu. Ft. Water - bbls.

Has this well ever produced oil or gas? no

Total Depth 2460 feet. Top of each producing sand none feet.

Was the well filled with mud-laden fluid, according to regulations of the Railroad Commission? yes

How was mud applied? pump

Were plugs used? no If so, show all shoulders left for casing, depth of each, and size of casing, size and kind of plugs used, and depth placed. Also amount of cement and rock. Was well shot? no

5 sks top surface weld steel cap on surface pipe

SIZE PIPE	PUT IN WELL		PULLED OUT		LEFT IN WELL		PACKERS AND SHOES
	Ft.	In.	Ft.	In.	Ft.	In.	
8 5/8	62	0	0	0	62		

Show depth found and thickness of all water, oil and gas formations no water, oil or gas formations

Have all abandoned wells on this lease been plugged according to Commissions rules? yes

Manner of confining all oil, gas or water to strata: mud & casing

The names of adjacent lease, royalty and landowners with their addresses in each instance as follows:

Gulf Oil Corporation, Box 1111 Wichita Falls, Texas

Wayne Petroleum Company, 101 Crescendo Bldg. Abilene, Texas

Was notice given before plugging to all available adjacent lease owners as required by Rule 10? Yes

I, B.G.Hatchett, being first duly sworn on oath, state that I have knowledge of the facts and the matter herein set forth and that the same are true and correct.

Name B G Hatchett Title President

Subscribed and sworn to before me this 5th day of May, 19 6

C.N. Griggs Jr

Notary Public Taylor County, Texas

RECEIVED
MAY 26 1961
Railroad Commission of Texas
OIL & GAS DIVISION
ABILENE, TEXAS

Correspondence regarding this well should be addressed to.

Name Copaz Oil & Gas Corporation Address Box 936, Baird, Texas

EXHIBIT D-1

30211

Please Refer
to File No.______

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

Form 2A
Application
To Plug and
Well Record

FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED FIVE FULL DAYS PRIOR TO PLUGGING

Company Fletcher Oil & Gas Drilling Corporation Address 1229 Merc. Sec. Bldg., Dallas,

Sec. No. 25 Block No. 19 Survey T&P RR County Jones

Well No. X 3 Name of Lease H. N. Smith (07927) No. of Acres 312.25 Elev. ______

Name of Field in which well is located ~~[illegible]~~ Hayner (4600' Canyon Reef)

Located 6-1/2 Miles SW Direction from Noodle (Nearest P. O. or Town)

Form 1, "Notice of Intention to Drill," was filed in name of Fletcher Oil & Gas Drilling Corporation

Drilling Commenced 3/10, 1960, Drilling Completed 3/23, 1960

Has this well ever produced Oil? No or Gas? No

Character of Well (Oil, Gas or Dry) Dry Total Depth 4630

Date you wish to Plug March 24, 1960.

Name of Party Plugging Well Fletcher Oil & Gas Drlg. Corporation Address 1229 Merc. Sec. Bldg., Dallas,

Correspondence regarding this well should be sent to: Name Fletcher Oil & Gas Drilling Corporation

Address 1229 Merc. Sec. Bldg., Dallas, Texas

Initial Production of Gas: Volume (MCF) ______ 24 hrs. Pressure ______ lbs. per square inch

Initial Production of Oil: Barrels ______

Give notice before Plugging to all available Lease Owners, as required by Rule (10).

When Plugging completed, file final Plugging Report, duly signed and sworn to. All necessary forms will be furnished by the Deputy Supervisor of district in which well is located.

NOTE: If no log available, so state and give all information that can be obtained as to total depth, whether or not cemented, producing formation, water sands, and as near as possible date well was drilled.

RECEIVED
MAR [illegible] 1960
Rail[illegible]
C[illegible] TEXAS

General Remarks: ______

FILL OUT FORMATION AND AFFIDAVIT ON REVERSE SIDE

[redacted]

660

3/28/11

Form 4

Plugging Record

Please Refer to

File No.

RAILROAD COMMISSION OF TEXAS

OIL AND GAS DIVISION

FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED

Company Fletcher Oil & Gas Drlg. Corp. Address 1229 Merc. Sec. Bldg., Dallas, Texas

Sec. No. 25 Block No. 19 Survey T&PRR County Jones

Well No. ~~XX~~ 3 Name of Lease H. N. Smith (07927) No. of Acres 312.25

Name of Field in which well is located Hayner (4600' Canyon) Date well was plugged 3/24, 19 60

Form 1 (Notice of Intention to Drill) Was Filed in Name of Fletcher Oil & Gas Drilling Corporation

Character of Well at the time of completion: Oil ____ bbls; (Initial Production) Gas ____ (Initial Production) Cu. Ft.. Dry X

Amount well producing when plugged: Oil -0- bbls; Gas -0- Cu. Ft.; Water -0- bbls.

Was this well ever produced oil or gas? No

Total Depth 4630 feet. Top of each producing sand None feet.

Was the well filled with mud-laden fluid, according to regulations of the Railroad Commission? Yes

How was mud applied? Pump

Were plugs used? Yes If so, show all shoulders left for casing, depth of each, and size of casing, size and kind of plugs used, and depth placed. Also amount of cement and rock. Was well shot?

25 sack plug from 128' upward into surface casing; hole filled with mud and steel cap welded on top of surface casing.

SIZE PIPE	PUT IN WELL		PULLED OUT		LEFT IN WELL		PACKERS AND SHOES
	Ft.	In.	Ft.	In.	Ft.	In.	
10-3/4	103				103		

Show depth found and thickness of all water, oil and gas formations None

Have all abandoned wells on this lease been plugged according to Commissions rules? Yes

Manner of confining all oil, gas or water to strata: Cemented

The names of adjacent lease, royalty and landowners with their addresses in each instance as follows:

Fletcher Oil & Gas Drilling Co4p. - Dallas, Texas
Reef Oil Co. - Abilene, Texas
Texam Oil Co. - Three Rivers, Texas
Elm Oil Co. - Dallas, Texas
Hack Drilling Co. - Abilene, Texas

Was notice given before plugging to all available adjacent lease owners as required by rule? Yes

RECEIVED
MAR 29 1960
Railroad Commission of Texas
Oil and Gas Division
ABILENE, TEXAS

I, Jo Robins, being first duly sworn on oath, state that I have knowledge of the facts and the matter herein set forth and that the same are true and correct.

Name Jo Robins Agent

Subscribed and sworn to before me this 28th day of March, 19 (

Notary Public Dallas County, Texas

Correspondence regarding this well should be addressed to:

Name Fletcher Oil & Gas Drilling Corp. [illegible]

52711

Please Refer
to File No.______

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

Form 2A
Application
To Plug and
Well Record

FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH
WELL IS LOCATED FIVE FULL DAYS PRIOR TO PLUGGING

Company Fletcher Oil & Gas Drilling Corp. Address 1229 Merc. Sec. Bldg., Dallas

Sec. No. Sub. 12 Block No. ______ Survey M. W. Dikes #218 County Jones

Well No. 3 Name of Lease V. P. Byrom (08217) No. of Acres 100 Elev. ___

Name of Field in which well is located Noodle, NW (4000' Canyon Sand)

Located 5 Miles NW Direction from Noodle (Nearest P. O. or Town)

Form 1, "Notice of Intention to Drill," was filed in name of Fletcher Oil & Gas Drilling Corporation

Drilling Commenced November 17, 1960, Drilling Completed November 26, 1960

Has this well ever produced Oil? no or Gas? no.

Character of Well (Oil, Gas or Dry) Dry Total Depth 4150

Date you wish to Plug December 2, 1960

Name of Party Plugging Well Fletcher Oil&GasDrlg.Corp. Address 1229 Merc. Sec. Bldg., Dallas

Correspondence regarding this well should be sent to: Name Fletcher Oil & Gas Drilling Corporation

Address 1229 Merc. Sec. Bldg., Dallas, Texas

Initial Production of Gas: Volume (MCF) ______ 24 hrs. Pressure ______ lbs. per square inch

Initial Production of Oil: Barrels ______

Give notice before Plugging to all available Lease Owners, as required by Rule (10).

When Plugging completed, file final Plugging Report, duly signed and sworn to. All necessary forms will be furnished by the Deputy Supervisor of district in which well is located.

NOTE: If no log available, so state and give all information that can be obtained to as total depth, whether or not cemented, producing formation, water sands, and as near as possible date well was drilled.

General Remarks: ______

RECEIVED
DEC 6 1960
Railroad Commission
OIL & GAS DIVISION
ABILENE, TEXAS

FILL OUT FORMATION AND AFFIDAVIT ON REVERSE SIDE

660

Di

32811

Please Refer to
File No: ______

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

Form 4
Plugging Record

FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED

Company Fletcher Oil & Gas Drilling Corp. Address 1229 Merc. Sec. Bldg., Dallas, Tex

Sec. No. Sub. 12 Block No. ______ Survey M. W. Dikes #218 County Jones

Well No. 3 Name of Lease V. P. Byrom (08217) No. of Acres 160

Name of Field in which well is located Noodle, NW (4000' Canyon Sd) Date well was plugged 12/22 1960

Form 1 (Notice of Intention to Drill) Was Filed in Name of Fletcher Oil & Gas Drilling Corporation

Character of Well at the time of completion: Oil ______ bbls: (Initial Production) Gas ______ Cu. Ft.: (Initial Production) Dry X

Amount well producing when plugged: Oil -0- bbls: Gas -0- Cu. Ft.: Water -0- bbls

Has this well ever produced oil or gas? no

Total Depth 4150 feet. Top of each producing sand -0- feet

Was the well filled with mud-laden fluid, according to regulations of the Railroad Commission? Yes

How was mud applied? Pump

Were plugs used? Yes If so, show all shoulders left for casing, depth of each, and size of casing, size and kind of plugs used, and depth placed. Also amount of cement and rock. Was well shot? ______

25 sack plug from 139' upward into surface casing; hole filled with mud and steel cap welded on top of surface casing.

SIZE PIPE	PUT IN WELL		PULLED OUT		LEFT IN WELL		PACKERS AND SHOES
	Ft.	In.	Ft.	In.	Ft.	In.	
10-3/4	114				114		

Show depth found and thickness of all water, oil and gas formations -0-

Have all abandoned wells on this lease been plugged according to Commissions rules? Yes

Manner of confining all oil, gas or water to strata: Cemented

The names of adjacent lease, royalty and landowners with their addresses in each instance as follows:

Texaco, Inc. - Wichita Falls, Texas
Sojourner - Abilene, Texas
Fletcher Oil - Dallas, Texas
Vengal Prod. - Abilene, Texas
E. L. Wilson Abilene, Texas

Was notice given before plugging to all available adjacent lease owners as required by Rule 10? Yes

I, Jo Robins, being first duly sworn on oath, state that I have knowledge of the facts and the matter herein set forth and that the same are true and correct.

Name Jo Robins, Title Agent

RECEIVED
DEC 6 1960
Railroad Commission of Texas
OIL & GAS DIVISION
ABILENE, TEXAS

Subscribed and sworn to before me this 5th day of December, 19

Notary Public Dallas County, Texas

Correspondence [illegible] should be addressed to:
Fletcher Oil & Gas Drlg. Corp. [illegible] Dallas

EXHIBIT E-1

Please Refer
to File No.

Form 3A

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

APPLICATION TO PLUG AND WELL RECORD

FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED FIVE FULL DAYS PRIOR TO PLUGGING

Name of Company or Operator Skelly Oil Company Address Box 690, Sweetwater, Texas

County Stonewall Survey Z. K. Smith, Abst. 1010 Blk. — Sec. —

Name of Lease T. B. Rutherford No. of Acres 400 Well No. 1 Elev. 1774' DF

Located 8 Miles SE Direction from Aspermont, Texas (Nearest P. O. or Town)

Name of Field in which well is located Flowers (Canyon Sand)

Form 1, "Notice of Intention to Drill," was filed in name of Skelly Oil Company

Drilling Commenced March 23, 1955, Drilling Completed April 5, 1955

Has this well ever produced oil? No or Gas? No

Character of Well (Oil, Gas or Dry) Dry Total Depth 4700'

Date you wish to Plug April 6, 1955

Name of Party Plugging Well Skelly Oil Company Address Box 690, Sweetwater, Texas

Correspondence regarding this well should be sent to: Name Skelly Oil Company - c/o C. M. Ambrose

Address Box 690, Sweetwater, Texas

CASING RECORD

SIZE	PUT IN WELL		PULLED OUT		LEFT IN WELL		PACKERS AND SHOES
	Ft.	In.	Ft.	In.	Ft.	In.	
8-5/8"OD	153	00	None		153	00	

IF CASING WAS CEMENTED GIVE NUMBER OF SACKS USED ON DIFFERENT STRINGS

8-5/8"OD casing cemented with 100 sacks.

Initial Production of Gas—Volume (MCF) None 24 hrs. Pressure None lbs. per square inch

Initial Production of Oil: Barrels None

Give notice before Plugging to all available Lease Owners, as required by Rule (10).

When Plugging completed, file final Plugging Report, duly signed and sworn to. All necessary forms will be furnished by the Deputy Supervisor of district in which well is located.

NOTE: If no log available, so state and give all information that can be obtained as to total depth, casing record, whether or not cemented, producing formation, water sands, and as near as possible date well was drilled.

RECEIVED
ABILENE
APR 11 1955
OIL & GAS DIVISION

General Remarks:

FILL OUT FORMATION AND AFFIDAVIT ON REVERSE SIDE

Please Refer to

File No.

Form 4

Plugging Record

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED

Company Skelly Oil Company Address Box 690, Sweetwater, Texas

Sec. No. -- Block No. -- Survey Z. K. Smith County Stonewall

Well No. 1 Name of Lease T. B. Rutherford No. of Acres 400

Name of Field in which well is located Flowers (Canyon Sand) Date well was plugged April 5 19 55

Form 1 (Notice of Intention to Drill) Was Filed in Name of Skelly Oil Company

Character of Well at the time of completion Oil (Initial Production) No bbls; Gas (Initial Production) No Cu. Ft. Dry Yes

Amount well producing when plugged Oil None bbls. Gas None Cu. Ft. Water None bbls.

Has this well ever produced oil or gas? No

Total Depth 4700 feet Top of each producing sand None feet.

Was the well filled with mud laden fluid according to regulations of the Railroad Commission? Yes

How was mud applied? Pumped through drill pipe

Were plugs used? Yes If so, show all shoulders left for casing, depth of each, and size of casing, also kind of plugs used and depth placed. Also amount of cement and rock. Was well shot? No. 4700-4550' with 10.1# mud, 4550-4420' with 40 sx. cement, 4420-164' with 10.1# mud, 164-30' with 10 sx. cement, 30' to surface with 5 sx. cement.

SIZE PIPE	PUT IN WELL		PULLED OUT		LEFT IN WELL		PACKERS AND SHOES
	Ft.	In.	Ft.	In.	Ft.	In.	
8-5/8"OD	153	00	None		153	00	

Show depth found and thickness of all water, oil and gas formations DST No. 1 - 4434-46', rec. 90' drilling mud, 450' salt water, no oil. DST No. 2 - 4515-37', rec. 500' gas, 10' GCM, no oil.

Have all abandoned wells on this lease been plugged according to Commissions rules? First well on lease.

Manner of confining all oil, gas or water to strata: Cement plugs.

The names of adjacent lease, royalty and landowners with their addresses in each instance as follows:

A. A. Annis, Aspermont, Texas. W. J. Hart, Aspermont, Texas.
G. P. Humphreys, Aspermont, Texas. Dick Carson, Aspermont, Texas.
Continental Oil Company, 451 Pine St., Abilene, Texas
General Crude Oil Company, 174 Cypress St., Abilene, Texas.
Sid Katz, Box 1698, San Antonio, Texas.

Was notice given before plugging to all available adjacent lease owners as required by Rule 10? Yes

I, C. M. Ambrose being first duly sworn on oath, state that I have knowledge of the facts and the matter herein set forth and that the same are true and correct.

Name C M Ambrose Title Dist. Supt.

Subscribed and sworn to before me this 7th day of April, 19 5

M. D. [illegible]
NOTARY PUBLIC

M. J. Havie
Notary Public Nolan County, Texas

RECEIVED
ABILENE
APR 11 1955
OIL & GAS DIVISION

Correspondence regarding this well should be addressed to:

Name Skelly Oil Company, c/o C. M. Ambrose Address Box 690, Sweetwater, Texas

EXHIBIT F-1

Form 2A

RECEIVED
JUN 8 1945
OIL & GAS DIVISION
TEXAS RAILROAD COMMISSION
WICHITA FALLS, TEXAS

Please Refer to File No.____________

RAILROAD COMMISSION OF TEXAS

OIL AND GAS DIVISION

APPLICATION TO PLUG AND WELL RECORD

FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED FIVE FULL DAYS PRIOR TO PLUGGING

Name of Company or Operator Mid-Continent Petroleum Corp.; Address Box 830, MIDLAND, TEXAS

County FOARD Survey S P RR CO. Blk. L Sec. 1

Name of Farm or Lease Tom L. Burnett No. of Acres 160 Well No. [illegible]

Located 24 Miles West Direction from Crowell, Texas (Nearest P. O. or Town)

Name of Field in which well is located Wildcat

Drilling Commenced March 20, 1945, 19___ Drilling Completed May 26th, 1945, 19___

Has this well ever produced oil? no or Gas? no

Character of Well (Oil, Gas or Dry) Dry Total Depth [illegible]'

Amount Well Producing—Oil none Bbls.; Gas none Cu. Ft.; Water none Bbls.

Date you wish to Plug at once 19___

Name of Party Plugging Well Mid-Cont. Petr. Corp. Address Box 830, Midland, Tex.

Correspondence regarding this well should be sent to: Name Harold Smith, Box 830, Midland, Tex.

Address Midland, Texas Box 830

CASING RECORD

SIZE	PUT IN WELL		PULLED OUT		LEFT IN WELL		PACKERS AND SHOES
	Ft.	In.	Ft.	In.	Ft.	In.	
12 1/2"	265	00	265.00	(Cemented 200 sacks) 00	265	00	T.P. Shoe
9 5/8"	1589	00	1589	(Cemented 1028 sacks) 00	1589	00	Float shoe.

IF CASING WAS CEMENTED GIVE NUMBER OF SACKS USED ON DIFFERENT STRINGS

Initial Production of Gas: Volume no MCF 24 hrs. Pressure ____ lbs. per square inch

Initial Production of Oil: Barrels none

Give notice before Plugging to all available Lease Owners, as required by Rule (10).
When Plugging completed, file final Plugging Report, duly signed and sworn to. All necessary forms will be furnished by the Deputy Supervisor of district in which well is located.

NOTE: If no log available, so state and give all information that can be obtained as to total depth, casing record, whether or not cemented, producing formation, water sands, and as near as possible date well was drilled.

General Remarks: Hole will be filled bottom to top with mud laden fluid and cement plug installed in top of 9 5/8" casing and cellar filled with dirt.

FILL OUT INFORMATION AND AFFIDAVIT ON REVERSE SIDE

Please Refer to File No.

Form 4

1

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

PLUGGING RECORD

FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED

Company MID-CONTINENT PETROLEUM CORPORATION Address BOX 830, MIDLAND, TEXAS

Sec. No. 9 Blk No. "L" Survey S.P.RR Co. County Foard

Well No. One Name of Lease Tom L. Burnett No. of Acres 160

Name of Field in which well is located Wildcat Date well was plugged May 31, 1945 , 194

Character of Well at the time of completion: Oil 0 bbls. (Initial Production); Gas 0 Cu. ft. (Initial Production); Dry yes

Amount well producing when plugged: Oil 0 bbls.; Gas 0 Cu. ft.; Water 0 bbls.

Has this well ever produced oil or gas? no

Total Depth 6825 feet. Top of each producing sand none feet.

Was the well filled with mud-laden fluid, according to regulations of the Railroad Commission? yes

How was mud applied? By pump through drill pipe

Were plugs used no If so, show all shoulders left for casing, depth of each, and size of casing, size and kind of plugs used, and depths placed. Also amount of cement and rock.

Was well shot? no

Show depth found and thickness of all water, oil and gas formations none

Have all abandoned wells on this lease been plugged according to Commission rules? yes

Manner of confining all oil, gas and water to strata: No shows of oil or gas encountered in drilling to total depth

The names of adjacent lease, royalty and landowners with their addresses in each instance as follows.

Tom L. Burnett Estate, Fort Worth, Texas.

Was notice given before plugging to all available adjacent lease owners as required by Rule 10? yes

I, HAROLD SMITH, being first duly sworn on oath, state that I have knowledge of the facts and the matter herein set forth and that the same are true and correct.

Name Harold Smith, Title DIST. SUPT.

Subscribed and sworn to before me this 2nd day of June, 1945, 19

Eugene Lynch
Eugene Lynch
Notary Public MIDLAND County, Texas

Correspondence regarding this well should be addressed to:
Name MR. HAROLD SMITH, BOX 830, MIDLAND, TEX. Address BOX 830, MIDLAND, TEXAS

1-976-147-95 M

JPT High Temperature Flow Properties of Water-Based Drilling Fluids

1698

High-Temperature Flow Properties of Water-Base Drilling Fluids

MAX R. ANNIS
JUNIOR MEMBER AIME

ESSO PRODUCTION RESEARCH CO.
HOUSTON, TEX.

ABSTRACT

Drilling mud rheological and gel property changes due to elevated temperatures frequently cause problems in drilling deep wells. A laboratory investigation of the effects of time, temperatures up to 300F and mud composition on these properties was made with concentric-cylinder, rotational viscometers of the Fann type. The viscometers were sealed from the atmosphere to prevent dehydration of the sample. Gel strengths were found to be more sensitive than viscosities to changes in temperature and mud composition. The high-temperature gel strengths of bentonitic clay drilling fluids were not predictable from low-temperature measurements.

At high temperatures, the clay flocculates. The flocculation temperature depends on the concentration and type of solids in the mud and the degree of chemical deflocculation. As the bentonite content of a mud increases, flocculation temperature decreases. Lignosulfonate treatment raises the flocculation temperature. To minimize adverse high-temperature effects on mud properties, the mud should be maintained at minimum solids content, properly treated with a deflocculant which is stable at the maximum temperature encountered and maintained at a pH high enough to insure activation of the deflocculant for the duration required. The Methylene Blue Test for cation exchange capacity of a clay was found to be a useful guide in determining when a mud contains a dangerously high clay content.

INTRODUCTION

In drilling a well it is desirable, for several reasons, to know the effects of time and temperature on the rheological and gel properties of the drilling fluid in the hole. Problems associated with drilling fluids normally occur down-hole, so it is reasonable to be interested in the properties of drilling fluids at the conditions which exist down-hole.

It has long been observed that high pump pressures are often needed to start circulation after a trip and that the "bottom-up" mud that is circulated back to the surface is usually more viscous than it was before "cooking" at the bottom of the hole for several hours. Burkhardt[1] showed that a knowledge of rheological properties of muds under down-hole conditions is necessary to predict pressure surges. He showed that the viscosity of a mud greatly influences the magnitude of pressure surges and the likelihood of lost returns. McLean *et al.*[2] showed that the rheological properties of a mud under down-hole conditions are very important to cementing operations.

This paper presents data showing the effects of time and temperature on rheological and gel properties of water-base drilling fluids. Measurements of gel strengths and rheological properties were made with two different concentric-cylinder rotational viscometers of the Fann type. One was the conventional six-speed viscometer modified to operate at temperatures up to 350F and at the vapor pressure of the liquid at test temperature. The other viscometer was newly designed to operate at temperatures up to 500F and pressures up to 1,000 psi. Tests with both instruments were made under essentially the same operating conditions. The new viscometer is shown in Fig. 1.

In this investigation, great emphasis has been placed on the rheological properties of clay suspensions, since clays are largely responsible for a mud's thixotropic and gel-

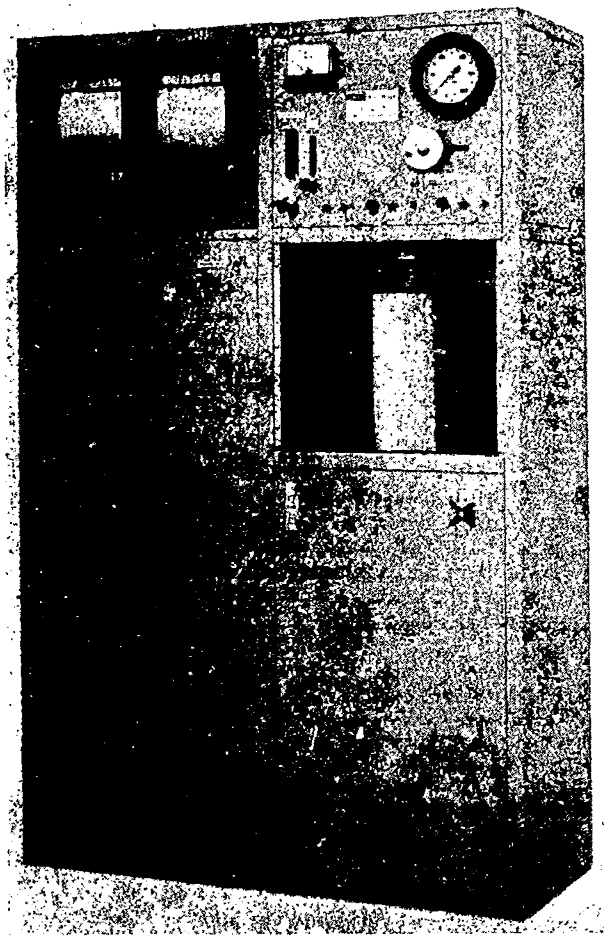

FIG. 1—HIGH-TEMPERATURE VISCOMETER.

Original manuscript received in Society of Petroleum Engineers office Jan. 18, 1967. Revised manuscript received May 18, 1967. Paper (SPE 1698) was presented at SPE Third Conference on Drilling and Rock Mechanics held at The U. of Texas, Austin, Tex., Jan. 25-26, 1967.

[1] References given at end of paper.

forming character. Darley,[3] for example, showed how important the degree of dispersion of clay is on the rheological properties.

CLAY PARTICLE LINKING PROCESSES

To understand and control rheological changes in drilling fluids, the clay particle linking processes must be understood. According to van Olphen,[4] plate-like particles have two different surfaces: the flat-face surface which normally is negatively charged and the edge surface which may be charged positively. These particles can associate in three different ways: face-to-face, edge-to-face or edge-to-edge. The linking of particles in these different fashions may proceed simultaneously, or one type or another may predominate.

Face-to-face association *(aggregation)* merely leads to formation of thicker plates. This decreases the number of particles and causes a decrease in viscosity. *Dispersion*, the reverse of aggregation, leads to a greater number of particles and to higher viscosities.

Edge-to-edge or edge-to-face association is a *flocculation* process that leads to the formation of a "house-of-cards" structure. This also causes an increase in viscosity. Certain chemicals added to mud neutralize the edge charge, with the result that particles no longer associate edge-to-edge or edge-to-face—the mud has *deflocculated.*

FACTORS THAT DETERMINE VISCOSITY

The solids fraction of a mud usually causes the most significant, and certainly the most unpredictable, changes in mud properties at elevated temperatures. Different types of solids have different shapes, sizes and surface charges; hence, they behave differently when suspended in a liquid and subjected to elevated temperatures.

Behavior of the liquid fraction of a mud at high temperature is reasonably well known. If the fluid is Newtonian, such as oil or water, its viscosity will be independent of shear rate and will decrease with increasing temperature. For example, the viscosity of water heated from 75 to 143F will decrease by half; heated to 250F, it will decrease again by half. Factors influencing the viscosity of a mud can be grouped as (1) mechanical interaction of solids and liquid, (2) electrical interaction of solids and (3) shear rate.

Most muds are somewhat non-Newtonian and tend to shear thin, i.e., the viscosity decreases as the shear rate increases. This non-Newtonian behavior is due to the interaction of solids in the mud. Solids interaction causes resistance to flow either from the electrical forces of attraction and repulsion of the charged surfaces of the solids, or from purely mechanical resistance to flow of the particles and the fluid.

MECHANICAL INTERACTION OF SOLIDS AND LIQUID

All solids in suspension tend to behave as uncharged, inert particles at high shear rates, and the viscosity of the suspension is predominantly due to mechanical interaction of the solids and liquid. The high-shear-rate viscosity of a suspension is a function of the viscosity of the liquid and the concentration and shape of the solids. As the solids concentration increases or the shapes of the particles become more asymmetrical, the viscosity increases. As temperature increases, the viscosity of the liquid fraction decreases; consequently, the high-shear-rate viscosity of a mud should decrease proportionately if the solids are not changed by temperature.

In Fig. 2, the change in plastic viscosity with temperature of a Wyoming bentonite suspension is shown in comparison with the change with temperature of the viscosity of water, normalized to the same room temperature viscosity as the bentonite suspension. The plastic viscosity, although not measured at high shear rates, is representative of a high-shear-rate viscosity and will ordinarily be reasonably close to a viscosity measured at shear rates above 10,000 sec.$^{-1}$

The good agreement between the change in plastic viscosity with temperature and the change in the viscosity of water with temperature indicates that high-shear-rate viscosities are predominantly due to mechanical interaction of the solids and liquid. This means that to minimize viscosities at high shear rates (such as the shear rates beneath the bit), the concentration of solids in a mud and the viscosity of the liquid fraction should be minimized. Viscosity of the liquid fraction is often overlooked since it is usually quite small; however, to double it is to double the high-shear-rate viscosity.

Almost any material dissolved in water will raise the viscosity of the water. Lignites and lignosulfonates are among the water-soluble materials commonly present in muds, and in high concentrations these increase the viscosity of water significantly. Many of the soluble salts, such as NaCl, do the same thing.

ELECTRICAL INTERACTION OF SOLIDS

Bentonitic clays are highly dispersible, leading to a large surface area per volume of solids present in the mud. These clays are predominantly the gel builders in water-base drilling fluids. Hauser and Reed[6] showed that gel structure can be detected in suspensions of the finest particles of bentonite at concentrations of less than 0.05 percent.

Van Olphen[4,5] and others[6,7] report that gelation of bentonite particles is largely controlled by electrical forces. These forces exist due to the electrically negative planar surfaces and to positive sites at the edges of the plates where the lattice is disrupted and a broken bond surface is exposed. As shear rate is decreased, these electrical interactions of solids begin to influence viscosity more and more. An example of how the low-shear-rate viscosity reacts to temperature differently than the high-shear-rate viscosity is shown in Fig. 2. Here the viscosity measured at 100 sec.$^{-1}$, as well as the plastic viscosity, is compared with the normalized viscosity of water. Although the high-shear-rate viscosity decreases as the viscosity of water does

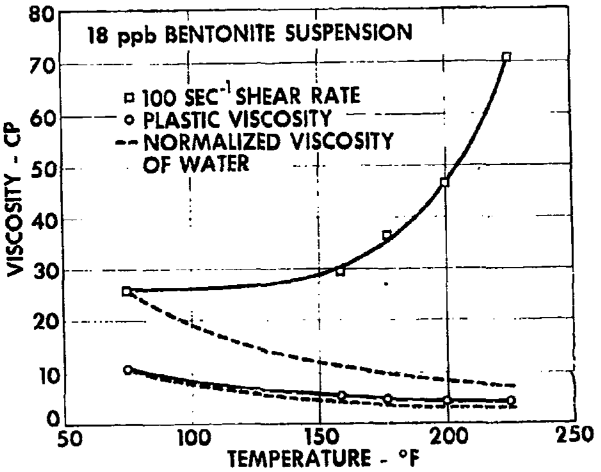

FIG. 2—EFFECT OF TEMPERATURE AND SHEAR RATE ON VISCOSITY.

with increasing temperature, the low-shear-rate viscosity increases with increasing temperature.

This shows very clearly how forces independent of the viscosity of the liquid fraction can dominate in controlling viscosity in the low-shear-rate region. In other words, the forces that orient particles into a gel structure, the electrical forces, predominate in this example.

EFFECT OF SHEAR RATE ON VISCOSITY

Fig. 2 also shows that the low-shear-rate viscosities are greater than the viscosity at higher shear rates and that this difference becomes greater as temperature increases. The suspension becomes more shear thinning with increased temperature. For these reasons rheological properties must be measured at the temperature and in the shear-rate range of interest. Extrapolation of properties to other shear rates and temperatures is subject to serious error. Treating a mud to reduce its viscosity at low or moderate shear rates does not assure a lower viscosity at the very high shear rates beneath a bit; and the fact that the plastic viscosity of a mud decreases with increasing temperature does not mean the viscosity at low shear rates, typical of annular flow, will decrease with increasing temperature.

HIGH-TEMPERATURE EFFECTS ON CLAY SUSPENSIONS

There are a number of ways that increasing temperature may cause the fundamental clay reactions of dispersion, deflocculation, aggregation and flocculation. In simple clay suspensions, however, increasing temperature causes only two primary clay reactions—flocculation and dispersion of the clay plates. If a high electrolyte content is present, a third reaction, aggregation, will usually follow flocculation.

TEMPERATURE FLOCCULATION AND GELATION

Fig. 3 shows the shear rate-shear stress relationship for Wyoming bentonite at 75, 200 and 225F. The mud becomes more non-Newtonian, more shear thinning, as the temperature is increased. This change is characteristic of a flocculation process in which the yield point greatly increases.

When a bentonite mud is quiescent, the gelation process depends on both time and temperature. Fig. 4 shows the effect of temperature on the initial and 30-minute gel strengths of a bentonite suspension. The 30-minute gel strength of this suspension is at any temperature approximately six times the initial gel strength. The dependence of gel strength on time at different temperatures is shown in Fig. 5. These and other tests of up to 18 hours indicated that gel strength increases indefinitely with time.

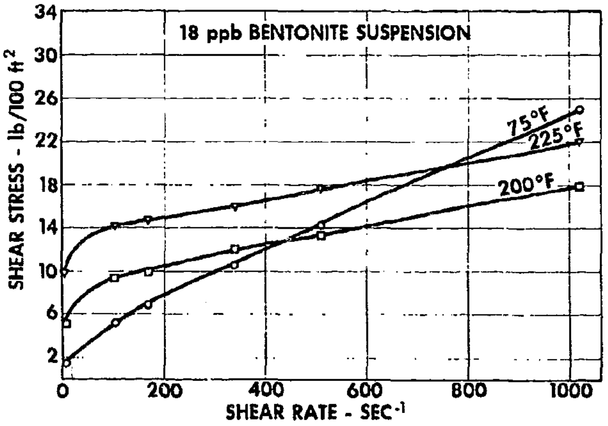

FIG. 3—EFFECT OF TEMPERATURE ON SHEAR RATE-SHEAR STRESS RELATIONSHIP.

TEMPERATURE DISPERSION

In addition to flocculation at high temperatures, bentonite suspensions undergo other changes. Most of the effect of temperature flocculation can be reversed by shearing the mud at high shear rates. This was shown by Hiller.[11] The shear rate-shear stress curve will regain its original shape, but a permanent thickening of the suspension will occur (Fig. 6). This figure shows how the rheological properties measured at room temperature are affected after hot rolling a bentonite suspension at various temperatures for various times.

The thickening of the mud with increasing temperature and increasing time at temperature is very similar to what could be exepcted if more bentonite were added to the mud. This suggests that the exposure to high temperature for a long period of time has caused the bentonite to become more dispersed, thereby increasing the number of individual platelets in suspension.

EFFECT OF BENTONITE CONCENTRATION

As the number of bentonite particles per unit volume of mud increases, the probability of two particles getting together also increases. Thus, increased bentonite concentration as well as increased temperature should promote flocculation. Fig. 7 shows how the 30-minute gel strength increases with temperature for several concentrations of bentonite. The temperature at which a very rapid increase

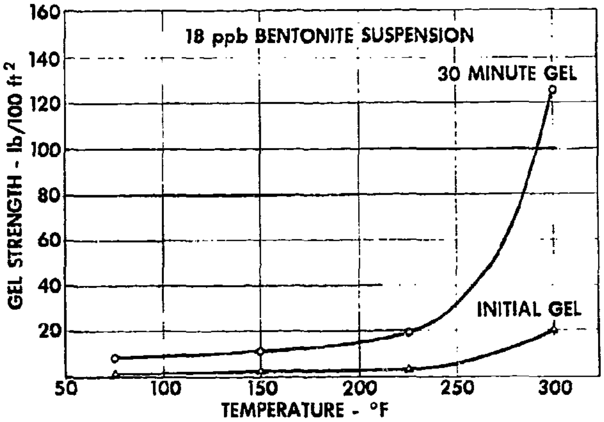

FIG. 4—EFFECT OF TEMPERATURE ON INITIAL AND 30-MINUTE GEL STRENGTHS.

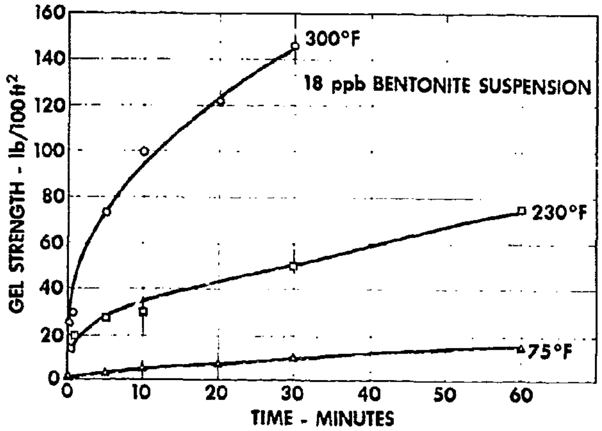

FIG. 5—EFFECTS OF TIME AND TEMPERATURE ON GEL STRENGTH.

in gel strength occurs, indicating the onset of flocculation, decreases as the concentration of betonite increases.

EFFECT OF ELECTROLYTES

Since clay particles have charged surfaces, they become quite responsive to additions of any material which ionizes. Much has been written[5-9] on how various electrolytes affect rheological properties at room temperature.

The electrical forces that influence rheological properties become quite complicated when an electrolyte is added to a clay suspension. Both concentration and type of ions in solution are important in determining how the particles interact and the strength of the bonds formed between particles. The different modes of particle association (flocculation and aggregation) may proceed simultaneously or one type may dominate.

High temperature further complicates the situation. First, the solubilities of various salts change with temperature. A change in ion concentration or a shift in relative concentrations of various ions may result from an increase in temperature. In this way temperature changes may bring about any of the electrolyte-clay reactions that occur at room temperature when the electrolyte content in a mud is changed. Since increased temperature appears to promote both dispersion and flocculation, it becomes even more difficult to predict which mode of particle association will prevail when electrolytes are present.

There is a great deal to be learned about high-temperature effects on muds containing various electrolytes and clay types. For the present, it seems advisable to measure rheological properties on muds at the temperatures of interest and not rely on a knowledge of how these particular muds behave at low temperatures. However, it is possible to make some generalizations about very simple systems.

SODIUM SYSTEMS

In muds used at very high temperatures, common practice is to precipitate multivalent cations (such as calcium) which promote flocculation, and convert the mud to a predominantly sodium system. Deflocculating chemicals are then used to combat the normal tendency of clay to flocculate at high temperatures. This leaves the mud with essentially two electrolytes: sodium chloride from formation water and sodium hydroxide added with the deflocculant.

Both of these electrolytes will thicken a bentonite suspension at room temperature if added in sufficient quantity. This is illustrated in Fig. 8 which shows the shear rate-shear stress relationship for a Wyoming bentonite suspension and for the same suspension with 0.5 ppb NaOH (pH 11.3) and with 0.5 ppb NaCl added. When temperature increases, the situation becomes quite different (Fig. 9). The sample containing NaOH was changed very little by increasing the temperature to 225F, while the sample containing neither NaOH nor NaCl appeared to be flocculating and the sample containing NaCl was severely flocculated. Prolonged exposure to high temperature further magnifies this effect (Fig. 10). Only a small

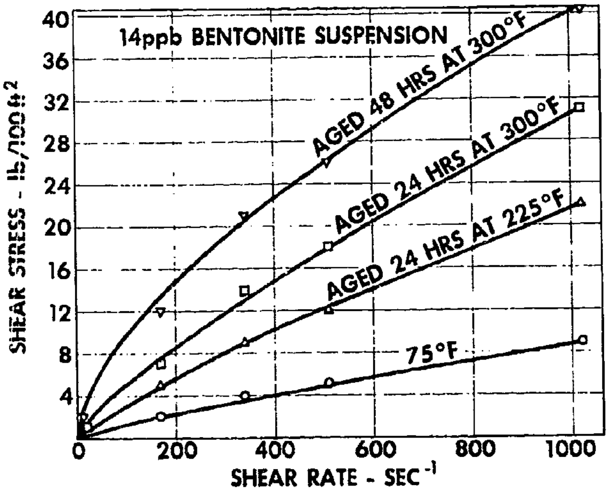

Fig. 6—Effect of Hot Rolling on Shear Rate-Shear Stress Relationship.

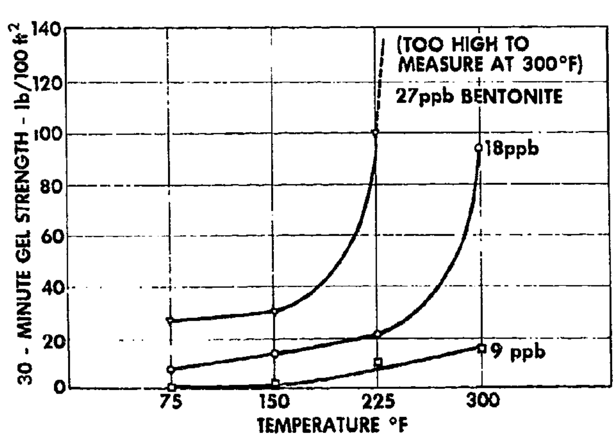

Fig. 7—Effects of Temperature and Bentonite Concentration on 30-Minute Gel Strength.

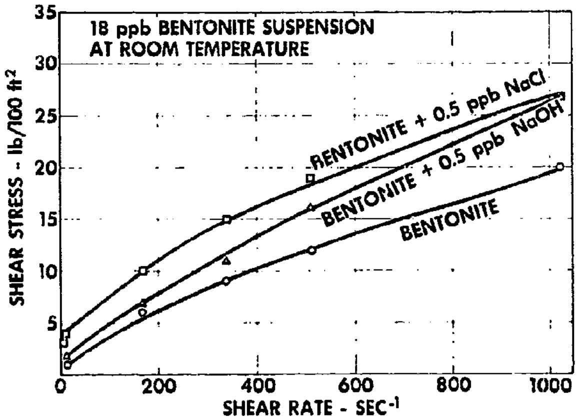

Fig. 8—Effect of Electrolytes on Shear Rate-Shear Stress Relationship.

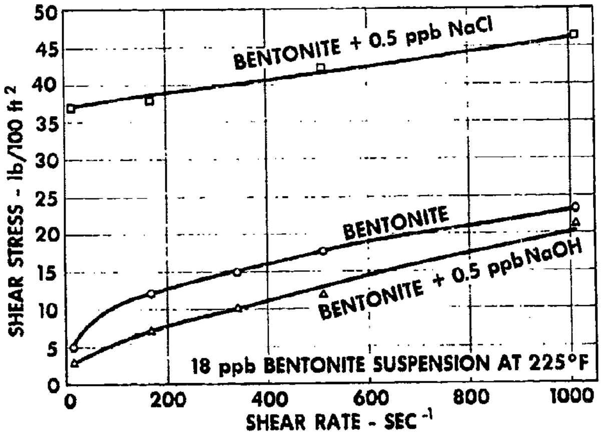

Fig. 9—Effect of Electrolytes on Shear Rate-Shear Stress Relationship.

amount of dispersion and no flocculation was observed at 225F in the sample with NaOH, but evidently a great deal of dispersion occurred in the other two samples with the resultant flocculation at high temperature.

Most common deflocculants require a basic solution to perform satisfactorily. For this reason NaOH is added to a mud with the thinner. Since NaOH appears to prevent flocculation of Wyoming bentonite at elevated temperature, a portion of the total thinning action of NaOH and lignosulfonate combination could be due to the NaOH alone.

Fig. 11 shows shear rate-shear stress curves for Wyoming bentonite, Wyoming bentonite plus 0.5 ppb NaOH and Wyoming bentonite plus 0.5 ppb NaOH, and 1 ppb ferrochrome lignosulfonate. These samples were hot rolled at 225F for 24 hours before testing at 225F. Data show that the NaOH alone has a significant thinning effect on Wyoming bentonite at elevated temperatures, even though the lignosulfonate did increase the amount of thinning.

EFFECT OF LIGNOSULFONATES

Lignosulfonates are thought to adsorb on the edges of clay plates, preventing flocculation by neutralizing the edge charges. The viscous, adsorbed layers of lignosulfonate may also serve to keep the particles apart and prevent flocculation. This deflocculation characteristic makes lignosulfonates most useful as an agent to suppress gelation of clay suspensions.

The pH must be maintained at a level high enough for the lignosulfonate to be activated. This can be seen in Fig. 12 where 10-minute gel strengths at various temperatures are shown for a clay suspension treated with 1 ppb ferrochrome lignosulfonate and different amounts of NaOH. The clay suspension contained sodium bentonite (Aquagel), a medium-yield bentonite (Baroco) and low-yield bentonite (X-Act). Samples were hot rolled 2 hours at 300F before testing.

Increasing the pH from 7.8 to 8.3 caused a marked decrease in gel strengths at all temperatures up to 225F; however, complete flocculation occurred in both samples before reaching 300F. At pH 9.5, the gel strengths were further decreased and the suspension did not completely flocculate at 300F as in the other samples. Although the gel strengths were reduced through treatment with NaOH and lignosulfonate, they did increase with increased temperature. The minimum lignosulfonate concentration required to minimize the gel strengths at each temperature is shown in Fig. 13. This minimum required concentration of lignosulfonate increased from less than 0.25 ppb at 75F to 1 ppb at 300F.

These concentrations are not absolute values for all muds because they will be influenced by the amount and type of solids in the mud; but they indicate relative concentrations required at the various temperatures. When concentrations less than these minimum values were used, very rapid increases in gel strengths were observed. Over-

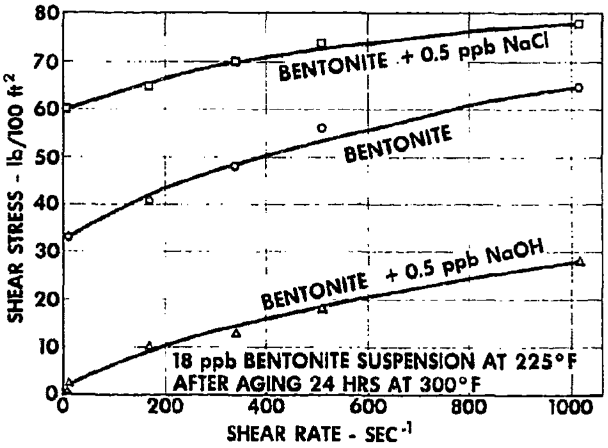

FIG. 10—EFFECT OF ELECTROLYTES ON SHEAR RATE-SHEAR STRESS RELATIONSHIP.

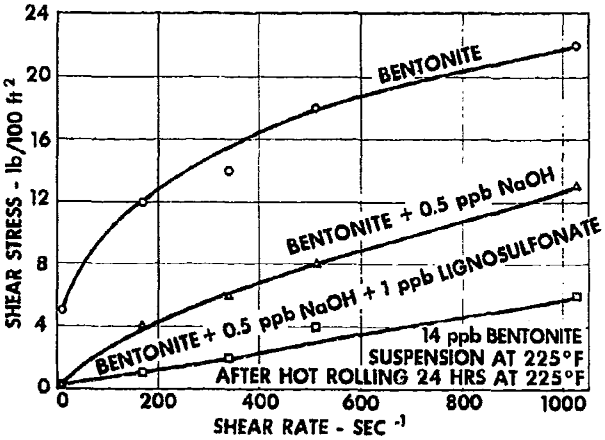

FIG. 11—EFFECTS OF CAUSTIC AND LIGNOSULFONATE ON SHEAR RATE-SHEAR STRESS RELATIONSHIP.

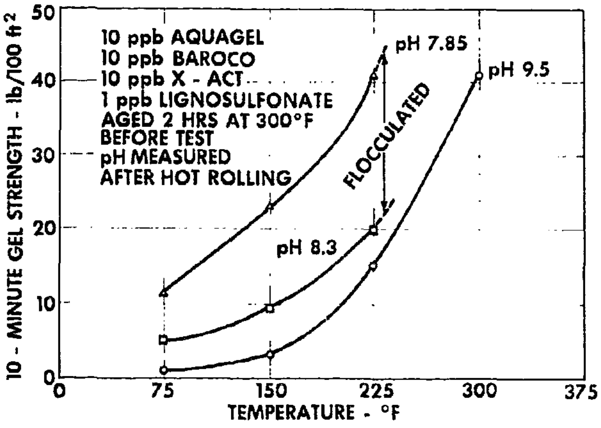

FIG. 12—EFFECTS OF TEMPERATURE AND pH ON GEL STRENGTH OF A LIGNOSULFONATE LABORATORY MUD.

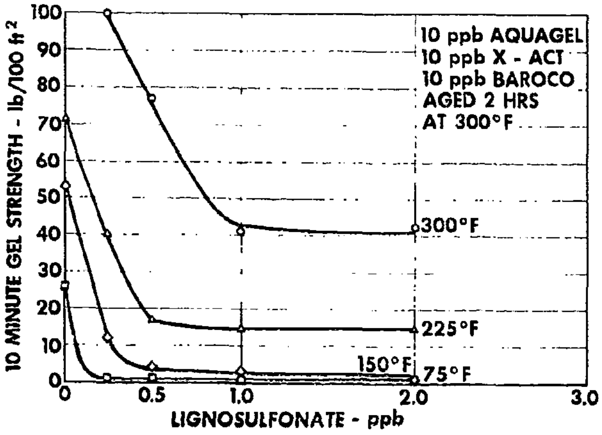

FIG. 13—EFFECTS OF TEMPERATURE AND LIGNOSULFONATE CONCENTRATION ON GEL STRENGTH.

treatment, within the range of concentrations tested, affected the gel strengths only slightly.

When the clay suspensions were fully dispersed and deflocculated, the gel strengths at high temperatures increased as the bentonite content increased and were greatly reduced from the gel strengths of the untreated suspensions (Fig. 14). Any dispersed and partially deflocculated clay suspension should yield a gel strength somewhere between the untreated and the treated lines in the figure. A fully deflocculated suspension should yield minimum values of gel strength for a given concentration of bentonite; as flocculation begins, higher gel strengths should result.

HIGH-TEMPERATURE EFFECTS ON FIELD MUDS

The previous discussion has shown how some of the individual components of a water-base mud are affected by high temperature. This information can be used to make some generalizations about high-temperature effects on actual field muds, but to make quantitative predictions of high-temperature effects, we must know the concentration of each component in the mud. Unfortunately, this information cannot be readily obtained for field muds. However, in the case of clay content, the cation exchange capacity is reasonably descriptive of an effective clay concentration in fresh-water suspensions and can be measured with the Methylene Blue Test described by Jones.[10] The results are expressed as the concentration of Wyoming bentonite required to give the same total cation exchange capacity as the solids in the mud.

The gel strengths of treated field muds are related to the equivalent bentonite concentration (Fig. 15) in much the same way that the gel strengths of the treated bentonite suspensions were related to the bentonite concentrations (Fig. 14). The field muds were all lignosulfonate-treated, fresh-water muds.

When the muds were not well deflocculated the gel strengths were high, but after deflocculation the gel strengths were reduced to near the deflocculated bentonite values. This is also shown in Fig. 15 for two muds. For one mud, the 10-minute gel strength was decreased from 104 to 45 lb/100 sq ft after raising the pH from 7.6 to 9.4. For another mud, addition of 3 ppb ferrochrome lignosulfonate reduced the gel strength from 75 to 26 lb/100 sq ft.

Muds that contained undispersed solids had low gel strengths, but hot rolling at 300F usually dispersed these solids and increased the gel strengths. Exceptions occurred with high electrolyte-content muds, such as seawater muds. In these muds, the clays did not swell and disperse at elevated temperature to the extent they would have in fresh water; consequently, the gel strengths remained low after hot rolling at 300F. It is possible, of course, that temperatures above 300F may have dispersed these clays.

As others have reported,[11,12] drill solids appear to be especially detrimental. At low temperatures a mud can carry large amounts of these solids without serious deterioration of flow properties; at high temperatures, however, these solids disperse, leading to high gel strengths and high viscosities.

Drill solids dispersion exposes new surface which can absorb hydroxyl ions and reduce the pH, thereby reducing the efficiency of the deflocculant. This effect appears quite large the first time a suspension is exposed to high temperature. Browning[9] reported a decrease in pH from 10.4 to 7.3 after aging a clay suspension 16 hours at 325F. In field muds repeatedly exposed to high temperature while being maintained at a pH above 9, the drop in pH with further exposure to high temperature is less pronounced.

As the equivalent percent bentonite in a mud increases, it becomes harder to keep the mud deflocculated, and the possibility of developing extremely high gel strengths at high temperature increases. The danger in using a mud with a high solids content and relying on lignosulfonate treatment to suppress high-temperature gel strength is demonstrated in Fig. 15 with a mud containing 5.45 equivalent percent bentonite. Although this mud had a gel strength that initially was near the treated bentonite line, hot rolling the mud for 2 hours at 300F more than doubled the gel strength at 300F. This large change did not occur in the room temperature measurements, and one might have assumed that the lignosulfonate was still suppressing the high-temperature gel strengths.

Flow properties of about 40 water-base field muds were measured at temperatures up to 300F. These muds covered a wide range of densities and mud types, although the majority were lignosulfonate muds. In an attempt to draw some generalized conclusions on the effects of high temperature on mud flow properties, the properties of these muds were averaged and are shown in Figs. 15 and 16.

Plastic viscosity decreased with temperature at essentially the same rate as the viscosity of water up to 225F; it then began to increase very slowly, remaining almost constant up to 300F. There were some minor differences among the various muds with respect to the temperature at which the rate of decrease in plastic viscosity departed from the normalized viscosity of water, but these were small.

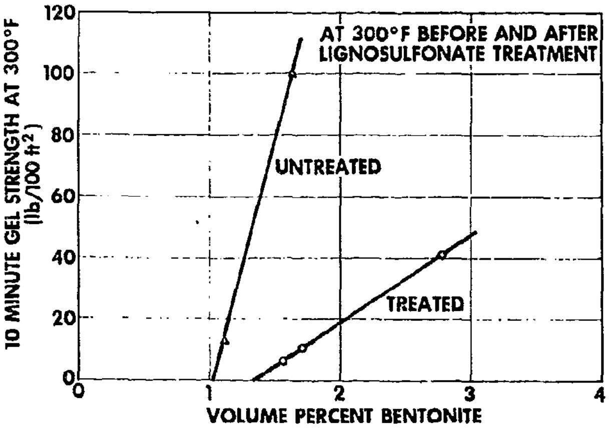

Fig. 14—Effect of Bentonite Concentration on Gel Strength.

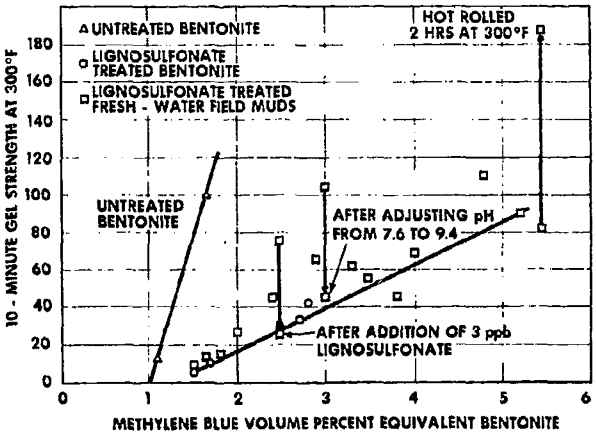

Fig. 15—Effect of Solids on 300F Gel Strengths of Field Muds.

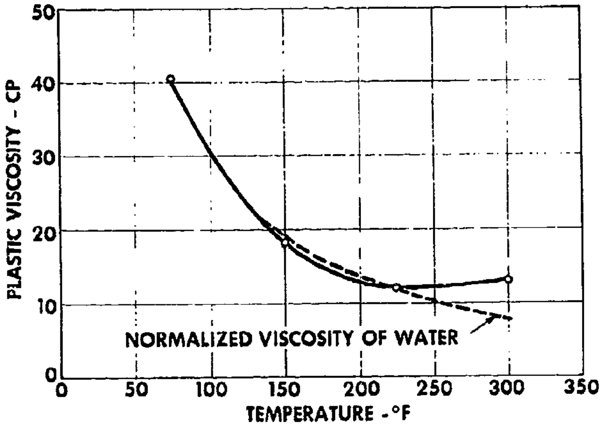

FIG. 16—EFFECT OF TEMPERATURE ON PLASTIC VISCOSITY OF WATER-BASE MUDS.

In the absence of measured plastic viscosities at the temperatures of interest, extrapolated values using the rate of decrease of the viscosity of water with temperature would probably be acceptable up to about 200F.

The average low-shear-rate shear stresses also decreased with temperature at the same rate as water, but only up to 150F; then they leveled out and began to increase slowly. These data are in contrast to what was found with untreated bentonite (for which the shear stresses at low shear rates increased with temperature). This difference is apparently due to deflocculation by the lignosulfonate in the field muds. Consequently, extrapolation of shear stresses, measured at low shear rates and low temperature, to high temperatures is subject to large errors unless the degree of deflocculation is known.

Gel strength was the mud property most affected by elevated temperature and changes in mud composition. On an average the 10-minute gel strength was at minimum between 100 and 150F and then increased sharply with temperature. Some muds, however, showed very little change in gel strength with increasing temperature, and some even decreased slightly. High-temperature gel strengths could not be predicted from low-temperature gel measurements.

CONCLUSIONS

Solids in a mud cause resistance to flow in two ways—through the electrical forces of attraction and repulsion of the particles and through purely mechanical interaction between the particles and liquid. The electrical interaction of solids is largely responsible for the low-shear-rate viscosities, and mechanical interactions largely determine the high-shear-rate viscosities.

It follows that effects of high temperature on mud flow properties are different at low shear rates than at high shear rates and must be considered separately. From this investigation the following conclusions on high-temperature effects on mud flow properties can be made.

1. High temperature causes flocculation of bentonitic clays, resulting in high yield points, high viscosities at low shear rates and high gel strengths.
2. High temperature causes dispersion of bentonitic clays resulting in a permanent thickening of the mud.
3. Proper treatment with NaOH and lignosulfonate reduces the effects of dispersion and flocculation at high temperature. Since the pH of a mud decreases during exposure to high temperature, it must be high enough initially to activate the lignosulfonate for the entire time the mud is left on bottom at high temperature.

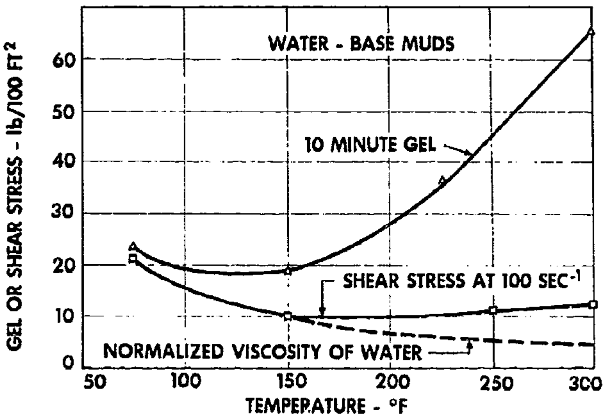

FIG. 17—EFFECT OF TEMPERATURE ON 10-MINUTE GEL STRENGTH AND SHEAR STRESS AT 100 SEC.$^{-1}$

4. The Methylene Blue Test provides a measurement of the clay content of a mud. The test is a useful guide in determining when dangerously high gel strength may develop at high temperature.
5. Only the plastic viscosity, or high-shear-rate viscosity, can be predicted with any degree of confidence at high temperature measurements. It decreases at the same rate as the viscosity of water with an increase in temperature to about 200F, and then it becomes nearly constant.

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Chapter One

Fundamentals of Drilling Fluids

Chapter 1
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Chapter 1

Fundamentals of Drilling Fluids

A major component in drilling operation success is drilling fluid performance. The cost of searching for hydrocarbon reserves becomes more expensive when drilling occurs offshore, in deep water, and in hostile environments. These drilling environments require fluids that excel in performance. Measuring fluid performance requires the evaluation of all key drilling parameters and their associated cost. Simply stated, the effectiveness of a fluid is judged by its influence on overall well cost. This chapter discusses the various fundamentals of drilling fluids and their performance in assuring a safe and expeditious drilling operation at minimum overall cost.

Functions of Fluids

Promote Borehole Stability

A fluid helps establish borehole stability by maintaining a chemical and/or mechanical balance.

Mechanical Stability

The hydrostatic pressure exerted by the drilling fluid is normally designed to exceed the existing formation pressures. The desired result is the control of formation pressures and a mechanically stable borehole. In many cases, these factors must also be considered:

- Behavior of rocks under stress and their related deformation characteristics
- Steeply dipping formations
- High tectonic activity
- Formations with no cohesive (lack of proper grain cementation) strength
- High fluid velocity
- Pipe tripping speeds and corresponding transient pressures
- Hole angle and azimuth

Any of these factors may contribute to borehole instability. In these situations, a protective casing string may be required, or hydrostatic pressure may need to be increased to values greater than the anticipated formation pressure.

Chemical Stability

Chemical interactions between the exposed formations of the borehole and the drilling fluid are a major factor in borehole stability. Borehole formation hydration can be the primary cause of hole instability, or a contributing factor.

Aqueous drilling fluids normally use a combination of:

- A coating mechanism (encapsulation)
- A charge satisfaction mechanism
- A mechanical or chemical method of preventing pore pressure transmission

The present use of low solids/non/dispersed fluids incorporates these principles. They rely on polymers and soluble salts to inhibit swelling and dispersion. Commonly used polymers include:

- Polysaccharide derivatives for filtration control
- Partially hydrolyzed polyacrylamides for encapsulation
- Xanthan gum for viscosity

Isolating the fluid from the formation minimizes the potentially detrimental interaction between the filtrate and the formation. This is accomplished by controlling mud filtrate invasion of the formation. Filtrate invasion may be controlled by the type and quantity of colloidal material and by filtration control materials and special additives like cloud point glycols and products containing complexed aluminum.

Non-aqueous drilling fluids minimize wellbore instability problems by having all-oil filtrates and by the osmotic pressure generated by the dissolved salt.

Remove Drilled Cuttings from Borehole

Drilling fluids transport cuttings from the well bore as drilling progresses. Many factors influence the removal of cuttings from the hole.

The *velocity* at which fluid travels up the annulus is the most important hole cleaning factor. The annular velocity must be greater than the slip velocity of the cuttings for the cuttings to move up the well bore.

The *size, shape*, and *weight* of a cutting determine the *viscosity* necessary to control its settling rate through a moving fluid. Low shear rate viscosity strongly influences the carrying capacity of the fluid and reflects the conditions most like those in the well bore. The drilling fluid must have sufficient carrying capacity to remove cuttings from the hole.

The *density* of the suspending fluid has an associated buoyancy effect on the cuttings. An increase in density increases the capacity of the fluid to carry cuttings.

Hole cleaning is such a complex issue that the best analysis method is to use a simulator, such as the one contained in ADVANTAGE®.

Cool and Lubricate Bit and Drillstring

Considerable heat is generated by rotation of the bit and drillstring. The drilling fluid acts as a conductor to carry this heat away from the bit and to the surface. Current trends toward deeper and hotter holes make this a more important function.

The drilling fluid also provides lubrication for the cutting surfaces of the bit thereby extending their useful life and enhancing bit performance.

Filter cake deposited by the drilling fluid provides lubricity to the drill string, as do various specialty products. Oil and synthetic base fluids are lubricious by nature.

Control Subsurface Pressure

As drilling progresses, oil, water, or gas may be encountered. Sufficient hydrostatic pressure must be exerted by the drilling fluid column to prevent influx of these fluids into the borehole. The amount of hydrostatic pressure depends on the density of the fluid and the height of the fluid column, i.e., well depth. Typical materials used to maintain drilling fluid density include barite (MIL-BAR®), hematite (DENSIMIX®), ilmenite and calcium carbonate (MIL-CARB®). The following formulae can be used to calculate the total hydrostatic pressure at any given depth or fluid density:

$$\text{Hydrostatic Pressure (psi)} = 0.052 \times \text{Depth (ft)} \times \text{Fluid Density } (\text{lb}_m / \text{gal})$$

or

$$\text{Hydrostatic Pressure (psi)} = 0.00695 \times \text{Depth (ft)} \times \text{Fluid Density } (\text{lb}_m / \text{ft}^3)$$

or

$$\text{Hydrostatic Pressure } (\text{kg} / \text{cm}^2) = 0.1 \text{ Depth (m)} \times \text{Fluid Density } (\text{g} / \text{cm}^3)$$

While static pressures are important in controlling an influx of formation fluids, dynamic fluid conditions must also be considered. Circulation of the drilling fluid and movement of the drillstring in and out of the hole create positive and negative pressure differentials. These differentials are directly related to flow properties, circulation rate, and speed of drillpipe movement. These pressures may be calculated using the engineering software contained within ADVANTAGE.

Suspend Cuttings / Weight Material When Circulation Ceases

When circulation is stopped, drilling fluids must suspend the drilled cuttings and weight material. Several factors affect suspension ability.

- Density of the drilling fluid
- Viscosity of the drilling fluid
- Gelation, or thixotropic properties of the drilling fluid
- Size, shape and density of the cuttings and weight material

Circulation of the suspended material continues when drilling resumes. The drilling fluid should also exhibit properties which promote efficient removal of solids by surface equipment.

Support Partial Weight of Drillstring or Casing

The buoyancy effect of drilling fluids becomes increasingly important as drilling progresses to greater depths. Surface rig equipment would be overtaxed if it had to support the entire weight of the drill string and casing in deeper holes. Since the drilling fluid will support a weight equal to the weight of the volume of fluid displaced, a greater buoyancy effect occurs as drilling fluid density increases.

Minimize Adverse Effects on Productive Formations

It is extremely important to evaluate how drilling fluids will react when potentially productive formations are penetrated. Whenever permeable formations are drilled, a filter cake is deposited on the wall of the borehole. The properties of this cake can be altered to minimize fluid invasion into permeable zones. Also, the chemical characteristics of the filtrate of the drilling fluid can be controlled to reduce formation damage. Fluid–fluid interactions can be as important as fluid-formation interactions. In many cases, specially prepared drill-in fluids are used to drill through particularly sensitive horizons.

Transmit Hydraulic HP to Clean Bit and Bottom of Borehole

Once the bit has created a drill cutting, this cutting must be removed from under the bit. If the cutting remains, it will be "re-drilled" into smaller particles which adversely affect penetration rate of the bit and fluid properties.

The drilling fluid serves as the medium to remove these drilled cuttings. One measure of cuttings removal force is *hydraulic horsepower* available at the bit. These are the factors that affect bit hydraulic horsepower:

- Fluid density
- Fluid viscosity
- Jet nozzle size
- Flow rate

Bit hydraulic horsepower can be improved by decreasing jet nozzle size or increasing the flow rate. The two most critical factors are flow rate and nozzle size. The total nozzle cross sectional area is a factor in increasing flow rate and hydraulic horsepower.

Release Undesirable Cuttings at the Surface

When drilled cuttings reach the surface, as many of the drilled solids as possible should be removed to prevent their recirculation. Mechanical equipment such as shale shakers, desanders, centrifuges, and desilters remove large amounts of cuttings from the drilling fluid. Flow properties of the fluid, however, influence the efficiency of the removal equipment. Settling pits also function well in removing undesirable cuttings, especially when fluid viscosity and gel strengths are low.

Ensure Maximum Information from Well

Obtaining maximum information on the formation being penetrated is imperative. A fluid which promotes cutting integrity is highly desirable for evaluation purposes. The use of electronic devices incorporated within the drill string has made logging and drilling simultaneous activities. Consequently, optimum drilling fluid properties should be maintained at all times during drilling, logging, and completion phases.

Limit Corrosion of Drillstring, Casing, and Tubular Goods

Corrosion in drilling fluids is usually the result of contamination by carbon dioxide, hydrogen sulfide, oxygen or, in the case of static fluids, bacterial action. Low pH, salt-contaminated, and non-dispersed drilling fluids are inherently more corrosive than organically treated freshwater systems. Oil or synthetic-based fluids are considered non-corrosive. A proper drilling fluid corrosion control program should minimize contamination and render the contaminating source non-corrosive.

Minimize Environmental Impact

Drilling creates significant volumes of used fluid, drill cuttings and associated waste. Increased environmental awareness has resulted in legislation that restricts the use, handling and disposal of the by-products generated during drilling and after the well is finished. Careful attention to the composition of the fluid and the handling of the residual materials reduces the potential environmental impact of the drilling operation.

Physical and Chemical Properties of Fluids

The physical and chemical properties of a drilling fluid play an important role in the success of a drilling operation.

The properties of drilling fluid are perhaps the only variables of the entire drilling process that can be altered rapidly for improved drilling efficiency. These properties usually receive the greatest attention.

API Recommended Practices

The American Petroleum Institute (API) has set forth numerous recommended practices designed to standardize various procedures associated with the petroleum industry. The practices are subject to revision from time-to-time to keep pace with current accepted technology. One such standard is API Bulletin RP 13B-1, "*Recommended Practice Standard Procedure for Field Testing Water-Based Drilling Fluids*". This Bulletin described the following drilling fluid measurements as necessary to describe the primary characteristics of a drilling fluid:

- Density – for the control of formation pressures
- Viscosity and Gel Strength – measurements that relate to a mud's flow properties
- Filtration – a measurement of the mud's loss of liquid phase to exposed, permeable formations
- Sand – the concentration of sand (solid particles < 74µ) being carried in the mud
- Methylene Blue Capacity – an indication of the amount of reactive clays present in the mud
- pH – a measurement of the alkaline / acid relationship in the mud
- Chemical Analysis – qualitative and quantitative measurement of the reactive chemical components of the mud

Chemical properties, such as chloride content, total hardness, etc., are important. They are discussed in Chapter 4 of this manual, "*Contamination of Water-Base Fluids*".

Density

The density of any fluid is directly related to the amount and average specific gravity of the solids in the system. The control of density is critical since the hydrostatic pressure exerted by the column of fluid is required to contain formation pressures and to aid in keeping the borehole open. Fluid density in English units is commonly expressed in lb_m/gal (lb_m/ft^3 in some locations) and in specific gravity or g/cm_3 in countries utilizing the metric system.

The density of any fluid should be dictated by formation pressures. The density must be sufficient to promote wellbore stability. The pressure exerted by the fluid column should ideally be only slightly higher than that of the formation to insure maximum penetration rate with minimal danger from formation fluids entering the well bore.

The common method for checking the density of any drilling fluid is the mud balance. The mud balance consists of a supporting base, a cup, a lid, and a graduated beam carrying a sliding weight. A knife edge on the arm rests on the supporting base. It has become common in many locations to use pressurized mud balances as these are considered to be more accurate.

Rheology, Viscosity and Gel Strength Relationships

The rheolgical properties, viscosity and gel strength of drilling fluids describe the ability of the fluid to transport cuttings while drilling and suspend them when circulation is interrupted. Frequently, the term “viscosity” is confused with the term “rheology”. A more detailed analysis of the term “rheology” follows.

Rheology

Rheology is defined as physics of the flow and the deformation of matter. Rheology and the associated annular hydraulics (Chapter 9) relate directly to borehole stability and how effectively the borehole is cleaned. An understanding of rheology is essential if wellsite engineering of the drilling fluid is to cost effectively complement the objective of drilling the well. Rheology and hydraulics of drilling fluids are not exact sciences, but are based upon mathematical models that closely describe the rheology and hydraulics of the fluid and do not conform exactly to any of the models. Consequently, different methods are used to calculate rheology and hydraulic parameters.

Fluid Deformation

Rheology is the study of the deformation of all forms of matter. The deformation of a fluid can simply be described by two parallel plates separated by some distance as shown in Figure 1-1.

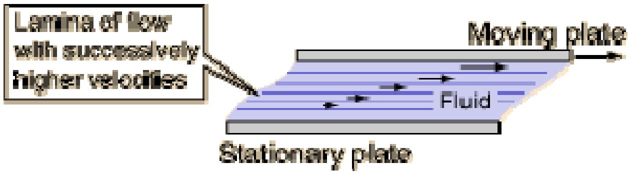

Figure 1-1 Deformation of a Fluid by Simple Shear

Shear Stress

An applied force (F), acting over an area (A), causes the layers to slide past one another. However, there is a resistance, or frictional drag, force that opposes the movement of these plates. This resistance or drag force is called *shear stress* (τ). In equation form,

$$\tau = \frac{F}{A}$$

with shear stress having typical units of $lb_f/100\ ft^2$.

Additionally, the fluid layers move past each other easier than between a pipe wall and fluid layer. Therefore, we can consider a very thin layer of fluid next to the pipe wall as stationary.

Shear Rate

The difference in the velocities between two layers of fluid divided by the distance between the two layers is called the shear rate (γ). In equation form,

$$\gamma = \frac{\text{velocity difference}}{\text{distance}}$$

With typical units of or, reciprocal seconds.

$$\frac{\text{ft/sec}}{\text{ft}} = \frac{1}{\text{sec}} = \text{sec}^{-1}$$

Newtonian and Non-Newtonian Fluids

The relationship between shear stress (τ) and shear rate (γ) defines the flow behavior of a fluid. for some fluids, the relationship is linear. If the shear rate is doubled, then the shear stress will also double. Such fluids are called Newtonian fluids. Examples of Newtonian fluids include water, alcohols, and light oils. Very few drilling fluids fall into the Newtonian category.

Fluids which have flow characteristics such that the shear stress does not increase in direct proportion to the shear rate are called non-Newtonian fluids. Most drilling fluids are of this type.

Viscosity

For a Newtonian fluid, the relationship between viscosity, shear stress and shear rate is defined as the viscosity (μ) of the fluid where,

$$\mu = \frac{\tau}{\gamma}$$

where,

τ = shear stress

μ = viscosity

γ = shear rate.

As previously described, the relationship between shear stress and shear rate is directly proportional for a Newtonian fluid. The viscosity remains constant and is the only parameter needed to characterize the flow properties. The metric unit typically used for viscosity is the *poise*, defined as the force in *dynes* per square centimeter required to produce a difference in velocity of one centimeter per second between two layers one centimeter apart. A *centipoise* is one hundredth ($1/_{100}$) of a poise.

For non-Newtonian fluids, the relationship between shear stress and shear rate is defined as the effective viscosity. However, the effective viscosity of a non-Newtonian fluid is not constant. For most drilling fluids, the effective viscosity will be relatively high at low-shear rates, and relatively low at high-shear rates. In other words, the effective viscosity decreases as the shear rate increases. When a fluid behaves in this manner, it is said to be *shear thinning*. Shear thinning is a very desirable characteristic for drilling fluids. The effective viscosity of the fluid will be relatively lower at the higher shear rates in areas such as the drill pipe and bit nozzles. Likewise, the effective viscosity of the fluid will be relatively higher at the lower shear rates in the annulus where the higher effective viscosity of the fluid aids in hole cleaning.

The relationship between shear stress and shear rate for non-Newtonian fluids is developed later in the sub-section, *Mathematical Fluid Models*.

Flow Regimes

In 1883, Osborne Reynolds conducted experiments with various liquids flowing through glass tubes. He introduced a dye into the flowing stream at various points. He found that when the flow rate was relatively low, the dye he introduced formed a smooth, thin, straight streak down the glass. There was essentially no mixing of the dye and liquid. This type of flow in which all the fluid motion is in the direction of flow is called *laminar flow*.

Reynolds also found with relatively high flow rates, no matter where he introduced the dye it rapidly dispersed throughout the pipe. A rapid, chaotic motion in all directions in the fluid caused the crosswise mixing of the dye. This type of flow is called *turbulent flow*.

Reynolds showed further that under some circumstances, the flow can alternate back and forth between being laminar and turbulent. When that happens, it is called *transitional flow*.

Therefore, we can describe a fluid's flow as being either laminar, turbulent, or transitional. Additionally, another term has been used to describe a fluid's flow at extremely low flow rates – *plug flow*.

The particular flow regime of a drilling fluid during drilling operations can have a dramatic effect on parameters such as pressure losses, hole cleaning, and hole stability.

Plug Flow

In plug flow, the fluid moves essentially as a single, undisturbed solid body. Movement of the fluid occurs due to the slippage of a very thin layer of fluid along the pipe wall or conductor surface. Plug flow generally occurs only at extremely low flow rates.

Laminar Flow

The laminar flow of a Newtonian liquid in a circular pipe is illustrated in Figure 1-2. Laminar flow of a Newtonian fluid can be visualized as concentric cylindrical shells which slide past one another like sections of a telescope. The velocity of the shell at the pipe wall is zero, and the velocity of the shell at the center of the pipe is the greatest.

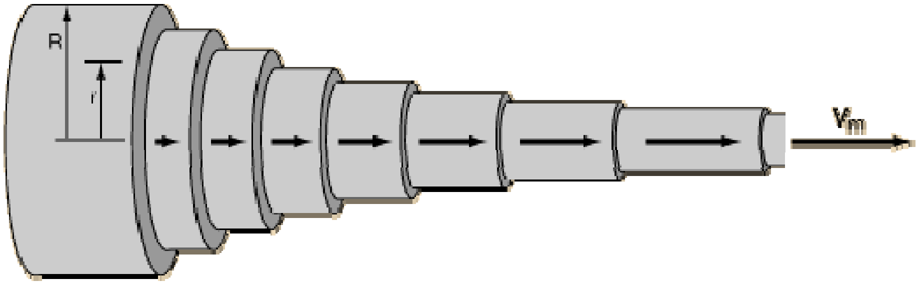

Figure 1-2 Three Dimension View of Laminar Flow in a Pipe for a Newtonian Fluid

A two-dimensional velocity profile is illustrated in Figure 1-3. The shear rate, previously defined as the velocity difference between two layers of fluid divided by the difference between the two layers, is simply the slope of a line at any point along the velocity profile. The shear rate is greatest at the wall and zero at the center of the pipe. Since the shear stress and shear rate for a Newtonian fluid are directly proportional, the shear stress is also greatest at the wall and zero at the center of the pipe.

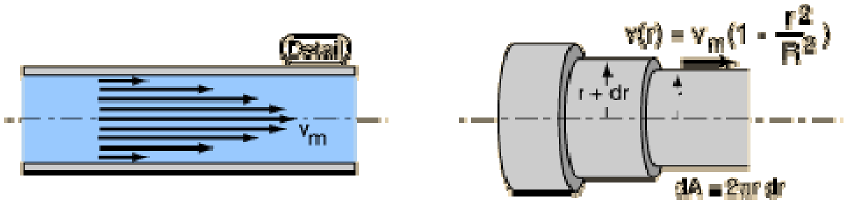

Figure 1-3 Two/Three Dimensional Velocity Profile of Laminar Flow in a Pipe for a Newtonian Fluid

The laminar flow of a non-Newtonian fluid is very similar to that of a Newtonian fluid with the exception that some portion of the cylindrical shells in the center of a pipe may not slide past one another.

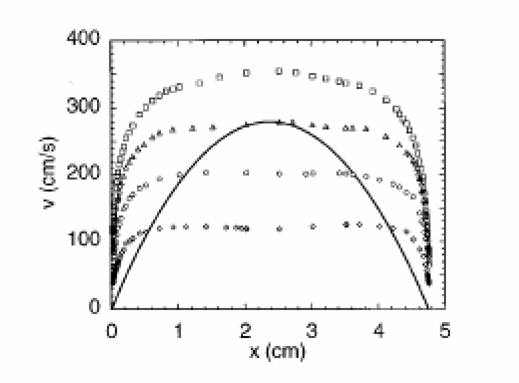

Figure 1-4 **Two Dimensional Velocity Profiles of Laminar Flow for a Non-Newtonian Fluid**

The two dimensional velocity profile of a non-Newtonian fluid in laminar flow depends upon the relationship between the shear stress and shear rate. Several examples of the velocity profile are shown in Figure 1-4.

Turbulent Flow

Turbulent flow occurs when a fluid is subject to random, chaotic shearing motions that result in local fluctuations of velocity and direction, while maintaining a mean velocity parallel to the direction of flow. Only near the walls does a thin layer of orderly shear exist. Thus the velocity profile is very steep near the walls, but essentially flat elsewhere as shown in Figure 1-5.

Transitional Flow

Transitional flow occurs when the flow of a fluid is neither completely laminar nor completely turbulent. In other words, there is no abrupt transition from one flow regime to another.

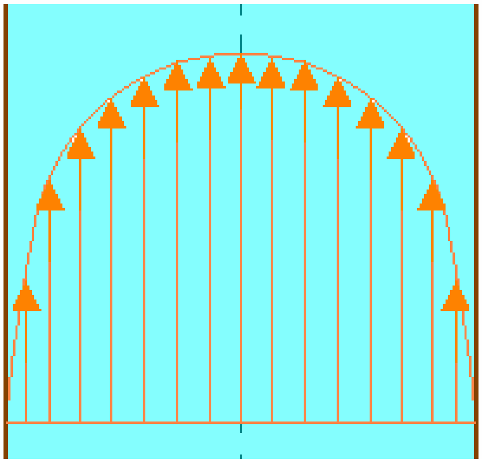

Figure 1-5 **Two-Dimensional Velocity Profile of Turbulent Flow in a Pipe for a Newtonian Fluid**

Determination of Flow Regime

The experiments conducted by Reynolds, besides naming the behavior of fluid flow, made the most celebrated application of dimensional analysis in the history of fluid mechanics by introducing the Reynolds Number (*Re*).

Reynolds number takes into consideration the basic factors of pipe flow – pipe diameter, average fluid velocity, fluid density, and fluid viscosity. Reynolds number is defined as

$$\mathrm{Re} = \frac{(V)(D)(\rho)}{\mu}$$

where,

V = average fluid velocity
D = pipe diameter
ρ = fluid density
μ= fluid viscosity

Reynolds showed that for smooth, circular pipes, for all Newtonian fluids, and for all pipe, the transition from laminar to turbulent flow occurs when the Reynolds number has a value of approximately 2000. However, turbulent flow *throughout* the fluid occurs when the Reynolds number is more than 4000.

Therefore, for Newtonian fluids, laminar flow is defined as a Reynolds number of 2000 or less. Turbulent flow is defined as a Reynolds number of 4000 or greater. Transitional flow is defined when the Reynolds number is between 2000 and 4000.

As previously shown, the viscosity of non-Newtonian fluids depends upon the relationship between shear stress and shear rate. Likewise, the value of the Reynolds number at which the transition from laminar to turbulent flow occurs depends upon the shear stress/shear rate relationship.

The relationship between shear stress and shear rate for non-Newtonian fluids is developed in the subsection, *Mathematical Fluid Models* .

Continuity of Flow

Many hydraulic calculations in this manual require the use of the fluid velocity. It is important to understand the difference between flow rate and velocity. Consider the flow of a liquid through a pipe at a constant flow rate, as illustrated in Figure 1-6

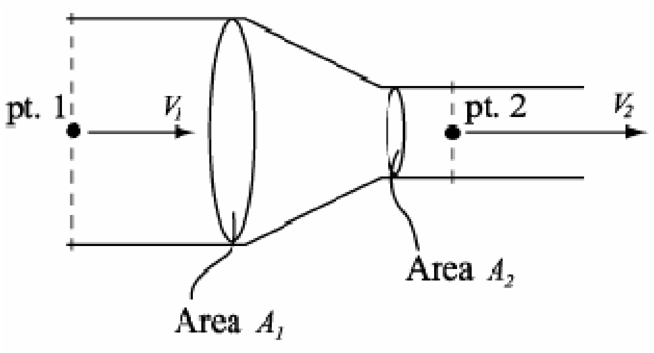

Figure 1-6 Fluid Velocity is inversely Proportional to the Cross-Sectional Area of the Fluid Conductor

An algebraic solution to the above diagram is described as follows:

$$Q_{flow} = V_1A_1 = V_2A_2$$

$$\text{If } A_2 = ½\, A_1$$

$$V_1\,(2A_2) = V_2A_2$$

$$V_1 = ½\, V_2$$

Because drilling fluids are very nearly incompressible, the volumetric flow rate of fluid entering the pipe must equal the volumetric flow rate leaving the pipe. This is the principle of *continuity of flow*. The important result of this principle is that, at a constant flow rate, the fluid velocity is inversely proportional to the area through which it flows. In other words, if the area decreases, the fluid velocity must increase for a constant flow rate.

Mathematical Fluid Models

A mathematical fluid model describes the flow behavior of a fluid by expressing a mathematical relationship between shear rate and shear stress. As described in the viscosity section, the shear stress/shear rate relationship is a constant for Newtonian fluids.

For non-Newtonian fluids, however, the relationship between shear stress and shear rate is much more complex. A generalized relationship for all non-Newtonian fluids has not been found. Instead, various mathematical models have been proposed. These mathematical models do not describe the behavior of non-Newtonian fluids exactly, but are merely close approximations.

Discussed below is a Newtonian Fluid Model which can be considered exact for Newtonian fluids, and two non-Newtonian fluid models – the Bingham Plastic Model and the Power Law Model. Additional models described are the Casson Model, the Robertson-Stiff Model, and the Herschel-Bulkley Model.

Newtonian Fluid Model

The Newtonian Fluid Model is the basis from which other fluid models are developed. The flow behavior of Newtonian fluids has been discussed and it can be seen from this equation that the shear stress-shear rate relationship is given by:

$$\tau = (\mu)(\gamma)$$

where,

τ = shear stress

μ = viscosity

γ = shear rate

At a constant temperature, the shear stress and shear rate are directly proportional. The proportionality constant is the viscosity (μ).

Figure 1-7 illustrates the flow curve of a Newtonian fluid. Note that the flow curve is a straight line which passes through the origin (0, 0) and the slope of the line is the viscosity (μ).

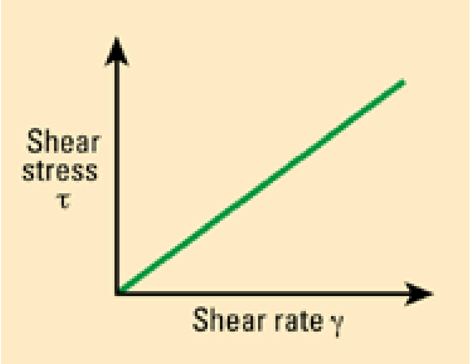

Figure 1-7 Flow Curve for a Newtonian Fluid

Bingham Plastic Model

In the early 1900s, E.C. Bingham first recognized that some fluids exhibited a plastic behavior, distinguished from Newtonian fluids, in that they require a yield stress to initiate flow. No bulk movement of the fluid occurs until the applied force exceeds the yield stress. The yield stress is commonly referred to as the *Yield Point*. The shear stress / shear rate relationship for the Bingham Plastic Model is given by:

$$\tau = \tau_o + (\mu_\infty)(\gamma)$$

where,

τ = shear stress

τ_o = yield point

μ_∞ = Plastic viscosity

γ = shear rate.

The flow curve for a Bingham Plastic fluid is illustrated in Figure 1-8. The effective viscosity, defined as the shear stress divided by the shear rate, varies with shear rate in the Bingham Plastic Model. The effective viscosity is visually represented by the slope of a line from the origin to the shear stress at some particular shear rate. The slopes of the dashed lines represent effective viscosity at various shear rates. As can be seen, the effective viscosity decreases with increased shear rate. As discussed in the Viscosity section, this is referred to as *shear thinning*.

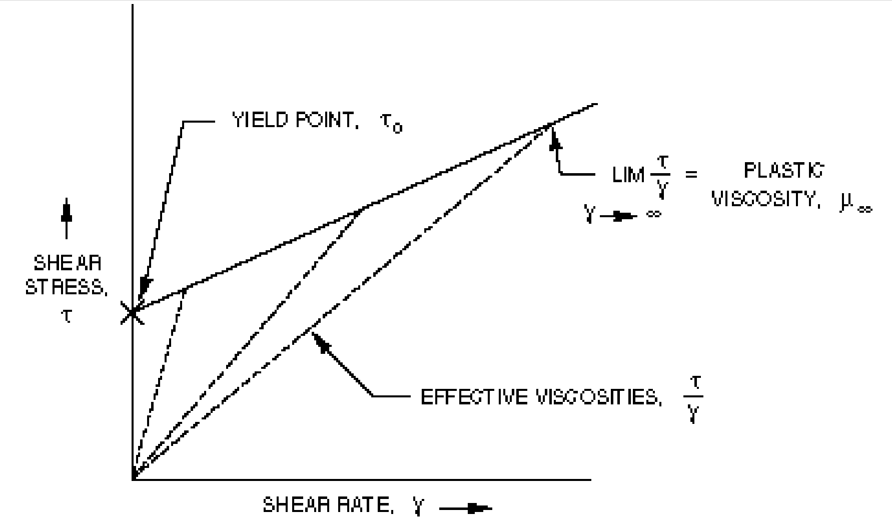

Figure 1-8 Flow Curve for a Bingham Plastic Fluid

As shear rates approach infinity, the effective viscosity reaches a limit called the *Plastic Viscosity*. The plastic viscosity of a Bingham Plastic fluid represents the lowest possible value that the effective viscosity can have at an infinitely high shear rate, or simply the slope of the Bingham Plastic line.

The Bingham Plastic Model and the terms plastic viscosity (PV) and yield point (YP) are used extensively in the drilling fluids industry. Plastic viscosity is used as an indicator of the size, shape, distribution and quantity of solids, and the viscosity of the liquid phase. The yield point is a measure of electrical attractive forces in the drilling fluid under flowing conditions. The PV and YP are two parameters of a drilling fluid that many in the industry still consider to be vitally important in the overall drilling operation. The YP is now considered an outdated concept that has no real meaning or application in drilling operations. The following rheological models better describe the behavior of drilling fluids. This can clearly be seen when the viscometer readings are plotted on a graph and the resultant line is a curve and not a straight line. The Bingham model uses a straight line relationship.

Determination of PV and YP

The commonly used V-G (viscosity-gel) meter, or direct indicator viscometer, was specifically designed to facilitate the use of the Bingham Plastic Model in conjunction with drilling fluids in the field. The instrument has a torsion spring-loaded bob which gives a dial reading proportional to torque and analogous to the shear stress. The speed of rotation (rpm) is analogous to the shear rate. When the V-G meter (with the proper rotor, bob, and spring) is used, the dial reading is determined as:

$$\theta = YP + PV\left(\frac{\omega}{300}\right)$$

where,

θ = dial reading

YP = yield point

PV = plastic viscosity

$\acute{\omega}$ = rotation speed (rpm)

Figure 1-9 Fann Model 35A 6 Speed V-G Meter

As defined in the Fluids Testing Procedures Manual, the determination of PV and YP are obtained from the dial readings at 600 rpm and 300 rpm. Substitution of the appropriate data into the equation shows how these terms are derived.

$$\theta_{600} = \text{YP} + \text{PV}\left(\frac{600}{300}\right) = \text{YP} + 2\text{PV}$$

$$\theta_{300} = \text{YP} + \text{PV}\left(\frac{300}{300}\right) = \text{YP} + \text{PV}$$

By subtracting θ_{300} from θ_{600}, we obtain,

$$(\theta_{600} - \theta_{300}) = (\text{YP} + 2\text{PV}) - (\text{YP} + \text{PV}) = (\text{YP} - \text{YP}) + (2\text{PV} - \text{PV}) = 0 + \text{PV}$$

or,

$$\text{PV} = (\theta_{600} - \theta_{300})$$

By re-arranging the earlier equation for θ_{300}, we have,

$$\text{YP} = (\theta_{300} - \text{PV})$$

where,

θ_{600} = 600 rpm dial reading

θ_{300} = 300 rpm dial reading

Effective viscosity has been previously defined as the shear stress divided by the shear rate or the slope of the line passing through the origin to the shear stress at some particular shear rate. From the equations above, we see that PV can represent the effective viscosity if YP = 0, written as,

$$\theta_{600} = 0 + 2(\mu_{\infty})$$

The effective viscosity at a shear rate of 600 rpm on the V-G meter is distinguished from the effective viscosity at other shear stress/shear rate data values by the term *apparent viscosity*. Therefore, apparent viscosity is defined at a 600 rpm shear rate by,

$$\mu_{\infty} = \frac{\theta_{600}}{2}$$

Although plastic viscosity (PV) and yield point (YP) are two of the most recognized properties of drilling fluids, these terms are simply constants in the Bingham Plastic Mathematical Model. Very few drilling fluids follow this model, but the empirical significance of PV and YP is firmly entrenched in drilling technology. In fact, drilling fluid systems such as the NEW-DRILL® system and many others deviate significantly from the Bingham Plastic Model and the terms PV and YP must be interpreted with caution.

Power Law Model

Most drilling fluids exhibit behavior that falls between the behaviors described by the Newtonian Model and the Bingham Plastic Model. This behavior is classified as *pseudo plastic*. The relationship between shear stress and shear rate for *pseudo plastic* fluids is defined by the power law mathematical model,

$$\tau = K(\gamma^{n})$$

where,

τ = shear stress

K = consistency factor

γ = shear rate

n = flow behavior index

Figure 1-10 illustrates the flow curve for a *pseudo plastic* fluid.

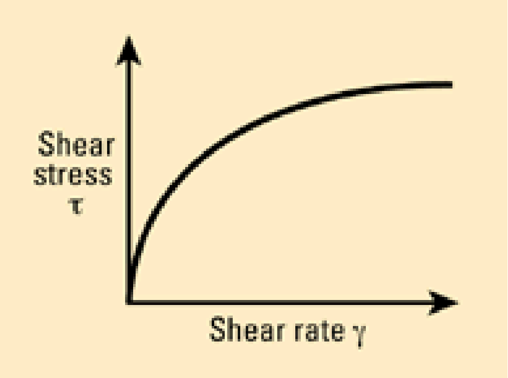

Figure 1-10 Flow Curve for a Power Law Fluid

The two terms, K and n, are constants in the Power Law Model. Generally, K is called the *consistency factor* and describes the thickness of the fluid and is thus somewhat analogous to effective viscosity. If the drilling fluid becomes more viscous, then the constant K must increase to adequately describe the shear stress/shear rate relationship.

Additionally, n is called the *flow behavior index* and indicates the degree of non-Newtonian behavior. A special fluid exists when $n = 1$, when the Power Law Model is identical to the Newtonian Model. If n is greater than 1, another type of fluid exists classified as *dilatant*, where the effective viscosity increases as shear rate increases. For drilling fluids, the pseudo plastic behavior is applicable and is characterized when n is between zero and one. Pseudo plastic fluids exhibit shear thinning, where the effective viscosity decreases as the shear rate increases just like the Bingham Plastic Model. Figure 1-11 shows the flow curves for these values of n.

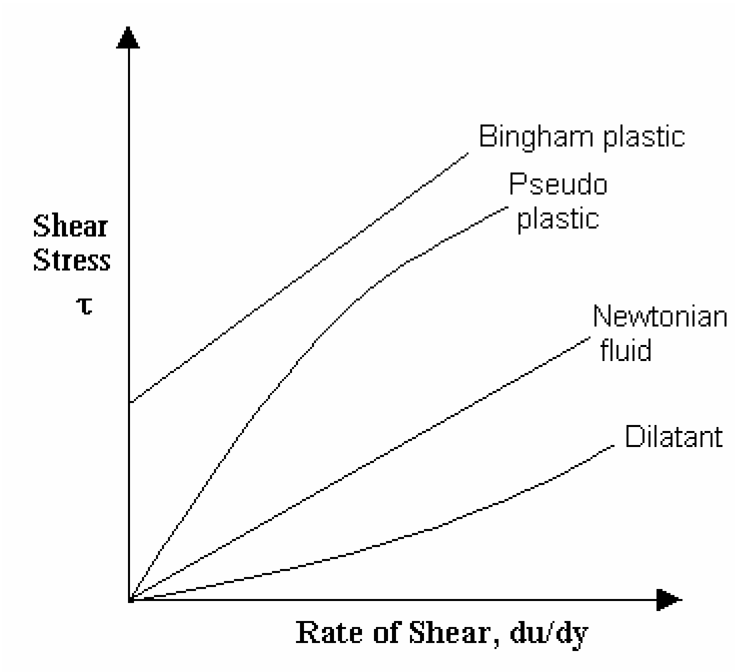

Figure 1-11 Flow Behavior for Power Law Fluids

Similar to the Bingham Plastic Model, the Power Law Model does not describe the behavior of drilling fluids exactly. However, the Power Law constants *n* and *K* are used in hydraulic calculations (Chapter 9) that provide a reasonable degree of accuracy.

Figure 1–12 compares the flow curve of a typical drilling fluid to the flow curves of Newtonian, Bingham Plastic, and Power Law Models.

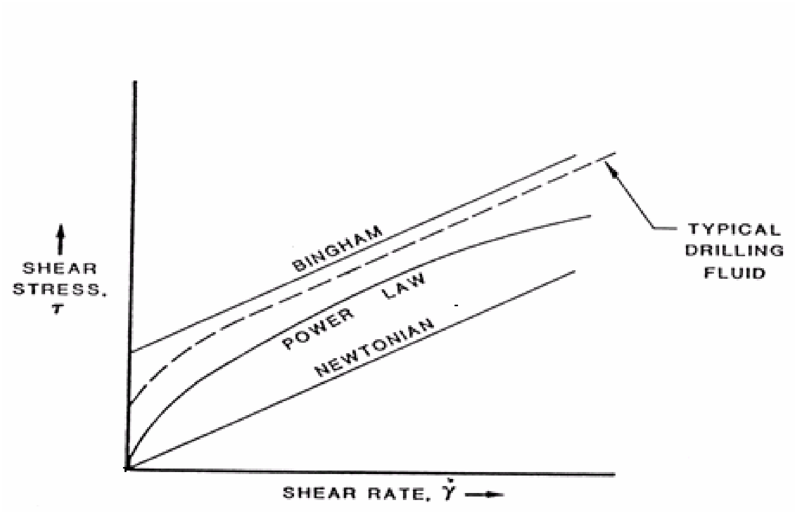

Figure 1-12 Drilling Fluid vs. Newtonian, Bingham, and Power Law Fluids

A typical drilling fluid exhibits a yield stress and is shear thinning. At high rates of shear, all models represent a typical drilling fluid reasonably well. Differences between the models are most pronounced at low rates of shear, typically the shear rate range most critical for hole cleaning and the suspension of weight material.

The Bingham Plastic Model includes a simple yield stress, but does not accurately describe the fluid behavior at low shear rates. The Power Law Model more accurately describes the behavior at low shear rates, but does not include a yield stress and therefore can give poor results at extremely low shear rates. A typical drilling fluid actually exhibits behavior between the Bingham Plastic Model and the Power Law Model. This sort of behavior approximates the Herschel Bulkley model which is described below.

Determination of n and K

The Power Law constants *n* and *K* can be determined from any two sets of shear stress-shear rate data. Baker Hughes Drilling Fluids has chosen to follow API Bulletin 13D in developing *n* and *K* values from 300 rpm and three rpm V-G meter readings (initial gel shear rate is approximately equal to three rpm) for the low shear rate region, and 600 rpm and 300 rpm readings for the high shear rate range. The low shear rate region corresponds roughly to the shear rate existing in the annulus, while the high shear rate region corresponds to the shear rate existing in the drill pipe. This may be written in logarithmic form as,

$$\log\tau = \log K + n(\log\gamma)$$

A plot of shear stress versus shear rate on log-log paper is linear for a *pseudo plastic* fluid. As shown in Figure 1–13, the slope of the curve is equal to *n*, and the intercept on the shear stress axis at $\gamma = 1$ is equal to *K* (since log 1 = 0).

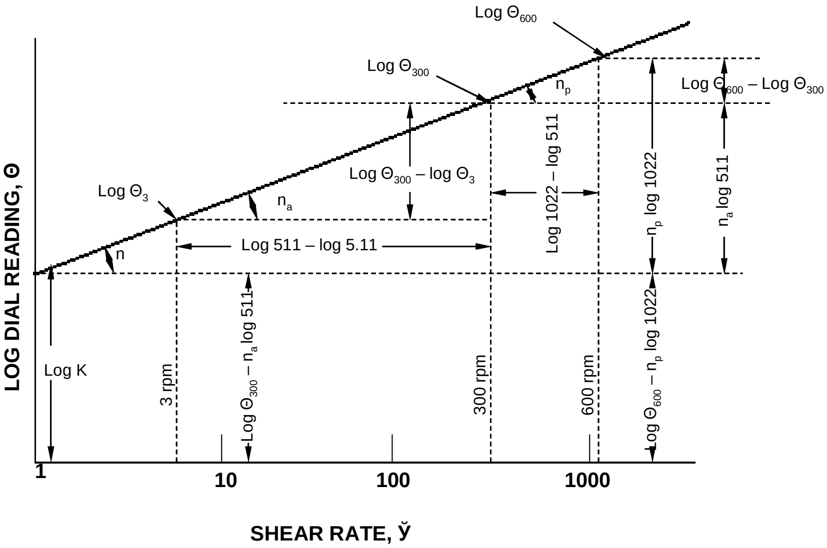

Figure 1-13 Determination of *n* and *K*

Table 1-1 shows the corresponding shear rate in reciprocal seconds to the V-G meter speed in rpm, with standard Rotor-Bob spring combination (R_1-B_1).

Table 1-1 V-G Meter Speed and Corresponding Shear Rate

V-G Motor Speed (rpm)	Shear Rate (γ) (Sec^1)
3	5.11
6	10.2
100	170
200	341
300	511
600	1022

We define n_a and K_a as the Power Law constants for the low shear rate range and n_p and K_p as the constants for the high shear rate range. From Figure 1–13, we find the slope (n_a) of the line between the dial readings at 300 rpm and 3 rpm. Since the slope of a line is equal to the "rise over the run" then,

$$n_a = \frac{(\log\theta_{300} - \log\theta_3)}{\log 511 - \log 5.11}$$

$$n_a = 0.5\log\frac{\theta_{300}}{\theta_3}$$

K_a may be obtained from Figure 1–12 by this equation.

$$\log K_a = (\log\theta_{300} - n_a \log 511)$$

$$K_a = \frac{\theta_{300}}{511^{n_a}}$$

In a like manner, n_p and K_p are obtained as follows:

$$n_p = \frac{\log\theta_{600} - \log\theta_{300}}{\log 1022 - \log 511}$$

$$n_p = 3.32\log\left(\frac{\theta_{600}}{\theta_{300}}\right)$$

$$\log K_p = (\log\theta_{600} - n_p \log 1022)$$

$$K_p = \frac{\theta_{600}}{1022^{n_p}}$$

Other Models

Three other mathematical models have been developed which, at low shear rates, exhibit behavior intermediate between that of the Bingham Plastic and Power Law Models. These models are, in effect, hybrid models of the Bingham Plastic and Power Law Models. These are the Casson Model, the Robertson-Stiff Model, and the Herschel-Bulkley Model. These mathematical models are represented by the equations where,

τ = shear stress

τ_o = yield stress

μ_∞ = plastic viscosity

γ = shear rate

K = consistency factor

γ_o = shear rate intercept

n = flow behavior index

Casson

$$\tau = [\tau_o^{.5} + (\mu_\infty \gamma)^{.5}]^2$$

The Casson Model is a two-parameter model that is widely used in some industries but rarely applied to drilling fluids. The point at which the Casson curve intercepts the shear stress axis varies with the ratio of the yield point to the plastic viscosity.

Robertson-Stiff

$$\tau = K(\gamma_o + \gamma)^n$$

The Robertson-Stiff Model includes the gel strength as a parameter. The model is used to a limited extent in the oil industry. This model is one of the two options available for hydraulics calculations in ADVANTAGE Engineering.

Herschel-Bulkley

$$\tau = \tau_o + K(\gamma^n)$$

The Herschel-Bulkley Model is a Power Law Model that includes a yield stress parameter. The Herschel-Bulkley Model gives mathematical expressions which are solvable with the use of computers. As a consequence the Helschel Bulkley model is more widely used than previously as it is seen to more accurately describe most fluids than the simpler Power Law and Bingham models.

Therefore, it is being widely used for hydraulics calculations both by Baker Hughes Drilling Fluids and other companies. Difficulties are still experienced making correlations between drilling fluid parameters measured in the field and hydraulic calculations.

Gel Strengths

Gel strength measurements are made with the V-G meter and describe the time-dependent flow behavior of a drilling fluid. Gel strength values must be recorded at 10-second (initial gel) and 10-minute intervals. One additional gel strength value should be recorded at 30 minutes. Gel strengths indicate the thixotropic properties of a drilling fluid and are the measurements of the attractive forces under static conditions in relationship to time. Plastic viscosity and yield point, conversely, are dynamic properties and should not be confused with static measurements. However, gel strengths and yield point are somewhat related in that gel strengths will typically decrease as the yield point decreases.

Gel strengths occur in drilling fluids due to the presence of electrically charged molecules and clay particles which aggregate into a firm matrix when circulation is stopped. Two types of gel strength occur in drilling fluids, progressive and fragile. A *progressive* gel strength increases substantially with time. This type of gel strength requires increased pressure to break circulation after shutdown. A *fragile* gel strength increases only slightly with time, but may be higher initially than a progressive gel. The NEW-DRILL® system is characterized by fragile gel strengths that are high initially but are very fragile. f gel strength measurements are taken after a 30-minute time period, the progressive or fragile nature of the gel strengths can be easily determined. Progressive and fragile gel strengths are illustrated in Figure 1–14.

Gel strength in a drilling fluid is dependent upon chemical treatment, solids concentration, time, and temperature. There is no well-established means of mathematically predicting gel strengths in any fluid system. Generally, gel strengths will increase with time, temperature, and increase in solids. If a fluid system is not sufficiently treated for temperature stability, the gel strength developed after a bit trip becomes a major factor in the pressure required to break circulation, and in the magnitude of swab and surge pressures. Additionally, initial gel strength in a weighted fluid system must be sufficient to prevent settling of weight materials. Therefore, the drilling fluids technician must be concerned with having sufficient initial gel strength, yet not having excessive long-term gel strength.

Gel strengths assume great importance with regard to suspension properties under static conditions and when performing *swab* and *surge analysis.* **When running a drill string or casing into the hole it is necessary to overcome the gel strengths. Gel strengths also affect the ability of a fluid to release entrained gases. At times it may be necessary to break circulation at intervals while running into the hole rather than to initiate flow in the entire wellbore at the same time in order to minimize the pressure spike to initiate circulation.**

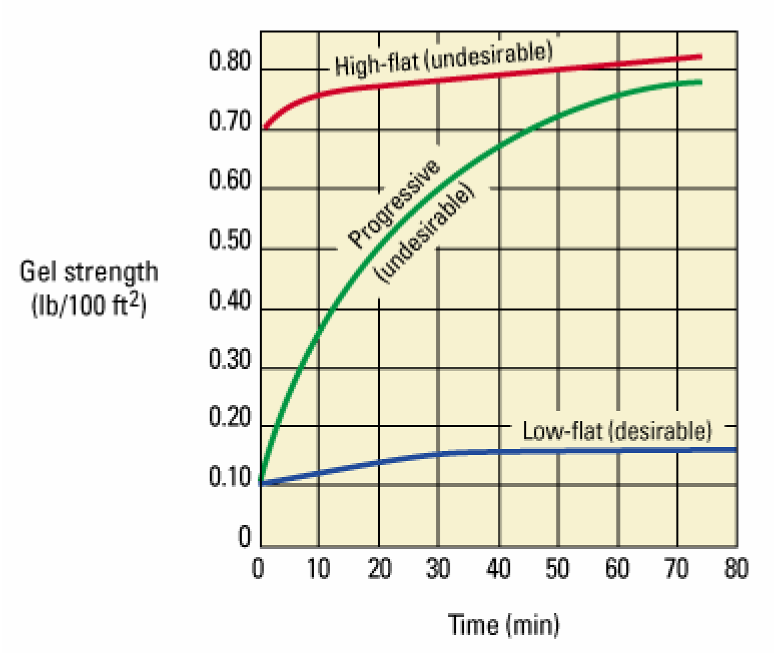

Figure 1-14 Gel Strength Characteristics vs. Time

Filtration

Two types of filtration are considered in this section, static and dynamic. *Static* filtration occurs when the fluid is not in motion in the hole. *Dynamic* filtration occurs when the drilling fluid is being circulated.

Dynamic filtration differs from static filtration in that drilling fluid velocity tends to erode the wall cake even as it is being deposited on permeable formations. As the rate of erosion equals the rate of build up of the wall cake, equilibrium is established. In static filtration, the wall cake will continue to be deposited on the borehole.

Testing Equipment

The standard API low-pressure filter press consists of a cylindrical cell three inches in I.D. and five inches high to contain the fluid. The bottom of the cell is fitted with a sheet of Whatman No. 50 filter paper. Pressure is applied to the top of the cell at 100 psi. The filtrate is collected over a period of 30 minutes and recorded in cubic centimeters (to 0.1 cubic centimeters) as the API filtrate.

The high temperature/high pressure (HT/HP) test is run at a temperature greater than ambient and a differential pressure of 500 psi for 30 minutes. The filtrate volume collected is doubled to correct it to the filter area of the API filtration test. The permeable medium used is the same as that used for the low temperature test. The filter cake should also be checked for thickness and consistency after the filtrate loss has been tested.

Correlation between API standard fluid loss at 100 psi and ambient temperature and high-temperature/high-pressure test at 500 psi and 300°F depends on several factors. Cake compressibility and thermal stability of additives contained in a fluid are primary factors. Generally speaking, a well treated lignosulfonate / lignite / bentonite system may have a ratio between HT/HP and standard API filtrate test in the range of 2:1 to 4:1, whereas a system comprised of a high concentration of drilled solids may have a ratio of 10:1 or higher. Obviously, a drilling fluid could exhibit a low API filtrate value at 100 psi and ambient temperature and an extremely high filtrate (thick wall cake) on the HT/HP test. For this reason, more emphasis is placed on HT/HP data on deeper wells encountering high bottom hole temperatures.

Permeability of Filter Cake

The permeability of the filter cake is one of the most important factors in controlling filtration. The size, shape, and concentration of the solids which constitute the filter cake determine the permeability. If the filter cake is composed primarily of coarse particles, the pores will be larger, therefore, the filtration rate greater. For this reason, bentonite with its small irregular shaped platelets forms a cake of low permeability. Bentonite platelets as well as many polymers compact under pressure to lower permeability, hence the term, *cake compressibility*.

Pressure

If the filter cake did not compress under pressure, the fluid loss would vary with the square root of the pressure. This does not normally apply to drilling fluids because the porosity and permeability of the filter cake is usually affected by pressure.

A useful field check for determining cake compressibility is to measure HT/HP filtrate in the normal manner then test again with 100 psi differential pressure. The lower the compressibility ratio,

$$Compressibility\ Ratio = \left(\frac{cc\ at\ 500\ psi}{cc\ at\ 100\ psi} \right)$$

the more compressible the filter cake becomes. If the compressibility ratio is 1.5 or greater, it could indicate that colloidal fraction is inadequate and that remedial measures are necessary.

Temperature

An increase in temperature will usually result in an increase in filtration rate because of adverse temperature effects on filtration control agents and decreased fluid phase viscosity.

Higher temperature may also increase the solubility of contaminants and, therefore, decrease the effectiveness of filtrate loss control chemicals. In addition, the colloidal fraction tends to flocculate and increase filtration at elevated temperatures.

Deflocculation of the colloidal fraction can contribute significantly to filtration rate. In a flocculated system, colloidal solids cluster or aggregate, this increases cake porosity and permeability and allows more fluid to pass through the filter cake. Conversely, dispersion of colloidal solids results in a more uniform distribution of solids in the filter cake which reduces cake permeability and lowers filtration rates. Deflocculants such as UNI-CAL® are beneficial as supplementary filtration control agents, particularly at elevated temperatures that are encountered with depth.

The theoretical change in filtrate, due to reduction of the viscosity of the filtrate as temperature is increased, can be expressed by the following equation:

$$f_1 = f \times \frac{\sqrt{\mu}}{\sqrt{\mu_1}}$$

where,

f = filtrate at a known temperature

f_1 = filtrate at an elevated temperature

μ = viscosity of water at known temperature

μ_1 = viscosity of water at an elevated temperature

The change in viscosity for water at various temperatures is noted in Table 1-2.

Table 1-2 Viscosity of Water vs. Temperature

Temperature		Viscosity of Water (Centipoise)	Temperature		Viscosity of Water (Centipoise)
°C	°F		°C	°F	
0	32	1.792	40	104	0.656
10	50	1.308	60	140	0.469
20	68	1.005	80	176	0.356
30	86	0.801	100	212	0.284

(Data from Rogers, W. F.; Composition and Properties of Oil Well Drilling Fluids, Third Edition)

For example, a fluid has a known filtrate of 6.0 mL at 86°F and 100 psi. It is desired to predict the resultant filtrate at 140°F with pressure constant.

$$f_1 = f \times \frac{\sqrt{\mu}}{\sqrt{\mu_1}} = 6.0 \times \frac{\sqrt{0.801}}{\sqrt{.469}} = 6.0 \times \frac{.895}{.685} = 7.8$$

Temperature changes of water-base fluid in the 80° to 140°F range will result in change of filtrate of approximately 10% for each 17°F change. Filtrate increases as temperature increases.

Viscosity

The viscosity of the fluid phase of the drilling fluid, which is the same as the viscosity of the filtrate, has a direct influence upon the filtration rate. The viscosity of filtrate, which is directly affected by temperature has been previously described. As the filtrate viscosity decreases, the filtration rate and total volume of filtrate measured increases.

Filtrate viscosity is also affected by water soluble materials, particularly polymers. When polymers are added to the mud system, the viscosity of the fluid phase as well as the whole mud is increased, thereby reducing the filtration rate. The equations presented above may be used to predict the effects of water soluble polymers on the filtration rate. One must know, or have measured, the effects of polymer additions on the viscosity of the filtrate in order to make such predictions.

Time

The calculation of filtrate loss at variable time intervals relative to known filtrate loss and time interval can be predicted by the following equation:

$$f_1 = f \times \frac{\sqrt{T_1}}{\sqrt{T}}$$

where,

f = known filtrate at a time interval of T

f_1 = unknown filtrate at a time interval of T_1

For example, if fluid loss is 8.0 mL in 15 minutes, the predicted fluid loss in 30 minutes would be,

$$f_1 = 8 \times \frac{\sqrt{30}}{\sqrt{15}} = 8 \times \frac{5.48}{3.87} = 11.3 \text{ mL}$$

or if time is doubled, filtrate theoretically would be increased by 41%. It should be noted that the above equation would apply only under conditions where pressure, filtrate viscosity, and cake permeability remained constant and no changes in chemical contents occurred due to effect of temperature and/or flocculation.

Summary

Filtration rate is often the most important property of a drilling fluid, particularly when drilling permeable formations where the hydrostatic pressure exceeds the formation pressure. Proper control of filtration can prevent or minimize wall sticking and drag, and in some areas improve borehole stability. Filtration control poses a question that should be answered only after a thorough study is made based on past experience, predicted pressure differentials, lithology, formation protection requirements, and overall economics.

Solids

Quantity, type, and size of suspended solids in a drilling fluid is of primary concern in the control of rheological and filtration properties. Solids in a drilling fluid are comprised of varying quantities of weighting materials [MIL-BAR®, DENSIMIX®, and/or W.O.™ 30 (Calcium Carbonate)], commercial bentonite, drilled solids (sand and shale) and, in some cases, loss of circulation additives. Material balance equations help differentiate high-specific gravity solids from low-specific gravity solids when the total solids content is obtained from the retort. These materials balance equations are presented in Chapter 10, *Mechanical Solids Control.*

Typically, the only high-specific gravity solid in a drilling fluid is the weight material, MIL-BAR®, ORIMATITA® or DENSIMIX®. However, low-specific gravity solids are defined as all other solids except weight material. Low-gravity solids are comprised primarily of MILGEL®, drilled solids and, in some cases, treatment chemicals. In the analysis of low-gravity solids, it will be assumed that any contribution from treatment chemicals is negligible. Therefore, the analysis of low-gravity solids distinguishes between the quantity of commercial bentonite added to a drilling fluid and the quantity of drilled solids incorporated into a drilling fluid.

ADVANTAGE performs solids analysis based on the retort and titration results. If barite is not being used then the default value for the weight material should be changed to the appropriate density.

Cation Exchange Capacity (CEC)

Commercial bentonite, other clays, and many chemicals exhibit a capacity to absorb a methylene blue solution ($C_{16}H_{18}N_3SCl{\bullet}3H_2O$). A standardized methylene blue solution is outlined in API Bulletin RP 13B-1. The testing procedure is described in the Fluid Facts Engineering Handbook. If the absorption effects of all treatment chemicals are destroyed by oxidation with hydrogen peroxide according to the test procedure, then the test results give the cation exchange capacity of only the commercial bentonite and other clays in the drilling fluid.

As discussed in the section, Functions of Fluids, shales contain varying types and quantities of clays within their structure. Some shales contain clays with characteristics very similar to that of commercial bentonite, while other shales have relatively inert characteristics.

These characteristics are defined as bentonite equivalent and are directly related to their cation exchange capacity. The term “bentonite equivalent” does not imply that the clays are bentonite. Therefore, the differences in cation exchange capacities of commercial bentonite and drilled solids allow the use of the methylene blue test (MBT) to distinguish between them.

The cation exchange capacity of a fluid is reported as the methylene blue capacity as follows.

$$\text{Methylene blue capacity} = \frac{\text{cm}^3\text{ of methylene blue}}{\text{cm}^3\text{ of fluid}}$$

The methylene blue capacity is frequently reported as pounds per barrel equivalent (referring to bentonite equivalent) by,

$$\text{lbs}_m\text{ per bbl equivalent} = 5 \times \text{methylene blue capacity}$$

This equation is based upon commercial bentonite having a cation exchange capacity of 70 milli-equivalents (meq) of methylene blue per 100 g of dry bentonite. This is typically a high value for most commercial bentonite. Depending upon the quality of the bentonite, the cation exchange capacity will be in the range of 50 to 65 milli-equivalents of methylene blue per 100 g of dry clay.

Therefore, for proper analysis of commercial bentonite and drilled solids, a correction must be made due to this difference. We know that the cation exchange capacity of the fluid is dependent upon the quantity (as well as quality) of total low-specific gravity solids in the fluid.

The following equation can be written,

$$\text{CEC}_{\text{fluid}} = \frac{\text{ml of methylene blue solution}}{\text{grams of LGS}}$$

In the MBT test, we use a volume of fluid and want to determine the total quantity of low-specific gravity solids.

$$\text{grams of LGS} = \frac{\text{vol \% LGS}}{100}(\text{mL of fluid})(\rho_{\text{LGS}})$$

where,

% LGS = low-gravity solids, (e.g., 5.5%)

ρLGS = density of the low-gravity solids, g/cm3

Substituting one equation into the other, you derive,

$$\text{CEC}_{\text{fluid}} = \frac{(100)(\text{mL of solution})}{(\text{\% LGS})(\text{mL of fluid})(\rho_{\text{LGS}})}$$

$$= \frac{100}{(\%\ \mathrm{LGS})(\rho_{\mathrm{LGS}})} \times \frac{\text{mL of methylene blue}}{\text{mL of fluid}}$$

Then,

$$\mathrm{lb_m/bbl\ equivalent} = 5 \times \frac{\text{mL of methylene blue}}{\text{mL of fluid}}$$

$$\text{or,} \quad \frac{\text{mL of methylene blue}}{\text{mL of fluid}} = \frac{\mathrm{lb_m/bbl\ equivalent}}{5}$$

Again, substituting one equation into another, you derive,

$$\mathrm{CEC_{fluid}} = \frac{100}{(\%\ \mathrm{LGS})(\rho_{\mathrm{LGS}})} \times \frac{\mathrm{lb_m/bbl\ equivalent}}{5}$$

$$= \frac{20(\mathrm{lb_m/bbl\ equivalent})}{(\%\ \mathrm{LGS})(\rho_{\mathrm{LGS}})}$$

The density of the low-gravity solids (ρ_{LGS}) is typically assumed to be 2.6 g/cm^3. However, measurement of the density of the drilled solids at a particular location will provide a more accurate value. Therefore, replacing ρ_{LGS} with 2.6 in the equation gives,

$$\mathrm{CEC_{fluid}} = \frac{7.69(\mathrm{lb_m/bbl\ equivalent})}{\%\ \mathrm{LGS}}$$

The following notation is common:

$$\mathrm{CEC_{avg}} = \frac{7.69(\mathrm{MBT_{fluid}})}{\%\ \mathrm{LGS}}$$

where,

$\mathrm{CEC_{avg}}$ = cation exchange capacity correction

$\mathrm{MBT_{fluid}}$ = methylene blue capacity, $\mathrm{lb_m}$ / bbl equivalent

% LGS = volume % of low-gravity solids (e.g., 6.1%)

Table 1-3 Typical CEC Values

Location	Depth of Sample (ft)	CEC (meq / 100g)
Lost Hills, CA	--	3
Alberta, Canada	6,150	5
Denver, CO	--	13
Assumption Parish, LA	9,050	22
Eugene Island Blk 19, LA	11,000	18
South LA (Gumbo)	3,000	34
South LA (Tuscaloosa)	19,300	5
St. James Parish, LA	14,500	22
South Marsh Island	9,800	21
Blk 244, LA	4,000	
Ship Shoal Blk 332, LA	11,000	16
Ship Shoal Blk 332, LA	9,000	17
St. Landry Parish, LA	20,000	18
St. Landry Parish, LA	10,600	5
Vermilion Blk 190 LA	--	21
Barzoria County, TX	--	13
Chambers County, TX	7,800	25
East TX (Midway)	8,900	12
South TX (Anhuac)	9,300	34
East Breaks Blk 160, TX	4,700	20
East Breaks Blk 160, TX	--	22
Centre County, PA	--	1
Teton, WY	--	14
Commercial Bentonite, WY	--	60-70
North Sea (Gumbo)	5,200	32

Low-Gravity Solids Analysis

As previously stated, the differences in cation exchange capacities of commercial bentonite and drilled solids allows the use of the methylene blue test to distinguish between them. From the earlier equations, we can deduce that,

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or

$$Methylene\ Blue Capacity = \frac{mL\ of\ methylene\ blue}{g\ of\ bentonite}\left(\rho_{bent}\right)\left(\frac{vol\ \%\ bentonite}{100}\right)$$

$$+\frac{mL\ of\ methylene\ blue}{g\ of\ drilled\ solids}\left(\rho_{drilled\ solids}\right)\left(\frac{vol\ \%\ drilled\ solids}{100}\right)$$

where,

ρ_{bent} = density of bentonite, g/cm^3

$\rho_{drilled\ \mathrm{solids}}$ = density of drilled solids, g/cm^3

The following rewrites the equation in terms of cation exchange capacities,

$$\begin{matrix}\text{Methylene blue}\\ \text{capacity}\end{matrix} = (\mathrm{CEC}_{\mathrm{bent}})(\rho_{\mathrm{bent}})\left(\frac{\text{vol \% Bentonite}}{100}\right)$$

$$+\ (\mathrm{CEC}_{\mathrm{DS}})(\rho_{\mathrm{DS}})\left(\frac{\text{vol \% drilled solids}}{100}\right)$$

The equation can be rewritten as,

$$\begin{matrix}\text{Methylene blue}\\ \text{capacity}\end{matrix} = (\mathrm{CEC}_{\mathrm{avg}})(\rho_{\mathrm{LGS}})\left(\frac{\text{vol \% LGS}}{100}\right)$$

Then, equating the two equations above, you have,

$$(\mathrm{CEC}_{\mathrm{avg}})(\rho_{\mathrm{LGS}})\left(\frac{\text{vol \% LGS}}{100}\right) = (\mathrm{CEC}_{\mathrm{bent}})(\rho_{\mathrm{bent}})\left(\frac{\text{vol \% Bentonite}}{100}\right)$$

$$+\ (\mathrm{CEC}_{\mathrm{DS}})(\rho_{\mathrm{DS}})\left(\frac{\text{vol \% drilled solids}}{100}\right)$$

We have previously defined low-gravity solids as comprised of commercial bentonite and incorporated drilled solids, or,

$$\%\ \mathrm{LGS} = \%\ \mathrm{Bentonite} + \%\ \mathrm{DS}$$

which can be written,

$$\%\ \mathrm{DS} = \%\ \mathrm{LGS} - \%\ \mathrm{Bentonite}$$

Making further equation substitutions, you see that,

$$(\mathrm{CEC}_{\mathrm{avg}})(\rho_{\mathrm{LGS}})\left(\frac{\text{\% LGS}}{100}\right) = (\mathrm{CEC}_{\mathrm{bent}})(\rho_{\mathrm{bent}})\left(\frac{\text{\% Bentonite}}{100}\right)$$

$$+ (\mathrm{CEC}_{\mathrm{DS}})(\rho_{\mathrm{DS}})\left(\frac{\%\ \mathrm{LGS} - \%\ \mathrm{Bentonite}}{100}\right)$$

Solving for % Bentonite gives,

$$\%\ \mathrm{Bentonite} = \frac{\%\ \mathrm{LGS}[(\mathrm{CEC}_{\mathrm{avg}})(\rho_{\mathrm{LGS}}) - (\mathrm{CEC}_{\mathrm{DS}})(\rho_{\mathrm{DS}})]}{(\mathrm{CEC}_{\mathrm{bent}})(\rho_{\mathrm{bent}})(\mathrm{CEC}_{\mathrm{DS}})(\rho_{\mathrm{DS}})}$$

If we again assume that all low-gravity solids have a density of 2.6 g/cm^3 then,

$$\%\ \mathrm{Bentonite} = \frac{\%\ \mathrm{LGS}(\mathrm{CEC}_{\mathrm{avg}} - \mathrm{CEC}_{\mathrm{DS}})}{\mathrm{CEC}_{\mathrm{bent}} - \mathrm{CEC}_{\mathrm{DS}}}$$

To convert the volume % Bentonite to pounds per barrel,

$$\mathrm{lb_m/bbl\ Bentonite} = (\%\ \mathrm{Bentonite})(9.1)$$

After the volume % drilled solids is found, conversion is made to pounds per barrel,

$$\mathrm{lb_m/bbl\ DS} = (\%\ \mathrm{DS})(9.1)$$

Summary

The solids analysis equations in this and other chapters are based upon numerous assumptions and test results from a fluid check. The potential errors are obvious; however, systematic use of these assumptions and test results will provide information during the drilling operation in which trends should be analyzed rather than a single value. In some cases, wrong assumptions or poor testing can lead to erroneous calculated values.

CEC values for the bentonite and drilled solids should be measured whenever possible. However, when measurements are not possible, assume CEC bent to be 60 milli-equivalents (meq) per 100 g. Table 1-3 can be used to find a typical value for $\mathrm{CEC}_{\mathrm{DS}}$ in the region.

Drilling Fluids pH and Alkalinity

The pH of a drilling fluid may be defined as the negative logarithm of the hydrogen ion (H^+) concentration. At any particular hydrogen ion (H^+) concentration, there is a corresponding hydroxyl ion (OH^-) concentration which will result in equilibrium. The hydrogen ion represents the acidic portion and the hydroxyl ion the alkaline or basic portion of the solution. Freshwater normally has an equal concentration of hydroxyl and hydrogen ions and a pH near 7, which indicates a neutral condition. Addition of a basic material such as caustic or lime would increase (OH^-)concentration and pH, whereas an acid would increase (H^+) concentration and reduce the pH. The maximum concentration of hydroxyl ions would result in a pH of 14, whereas the maximum concentration of hydrogen ions would result in a pH of 0.

The pH of a drilling fluid is determined either by the *colorimetric* method or the *electrometric* method. The *colorimetric* method utilizes chemically-treated pHydrion paper which is placed on the fluid's surface until a color change is noted. The color observed is matched with a color chart on the side of the dispenser. If the salt concentration is greater than 16,000 mg/l Cl^-, pH paper is not recommended. The *electrometric* procedure employs a pH meter with a glass electrode. Although more accurate than pHydrion paper, it is quite sensitive to shock and difficult to maintain under field conditions.

The pH of many water-base drilling fluid systems is maintained in the 9.5 to 10.5 range for the following reasons:

- Organic dispersants and filtration control agents generally achieve maximum effectiveness in an alkaline environment.
- Adverse effects of contaminating electrolytes are usually minimized at higher pH levels.
- Corrosion rates can be reduced at higher pH levels and bacterial action on organic materials is retarded at elevated alkalinity levels.
- Thermal stability of lignosulfonate systems may be improved at a pH of 10.0 or above.

The pH ranges of some of the more common water-base fluid systems are shown in Table 1-4.

Table 1-4 Fluid System pH Ranges

Type System	pH Range
UNI-CAL®, Freshwater	9.0 - 11.5
UNI-CAL®, Seawater	10.0 - 11.5
UNI-CAL®, Gypsum	9.0 - 10.0
NEW-DRILL®	8.5 - 10.0
Lime-Base	11.5+
BENEX, Low-Solids	9.0 - 10.0
Saturated Saltwater	9.5 - 11.5
KCl Systems	10.0 - 11.5

Note: Increasing concern with corrosion control has led to higher pH values. Usually, pH values below 10.5 are compatible with most shales drilled, however, there are some shales which exhibit poor stability in the presence of excess hydroxyl ions. UNI-CAL® systems function effectively over a broad pH range and have been run as low as 8.0 to 8.5 to improve shale stability.

Approximate pH of some common fluid additives are listed in Table 1-5

Table 1-5 Typical pH Levels of Some Common Drilling Fluid Additives

Material	PH
CHEMTROL®	9.0
LIGCO®	4.5
LIGCON®	9.5
NEW-DRILL®	8.7
UNI-CAL®	4.5
SAPP	4.8
Sodium Bicarbonate ($NaHCO_3$)	8.3
Sodium Carbonate (Na_2CO_3): soda ash	11.0
Sodium Hydroxide (NaOH): caustic soda	13.0
Calcium Hydroxide ($CaOH_2$): lime	12.0
Calcium sulfate dihydrate ($CaSO_4H_2O$): gypsum	6.0
Potassium Hydroxide (KOH): caustic potash	12.8
MIL-BAR®	7.0
MILGEL®	8.0

The alkalinity of a solution is related to pH since alkalinity is the measure of the quantity of an acid needed to reduce the pH of a filtrate to a particular value. The two common filtrate alkalinities utilized in fluid analysis are P_f and M_f. P_f alkalinity is the volume of N/50 (0.02 normal solution) sulfuric acid required to reduce the pH of 1 cc of filtrate to 8.3. The end point is noted when the phenolphthalein indicator solutions changes from pink to colorless.

M_f is the quantity of N/50 sulfuric acid required to reduce the pH of 1.0 cc of filtrate to 4.3. The end point is obtained when a methyl orange indicator solution changes from orange to salmon pink or red. If the sample color is obscured with organic materials, the pH can be determined with a glass electrode pH meter.

If there were no interfering ions present, the P_f and M_f alkalinities could be used to calculate the amounts of OH^-, $CO_3^=$, and HCO_3^- ions present in the filtrate. However, the presence of organic acids or buffering ions cause the M_f determination to indicate more $CO_3^=$ and HCO_3^- ions than actually present. This is the usual case in fluid filtrate, and the M_f determination is only a very rough indicator of the $CO_3^=$ and HCO_3^- ions present. As a general guide, M_f values above 5 mL indicate that excessive amounts of $CO_3^=$ and HCO_3^- ions are probably present in the fluid.

When excessive concentrations of $CO_3^=$ and HCO_3^- are suspected, another titration procedure, as shown in the Measurement of Carbonates (p 2-87 *Water-Base Fluid Systems*) in the *Fluid Facts Engineering Handbook*, can be used to determine their concentrations.

Another alkalinity measurement (Pm) is made with the whole fluid rather than filtrate. This test (refer to Fluid Facts Engineering Handbook for details) is made in a manner similar to the P_f test and is used primarily to determine concentrations of lime and cement being carried as solids in the system. Because it has limited solubility, considerable cement may be carried as a solid which tends to replenish calcium and hydroxylions as they are used up. This can be a problem when it is necessary to calculate the quantity of treating agent to neutralize the cement.

Example Calculations

Parameters

Table 1-6 Fluid Parameters for Exercise Problem

Fluid Properties	
Fluid Weight, lbm/gal	15.5
Retort Analysis	
Solid, %	30
Oils, %	0
Water, %	70
MBT, lb_m / bbl equivalent	15.0
Chlorides, ppm	21,000
Measurement	
CEC_{bent}	63 meq/100 g
CEC_{DS}	16 meq/100 g
Calculation	
% LGS	5.9%

Exercise

Perform the steps and calculations to show that this is the correct value for % LGS. Find the % Bentonite and % DS in the fluid and the corresponding pounds per barrel of each.

1. Make the cation exchange capacity correction.

$$CEC_{avg} = \frac{7.69(MBT_{fluid})}{\%\ LGS} = \frac{7.69(15.0)}{5.9} = 19.55\ meq/100\ g$$

2. Find the % Bentonite.

$$\%\ Bentonite = \frac{\%\ LGS(CEC_{avg} - CEC_{DS})}{CEC_{bent} - CEC_{DS}} = \frac{5.9(19.55 - 16)}{63 - 16} = 0.45\%$$

3. Find the pounds per barrel of Bentonite.

$$lb_m/bbl\ Bentonite = (\%\ Bentonite)(9.1) = (0.45)(9.1) = 4.1\ lb_m/bbl$$

4. Find the % drilled solids.

$$\%\ DS = \%\ LGS - \%\ Bentonite = (5.9 - 0.45) = 5.4\%$$

5. Find the pounds per barrel of drilled solids.

$$lb_m/bbl\ DS = (\%\ DS)(9.1) = (5.45)(9.1) = 49.6\ lb_m/bbl$$

Notice that the quantity of Bentonite is relatively low. This is very typical of the NEW-DRILL® system.

Drill-In Fluids

Function

A *drill-in* fluid must possess the desirable properties of a good *drilling* fluid, as discussed earlier, and provide the necessary attributes of a *completion* fluid. The primary function of a drill-in fluid is to develop a filter cake which effectively prevents formation damage (production impairment) and which is easily removed. As a standard, a drill-in fluid, like the drilling fluid itself, must provide lubricity, inhibition, solids suspension, and well bore stability.

Development

Formation protection is critical while drilling the production zone since damage to the formation can adversely affect the well’s production potential. This pay zone damage is minimized with the use of drill-in fluids - specialized fluids for “drilling in” and protecting oil/gas producing formations. Damage to the pay zone, including fine solids migration into the formation permeability channels, clay swelling within the formation pore spaces, and irreversible reactions with invading polymers, reduce the average permeability of the formation, resulting in lower production rates. Most formation damage caused by conventional drilling fluids is by fluid invasion containing barite, finely ground drill solids, and/or bentonite. Drill-in fluids have reduced the use of such non-acid soluble products across the pay zone.

Attributes

A non-damaging drill-in fluid should ideally possess the following characteristics:

Easily removable filter cake

Acid soluble bridging agents

Bridging agents sized for flow-back through the designed completion process

Exhibit excellent fluid loss control

Temperature stability

Excellent lubricity

Provide inhibition

The reservoir drill-in fluid is designed to protect the pay zone during well bore construction, simplify the clean-up process, and maximize production rates.

Screening and Selection

Selecting a reservoir drill-in fluid for a specific application to satisfy each of the above criteria must involve laboratory testing of the candidate fluids using the following screening parameters.

Leak-off control tests

Net breakout pressure determination

Return permeability tests

Fluid-fluid interactions

Drill-in fluid properties

Environmental considerations

Using these screening parameters will yield a designed drill-in fluid that will create a filter cake which will mechanically seal off all pore openings exposed to the well bore, remain intact during the completion phase, and be easily removed for the production (or injection) of oil and/or gas.

The Proposed Drill-In and Completion Program

Prior to testing and recommending a drill-in fluid, fundamental details about an operator's reservoir must be known. Recording information on the items listed below will assist those involved to decide what application exists and which fluid should be selected for that application.

Local Environmental Regulations

Reservoir Characteristics

- Reservoir fluid composition (oil, gas, or formation water)
- Lithology (sandstone, limestone, etc.)
- Cementation (consolidated, unconsolidated, fractured)
- Quantity and type of clays present

Operator Recommendation/Plan

- Slim or large hole
- Completion technique (gravel pack, non-gravel pack)
- Hole geometry (horizontal, vertical, or high-angle)

Note: To learn more about the effects of a drill-in fluid on a particular type of completion, refer to the *Baker Hughes Drilling Fluids Drill-In Fluids Manual*

As previously listed, the drill-in fluid must be subjected to the following testing to ensure adequate protection of a producing reservoir.

Leak-Off Control Tests

Permeability Plugging Test Apparatus

Spurt and cumulative leak-off into a producing reservoir is a concern because of its effect on permeability. Altering the chemistry and/or disturbing in-situ particles in a producing zone are the most common formation damage mechanisms, and must be controlled. Control of filtrate loss into a producing formation is an important factor to consider when designing a drill-in fluid.

The Permeability plugging test apparatus helps determine the bridging characteristics of the drill-in fluid. A low initial spurt filtration and low final filtration are desirable.

Net Breakout Pressure Determination

Breakout Pressure

The ability to deposit a filter cake that is easily removed when the reservoir is produced is a major attribute of drill-in fluids. Some drill-in fluids deposit filter cakes that are easily removed by flowing the well, while other deposits require remedial treatments to remove skin damage. Net breakout is the difference in pressure required for oil flow before fluid-off or “mud-off” (recorded while determining initial permeability) and the pressure required to initiate flow after fluid-off. Determining the net breakout pressure before and after acidizing is useful in selecting a drill-in fluid.

A fluid that requires little or no procedural clean-up after drill-in is superior to one involving a series of specialized steps to remove the filter cake.

Return Permeability Tests

Hassler Cell Permeameter

This test procedure determines the effect a drill-in fluid has on reservoir permeability. The return permeability set-up is designed to simulate flow through a core sample under downhole conditions. The set-up allows flow through a core (or simulated core) from two opposite directions under controlled temperature and pressure.

A high-percentage return permeability indicates minimum formation damage.

Sandpack Permeameter

This test procedure determines the effect of a drill-in fluid on an unconsolidated sand reservoir. The return permeability set-up is designed to simulate flow through a core sample under down hole conditions. The set-up allows flow through a core (or simulated core) from two opposite directions under controlled temperature and pressure. A high-percentage return is desirable.

Drill-In Fluid Properties

Static Filtration

Test seeks to find the filtrate volume and the quality of the filtrate cake. Although evaluating filter cake quality is generally limited to estimating the thickness of the cake, other properties such as lubricity, erodibility, and texture must be considered.

Lubricity Testing

Lubricity testing evaluates the lubricating qualities of drilling fluids. The different test procedures measure the coefficient of friction characteristics of a fluid. These tests can measure the coefficient of friction between two metal surfaces, or between a metal surface and a piece of rock. Since drill-in fluids can be used to drill horizontal or highly deviated well bores, the coefficient of friction can be a critical issue when selecting an applicable fluid.

Particle Size Distribution

Effective bridging of a reservoir depends upon both the particle size distribution of materials comprising the drill-in fluid and the pore throat diameters of the reservoir rock. A bridging material is chosen by matching its size to the diameter of formation pore throats. The industry-accepted rules for selecting size and concentration of bridging materials are based upon work carried out by A. Abrams, "*Mud Design to Minimize Rock Impairment Due to Particle Invasion*", SPE 5713, 1977, and include the following:

The medium particle size of the bridging additive should be equal to or slightly greater than one-third the medium pore size of the formation.

The concentration of the bridging solids must be at least 5% by volume of the solids in the final fluid mix.

Once the mean pore diameter is known, the particle size distribution of the bridging solids must be measured and adjusted to meet the required specifications and included in the drill-in fluid formulation.

An alternative method of determining optimal particle size distribution is to use the ideal packing theory. This theory determines a particle size distribution based on sealing the pore sizes over a total range, including pore spaces created by bridging agents.

Shale Inhibition (Wafer Test)

The shale wafer test measures the disintegrative properties of particular shale in contact with a drilling fluid or liquid composition over a measured period of time. Knowledge of shale disintegration tendencies is important because of their effects on drilling fluid properties in actual field use. Incorporation of unwanted drill solids into the fluid negatively impacts the rheological properties of the system, reduces rates of penetration, produces poor filter cake quality, increases dilution rates and potential pore throat plugging that cannot be cleaned up.

Shale disintegration, as defined in this test procedure, is measured and recorded in four ways:

3. Weight recovery in weight percent
4. Shale hydration in weight percent
5. Change in shale wafer hardness
6. Increase or decrease in shale wafer volume

This test compares results of one fluid to another. It is one of several tests providing information on the interaction of a fluid in contact with a given shale. This testing is important for the design of reservoir drilling fluids that will ensure well bore stability and maximum fluid stability.

Density (API Standard Practice 13B-1, June 1990)

This test procedure determines the weight of a given volume of liquid. Fluid weight may be expressed as pounds per gallon (lb_m/gal), pounds per cubic foot (lb_m/ft^3), kilograms per cubic meter (kg/m^3), or specific gravity. Density is designed to meet well bore pressure requirements.

Fluid Viscosity

A viscometer is a mechanical device used to measure viscosity at varying shear rates. Viscosity and gel strength measurements relate to the flow properties of fluid. From the viscometer readings rheological parameters may be determined. *Rheology* is the study of deformation and flow of matter. Hole size, hole angle, and formation type determine optimal rheological properties.

Water, Oil and Solids

The retort instrument provides a means for separating and measuring the volumes of water, oil, and solids contained in a sample of fluid. In the retort, a known volume of a whole mud sample is heated to vaporize the liquid components which are then condensed and collected in a graduated receiver. Total volume of solids (suspended and dissolved) is obtained by subtracting the liquid volume from the total sample volume. Calculations are necessary to determine the volume of suspended solids since any dissolved solids will be retained in the retort. The relative volumes of low-gravity solids and weighting material can also be calculated. Knowledge of the solids concentration and composition is considered basic to viscosity and filtration control in reservoir drill-in and drilling fluids.

MBT (Methylene Blue Titration)

Methylene Blue Testing provides field measurement of the reactive clay content of a drilling fluid. The PERF*FLOW*® DIF system is formulated with no reactive clays. Minimal clay content in the system is desired so as not to promote any damage to the reservoir.

PH (API 13B-1) Field measurement of drilling fluid (or filtrate) pH and adjustments to the pH are fundamental to drilling fluid control. Clay interactions, solubility of various components and contaminants, and effectiveness of additives are all dependent on pH, as are the processes that control acid and sulfide corrosion.

Note: See Donvan, J. P. and Jones, T. A.,“*Specific Selection Criteria and Testing Protocol Optimize Reservoir Drill-In Fluid Design*”, SPE 30104, May 1995 for a more detailed discussion of drill-in fluid selection and testing

Filter Cake Formation and Dispersability

Fluid loss or leak-off is effectively controlled by bridging the pore openings with rigid or semi-rigid particles of sufficient size and number. However, in order to ensure that the filter cake can be effectively removed after placing the well in production, it must meet two important requirements:

The fluid must possess the right particle size distribution and particle concentration to build a filter cake that will quickly and effectively bridge the pore openings.

The fluid must deposit a filter cake that is highly dispersive to the produced fluid. A quick and effective particle bridge will limit particle invasion to maximize return permeability. In addition, a highly dispersive cake will be removed by the production fluids, thus requiring no acidizing or treatment with breakers.

The scanning electron microscope is a very useful tool to guide the selection of the bridging materials since one can obtain a microscopic picture of the filter cake in place. Figure 1-15 shows a photomicrograph of a PERF*FLOW*® filter cake on a 3-Darcy filter media. These are lateral or cross-sectional views of the cake deposited on the filter surface. Note the clean delineation between the filter cake on the left and the surface of the permeable rock. Intrusion of calcium carbonate bridging particles has been limited to the first few micrometers of the rock surface.

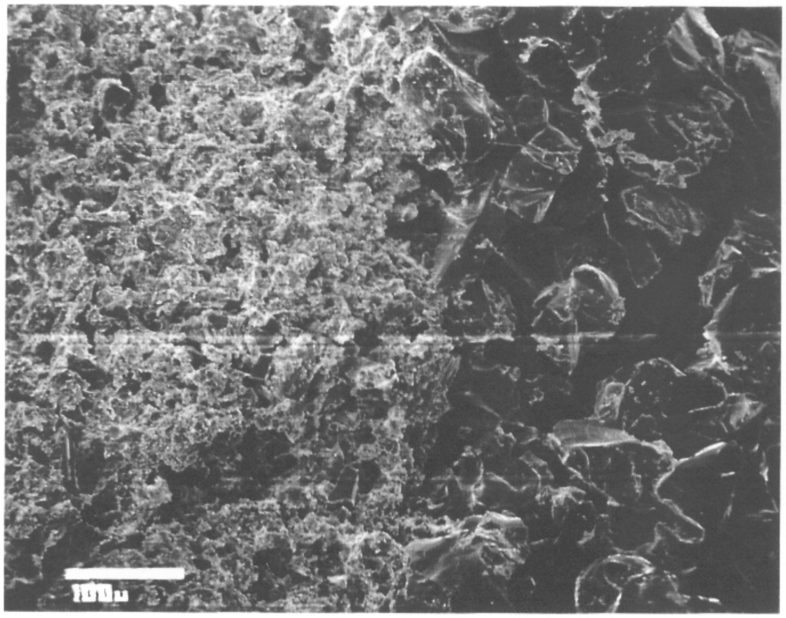

Figure 1-15 SEM Photomicrograph X 150 – 2% PERF*FLOW*® Filter Cake on AF-6

Figure 1-16 shows a photomicrograph of a cross section of a filter cake on a filter media with 24-Darcy permeability. In Figure 1-16 the particles have formed an internal bridge in a pore opening that is approximately 20 micrometers in diameter but, even in this size opening, the intrusion is only about 50 micrometers

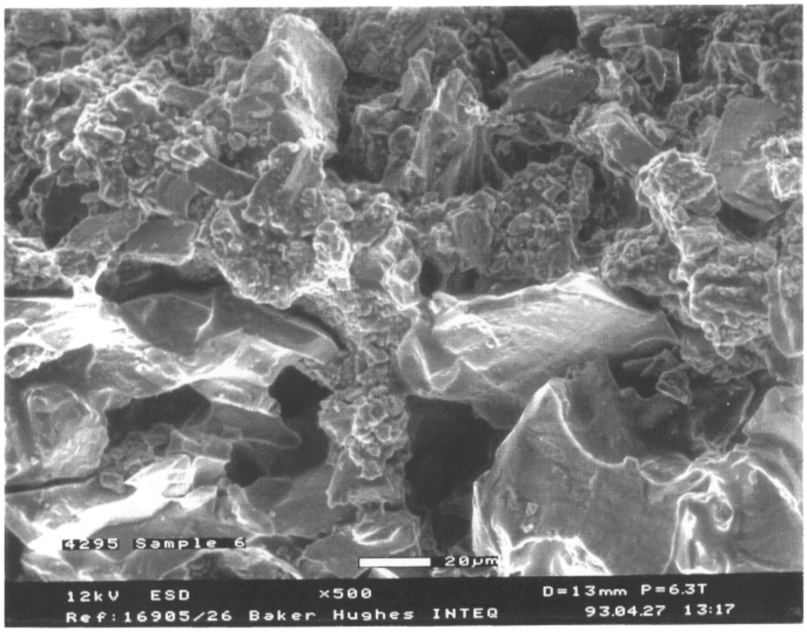

Figure 1-16 SEM Photomicrograph 2% KCl PERF*FLOW*® – Pore Bridging

At differential pressures in excess of 200 psi, the calcium carbonate bridging particles can form strong adherence between them and be very difficult to disperse and remove from the filter surface. The dispensability of these particles can be greatly increased by placing a parting agent or barrier between them during cake formation. One of the most effective methods of accomplishing this is to coat the particles with certain organic water soluble polymers prior to filtration. This has been accomplished in the PERF*FLOW*® systems as evidenced by the high return permeability results.

Figure 1–17 shows a photomicrograph of filter cake from a 17 lb_m/gal PERF*FLOW* fluid while that of a sized salt fluid is shown in Figure 1–18. Note the granular and irregular packing of the calcium carbonate particles in Figure 16. In contrast, note the highly oriented cubic salt crystals in Figure 1-18. This difference in packing will result in much less surface area for particle adhesion in the calcium carbonate cake. This appears to be a major factor in the ease of dispersability of the PERF*FLOW* filter cake upon production as compared to the sized salt filter cake.

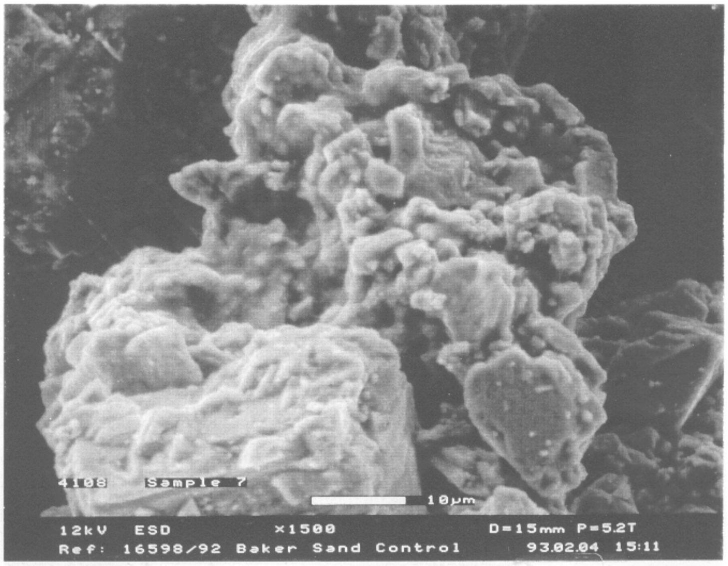

Figure 1-17 SEM Photomicrograph – 17 lb/gal PERF*FLOW*

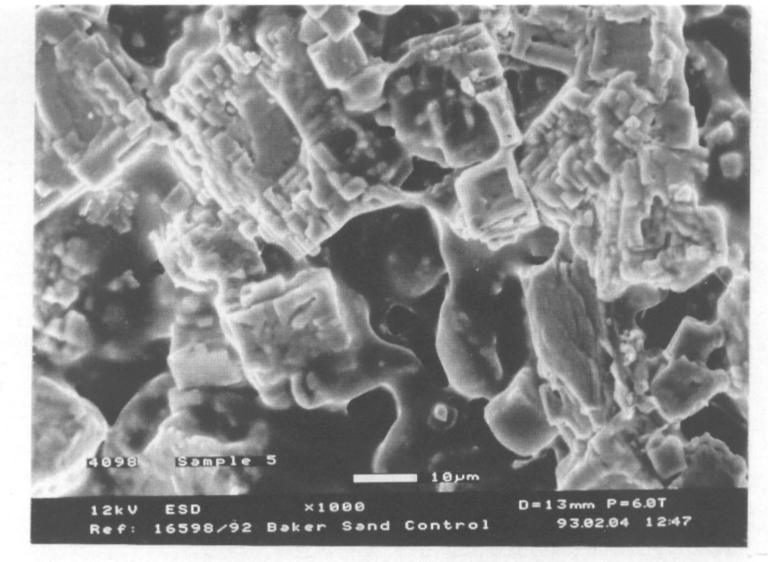

Figure 1-18 SEM Photomicrograph - Sized Salt System

Return Permeability vs. Breakout Pressure

The following example shows that fluids with similar leak off or fluid loss characteristics can exhibit extremely different return permeabilities and net breakout pressures. This example relates the importance of complete system analysis before utilization and possible reservoir impairment.

Return Permeability is a measure of that permeability that can be re-established after a core has been damaged by the flowing of a fluid through it and then being reversed out. *Net Breakout Pressure* is the maximum pressure required to initiate flow after mudoff. Mudoff is defined as the condition where a mud filter cake has been deposited on the face of and a short distance into the formation. Figure 1-19 describes the relationship that exists between *return permeability* and *net breakout pressure*. Note that the lower the *net breakout pressure*, the higher the percent *return permeability* value. This is indicative of a minimum of formation damage having occurred from the invasion of mud solids.

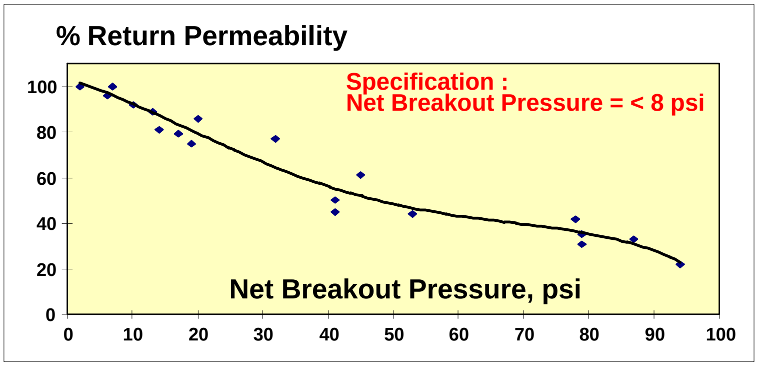

Figure 1-19 A Plot of Net Breakout Pressure vs. Return Permeability

Figure 1-20 and Figure 1-21 compare the results of two different systems formulated with PERF*FLOW* vs. those with the TBC salt system on return permeability and net breakout pressure. The PERF*FLOW*® DIF (drill-in fluid) system's bridging agent design and unique polymer chemistry form a thin filter cake protect the pay zone from damage caused by fluid invasion. The filter cake is efficiently removed by low breakout pressures, leaving no residual material to inhibit the well's productivity.

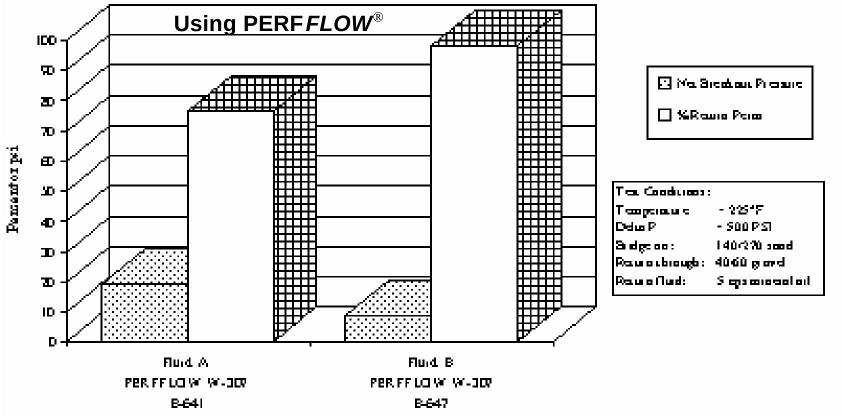

Figure 1-20 The Effects of PERF*FLOW*® on Return Permeability and Breakout Pressure

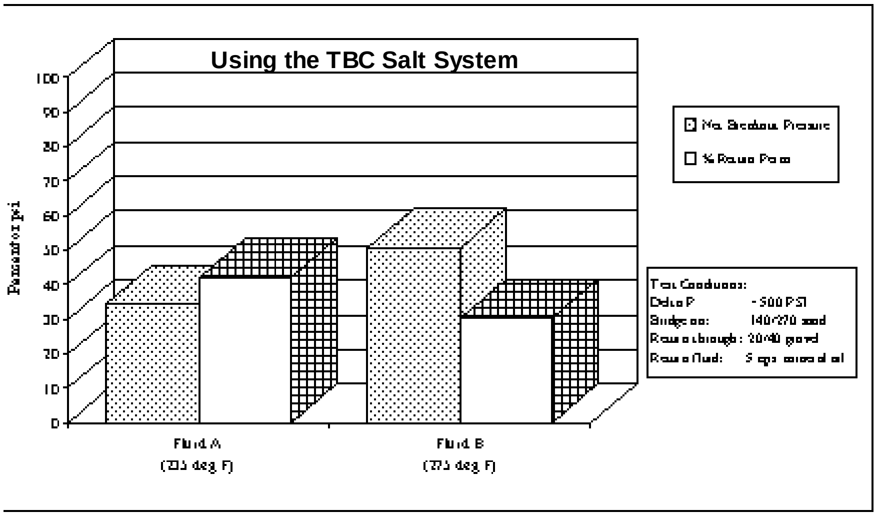

Figure 1-21 Effects of TBC Salt System on Return Permeability and Breakout Pressure

Completion Fluids

Definition

By definition, workover or completion fluids are fluids placed across the producing zones before or immediately after perforating, or any fluid placed across the formation during reworking, under-reaming, drill-in, or gravel pack operations. These fluids help ensure that production is consistent with the expected potential of the well.

Function

The primary functions of completion/workover fluids are to:

provide pressure control by preventing formation fluids from entering the borehole

maintain borehole stability

minimize formation damage

control fluid loss with minimal solids invasion

These fluids also keep the borehole “clean” of perforation debris, solids such as drill cuttings, sand, etc., or any other contaminants by providing a transportation medium that for circulating loose material to the surface.

Attributes

A completion/workover fluid must possess the following attributes:

- enough density to control subsurface pressures
- enable efficient solids removal during circulation through filtration systems
- stable, nontoxic, low corrosivity, and bacterial growth retardant
- non-reactive to other soluble salts, minerals, cement, etc.
- retain desirable properties such as viscosity and other physical properties under prolonged exposure to high shear
- readily degas

Mechanisms for Formation Damage

For a well to be profitable, the reduction of virgin permeability should be minimized. Permeability can be reduced by the invasion of foreign liquids and/or solids into the near well bore region. This hampered permeability or damaged zone is known as a *skin effect*.

A critical function of completion fluids is to contain formation pressures. To accomplish this, hydrostatic pressure must be higher or equal to the pressure of the formation. Consequently, if the hydrostatic pressure is higher, the fluid would allow a certain amount of solids and liquids to be lost to the formation.

Primary Factors Causing Formation Damage

Solids Invasion

Solids can enter or penetrate the producing zone due to differential pressure placed across the interval. These solids can plug internal pores and flow channels, thus increasing the potential for formation damage. Factors which influence the migration or entrance of particles into the formation are as follows.

Size and shape of particulates

Permeability and porosity of the formation

Differential pressure applied

Compressibility or incompressibility of solids

Generally, compressible solids such as polymers can be more damaging because they tend to deform the shape of the pore throat, thereby building an internal bridge that could eventually seal off pore channels connecting the pore spaces. Incompressible solids, on the other hand, become wedged, thus leaving some communication between the pore spaces. Also, depending on the size, quantity, and shape, an instantaneous bridge could occur at the pore openings, thus delivering minimal invasion of particulates.

Filtrate Invasion, Hydration Inhibition, and Emulsions

Producing zones are seldom homogeneous; therefore the detrimental effects of filtrate invasion are often encountered. The most frequent effect is the alteration of clays by the influx or invasion of freshwater. Freshwater can cause damage by the hydration and swelling of clays in the rock matrix, thus causing particle plugging by clay dispersion. Freshwater can cause further damage by increasing pore channel capillary pressure or by creating an emulsion block.

Smectite or montmorillonite is the most important clay mineral associated with swelling. This clay is capable of expanding by interlayer adsorption of water and can expand as much as 10 times its normal occupied volume. The degree of swelling is dependent upon the type of cation present within the interlayer. Thus, introducing an appropriate type and quantity of cation can reduce the amount of swelling a particular clay undergoes.

This reduction occurs because the positive ions have a stronger attraction or force on the negatively charged surfaces of the silica and alumina particles than the displaced ion. This base exchange can be induced by either the introduction of highly active cations, the mass action of cations, or cations with sufficient size to fill all available bonding sites with the structure of the clay. Thus, understanding the mechanisms of cation exchange is beneficial in minimizing formation damage by the hydration of clays within the pore throats of producing zones.

Note: See Chapter 3, *Water Base Fluids* and Chapter 7, *Borehole Problems*, for a thorough explanation of formation clays and their associated properties.

In addition to formation damage, freshwater invasion can cause the misinterpretation of logs, coring samples, and drillstem tests.

Fluid Loss

In general, completion fluids are used to create hydrostatic pressures greater than the pore pressures of permeable producing zones. The completion fluid invades the permeable zone. The degree of invasion is dependent on the amount, size, and type of solids present in the fluid and the type of porosity in the permeable zone. When losses of whole fluid to the formation occur, the situation is referred to as lost circulation, either total, severe, partial, or seepage. These terms denote the severity of loss, although any loss of whole fluid or any degree of invasion of solids or liquids into producing zones is considered undesirable.

Controlling fluid loss is important for preventing the impairment of production and the loss of expensive completion fluids during workover, drill-in, and gravel pack operations. The selection and use of fluid loss control media and methods should be carefully considered prior to any drilling operation.

Nomenclature

A	Area
CEC	Cation Exchange Capacity
CEC_{bent}	Cation Exchange Capacity, bentonite
CEC_{DS}	Cation Exchange Capacity, drilled solids
CEC_{fluid} CEC_{avg}	Bentonite correction
D	Diameter
f	Filtrate, known temperature
f_l	Filtrate, elevated temperature
F	Force
K	Consistency factor
K_a	Consistency factor, annular
K_p	Consistency factor, pipe
lb_m / bbl	Pounds per barrel
MBT_m	lbm / bbl equivalent of methylene blue capacity
n	Flow behavior index
n_a	Flow behavior index, annular
n_p	Flow behavior index, pipe
% Bentonite	Volume % of bentonite
% DS	Volume % of drilled solids
% LGS	Volume % of low-specific gravity solids
PV	Plastic Viscosity
Re	Reynolds number
T	Time interval
V	Velocity
YP	Yield Point
g	Shear rate
μ	Viscosity
μ_a	Viscosity, apparent
μ_e	Viscosity, effective
μ_∞	Plastic viscosity
μ_1	Viscosity, elevated temperature
ω	Rotation speed
ρ	Density
ρ_{bent}	Density, bentonite
ρ_{DS}	Density, drilled solids
ρ_{LGS}	Density, low-gravity solids
τ	Shear stress
τ_o	Yield stress
θ	Dial reading, viscometer
θ_3	Dial reading, 3 rpm (initial gel)
θ_{300}	Dial reading, 300 rpm
θ_{600}	Dial reading, 600 rpm

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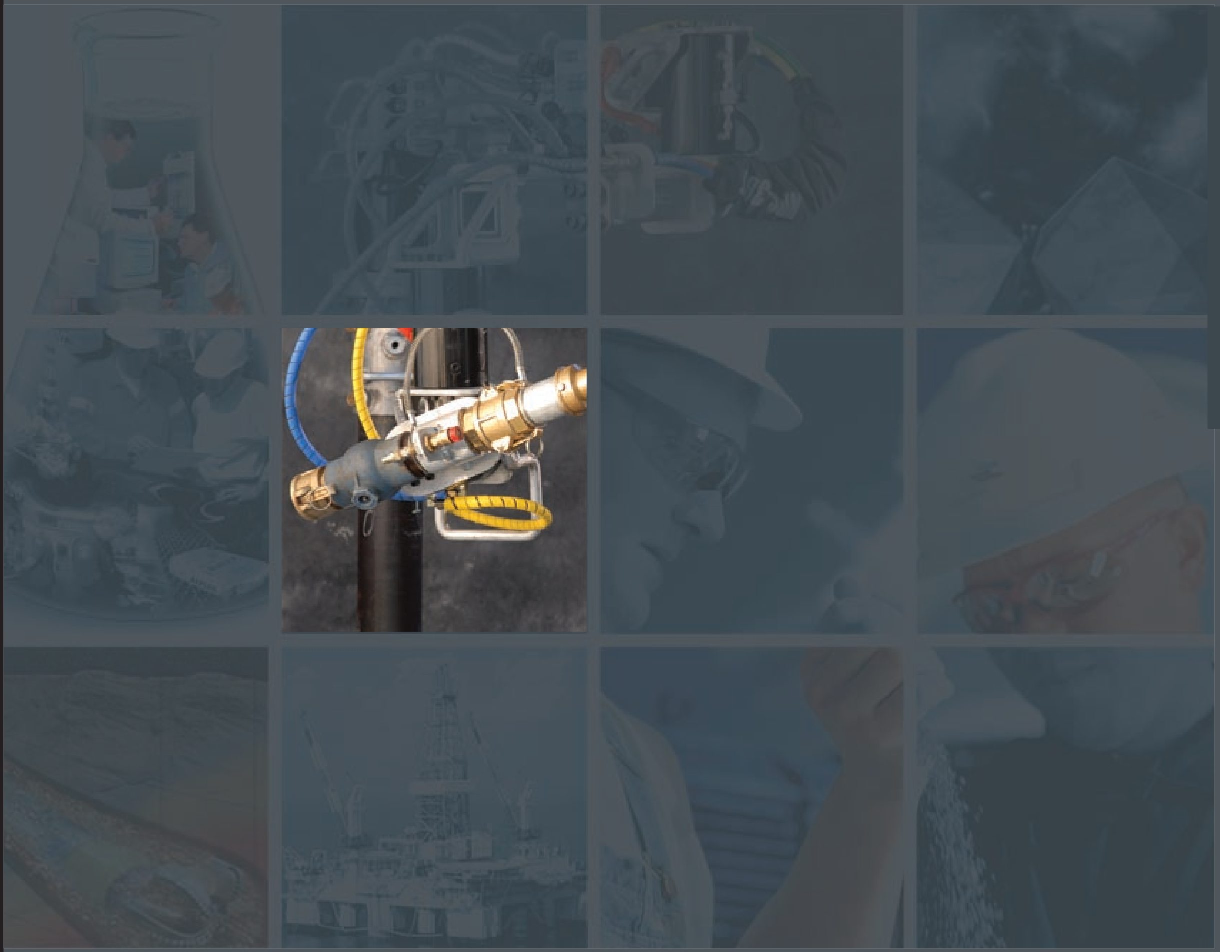

Chapter Two

Formation Mechanics

Chapter 2

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Chapter 2

Formation Mechanics

Successful drilling requires knowledge of the formation type into which the borehole is drilled. The characteristics of that formation, i.e., geological composition, liquid or gas content, pressure, permeability, porosity, reactivity, hydration, etc. will help determine the type of fluid to be used in drilling and completing the wellbore.

Clay and Clay Minerals

The importance of clay and clay minerals in the drilling industry is evident from two viewpoints:

- Commercially mined *clays* are added to drilling fluids to build viscosity, thixotropy, and to contribute to wall building properties.
- C*lay minerals* are present in nearly all sedimentary rocks.
- Clay reaction to the drilling process can produce major problems such as,
- Hole enlargement
- Sloughing
- Hydration
- Rheological problems.

The magnitude of the potential problems is apparent when one realizes that more than half of sedimentary rocks are composed of shales, siltstones, mudstones, etc. These rock types are composed of more than 50% clay minerals. Even sandstones may have as much as 20% to 30% clay minerals. The better understanding one has of clays and clay minerals, the greater the control over problems that may develop in the drilling process.

Definitions / Terminology

Clays can be defined according to physical properties, chemical properties, size, structure, and reactivity in water. One definition cannot adequately describe all types of clays. A simple definition used by many people is that clay is a finely ground, earthy material that can be molded into shapes when wet.

Geologists and mineralogists usually define clays according to the chemical and mineral content that make up the clay. Elements that commonly make up clays are oxygen, silicon, aluminum, calcium, magnesium and potassium. Non-clay minerals generally found are quartz, feldspar, pyrite, and calcite.

Clays are also defined according to their size. The American Petroleum Institute (API) defines clays as being those particles that are two microns or less in size. A micron is equal to one millionth of a meter. In order to grasp the concept of this size, it is sometimes easier if the sizes are scaled up a million-fold. For example:

- A million yard sticks end to end would stretch from Houston to El Paso

- 3 million grains of sand (74 microns) in line would be about the size of the Astrodome (216 meters in diameter)
- A water molecule and most ions increased a million times would be the size of a grain of sand
- A clay particle enlarged a million times would be like a piece of poster paper six inches to six feet across

In terms of reactivity, clays can be classified as either swelling or non-swelling in nature. Regardless of whether a clay will hydrate in water or not, the presence of clays still contribute to the viscosity, gel strengths, and other properties of drilling fluids.

Structure

Clay minerals are hydrous aluminum silicates of a layer-type lattice structure (honeycomb) with magnesium, iron, and potassium located either between the layers or substituted within the lattice. The major exceptions to this are the attapulgite-sepiolite type clays which have a chain-type structure. Basic components of clays are silica tetrahedrons and alumina octahedrons, arranged in a sheet-like structure. These sheets are bound together by shared oxygen between the sheets.

Clays are classified into three major categories depending upon the arrangement of these structural units. For example, if a clay has two silica tetrahedral layers and one alumina octahedral layer, it is referred to as a 2:1 clay type. The structure is an alumina sheet sandwiched between two silica sheets.

Six or seven major clay types make up most of the clay minerals. The seven clay types can be divided into two major groups – *layered* clays and *chain-type* clays.

The layered clays include smectites, illites, kaolinites, chlorites, vermiculites, and mixed-layer clays. The chain-type clays are the attapulgite-sepiolite minerals. Since the smectites are the most important in terms of drilling fluids, most of this discussion will center on these clay minerals. The other clay minerals will be discussed only briefly.

Smectite

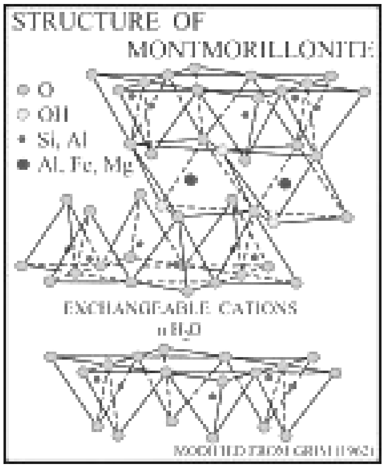


Figure 2-1 Structure of Montmorillonite

Of the clay minerals, smectite is the least stable and the most susceptible to hydration and diagenetic alteration. Two other terms often associated with the smectites are montmorillonite and Bentonite. Montmorillonite is the name given to the clay mineral found near Montmorillon, France. The term was used until recently to refer to the now known smectite group of clays. Bentonite is the term applied to a clay type found near Fort Benton, Montana. Bentonite was formed by the alteration of volcanic ash by water. For this discussion, the terms smectite, montmorillonite, and Bentonite will be used interchangeably.

The basic structure of Bentonite is a thin sheet-like form of alternating layers of silica and alumina. The figure contains diagrams of the montmorillonite structure. Each sheet would resemble a honeycomb three layers thick. The two outside layers would be silica tetrahedrons and the central layer alumina octahedrons. The layers are held together in a very intricate lattice of aluminum, silicon, oxygen, and hydrogen atoms.

This clay “sheet” is a rigid crystal-like salt or diamond. If the clay sheet were pure aluminum, silicon, oxygen, and hydrogen, all of the charges would be equal and the sheet would be electrically neutral and inert. Mica is a common mineral having this characteristic.

Since Bentonite has been exposed to seawater and other sources of cations, some of the silicon and aluminum cations in the structure have been replaced. Iron and magnesium typically replace aluminum and aluminum typically replaces silicon. This replacement causes an imbalance in charges in the structure. This causes the bentonite sheet to be negatively charged. This charge occurs on the flat surface of the sheet or the area called the basal plane. Cations (positive charged particles) are attracted to this negatively charged surface. The predominant cation type determines the type of bentonite and the degree of hydration that it will undergo. The rank of cations from those which promote the most amount of swelling to those which promote the least amount of swelling is lithium, sodium, potassium, magnesium, calcium, aluminum, and hydrogen.

Hydration Mechanics

If a particle of dried bentonite could be enlarged so that it would be visible to the naked eye, it would look like a fan of cards. Each card would be composed of alternating layers of silica and alumina. Between the individual platelets, there would be a thin layer or layering of partially hydrated cations.

These cations would be composed mainly of sodium, calcium, magnesium, and potassium. The origin of these cations was the environment into which the clay was deposited. These positive particles are attracted to the negative charge that exists on the surface of the clay. They loosely hold the clay platelets together. Even in a dehydrated state, each of the cations is surrounded by a thin layer of water and the entire clay platelet is surrounded by a thin layer of water. If this group of clay platelets is dropped in water, the outer exposed surfaces of the platelets and attached ions immediately become hydrated.

As time goes on, water molecules begin to seep in between the platelets. Some of the molecules of water adhere to the clay platelets and some of them go to the individual cations on the platelet surface. In freshwater, bentonite will swell 8 to 10 times its original dry volume. This process is a form of osmosis and hydrogen attraction into the negative clay surfaces. The net effect of these processes is that the clay platelets are pried apart. This is the swelling effect that is noticed when dried bentonite is placed in freshwater. This process of hydration also causes the individual clay platelets to disperse (separate). Even in pure water, complete dispersion of all clay platelets is unlikely. The amount of dispersion that occurs will be dependent upon the type and number of cations that are on the clay surface. If the cations are divalent (two positive charges) dispersion will be less complete. Other factors which contribute to the amount of dispersion are temperature, mechanical agitation, and the purity of the water.

When a clay platelet is fully hydrated, it is surrounded by a cloud of water and hydrated ions. The greatest concentration of water molecules and hydrated cations are near the surface of the clay.

Other Clay Types

Illite

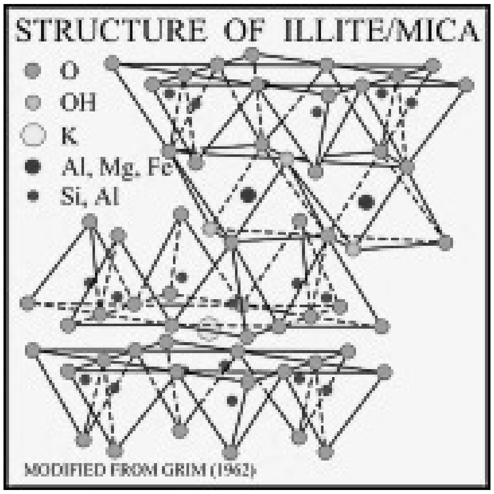
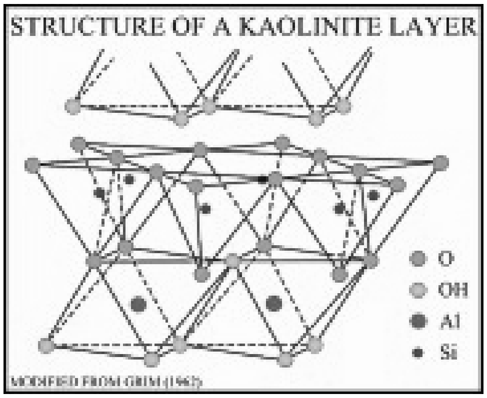


Figure 2-2 Structure Illite/ Mica

Illite is essentially a group name for non-expanding, clay-sized, dioctahedral, micaceous minerals. It is structurally similar to muscovite, but substitution of aluminum for silicon in the silica tetrahedron creates a greater charge deficiency. This deficiency is frequently satisfied by potassium ions located between the successive clay units. Illites are essentially inert to hydration. It is the most abundant clay mineral found in sedimentary rocks.

Kaolinite

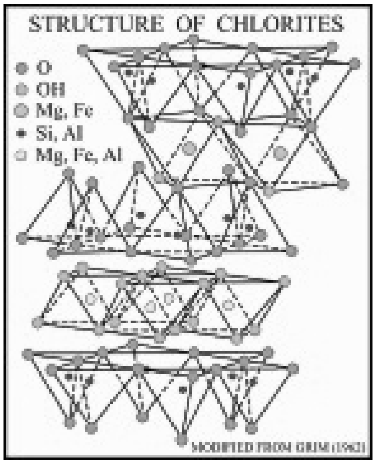

STRUCTURE OF A KAOLINITE LAYER

MODIFIED FROM GRIM (1962)

Figure 2-3   Structure of a Kaolnite Layer

The kaolinite group includes dioctahedral minerals and trioctahedral minerals. These minerals are composed of one silica (octahedral) sheet and one alumina (tetrahedral) sheet. The atoms making up its structure combine almost completely, resulting in a neutrally charged surface. This provides for very little expansion or hydration of the structure.

Chlorite


STRUCTURE OF CHLORITES

MODIFIED FROM GRIM (1962)

Figure 2-4   Structure of Chlorites

Chlorite is similar to the smectite minerals except for a layer of magnesium hydroxide between the clay sheets. This layer neutralizes the surface charge so that the chlorite is non-expandable. Chlorites are common constituents of argillaceous sedimentary rocks where these minerals occur in both detrital and authigenic forms. The basic structure of chlorites consists of negatively charged mica-like layers regularly alternating with positively charged brucite-like octahedral sheets. The various members of this group of clays are differentiated by the kind and amount of substitutions within the brucite-like layer and the tetrahedral and octahedral positions of the mica-like layer.

Attapulgite

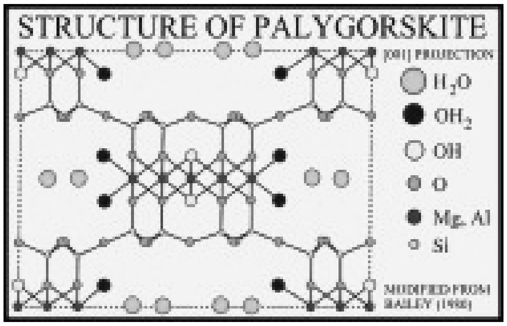


Figure 2-5 Structure of Palygorskite

The attapulgite, sepiolite and polygorskite clay minerals are completely different in structure and shape from the clay minerals discussed so far. Chemically, attapulgite is a hydrous magnesium alumina silicate. The structure of the attapulgite crystals consist of bundles of laths. These are hollow needle-like structures. When mixed vigorously with water the bundles separate into individual laths. The individual laths then clump together in “brush heap” type arrangements. This provides a viscosifying effect to the water. Since the viscosity in attapulgite suspensions is dependent on mechanical interference rather than electrostatic forces, it makes an excellent suspending agent in saltwater.

Sepiolite is similar to attapulgite in structure and chemistry. Sepiolite-base fluids have high-temperature stability and have been used on many high-temperature wells.

Mixed-Layer Clays

Mixed-layer clays are formed by the alteration of different clay minerals. The mixed-layer clays are usually a combination of illite and smectite type clays. The proportion of swelling to non-swelling layers determines the expandability of these clay minerals.

Base Exchange

Base exchange in clays occurs when certain cations in solution are exchanged for others which are adsorbed on the crystalline surfaces of the clay. In many clays, the adsorbed cations control the tendency of the clay to swell and/or disperse in the presence of water. Those cations that are most frequently involved in the base exchange of clays are sodium, potassium, magnesium, and calcium. These cations are adsorbed on the clay surfaces between individual platelets and around the edges of the structural units. The crystalline structure of the clay mineral is not altered in the base exchange progress. Several factors affect base exchange in clays.

- The relative replacement power of the available cations
- The type of clay (see Table 2-1)

Table 2-1 Clay and Clay Minerals Base Exchange Capacity

Clay Material	Meg/100 g of Dry Clay
Montmorillonite	50 - 130
Illite	10 - 40
Kaolinite	3 - 15
Attapulgite-Sepiolite	10 - 35

- The amount of charge deficiency on the clay surface
- The concentration of the cations in solution
- The size and type of the replacing cations

The replacement power of various cations is controlled by two major factors:

- The number of charges on the cation
- The size of the hydrated cation

In general, cations with more positive charges (polyvalent) will have greater replacement power. An exception to this is the hydrogen ion which often acts as a polyvalent ion.

The most commonly occurring cations may be ranked according to their replacement power as shown in Table 2-2**.**

Table 2-2 Order of Cation Replacibility

Easiest
Lithium
Sodium
Potassium
Magnesium
Calcium
Hydrogen
Hardest

For example, if the concentration of calcium ions in a sodium bentonite suspension were increased, the calcium ions would tend to replace the sodium cations.

The relative concentration of the various cations present has a significant effect on base exchange. When cations of a lower replacement power are present in greater concentration than those of a higher replacement power, the desired base exchange may not occur. In this situation, the lower replacement power cations are occupying a large number of the base exchange sites.

Cation size is determined by the atomic radius of the cations and the amount of water required to hydrate the cations. Smaller cations are easier to exchange and result in less hydration. Most monovalent cations are smaller and allow less hydration. An exception to this is the potassium cation.

The potassium cation is thought to prevent hydration of clays due mainly to its size. The potassium cation hydrates very little and has a diameter almost the same size as the spacing between the oxygen in the outer silica tetrahedrons of the clays. Since the potassium cation fits nicely in the molecular structure of the clays, it is able to hold two platelets tightly together.

The phenomenon of base exchange is used in the design of wellbore fluid systems. The basis for calcium and potassium fluid systems is to prevent the hydration and swelling of formation drill solids through the mechanism of base exchange.

States of Clays

In general clays exist in one of two states, either that of *aggregation* or *dispersion*. Clay particle association is shown in Figure 2-1.

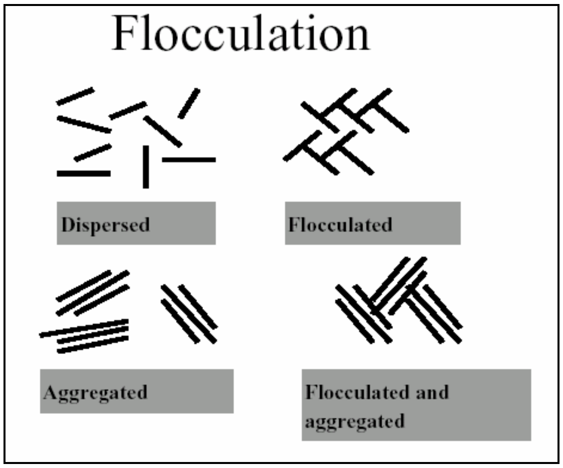


Figure 2-6 Cays and Clay Minerals Particle Association

The aggregated state occurs when the clay platelets are stacked parallel to each other, similar to a stacked deck of cards. Unhydrated clay exists in this state. When the clay contacts water, the nature of the cations holding the clay platelets together may or may not allow dispersion to take place. The dispersed state occurs when the clay platelets separate. Aggregated or dispersed clays can undergo *flocculation* or *deflocculation*. Flocculation occurs when clay platelets are electrically attracted to each other. The predominant area of attraction is thought to be on the edges of the clay platelets.

The edges of the clays are thought to be predominately positively charged, as opposed to the negatively charged clay basal plane area. When flocculated, the individual clays can clump together in particles large enough to be seen by the naked eye. They are often large enough to separate and settle out of solution.

Several mechanisms exist by which flocculation can occur. It is generally caused by changes in the electrolyte concentration, temperature, and solids crowding. Deflocculation is the reverse of the flocculation process. Deflocculation occurs when the clay particles remain geometrically independent and unassociated with adjacent particles. It is achieved by the addition of a deflocculant, a temperature stabilizer, or a dilution fluid.

Chemical deflocculants are thought to adsorb on the edges of the clays, thereby neutralizing the positive charges and allowing the clay platelets to separate.

Clay Identification

The most common analysis at present to determine the type of clays in cuttings or cavings is *X-ray diffraction*. Table 2-3 is an example of an X-ray diffraction analysis of a Norway shale. It is based on the reflection of monochromatic radiation of known wavelength. Each atom produces a characteristic wave reflection which depends on its type and its position in the molecular structure. Each mineralogical type produces a characteristic spectrum. With the help of a collection of spectra, mineral structures can be identified.

Table 2-3 Typical Mineralogical Analysis of Norway Shale

Mineral Component	Percentage
Quartz	10 - 15
Feldspar	1 - 2
Calcite	Trace
Pyrite	1 - 2
Illite	10 - 15
*Mixed Layer	35 - 40
Kaolinite	15 - 20
Chlorite	3 - 5
** Mixed layer clays have 25% to 50% expandable layers*	

Sandstone

Composition and Characteristics

Sandstone bodies are formed in a large variety of environments and acquire a variety of shapes and characteristics. Because sandstone is deposited virtually everywhere, it occurs most often as a reservoir rock.

Sandstone is composed of sand-sized particles, ranging in size from 1/16 mm to 2 mm, that have been compacted or cemented together. Its size relative to other clastic sedimentary rocks (rocks composed of *clasts*, which are fragments or grains of pre-existing rock) is shown in table 2-4.

Table 2-4 Clastic Sedimentary Rocks

Sediment	Size	Rock
Gravel	> 2 mm	Conglomerate
Sand	2 to 1/16 mm	Sandstone
Silt	1/16 to 1/256 mm	Siltstone
Clay	< 1/256 mm	Shale

Sorting of sandstone particles ranges from good to poor in a rock that can be designated as coarse, medium or fine within the size range for sandstone. Since sandstone fragments can be of virtually any composition, sandstone rock itself can be designated according to its mineral composition or its combination of constituents. Examples are:

- Quartz sandstone, consisting of resistant quarts grains
- Felspathic or Arkosic sandstone with more than 20% feldspar grains
- Greywacke, consisting of poorly-sorted grains with abundant feldspar
- Clay matrix, some of which may be altered to chlorite

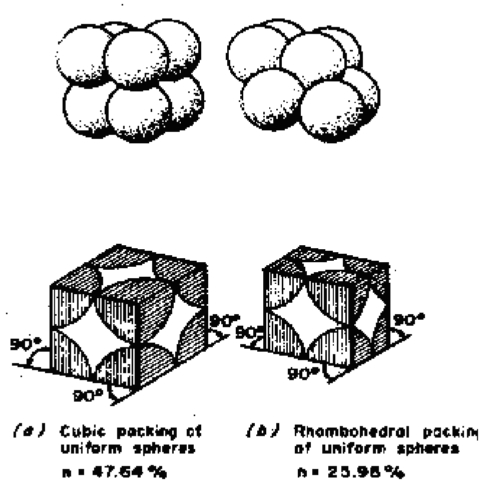
- Calcareous sandstone, composed of limestone fragments

Clean, well-sorted sandstones can be tightly or loosely cemented and can, therefore, have a wide range of porosity and permeability. Many Gulf Coast sandstones, because they are clean, well-rounded, and weakly cemented, provide good hydrocarbon reservoirs. Certain Ordovician sandstones of the Mid-Continent area are some of the best-sorted, best-rounded, clean sandstones developed anywhere in the world. Again, being loosely cemented, they are excellent reservoirs for hydrocarbon deposits.

Porosity and Permeability

Porosity represents the amount of void space in a rock and is measured as a percentage of the rock volume. In sandstones, porosity is controlled primarily by sorting, cementation, and to a lesser extent, by the way the grains are packed together. Porosity is maximized when grains are all spherical and of equivalent size, but becomes progressively less as the gains are more angular since such grains pack together more closely.

Grains pack together in one of two ways – cubic or rhombohedral as shown below.



(a) Cubic packing of uniform spheres n = 47.64 %

(b) Rhombohedral packin of uniform spheres n = 25.96 %

Figure 2-7 Structure of Montmorillonite Clay

The figure on the left is open (cubic) packing where the porosity is about 48 percent. The close (rhombohedral) packing on the right has only 26 percent porosity because the grains are packed into a smaller space. Artificially mixed clean sand has measured porosity of about 43 percent for extremely well sorted sands, irrespective of grain size, decreasing to about 25 percent for poorly-sorted, medium to coarse sand, while very fine grained sands still have over 30 percent porosity.

The ease with which a fluid moves through the interconnected pore spaces of a rock denotes the degree of permeability. Permeability of highly porous, well-sorted sand varies from 475 millidarcies (mD) for a coarse-grained sand to about 5 mD for a very fine-grained sand. Permeability may decrease for a coarse-grained sand to about 10 mD if it is poorly sorted.

Compaction and Sedimentation

Compaction by weight of the overlying sediments squeezes the sand grains closer together. At greater depths, it may crush and fracture the grains. The results are smaller pores and, therefore, lower porosity and a decrease in permeability. Thus, a sandstone reservoir which could produce petroleum at 10,000 feet might become too impermeable to be of any economic value at 20,000 feet.

Deposits of cementing material between grains of sediment, whether compacted or uncompacted, will bind grains together. Sediments that are tightly cemented produce hard, coherent rocks, thus solidifying the formation. Since this solidity reduces both porosity and permeability characteristics of rock, the formation loses its potential as a productive reservoir. Should this be the case, fracturing of very hard limestones and sandstones can greatly enhance their intrinsically low reservoir potential.

Carbonates

An abundant rock that often contains oil is limestone. Sometimes the limestone contains substantial amounts of magnesium, replacing calcium, and it then becomes dolomite. It has become customary in the oil business to call both limestone and dolomite carbonates to avoid making a distinction.

Oil was first discovered in carbonate rocks in Ontario in the 1850's and later (in the early 1900's) in the Tampico region of Mexico. In the 1920's, the carbonates of West Texas became important. By the 1930's and 1940's, the great oilfields of Iran and Saudi Arabia were found in the Asmari limestone of Miocene age and the Jurassic limestone, respectively. It has been estimated that half the world's oil reserves are in carbonates, although there are numerically fewer carbonate than sandstone reservoirs outside the Middle East.

Carbonates differ in many respects from sandstones. They are mostly formed from the remains of animals (shellfish) and plants (algae); they are therefore found in nearly the same place where they originated and were not transported and then deposited like sandstones. Calcium carbonate can easily be dissolved in water solutions, so that solution and re-crystallization of the carbonates after their deposition (diagenesis) is very common. This solution forms some of the cavities that can store oil. Limestones are much more brittle than sandstones, and as a result of folding or faulting they may break, leaving open fractures that serve as routes of fluid flow.

Modern Carbonate Depositional Environments

Calcium carbonate is precipitated from seawater by many types of organisms. Mollusks such as oysters and clams make their shells of calcium carbonate, but many other animals and plants also form shells which are called exoskeletons. Some animals, notably the corals, live in large colonies and form sturdy build-ups or reefs. These are attacked by waves and fish, producing fine calcareous mud that washes down the sides of the reefs.

Naming Carbonate Rock Types

The interpretation of carbonate facies to define zones of good reservoir properties has been held back by the lack of a generally accepted system for naming the different rock types. Two different geologists describing the same core might very well use different words.

In 1913 A. W. Grabau proposed the words calcilucite for consolidated lime mud, calcarenite for limestones whose particles are sand size, and calcirudite for limestones with pebble size grains. These terms are simple, descriptive, and still widely used.

Beginning about 25 years ago, it became obvious to oil company geologists that some uniformity in the terms used to describe carbonates was desirable. Several major oil companies developed classifications about the same time. The most widely used have been those of Robert Folk of the University of Texas, Robert Dunham of Shell, and Leighton and Pendexter of Exxon. The latter is similar to Folk's. Perhaps the most practical and easily understood classification is a modification of Folk's suggested by G. M. Friedman.

Folk said that a carbonate rock consists of three textural components: grains, matrix and cement. The cement is clear calcite that filled or partially filled the pores after the original deposition. There are several different kinds of grains, of which four are the most important. These are (1) shell fragments called “bio”; (2) fragments of previously deposited limestone, called “intraclasts”, (3) small round pellets, the excreta of worms and other small burrowing organisms; and (4) ooliths, spheres formed by rolling and coating lime particles along the bottom.

The matrix is lime of clay particle size (lime mud). It is called micrite. The clear secondary calcite cement is called sparite.

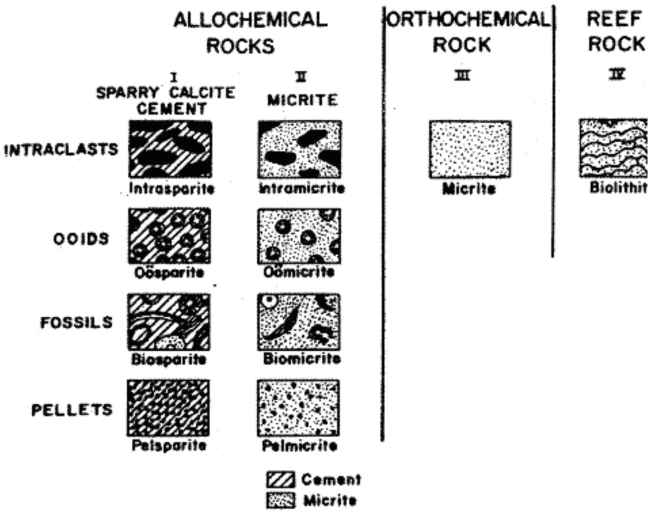


Figure 2-8 Carbonate Rock Types

Thus, a rock consisting mainly of clear secondary calcite with intraclast grains would be called a “intrasparite”. A rock consisting mainly of micrite (lime mud) with grains of broken shell fragments would be called “biomicrite”. Biomicrite and pelmicrite are the most common limestone types. These eight types are shown in diagrammatically below.

Besides these eight combinations, there are limestones consisting only of micrite and some consisting of the remains of upstanding reef-building organisms. So there are ten types of limestone in all.

Diagenesis of Carbonates

Lithification. Calcium carbonate ($CaCO_3$) is slightly soluble in water, but calcium bicarbonate ($CaHCO_3$) is very soluble. When carbon dioxide gas (CO_2) is dissolved in water, it forms carbonic acid (H_2CO_3), which changes calcium carbonate to calcium bicarbonate. The reactions are complicated but may be summarized in the following equation:

$$CaCO_3 + H_2O + CO_2 \leftrightarrow Ca^{++} + 2 \bullet HCO_3^{-}$$

The $CaCO_3$ is crystalline, the Ca^{++} and 2 HCO_3^{-} are ions in solution. The reaction is reversible, so that crystalline calcium carbonate may be either dissolved or precipitated, depending on conditions in the water solution. Of these, the most important is pH. When carbon dioxide dissolves in water it makes the water more acid, that is, it lowers the pH. Carbon dioxide is dissolved out of the air and is also produced by bacteria that decompose organic matter and by animals in their respiration. It is taken out of water by plants such as algae that use it to form organic carbonic compounds. Slight changes in pH (and also in Eh, which is oxidation-reduction potential) thus cause solutions to dissolve or precipitate calcium carbonate.

The porosity and permeability of carbonate rocks, like those of sands, are controlled by the currents and waves in the original depositional environment. However, the original texture is vastly altered by the solution and re-precipitation of calcium carbonate after burial.

Recently deposited lime muds consist mainly of aragonite (which is a different and more unstable crystallographic form of calcium carbonate) and high-magnesium calcite. Consolidated limestones consist of low-magnesium calcite and sometimes dolomite. Profound changes take place soon after burial.

When originally deposited, lime muds have a porosity of 50 percent or more, but when they are consolidated into limestone their porosity is generally less than two percent. Shales lose porosity by a compaction process that involves flattening. However, limestones are formed from lime mud by re-crystallization, and the pores are filled by precipitation of calcite, apparently brought in from elsewhere, because no compaction has occurred. Oolites and fossils are not squashed and flattened.

Consolidated limestones show abundant evidence of solution and precipitation. Micritic skeletal limestones often have the original shells dissolved out, leaving cavities. Irregular channels and cavities (vugs) formed by solution permeate some limestones. These, like fractures, are usually lined and are sometimes filled with clear crystalline calcite.

Dolomitization. Limestones are often partially or completely changed to dolomite. Dolomite has the composition $CaMgCO_3$ and it is crystallographically similar to calcite. However, it has a greater density, less solubility in water, less ductility, and more brittleness. Obviously, waters enriched in magnesium permeated the calcium carbonate deposits sometime after their burial. They laid down an atom of magnesium and picked up one of calcium. Usually the dolomitization involved a re-crystallization. First, dolomite crystals (rhombi) form from the micrite in a random manner. Later, the dolomitization micrite is dissolved, leaving intracrystalline porosity. Some of the Arabian fields produce from beautiful crystalline dolomite, which resembles granulated sugar.

Types of Pores in Carbonates

The interstitial pores in carbonates basically resemble those in sandstones. They are the open cavities between the grains, usually more or less clogged by mud or precipitated substances, or opened by water solution. However, carbonates differ from sandstones in being soluble and brittle. Because they are soluble, they often have large cavities called channels or vugs. Because they are brittle, they often have fractures that, if they are open or enlarged by solution, are also large openings. Carbonates therefore often – but by no means always – have a secondary porosity that may be greater than the primary interstitial, or matrix, porosity. The fractures may contribute only slightly to porosity but vastly increase the permeability. The behavior of fluids in carbonates containing only interstitial porosity resembles that in sandstones, but in vuggy or fractured carbonates it is entirely different.

Permeability in Carbonates

Carbonates are characterized by different types of porosity and have unmodal, bimodal and other complex pore size distributions, which result in wide permeability variations for the same total porosity. Although most sedimentary rocks possess significant porosity when freshly deposited, the rate at which these vital properties undergo reduction with age is principally due to compaction. The compatibility of sedimentary rock depends more on the texture than it does on composition. The textures of dense limestones are not effective reservoir materials because of compaction, unless they have been extensively fractured after they were formed. Fracturing produces secondary permeability meaning it was created *after* the rock in question was formed. The fractures create new void spaces in the rocks which allow fluids to move into the voids. Primary permeability occurs *during* the compaction process when the original materials are forming the rock.

Reservoir Pressure

The fluid in the pores of reservoir rock is under a certain degree of pressure, generally called reservoir (or formation) pressure. A normal reservoir pressure at the oil-water contact approximates very closely the hydrostatic pressure of a column of salt water to the depth. The hydrostatic pressure gradient varies somewhat, depending on the amount of dissolved salts in the average water for a given area. For fresh water, it is 0.433 psi/ft of depth. For water containing 80,000 ppm of dissolved salts (U.S. Gulf Coast), the pressure is approximately 0.465 psi/ft. However, normal marine water is about 35,000 dissolved salts, approximately 0.446 psi/ft. Reservoirs can contain fluids under abnormal pressure up to as high as 1.00 psi/ft of depth.

Abnormal pressure may develop in isolated reservoirs as a result of compaction of the surrounding shales by the weight of the overburden. During this process, water is expelled from the shale into any zone of lower pressure. This may be into a wholly confined sandstone which does not compact as much as the shale. Consequently, its contained water is under a lower pressure than that in the shale. Ultimately, a state of equilibrium can be reached when no further water can be expelled into the sandstone, and its fluid pressure will approximate that of the shale.

Since compaction of sandstones is related to the pressure of the pore fluid as well as to the pressure exerted by the overburden, it follows that abnormally pressured sandstones are partially supported by the fluid pressure and partially by grain-to-grain contact. Consequently, when the abnormal pressure is reduced by production, compaction of the reservoir begins to occur. Subsurface compaction can cause serious problems, not only in collapse of the well casing, but also because of the subsidence reflected at the surface. Such occurrences result in very expensive landfill and well repair costs.

It has been demonstrated that there can be a direct relationship between subsidence and the amount of liquid withdrawn. Studies of the Wilmington Field in California indicated that re-pressuring by water injection would increase oil recovery and stop compaction. Subsidence was stopped by such a program, and, in places, the surface regained some of the elevation that was lost. However, work on sediments has shown that this compaction is not entirely reversible. Some permanent reduction of porosity and permeability results from permitting abnormal reservoir pressure to decline, and this may adversely affect the rate of production and possibly, the ultimate recovery.

Formation Damage

Permeability

It is imperative that rocks containing hydrocarbons not be inhibited in their ability to produce oil or gas during drilling. Rocks allow the flow of a liquid or gas when their pore spaces are connected to form channels. This ability to flow is called *permeability*, and the standard unit of measure is termed the Darcy, named for Henry Darcy who developed a mathematical equation called Darcy's Law that can be used to calculate permeability. Using this equation, the permeability of a material can be measured if the following values are known:

- Length and cross-sectional area of the material
- Viscosity of the fluid flowing through it
- Amount of pressure needed to cause the flow
- Flow rate (i.e., the volume of fluid that flows through the material in a given amount of time)

A piece of material one centimeter long and one square centimeter in area that will flow water at a rate of one cubic centimeter per second at a driving pressure of one atmosphere (14.7 psi) has a permeability of one Darcy. Most rocks have much less than one (1) Darcy permeability, so the most commonly used unit of measure in the oil and gas industry is the millidarcy, which is $^1/_{1000}$ of a Darcy. Devices which measure permeability, called permeameters, are used extensively to measure the permeabilities of formation samples.

Causes and Remedies

As was stated earlier, it is obvious that a rock formation's permeability should be reduced as little as possible when it is drilled and completed. This is difficult to avoid, however, and the reduction of permeability is referred to as *formation damage*. In the drilling fluids industry, the principal concern is formation damage caused by drilling fluids. Formation damage caused by drilling fluids involves the interaction of the drilling fluid or the filtrate with a permeable rock formation that results in a loss of permeability. After a formation is drilled, pressure and flow tests can sometimes be carried out to determine if it has experienced damage.

The simplest form of formation damage involves the flow of the entire drilling fluid (liquids and solids) into the pores of the rock; this is usually called *fluid invasion*. If enough solid material such as bentonite or weighting agents accumulate in the pores, blockage and permeability loss can result. This type of damage can occur due to one or a combination of the following factors:

- Poor fluid loss control
- Excessive overbalance
- High-formation permeability

An example of a sandstone which experienced such invasion is shown in Figure 2-9. Fluid invasion can be avoided if the drilling fluid forms a stable filter cake on the borehole wall that serves as a barrier to invasion. One possible remedy in extreme cases is the use of *bridging agents*, which are particulate materials such as calcium carbonate that block the formation's pores at or near the borehole wall.

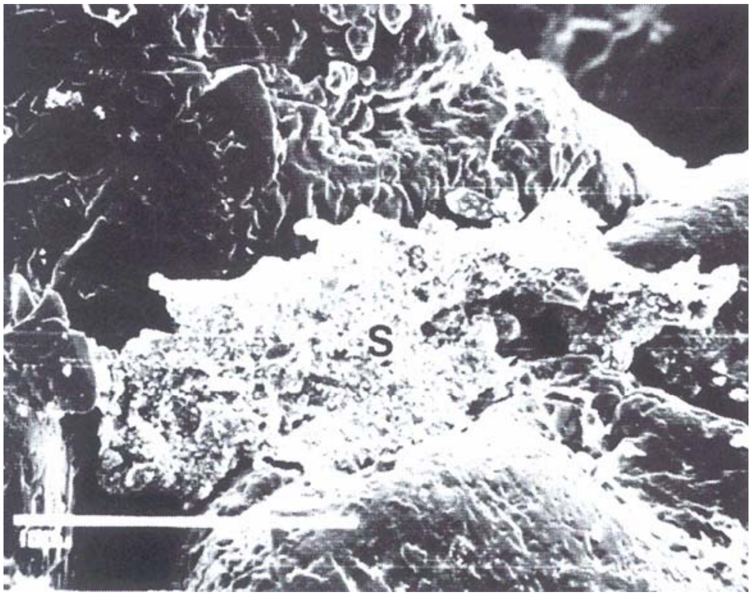


Figure 2-9 SEM Photomicrograph of Venezuelan Sandstone

The permeability of this sandstone was greatly reduced by fluid invasion during a return permeability test. The light gray material labeled "S" in the center of the photograph are drilling fluid solids (barite and gel) that have plugged a pore space. Some open pore space can be seen in the lower left corner.

Selecting the proper size bridging agent is critical; if the size of the formation pores is known, a bridging agent that will block the pores without passing through them can be selected. Abrams[1] presents guidelines for bridging agent use.

Other forms of formation damage are more complex, involving chemical reactions between the drilling fluids and formations. Carbonate rocks (limestones and dolomites) are not very reactive with most drilling fluids, so this type of damage is most likely to occur in clastic rocks such as sandstones. Clastic rocks consist of a network of interconnected particles, usually quartz or feldspar, called *framework grains*. The pore spaces between these grains may be empty or filled by other minerals. The pore spaces in these rocks may contain clay minerals. Because clay minerals can be highly reactive with drilling fluids, formation damage can occur in clay-bearing clastic rocks. “Clean” sandstones that have no clay are not highly vulnerable to chemical formation damage since most framework grains are not reactive.

If a sandstone contains expandable clays such as smectite or mixed-layer types, the potential for formation damage exists. If a drilling fluid causes these clays to swell by cation exchange or further hydration in their interlayer sites, this may cause them to detach, migrate, and plug the pores, causing a loss of permeability (see Figure 2-10). In rocks whose framework grains are bound together by expandable clays, disaggregation and borehole washout can also occur (see Figure 2-11).

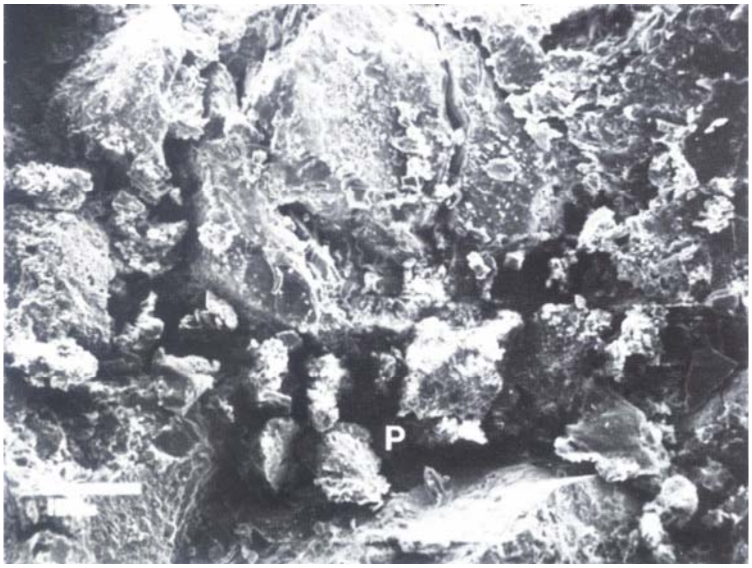


Figure 2-10 Photomicrograph of Wilcox Sandstone

The particles labeled “P” are clay and other fine material that have migrated and plugged a pore space. Mixed-layer clays are common in this sample, and exposure to a high pH lignosulfonate fluid caused them to swell and detach, causing a 63% loss of permeability.

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[1] A. Abrams, *“Mud Design to Minimize Rock Impairment Due to Particle Invasion”*, SPE 5713, 1977

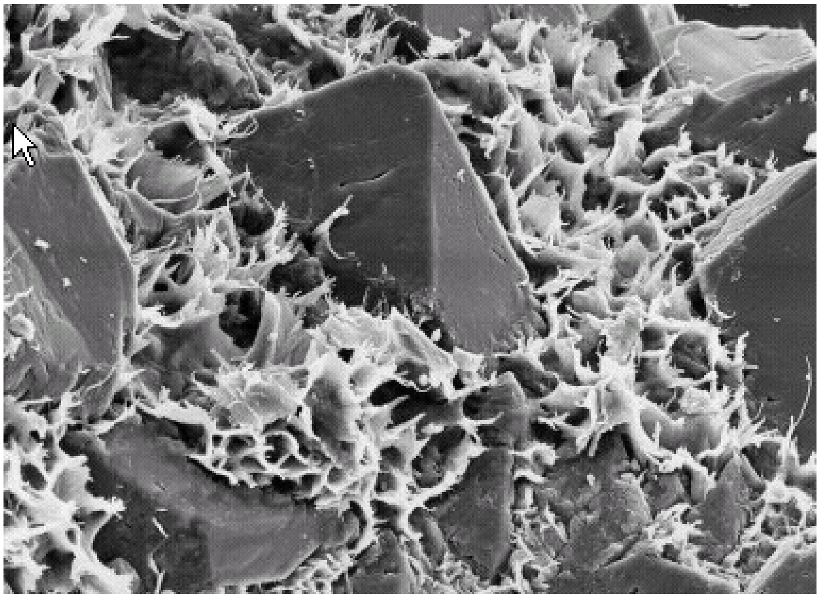


Figure 2-11 Photomicrograph of Sandstone Impregnated with Clay

Some sandstone such as this one has extensive coatings of clays on the framework grain surface. In this image, the clay, presumably illite, is the feather-like material filling the pore spaces between the quartz crystals.

The prevention of clay swelling and resulting problems can be accomplished by minimizing fluid loss and using inhibitive drilling fluids. Such fluids include certain polymers, those with potassium salts and oil-base fluids. Clay swelling is prevented by the potassium ion because it fits well into a clay's interlayer sites and stabilizes its structure. Polymers tend to be adsorbed on the clay's outer surfaces and prevent chemical alteration in the interior sites.

Because hydroxyl ions tend to hydrate expandable clays, drilling fluids such as lignosulfonates that are run at high pH can be damaging. This is part of the reason why lower pH fluids such as polymers are less damaging, and laboratory tests have shown that keeping the pH as low as possible in dispersed fluids will reduce formation damage in fluid-sensitive rocks. The base oils in oil-base fluids do not react with clays and, if included water is kept as the internal phase of the emulsion, an oil-base fluid will be highly inhibitive.

Formation damage can also occur in clastic rocks with non-expandable clays such as kaolinite or illite. These clay minerals tend to form plates and fibers that are loosely attached to the pore walls (see Figure 2-12).

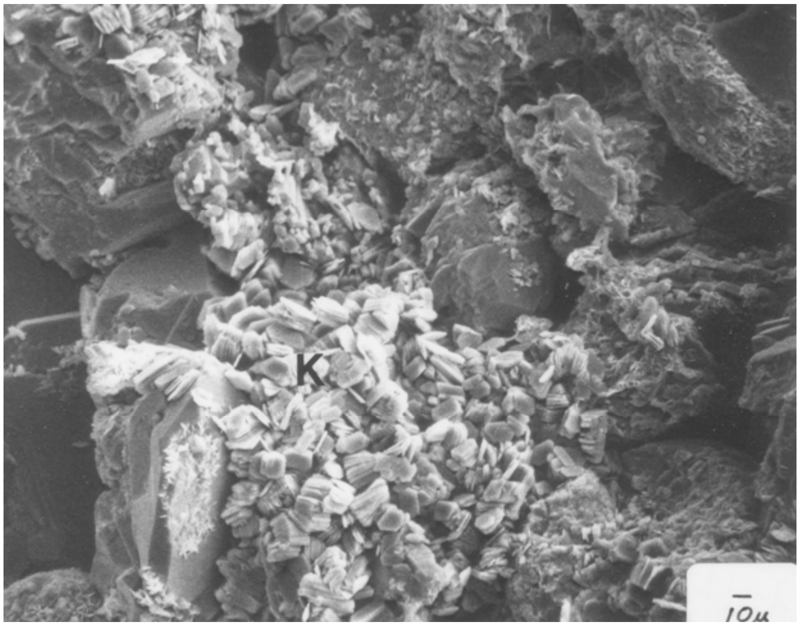


Figure 2-12 Photomicrograph of Platy Kaolinite Crystals

This photomicrograph is of a cluster of platy kaolinite crystals (k) that are filling a sandstone pore. Although these clays do not swell, they can still be made to detach and migrate if a fluid of greatly higher or lower salinity than the natural formation water is introduced.

If a fluid is introduced into a rock that contains many of these clays, they can detach, migrate, and plug pores if the invading fluid is chemically different from the natural formation fluid. Knowledge of a formation's water chemistry can be helpful in designing a non-damaging fluid. Another type of chemical formation damage, not caused by clays, involves the precipitation of materials in the pore spaces due to a reaction between formation water and the drilling fluid. For example, if a formation's water contains abundant bicarbonate ions, it could react with a calcium-rich drilling fluid to form pore-blocking calcium carbonate.

Laboratory Studies

Formation damage can be studied in the laboratory using a *return permeameter*, a device that can measure the permeability of rock samples before and after exposure to drilling fluids (see Figure 2-13).

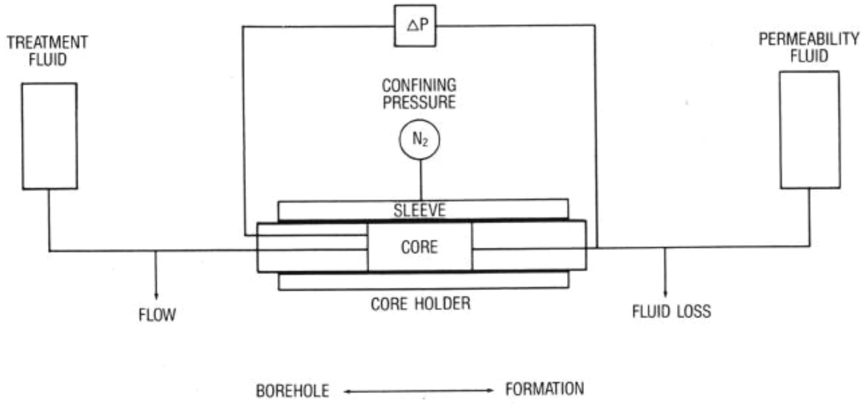


Figure 2-13 Schematic Diagram of a Return Permeameter

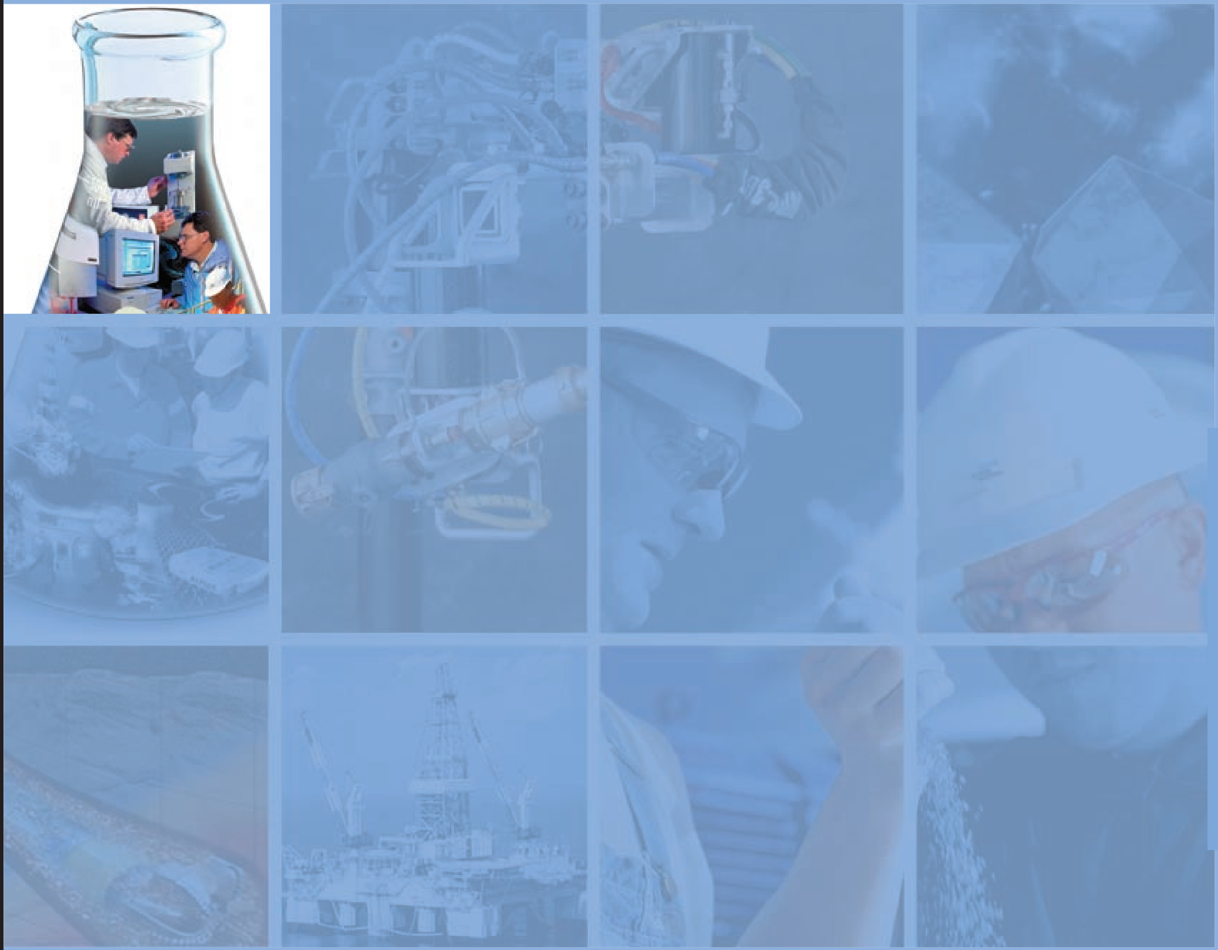
The cylinder in the center is a pressure cell that contains the rock sample at a specified temperature and pressure. A fluid or gas is flowed through from right to left in order to measure permeability, and then the test drilling fluid is circulated through the left side of the cell where it will contact one end of the core sample. The permeability is then re-measured to determine the percent return permeability.

This device consists of a pressure chamber that contains the core sample at a certain temperature and pressure, flow lines for fluids and gasses, and gauges to measure pressures and flow rates in order to calculate permeability. After the permeability of the sample in its natural state is measured, the core is then exposed to a drilling or other test fluid for a specified time, and then its permeability is re-measured.

The results of these tests are often given as *percent return permeability* which is simply the percentage of the original permeability retained by the core after exposure to the test fluid. In other words, a sample that experienced no damage would have 100% return permeability. The purpose of these tests is to evaluate a variety of drilling fluids to see which ones cause the least amount of damage.

Some rocks are more prone than others to formation damage, so samples from the actual formation to be drilled are necessary to properly evaluate test fluids. Because this is useful information, many operators will furnish samples for return permeability testing. As more samples from a particular region are tested, a valuable database can be built up that can be used in selecting drilling fluids for use in that area.

Besides their use in return permeability testing, formation samples can be examined by X-ray diffraction, scanning electron microscopy, and thin section analysis to determine the mineralogical content, pore structure, and how the clay minerals are distributed in the rock. The vulnerability of a reservoir rock to formation damage can often be predicted by using these techniques. After the cores are tested for return permeability, they can be examined in the scanning electron microscope for evidence of permeability loss.



Chapter Three

Water–Base Drilling Fluids

Chapter 3

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Chapter 3

Water-base Drilling Fluids

Water-based drilling fluids, regardless of the name assigned to them, usually contain clays, water soluble chemicals (including salts), a pH control additive (hydroxyl source), and one or more organic polymers, surfactants, and deflocculants.

Introduction

In order for drilling fluid engineering to be a science and not an art, a basic understanding of the chemistry involved is required. This chapter attempts to provide the chemical background to the reactions that take place in the fluid.

By adoption of this approach the engineer will be well equipped to deal with variations in the fluid properties which may occur from time to time. If the basic chemical concepts are well understood, then the causes of any problems can be better identified and dealt with

The Structure of Matter

The properties and reactions of materials can be related to the basic structures of the atoms and molecules of which they are formed. The difference between water and diesel, bentonite and sand, and so on, arises from their physical and chemical properties which are best understood in these terms

Elements and Compounds

An element is a chemically unique substance which cannot be split up into a simpler chemical form by chemical means. The names of the various elements are usually written as abbreviations to simplify chemical notation. A full list of elements and their symbols is given in Table 3-1.

Elements can combine together to form compounds. A compound has different chemical and physical properties than those of the simple mixture of elements from which the compound is formed. Thus hydrogen and oxygen are both gases and remain gases when they are mixed together. However, if they are chemically combined, they form water, which is a liquid. When elements combine together, they do so in a fixed ratio by weight, which always remains constant for one particular compound.

Atoms and Molecules

An *atom* is the smallest particle of an element which can exist and still retain the same chemical properties of that element. Atoms are the basic building bricks of matter from which all things are constructed. They are the smallest units of matter which can undergo chemical change.

A *molecule* is the smallest particle of a compound which can exist and still retain the same chemical properties of that compound. Molecules consist of atoms chemically bonded together in a precise arrangement. A molecule of water consists of two atoms of hydrogen combined with one atom of oxygen to give a chemical formula of H_2O. When the elements hydrogen and oxygen combine to form the compound water, each molecule of water consists of two atoms of hydrogen bonded to one atom of oxygen.

Atomic structure

Atoms are indivisible by chemical means, but other methods show that they are composed of three simpler particles. These are neutrons, protons, and electrons.

Neutrons have no charge and are assigned a mass of one atomic mass unit, or 1 a.m.u., but carry a single positive charge. Electrons are much lighter, being only 1/1840 a.m.u. They carry a single negative charge.

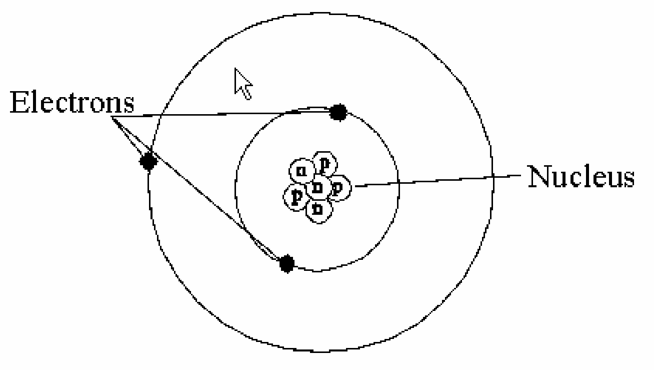


Figure 3-1 Pictorial Representation of Atomic Structure

The simplified picture of an atom is that of a dense nucleus containing all the neutrons and protons surrounded by a diffuse “cloud” of electrons which orbit the nucleus in various electron “shells” or orbitals. Thus the nucleus carries all the positive charge of the atom and negative charge is spread over a comparatively much larger area by the electron cloud. The electrons are equal in number to the protons so that overall the atom is electronically neutral.

Atomic number

The number of protons in the nucleus is called the atomic number and determines the identity of an atom. There are over a hundred different elements, each characterized by a different number of protons in the nucleus of their atoms. Hence each element has a different atomic number. Most elements are found in nature, though some only exist on earth by virtue of artificial synthesis in a nuclear reactor.

The terms “atom” and “element” are often mixed up or left out when referring to elements by name. Thus “Iron has a density of 7.7” refers to the element but “Iron has an atomic number of 26” refers to the atoms of the element iron having 26 protons in their nucleus.

Lists of atomic numbers are given in Table 3-1.

Atomic weight

Carbon has six protons (each of mass 1 a.m.u.) in its nucleus and thus has atomic number 6. Most carbon atoms have six neutrons (also each of mass 1 a.m.u.) in their nucleus and the atomic weight of one atom of this type of carbon is defined as 12.00000 a.m.u. The mass of the electrons is included in this figure, but their contribution to the total is very small. All other elements are compared to this on a relative scale.

Atomic weights for all the elements are given to the nearest 0.01 a.m.u. in Table 3-1. At this level of accuracy, the mass of the electrons is negligible. Thus, the atomic weights might be expected to be whole numbers, since they are simply the sum of the number of protons and neutrons in the nucleus. Table 3-1 shows that this is not so. The explanation is that atoms of the same element can have different numbers of neutrons in their nucleus and thus different atomic weights. For example the majority of carbon atoms have 6 neutrons but some have 7 or even 8 making their atomic weight 13 or 14 respectively. The atomic weight of the element carbon is an average of all the forms that occur, taking into account their relative abundance in nature, and is thus 12.01.

Table 3-1 Known Elements and Atomic Weights

Element	Symbol	Atomic Number	Atomic Weight	Element	Symbol	Atomic Number	Atomic Weight
Actinium	Ac	89	227*	Mercury	Hg	80	200.59
Aluminum	Al	13	26.9815	Molybdenum	Mo	42	95.94
Americum	Am	95	243*	Neodymium	Nd	60	144.24
Antimony	Sb	51	121.75	Neon	Ne	10	20.179
Argon	Ar	18	39.948	Neptunium	Np	93	237.0482
Arsenic	As	33	74.9216	Nickel	Ni	28	58.71
Astaline	At	85	210*	Niobium	Nb	93	237.0482
Barium	Ba	56	137.33	Nitrogen	N	7	14.0067
Berkelium	Bk	97	247*	Nobelium	No	102	259*
Beryllium	Be	4	9.01218	Osmium	Os	76	190.2
Bismuth	Bib	83	208.9808	Oxygen	O	8	15.9994
Boron	B	5	10.81	Palladium	Pd	46	106.4
Bromine	Br	35	79.904	Phosphorus	P	15	30.9738
Cadmium	Cd	48	112.41	Platinum	Pt	78	195.09
Caesium	Cs	55	132.9054	Plutonium	Pu	94	244*
Calcium	Ca	20	40.08	Polonium	Po	84	209*
Californium	Cf	98	251*	Potassium	K	19	39.0983
Carbon	C	6	12.011	Praseodymium	Pr	59	140.9077
Cerium	Ce	58	140.12	Promethium	Pm	61	145*
Chlorine	Cl	17	35.453	Protactinium	Pa	91	231.0359
Chromium	Cr	24	51.996	Radium	Ra	88	226.0254
Cobalt	Co	27	58.9332	Radon	Rn	86	222*
Copper	Cu	29	63.546	Rhenium	Re	75	186.2
Curium	Cm	96	247*	Rhodium	Rh	45	102.9055
Dysprosium	Dy	66	162.50	Rubidium	Rb	37	85.467
Einsteinium	Es	99	254*	Ruthenium	Ru	44	101.07
Erbium	Er	68	167.26	Samarium	Sm	62	150.4
Europium	Eu	63	151.96	Scandium	Sc	21	44.9559
Fermium	Fm	100	257*	Selenium	Se	34	78.96
Fluorine	F	9	18.9984	Silicon	Si	14	28.0855
Francium	Fr	87	223*	Silver	Ag	47	107.868
Gadolinium	Gd	64	157.25	Sodium	Na	11	22.9898
Gallium	Ga	31	69.72	Strontium	Sr	38	87.62
Germanium	Ge	32	72.59	Sulphur	S	16	32.06
Gold	Au	79	196.9665	Tantaium	Ta	73	180.9479
Hafnium	Hf	72	178.49	Technetium	Tc	43	98.9062
Helium	He	2	4.0026	Tellurium	Te	52	127.60
Holmium	Ho	67	164.9304	Terbium	Tb	65	158.9254
Hydrogen	H	1	1.0079	Thalliium	Tl	81	204.37
Indium	In	49	114.82	Thorium	Th	90	232.0381
Iodine	I	53	126.9045	Thulium	Tm	69	168.9342
Iridium	Ir	77	192.22	Tin	Sn	50	118.69
Iron	FE	26	55.847	Titanium	Ti	81	204.37
Krypton	Kr	36	83.80	Tungsten	W	74	183.65
Lanthanum	La	57	138.9055	Uranium	U	92	238.029
Lawrencium	Lr	103	260*	Vanadium	V	23	50.941
Lead	Pb	82	207.2	Xenon	Xe	54	131.30
Lithium	Li	3	6.941	Ytterbium	Yb	70	173.04
Lutetium	Lu	71	174.97	Yttrium	Y	39	88.9059
Magnesium	Mg	12	24.305	Zinc	Zn	30	65.38
Manganese	Mn	25	54.9308	Zirconium	Zr	40	91.22
Mendelevium	Md	101	258*				

Atomic weights quoted are the 1969 values based on carbon 12 and include the IUPAC revision 1971

*Values marked * are for the most stable or most common isotopes*

Isotopes

These different forms of the same element are called isotopes and are denoted by writing the atomic weight as a superscript. Thus, carbon has three isotopes; C^{12}, C^{13}, and C^{14}.

Hydrogen also has three isotopes, with either zero, one or two neutrons in the nucleus. The most common form is H^1 (99.985%). The other two isotopes have been given special names (the only isotopes to have been so honored). H^2 is known as deuterium (D) and H^3 is known as tritium (T). Tritium is radioactive, that is, it has an unstable nucleus which can emit an electron and thus change the tritium into a stable isotope of helium He^3. This fact makes tritium easy to detect and for this reason titrated water (that is water to which T_2O gas been added) is used as a tracer in formation analysis.

Many other isotopes are also radioactive. For example, the heavy isotope of potassium, K^{40} emits high energy radiation known as gamma rays. This gamma radiation is utilized in well logging. A gamma ray log shows high concentrations of potassium bearing minerals, such as micas, in a shale, or carnallite in a salt section.

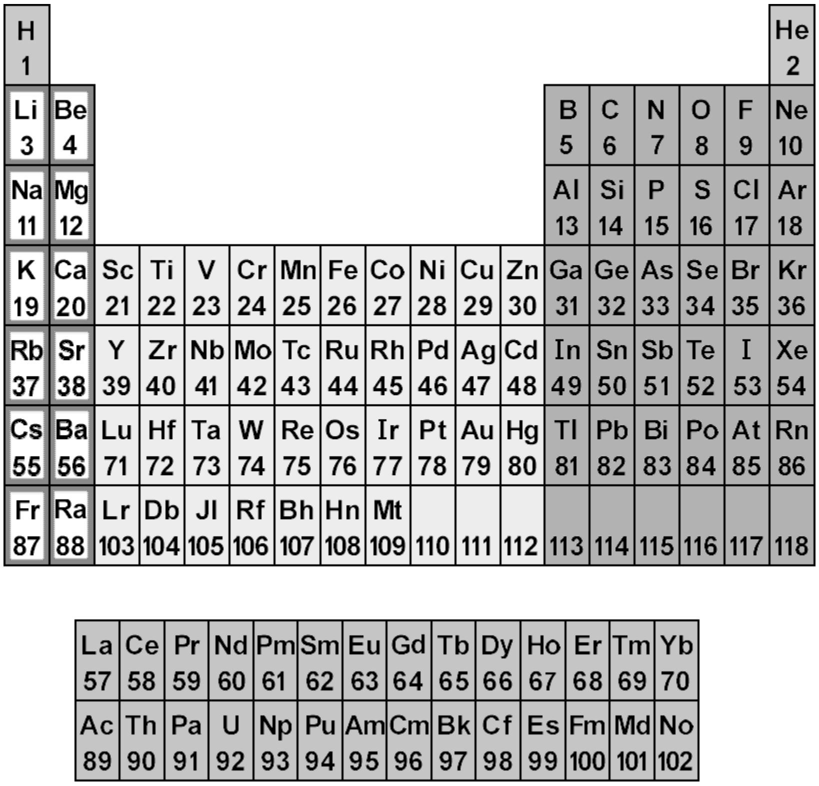
Molecular Weight

The molecular weight of a compound is simply the sum of the atomic weights of the atoms it contains. For example, water, H_2O, has molecular weight 18 (atomic weight of hydrogen = 1, atomic weight of oxygen = 16).

The Periodic Table

Table 3 - 2 shows the elements grouped together in a special way known as the periodic table. The elements are shown in order of increasing atomic number and are arranged in a series of column (groups IA – VIIA). This reflects an earlier classification based on the chemical properties of the various elements. In the modern form, elements in the same group are chemically related and show regular trends in chemical properties. Thus the chemical nature of an element is in some way related to its atomic number. This relationship involves the configuration of the electrons which orbit the nucleus where the number of electrons is determined by the atomic number.

Table 3-2 The Periodic Table



H 1																	He 2
Li 3	Be 4											B 5	C 6	N 7	O 8	F 9	Ne 10
Na 11	Mg 12											Al 13	Si 14	P 15	S 16	Cl 17	Ar 18
K 19	Ca 20	Sc 21	Ti 22	V 23	Cr 24	Mn 25	Fe 26	Co 27	Ni 28	Cu 29	Zn 30	Ga 31	Ge 32	As 33	Se 34	Br 35	Kr 36
Rb 37	Sr 38	Y 39	Zr 40	Nb 41	Mo 42	Tc 43	Ru 44	Rh 45	Pd 46	Ag 47	Cd 48	In 49	Sn 50	Sb 51	Te 52	I 53	Xe 54
Cs 55	Ba 56	Lu 71	Hf 72	Ta 73	W 74	Re 75	Os 76	Ir 77	Pt 78	Au 79	Hg 80	Tl 81	Pb 82	Bi 83	Po 84	At 85	Rn 86
Fr 87	Ra 88	Lr 103	Db 104	Jl 105	Rf 106	Bh 107	Hn 108	Mt 109	110	111	112	113	114	115	116	117	118

La 57	Ce 58	Pr 59	Nd 60	Pm 61	Sm 62	Eu 63	Gd 64	Tb 65	Dy 66	Ho 67	Er 68	Tm 69	Yb 70
Ac 89	Th 90	Pa 91	U 92	Np 93	Pu 94	Am 95	Cm 96	Bk 97	Cf 98	Es 99	Fm 100	Md 101	No 102

Types of Bonding

Chemical Bonding

Chemical reactions involve a rearrangement of the electron shells surrounding the atoms involved. This rearrangement generally produces a more stable structure and links the atoms together, thus producing a chemical bond.

The most stable configuration is found to be a completely full outer shell of electrons. Simple chemical combination between elements can be explained by assuming that the atoms concerned are trying to attain this state.

The so called “noble gases”, such as helium, neon and argon, which form group O of the periodic table, already possess full outer electron shells. These elements are thus extremely un-reactive and can only be made to combine with other elements under very specialized conditions. Other elements can obtain the “noble gas structure” by losing, gaining, or sharing electrons.

Ionic Bonding

Ionic bonding involves a transfer of one or more electrons from one atom to another. Atoms which have lost or gained electrons are ions.

Electrons are negatively charged and thus, an atom that loses an electron becomes positively charged, as there are now more protons in the nucleus that there are electrons around it. A positively charged ion is called a cation and is denoted by writing a “+” sign as a superscript after the chemical symbol. Thus Na^+ is a sodium ion (one positive charge) and Mg^{2+} is a magnesium ion (two positive charges, i.e., two electrons lost).

Atoms which gain electrons, and thus become negatively charged ions, are called anions. Thus Cl^- is the chloride ion (one negative charge) and S^{2-} is the sulfide ion (two negative charges, i.e., two electrons gained).

Groups of atoms can also gain or lose electrons to become ions. For example, SO_4^{2-} is the sulfate ion. CO_3^{2-} is the carbonate ion and NH_4^+ is the ammonium ion. A full list of these types of ions is given in Table 3-3.

When an ionic bond forms, electrons are transferred in such a way that each atom attains a complete outer shell of electrons. When one electron is lost, the remaining electrons are held more tightly by the nucleus and it becomes progressively more difficult to remove them. True ionic bonds rarely exist when the transfer involves 3 or more electrons, as this procedure requires too much energy.

Thus sodium, with one electron in its outer shell readily loses this electron to form the Na^+ ion. Chlorine, with seven electrons in its shell, readily accepts an electron to form the Cl^- ion. The compound sodium with chlorine, sodium chloride, is ionic and can be written Na^+Cl^-, in which each ion would again have a full outer electron shell. The formation of sodium chloride is illustrated schematically below.

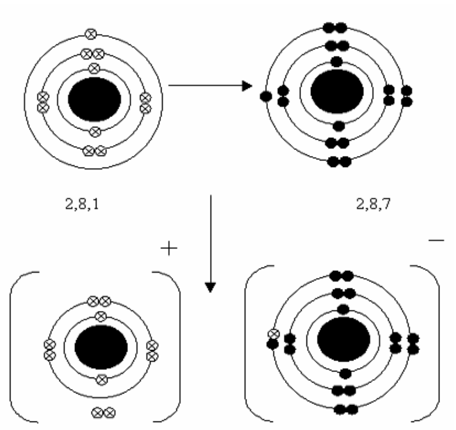


Figure 3-2 The Formation of Sodium Chloride as an Example of Ionic Bonding

Covalent Bonding

Where electrons are shared between atoms, the bond said is to be covalent. This is illustrated in below for water and carbon dioxide. By this sharing process, the electron clouds of the atoms overlap such that each atom thinks it has a full outer electron shell.

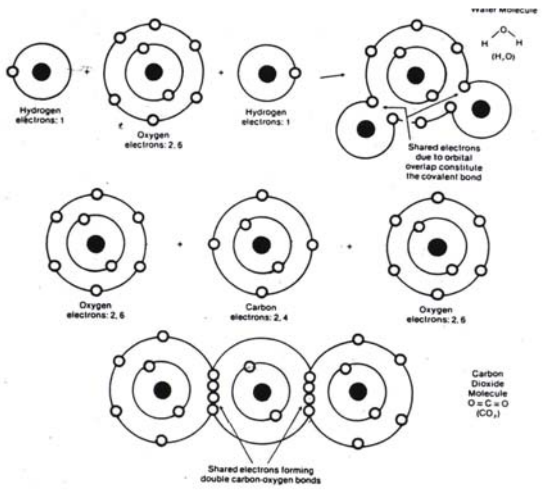


Figure 3-3 The Formation of Water and carbon Dioxide as Examples of Covalent Bonding

Atoms can share one, two, or three electrons, thus forming single, double, or triple bonds. These bonds are denoted by lines joining the two atoms together. For example, carbon can form each of the following compounds all of which contain a single, double, and triple carbon-carbon bond, respectively. Although these compounds are made up of the same two elements, they differ in their chemistry due to the different carbon-carbon bonds present.

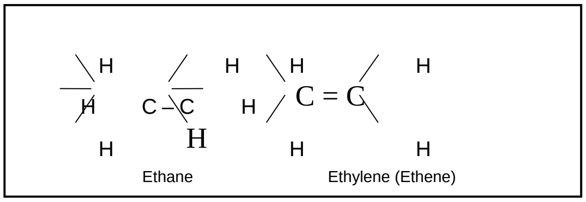


Figure 3-4 Differences in Compounds due to Chemistry

Valency

The numbers of electrons which an atom needs to gain lose, or share to obtain a stable structure is called its valency. The valency of an element predicts the ratios in which it can combine with other elements. For example, two atoms of hydrogen (valency 1) combine with one atom of oxygen (valency 2) to form water. Three atoms of chlorine (valency 1) combine with one atom of aluminum (valency 3) to form $AlCl_3$.

The table below shows that atoms with the same number of electrons in their outer shell all have the same valency. Thus all the group IA metals have valency 1, as do the group VIIA elements (which are known as the halogens).

Table 3-3 Formula and Valency of Common Ions formed From Groups of Atoms

Name of Ion	Formula	Valency
Ammonium	NH_4^+	1
Nitrate	NO_3^+	1
Hydroxide	OH^-	1
Hydrogen Carbonate	HCO_3^-	1
Hydrogen Sulfate	HSO_4^-	1
Hydrogen Sulfite	HSO_3^-	1
Dihydrogen Phosphate	$H_2PO_4^-$	1
Sulfate	SO_4^{2-}	2
Carbonate	CO_3^{2-}	2
Sulfite	SO_3^{2-}	2
Hydrogen Phosphate	HPO_4^{2-}	2
Phosphate	PO_4^{3-}	3

Some elements, particularly nitrogen, sulfur, and iron, can show more than one valency, as there is more than one way for them to obtain a stable electron configuration. The valency is written in brackets when describing the compound. Thus iron (II) chloride is $FeCl_2$, iron (III) chloride is $FeCl_3$.

The concept of valency also applies to groups of atoms which carry a charge, such as the sulfate group SO_4^{2-}, which has valency 2. The valency in this case equals the number of electrons which have already been transferred, and thus equals the magnitude of the charge on the ion. Table 3-3 gives the commonly occurring ions of this type.

Determination of Bond Type

Ionic and covalent bonding can both be present in the same compound. Figure 3-4 shows the structure of sodium carbonate. The two sodium ions and the carbonate ion are held together by ionic bonding, but the carbonate ion itself contains three covalent carbon-oxygen bonds.

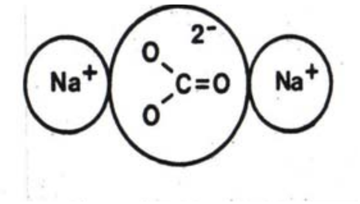


Figure 3-5 Sodium Carbonate Structure (schematic)

In this example both types of bonding are present and are easily distinguishable. However, this is not always the case. Many ionic bonds have a certain amount of covalent character. This can be thought of as an incomplete transfer of the electrons involved so that the atom that has lost them still retains a small share. An example of this type of bonding would be zinc bromide, $ZnBr_2$, which is used to prepare high density completion fluids. This compound can nominally be written as $Zn^{2+}Br^{-}_2$, but in fact the bond has considerable covalent character in that the zinc retains partial control over the two electrons which it has lost.

Conversely, many covalent bonds show varying degrees of ionic character. Some atoms are greedy for electrons and when they enter into a covalent bond they try to take more than their fair share. The electron orbitals are thus distorted towards them and the atoms develop partial charges. Water is the best known example of this. In the water molecule, the oxygen atom attracts far more than the two hydrogen atoms and the electrons are thus not shared equally. The orbitals are distorted towards the oxygen which thus develops a partial negative charge, written δ^-. The hydrogen atoms develop a corresponding δ^+ charge. This type of covalent molecule is said to be polar. Where the electrons are shared equally, no partial charges develop and the molecule is non-polar. This is shown diagrammatically in

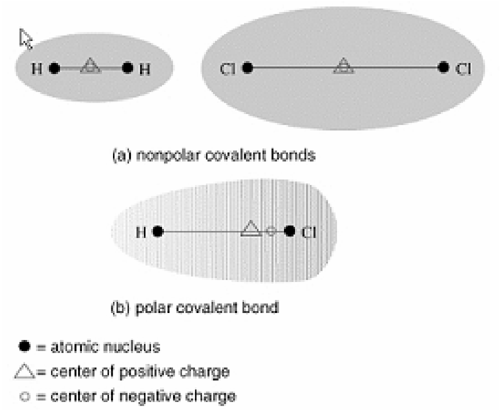


Figure 3-6 Polar and Non-Polar Covalent Bonding

The tendency to attract electrons within a covalent bond is known as electronegativity. The electronegativity of an element depends on its position in the periodic table.

Fluorine is the most electronegative element. It is followed by oxygen, nitrogen, and chlorine, in that order. The metals in groups IA and IIA are the least electronegative and are generally referred to as electropositive elements due to their tendency to form positively charged ions. The electronegative elements have the greatest tendency to form negative ions, though this is modified by the number of electrons needed to be gained.

The larger atoms in groups IA and IIA lose their outer electrons very rapidly as they are a long way from the nucleus and shielded from it by the other electron shells. Thus, cesium and barium are more electropositive that sodium and magnesium respectively and more readily form cations. The group IA metals are more electropositive than their group IIA counterparts, as only one electron needs to be lost to form the stable ion. Thus potassium more readily forms K^+ ions, than calcium does Ca^{2+} ions.

The larger the difference between the electronegativity of two elements, the more likelihood there is of ionic bonding between them. Alternatively, if the bond is covalent, the more polar it will be.

The electropositive elements in groups IA and IIA form strong ionic bonds and rarely, if ever, form covalent bonds. The metals in the middle of the table (groups IVB – IIB) are weakly electropositive and form either weak ionic bonds with the strong electronegative elements, or polar covalent bonds with the weak electronegative elements. The weakly electronegative elements form mainly covalent bonds but can form ionic bonds with the group IA metals. The strongly electronegative metals form ionic bonds with electropositive metals or polar covalent compounds with weakly electronegative elements.

Properties of Compounds

Ionic Compounds

Ionic compounds do not generally form discrete molecules. Instead, the ions tend to arrange themselves in a three dimensional lattice structure with each other surrounded by anions and vice versa. The relative number of cations to anions is the same as is written in the chemical formula. You will find the structure of sodium chloride illustrated in Figure 3-7.

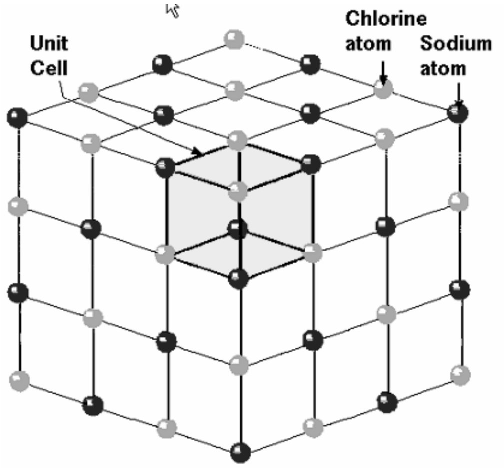


Figure 3-7 The Sodium Chloride Structure

The ions are held together in the lattice by strong electrostatic forces (ionic bonds) and it is difficult to force them apart. Thus ionic compounds are usually solids with high melting points and boiling points. The energy required to separate the ions is called the lattice energy. Lattice energies are usually quite large compared to other bond energies.

Covalent Compounds

In covalent compounds the bonds that hold together are usually quite strong, but there are strong forces holding the molecules together. These low intermolecular forces mean that covalent compounds tend to be liquids or gases, as the molecules are not sufficiently attracted to each other to hold them in place in a solid structure against the random molecular motion produced by thermal energy.

The heaver the molecules, the more thermal energy is usually needed to separate them. Thus, compounds with high molecular weight usually have higher melting points and boiling points.

The degree of polarity has a very important influence on intermolecular forces. In polar compounds these are increased by the attractions between the opposite partial charges, as shown in Figure 3-8.

The polar attraction between molecules explains why water is a liquid, although having a lower molecular weight than Hydrogen Sulfide, which is a gas. (see Table 3-5)

Table 3-4 Examples of Different Bond Types

Example	Formula	Bond Type
Potassium Chloride	KCl	Strongly ionic
Iron (11) Chloride	$FeCl_2$	Weakly ionic
Iron (111) Chloride	$FeCl_3$	Weakly ionic/covalent
Carbon Tetrachloride	CCl_4	Covalent, polar
Chlorine	Cl_2	Covalent, non polar
Sodium Sulfide	Na_2S	ionic
Hydrogen Sulfide	H_2S	Covalent, slightly polar
Water	H_2O	Covalent, strongly polar
Diesel Oil	Mixture of hydrocarbons (compounds of carbon and hydrogen)	Covalent, non polar

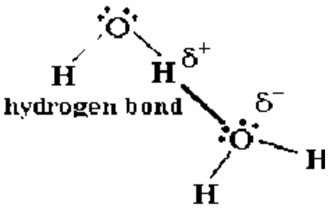


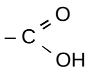
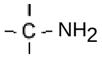
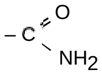
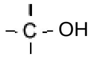
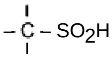
Figure 3-8 Intermolecular Attractions in Water

Organic and Inorganic Compounds

Organic chemistry is the study of carbon compounds other than the simple carbonates, which are generally classified as inorganic. Organic chemistry is based around the ability of carbon to form chains of atoms linked by covalent bonds. These bonds are non-polar, as are the carbon-hydrogen bonds which are also found in the majority of organic molecules. Crude oil consists of a mixture of organic molecules which are mainly compounds of carbon and hydrogen (hydrocarbons). Natural gas is mainly methane, CH_4, the simplest organic molecule.

Polar organic compounds are common – the molecules contain electronegative elements, such as oxygen and nitrogen. The table below shows the more commonly occurring polar groups.

Table 3-5 Common polar groups in organic compounds

GROUP	FORMULA
CARBOXYL	
AMINE	 $-\overset{\vert}{\underset{\vert}{C}}-NH_2$
AMIDE	
HYDROXYL	 $-\overset{\vert}{\underset{\vert}{C}}-OH$
SULFONATE	 $-\overset{\vert}{\underset{\vert}{C}}-SO_2H$

All of these groups are commonly found in the organic polymers used in drilling fluids. Inorganic compounds are the ionic ones (other than the salts of organic acids) and those covalent compounds which do not contain carbon.

Solubility and Solutions

Solutions are homogenous mixtures of various compounds. For the purposes of drilling fluids, only solutions in water and diesel oil will be considered. These two substances form the continuous liquid part of the solution, which is known as the solvent. The substance dissolved in the solvent is called the solute and may be solid, liquid or gas. If two liquids are soluble in each other, they are said to be miscible.

Water is often described as the universal solvent, due to its ability to dissolve a large number of different substances.

Many ionic compounds are soluble in water. The attractive forces between oppositely charged ions are reduced by the water, so that it may become possible for each individual ion to separate from the lattice, which thus breaks up. Each ion is normally hydrated, which means that it is surrounded by a shell of water molecules which, due to their polar nature, are attracted to the charge on the ion and are thus loosely bonded to it. This attraction of the solvent molecules to the ions is called solvation, in solvents other than water.

The solution of sodium chloride in water can be written as $NaCl + Water \rightarrow Na^+ (aq) + Cl^- (aq)$ where (aq) denotes the hydration as depicted below.

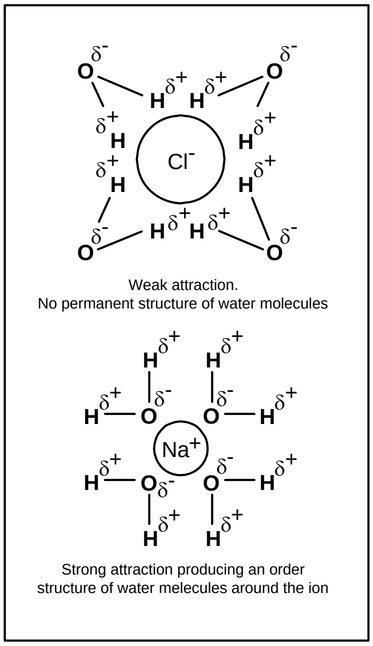


Figure 3-9 Hydration of Sodium Chloride in Water

This ability to dissolve ionic compounds is solely due to the polar nature of water. Non-polar solvents, such as diesel oil, do not hydrate the ions and ionic compounds are not soluble in them.

The salts that are soluble and insoluble are summarized in Table 3-6 The insoluble salts are generally those where both anion and cation are multivalent (i.e. their valency is greater than one). The attraction between multivalent ions is much stronger than that between univalent ions (with only one charge). Salts such as $CaCO_3$ have much higher lattice energies than salts such as NaCl. The hydration energies of the calcium and carbonate ions are not high enough to compensate for this high lattice energy and thus $CaCO_3$ is insoluble. In contrast, the energy released by hydrating sodium and chloride ions is sufficient to overcome the lattice energy of sodium chloride and thus NaCl is soluble.

Solutions of a salt, or salts, in water are frequently termed brines and are a common base from which drilling fluids are often made up.

Table 3-6 Solubility of Salts

			Anions	*** Soluble ** Slightly Soluble *** Insoluble**		
Cation	OH^-	Cl^-	HCO_3^-	CO_3^{2-}	SO_4^{2-}	S^{2-}
Na^+	*	*	*	*	*	*
K^+	*	*	*	*	*	*
Mg^{2+}	***	*	**	***	*	–
Ca^{2+}	**	*	**	***	**	**
Ba^{2+}	*	*	**	***	***	*

Solubility of Covalent Compounds in Water

Covalent compounds are generally soluble, or miscible, if they are polar. If polar groups are present, they tend to interact more strongly with water molecules than with each other. Thus the molecules split apart and the substance dissolves. There are no ions present, but each molecule is separated from its companions and the substance is said to molecularly dispersed. Examples of this type of compound include sugar, alcohol, and starch.

Non polar covalent compounds are generally insoluble in water, as there are no strong attractive forces between them and the water molecules. Thus diesel oil is insoluble in water.

Solubility of Gases in Water

This is an important topic for drilling fluids, as small quantities of dissolved oxygen, carbon dioxide or hydrogen sulfide can have a large effect in making the fluid more corrosive. Hydrogen sulfide is also extremely poisonous and represents a real hazard to rig personnel. Carbon dioxide in solution can also alter the interaction between clay particles in a fluid and thus change the fluids rheological properties. All of these gases are soluble in water, particularly at high pressure, and efforts are generally made to exclude them as much as possible.

Factors Affecting Solubility

The maximum amount of a substance that can be dissolved under any given condition is called its solubility. This figure depends on the nature of the solute and solvent, and on the amount and type of other solutes already in solution. Most solubility's increase when the temperature increases, although gases are an exception to this. The solubility of a gas decreases when the temperature rises, and increases when the pressure increases. The pressure effect is more important and gases are generally more soluble when a drilling fluid is at the bottom of a well than when it is on the surface.

Other ions in solution have a very important influence. When a mixture of salts is present, the most soluble one suppresses the solubility of the other components. Sodium chloride and potassium chloride are much less soluble in concentrated magnesium chloride solutions.

Reactions in Solution

If two compounds which are soluble in water can react together to form an insoluble compound, then they will do so. Thus calcium chloride and sodium carbonate are both soluble in water on their own, but if they are mixed together, insoluble calcium carbonate precipitates out of solution. The reaction is written as follows:

$$Na_2CO_3 + CaCl_2 \rightarrow CaCO_3 + 2NaCl$$

Sodium chloride, being soluble, is left in solution. The reaction occurs because both the reactants, being ionic, are split up into their constituent ions in solution. When mixed together, the solution does not contain sodium carbonate and calcium chloride as such, but rather sodium, calcium, carbonate and chloride ions, and it is impossible to say which cation is associated with which anion.

This type of reaction occurs very commonly in drilling fluid chemistry. It is the basis of many analytical tests and chemical treatments. Sodium carbonate is used, as above, to "treat out" soluble calcium, in order to maintain the correct chemical properties of the fluid. Silver nitrate ($AgNO_3$) which is soluble is used to test for chloride ions, due to the formation of insoluble silver chloride (AgCl).

These types of reactions also exert a strong influence on solubility. If a reaction can occur between two components, then their solubility's will be interdependent. For example, the solubility of CMC (carboxymethylcellulose), a polymer commonly used in drilling fluids), depends on the concentration of calcium ions in the mud. If this exceeds a certain value, then the CMC precipitates out as an insoluble calcium salt.

Intimate Mixtures of Solids, Liquids and Gases

One characteristic of solutions is that they are homogenous mixtures. This implies that the solute should be split up into its constituent ions or molecules and that these should be dispersed uniformly throughout the solvent. Many insoluble substances apparently form homogenous mixtures with a liquid, but are not dissolved, as the mixture consists of very small particles of the substance dispersed throughout the liquid. Such a mixture is said to consist of two phases, as it contains two physically distinct parts. In contrast, a solution of sodium chloride in water is only one phase, as no physical distinction can be made between the sodium chloride and the water.

The case of a solid mixed with a liquid or gas is called a suspension or dispersion. All drilling fluids are suspensions. If the particle size of the solid phase is fine enough, the solid stays in suspension and does not separate out under gravity. Thus a typical water-based drilling fluid consists of bentonite (a clay mineral) and barite ($BaSO_4$) suspended in water. Neither substance is dissolved, since both are insoluble and are not split up into ions or molecules.

A liquid mixed into a different liquid with which it is immiscible is known as an emulsion. This is illustrated in Figure 3-10, for the case of water emulsified into oil. The water is dispersed in the form of fine droplets throughout the oil. The oil is known as the continuous or external phase. The water is called the dispersed, or internal phase. This example is the basis of the invert emulsion drilling fluid. These "invert" systems also contain calcium chloride dissolved in the water phase, and solids dispersed in the oil phase, giving an intimate mixture of three separate phases.

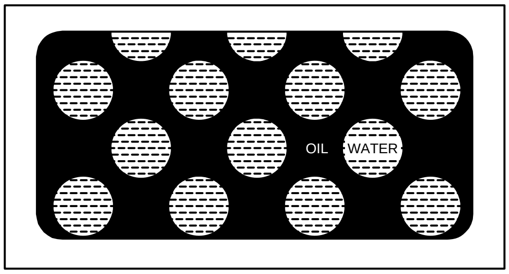


Figure 3-10 Invert Emulsion Water Droplets in a Continuous Oil Phase

A gas mixed into a liquid is called foam. Foams have been used as drilling fluids and consist of air dispersed in the form of bubbles throughout a continuous liquid phase (usually water).

In a water-based drilling fluid, certain chemicals cause foaming by increasing surface tension stabilizing air/water mixtures. This is to be avoided as it leads to a decrease in mud weight and makes estimation of mud volumes very difficult.

Dispersibility of Solids in Water

Some solids are much more readily dispersed in water than others and the reason is again due to the polar character of water. Ionic compounds that are insoluble tend to disperse easily since water is attracted to the surfaces of the particles, which are charged, in much the same way as hydration of ions occurs for soluble compounds. This attraction is commonly known as water wetting. Examples of solids which readily water wet are the rock forming silicate minerals, particularly clays, and the insoluble ionic compounds, such as barite ($BaSO_4$). The process is illustrated in Figure 3-11.

Water wetting generally involves the formation of a monomolecular layer of water chemically adsorbed on to the surface of the particle. The arrangement of the water molecules depends on the distribution of charges, or partial charges, on the surface of the particle. The faces of clay minerals are normally negatively charged, thus attracting the hydrogen atoms in the water molecule (as in Figure 3-11). However, the edges of clay minerals usually carry positive charges and attract the oxygen atoms.

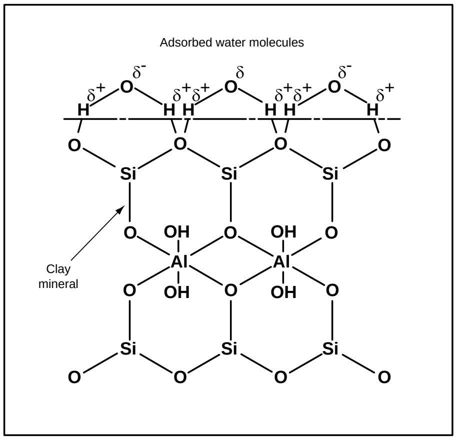


Figure 3-11 Water Wetting of Clay Mineral Surfaces

When water wetting occurs, the adsorbed water molecules are still attracted to the other water molecules in the liquid and thus the particles can be easily dispersed. This “solid-liquid” attraction partly accounts for the viscosity increase observed when an easily dispersed solid, such as bentonite is added to water. The other effect is the solid-solid interaction between the bentonite particles.

Non-polar substances, as well as being insoluble in water, are difficult to disperse because there is no force of attraction between the surfaces of the particle and the water molecules. The particles are usually more attracted to each other and thus tend to stick together, inhibiting dispersion. A dispersion of diesel oil in water is therefore unstable if no surfactants are present. The droplets of diesel are more attracted to each other than to water and tend to coalesce, so that separation of the two phases occurs, giving a layer of diesel floating on the surface of the water. A surfactant, because it contains a polar and non-polar group on the same molecule, can concentrate between the water and oil, and thus make the two phase’s compatible, and an emulsion stable.

Acids

An acid is a compound containing one or more hydrogen atoms, which can be replaced by a metal, to form a salt. When acids are dissolved in water, they ionize to produce “hydrogen ions”.

Strictly, these have the formula H_3O^+, but are generally denoted simply as H^+, The common acids include hydrochloric acid (HCl), sulfuric acid (H_2SO_4), and acetic acid (CH_3COOH), which is an organic acid.

The reactions with metals are illustrated by the following equations:

$$2\,HCl + Fe \rightarrow FeCl_2 + H_2 \uparrow$$

Hydrochloric acid + iron → Iron (II) chloride + hydrogen

$$2\,CH_3COOH + 2\,Na \rightarrow 2\,CH_3COONa + H_2\uparrow$$

Acetic acid + sodium → Sodium acetate + hydrogen

In both cases, the products are a salt and hydrogen gas. The number of hydrogen atoms that are available to be replaced is known as the basicity of the acid. Both hydrochloric acid and acetic acid are monobasic, since only one hydrogen is replaceable. Sulfuric acid is dibasic, as both of the hydrogen atoms can be replaced.

Dibasic salts and tribasic acids can form salts in which not all of the hydrogen atoms are replaced. These are generally acidic in nature, as further replacement of hydrogen is possible. Examples Are: $NaHCO_3$,– sodium hydrogen carbonate, also called sodium bicarbonate, or bicarbonate of soda; NaH_2PO_4 – sodium dihydrogen phosphate; and Na_2HPO_4 – disodium hydrogen phosphate.

Bases and Alkalis

A base is a compound that will react with an acid to form a salt and water only. A base that is soluble in water is called an alkali.

Bases are either oxides or hydroxides of metals. Alkalis are exclusively hydroxides of electropositive metals. Thus CuOH – copper (I) hydroxide and Fe_2O_3 – iron (II) oxide are both bases, since they are both insoluble. NaOH – sodium hydroxide (caustic soda) and NH_4OH – ammonium hydroxide, are both soluble and are alkalis. The reaction of an acid with a base and an alkali is illustrated by the following equations:

$$FeO + HCl \rightarrow FeCl_2 + H_2O$$

Iron (II) oxide + hydrochloric acid → iron (II) chloride + water

$$NaOH + HCl \rightarrow NaCl + H_2O$$

Sodium hydroxide + hydrochloric acid → sodium chloride + water

Both acid and base are said to be neutralized as the resulting solution is neutral, in other words, neither acidic (containing an acid) nor alkaline (containing an alkali).

Other compounds react with acids to produce a salt and water, but are not strictly bases, as other compounds are formed in the reaction. Thus all carbonates and hydrogen carbonates are decomposed by acids, liberating carbon dioxide as a gas. For example:

$$CaCO_3 + 2\,HCl \rightarrow CaCl_2 + CO_2 + H_2O$$

Calcium carbonate + hydrochloric acid → calcium chloride + carbon dioxide + water

This equation describes the reaction that occurs when acidizing a limestone reservoir rock to increase the flow of oil. A strong solution of hydrochloric acid is pumped down the well and reacts with the limestone (mainly calcium or magnesium carbonate), thus enlarging the fissures and pores in the rock and allowing the oil to flow more freely.

pH

Water itself is very slightly ionized under ordinary conditions. Thus a very small number of hydrogen and hydroxide ions exist free in solution and in equal numbers.

$$H2O \leftrightarrow H+ + OH^-$$

Water ↔ hydrogen ion + hydroxide ion

The reaction can proceed both ways and is said to be reversible. The reaction proceeds more easily from the right to left than from left to right.

In one liter of pure water, there will be 10^{-7} (0.0000001) moles of hydrogen ions (10^{-7} grams) and 10^{-7}moles of hydroxide ions (17 x 10^{-7} grams, as the molecular weight is 17). The concentration of H^+ ions, written as $\{H^+\}$, is thus 10^{-7} moles/liter and similarly $\{OH^-\} = 10^{-7}$ moles/liter and $\{H^+\}\cdot\{OH^-\} = 10^{-7}\cdot 10^{-7} = 10^{-14}$ moles^2/l^2.

The pH of a solution is defined as the negative log to the base of 10 of the hydrogen ion concentration. Thus $pH = -\log_{10} \{H^+\}$ where $\{H^+\}$ is in moles/liter. For pure water as above, with $\{H^+\} = 10^{-7}$ moles/liter:

$$pH = -\log_{10} \{10^{-7}\} = 7 \text{ (since } \log_{10}\{10^{-7} = -7\}$$

If an acid is added, the number of hydrogen ions in the solution increases such that the product of $\{H^+\}\cdot\{OH^-\}$ remains at 10^{-14} (as long as the temperature remains constant).

Thus if hydrochloric acid is added until $\{H^+\} = 10^{-3}$ then pH = 3 and $\{OH^-\} = 10^{-11}$ since 10^{-3} x $10^{-11} = 10^{-14}$. The addition of an alkali to water increases $\{OH^-\}$. Thus, $\{H^+\}$ drops and the pH rises above 7. If caustic soda is added to 10 pH, then $\{H^+\} = 10^{-10}$ and $\{OH^-\} = 10^{-4}$.

Acids always lower pH, alkalis always raise pH. A strictly neutral solution, with no acid or alkali present, has pH 7. Acid solutions have pH less than 7; alkaline solutions have pH greater than 7. This is illustrated below.

Table 3-7 The pH Scale

	ACIDIC					NEUTRAL					ALKALINE				
pH	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14
$[H^+]$m/l	1	10^{-1}	10^{-2}	10^{-3}	10^{-4}	10^{-5}	10^{-6}	10^{-7}	10^{-8}	10^{-9}	10^{-10}	10^{-11}	10^{-12}	10^{-13}	10^{-14}
$[OH^-]$m/l	10^{-14}	10^{-13}	10^{-12}	10^{-11}	10^{-10}	10^{-9}	10^{-8}	10^{-7}	10^{-6}	10^{-5}	10^{-4}	10^{-3}	10^{-2}	10^{-1}	1

The pH scale, running from 0 – 14, is adequate for the majority of situations, although some acids and alkalis, if they are very soluble, can produce pH's outside this range. Drilling fluids are run at between pH 6 and pH 13.5, with the majority being moderately alkaline (pH 9 – 10.5).

It is important to realize that pH is a logarithmic function. In pure water it takes ten times as much caustic soda to increase pH from 11 → 12, as from 10 → 11, as $\{OH^-\}$ must be increased by a factor of ten.

Solutions at pH 6 – 8 are generally termed "neutral", as they are so close to pH 7 as to make very little difference in properties.

Strong and Weak Acids and Alkalis

Strong acids are completely ionized in water such that all the molecules split up into ions. Acids of this type include hydrochloric and sulfuric acids.

Weak acids are not fully ionized in concentrated solutions. The acid molecules are dispersed throughout the water, but only a small proportion of them split up into ions. Thus, at the same concentration, weak acids, such as acetic or carbonic acids, give a higher pH than strong acids, as there are fewer H^+ ions in the water.

Similarly, strong alkalis, such as sodium and potassium hydroxides (the hydroxides of strongly electropositive metals) are fully ionized in solution and give higher pH's than weak alkalis, such as calcium hydroxide or ammonia solution. In the case of calcium hydroxide, molecular dispersion does not occur. The pH obtained is limited by the solubility, which about 1.6 grams of lime per liter at 20 º C, giving a pH of 12.5.

Carbonic Acid and Carbonates

Pure water at pH 7 is very difficult to obtain, because carbon dioxide from the air readily dissolves in it, forming a solution of carbonic acid.

$$CO_2 + H_2O \leftrightarrow H_2CO_3$$

Carbon dioxide + water ↔ carbonic acid

Carbonic acid is a weak dibasic acid and the hydrogen carbonate ion is commonly referred to as the bicarbonate ion ionized to a small extent producing small numbers of hydrogen carbonate and carbonate ions.

$$H_2CO_3 \leftrightarrow H^+ + HCO_3^- \leftrightarrow 2H^+ + CO_3^{2-}$$

Carbonic acid ↔ Hydrogen ion + Hydrogen carbonate ion ↔ Hydrogen ion + Carbonate ion

Thus distilled water frequently has a pH in the range of 4 – 6.

If an alkali is added to water containing dissolved carbon dioxide, then the hydrogen ions produced by the dissociation of carbonic acid react with the alkali. The effect of this is to push all the reactions over to the right hand side, thus producing mainly carbonate ions at high pH (see Figure 3-12). This is one of the reasons for running drilling fluids at alkaline pH. Hydrogen carbonate ions can have a detrimental effect on the viscosity of clay based drilling fluids. By adding caustic soda they are converted into carbonate ions, which are less of a problem.

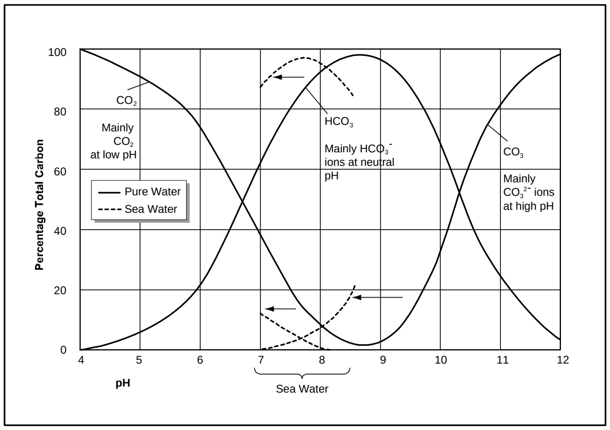


Figure 3-12 **Distribution of the CO_3 - HCO_3^- - CO_3^{2-} System in Pure Water and Sea-water at 1 atm. as a Function of pH**

Carbonates, which are soluble (only those of the Group IA metals, such as sodium), produce alkaline solutions by the reverse of the reactions given for carbonic acid.

$$Na_2CO_3 \rightarrow 2Na^+ + CO_3^{2-}$$

Sodium carbonate → Sodium ions + Carbonate ion

The hydrogen ions are provided by the ionization of water. Since hydrogen ions are removed, the pH increases. Thus sodium carbonate is occasionally used to increase pH in a drilling fluid. It is not as effective as caustic soda in this respect and the maximum pH that can be achieved in pure water is only 10.3.

Chemical Equilibria

Many of the reactions that have been considered are examples of chemical equilibria. The ionization of water, written as:

$H_2O \leftrightarrow H^+ + OH^-$

is a description of an equilibrium. Both the forward reaction, H2O → H+ + OH– and

the back reaction, $H^+ + OH^- \rightarrow H_2O$, occur all the time at identical rates such that at one time:

Where K is a constant, known as the equilibrium constant.

$$\frac{(H^+)(OH^-)}{(H_2O)} = K$$

In the case of water, where the amount of ionization that occurs is very small, the concentration of un-dissociated water remains constant so that:

Therefore $\{H^+\}\{OH^-\} = KC = 10^{-14}$ $\text{moles}^2/\text{liter}^2$

Any one water molecule will never remain un-ionized for very long. It will be continuously changing from the un-ionized to the ionized state and back again. When an H^+ ion combines with an OH^- ion, there is no special reason for it to combine with the same OH^- ion with which it was formerly associated in a water molecule. Thus, the H^+ and OH^- ions are continually changing partners with ions from different water molecules in an unending game of “musical chairs”.

When something acts to change an equilibrium, it always does so such that the equilibrium constant remains constant. For example, when an acid is added to water, $\{H^+\}$ increases. Then in order to preserve the equilibrium, some of the hydrogen ions react with the hydroxide ions so that $\{OH^-\}$ decreases and $\{H^+\}\{OH^-\}$ stays at 10^{-14} $\text{moles}^2/\text{liter}^2$.

Solubility of Lime

The solution of slightly soluble salts is an important example of equilibria. The solution of lime (calcium hydroxide) in water is written:-

Ca(OH)2 ↔ Ca2+ + 2OH–

And at equilibrium

$$\frac{(Ca^{2+})(OH^-)^2}{\{Ca(OH)_2\}} = K$$

The $\{OH^-\}$ term is squared, since two OH^- ions appear in the equation. For this reason the equilibrium is more sensitive to $\{OH^-\}$, than to $\{Ca^{2+}\}$.

The un-dissociated lime remains as a solid (it is not molecularly dispersed) and has effective concentration of unity as long as it is present.

If calcium ions or hydroxide ions are added to the system from an independent source, then the solubility of the lime will be suppressed. Thus, if caustic soda is added, $\{OH^-\}$ increases and $\{Ca^{2+}\}$ must decrease, so that the equilibrium is maintained. Thus the concentration of calcium in drilling fluids can be controlled by the addition of caustic. This is shown in Figure 3-13 (the addition of sodium carbonate which removes all calcium as insoluble, calcium carbonate). Since the solubility of calcium is controlled by $\{OH^-\}$, it can also be expressed as a function of pH.

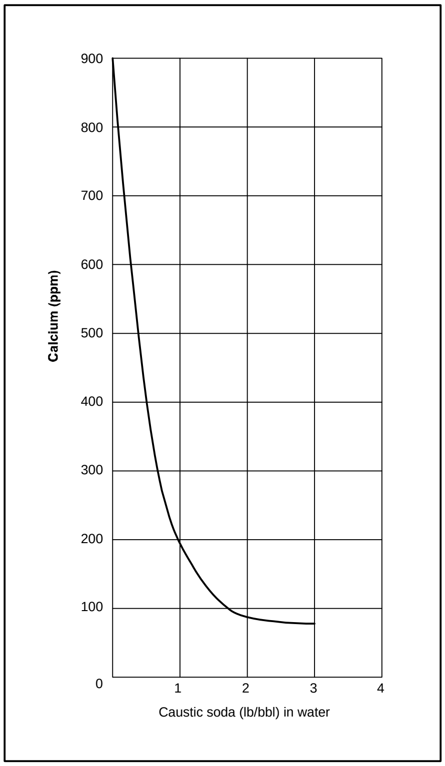


Figure 3-13 Solubility of Calcium in a Solution Containing 4 lb/bbl Lime vs. Caustic Soda Addition

Solubility of Other Compounds in Water

The solubilities of many other compounds, other than lime, are also controlled by equilibria involving $\{OH^-\}$ and therefore, can be expressed as a function of pH. Generally, metal hydroxides are insoluble, thus the higher the pH, the higher $\{OH^-\}$ and the less soluble the metal becomes. Some elements with high valences form complex negatively charged anions at high pH and thus become more soluble. Silica, for example, forms the $H_3SiO_4^-$ and the $H_2SiO_4^{2-}$ ions and aluminum forms the aluminate ion, AlO_2^-.

The electronegativity of an element can be looked at in terms of the charge and size of its cation. The group 1A metals, such as sodium and potassium, form singly charged cations which have a large ionic radius. As the charge on a cation increases, the size of the ion decreases. This is because, as electrons are lost, the nucleus exerts a greater pull on those electrons that are still left. Thus, reading along the third row of the periodic table (see Table 3-2), Mg^{2+} is a smaller ion than Na^+; Al^{3+} is smaller than Mg^{2+} and Si4+, if it ever existed, would be smaller than Al3+ and so on, across the row. The other effect in determining ionic size is atomic weight. The higher the atomic weight, the more electrons there are and the more space they occupy. Thus, the K+ ion is larger than Na+ ion and similarly Ba2+ is larger than Mg^{2+}.

Hydration of Ions

Most ions in solution are hydrated, that is they are surrounded by a shell of water molecules that form an organized structure around the ion. The size of this water shell depends on the intensity of the ions' electric field. Thus small highly charged ions are extensively hydrated. The attraction of water to doubly or triply charged metal ions is so strong that many of these metals form salts which contain chemically bound water, known as water of crystallization. Calcium and magnesium salts such as $MgCl_2 \cdot 6H_2O$ or $CaCl_2 \cdot 2H_2O$, are common examples. If the water is driven off by heating, the resulting anhydrous salts absorb water readily from the atmosphere so that the hydrous salt reforms rapidly. Even in the hydrous form, the salts given above absorb water and if left standing in the open for long enough they will eventually absorb enough water to dissolve completely. The group 1A metals, being singly charged, are much less hydrated that the group IIA metals, such as calcium and magnesium.

An important break occurs between sodium and potassium. The Na^+ ion of radius 0.98Å, is hydrated, but the K^+ ion, of radius 1.33Å is not hydrated, since the slight difference in size leads to the potassium ion having a lower electric field than the sodium ion. This means that the K^+ ion is **effectively smaller** than the Na^+ ion as it is not dragging around a shell of water molecules on its back. This is very important in determining the way in which these two ions react in solution with clay surfaces and also explains why strong potassium brines have less viscosity than strong sodium brines. This also explains why potassium form of clays (Illite) is more stable and is the basis of the potassium inhibited drilling fluids. Anions are not hydrated because they are much larger in size than cations. Thus the electric field around anions is not very strong. Temporary attraction of water molecules occurs, but no permanent structuring of the water molecules around the anion exists.

Chemical Calculations

An important aspect of drilling fluid engineering involves a careful chemical analysis of the fluid, as certain chemical characteristics can substantially affect the performance. Also, calculations have to be performed to determine treatment levels. This section deals with both these aspects.

Concentration of Solutions

The concentration of a solution is a measure of how much of a particular substance is dissolved in a certain volume or weight of solution. There are various ways of expressing this.

1. **Weight of solute per volume of solution** (w/v). This is normally expressed in grams/liter (g/l), kilograms/meter3 (kg/m3), milligrams/liter (mg/l) or pounds per barrel (lb/bbl).
2. **Weight of solute per weight of solution** (w/w). This is normally expressed as a percentage (%). Thus a 10% solution = 100g solute/kg solution. In lower concentrations it is expressed as parts per million (ppm). Thus, 1 ppm = 1 mg solute/kg solution and 1% = 10,000 ppm. Parts per thousand (ppt) is occasionally used as a unit, especially for sea water analysis. 1 ppt = 1,000 ppm = 0.1%
3. **Volume of solute per volume of solution** (v/v). This is often used to describe mixtures, rather than true solutions, and is the unit used for retort analysis of drilling fluids.

Thus 1% (v/v) = 1 m^3 of dispersed phase/100 $m^{3.}$

4. **Molarity (M)**. This is used mainly for laboratory analytical reagents. A one molar solution (1M) contains one mole (molecular weight in grams) dissolved in one liter of solution.
5. **Normality (N).** Again, this is used mainly for laboratory reagents. A one normal solution (1N) contains one mole of solute divided by its valency in one liter of solution.

Table 3-8 Equivalent Weights

Element/Compound or ion	Atomic/Molecular Weight	Valency	Equivalent Weight
Na, Na^+	23	1	23
K, K^+	39.1	1	39.1
Mg, Mg^{2+}	24.3	2	12.15
Ca, Ca^{2+}	40.1	2	20.05
Fe(iii), Fe^{3+}	55.8	3	18.6
Cl^-	35.5	1	35.5
SO_4^{2-}	96	2	48
H_2SO_4	98	2	49
HCl	36.5	1	36.5
NaOH	40	1	40
$Ca(OH)_2$	74.1	2	37.05
$CaSO_4$	136.1	2	68.05
Na_2CO_3	106	2	53
$CaCO_3$	100.1	2	50.05
$MgCO_3$	84.3	2	42.15
$NaHCO_3$	84	1	84
$AgNO_3$	169.9	1	169.9
NaCl	58.5	1	58.5

Conversion of Units

Conversion from w/v to w/w and vice versa, depends on the density of the solution,

$$ppm = \frac{mg / L}{Density\, of\ Solution}$$

Or, converting the other way

1% = 10 g/L x Density of the solution

This relationship is ignored by many people in the oil industry who take ppm and mg/l as equivalent units. In a dilute solution, where the density is very close to 1.00 this is true. In heavy brines or weighted drilling fluids the units (ppm vs. mg/L) are very different.

It is recommended that all analysis of drilling fluids be calculated on a w/v basis as g/l or mg/l.

Conversions of molarity to w/v depends on the molecular weight. Thus 1M HCl contains 36.5 g HCl dissolved in one liter of solution, as the molecular weight is 36.5. Thus, 1M HCl = 36.5 g/l.

Equivalent Weights

The equivalent weight of an element or ion is:

$$equiv.wt. = \frac{Atomic\, Weight}{Valency}$$

For a compound, the equivalent weight equals:

$$equiv.\,wt. = \frac{Molecular\,Wt.}{Total\,Valency\,of\ "cations"}$$

Common equivalent weights are listed in Table 3-8.

It can now be seen that a one normal solution contains the equivalent weight of the solute in grams dissolved in one liter of solution.

For compounds of valency one, a 1M solution is identical to a 1N solution. If the valency is two, then a 1M solution is twice the strength of a 1N solution.

Sulfuric acid (H_2SO_4) has a molecular weight of 98 (a 1 M solution is 98 g/l) and "valency" 2. Thus its equivalent weight is 49 (a 1 N solution is 49 g/l). Thus, 1M H_2SO_4 is 98 g/l. This compares with hydrochloric acid, HCl, where a 1M and 1N solution both contain 36.5 g/l.

Calculation of Reacting Weights

There are two methods:

1. Write down the chemical formulas of the reactants and products and balance the equation which describes the reaction, bearing in mind the valences of the ions involved. This gives the ratios in which the molecules combine. Multiplying by the molecular weights thus gives the ratios of weights, which combine.

An example calculation is given below.

Calculate the weight of sodium carbonate needed to completely remove calcium from $100m^3$ of a drilling fluid containing 1000 mg/l Ca^+.

The reaction of sodium carbonate with calcium is:

$$Na_2CO_3 + Ca^{2+} \rightarrow CaCO_3 + 2Na^+$$

from this equation, we know that 1 mole Na_2CO_3 reacts with 1 mole of Ca^{2+}

Na_2CO_3 molecular weight = 106 (Table 3-8)

Ca^{2+} molecular weight = 40.1 (Table 3-8)

Thus, 106 g Na_2CO_3 always reacts with 40.1 g of calcium. $100m^3$ of drilling fluid, with Ca^{2+} at 1000 mg/l, contains 1000 x 100 mg Ca^{2+}, or 100 kg Ca^{2+}

Units conversion

$$1000\text{ mg/L} \times 1000\text{L/m}^3 \times 1\text{ Kg/1,000,000 mg} \times 100\text{ m}^3 = 100\text{ Kg}$$

Therefore, weight of sodium carbonate needed is:

$$(106 / 40.1) \times 100\text{ kg} = 264\text{ kg}$$

3. This method involves the use of equivalent weights. The equivalent weights of elements always combine on a 1:1 basis, since the "balancing of the equation" has already been taken into account when dividing molecular weight by valency to obtain the equivalent weight.

Referring to the previous example, sodium carbonate has equivalent weight 53, while calcium has equivalent weight 20.05. Therefore, when these combine, they will do so in the ration 53g sodium carbonate to 20.05g calcium. It is not necessary to know the formula of the reactants, nor of the products (or even what reaction occurs).

Thus to remove 100 kg of calcium requires (53/20.05) x 100 kg of sodium carbonate giving 264 kg as before

In some calculations, milliequivalents are used. This is simply 1/1000 of the equivalent weight. Thus 1 milliequivalent (1 me) is the equivalent weight in milligrams.

Techniques of Chemical Analysis

In order that a drilling fluid may function correctly, it is important to monitor its chemical composition. If the chemical composition varies from that required for optimum performance, then this variation will be detected and corrections can be made.

Chemical analysis is nearly always done on the filtrate rather than on the drilling fluid itself. The reason for this is that the viscosity, solids content and even the color of the drilling fluid make analysis difficult or may interfere with the analysis itself. The filtrate can be used because, with the exception of polymers which are rarely analyzed for, it contains the same concentration of dissolved substances as the drilling fluid.

Methods of Testing for Dissolved Ions

The most common method is to take a solution of known strength (often called a standard solution) of a compound which reacts with the particular ion to be measured. This solution is added gradually to a known volume of the filtrate until the reaction is just complete. Then, knowing the volume of solution added, its concentration and the chemistry of the reaction that occurs, it is possible to work out how much of the ion under test is in the filtrate. This is the titration method of chemical analysis.

This technique requires an accurate measure of the volumes of filtrate and standard solution and an accurate method for determining the “end point” of the reaction. This end point is the exact point at which all of the ions being tested for have reacted with the standard solution.

Measurement of Volumes

An accurate measurement of volumes is accomplished by using pipettes and burettes. These are glass or plastic tubes which are calibrated on the outside to measure liquid volumes. (See Figure 3-14.

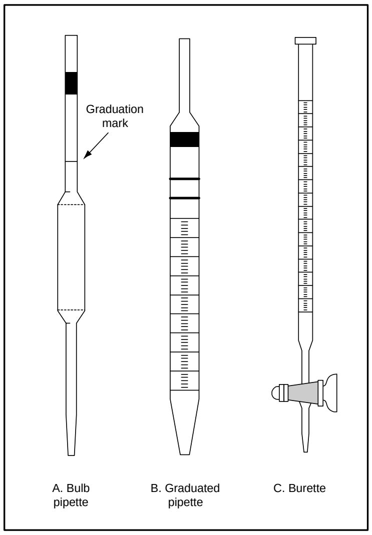


Figure 3-14 Pipettes and Burette Used in Chemical Analysis

A bulb pipette (Figure 3-14 A) is used to measure out a certain volume, such as 5 or 10 ml, with far greater accuracy that a measuring cylinder. The pipette is dipped into the solution, which is then sucked up into the upper stem to above the graduation.

After ensuring that there are no air bubbles trapped in the liquid, the level is then slowly dropped, using a finger on the top of the pipette, until the bottom of the meniscus coincides exactly with the graduation mark. The pipette is then removed from the liquid and the lower end wiped to remove liquid on the outside. The volume of liquid inside the pipette is then transferred to the required container by removing the finger at the top and letting the liquid drain out slowly. The pipette should not be blown our, nor should the last drop be shaken from the tip as this will alter the volume delivered.

Bulb pipettes should never be used for any volume other than the one stated on the pipettes. The straight stem, or graduated pipettes (Figure 3-14 B), are usually calibrated to enable different volumes to be delivered.

The burette (Figure 3-14 C), is like a graduated pipette with a tap at the bottom which controls the release of liquid. A burette is used for titrations as follows:

With the tap closed, it is filled with the titrant. This is usually a standard solution which reacts with the ion under test. After filling, the tap is opened briefly to fill the lower part of the burette. The burette is then checked for air bubbles. If these exist they can usually be removed by gently tapping the sides of the burette or by rotating it rapidly (but carefully) between the palms of the hands.

Before starting the titration, the level of titrant is recorded. The titrant is then added carefully to a known volume of filtrate (added by pipette to the titrating flask) until the end point is reached. The volume of titrant in the burette at the end point is then recorded and the volume used is simply the difference between this reading and initial one.

The volume must never be allowed to drop below the last graduation mark or inaccurate readings will be obtained. If the end point has not been reached with the burette nearly empty, the titration is stopped, the volume is recorded and more titrant added to the burette with the new volume recorded as before.

Measurement of the End Point.

The end point of titration is usually amplified by adding a suitable indicator to the titrating flask. An indicator is a chemical that changes its color when its chemical environment changes. For the indicator to be effective this color change must be abrupt and must occur over a very small range or chemical change.

Different indicators are used for different titrations, depending on the chemicals involved. For acid-base titrations, phenolphthalein is commonly used. It is pink in alkaline solutions, but at pH 8 - 8.3, it becomes colorless. The titration is stopped at this point as virtually all the alkali will have been neutralized at pH 8 – 8.3. The common indicators and the titrations for which they are used are shown below.

Table 3-9 Commonly Used Indicators

Indicator	Titration	Color Change
Phenolphthalein	Acid/base	Pink @ pH>8 – 8.3, Colorless @ pH<9
Methyl orange	Acid/base	Red @ pH>4, Yellow @ pH <4
Cresol red	Acid/base	Yellow @ pH >8, Red @ pH <8
Bromocresol green	Acid/base	Yellow @ pH >4, Blue @ pH <4
Potassium chromate	Chloride/Silver nitrate	Yellow, Red with excess Ag+ ions
Murexide	Calcium/E.D.T.A.	Pink with Ca2+ or Mg2+, blue without
Solochrome Black T	Ca, Mg/E.D.T.A.	Red with Ca2+ or Mg2+, blue without

Example Titration and Calculations

The concentration of the chloride ion in drilling fluids is usually determined by titration with a standard silver nitrate solution. This reacts with chloride ions to precipitate insoluble silver chloride. Potassium chromate is used as an indicator. It is yellow in solution, but forms an orange-red complex with silver ions. Silver nitrate is added, from a burette to a known volume of the filtrate, until all the chloride ions have reacted. When more silver nitrate is added, an orange-red color then develops which indicates that the end point has been reached.

The filtrate is commonly diluted with distilled water before analysis. This produces the right concentration for the standard solutions used and also enables a comprehensive chemical analysis to be made on small volumes of filtrate.

Example

The filtrate was diluted one hundred times to 10 mls then titrated with 0.0282N $AgNO_3$. The amount of titrant was 19.1 mls.

The reaction is: $AgNO_3 + Cl^- \rightarrow AgCl + NO_3^-$

Thus 1 mole of silver nitrate reacts with 1 mole of chloride ions.

Moles $AgNO_3$ used = 19.1/1000 x 0.0282

(Since 1 liter of the $AgNO_3$ solution contains 0.0282 moles $AgNO_3$)

This has all reacted with chloride ions therefore there must be 19.1/1000 x 0.0282 moles of chloride ions in the 10 ml sample of diluted filtrate.

Therefore, g Cl^- in diluted filtrate = 19.1/1000 x 0.0282 x 35.5 (since atomic weight of Cl^- is 35.5)

0.0282 x 35.5 = 1.0, which is why this strength of $AgNO_3$ is used as a standard solution.

Calculating the concentration of Cl^- in the solution, we have:

mg Cl^- = (19.1/1000 x 0.282 x 35.5) x 10 x 100 = 19.1

Therefore, The 10 ml sample of x 100 diluted filtrate contains 19.1 mg Cl^-

The concentration in the diluted filtrate sample is thus (19.1 x 1000)/10 = 1919 mg/l and in the filtrate thus 1919 x 100 = 191,000 mg/l

This corresponds roughly to the saturation value for sodium chloride at 20ºC.

Other Methods of Analysis

Very often it is found that there is no suitable indicator to determine the end point of a reaction. If this is the case, other methods must be used.

A common solution to this problem is to add an excess of a standard solution to a known volume of the filtrate and precipitate the ion under test as an insoluble compound. Since excess of the reagent is added, all of the ions are precipitated and the amount of precipitate is thus proportional to the amount of the ion present in the filtrate. The amount of precipitate can be measured in three ways:

1. **"Gravimetric" Analysis**. The precipitate is dried and weighed as accurately as possible. This method is rarely used on a drilling rig because of the need for expensive and delicate equipment and the time needed for the test.
2. **Centrifugation**. The precipitate is centrifuged under standard conditions of speed and time and the floc volume in the centrifuge tube is measured. This is proportional to the weight of precipitate. The test is not particularly accurate and is comparative in nature rather than absolute. It is used quite commonly to measure potassium ion concentration and the concentration of certain polymers, as great accuracy is not usually required.
3. **"Turbidimetric" Analysis**. This method is used for dilute solutions and depends on an estimate of the cloudiness (or turbidity) caused when the precipitate forms. The estimation can be done instrumentally using a photo-electric cell or it can be done by eye. It is again a comparative test and when the eye is used as a detecting "instrument', there is no pretense of accuracy. This method is used to indicate the presence of the sulfate ion in drilling fluids by reaction with barium chloride solution.

$$\underset{\text{cloudy}}{BaCl_2 + SO_4^{2-}} \rightarrow \underset{\text{precipitate}}{BaSO_4 \downarrow} + 2Cl^-$$

Two other techniques of analysis are occasionally used for drilling fluids.

1. **Flame Photometer**. This is used for an accurate determination of sodium, potassium and lithium ions and depends on a measurement of the intensity of the light of a well defined wavelength that is emitted by these ions when they are heated. The instrument is quite delicate and is also fairly expensive.
2. **Colorimetric Analysis**. This may be used to determine the quantities of silicon, iron or aluminum. These ions form colored complexes with certain chemicals. The intensity of color developed is proportional to the concentration of the complex and to the concentration of the ion under test.

Many other techniques for chemical analysis exist, but are rarely, if ever, used for drilling fluids, owing to the need for expensive, intricate equipment and trained operators.

Common Names of Compounds used in Drilling Fluids

Many different “chemicals” and minerals are used on drilling rigs. These are often known by a common name in the case of “chemicals”, or by their geological name in the case of minerals. Table 3-10 gives the main examples.

Note that the term “lime” is used for two different compounds. This is due to historical reasons. Any product derived from heating limestone (mainly calcium carbonate), has been called in the past “lime”. Thus:

$$CaCO_3 \rightarrow CaO + CO_2$$

This reaction produces calcium oxide (quick lime). On adding water this forms calcium hydroxide (slaked lime).

$$CaO + H_2O \rightarrow Ca(OH)_2$$

Table 3-10 Common Names, Chemical Nature and Formula of Materials

Common Name or Mineral Name	Chemical Nature	Formula
Anhydrite	Calcium Sulfate	$CaSO_4$
Barite or baryte or barytes	Barium Sulfate	$BaSO_4$
Bicarbonate of soda or bicarb	Sodium Hydrogen Carbonate	$NaHCO_3$
Calcite	Calcium Carbonate	$CaCO_3$
Caustic or caustic soda	Sodium Hydroxide	NaOH
Cement	Calcium Oxide + clays	CaO + clays
Gypsum	Calcium Sulfate	$CaSO_4 + 2H_2O$
Lime or quick lime	Calcium Oxide	CaO
Lime or slaked lime	Calcium Hydroxide	$Ca(OH)_2$
Marble	Calcium Carbonate	$CaCO_3$
Muriate of potash	Potassium Chloride	KCl
Potash	Potassium Chloride	KCl
Salt	Sodium Chloride	NaCl
SAPP	Sodium Acid pyrophosphate	$Na_2H_2P_2O_7$
Soda ash	Sodium Carbonate	Na_2CO_3

Conventional (Basic) Fluid Systems

Spud Muds

A spud fluid, often referred to as a spud mud, is normally a very simple inexpensive fluid for drilling the first and sometimes second intervals from surface. Under certain drilling environments such as reactive shales, water flows, surface gas, bit balling, and poor penetration rate, the spud mud requirements can be more complex. However, a typical spud mud is one of simplicity, low cost, and can be easily and rapidly mixed, due to the large volume requirements associated with large diameter surface hole in a traditional wellbore design.

Spud fluids can vary considerably depending on lithology, make-up water, and hole size. When freshwater is available and surface formations contain considerable quantities of reactive clays, the well may be spudded with water only. As a contrast, when surface formations consist of loosely consolidated sand and/or gravel, it may be necessary to spud with a drilling fluid having good wall cake properties and sufficient viscosity to keep the hole clean. Some typical spud fluid practices are described below.

Freshwater / MILGEL® (Bentonite)

Make-up water should be checked for calcium and magnesium. If the hardness check indicates a calcium ion concentration in excess of 150 mg/L, the water can be pre-treated with soda ash. As a rule of thumb, 10 lb of soda ash will lower the calcium by 100 mg/L in 100 bbl of water. Be careful to avoid over treatment with soda ash. This product can change from being beneficial in removing the calcium contaminant, to being detrimental by increasing the carbonate radical anion which is a clay flocculent After the make-up water quality is acceptable, a good spud fluid may be mixed by using one of the following procedures.

1. Mix 20 to 25 lbm/bbl of MILGEL®. Mixing rate will vary between two to 10 minutes per sack dependent upon the efficiency of the mixing equipment. In some cases, small quantities of lime may be added to bentonitic spud fluids (after bentonite is hydrated) to thicken the fluid and improve hole cleaning. If optimum cake quality and filtrate is desired it is better to use additional viscosifiers and avoid the addition of lime, a recognized clay flocculent and source of calcium ion.
2. Add 10 to 12 lbm/bbl of SUPER-COL®. The yield of SUPER-COL is approximately twice that of MILGEL. SUPER-COL® results in a lower solids concentration than MILGEL formulations, and uses half the volume of product which may be critical on some wells.

Note: SUPER-COL should not be used where chlorides are above 2000 mg/L or where hardness cannot be reduced to less than 100 mg/L.

3. Bentonite extenders (e.g. BENEX) added to MILGEL slurries increase the viscosity of the suspension. Normally, two sacks of BENEX and 10 to 12 sacks of MILGEL per 100 bbl of fluid result in an excellent freshwater spud fluid. Depending on the quality or amount of peptizing on the bentonite in use these extenders may not perform as efficiently. The best results are obtained with BENEX when combined with a non-treated bentonite, such as MILGEL® NT. A disadvantage of this system is the increased mixing complexity. Normally, a mixing tank with a chemical feed pump is required for mixing and adding extenders. Care must be taken to hydrate the bentonite extenders thoroughly to remove

lumps and so provide efficient use of these polymers, and optimum extension of the clay. Mixing clay extenders in a five gallon bucket with a nail hole in the bottom for dripping the clay extender into the flowline will work as a “poor-boy” method, but leaves a lot to be desired for proper metering of the product into the active system.

Brackish Water and Seawater

Brackish water and seawater are often used as make-up water for spud fluids on inland barge and offshore drilling operations. The sodium chloride content generally ranges from 10,000 to 35,000 mg/L. Hardness ranges from 300 to 1300 mg/L depending upon proximity to river drainage. Although hardness may be reduced to an acceptable level by adjusting the pH to 10.5 with caustic soda, the chloride content cannot be treated out economically, thus it remains as a contaminant which suppresses the yield of bentonite. Therefore, bentonite should be pre-hydrated in fresh water, or other viscosifiers such as SALT WATER GEL should be considered if this water is to be used.

SALT WATER GEL (attapulgite) is an effective viscosifier in a sodium chloride environment. Normally, 20 lbm/bbl (with good shear) is sufficient to obtain sufficient hole cleaning on surface. Pre-hydrated bentonite can provide additional viscosity and will also improve the quality of the filter cake. However, if facilities are not available for pre-hydration the addition of 5 to 6 lbm/bbl of MILGEL directly to the system improves cake characteristics to some extent. Attapulgite is not allowed in many parts of the world due to working environment concerns related to lung disease. A proper respirator or breathing filter mask must be used while mixing SALT WATER GEL as a safety measure. When the clay is in the wet state no potential working environment risks exist.

GUAR GUM (2 to 4 lbm/bbl) is a cost-effective viscosifier in seawater and is commonly used in offshore environments, especially where drill water (freshwater) supplies may be limited. GUAR GUM viscosity decreases with increased temperature and has a temperature limit of approximately 150°F. GUAR GUM is typically used for viscous pills. GUAR GUM fluid should not be stored in the pits for greater than 24 hours due to the possibility of bacterial degradation. It is recommended that a bactericide/biocide be used to prevent degradation.

Seawater is often used for fluid make-up and maintenance on inland barge and offshore drilling operations, primarily because of its availability and inhibitive characteristics.

The ionic composition of typical seawater is noted below.

Table 3-11 Composition of a Typical Seawater Sample

Constituent	mg/L
Sodium	10,400
Potassium	375
Magnesium	1,270
Calcium	410
Chloride	18,970
Sulfate	2,720
Carbon dioxide	90
(Density above - 8.56 lbm/gal)	

Hydration and subsequent swelling of clays and reactive shale is minimized by the sodium chloride, magnesium, and calcium in seawater.

These inhibitive properties are particularly useful when drilling the surface interval of a hole with a non-dispersed, low pH fluid system.

A dispersed system may be required for drilling other intervals, however. These same inhibitive properties make it more difficult and costly to control and maintain the rheological and filtration characteristics of the fluid.

For non-dispersed seawater fluids, use a viscosifier (SALT WATER GEL, pre-hydrated MILGEL) and, if filtration control is necessary, use materials such as BIO-PAQ®, CMC or MIL-STARCH® and pre-hydrated MILGEL. Pre-hydrated MILGEL contributes to viscosity and filter cake quality and gives a slight fluid loss reduction. The advantage of pre-hydrating bentonite prior to its addition to salt water is illustrated below.

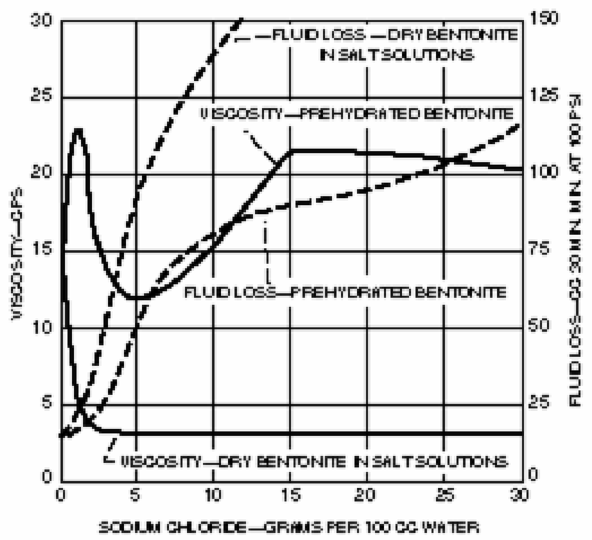


Figure 3-15 Fluid Loss and Viscosity with Bentonite Prehydration

Pre-hydrated bentonite mixtures can be prepared by mixing 25 to 35 lbm/bbl of MILGEL in freshwater. To this slurry is added 0.5 to 1 lbm/bbl UNI-CAL® and 0.2 to 0.4 lbm/bbl of caustic soda. To this slurry is added 10 to 15 lbm/bbl additional MILGEL. This mixture is generally added at an initial concentration of 25% to 30% of circulating volume, and then added as required while drilling. A defoamer such as LD-8 may be required (0.5 to 1.5 gal/100 bbl of volume) to control foaming.

As drilling progresses, it is usually desirable to disperse or deflocculate fluid solids and lower API filtrate. Addition of 2 to 6 lbm/bbl of UNI-CAL®, 4 to 12 lbm/bbl of LIGCON® or CHEMTROL® X, 0.25 to 1 lbm/bbl of CMC, and caustic soda as required for a 1 to l.5 P_f (10.0 to 10.5 pH) results in a fluid with excellent flow properties and a filtrate value in the range of 4 to 8 cc. To aid in filtrate control and cake quality, bentonite should be maintained (by Methylene Blue Test) in the 15 to 25 lbm/bbl range. If improved inhibition from magnesium is desired, pH should be maintained below 10. Magnesium begins to precipitate as magnesium hydroxide at higher pH ranges. Rheological properties and filtration control will be less difficult, however, if magnesium is precipitated.

Seawater fluids require substantially greater additions of caustic soda for alkalinity control than freshwater systems. This is due in part to the loss of hydroxyl ion reacting with magnesium, drill solids, and commercial clay.

In an effort to improve inhibition, lime or gypsum base seawater fluids are sometimes employed. UNI-CAL is normally used as a deflocculant and CMC, MIL-PAC™, or MILSTARCH are generally required for filtration control. Although some improvements in stabilizing gumbo shales have been observed with this approach, the most effective method for preventing bit and collar balling and flow line plugging while drilling highly bentonitic gumbo shales is controlled drilling. This reduces the packing action of drilled solids. These hazards exist when the total clay solids approach or exceed 10%. In some areas of drilling activity it may be a lesser amount and in others a higher concentration of solids can be tolerated. It is the instantaneous penetration rate that is the culprit impacting the packing action. If a penetration rate of 90 feet per hour is the calculated rate to prevent balling, that means 90 feet per hour for the total stand. Not 20 minutes and then reaming the hole for the remainder of the hour.

In summary, seawater is often used in offshore drilling operations to avoid transportation of freshwater. Non-dispersed seawater fluids also offer substantial inhibition against clay swelling and are sometimes effective in stabilizing bentonitic intervals while drilling the surface hole. If a dispersed fluid with low fluid loss is required, treating costs will be considerably greater than with comparable freshwater fluids. For this reason, seawater is often used on the surface portion of the hole in many operations. Chlorides are then gradually reduced with freshwater additions as rheological properties and filtration control requirements become more stringent.

Saturated Salt Water Fluids

Saturated salt water fluids are generally limited to drilling operations encountering salt formations. Saturated salt fluids are prepared by adding NaCl to water up to saturation and then adding appropriate viscosifiers and fluid loss control agents. In some instances, freshwater fluids are converted to salt fluids by inadvertently drilling into salt formations. At such a point a decision has to be made as to the route to take while drilling the salt interval. Let the formation saturate the fluid and start treating the system with salt tolerant additives, or stop the drilling process and saturate the active system or dump the active system and build a saturated salt mud from scratch.

Preparation of Saturated-Salt Fluids

Initially, sufficient salt should be added to saturate the system. At 60°F, approximately 127 lb of salt per barrel of freshwater is required. A volume increase of approximately 13% is obtained when 127 lbm/bbl of salt is added.

With good mixing conditions (good shear) 20 to 25 lbm/bbl of SALT WATER GEL generally yields a funnel viscosity in the range of 35 sec/qt.

MILSTARCH should be mixed through the hopper slowly to prevent high-viscosity peaks. Four to six lbm/bbl of MILSTARCH usually produces a 5 to 10 cc API fluid loss, depending upon the amount and type of solids present.

Caustic soda should be added to obtain a pH of 10.0 to 11.0 (l.0 or greater P_f). Higher alkalinities reduce the tendency to foam and minimize corrosion. Calcium and magnesium levels are also reduced.

Organic deflocculants such as UNI-CAL and DESCO® are beneficial in some instances for thinning (UNI-CAL offers maximum effectiveness if dissolved in freshwater prior to addition), but viscosity control is achieved primarily through dilution and with solids control equipment. In some instances, small additions of MIL-PAC or CMC have been noted to have a thinning effect on saturated salt fluids.

Since MILSTARCH will begin to degrade at temperatures in excess of 250°F, it may be necessary to utilize supplementary additions of MIL-PAC. MIL-PAC is stable at temperatures to about 300°F. Salt-saturated systems display a foaming tendency, but this problem can be minimized or eliminated with defoamers such as LD-8 or W.O.™ DEFOAM.

Starch fermentation is generally not a problem if the system is saturated with salt or if pH is 11.5 or above. However, to insure against starch fermentation, add a suitable biocide.

Where high salinity, salt saturated produced brines are used to prepare starch based fluids, it may be necessary to run the resulting system without pH control. Certain produced brines can exhibit an acidic pH and be high in hardness (Ca^{++} and Mg^{++}) thereby negatively affecting the addition of Caustic Soda. In this case is usually more economical to run the system without pH control, therefore eliminating this measure as a means of preventing fermentation. The high salinity of the brine alone may not be a deterrent to fermentation.

Anaerobic bacteria can exist in certain produced brines. Starch based systems are a food source for such bacteria and once exposed to these circumstances, degradation and fermentation of the starch can proceed at a rapid rate. It will be necessary to treat the system with a biocide to prevent fermentation prior to the addition of the starch. Once fermentation starts, it may be impossible to get enough biocide into the system to offset the problem. In this case, treatment with the biocide prior to adding any starch will be necessary.

Case History No. 1

Extremely high-density (20.0 to 21.0 lbm/gal) saturated-salt fluids are commonly employed in southern Iran. These fluids are prepared with barite, saturated salt water and 12 to 18 lbm/bbl of starch. The starch furnishes the desired filtration control. API filtrate is usually below 1 cc with this concentration of starch.

The local barite often contains a high percentage of low-gravity solids and some of the formations penetrated are “fluid making.” For this reason, it is essential to utilize fine screen shakers and centrifuges. The pH is maintained in the 7.0 to 7.5 range with Caustic Soda.

Case History No. 2

The Nisku formation on the Western flank of the Williston Basin in Montana has been analyzed to contain certain strains of bacteria. Drilling this formation releases the bacteria into the mud system. If a starch based mud is used to drill the Nisku, it will be necessary to pre-treat the system with a biocide to kill the bacteria before the formation is penetrated. Otherwise, the bacteria will attack the starch and fermentation will proceed at a rapid rate. This will be observed by a rapid loss of fluid loss control.

Prehydrated MILGEL and Salt Fluids

Pre-hydrated MILGEL salt fluids are used in top hole drilling for hole cleaning and suspension. The pre-hydrated MILGEL slurry increases the yield point and gel strengths due to flocculation of the bentonite with salt compounds. These properties give the fluid excellent carrying capacity.

Colloidal Protected MILGEL may be pre-hydrated as follows.

- 1.0 bbl Drill Water
- Soda Ash (as needed)
- 0.5 lbm/bbl Caustic Soda
- 20 to 25 lbm/bbl MILGEL
- 0.50 to 2.0 lbm/bbl UNI-CAL
- 15 to 20 lbm/bbl additional MILGEL

This slurry should be mixed thoroughly before it is added to the salty drilling fluid.

Since pre-hydrated bentonite contributes very little to fluid loss control, normal salt water fluid loss control materials such as MILSTARCH should be used as required.

The high gel strengths of these fluids contribute to the retention of air or gas. Adding small quantities of MIL-PAC and UNI-CAL will aid in controlling gel strengths and allow gases to break out of the fluid. LD-8 or the alcohol-base defoamers may also be required to control gas or air entrainment and foaming.

Avoid using surface guns for fluid agitation because they tend to inject air into the system, foaming problems are inherent to saturated salt systems.

High-Salt or Salt-Saturated Polymer Fluids

High-molecular-weight polysaccharides and XAN-PLEX® (xanthan gum) are unique because they perform in saturated salt water as well as freshwater. XAN-PLEX has shear thinning characteristics which result in very low bit viscosities with good annular viscosity recovery as shear rate decreases. This characteristic contributes to increased penetration rates and good hole cleaning.

Under laboratory conditions these polymers start to degrade at temperatures above 250°F. However, this does not prevent their practical use at temperatures greater than this range. Polymers tend to exhibit lower viscosities as temperature increases. Viscosity may decrease to one-half or less when temperature is increased from 125°F to 250°F. For this reason, supplementing the material with small quantities of pre-hydrated MILGEL (5 to 10 lbm/bbl) would be advantageous. Bentonite tends to flocculate at elevated temperatures, which helps counteract the temperature thinning action on the polymers.

If an API filtrate below 20 to 25 cc/30 min is desired, it is necessary to add a supplementary filtration control material such as BIO-LOSE® or MIL-PAC. Small additions of MIL-PAC (0.1 to 0.25 lbm/bbl) may have a thinning effect on these fluids if they contain flocculated drill solids.

Although deflocculants are not normally added to this system, pre-solubilized UNI-CAL can be added. The pH of these fluids is usually maintained on the basic side (10.0) to minimize hardness. Caustic Soda is used, but should be added slowly to prevent momentary pH humps above 11.0, which can be detrimental to the polymer. In most drilling situations (high salinity and pH), these polymers will not usually biodegrade. If, however, a polymer system is to be stored or bacterial degradation is a possibility, a preservative should be added (0.25 to 0.5 lbm/bbl).

Note: Once fermentation starts, it is too late to treat with a preservative.

Although this system has mostly been associated with low-solids applications, it can be weighted if higher densities are necessary. The performance of a weighted system can be improved with a centrifuge and fine screens on the shakers to minimize the incorporation of drilled solids.

Phosphate-Treated Fluids

Phosphates are used for deflocculating drilling fluids. The ones most commonly used are sodium tetraphosphate (OILFOS®) which has a pH near 7.0 and sodium acid pyrophosphate (SAPP) which has a pH near 4.0.

Sodium tetraphosphate and SAPP are most commonly used to control rheological properties in freshwater, low-solids systems. Treatments of 0.1 to 0.2 lbm/bbl are normally sufficient when the system is maintained in the 8.0 to 9.0 pH range. Care should be taken to avoid overtreatments which results in excessive viscosity.

Since SAPP sequesters calcium and reduces pH, it is often used to combat cement contamination. The amount required depends upon the severity of the contamination. However, as a general guide, 0.2 lbm/bbl of SAPP will treat out approximately 200 mg/l of calcium ion. Monitor the chemical properties of the fluid (P_m, pH, P_f, Ca^{++}) carefully. When the P_m to P_f ratio approaches 3:1, discontinue use of SAPP to avoid over treatment.

Phosphates revert to orthophosphates at temperatures above 175°F. Orthophosphates will not thin above this temperature, but still function as a sequestering agent. Therefore, this material is rarely used at deeper depths, because of the temperatures normally encountered. Phosphates are also ineffective as dispersants in the presence of severe calcium and salt contamination.

Under proper conditions phosphate fluids offer good rheological properties at a minimum cost. Caustic Soda is normally added for pH maintenance. Small quantities of tannin-type dispersants may further enhance deflocculation of the system. MILGEL® is added periodically to improve filter cake and to reduce filtrate.

Tannin and Lignin Fluids

Additives rich in tannin, namely quebracho, were commonly employed as thinners prior to the advent of lignosulfonate. The material is derived from the quebracho tree and normally has a pH of 3.8.

Most quebracho products are a quebracho extract blend. These are used primarily as a thinner in freshwater drilling fluids for moderate depth wells. The product is unstable at temperatures above 240°F. It also loses its effectiveness in environments containing excess salt (6000 to 7000 mg/L) or calcium ion (240 mg/L). The system can be maintained at a pH as low as 9.0, but it will tolerate more salt and calcium contamination at pH ranges of 10.5 to 11.5. When used as a thinner for freshwater fluids, 1 to 2 lbm/bbl of the material is normally required. When used with lime fluids, 2 to 4 lbm/bbl will be needed for initial conversion. For treatment of cement contamination in freshwater fluids, concentrations of 1 to 2 lbm/bbl are usually sufficient.

Note: Quebracho, as a deflocculant, is rarely used and is only mentioned in case it is encountered while drilling in a remote location.

Lignite materials (LIGCO®, LIGCON®, and CHEMTROL® X) are normally used for filtration control and are sometimes used in low-solids, freshwater fluids as thinners. Generally, lignitic materials are less effective as thinners than tannates and lignosulfonates. When treating with lignitic materials, first add sufficient CAUSTIC SODA (1:2 to 1:4 mixture) to obtain a pH of 9.5 to 10.5, otherwise the product is not soluble and non-functional. Treatments of 1 to 2 lbm/bbl are normally recommended when these materials are used as thinners in freshwater fluids.

The tannin and lignin fluids of the 1940s and 1950s gave rise to newer modifications. Although there are still applications for this technology - in shallow holes - today's deeper holes often require higher temperature stability and broader tolerance to salt.

The tannins most commonly to be used are DESCO® and DRILL-THIN®, which is a sulfomethylated quebracho, applicable across a wide range of pH, with the optimum being 9 to 11 pH. Salinity tolerance from freshwater to saturated is also possible.

DESCO® CF is a chrome-free version of DESCO. Additional technical information on DESCO, DESCO CF, and DRILL-THIN can be obtained from Drilling Specialties Company technical literature.

Calcium-Base Fluids

Clay swelling is generally attributed to the penetration of water along the planar surfaces of the mineral, increasing the cleavage spacing between adjacent sheets. These individual clay layers are stacked one upon another in varying thicknesses and held together by cations such as sodium and calcium, which occupy sites on the silica sheets.

The degree of volume increase depends upon the clay that is hydrated and the cation type and concentration in the surrounding water. Sodium clays give the greatest hydration. Because of the dissociation of the sodium cation, the attractive forces which bond the platelets together are weakened to the extent that individual sheets literally float away from each other and disperse in the aqueous environment. This dispersion is even greater with agitation and high pH. On the other hand, calcium clays exhibit considerably less hydration because the calcium ion does not readily dissociate from the silica sheet and attractive forces remain strong.

For equal concentrations, sodium clays have the capacity for greater expansion than calcium clays. The degree of expansion decreases as the clay type changes from sodium to calcium. Consequently, sodium clays have greater viscosity building potential in freshwater fluids than do calcium clays.

Obviously, it is not always possible to predict the type of clays that will be encountered in drilling operations, but we can control the type of environment to which these cuttings are exposed.

Since the rate and degree of cation dissociation is directly related to the type and concentration of cations present in the surrounding water, we must also consider the process of cations leaving the surrounding aqueous environment and replacing the cations attached to the basal plane surface.

The relative replacing power of one cation for another is,

$$\text{(highest) } H^+ \rightarrow Ca^{++} \rightarrow Mg^{++} \rightarrow K^+ \rightarrow Na^+ \rightarrow Li^+ \text{ (lowest).}$$

This indicates that the calcium ion will readily displace the sodium ion. This phenomenon is referred to as *Base Exchange*. It should be noted, however, that this process is also subject to reverse mass action effects, i.e., sodium will displace calcium from clays if a sufficient concentration is present. Therefore, Base Exchange depends on the type and concentration of all cations present as well as the surrounding environment.

High concentrations of calcium are added to a drilling fluid in an effort to convert sodium clays to calcium clays and also to create a calcium environment for incorporated cuttings to minimize their hydrated volume through Base Exchange. Consequently, the relative viscosity effect will be less. This method of controlling the hydrated volume of formation clays is often called inhibition.

There are currently two main types of calcium treated fluids available.

Lime, $Ca(OH)_2$

Gypsum, $CaSO_4 \bullet 2H_20$

Lime Muds

Lime fluids have been used since the early 1940s and were the first of the calcium-base fluids. Primary application of lime fluids has been in areas where inhibition of reactive clays was desired and to improve the fluid systems' tolerance for salt, anhydrite, and drilled solids. Due to their tendency to solidify at elevated temperatures, particularly in fluids with high solids concentrations, these fluids are seldom used in wells having downhole temperatures in excess of 275° to 300°F.

Classification of Lime Muds

1. High-Lime Fluid
   - 5 to 10 ml Pf
   - 5 to 15 lbm/bbl excess lime
   - 80 to 120 mg/L filtrate calcium
2. Low-Lime Fluid
   - 0.8 to 2.0 ml P_f
   - 1.0 to 2.5 lbm/bbl excess lime
   - 75 to 200 mg/L filtrate calcium
3. Modified-Lime Fluid
   - 2 to5 ml P_f
   - 2 to 5 lbm/bbl excess lime
   - 80 to 200 mg/L filtrate calcium

Preparation of Lime Fluids

1. The degree of viscosity change during and after conversion to a lime fluid depends upon the total solids concentration of the fluid system. Therefore, dilution with water is necessary prior to conversion. Fine screen shakers and centrifuges are recommended for weighted fluids, and shakers and hydrocyclones (desilters and desanders) are desirable for low-weight fluids.

2. The type of clay solids present in the fluid influences the viscosity during conversion. Because MILGEL has a much higher base exchange capacity than most drilled clays, the viscosity increase is much more pronounced when converting fluids that contain high concentrations of MILGEL (MBT for base exchange capacity gives a general idea of conversion severity).
3. The type and amount of deflocculating agents added to the fluid prior to conversion have a significant influence on viscosity during conversion. If a phosphate has been used, the conversion will normally be drastic viscosity humps which are prolonged due to the reaction between phosphate, lime, and solids all caught up in a mass ion impact while displacement and sequestering is all taking place simultaneously.
4. Maximum agitation should be maintained in the surface active system.
5. Pilot tests should be run prior to conversion to help determine amounts of dilution and concentration of conversion chemicals needed.
6. The pits should have adequate space available to allow room for dilution.
7. Necessary amounts of lime and deflocculant should be stacked near the hopper, and caustic soda should be carried to the top of the suction (mixing) pit. Lime and deflocculant are added through the hopper. Caustic soda is added directly to the suction (mixing) pit near the point of maximum agitation.
8. Accurate circulation time should be determined so that conversion materials can be added at timed intervals over a period of one or two complete circulations.

Conversion Procedure

1. Conversion to a lime fluid should be initiated shortly after a new bit has been placed on bottom, i.e. once the conversion starts it should not be interrupted until the system has achieved stability. Best results are obtained when the conversion is made inside the casing prior to drilling out.
2. The amount of material needed for conversion will vary depending upon the desired properties and the condition of existing fluid. Most conversions can be made as follows.
3. Drilling fluid systems low gravity solids content has been diluted to a minimum solids content of 3 to 5% by volume. If the system is weighted then the calculated dilution volume is to be added simultaneously with the necessary chemical additions. The biggest concern is that after the breakover the fluids viscosity could drop so low that the barite may fall out of a weighted system.
   - 2 to 4 lbm/bbl deflocculant (UNI-CAL®)
   - 2 to 3 lbm/bbl caustic soda
   - 4 to 8 lbm/bbl lime hydrate [$Ca(OH)_2$]
   - 1 to 2 lbm/bbl MILSTARCH® with preservatives
   - 0.5 to 1 lbm/bbl CMC
4. The deflocculant should be started through the hopper while caustic soda is added to the pit. After five or six sacks of deflocculant and two or three sacks of caustic soda have been added, the lime additions should begin and be mixed through the hopper along with the deflocculant. The lime addition will cause a viscosity hump, but the system will “break over” when agitated and become quite fluid. If the viscosity becomes excessive, the rate

of addition of deflocculant and caustic soda should be increased along with an increase in water dilution.

5. The API Filtrate is normally controlled with starch and/or CMC. Periodic additions of MILGEL® normally should be accompanied by treatments with a deflocculant.
6. After all chemicals have been added to the fluid system, a check should be made of fluid properties. Minor adjustments can then be made on subsequent circulations with additional lime, UNI-CAL®, caustic, and a fluid loss control agent such as MIL-PAC®.
7. The addition of lime and MILSTARCH®, BIO-LOSE®, BIO-PAQ® or CMC simultaneously through the hopper should be avoided because of drastic viscosity increases.
8. Typical fluid properties after conversion and before weight-up are as follows.

Table 3-12 Typical Fluid Properties after Conversion and Before Weight-up

Fluid Weight	10.0 lbm/gal
Funnel Viscosity	40 to 44 sec/qt
Plastic Viscosity	18 cP
Yield Point	6 lb_f /100 ft^2
Gels	0/0 lb_f /100 ft^2
API Filtrate	6 to 12 cc/30 min
Calcium	75 to 200 mg/L
pH	11.5 to 12.0
Pf	1.0 to 2.0 ml
Pm	5.0 to 10.0 ml
Excess Lime	1.0 to 2.0 lbm/bbl (low lime)

9. Occasionally, it is necessary to convert weighted fluids when dilution is not practical. In this case, the fluid can be converted in the surface pits and displaced down the hole in stages.

Maintenance of Lime Fluids

1. Lime fluid properties to be maintained should be determined and recorded; i.e., low-lime, moderate-lime, or high-lime properties.
2. The P_f and excess lime should be adjusted and maintained at near equal values. Low excess lime with high P_f or high excess lime with low P_f tends to cause rheological difficulties, i.e. the concentration of soluble calcium from lime is a function of pH, the higher the pH the less soluble.
3. Caustic soda should be added to adjust the P_f. The alkalinity of the filtrate affects the solubility of added lime. As the filtrate alkalinity approaches 1.0 ml, the solubility of lime decreases rapidly. After the 1.0 ml level is reached, solubility is only slightly affected. Normal additions of lime to the fluid will maintain the alkalinity of the fluid and the filtrate so that only small portions of caustic soda are required to maintain the desired alkalinity level in the filtrate.
4. Lime is added to maintain the desired P_m which controls the amount of excess lime. Excess lime can be calculated by the formula.

$$lb_m/bbl\ Lime = .26(P_m - F_1\ P_f)$$

where,

F_1 = percent retort water, or can be estimated by,

$$lb_m/bbl\ excess\ Lime = \frac{P_m - P_f}{4}$$

5. Fluid loss control should be maintained with CMC, BIO-LOSE, and MILSTARCH, as needed.
6. Solids concentration should be kept at a minimum; otherwise, the additions of lime and fluid loss control materials such as starch or CMC cause undue increases in flow properties and gel strengths.
7. Small additions of MILGEL to maintain proper colloidal distribution in the lime fluid is often necessary for maximum filtration control.
8. Lime fluids are considered to be ideal rheological condition when they possess zero initial and 10-minute gels and when lime additions do not cause flow property increases. Flow properties are easily controlled under normal conditions with sufficient amounts of water and/or chemicals.

Treatment of Contamination in Lime Fluids

1. *Salt* – Lime fluids will tolerate salt contamination up to 50,000 mg/L if the fluid is in proper condition. Since an increase in salt increases the solubility of the calcium ion, the lime fluid should be treated with large concentrations of caustic soda to maintain a high P_f which will limit the level of soluble calcium. UNI-CAL should be added as needed to control the rheological properties during salt contamination.
2. *Gypsum and Anhydrite* – Under normal conditions, drilling of gypsum or anhydrite has little or no effect on a properly-treated lime fluid. However, when large quantities are drilled, the lime fluid may exhibit increases in flow properties and gel strengths, as well as increased API Filtrate. Caustic soda can be used as a pretreatment or a post-treatment to maintain the P_f at the desired level. Lime additions are not necessary when gypsum is encountered until the P_m begins to decrease. UNI-CAL should be added to the fluid to help restore and maintain flow properties. MIL-PAC, MILSTARCH, BIO-LOSE, or CMC should be used for filtrate control depending upon the severity of the contamination.
3. *Cement* – Cement has very little effect on properly-conditioned lime fluids. If the solids content is in balance and sufficient UNI-CAL has been added to the fluid, little or no change will occur. However, when large quantities are drilled, the fluid alkalinity increases and calculates out as additional excess lime. This is not normally detrimental unless the cement concentration becomes so high that the total solids content is increased, in which case proper use of solids control equipment is necessary.
4. *Temperature* – High-temperature gelation and solidification is a major problem with lime fluids. Higher alkalinity along with high-lime content of this system causes it to be more difficult to control when subjected to excessive temperature. Depending upon the concentration of low specific gravity solids and the amount of excess lime and alkalinity, solidification may occur at a temperature as low as 275°F. The degree of gelation or solidification depends upon the concentration of solids, alkalinity of the fluid, and amount

of available lime in the fluid. A lime fluid should be conditioned to handle excessive temperatures by dilution and centrifugation of the solids to a minimum and by reducing the alkalinity and excess lime content to approximately that of a low-lime fluid. Reduction of alkalinity and lime content should be done while diluting and adding UNI-CAL® over a period of several circulations. ALL-TEMP® or MIL-TEMP® are beneficial (0.5 to 4 lbm/bbl) to prevent high temperature solidification.

Gypsum (Gyp) Muds

1. Gypsum fluids are maintained with higher filtrate calcium and lower alkalinity than lime fluids to increase their inhibiting affect on clays.
2. Gypsum fluids are used when large sections of gypsum or anhydrite are to be drilled. Because of the limited solubility of $CaSO_4$ in water, additional gypsum or anhydrite will not dissolve into the fluid system but will be carried as a solid.
3. Gypsum fluids are more resistant to salt and salt water than lime fluids, as long as solids are kept in line.
4. Gypsum fluids are less susceptible to high temperature solidification than other calcium fluids because the alkalinity is maintained at a lower value. A temperature of 350°F is usually considered to be the upper limit for well-treated gypsum fluids.

Factors Which Affect Gypsum Fluid Breakovers

1. Since the degree of viscosity change during and after conversion to a gypsum fluid depends upon the total solids concentration of the fluid system, dilution with water is necessary prior to conversion. Good solids control equipment is strongly recommended. A centrifuge is recommended for weighted fluids.
2. The type of clay solids present in the fluid influences the viscosity during conversion. Because MILGEL has a much higher Base Exchange capacity than most drilled clays, the viscosity increase is much more pronounced need when converting fluids that contain high concentrations of MILGEL.

Note: Methylene Blue Test for Base Exchange gives a general idea of the severity of conversion.

3. The type and amount of deflocculating agents added to the fluid prior to conversion will have a significant influence on viscosity during the conversion. When necessary, treatments should be made with small increments of UNI-CAL and caustic soda. If a phosphate has been used, the conversion will normally exhibit drastic viscosity humps. These are the result of the reaction between phosphate, lime, and solids all caught up in a mass ion impact while displacement and sequestering is all taking place simultaneously.
4. Maximum agitation should be maintained in the surface active system.
5. Pilot tests should be run prior to conversion to help determine necessary amounts of dilution and concentration of conversion chemicals.
6. The pit volumes should be reduced to allow room for dilution.
7. Necessary amount of gypsum and deflocculant should be stacked near the hopper, and caustic soda should be carried to the top of the suction (mixing) pit. Gypsum and deflocculant are added through the hopper. Caustic soda is added directly to the suction (mixing) pit near the point of maximum agitation.

8. Accurate circulation time should be determined so that conversion materials can be added at timed intervals over a period of one or two complete circulations.

Conversion Procedure

1. Conversion to a gypsum fluid should be initiated shortly after a new bit has been placed on bottom, i.e. once the conversion starts it should not be interrupted until them mud system has stabilized. Best results are obtained when the conversion is made inside the casing prior to drilling out.
2. The amount of material needed for conversion varies depending upon the desired properties and the condition of existing fluid. Most conversions can be made as follows.
   - Drilling fluid systems low gravity solids content should be diluted to a minimum solids content of 3 to 5% by volume. If the system is weighted then the calculated dilution volume is to be added simultaneously with the below listed chemical additions. The biggest concern is after the break over the fluids viscosity could drop so low that the barite would fall out if a weighted system.
   - 3 to 6 lbm/bbl UNI-CAL®
   - 4 to 6 lbm/bbl gypsum ($CaSO4 \bullet 2H20$)
   - 1.0 lbm/bbl caustic soda
   - 0.5 to 1.5 lbm/bbl CMC, or
   - 2 to 6 lbm/bbl MILSTARCH with preservative.
3. UNI-CAL should be started through the hopper while caustic soda is added to the pit. After five or six sacks of deflocculant and two or three sacks of caustic soda have been added, the gypsum additions should then be mixed through the hopper along with the UNI-CAL. The gypsum addition will cause a viscosity hump but will “break over” when agitated and become quite fluid. If the viscosity becomes excessive, the rate of addition of deflocculant and caustic soda should be increased along with an increase in water dilution.
4. API Filtrate is normally controlled with CMC and/or MILSTARCH. Periodic additions of MILGEL in moderate quantities will help also help. MILGEL is usually accompanied by treatments of UNI-CAL.
5. After all chemicals have been added to the fluid system, a check should be made of fluid properties. Minor adjustments can then be made on subsequent circulations with additional gypsum, UNI-CAL, caustic soda, and filtration control agents.
6. The addition of gypsum and CMC simultaneously through the hopper should be avoided because of drastic viscosity increases.
7. Typical fluid properties after conversion and before weight-up are as described below.
8. Occasionally, it is necessary to convert weighted fluids when dilution is not practical. In this case, the fluid can be converted in the surface pits and displaced down the hole in stages.
9. If a high pH fluid is being converted to a gypsum fluid, more water dilution and higher concentrations of UNI-CAL and gypsum are necessary to obtain desired properties.
10. Abnormal foaming may occur during and immediately after conversion. This foaming is usually confined to the surface of the pits and can be reduced by adding a defoamer such as LD-8 to the pits. Mud guns should be turned off if excessive foaming persists.

Table 3-13 Typical Fluid Properties after Conversion and Before Weight-up

Fluid Weight	10.0 lbm/gal
Funnel Viscosity	40 to 44 sec/qt
Plastic Viscosity	16 cP
Yield Point	6 lbf /100 ft2
Gels	2/10 lbf /100 ft2
API Filtrate	4 to 8 cc/30 min
Calcium	600 to 1200 mg/L
pH	9.5 to 10.5
Pf	0.2 - to 0.7
Excess Gypsum	2 to 4 lbm/bbl

Maintenance of Gypsum Fluids

1. Treatments of gypsum, caustic soda, UNI-CAL, and a filtration control agent are normally required each tour to maintain desirable properties. The amounts added depend upon volume, rate of penetration, amount and type of formation being drilled, and degree of dilution.
2. The pH of a gypsum fluid is normally controlled between 9.0 and l0.5. Often the pH is slightly higher just after a conversion but can be allowed to drift back to the desired range as drilling progresses. The Pf should be in the 0.2 to 0.6 range.
3. Gypsum is added to maintain filtrate calcium between 600 and 1200 mg/L. The solubility of the calcium greatly depends upon the alkalinity and salinity of the filtrate.
4. Excess gypsum should be maintained above 2 lbm/bbl. This can be determined by titration for total calcium sulfate as shown in the Drilling Fluid Testing Procedures Manual.
5. CMC, and/or MILSTARCH with a preservative or additional deflocculant can be added as required for desired filtration control.
6. If starch is used for filtration control, it will be necessary to add proportional amounts of a preservative.
7. Although gypsum fluids tolerate a higher concentration of colloidal solids than conventional fluids, solids must still be controlled at a reasonable level to obtain optimum rheological and filtration values. Mechanical solids control equipment such as fine screen shakers, hydrocyclones (low-density fluids), and centrifuges (high-density fluids) should be used to minimize dilution requirements. MILGEL should be added daily to provide proper particle size distribution.
8. Gypsum fluids normally possess high gel strengths, but they are fragile gels and should not be considered alarming. Gels can be decreased by reducing total solids content and increasing concentration of UNI-CAL. Gypsum fluids are considered in good rheological condition if initial gel is less than 5 lbf /100 ft2 and ten-minute gel is less than 15 lbf /100 ft2.

Treatment of Contamination in Gypsum Fluids

Salt – A properly conditioned gypsum fluid can be expected to tolerate up to 100,000 mg/L salt. Since an increase in salt increases the solubility of the calcium ion, the filtrate alkalinity should be increased with caustic soda to limit the level of soluble calcium. UNI-CAL should be added as needed to control the rheological properties.

Air, Mist, and Foam Drilling

The use of air for drilling, with or without a fluid phase, is a technique that has been used in many areas of the world to increase penetration rates, overcome lost circulation zones, and improve lifting capacity. Because of inherent limitations, equipment requirements, and handling techniques, this is considered a highly specialized technique and is used only in selected applications.

There are at least four basic methods which utilize air alone or in combination with water or a drilling fluid. They can be classified as follows:

Table 3-14 Classifications of Air / Water Drilling Fluids

Classification	Components	Lift Medium
Dusting	Air alone	Air
Water misting	Air Foaming agent Water	Air
Aerated fluid	Air Fluid	Fluid
Stiff foam	Air Foaming agent Viscosifier	Foamed fluid

As indicated, the systems can be classified further according to the lift media. In classifications 1 and 2, air is the lift medium for the generated cuttings, therefore, the formation is in contact with air. In systems 3 and 4, the drilling fluid or foam is the external phase of the air fluid dispersion. Therefore, the formation is in contact primarily with the fluid phase. These two distinguishing factors are important with respect to their effect on the borehole. The classifications and their distinguishing factors are discussed below.

Dusting

This drilling system injects only air down hole at sufficiently high rates to carry the cuttings from the hole. Dusting provides minimum back pressures and produces the fastest penetration rates attainable with air drilling techniques. As long as the hole is dusting, there are usually few problems, but when water is encountered, several problems can occur.

- A water column can build up causing loss of circulation if the formation is not competent.
- Formation water can mix with the drill dust causing what are commonly called fluid rings. These rings can restrict air flow and, in some instances, cause tight hole problems.
- The water will wet shale formations and possibly create sloughing and borehole instability. Where only small amounts of water are encountered during drilling operations, a drying agent such as silica gel may be injected into the air stream.

Mist Drilling

To overcome some of the problems associated with water encroachment while air drilling, the technique of injecting a small amount of water containing a foaming agent into the air stream was devised. The foaming agent aids in trapping water as a mist in the circulated air stream, thereby removing it from the hole. Hence, the name *mist drilling*. Air is still the external phase of this dispersion and principal lift medium. Mist drilling does not overcome the problem of water-wetting the shale formation and, in sensitive formations, this condition may result in hole instability. Formation water may also enter the hole at such a rate that mist drilling becomes impractical.

Aerated Fluid

Where air or mist drilling cannot be used effectively, air is sometimes injected into the drilling fluid, creating an aerated condition. This technique reduces the hydrostatic head sufficiently to allow fluid circulation. Otherwise, it would be lost. An *aerated fluid* system requires high volumes of both air and fluid. It is often difficult to maintain satisfactory air-fluid dispersion on connections or during any extended period of shutdown.

Stiff Foam

To overcome some of the difficulties with aerated fluids, special fluid formulations have been developed to maintain more stable air-fluid dispersions. This has enabled the industry to prepare lighter fluids with excellent hole cleaning abilities. Though some operators consider the addition of a foaming agent to water alone to be sufficient, the normal practice is to add a viscosifier and film strengthening agent. This latter practice produces foam with shaving cream consistency and is referred to as *stiff foam* drilling. A typical fluid slurry composition for a stiff foam preparation in fresh water is as follows.

Table 3-15 Typical Formulation for Air-Fluid Dispersions

SUPER-COL®	6 lbm/bbl
XAN-PLEX® D	¼ to ½ lbm/bbl
caustic soda	½ lbm/bbl

The amount of foaming agent depends on the volume of water invasion from the hole. The more water coming in, the more foaming agent required. The intrusion of oil has a dampening effect on foam. When oil is encountered, the addition of a high-molecular polyacrylate such as CYPAN® may be used.

In some cases, it may be desirable to use brackish or saline water for slurry make-up. AMPLI-FOAM™ should be used as the foaming agent with this type of water because it will be more effective in this environment.

As mentioned earlier, air-fluid dispersions require special rig equipment. Requirements for stiff foam drilling are listed below:

- Air compressor capability of 800 to 1000 ft^3/min.
- Rotating head
- Blooie line – length recommended of 100 to 150 ft., size 6 to 10 in diameter.
- Two injection pumps – triplex capable of injecting fluid rates up to 55 to 60 bbl/hr.
- Air charts for constant recording of ft^3/min.
- Meter for determining gallons required.

- Bleed-off lines for air line and drillpipe.
- String float in drill pipe.
- Large disposal pit for retention of foam and slurry.
- Butane or propane flare at blooie line for detection of gas.
- Bath device for applying corrosion inhibitors to drill pipe.

The primary objection to stiff foam drilling is that the foam must be discarded as it comes from the well. A satisfactory chemical or physical method of de-foaming the system has not been found. The cost of new slurry volume is minimized, however, by the fact that relatively low-slurry volumes can be circulated with good hole cleaning. Slurry injection rates may vary from 12 to 30 gal/min depending on hole size. Twenty (20) gal/min would be typical for a $9^5/_8$ inch hole.

Stiff foam densities as low as 4 lbm/gal measured at the flow line can be maintained. This not only results in reduced lost circulation, but provides a fluid which permits good penetration rates. Use of a stiff foam system is quite effective to depths of around 6000 feet. Below this depth, compressibility of the foam by the hydrostatic head is such that little reduction in density is obtained. Maintaining back pressure on the well enables a higher air/fluid ratio and, thus, reduced fluid density, but the operation is more complicated and has not been used extensively.

Potassium-Base Fluids

The use of potassium as a Base Exchange ion to stabilize drilled shales has been accepted by many operators in various geographic areas worldwide. Its use in the Gulf of Mexico has been greatly restricted due to the toxic affect of potassium on the test species, Mysidopsis Bahia shrimp. Potassium is widely used internationally, and comes from many sources, including; potassium chloride, potassium carbonate, potassium acetate, and potassium hydroxide.

The major applications for potassium systems are,

- Drilling soft gumbo (high water content reactive clay structure with elevated cation exchange capacity) formations to prevent bit balling, clay swelling, clay hydration and tight hole problems that are commonly associated with drilling reactive formations.
- Drilling indurate shales such as those in the foothills of Canada and West Texas where excessive sloughing and borehole enlargement are common problems. This is not to mistaken for tectonically stressed formations.
- Drill-in or workover fluids where the pay zone contains water sensitive clays intermixed with the producing formation.
- Functioning as the first line of defense for all dispersible drill solids, i.e. preventative pretreatment chemistry for dispersible clay, thus enhancing solids control efficiency.

Potassium is an effective clay swelling/hydration inhibitor, where the concentration of potassium to achieve the desired result is often a function of the shale being drilled. There are many areas in the world where successful potassium applications have been documented; however there are other areas such, as in the kaolinitic shales of northern South America, where failures are also well documented. The use of potassium in kaolinitic shales is strongly discouraged due to the destabilizing affect of the potassium ion on kaolinite.

To accomplish maximum inhibition with potassium, it must be the intervening ion within the fluid phase of the drilling fluid. As an example, it would require a minimum of 18 lbm/bbl of potassium chloride in sea water before the potassium ion became the dominant ion as apposed to magnesium, calcium, and the other cations indigenous to naturally occurring seawater.

Potassium

KCl is most often used to supply the major source of potassium. Most data to date indicates that a 3% to 5% concentration (10.7 to 18.1 lbm/bbl) is sufficient to provide inhibition of clay swelling and hydration. Attempts have been made to increase the inhibitive effect by increasing the KCl concentration up to 15% (57.6 lbm/bbl), but improved clay stability has not always been achieved.

A secondary source of potassium is potassium hydroxide (KOH) which is sometimes used as an alkalinity agent, similar to caustic soda (NaOH). Generally, it is used in such low concentrations that the K^+ ion contribution is insignificant. Approximately 1.6 lb of KOH is required to get the same pH effect as one pound of caustic soda. KOH provides approximately 2000 ppm of K^+ ion for each pound per barrel added.

Viscosifiers

Materials used as viscosifiers in potassium-based systems include,

- XAN-PLEX® (xanthan gum)
- MILGEL® (Wyoming bentonite)
- Colloidally protected bentonite
- Guar gum (modified)
- Hydroxyethylcellulose (HEC).

PERMA-LOSE™ HT (Modified starch - functions as both viscosifier and filtration additive)

The combination of 6 to 10 lbm/bbl pre-hydrated bentonite plus 1.0 lbm/bbl XAN-PLEX has been a commonly used viscosifying treatment. In some cases, because of shortages, guar gum and HEC have been used as viscosifiers. Though these products do increase viscosity, they do not increase carrying capacity satisfactorily; accordingly they are considered **unsatisfactory substitutes** and require higher bentonite concentrations to provide adequate hole cleaning.

Note: Colloidally protected bentonite will yield higher Fann low rpm viscosities in a potassium chloride environment and retain this viscosity longer when compared to unprotected pre-hydrated bentonite.

This base fluid typically exhibits an extremely high yield point, plastic viscosity ratio, and a relatively high filtration rate. For example,

- PV = 5 cP
- YP = 35 lb_f / 100 ft^2
- Filtrate (API) = 25 to 35 mL/30 min

Filtration Control Agents

High filtration is characteristic of these fluids and almost any attempt to establish control results in some deflocculation.

The materials used to reduce filtration are,

- BIO-LOSE®
- BIO-PAQ®
- CMC HV & LV
- MIL-PAC
- MIL-PAC™ LV
- MILSTARCH

BIO-LOSE

Addition of 5.7 to 11.4 kg/m^3 (2.0 to 4.0 lbm/bbl) is usually adequate for filtration control and elevating low-shear rate viscosity. Although it contains no biocides, BIO-LOSE resists bacterial degradation and is effective in both weighted and low-solids fluids over a wide pH range.

BIO-PAQ

Reduces filtration rate and increases low-shear rate rheological properties in brine systems (seawater, NaCl, KCl, and high-hardness water-base fluids) where expected bottom hole temperatures exceed 250°F. It also provides filtration control in divalent brines such as $CaCl_2$ and $CaBr_2$. Recommended treatment is 1.0 to 4.0 lbm/bbl (2.85 - 11.4 kg/m^3).

CMC (HV or LV)

CMC will provide filtration control, though it is not as effective as MIL-PAC. The same deflocculating effect has been observed.

MIL-PAC

MIL-PAC is an effective filtration control agent in KCl systems (0.5 to 1.0 lbm/bbl). It may exhibit a deflocculating effect on rheological properties which could drastically reduce yield point to plastic viscosity ratio.

MILSTARCH

In concentrations of 3 to 4 lbm/bbl, MILSTARCH has reduced filtration rates (15 to 20 cc) with no appreciable deflocculation. In order to lower filtrate to the 5 cc range, 6 to 7 lbm/bbl of starch are required.

Complex Systems

NEW-DRILL® System

The term "low-solids/polymer" fluids include variations from a simple formulation for shallow drilling to much more complex formulations for a wide variety of drilling objectives. The "polymer fluid" of the 1990s ranges from fresh to saturated salt water, from zero clay content to over 20 lbm/bbl (0% to 8% by volume low-gravity solids), with pH values from near neutral (7.0) to as high as 11.0. This family of fluids has one primary "thing" in common. These fluids all achieve their performance characteristics from the presence of a protective colloid (water soluble organic polymer) or a combination of both protective colloids and salts.

The performance of partially hydrolyzed polyacrylamide (PHPA) polymers such as NEW-DRILL is significant in encapsulating cuttings and improving solids removal efficiency. By bonding on sites that would otherwise react with water, these polymers "inhibit" the dispersion (physio-chemical breakdown) of cuttings and formation solids into the fluid system. Due to their high molecular weight, these molecules are infinitely longer than they are wide or thick. At small concentrations (0.25 to 3.0 lbm/bbl) they impart a high level of cuttings encapsulation to water-base fluids (even in freshwater).

The philosophy of engineering the NEW-DRILL® system is geared towards maintaining the low–gravity solids content of the mud at or below a level of 5% by volume. This solids control level will insure a high-quality filter cake. Higher solids content result in a thick cake conducive to differential sticking.

Another objective, accomplished by the low content of drilled solids in these fluids, is a low impediment to fluid flow. Lower friction means lower system pressure losses as compared to a fluid with higher solids content. This converts to less pump wear, lower diesel consumption, and better opportunity for hydraulic horsepower to do work at the bit. Lower viscosities at high rates of shear convert to better separation (within pieces of solids removal equipment) of drilled solids from whole fluid. This enhances the performance of all the screens, hydroclones, and centrifuges.

Even lower total solids content is possible when using iron oxide or ORIMATITA as a weighting agent. Since its specific gravity is 5.0 to 5.1, fewer solids will be present (in the ratio of 4.2 to 5.0) at a given fluid density when compared to a barite weighted fluid.

Materials used to control various fluid characteristics differ greatly. Although the NEW-DRILL family is not normally thought of as a potassium-base fluid, many NEW-DRILL fluids have used KCl or other K^+ sources as an additional inhibitor. (Confusion abounds as to whether a *name* really describes a drilling fluid.)

A key point to note is that in some shale compositions and various areas around the world, NEW-DRILL alone has been effective in achieving good caliper logs. In some areas, it appears that as little as 1% KCl, 3% KCl, or up to 6% KCl has been effective where NEW-DRILL alone has not. Commonly the combination of NEW-DRILL and potassium has yielded a synergistic effect which outperforms either additive when independently applied.

Many laboratory tests and field case histories have shown increased clay swelling/hydration inhibition with the addition of a partially hydrolyzed polyacrylamide (PHPA) to a KCl or NaCl type fluid. NEW-DRILL® HP is especially effective, being able to be stored and mixed more effectively due to being blended with KCl. These reasons explain why NEW-DRILL HP is often more cost effective than competitive products claiming to have "higher activity" or being "pure" polymer. Performance and desirable results should be the determining factors in establishing the value of a product or a fluid system.

Baker Hughes Drilling Fluids uses potassium in its NEW-DRILL system, especially in the tectonically stressed shale encountered in the foothills of the Canadian Rockies. NEW-DRILL is believed to adsorb on the positive charged edges of exposed clays, reducing the water sensitivity of the clay formations and contributing to increased inhibition. The potassium ion is also absorbed on to the clay structure causing it to take on the characteristics of illite. This action results in the loss of polymer as well as a decrease in potassium ion concentrations as solids are discharged, thus requiring constant monitoring of the concentrations of each and replenishing them as needed.

Mixing Procedure for NEW-DRILL System with KCl

Add desired KCl concentration to water in the active system (see Chapter 16, *Engineering Data*). Normally 10 to 17.0 lbm/bbl meets inhibition requirements.

Pre-hydrate MILGEL in premix tank (approximately 30 lbm/bbl) and add pre-hydrated MILGEL slowly (1 in. to 1½ in. stream) to KCl solution to obtain desired viscosity. Normally 6 to 8 lbm/bbl of pre-hydrated bentonite in the KCl solution is adequate. Additional KCl will be required to offset the fresh water added to the system in the form of pre-hydrated bentonite.

Note: On initial make up, where large volumes are needed for displacement, the active system can be filled with fresh water and the bentonite added first and pre-hydrated and then followed by KCl.

Adjust pH to approximately 9 - 10 with caustic soda or KOH.

Add ½ to l.0 lbm/bbl of XAN-PLEX® D slowly.

Add ¼ to ½ lbm/bbl NEW-DRILL®.

For additional filtration control. Use MILSTARCH or BIO-LOSE and MIL-PAC in a 2:1 ratio. If MIL-PAC is used, add very slowly (1/8 to ¼ lbm/bbl over a 6 to 8 hour interval) and monitor rheological properties.

Maintenance

1. Monitor potassium ion (*see Fluid Testing Procedures Manual)* to maintain the desired concentration.
2. If desirable, pre-hydrate bentonite in premix tank. Add sufficient potassium material to compensate for water additions. A water meter is recommended to determine dilution volumes.
3. Solids control equipment (desander, desilter, and fine screen shakers, plus a centrifuge for weighted systems) should be considered absolute necessities with this system.
4. Control pH in the 8.5 to 10.0 range with caustic soda. Corrosion rates can be reduced with oxygen scavengers such as NOXYGEN™.
5. Keep entrained air out of the system by:
    - Shutting the mud hopper down when it is not in use
    - Submerging mud guns to prevent aeration
    - Judicious use of hydrocyclones

6. Filtration control in the range of 15 to 20 cc can be achieved with MIL-PAC. For further filtration control, it may be necessary to add MILSTARCH or BIO-LOSE or BIO-PAQ in a 2:1 ratio.
7. Remember that NEW-DRILL encapsulates solids and cuttings discarded and is also discarded from the system. Therefore, it is recommended that NEW-DRILL be added at 0.15 lbm/bbl for each barrel of drill water added. Also add 0.5 to 3.0 lbm/bbl to new mud volume built. This usually equates to about 5 to 7 lb of NEW-DRILL for each barrel of formation solids drilled up and discarded. This treatment will vary widely depending on activity of formation being drilled.

Typical properties for this type system are,

- Density (lbm/gal) – 8.8 to 9.2
- PV (cP) – 4 to 6
- YP (lbf/100 ft^2)– 25 to 45
- Gels(lbf/100 ft^2)– 23/26 (high, but fragile)
- API fluid loss – 15 to 35 cc/30 min
- pH – 8.5 to 10.0
- Low gravity solids (LGS) content - 3 to 5% with 5% being the maximum

Much of the success achieved in stabilizing reactive clays with this fluid has resulted from awareness and control of mechanical factors, combined with inhibitive characteristics of potassium fluids. It is a good practice, therefore, to maintain laminar flow in the annulus while drilling and minimize swab and surge pressures to reduce mechanical aggravation of sloughing shales.

Additives for Control and Maintenance of Properties

Electrolytes

NEW-DRILL® is compatible with all concentrations up to and including saturated sodium chloride (NaCl). Viscosity decreases with increased concentration of electrolyte.

NEW-DRILL® systems have been run at concentrations of KCl up to 18% by weight.

NEW-DRILL® is compatible with a seawater environment although hardness of the system should be treated downwards with caustic soda.

Alkalinity Control

NaOH (caustic soda) – most common alkalinity and pH control product.

KOH (caustic potash) – has been used frequently. Requires about 40% by weight more than NaOH to achieve an equivalent pH.

Lime & gypsum – used almost exclusively to treat alkalinity imbalances due to carbonates when in a reactive or ionic state. Carbonates reduce the inhibitive properties of the polymers.

Fluid Loss Control Agents

BIO-LOSE® – acceptable in low pH seawater system. At low pH, some preservative may be needed.

BIO-PAQ® - acceptable in low pH seawater system. At low pH, some preservative may be needed. This product has higher temperature stability than BIO-LOSE.

CHEMTROL® X – effective HT/HP fluid reduction additive in seawater and high-hardness environments. CHEMTROL® X is an effective deflocculant (thinner) at hardness levels of 400 mg/L or above. It also works well at lower pH ranges of 8.0 to 9.0.

LIGCO®– lignite additive for fresh and seawater systems. A minimum pH of 9.5 is required. This product works well as an HT-HP fluid control additive and will also provide some degree of deflocculation and gel strength reduction

MIL-PAC – (polyanionic cellulose) polymer-based additive for all systems. Performs more effectively in hardness levels of 500 mg/L or less.

MILSTARCH – not applicable for low pH seawater systems, usually requires a preservative.

SULFATROL® - sulfonated asphalt product for HT-HP fluid loss reduction and to provide some degree of shale stabilization by plugging shale micro-fractures.

Viscosifying Agents

MIL-BEN® – OCMA-grade bentonite for international (non-US) locations. Produces ½ the viscositiy of MILGEL®.

MILGEL® – Wyoming bentonite meeting API specifications. Used sparingly for viscosity in maintenance treatments. Pre-hydrate bentonite for use in seawater and high-salt NEW-DRILL® fluids.

MILGEL® NT – Untreated Wyoming bentonite meeting API specifications. Pre-hydrated bentonite is used in seawater and high-salt NEW-DRILL® fluids.

XAN-PLEX® D – Xanthan gum additive used to increase viscosity and suspend barite and drill cuttings. Often used in situations where bentonite will not build viscosity, such as in a seawater or high salt environment.

SALT WATER GEL® – Attapulgite clay meeting API specifications that serves as a viscosifier in high salt concentration environment. Generally produces a more viscous “hump” than MILGEL with various polymer additions.

Weighting Agents

MIL-BAR® (4.2 s.g.). – barium sulfate (barite) weight material

ORIMATITA (5.0-5.1 s.g.) – hematite-based weighting agent that, because of its higher density compared to barite, provides a low-solids environment and high ROP in conjunction with the polymer viscosifiers.

MIL-CARB® (2.5-2.65 s.g.) – calcium carbonate weight material and bridging agent. MIL-CARB has a lower density than barite or hematite and works well as a weight material and helps minimize mud losses in low density NEW-DRILL Systems. MIL-CARB is also the only weight material that is acid soluble.

W.O. 30 – calcium carbonate used as a bridging and/or weighting material in workover, completion and drill-in fluids. W.O. 30 is 95 to 98% soluble in hydrochloric acid, which minimizes permanent plugging of the producing formation. W.O. 30 is available in grades from fine to coarse.

Deflocculating Agents

ALL-TEMP® – Water-base deflocculant/rheological properties stabilizer with special applications in high temperature environments.

NEW-THIN™ – low molecular weight polyacrylate polymer dispersed in water. Effective thinner in low-weight, low-solids systems. Contains *no chrome* or heavy metals. Hardness levels should be less than 500 mg for optimum thinning, the lower the hardness the more efficient the viscosity reduction.

UNI-CAL® – lignosulfonate used as a supplemental thinner if solids overload the system.

Treatment and Control Techniques for NEW-DRILL Systems

The composition and properties of drilling fluids are greatly affected by the formation contaminants encountered while drilling. Selected drilling fluid components are added to negate a contaminant or potential contaminant. In order to limit the scope of discussion the following common contaminants will be discussed:

- Salt and salt water flows
- Calcium or magnesium
- Cement
- Carbonates
- Temperature
- Dispersible Cuttings

The problem of solids contamination will be considered in Chapter 4, *Contamination of Water-Base Fluids*. It should be emphasized, however, that the problems associated with all of the above mentioned contaminants will be magnified by the presence of solids. In all cases, limit the amount of undesirable reactive solids, i.e., drilled solids, should be kept to the lowest practical level.

Salt Contamination

Source

Salt may come from make-up water, salt stringers, massive salt sections, salt water flows, and commercial sources. Regardless of the source it has an impact on drilling fluid properties and chemical selection.

Since salt cannot be precipitated by chemical means, the only method of reducing salt concentration is through dilution. This will also help to reduce the problems caused from flocculation of clay solids by reducing the concentration of the solids in the fluid. If dilution is not possible due to density requirements or water availability, then treatment with chemicals may be necessary.

Deflocculation – If chloride levels remain below 30,000 mg/L, then NEW-THIN can be used to reduce yield point and gel strength. Other deflocculants such as UNI-CAL can be used, but it may be necessary to increase the pH to 9.5 for this product to be effective. The dispersion of drilled solids can also result from the addition of a lignosulfonate and caustic to the NEW-DRILL system. Because of these two factors, treatment with organic thinners is not recommended unless viscosity reductions are not satisfactory using NEW-THIN.

API Filtrate Reduction – If reductions in API filtrate are required, additions of MIL-PAC should be used. Concentrations required will vary depending on the degree of reduction needed.

Seawater/KCl Systems

Depending upon how massive the sections of salt are, there may be little or no effect on the system except for an increase in chloride concentration. If reductions in rheological properties or API filtrate are required, the same methods of treatment as above should be used except for dilution.

Saturated-Salt Systems

If the formations being drilled are massive enough to require saturation of the fluid, several differences should be noted. Viscosity reductions will occur from (1) the effect of salt saturation on the NEW-DRILL, and (2) the shrinkage of the water envelope around the clay solids.

Additions of a viscosifier such as XAN-PLEX may be required to maintain hole cleaning properties. The API filtrate will need to be controlled with either MIL-PAC, PERMA-LOSE, BIO-LOSE, MILSTARCH, or a combination of these polymers. Typically, a combination of MIL-PAC to MILSTARCH (in a 1 to 4 ratio) often gives the most economically acceptable filter cake.

Effects on Fluid Properties

In a freshwater drilling fluid, an increase in the salinity of the fluid will cause the clay solids to flocculate. The result of this flocculation is an increase in yield point, gel strengths, and API filtrate. The pH of the fluid will also be reduced slightly.

The NEW-DRILL polymer itself is not adversely affected by increasing salt concentrations; however, the normal viscosity obtained from the polymer is reduced as the chloride content increases NEW-DRILL systems have been used effectively to inhibit shales in salt-saturated environments. If the NEW-DRILL system is made up from a brine such as KCl or NaCl, the effects from salt “contamination” will be much less severe or, in most cases, negligible.

Salt Water Flows

The effects of salt water flows on a NEW-DRILL system will be similar to that of drilling salt except for (1) reductions in fluid density of heavily weighted fluids, and (2) increases in the concentration of soluble cations and anions. Almost all water flows contain cations in addition to sodium, usually calcium and magnesium. Total hardness levels should be maintained below 500 mg/L by maintaining the pH from 9.0 to 9.5 and using soda ash to remove residual calcium not removed by adjusting the pH.

Note: A note of caution regarding NEW-DRILL, at elevated pH. The product will hydrolyze and thus loose its clay inhibitive qualities. If hardness is present and pH is elevated to the high pH range the calcium cation will precipitate and in so doing precipitate out the NEW-DRILL polymer with it.

Calcium or Magnesium Contamination

Source

Calcium and magnesium are closely related ions that have similar effects on fluid properties. These ions can originate from make-up water, salt water flows, drilling of gypsum or anhydrite, drilling cement, and some formations such as the Zechstein, which contains a multitude of problematic ions.

Effects on Fluid Properties

Calcium and magnesium will replace sodium ions on reactive clays. This effect reduces the hydration of the clays and promotes flocculation. These actions increase the yield point, gel strength, and API filtrate of the fluid. In concentrations above 500 mg/L, the NEW-DRILL® polymer will also be dehydrated and viscosity and API filtrate may become difficult to control. The presence of these two cations is measured collectively using the total hardness titration. The calcium ion can be titrated separately to determine the concentrations of each ion.

Treatment and Control Techniques

Magnesium – The magnesium concentration can be decreased by increasing the pH. Historically, the solution was to increase the pH of the fluid to 10.5 or above. At this pH level, the magnesium precipitates as insoluble magnesium hydroxide. A pH level this high is not normally recommended in the NEW-DRILL® system. Increasing the pH level to 9.8 should reduce the magnesium concentration to acceptable levels.

Calcium – Concentrations of this cation above levels of 400 to 500 mg/L are not recommended in the NEW-DRILL® system. Reduction of the calcium to this range can be accomplished by increasing the pH to 9.0 to 9.5 and adding soda ash to remove any calcium above the 500 mg/L level.

A treatment with 0.1 lbm/bbl of soda ash will remove approximately 100 mg/L of calcium.

Cement Contamination

Source

In most drilling operations, cement contamination may occur when casing is cemented and plugs are drilled out. The severity of contamination depends on,

- solids content
- concentration of deflocculants
- type of deflocculants
- quantity of cement drilled
- whether the cement is green or cured
- the amount of pH increase.

Effects on Fluid Properties

The problem with cement contamination is a result of the combination of high pH and calcium. The presence of solids in the fluid causes a viscosity increase, resulting from the flocculation of these solids due to the high pH and calcium (from drilling cement). The problem may be aggravated somewhat in a NEW-DRILL system because of the low pHs and low concentration of thinners typical in this system. If possible, use water to drill cement.

Treatment and Control Techniques

Prior to Cementing

1. Reduce low-gravity solids to a minimum level. This can be accomplished by utilizing solids control equipment and dilution/displacement with water.
2. Use pump rates sufficient to achieve turbulent flow of the drilling fluid.
3. Pretreatment of the system with a small concentration of sodium bicarbonate or phosphate This will help in two ways:
    - Removes calcium as a precipitate with sodium bicarbonate or by sequestering the divalent cation with phosphate.
    - Reduction of the pH while drilling the cement

Drilling Cement

1. Avoid adding NEW-DRILL prior to, or while drilling cement.
2. If cement is hard, small treatments of sodium bicarbonate may be made to precipitate calcium, reduce pH, and reduce viscosity.
3. If the cement is “green” or soft, the method of treatment will be the same although greater increases in rheology may occur. This will especially be true if the solids level has not been lowered enough before drilling cement.
4. Operate the solids control equipment to remove cement particles.
5. Various acids can be used to control pH more rapidly after drilling cement (Citric, Acetic, hydrochloric, or phosphoric are the most commonly used.)

CAUTION

Two problems can result from the use of sodium bicarbonate.

1. Overtreatment can initially cause the fluid to thin severely.
2. Overtreatment can cause a carbonate problem which can result in fluid instability and high gel strengths.

Carbonates

Source

Large accumulations of soluble carbonates or bicarbonates can affect rheological properties in much the same way as salt or calcium. Carbonates may come from aeration of the fluid, CO_2 from the formation, thermal degradation of organic fluid additives, and over treatment with soda ash or sodium bicarbonate.

Effects on Fluid Properties

Carbonates adversely affect rheological properties in several ways. First, carbonate ions cause reactive clays to flocculate, thereby increasing yield point and gel strengths. Secondly, organic deflocculants do not function properly because of the chemical imbalances created when carbonates react with the hydroxyl ions in solution. Thirdly, in a NEW-DRILL® system, there is some evidence to indicate an excessive concentration of carbonates in the fluid system will cause the NEW-DRILL® polymer to lose some of its encapsulating ability. The concentration of carbonates that will create a problem is greatly dependent on the concentration of reactive solids in the fluid. In the NEW-DRILL® system, reactive solids are typically maintained at very low levels. To prevent excessive carbonate levels, it is recommended that a minimum of 100 to 200 mg/L calcium be maintained in the fluid system and the pH be maintained in the 9.0 to 9.5 range.

Treatment and Control Techniques

If excessive carbonates occur in a fluid system and treatment is necessary, the following methods are recommended. The first method is to treat the system with lime. A sufficient quantity of lime should be added to increase the pH to at least 9.5 and measurable calcium levels to 100 mg/L. If noticeable improvement in fluid properties does not occur, continued treatment is necessary. Treatments of 0.25 to 0.5 lbm/bbl lime may be necessary to reduce carbonates to acceptable levels. When treating carbonates it is best to make small, incremental additions of the chosen treatment and observe the results after one complete circulation. Since over-treatment with lime can be harmful to the NEW-DRILL system, an alternative treatment would be to use a combination of gypsum and lime. These chemicals should be added simultaneously to raise the pH and soluble calcium to the levels indicated above. An advantage of using a combination of gypsum and lime is to buffer the pH increases caused by using lime. A problem can also occur by over treating with this method as well. Careful monitoring of pH and calcium levels should be maintained during the treatment phase.

Temperature

Source

As wells are drilled deeper, higher bottom hole temperatures are being encountered. In some areas with very high geothermal gradients, temperatures may approach 600°F to 700°F at depths as shallow as 5000 ft. These severe requirements may necessitate designing a special drilling fluid. Today's drilling fluids are being frequently required to function above 300°F. The NEW-DRILL system has been used in wells having bottom hole temperatures of 350°F, however, it is suggested that the PYRO-DRILL or other mud systems specifically developed for geothermal or high temperature/high pressure (HT-HP) be considered at temperatures above 350° F.

Effects on Fluid Properties

As temperatures rise above 250°F, the degree of flocculation of bentonite starts to increase. This flocculation can be controlled to some extent with organic thinners but, above 300° to 350°F, these thinners also begin to degrade and lose their ability to deflocculate the system.

Treatment and Control Techniques

The NEW-DRILL system, because of its low-solid content, is reasonably tolerant to temperatures up to 300° F. One problem that may occur in a NEW-DRILL system is viscosity reduction at elevated temperatures. Viscosity may need to be supplemented with a temperature stable biopolymer such as XAN-PLEX D. If the solids concentration is severe enough to create viscosity problems from clay flocculation, then deflocculation can be achieved using NEW-THIN and/or MIL-TEMP (or ALL-TEMP). API filtrate can be controlled with CHEMTROL X.

NEW-DRILL System Benefits

Effects on Torque and Drag

One of the supplemental benefits with the NEW-DRILL systems is related to the low coefficient of friction of the polymer, coupled with its thixotropic nature and inhibitive qualities. These factors, in conjunction, have reduced the torque and drag experienced in the field. This has been particularly evident in directional holes.

The degree of torque is usually strongly influenced by the size of the cuttings bed upon which the pipe string is rotating. Often, the more inclined the hole, generally the larger the cuttings bed. This is increased by the amount of wall instability experienced (hole closure).

Effect on Differential Sticking

Differential pressure sticking is a condition in which the drill pipe becomes stuck against the wall of the wellbore because it has become embedded in the filter cake. There must be a permeable formation present and a pressure differential across a nearly impermeable filter cake. The quality of the filter cake and the rate of filtrate produced by the drilling fluid in use affect the possibility of differential sticking.

NEW-DRILL fluids exhibit a compressible filter cake which helps considerably in preventing differential sticking. The NEW-DRILL system has accomplished this without the traditional liberal use of commercial bentonite. Cases of differential sticking in the field while using a NEW-DRILL system have been rare. In fact, highly depleted zones have been drilled utilizing the NEW-DRILL system with no occurrence of differential sticking. This has helped reduce fluid cost and prevent one of the most costly delays in drilling - stuck pipe

Effects on Weight-On-Bit (WOB)

Due to the reduced coefficient of friction from the NEW-DRILL, more effective collar weight is transferred to the bit. Less collar-to-wellbore friction has multiple benefits including less drill string wear. Reductions in torque of as much as 50% have been observed in the field.

NEW-DRILL Operational Procedures

NEW-DRILL systems have been developed through experience in several geographic areas under various drilling conditions. Consequently, techniques have been developed to meet the needs of customers at various locations.

Methylene Blue Test (MBT)

The performance of the NEW-DRILL System is based on a low colloid philosophy. Utilize solids control equipment for controlling solids content and plastic viscosity. Daily solids analysis must be used to monitor the solids content. Low gravity solid content is the key to proper control of the system. Total low gravity solids should be held in the range of 3 to 5% by volume, inclusive of commercial clay. Inadequate solids control equipment will cause increases in solids content and result in high rheological values and/or the need for a strong deflocculant such as UNI-CAL (lignosulfonate).

Gel Strengths

Gel strength values as determined by a 6-speed viscometer are generally higher for a NEW-DRILL system than traditional UNI-CAL lignosulfonate fluids. This illustrates the difference between a semi-dispersed as compared to a dispersed mud system. Also, the aqueous phase viscosity of the lignosulfonate system is only slightly greater than water while the NEW-DRILL® system's water is significantly thicker. It is common for 10-minute gels to reach 35 $lb_f/100\ ft^2$. Drilling conditions and economics should determine the need to reduce gel strengths. Report the initial, 10-minute and 30-minute gel strengths on all NEW-DRILL systems.

Filtrate Ph Range

Freshwater System

Filtrate pH is normally controlled in the 8.0 to 10.0 range with caustic soda additions being made slowly using a chemical barrel. The hopper should never be used to mix caustic soda (NaOH) or caustic potash (KOH). Ideally, pH values of 8.0 to 9.0 are preferred for freshwater systems. Limit the pH to a maximum of 9.5 when UNI-CAL (lignosulfonate) is used. The pH should be reported on the filtrate, and not on the whole fluid.

Seawater System

A pH of 9.5 to 10.0 should be maintained if hardness reduction is necessary for API filtrate control.

Range for Filtrate Hardness (Ca++, Mg++)

Freshwater System

Maintain hardness levels below 400 mg/L. A concentration of 200 to 300 mg/L calcium tends to show the best stability.

Seawater System

If low viscosity and API filtrate values are not required, seawater systems may be run at natural pH and hardness. This is especially true when the objective of the system is to control gumbo shale.

Filter cake quality and API filtrate control are adversely affected by high hardness. Therefore, when sand sections are drilled, the pH of the system may be increased to chemically suppress the hardness level. This aids in attaining the maximum hydration of both bentonite and polymers to improve the control both the cake and filtrate quality. In seawater, the pH should be raised initially with caustic or potassium hydroxide to a maximum value of 9.5 to 9.7. This will precipitate most of the magnesium. Caustic soda is the preferred product for pH increases because the potassium ion will have a negative effect on filtration control. Additions of soda ash and/or sodium bicarbonate should then be used to precipitate out calcium to the desired hardness level.

Note: Calcium and magnesium concentrations should be measured and reported, not total hardness.

API Filtrate

A variety of products are available for API filtrate control. Laboratory and field tests have indicated that LIGCO® is an effective filtrate control agent at moderate pH levels. In addition, LIGCO will act as a mild deflocculant. MIL-PAC is also effective for filtrate control; however, it may increase the viscosity to an undesirable range. MIL-PAC and MIL-PAC LV are effective in seawater NEW-DRILL systems.

The filter cake quality of the NEW-DRILL system makes API filtrate values of 10 to 20 cc/30 minutes sufficient in “most” situations. To determine cake compressibility, filtrate values should be measured and reported at 100, 200, or 500 psi, and at 7½ and 30-minute intervals**.**

UNI-CAL Additions

Lignosulfonate additions are often unnecessary. However, UNI-CAL may be used in NEW-DRILL systems when excess solids cannot be mechanically removed or diluted. Avoid excessive thinning with lignosulfonate to insure effective hole cleaning and to prevent mechanical erosion of the wellbore.

Maintain pH values from 9.0 (freshwater) to 10.5 (seawater) when using lignosulfonate. This increases the solubility of UNI-CAL while limiting destabilization of shales from the hydroxide ion.

Deepwater Drilling Fluid Systems

Drilling off the outer continental shelf has become more common in an effort to find significant hydrocarbon deposits. Water depths range from 1,000 to 8,000+ ft in deepwater wells.

A special consideration related to deepwater exploration is gas hydrates. Gas hydrates are ice-like crystalline solids formed by the physical reaction of gas and water under pressure. They can form in aqueous systems at temperatures well above the freezing point of water if the pressure is sufficiently high. Low temperatures, when coupled with hydrostatic pressure or pressures encountered during well control operations, create an environment conducive to the formation of gas hydrates. NF2® and NF3™ are gas hydrate suppressors specifically designed for use in water-base drilling fluids.

In addition to gas hydrates, other potential problems must be considered when designing a drilling fluid system for deepwater. Hole cleaning becomes critical in the surface casing due to the necessity for a large inside diameter (I.D.) riser. A fluid with a high effective viscosity in the riser, yet shear thinning for good hydraulics, is desirable. Boosting the riser with a third fluid pump is a common practice to aid in hole cleaning.

Deepwater projects utilize large circulating volumes. The drilling fluid system of choice should be easily mixed and maintained. It is advantageous to minimize the number of additives due to logistics and storage space

A growing trend is the use of riserless drilling techniques, using the Dynamic Kill Drilling (DKD) process with water-based mud. The DKD process uses large volumes of weighted water-based mud blended “on the fly” to achieve a specific density while dumping the returns to the seabed. This technique is used to reduce the overall hydrostatic pressure exerted by the mud column on deepwater formations. The fracture pressure integrity of deepwater formations is low compared to onshore and shelf formations. This is compounded by the depths of the water column in deepwater (> 1000 feet). The riser is eliminated because the hydrostatic pressure exerted by the mud column (within the riser), combined with the great depths (> 1000 feet), leads to hydrostatic pressures greater than those of the fracture gradient of the formation, which in turn can lead to lost circulation. Since the density of seawater is less than that of drilling fluid, the total hydrostatic pressure “felt” by the formation is reduced because the hydrostatic pressure exerted is a combination of the density of seawater, together with a component from the drilling fluid in the annulus.

PYRO-DRILL®, High-Temperature Drilling Fluid

Introduction

The PYRO-DRILL® system is a very flexible drilling fluid system that is used when temperature, contaminants, and/or borehole instability make conventional systems impractical or uneconomical. Components of the system have been used in geothermal wells with bottom hole temperatures (BHT) in excess of 600°F. This high temperature system has been formulated in weighted freshwater and salt water fluids with excessive hardness (30,000 mg/L) and at temperatures approaching 500°F.

Application

The system can be composed of any combination of the products shown in Table 3–16 depending upon pH, temperature, and total hardness of the drilling fluid. As in any drilling fluid system, the optimum properties will be achieved when the low-gravity solids are in the proper range for the desired fluid density.

Most of the PYRO-DRILL components are used in small concentrations, usually not exceeding 3 lbm/bbl. The major parameters determining product concentrations will be density, drill solids content, particle size, pH, salinity, total hardness, and bottom hole temperature. Some general product concentration guidelines for use with the PYRO-DRILL system at varying densities, salinities, and hardness levels are presented in Table 3-17 PYRO-DRILL Product Concentration Guidelines for Various Fluid Types

Table 3-16 Component Description of the PYRO DRILL System

Product	Description	Function
MIL-TEMP	Sulfonated styrene, maleic anhydride co-polymer	Provide thermal stability
ALL-TEMP	Derivatized synthetic interpolymer	Water-base deflocculation Rheology control where BHST > 300°F (149°C)
CHEMTROL X	Modified lignitic polymer blend	HT/HP filtration control Deflocculation
KEM-SEAL	AMPS/AAM co-polymer	High-temperature viscosifier freshwater HT/HP filtration control SALT WATER
PYRO-TROL	AMPS/AM co-polymer	HT/HP filtration control Shale stabilizer Lubricity
POLYDRILL	Sulfonated synthetic polymer	HT/HP filtration control for high-hardness fluids Deflocculation
PYRO-VISTM	Chemically modified sugar beet extract	Supplementary viscosifier for SALT WATER/high-hardness fluids to increase yield point and gel strengths

Mixing Recommendations

Most of the additives in the PYRO-DRILL system are polymers, therefore, they should be added slowly (20 to 45 min/container) through the chemical hopper for optimum blending and solubility of the products. In almost all cases, PYRO-DRILL system products can be added directly through the chemical hopper. The two exceptions are the use of PYRO-VIS® and the use of CHEMTROL X in saturated salt water fluids. PYRO-VIS must be pre-hydrated and sheared extensively in a high-shear device prior to addition to the active system. This procedure will alleviate over-treatment and optimize usage of the polymer for supplementing gel strengths and yield points in highly saline and high hardness fluids. If facilities are available, CHEMTROL X should be pre-solubilized in freshwater with caustic soda prior to adding to a saturated salt water fluid. This procedure will assure optimum solubility of the CHEMTROL X in a very harsh environment

Table 3-17 PYRO-DRILL Product Concentration Guidelines for Various Fluid Types

Concentration	Product	Freshwater Brackish Water	SALT WATER Chlorides (20,000-190,000 mg/L)	Saturated SALT WATER	High Hardness Ca++/Mg++ (5,000± mg/L)	Lime Base pH ≥ 11.0
10.0 lbm/gal	MIL-TEMP	0.25-0.50	0.25-0.50	0.25-0.50	0.25-0.50	0.50-0.75
	CHEMTROL X	0.50-2.00	0.50-2.00	1.0-2.00	0.50-2.00	1.00-3.00
	PYRO-TROL	0.25-2.00	0.50-2.00	1.0-3.00		*
	KEM-SEAL	0.75-1.50	0.75-1.50	1.0-2.00	1.00-3.00	1.00-3.00
	POLYDRILL	N/A	N/A	3.0-6.00	4.00-8.00	4.00-8.00
12.0 lbm/gal	MIL-TEMP	0.50-0.75	0.50-0.75	0.50-0.75	0.50-1.00	0.75-1.00
	CHEMTROL X	1.00-3.00	1.00-3.00	2.0-4.00	2.00-4.00	3.00-5.00
	PYRO-TROL	0.50-2.00	0.50-2.00	1.0-2.00		*
	KEM-SEAL	0.50-1.00	0.75-1.50	1.0-2.00	1.00-2.00	1.00-2.00
	POLYDRILL	N/A	N/A	3.0-6.00	4.00-8.00	4.00-8.00
15.0 lbm/gal	MIL-TEMP	0.75-1.25	0.75-1.25	0.75-1.25	0.75-1.50	1.00-2.00
	CHEMTROL X	3.00-5.00	3.00-5.00	4.0-6.00	4.00-6.00	5.00-7.00
	PYRO-TROL	0.50-2.00	0.50-2.00	1.0-2.00		*
	KEM-SEAL	1.00-2.00	0.50-1.00	0.75-1.50	0.75-1.50	1.00-2.00
	POLYDRILL	N/A	N/A	3.0-6.00	4.00-8.00	4.00-8.00
18.0 lbm/gal	MIL-TEMP	1.50-2.00	1.50-2,00	1.5-2.00	1.50-2.50	1.50-3.00
	CHEMTROL X	4.00-6.00	4.00-6.00	5.0-8.00	5.00-8.00	6.00-8.00
	PYRO-TROL	1.00-2.00	1.00-2.00	1.00-2.00		*
	KEM-SEAL	0.25-0.75	0.50-1.00	0.75-1.50	0.75-1.50	0.75-1.50
	POLYDRILL	N/A	N/A	3.00-6.00	4.00-8.00	4.00-8.00

NOTES:

- All concentrations are in lbm/bbl. To convert lbm/bbl to kg/m^3, multiply lbm/bbl by 2.85.
- Product concentration ranges should build stable fluids to 500^{o}F (260^{o}C).
- * pH levels of 11.0 or above will hydrolyze PYRO-TROL® and reduce its effectiveness.
- PYRO-VIS is to be used as a supplementary viscosifier only as needed. Typical treatments are 0.25 to 2.00 lbm/bbl, depending on density, salinity, and hardness levels.
- AVOID OVERTREATMENT.

N/A = Not Applicable.

System Maintenance

Drilling in high-temperature environments requires close monitoring of solids content, solids type, and particle-size distribution. Daily retort analyses and physical observations at the rig site should be supplemented with weekly particle-size distribution analyses (at a Field Service Laboratory) if penetration rates are slow, otherwise laboratory monitoring should be more frequent. This will enable the engineer to closely monitor solids control equipment efficiency.

Standard chemical analyses (pH, alkalinity, salinity, total hardness) must be closely monitored because at elevated bottomhole temperatures (350°F and above) chemical reactions are occurring much more rapidly. Physical properties can change radically in a fairly short time.

Rheological parameters need to be closely watched because they affect hole cleaning and hydraulic parameters. Rheological properties must be checked in a thermal heat cup at 120°F so a standardized record can be maintained at the rig site. Hot-rolling and static aging of samples should be done at current bottom hole temperatures to observe thermal stability characteristics.

Pilot testing and thermal testing of fluid samples at projected bottom hole temperatures should be done weekly to establish responses to possible problems. Fann 70 Viscometer tests can be used to observe thermal stability trends and formulate responses to problems that will help the engineer at the well site.

API and HT/HP filtrate trends should be closely observed to see if properties are stable or degrading from temperature increases and/or contaminants. Dynamic filtration studies can be performed to simulate dynamic down hole conditions at the rig site. Filter cake formation and erosion studied under these conditions are more representative of the drilling operation than static tests. Cake compressibility tests can supplement the aforementioned tests by observing how different products will affect filter cake quality and change filtration rates.

Advantages and Limitations of the PYRO-DRILL System

There are many advantages to the PYRO-DRILL system. Almost all drilling fluids can be easily and economically conditioned with the appropriate PYRO-DRILL additives for enhanced thermal stability. The base fluid should be in good condition prior to treatment.

Listed below are some of the advantages of the PYRO-DRILL system.

- Properly maintained systems are thermally stable to 600°F+.
- PYRO-DRILL fluids are not adversely affected by carbonates, salt water influxes, anhydrite, or cement provided low-gravity solids values are in the proper ranges for the respective fluid density.
- The PYRO-DRILL system can provide excellent borehole stability.
- Properly maintained systems do not cause excessive pump pressures to break circulation. This is especially significant for high-density and high-temperature, deep wells.
- No excessive torque or drag is exhibited with a properly maintained system.
- Properties are easy to maintain with the PYRO-DRILL system.
- PYRO-DRILL systems typically exhibit low corrosion rates. This is due to the reduction in oxygen content of the fluid by the organic additives acting as oxygen scavengers.
- Well costs can be significantly reduced while drilling in hostile environments because of previously mentioned advantages.

One component of the PYRO-DRILL system has some minor limitations. PYRO-TROL should not be used in high hardness fluids (where Ca^{++} and $Mg^{++} \geq 5000$ mg/L) or in lime-base systems (pH ≥ 11.0 are not recommended because of shrinkage/hydrolysis of monomer chains).

UNI-CAL® Systems

Lignosulfonates were introduced in the late 1950s as deflocculants for calcium-base systems. In the early 1960s, Milchem Drilling Fluids (Baker Hughes Drilling Fluids) introduced lignosulfonate to the industry as a deflocculant in drilling fluids without the presence of gypsum or lime. The petroleum industry has since used the material regularly in this manner.

UNI-CAL®, a chrome lignosulfonate product, is extremely effective in the presence of salt and calcium contamination and has performed well in wells with bottom hole temperatures approaching 400°F.

Flocculation is the clustering of suspended colloidal particles. The two forces of attraction usually considered are: (1) partial valence forces, and (2) London Van der Waals forces. The two mechanisms generally credited with deflocculation or thinning are: (1) *electro kinetic* stabilization, which is a rather delicate form of control achieved with materials such as phosphates, silicates and tannins, and (2) *mechanical* stabilization, which is fairly rugged in nature.

The latter type of stabilization is achieved through the formation of a viscous physical barrier. It is the result of the adsorption of an organic polyelectrolyte on the clay particles. This type of stabilization requires higher UNI-CAL concentrations in the system on the order of 6 to 8 lbm/bbl. One of the unique properties of UNI-CAL is its ability to deflocculate effectively at relatively low pH values. This is most helpful when drilling hydroxyl-sensitive clays and shale formations.

With any fluid conditioning agent, preparing a “recipe” to accurately predict the quantities of materials required is difficult. Therefore, the following recommendations should be viewed only as guidelines.

- For top-hole drilling with freshwater fluids, 0.5 to 1.0 lbm/bbl of UNI-CAL is usually sufficient to establish rheological and filtration control.
- As a deflocculant for seawater fluids, 3 to 6 lbm/bbl is usually adequate. The pH is normally maintained in the 10.0 to 10.5 range to suppress calcium and magnesium solubility and to minimize corrosion problems.
- To obtain inhibition with UNI-CAL systems, concentrations of 6 to 8 lbm/bbl are necessary. Inhibition is derived from the adsorbed layers of UNI-CAL and offers a significant degree of protection against dispersion and swelling of clay solids.
- For rheological stability in the presence of high bottom hole temperatures (350°F+), supplementary additions of ALL-TEMP® are beneficial. Field test data indicates that this material effectively extends the thermal stability of UNI-CAL systems. ALL-TEMP treatment ranges between 0.5 and 3 lbm/bbl.
- Maintenance requirements for UNI-CAL systems vary with penetration rate, hole size, fluid density, temperature, solids control program, and the formation being drilled. With good solids control, maintenance additions can range between 0.5 and 1 lbm/bbl with an average daily penetration rate of 100 to 200 ft.
- Supplementary filtration control can be maintained with treatments of MILGEL (approximately 20 lbm/bbl in freshwater and 30 to 35 lbm/bbl in seawater) and a lignite material such as LIGCO or LIGCON. For temperatures above 300°F or severe salt and calcium contamination, CHEMTROL X would be a more effective additive.

GLYCOL Systems

Glycol Chemistry

Polyols (the term “polyol” includes glycols glycerols, polyalkylene glycols and alcohol ethoxylates) are well established shale inhibitors for water-base fluids. These compounds are typically added to water-base fluids at concentrations between 3% and 10% by volume. They are most commonly used in conjunction with a KCl/polymer-base fluid, but have also been added to a wide range of systems from fresh water to salt saturated fluids.

Glycols are compounds containing two hydroxyl groups attached to separate carbon atoms in an aliphatic chain. Although there are a few exceptions, nearly all glycols consist solely of carbon, hydrogen, and oxygen. Simple glycols are those in which both hydroxyl groups are attached to an otherwise un-substituted hydrocarbon chain as represented by the general formula, $C_nH_{2n}(OH)_2$.

Note: The more complex glycols are given the name **polyglycols** and are distinguished by intervening ether linkages in the hydrocarbon chain, as represented by the general formula $C_nH_{2n}O_x(OH)_2$.

A common method of manufacturing these simple glycols is by hydrolysis of the epoxides. These epoxides are polymerized in the presence of other compounds and initiators (glycols, amines, acids, or water) that contain active hydrogen. The end result is a vast range of products with varying molecular weights and characteristics. The glycols are characterized by the way in which the basic building blocks are arranged. The specific glycol products show a wide range of properties depending on the molecular weight and the composition of the polymer. In general, increasing molecular weights result in the following:

- lower water solubility
- higher viscosity
- higher flash point
- lower cloud point.

Prior to considering their field application, some key aspects of glycols are discussed below.

Simple Polyhydric Alcohols

Glycols are dihydric alcohols containing two hydroxyl groups and are members of the general chemical class of polyhydric alcohols. Two commercially important glycols are ethylene glycol (commonly used for automotive antifreeze) and propylene glycol (a food additive). A related trihydric alcohol is glycerol (present in all vegetable oils and animal fats as glyceride esters). Other polyhydric alcohols include sugar alcohols, sorbitol, and mannitol.

Polyglycols and Polyglycerols

Polyglycols and polyglycerols are oligormeric or polymeric forms of the simple glycols and glycerols. The size and molecular weight of the polyglycols and polyglycerols increase as the degree of polymerization or number of repeating units in the oligomers or polymers increases. The properties of polyglycols and polyglycerols depend primarily on the molecular weight, chemistry of the repeating units, and the chemistry of the starting material. Viscosity, flash point, and pour point/freezing point all typically increase with increasing molecular weight, while biodegradability and toxicity typically decrease.

Polyethylene Glycols

Polyethylene glycols are polyglycols made from the addition of ethylene oxide to water (or low molecular weight alcohols). The lower molecular weight commercial polyglycols are viscous liquids while the higher molecular weight materials are tough solids. All are soluble in fresh water at room temperature and up to near the boiling point of water. Toxicity of these products is low. Biodegradability of polyethylene glycols is typically good due to the linearity of the molecules.

Polypropylene Glycols

Polypropylene glycols are polyglycols made from the addition of propylene oxide to water or low molecular weight alcohols (although other polyhydric alcohols can also be used). All are viscous liquids and the higher molecular weight products (molecular weight > ~1,000) are essentially insoluble in water. The lower molecular weight products (molecular weight < ~1,000), however, tend to be soluble in fresh water (at least at room temperature) although some show inverse water solubility with temperature changes. Toxicity of polypropylene glycols is typically low and usually decreases with molecular weight. The lower molecular weight polypropylene glycols normally show good biodegradability, while the higher molecular weight polypropylene glycols are usually more resistant.

EO/PO Copolymers

EO/PO copolymers are polyglycols made from the random addition of both ethylene oxide (EO) and propylene oxide (PO) to low molecular weight alcohols (commonly methyl or butyl). The ratios of ethylene oxide and propylene oxide used is either close to unity, or ethylene oxide is used in abundance. All are viscous liquids, soluble in fresh water at room temperature, and all show inverse water solubility with temperature. Toxicity of EO/PO copolymers has been good and would be expected to decline with molecular weight. The lower molecular weight EO/PO copolymers tend to show acceptable biodegradability and the higher molecular weight materials would be expected to be more resistant.

Polyglycerols

Polyglycerol is, or can be thought of as, a condensation product made from the dehydration/condensation of glycerol. The commercial product is a blend of polyglycerol with polyglycol for defoaming and ease of handling. The product appears to be soluble in fresh water at all temperatures. The toxicity of polyglycerols is low, and biodegradability would be expected to be good.

The selection of a particular polyol for use in a drilling fluid depends on the application required and the environment to which it will be exposed. Low molecular weight water soluble glycols find applications for cuttings and borehole stabilization. The scope of this document is restricted to detailing the theory and application of low molecular weight polyols only.

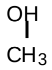
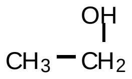
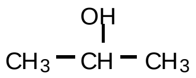
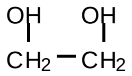
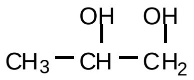
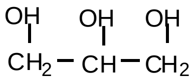
The basic properties of glycols used in the AQUA-DRILL system are shown below.

Table 3-18 Basic Properties of Glycols Used in the AQUA-DRILL System

Glycol	Density	Mol. Wt.	Freezing Point °F	pH at 10%	Flash Point °F
AQUA-COL™	8.4	500	< 10	7 - 10	> 200
AQUA-COL™ D	8.5	380	< 15	7 - 10	> 250
AQUA-COL™ S	9.1	500	< 10	7 - 10	> 212

Glycol and glycerol have been used in water-base drilling fluids for many applications. Chemically related to alcohols, glycols have many of the properties of diesel and mineral oils, but contribute virtually no toxicity to the fluid. Having low vapor pressure at normal temperatures, glycols are not an inhalation hazard. The similarities between glycols and alcohols are shown below.

Table 3-19 Chemical Similarities Between Glycols and Alcohols

Common Name	Chemical Name	Chemical Structure
Wood Alcohol	Methanol	 $\overset{OH}{\overset{\mid}{CH_3}}$
Drinking Alcohol	Ethanol	 $CH_3-\overset{OH}{\overset{\mid}{CH_2}}$
Rubbing Alcohol	Isopropanol	 $CH_3-\overset{OH}{\overset{\mid}{CH}}-CH_3$
Antifreeze	Ethylene Glycol	 $\overset{OH}{\overset{\mid}{CH_2}}-\overset{OH}{\overset{\mid}{CH_2}}$
	Propylene Glycol	 $CH_3-\overset{OH}{\overset{\mid}{CH}}-\overset{OH}{\overset{\mid}{CH_2}}$
Glycerin	Glycerol	 $\overset{OH}{\overset{\mid}{CH_2}}-\overset{OH}{\overset{\mid}{CH}}-\overset{OH}{\overset{\mid}{CH_2}}$

The chemistry of glycol additives can be varied to meet the demands of the product application. This formulation flexibility makes the AQUA-DRILL system the ideal fluid for many applications, including:

- reducing pore pressure transmission into the shale matrix, thus stabilizing the shale
- use on operations in environmentally-sensitive areas

The full benefit and cost-effective use of glycols can only be realized when their use is engineered correctly. The chemistry of the glycols is such that they possess the physiochemical characteristics that make them capable of producing a cloud point (coming out of solution) behavior in the right circumstances. It is the engineering ability to control this physiochemical phenomenon that can make a mud a success or a failure.

Cloud point, or more precisely the Cloud Point Temperature (CPT), is defined as that temperature where glycol comes out of solution as small dispersed droplets forming a “cloud”. The cloud point can also be referred to as the Lower Consulate Solution Temperature (LCST). The ability to “cloud” reduces consumption of glycol because as fluid cools, glycol goes back into solution and is not removed with cuttings.

Applications

The principal application for low molecular weight water-soluble glycols is in the drilling of reactive shales. Wellbore stability is improved over conventional water-based drilling fluids because of the ability of the glycol to “cloud-out” within the shale matrix and form a physical barrier to reduce filtrate invasion into the shale matrix. This mechanism of minimizing water invasion into the matrix reduces pore pressure transmission into the shale and improves the strength and stability of the wellbore. The AQUA-DRILL system was the first water-based drilling fluid that was specifically designed to reduce pore pressure transmission into shales. Pore pressure transmission reduction is considered to be the primary wellbore stability mechanism of emulsion-based drilling fluids.

The higher initial make-up cost of the glycol-base fluid is often entirely offset by reduced dilution costs. In less reactive areas, the benefits of reduced dilution can also be realized, making the fluid viable across a wide range of applications. Selection of the correct glycol allows partially saturated or salt-saturated fluids to be formulated. This extends the potential use of these fluids into wells where salts will be encountered. Return permeability figures obtained by several operators on glycol fluids indicate no detrimental effects (and perhaps even some beneficial effects) in using glycols across reservoir sections. This is particularly true at higher glycol concentrations (5% to 10% by volume).

AQUA-DRILL System

The AQUA-DRILL system uses glycols to stabilize shales by reducing pore pressure transmission into the shale matrix and was the first-generation high-performance water-based mud system for Baker Hughes Drilling Fluids. AQUA-DRILL is a non-toxic, non-sheening system that eliminates the potential environmental disadvantages associated with oil/synthetic base fluids.

The Core System

The “core” AQUA-DRILL system is comprised of the following products.

Water Soluble Glycol

- **AQUA-COL™** – a low molecular weight glycol ether for increasing the inhibitive properties of fresh water and low salinity water-base fluids when drilling reactive shales.
- **AQUA-COL™ B** - a low molecular weight glycol ether providing enhanced shale stabilization when using higher salt concentrations in water-base fluids.
- **AQUA-COL™ D** – a low molecular weight glycol ether providing enhanced shale stabilization when using higher salt concentrations in water-base fluids.
- **AQUA-COL™ S** – a low molecular weight polyglycol ether providing enhanced shale stabilization when using higher salt concentrations in water-base fluids (up to saturation).

Polymeric Shale Inhibitor

- **AQUA-SEAL™** – a proprietary polymer to aid in preventing hydration and dispersion of drill cuttings, and for delivering filtration control.
- **NEW-DRILL® –** a partially hydrolyzed polyacrylamide (PHPA) polymer that provides cuttings encapsulation and helps reduce dispersion of cuttings.

Salt Component

Potassium chloride, sodium chloride or formates – various salts for adjusting the system's water activity coefficient to match that of the shale being drilled. Local environmental regulations should be consulted when selecting a salt.

- **Biopolymers -** rheological control is achieved using biopolymers such as XAN-PLEX.
- **Potassium Carbonate -** a source of K^+ ions for additional shale inhibition and alkalinity control (eliminating the need for caustic soda at the wellsite).

Supplementary Products

Several supplementary products can be used to enhance the performance of the AQUA-DRILL system. Applications include:

- dynamic filtration control
- drilling or running casing through depleted zones
- improved rates of penetration and reduced bit-balling
- enhanced lubricity for drilling highly-deviated wells
- spotting applications.

AQUA-MAGIC®

AQUA-MAGIC® is a chemically-modified glycol-based material designed for all types of water-base drilling fluids. AQUA-MAGIC additions are recommended whenever differential sticking may occur, especially while drilling high-angle wells.

AQUA-MAGIC is added at a concentration of 2 - 4% by volume, when running casing through depleted zones. It is recommended to spot 10% by volume in the open hole through the zone.

Inhibition Mechanisms

Figure 3-15 illustrates how the addition of a glycol (AQUA-COL) improves the inhibition of a water-base fluid system. The inhibition mechanisms related to the AQUA-DRILL system can be divided into three components.

- Pore pressure transmission
- Capillary effects
- Cloud point behavior

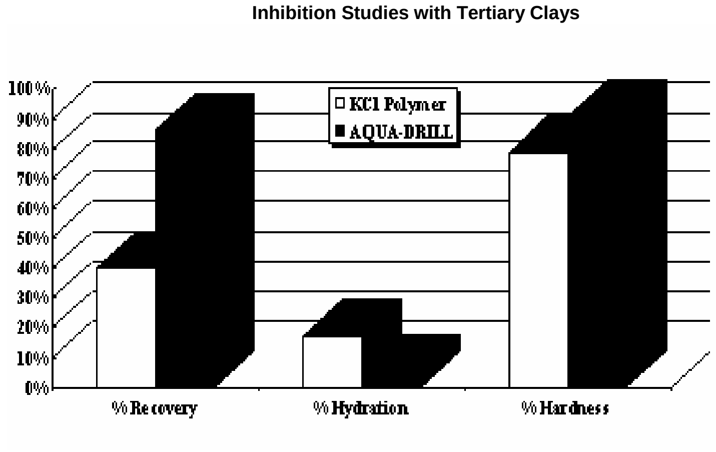
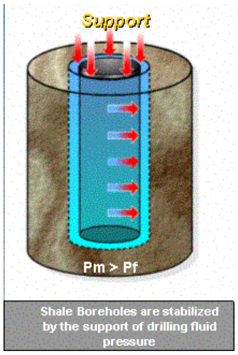
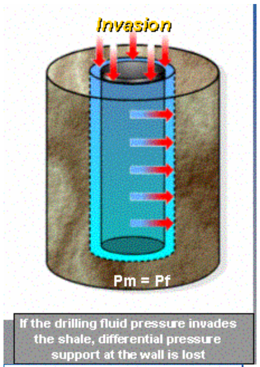


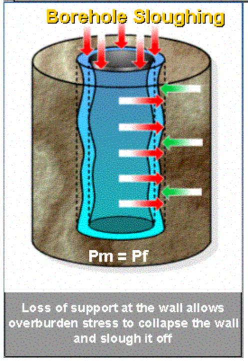
Figure 3-16 Inhibition Studies with Tertiary Clays

Pore Pressure Transmission

Baker Hughes Drilling Fluids has explored pore pressure transmission (PPT) testing for several years. PPT testing measures the formation pore pressure increase from filtrate invasion in very low permeability formations such as shales. In highly permeable formations the pressure rise from filtrate flow is rapidly dissipated in the formation volume and pore pressure is not affected. However, in very low permeability formations, the pressure increase from filtrate invasion declines very slowly and the pore pressure continues to increase with additional filtrate flow. This pore pressure increase reduces the effective over balance pressure. Over-balance pressure decline is exaggerated by wall fractures from drilling. These fractures increase near-wellbore permeability resulting in rapid pressure increase inside the wall. Reduced overbalance tends to destabilize the wellbore and promote sloughing. The introduction of cloud point glycols (AQUA-DRILL), aluminum complexes (ALPLEX) and sealing polymers (PERFORMAX) by Baker Hughes Drilling Fluids has greatly improved the osmotic effectiveness of water-based drilling fluids.







Properly Pressured: Ideally, the hydrostatic pressure exerted by the mud column is higher than the formation (pore) pressure. Here, there is a pressure differential at the shale surface which serves as a **support** mechanism (**first image**) to offset over-burden pressure.

Over Pressured: Here, drilling fluid pressure **invasion** (**second image**) occurs into the shale matrix. Due to the low permeability of the shale, the added pressure dissipates very slowly. In emulsion fluids, the capillary entry pressure effects strongly impede the invasion of pressure from base fluids (oils, esters or synthetics) because of the wetting characteristics of water vs. base fluids. However, in water-based muds, the capillary entry pressure can be very low and therefore water pressure invasion can easily occur in the matrix. As pressure invasion occurs, the pore pressure at the shale surface rapidly increases to a level equivalent to that of the mud column. Then, the differential pressure at the surface is reduced and pressure support (over-balance) is lost.

Pressure Invasion: Finally, loss of differential pressure support at the wellbore surface allows the over-burden pressure (weight of shale pressing down) to destabilize the invaded shale and it will **slough** off (**third image**) into the annulus. In this case, the pressure of the mud column is equal to the pressure within the shale, leaving no supporting pressure to prevent the overburden force from sloughing the shale.

Capillary Effects

Neither water-base fluids nor oil-base fluids form a solid filter cake in shale. Under normal fluid pressures, shales are permeable to water-base fluids but almost impermeable to oil. The stable behavior of shales while drilling with oil-base fluid or synthetic-base fluids is a result of *capillary action*. When oil enters a shale, it has to overcome a threshold pressure caused by the capillary effect between oil and the pore fluid. The capillary pressure is in the order of thousands of psi and is generally too large to be overcome by the fluid pressure differential. The threshold pressure, therefore, acts as an alternative semi-permeable membrane and provides effective fluid support to the wellbore.

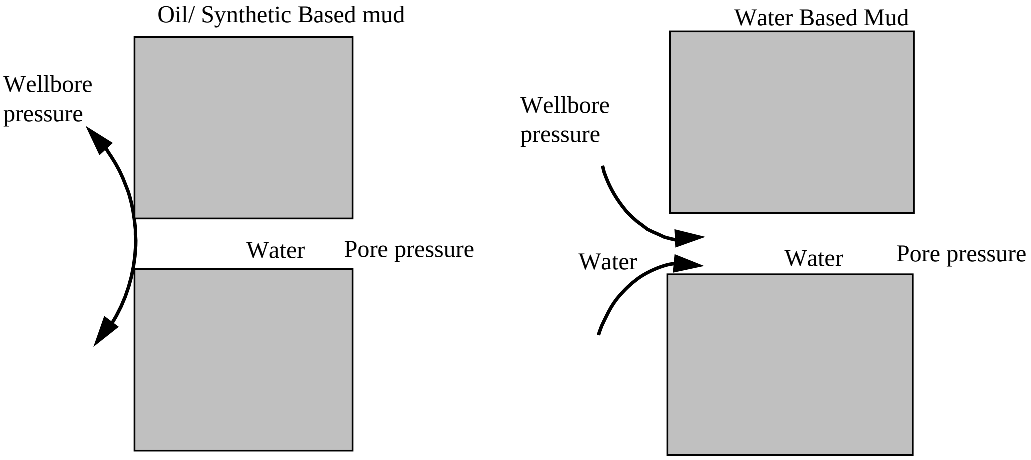


Figure 3-17 Capillary Action in Oil/Synthetic vs. Water Base Fluids

As a consequence, shale instability with oil and synthetic drilling fluids is normally caused by lack of fluid support, i.e., too low of a fluid density.

Cloud Point Behavior

Definition

Cloud point is a phenomenon exhibited by many glycols. The solubility of these glycols in water decreases as temperature increases, with materials that are fully soluble at room temperature forming separate phases at higher temperatures. The temperature at which the glycol and water separate is known as *cloud point*, since the previously clear solution becomes “cloudy” upon separation as shown in Figure 3-17 Capillary Action in Oil/Synthetic vs. Water Base Fluids

Glycol and water together

At room temperature, the glycol demonstrates complete water solubility.

Glycol/Water solution at cloud point

When the solution's temperature is raised to the cloud point, the glycol becomes insoluble and begins to form individual droplets (micelles). The solution's appearance becomes "cloudy".

Solution above cloud point temp.

If the temperature remains above the cloud point, the seperation of glycol and water becomes distinct and both phases are clearly visible.

Figure 3-18 Cloud Point: Temperature at Which Water and Glycol Begin to Separate

Engineering Cloud Point

For glycols at room temperature, water solubility decreases with increasing molecular weight. Low molecular weight glycols are typically more soluble in freshwater systems than in high molecular weight glycols. Two factors control the cloud point of freshwater glycols:

- salinity
- glycol concentration

An increase in either of these factors results in a lower cloud point temperature.

When a glycol is mixed in water below the resultant solution’s cloud point, it is evenly distributed as minute droplets known as *micelles*. The micelles are stabilized by hydrogen bonding between the water molecules and oxygen atoms present in the glycol molecule. The stabilization process is known as *hydration*. When the temperature increases, hydration decreases until the micelles are no longer stable in an aqueous environment. Consequently, they coalesce in large numbers and form a separate phase that is distinct from the water.

The “clouding” process is reversible. If the solution is subsequently cooled, the two phases recombine to form a clear, single-phase solution. Baker Hughes Drilling Fluids has engineered combinations of glycol concentration and salinity to design a drilling fluid where glycols are in solution on the surface and out of solution downhole. As bottom-hole temperatures change with depth, the system’s cloud point can be adjusted to maintain optimized drilling performance and shale stability.

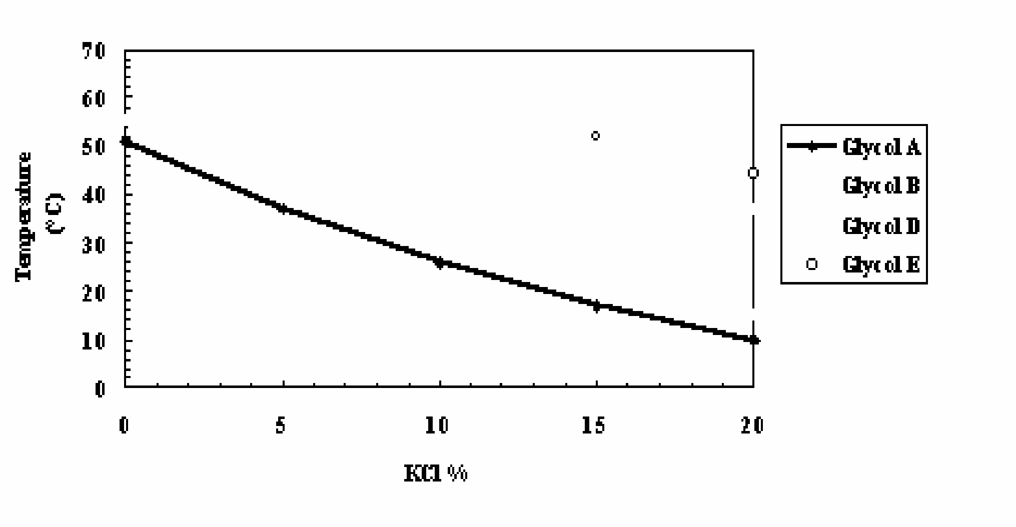


Figure 3-19 Cloud Points for Various Polyols in KCl Solutions

The great variety of cloud point temperatures seen indicates that one polyol may not be suitable for all applications. Additionally, the polyol will have to be selected based upon its cloud point at a specified salinity. Alternatively, the cloud point of the polyol can be adjusted by altering the salinity of the liquid phase. Varying the polyol type and system salinity has afforded Baker Hughes Drilling Fluids effective control of the cloud point over a wide operating range.

Cloud point is modified at the wellsite using the software program (available through Baker Hughes Drilling Fluids TITAN group) GLY-CAD® which models the downhole behavior of all of drilling fluids water-soluble glycol products. With this program, the concentrations of salt and glycol can be engineered to match the operational needs of the drilling fluid. Depending on downhole conditions, such as formation temperature, the optimum blend of glycols and salts is determined to achieve the most effective cloud point for shale inhibition.

Shale Inhibition and Drilling Performance

Baker Hughes Drilling Fluids has conducted studies to examine the benefits of cloud point behavior on drilling performance and shale stability. The results have shown distinct performance benefits both above and below cloud point. Improvement in inhibition seen over a wide range of temperatures is directly related to the *cloud point* of the glycol. Cloud point is the transition point or start of phase separation at which the glycol changes from being water soluble to water insoluble.

Explanation

Research carried out by other investigators (SPE 28960) concluded that the glycol is adsorbed by the clay. During the adsorption process, water is displaced from the clay surface and ordered structures of polyols are formed. A weak attachment is postulated because of the observation that there is no rapid depletion of the polyol in the drilling fluid system. For this to be the case, there must be some mechanism of association and disassociation of the polyol in the circulating system. The nature of these structures and their stability in aqueous fluids is strongly controlled by the presence of potassium cations with certain polyols.

- Under most conditions, a single polyol layer forms on the clay in the presence of potassium. The resulting complexes are stable in water.

- A complex containing two polyol layers is formed when potassium is absent. This complex is less stable in water.
- Studies on other polyols conclude an additional contribution comes from interactions between polyol molecules at the clay surface.

Polyol fluids are effective in most shale types, particularly in young or relatively non-compacted shales with high clay contents. Compared with, for example, KCl/polymer fluid, polyol systems give improved wellbore conditions and produce firmer cuttings that do not readily disperse into the fluid. These attributes frequently combine to give faster drilling rates, and reduced fluid volumes that translate into reduced drilling costs.

Above the Cloud Point

Above the cloud point, glycols are present as emulsions while the separate phases are continually intermixed by the circulating system, particularly at the bit. These emulsions block pores in the formation, preventing fluid invasion and consequent instability in water-sensitive formations.

The AQUA-DRILL system can be engineered so drill cuttings at the bottom of the hole are initially above the system's cloud point. A protective glycol layer forms around the cuttings as a result of glycol "clouding out" on its surface. This prevents the cuttings from reacting with water until they have risen to a point in the wellbore where the fluid temperature drops below the cloud point, allowing the glycol to re-dissolve into the fluid. This explains both the increased inhibition present when using the AQUA-DRILL system in reactive shales and the low glycol depletion rates seen in the field.

Below the Cloud Point

Glycols still provide enhanced performance below the cloud point. Field evidence has shown that glycols below the cloud point deliver improved shale stability. Also, laboratory studies have shown that shale inhibition with glycols is more effective when water-soluble, rather than water-insoluble, glycols are employed. One explanation is that the glycols adsorb onto shale surfaces via oxygen molecules present in the glycol chain. Once the water-soluble glycols enter the formation, the higher formation temperature causes the glycol/water solution to phase separate in-situ, forming an emulsion. The hydrophobic glycol droplets in the emulsion fill and block the shale pores, preventing further fluid invasion and stabilizing the shale.

It can be concluded that shale inhibition and formation protection is achieved by:

- the polyol displacing water from adsorption sites on clay minerals present in shales, and
- blocking the formation pores from further ingress of invasive fluids by "clouding out."

Formation Damage

Several operators have now carried out studies to evaluate the effect of polyols in drilling/coring fluids on return permeability. These studies have shown no adverse effects on the formation samples tested. Many suggest that the polyol actually protects the productive rock from impairment by the drilling fluid provided it is above the cloud point.

As discussed earlier, the theory is that the polyol emulsion protects the formation from excessive fluid invasion by pore plugging just inside the rock matrix as the material "clouds out" within the hotter environment, thus sealing the pores against further ingress. At this point, surfactant/polymer interactions and complexation of surfactant with monovalent ions (such as potassium in solution) will occur more frequently. These reactions provide optimum benefit for long term borehole protection by acting as a blocking layer which compliments polymer additions. An additional benefit may be the inhibition of interstitial clays.

Filter Cake

Once part of the clouding polyol in solution becomes hydrophobic, a significant improvement in filter cake quality is seen. Water tends to bead on the surface and the cake is easier to “peel off” the filter medium.

Well Clean-Up

Production after acidization and completion of wells has been above operator expectations. Unfortunately, no information on skin damage and comparisons of production rates before and after using polyols has been made available. It is thought that quick plugging of low permeability sandstones (< 20 mDarcy) by the polyol leads to minimal formation damage inside the reservoir. Later acidization could then reach beyond the invasion zone around the wellbore leading to a better clean-up and enhanced production.

Viscosity Effect

In general, polyols added at low concentrations (< 5%) have little effect on the viscosity of the drilling fluid. At increased concentrations, there will be some variation in viscosity with the maximum rheology obtained in the 110° to 130°F temperature range.

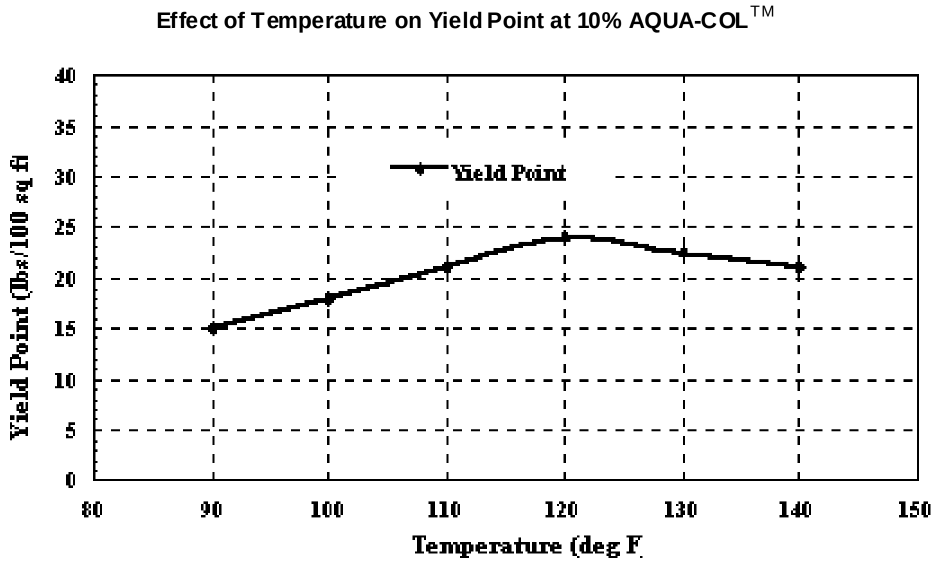


Figure 3-20 Effect of Temperature on Yield Point at 10% AQUA-COL™

Environment

As a group, low molecular weight polyols are considered low in toxicity and readily biodegradable. The fact that they are water soluble means that they are able to disperse in the water column and biodegrade easily. An added feature of polyol use in water-base fluid is the reduction in dilution rates due to their inhibitive nature which reduces the overall volume of water-base fluid products discharged to the environment.

Elastomer Testing

The following elastomer tests (Table 3-20 Effects of AQUA-COL® and AQUA-COL® D on Elastomers in a 5% Solution) show the effect of AQUA-COL® and AQUA-COL® D on elastomers in a 5% solution.

Table 3-20 Effects of AQUA-COL® and AQUA-COL® D on Elastomers in a 5% Solution

Product	Elastomer	Time (hrs)	Temp (°F)	Volume Change %	Hardness Change %
AQUA-COL®	Type D	72	250	5.92	5.3
AQUA-COL D®	Type D	72	250	7.50	6.3
AQUA-COL®	Type F	72	250	5.44	4.0

Engineering Guidelines and Comments

Premixed Fluid

North Sea

An existing practice in the North Sea has typically been to utilize concentrated premixes of AQUA-COL® to cut down on the number of drums of glycol required at the rig-site and then to maintain glycol levels at 3% to 5% while drilling. A glycol premix has typically contained 80 lbm/bbl KCl, 7% AQUA-COL® and 5 lbm/bbl MIL-PAC® LV. Laboratory tests were conducted which showed that this mixture produced a cloud point of 6°C (43°F) with complete phase separation at 8°C (47°F).

Further cloud point measurements have been made to determine the highest levels of KCl and AQUA-COL® which could be combined without the risk of phase separation under normal operating conditions. If the same ratio of salt to glycol as in the original premix is to be maintained, then 60 lbm/bbl KCl and 5.25% AQUA-COL® will give a cloud point in the region of 24°C (75°F). This should be adequate unless there is significant heat input to the fluid resulting from shear during mixing.

If the KCl concentration is reduced to 50 lbm/bbl, this will allow 7% AQUA-COL® to be added. This formulation should be used if the primary requirement is to minimize the number of drums of glycol shipped to the rig. At 70 lbm/bbl KCl, the highest level of AQUA-COL® which can be added without the cloud point dropping below 20°C (68°F) is 2%. Premixes containing more than 60 lbm/bbl KCl should not be used in conjunction with AQUA-COL®.

Gulf of Mexico

The practice of shipping premixed fluid to the rig is becoming more commonplace. The desired fluid properties for the anticipated interval are established and a suitable volume of liquid is prepared. After drilling the cement and performing the formation integrity test, the wellbore is displaced with the AQUA-DRILL® fluid. A suitable high viscosity spacer of 30 to 50 bbls is pumped ahead of the AQUA-DRILL® fluid.

System Preparation

Table 3-21 Range of Glycol Cloud Points in KCl and NaCl Brines is a compilation of various brine and glycol cloud points. It can be used for planning purposes in lieu of the software program, GLY-CAD®. However, the final system formulation should be prepared from GLY-CAD.

Table 3-21 Range of Glycol Cloud Points in KCl and NaCl Brines

Product	Brine	Salt, %	CPT, °F
AQUA-COL, 1 – 10% by wt.	KCl	5 - 20	42 - 130
AQUA-COL, 1 – 10% by wt.	NaCl	5 – 26	25 - 124
AQUA-COL B, 1 – 10% by wt.	KCl	5 – 20	104 - 241
AQUA-COL B, 1 – 10% by wt.	NaCl	5 – 26	62 - 225
AQUA-COL D, 1 – 10% by wt.	KCl	5 – 20	92 - 242
AQUA-COL D, 1 – 10% by wt,	NaCl	5 – 26	74 - 425
AQUA-COL S, 1 – 10% by wt.	KCl	15 – 20	195 – 286
AQUA-COL S, 1 – 10% by wt,	NaCl	15 – 26	146 - 262

Cloud Point Maintenance Offshore

Under normal drilling, there will be a temperature differential between BHCT and formation temperature. To achieve the maximum performance from cloud point glycols, it is desirable to maintain the cloud point within this range as close as possible. This requires that glycols are available so that any cloud point can be achieved between approximately 30°C (86°F) and 75°C (167°F). The lower end of this range (30°-40°C [86°-104°F]) can be readily achieved with AQUA-COL in the 2% to 3% range and KCl levels of 15 to 30 lbm/bbl. The higher end (55°C to 75°C (131°F to 167°F) can also be achieved by utilizing AQUA-COL D at 3% to 5% together with higher levels of KCl.

Note: All references to percentages of glycol in fluid should be interpreted to relate to the glycol as a percentage of the brine phase of the fluid. Adding 30 bbls glycol to 970 bbls fluid will only result in 3% glycol concentration if the fluid is completely unweighted and devoid of drill solids. In all other cases, the solids volume of the fluid should be backed out of any calculations relating to volume percentages of glycols.

Rheological Properties

The following ranges for gel strengths and yield points are recommended when drilling at rates of 100 – 200 ft/hr in the indicated hole sizes.

Table 3-22 Recommended Ranges for Gel Strengths and Yield Points for AQUA-COL Systems

Hole Size	Yield Point lbs/100 sq ft	Initial Gel lbs/100 sq ft	10 Min Gel lbs/100 sq ft
17½" / 16"	25 - 40	5 - 10	9 - 20
12¼"	18 - 25	4 - 8	7 - 15
8 3/8" / 8"	10 - 15	4 - 8	7 - 15

High and low viscosity sweeps will give further assistance in hole cleaning. In an ideal consistent drilling situation, occasional sweeps will serve as an indication of successful hole cleaning. A minimum initial gel strength of 4 lb/100 ft^2 will be required to ensure that there is no barite settling on surface.

Test Procedures

In addition to the basic fluid tests of density, rheological, and filtration properties, tests for excess NEW-DRILL, PHPA and AQUA-COL should be carried out. Two tests for AQUA-COL are available.

Colorimetric Method (GLY-KIT)

This is the standard method for the determination of glycols in drilling fluid filtrates. The glycol is extracted into dichloromethane using a blue complexing agent. The resulting blue color of the dichloromethane is compared to standard solutions and the concentration determined.

Equipment

- Eppendorf Model 3190 Fixed Volume Pipette, 100 µL
- Pipette tips, 10 to 100 µL range
- Test Solution Vials
- Color Wheel for viewing samples and holding vials
- Box of Kemwipes.

Procedure

1. Obtain 1 or more ml of filtrate.
2. Attach pipette tip to pipette.
   - Press the yellow control knob down to the first stop.
   - Hold the pipette vertically and immerse tip about 3 mm into the filtrate.
   - Let the yellow control knob rise slowly to fill the tip with liquid.
   - Slide the tip out of the filtrate along the wall of the container.
   - Wipe off any droplets on the outside of the tip with a Kemwipe.
3. Open the test vial and dispense the filtrate.
   - Hole the pipette tip at an angle against the inside of the vial.
   - Press the yellow control knob slowly down to the first stop and wait about three seconds.

- Press the button down to the second stop to empty the tip completely.
- Hold the button down and slide the tip along the wall on the vial and remove.
- Let the yellow control knob glide back to its rest position.
- Eject the tip by pressing the tip ejector button.

4. Cap the vial and shake for 1 minute.
5. Allow vial to rest for 2 to 3 minutes while the phases separate.
6. Place vial in the top of the color wheel viewer to best match its color to one of the standard solutions. Tilt the color wheel forward and view the % by volume glycol in the aqueous phase on the scale which is visible through the small hole on top of the color wheel and record.

Note: For glycol concentrations between 5% and 10% by volume, the filtrate must be diluted 50:50 with distilled water. (Refer to detailed instructions with equipment)

Cloud Point Method

This method makes use of the polyols cloud point properties. A filtrate sample is collected in a graduated cylinder and placed on a heating element. The temperature is raised until the filtrate “clouds out”. At this point, there will be a phase separation and the polyol will form a discrete liquid on top of the filtrate. If phase separation does not occur, then the salinity of the filtrate can be raised by adding KCl or salt. The approximate concentration of polyol can be expressed as a percentage of the total fluid phase. It must be stressed that this is an approximate guide only.

Logistics

In order to minimize the amount of material transported to the rig, the fluid can be shipped as a concentrated bulk liquid. This method has been used on numerous wells to date. Typically 3.5 to 4 lbm/bbl MIL-PAC polymer and 5% to 5.5% AQUA-COL are mixed into 60 lbm/bbl KCl brine. Concentrations of AQUA-COL and polymer are such that when the brine is cut back with drill-water, all products are at the desired concentration.

Only small amounts of sacked products are shipped to the rig for maintenance and contingency. Higher concentrations of products in the premix are not possible due to the glycol clouding out in the fluid plant at ambient temperatures. The inhibitive nature of the AQUA-COL fluid results in end of section fluid properties being similar to starting properties. The fluid is therefore ideal for re-use, either on the next interval or similar interval on another well. The re-use of the fluid has significantly reduced costs and minimized the amount discharged into the sea.

Whole Fluid (Mud) Discharge

Minimal dilution requirements reduce surface losses therefore little whole fluid is dumped. The use of AQUA-DRILL has dramatically reduced the amount of chemical discharged into the sea. On a recent Central Graben 17½" section, surface losses were 1230 bbls (0.29 bbls/ft). The only whole fluid lost was associated with the cuttings and dumping of the header box.

Tripping Procedures

Using the AQUA-DRILL system yields a gauge or very close to gauge hole. Therefore, it is important to ensure that the hole is circulated clean prior to trips. A tight hole can be experienced on the first trip in a new hole. On rigs equipped with a top drive, it has become routine to pump out of new hole in stands.

Solids Control

A wide variety of solids control systems have been used with the AQUA-DRILL system. Good solids control will always be of benefit, but the system has been particularly beneficial when only average or poor solids control equipment was available. Reduced dispersion of solids and minimal clay blinding on screens makes the system more flexible than conventional polymer systems.

MBT Values

A common scenario when drilling reactive clays with conventional polymer fluids is to see a rapid buildup of gels and MBT requiring rapid dilution to control these properties. In the AQUA-DRILL system, the problem is often the reverse, i.e., low gels resulting from low MBT values requiring supplemental additions of XAN-PLEX®. It is quite normal under these circumstances to see an MBT value of 15 after 5,000 ft of drilling a 17½" hole through reactive clay formations with minimal dilution.

Dilution Rates

Experience from past wells has provided the following expected dilution rates. The figures quoted below are for 4,000 ft of clay with average solids control equipment and fluid weight in the 11.0 to 13.0 ppg range.

Table 3-23 Recommended Dilution Rates for AQUA-DRILL Systems

Clay Type	Hole Size	
	17½"	**12 1/4"**
Low Reactivity	0.1 - 0.2 m^3/m 0.2 - 0.4 bbl/ft	0.05 - 0.15 m^3/m 0.1 - 0.3 bbl/ft
Intermediate	0.15 - 0.3 m^3/m 0.3 - 0.6 bbl/ft	0.15 - 0.3 m^3/m 0.3 - 0.4 bbl/ft
Highly Reactive	0.25 - 0.5 m^3/m 0.5 - 1.0 bbl/ft	0.2 - 0.4 m^3/m 0.4 - 0.8 bbl/ft

Mud Weight Selection

As with any system, poor mud weight selection will mask the benefits of this improved water-base fluid. An additional benefit from the improved fluid system can be lost by poor mud weight selection. In most cases, inadequate weight is the problem. There is no substitute for good offset data in well planning.

pH Control

The AQUA-DRILL system functions over a wide range of alkalinity values. However, to minimize clay dispersion, a pH in the range 8.5 to 9.5 is recommended.

AQUA-DRILL Application (North Sea)

Product Descriptions

Potential applications for the potassium chloride AQUA-DRILL system include a wide spectrum of wells. To date, the primary application has been for inhibition in *tertiary clays*. Details of the fluid system are outlined in the following pages together with general recommendations on system maintenance. Product applications and concentrations are listed in the following table.

Table 3-24 Recommended Product Concentrations and Applications for the AQUA-DRILL System

Product	Field Concentration	Application
Potassium Chloride (KCl)	25 - 40 lbm/bbl	Inhibit clay swelling & hydration
MIL-PAC® LV	2 - 4 lbm/bbl	Filtration control
MIL-PAC® R	0 - 2 lbm/bbl	Filtration control
XAN-PLEX® D	0 - 1 lbm/bbl	Rheology control
NEW-DRILL®	2 - 4 lbm/bbl	Improve cuttings integrity
AQUA-COL®	2% - 5% by vol.	Reduced Pressure Transmission
Caustic soda	0.1 - 1 lbm/bbl	pH control
MIL-BAR®	As required	Density control

KCl – Potassium Chloride can be used at varying concentrations from 0 to 80 lbm/bbl (saturation). The product is usually shipped in its concentrated form to ease logistics. The level of inhibition generally increases with increasing concentration of potassium chloride. A typical curve is illustrated in Figure 3-20 Effect of Temperature on Yield Point at 10% AQUA-COL™ or tertiary clay. Several wells have been engineered using saturated potassium chloride. On these wells, only marginal increases in shale inhibition were observed.

In saturated conditions, there is also the potential for formation embrittlement due to the movement of water from the formation into the drilling fluid. In addition, high chloride levels can affect log evaluation in reservoir sections. A suitable compromise on inhibition, logistics, and economics using KCl is to maintain the concentration in the range 25 to 40 lbm/bbl.

Note: Chloride concentration will affect the cloud point of the polyol in the system and this should be considered when selecting the salt concentration.

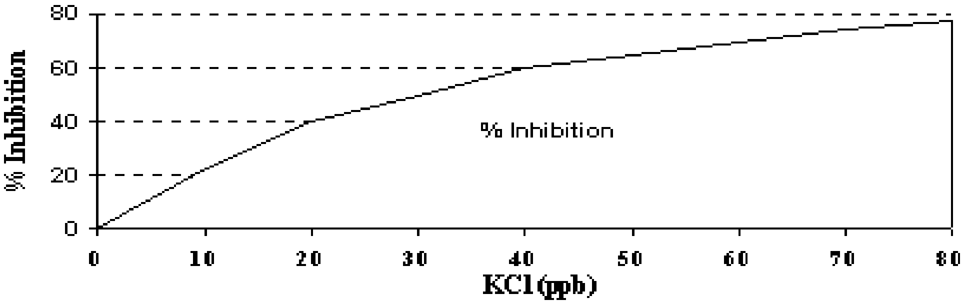


Figure 3-21 Relative Inhibition of Tertiary Clay in KCl Solutions

MIL-PAC LV – Low viscosity polyanionic cellulose will provide a degree of polymer encapsulation, but its principle function is in the control of the API filtrate. MIL-PAC LV as a filtration control agent will impart minimal viscosity to the system. Concentrations will vary with filtration rate desired and overall salinity of the fluid. Normally, a treatment level of 1.43 to 5.7 kg/m^3 (0.5 to 2.0 lbm/bbl) will provide the desired results.

MIL-PAC R – The regular grade polyanionic cellulose functions in a similar way to the low viscosity version but will also impart viscosity. The ratio of MIL-PAC R to MIL-PAC LV will control the degree of viscosity-to-filtrate control required. MIL-PAC R will impart a significant level of high shear viscosity, but minimal gel strength.

Traditionally, the gel strengths in the system were provided in part by formation clays in a conventional polymer system while drilling in a reactive area. However, the high level of inhibition provided by AQUA-COL has led to minimal increase in gel strengths. On recent wells, the concentration of MIL-PAC R has been decreased in favor of XAN-PLEX D polymer. Improved hole cleaning is a direct result of this change. To reduce fluid loss or increase viscosity, 1.43 to 5.7 kg/m^3 (0.5 to 2.0 lbm/bbl) is normally required.

XAN-PLEX D– Xanthan gum used to increase viscosity and gel strengths, as well as to aid in suspending weight materials and cuttings. Normal treatment is 2.85 kg/m^3 (1.0 lbm/bbl) to achieve a funnel viscosity of 35 to 38 sec/qt.

NEW-DRILL – This is a PHPA polymer supplied in fine powder form. The high molecular weight of this anionic polymer is designed to encapsulate and reduce drill cutting dispersal and swelling. Addition of a PHPA polymer is a preventative measure and not a cure for high solids induced mud rheological properties. If PHPA polymer is added to a system that is solids laden, this will result in excessive viscosities. NEW-DRILL additions to new polymer fluid will result in a viscosity hump, therefore, allow a minimum of four (preferably eight) hours mixing time. If the drill-out formation is a clay, then it is recommended that a minimum of half the NEW-DRILL concentration be added prior to displacement. The level of NEW-DRILL in the system can be monitored using the Clapper Gas Train test. While this provides only approximate values, it will clearly indicate an excess of the polymer in the system. A minimum excess of 1.0 lbm/bbl is recommended.

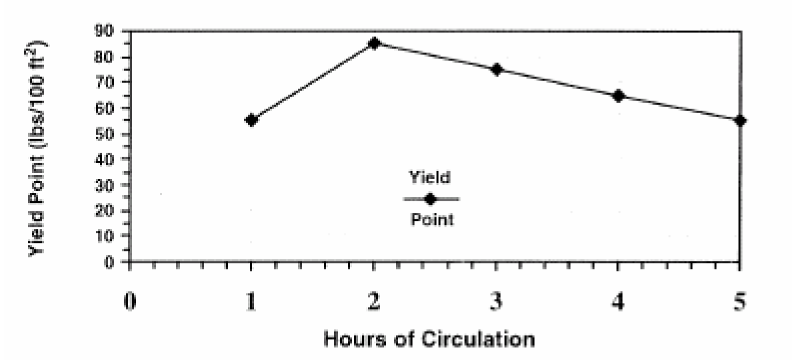


Figure 3-22 Viscosity Increases with NEW-DRILL Additions

AQUA-COL, **AQUA-COL D**, and **AQUA-COL S** – These are low molecular weight water soluble polyols. The concentration is proportional to the level of inhibition. Addition of polyol to improve inhibition must be viewed against the increased cost of the fluid. The optimum concentration for clay inhibition in North Sea wells is in the range 3% to 5% by volume. The GLYKIT test can be used for measuring AQUA-COL concentration in the drilling mud system. In order to allow for (theoretical) depletion, the product concentration is usually allowed to increase by 0.5% to 1.0% through the interval. At high AQUA-COL concentrations (> 7.0%), there have been some flocculating effects in laboratory fluids. Consultation with BHDF is required before considering raising the active concentration above 7.0% by volume AQUA-COL.

Caustic Soda – Caustic Soda, is used primarily for pH and alkalinity control. It minimizes the solubility of calcium as well as magnesium contaminants in water-base drilling fluids. Caustic Soda is always added to solubilize and activate LIGCO and UNI-CAL. Do not mix it through the fluid hopper. Dissolve it in water in a chemical barrel. One sack should be added *very slowly* with careful agitation to 189 liters (50 gal) of water in the chemical barrel. Caustic soda is a corrosive material and should be handled with extreme caution.

MIL-BAR - Barium sulfate ($BaSO_4$), commonly known as barite is used to increase the density of all types of drilling fluids. MIL-BAR is chemically inert to all drilling fluid additives

Selected Well Summaries

Table 3-25 AQUA-DRILL Applications in the North Sea provides an overview of six AQUA-DRILL mud wells drilled in the North Sea. Data from each well was from the 17 ½” hole section.

Table 3-25 AQUA-DRILL Applications in the North Sea

Well Name	21/25-10	29/3a-5	21/25-12	30/16-13	211/29-BD-46	29/7-5
Product Concentrations						
KCl, lbm/bbl	35.00	37.60	39.58	35.52	33.83	39.19
MIL-PAC REG, lbm/bbl	1.26	0.87	1.07	0.58	1.03	0.57
MIL-PAC LV, lbm/bbl	2.10	2.01	3.91	1.00	1.10	2.01
NEW-DRILL L, lbm/bbl	2.10	1.99	1.78	1.17	1.65	2.42
XAN-PLEX D, lbm/bbl	0.56	0.31	0.47	0.49	0.80	0.60
AQUA-COL M, % by vol	3.00	3.40	3.94	3.10	3.11	3.73
CAUSTIC SODA, lbm/bbl	0.49	0.94	0.57		0.80	0.79
MIL-BAR, lbm/bbl	267.00	223.90	283.30	141.89	120.00	232.30
Typical Drilling Fluid Properties						
Fluid Weight, ppg	13.1	12.5 - 13.2	13.1	11.4	9.8 - 11.1	12.5 - 13.3
Plastic Viscosity, cP	25 - 30	30 -35	25 - 35	20 - 25	18 - 25	34
Yield Point, lbs/100 ft^2	25 - 30	25 - 30	28 - 32	20 - 27	20 - 34	36
Gel Strength, lbs/100 ft^2	3-4 / 4-8	4-7 / 5-14	3-5 / 7-8	4-5 / 6-9	6 / 12	7 / 12
MBT, lbm/bbl	5 - 15	5 - 22.5	5 - 15	5 - 11.5	5 - 20	5 - 12
KCl, lbm/bbl	25 - 35	33 - 36	25 - 35	30 - 35	35	33
Chlorides, g/L	45 - 55	45 - 57	35 - 45	40 - 46	55	50
API Filtrate, cc	4.0 - 6.0	3.0 - 5.6	4.0 - 4.8	5.0 - 6.4	5.0	5.0 - 6.0
Pf / Mf, cc	0.2 - 0.6	0.2 / 0.6	0.4 / 1.2	0.2 / 0.4	0.3 / 1.0	0.05 / 0.15
pH	9.0 - 9.5	9.0 - 9.5	9.5	9.5 - 10.0	9.5 - 10.0	9.5
Volume Built and Dilution Rate						
Dilution Rate, bbl/ft	0.45	0.78	0.52	0.60	1.05	0.42
Total Volume Built, bbl	4022	7535	5063	3450	6809	4652

Hole Stability

All six wells showed good hole stability with logs, casing run, and cementing on all wells without incident. Trips off bottom in new hole were characterized by minor tight hole due to gauge conditions. To avoid delays, the new hole sections were pumped out using the top drive.

Further indications of the inhibition of the fluid system were the low dilution rates and minimal increase in MBT. There may be further cost savings on future wells if fluids are run with less dilution allowing MBT's to reach levels in the range 20 to 25 lbm/bbl. No dumping of whole fluid is expected to be a characteristic of future wells. On Well #29/7-5, the only additional fluid built was that to replace fluid lost on cuttings discharged over the shaker.

Chemical Discharge

Routine procedures are in place to measure the amount of oil fluid discharged with cuttings. Similar measures to record total water-base discharges are now in place. The use of AQUA-DRILL has resulted in dramatic reduction in the levels of chemical discharge. The typical offshore discharge figures for water-base fluid systems are shown below

Table 3-26 Typical Offshore Discharges Figures for Water Base Mud Systems

AQUA-DRILL	0.4 - 0.8 bbls/ft
KCl Polymer	0.8 - 1.5 bbls/ft
GYPSUM	2.0 - 4.0 bbls/ft

Logistics

Most polymer fluids are routinely shipped as premix concentrates from the shore based fluid plants. The use of AQUA-DRILL and the consequent reductions in fluid volumes have reduced the volumes required by 40% to 70%. Typically, one or two boat movements replace the previous four to eight.

Conclusions

The AQUA-DRILL System is a proven inhibitive fluid system. Increasingly demanding applications will establish the degree to which it can be considered a viable replacement for oil-base fluids. Relatively high initial make-up costs of the system are offset by reduced dilution requirements. Overall, a more stable wellbore and reduced chemical discharge to the sea is achievable. Additional benefits such as improved lubricity and reduced formation damage require further qualification in the field.

ALPLEX® – Aluminum-Based Shale Stabilizer

Introduction

Laboratory results and actual field experience have shown that aluminum compounds are viable additives in water-base fluid systems for reducing pore pressure transmission in shales via a mechanism similar to that of the PERFORMAX and AQUA-DRILL Systems.

Aluminum Chemistry

Under alkaline (high pH) conditions, aluminum sulfate or aluminum chloride form colloidal aluminum hydroxide. In addition, free aluminum ions are highly flocculating to clay particles found in drilling fluid. The high viscosity produced by these salts is unacceptable for drilling operations. Consequently, a *complex* reaction with the aluminum ion is needed to reduce its tendency to precipitate. “Complex” is the general term used for this new structure. Aluminum salts that have been reacted to form complexes are stable in alkaline environments. The degree of stability depends upon the complex agent, the fluid pH, and time. ALPLEX is soluble in the form of an aluminate ion, $Al(OH)_4^-$, at pH levels above pH 10. ALPLEX becomes insoluble in the form of aluminum hydroxide, $Al(OH)_3$, as pH decreases below pH 10. The pH of the connate water in shales is typically below pH 10, so the mechanism imparted by ALPLEX in plugging shale pores and micro fractures is driven by the change in pH from the drilling fluid and the formation. ALPLEX enters the pores and micro fractures in a soluble form, but then quickly forms an insoluble aluminum hydroxide precipitate (gel) with pH reduction in the shale matrix. Effectively, this precipitate acts as a barrier to prevent further fluid invasion (pore pressure increase) within the shale matrix. The concentration of ALPLEX must be measured using a Fluoride Selective Electrode (FSE) probe. Material (mass) balance CANNOT be used to accurately measure the ALPLEX concentration.

ALPLEX

Overview

ALPLEX is a dry aluminum complex, highly soluble in all water-base drilling fluids, designed to stabilize shales via a mechanism of reducing pore pressure transmission. Although some base exchange occurs, ALPLEX contains certain derivatives which are designed to form humic acid complexes that contribute to shale stabilization by complexation on basal hydroxides on the octahedral/tetrahedral sheets of formation clays (depending upon the clay type). The humic acid, by virtue of its chemistry will act as a dispersant and develops a needed low fluid viscosity without compromising the inhibitive/stabilization characteristics of the system.

The main mechanism of shale stabilization is driven by the chemical interaction of the high pH filtrate with low pH connate (pores and fractures) water. This reduction of the mud filtrate pH will cause the aluminum hydroxide to precipitate in the shale pores and micro-fractures. Basically the tetrahydroxyl aluminate, $Al(OH)_4^-$, that is present in the higher pH filtrate of an ALPLEX system will precipitate into an insoluble aluminum hydroxides $Al(OH)_3$ when exposed to lower pH connate water. This crystalline form of aluminum hydroxide blocks the filtrate invasion (reduction in pore pressure transmission) into the shale pores and micro-fractures, thus enhancing the shale strength by preventing it from swelling and/or disintegrating.

The alkalinity (pH) of the system should be managed using caustic soda, not ALPLEX. In freshwater systems, ALPLEX can be added directly through the mixing hopper. To increase its performance in salt water systems, the ALPLEX should be pre-solubilized in fresh water before adding it to the system. The pH of the freshwater should be increased to pH 10.5, using caustic soda, before adding ALPLEX to make the slurry.

ALPLEX increases shale inhibition in all water-based mud systems using freshwater, seawater, sodium chloride and other salts.

Application Guidelines

Basic Formulation

This basic formulation can be used in wells with bottom hole temperatures not exceeding 300°F. For higher BHT, special formulations may be required.

Table 3-27 Basic Formulation for ALPLEX Systems

Water	Fresh to saturated NaCl
MILGEL, lbm/bbl	5 - 15
NEW-DRILL, lbm/bbl	1 - 3
BIO-LOSE, lbm/bbl	2 - 3
XAN-PLEX D, lbm/bbl	As needed for desired yield point
Caustic Soda, lbm/bbl	As needed for pH 10.5
ALPLEX, lbm/bbl	1 - 6 depending on shale reactivity

Mixing Procedure

Freshwater System

ALPLEX can be added directly to the circulating system through the hopper. To achieve maximum effectiveness, the water should be treated for any possible hardness.

Seawater System

1. The seawater system should be pretreated with caustic soda and soda ash to precipitate any magnesium and calcium. The pH of seawater should reach pH 10.5, using caustic soda, to precipitate most of the magnesium. This will increase the performance of the PHPA and eliminate pH decreases due to magnesium.
2. The ALPLEX should be mixed in fresh water (treated with caustic soda for pH 10.5) at a high concentration (80 to 120 lbm/bbl) in the slug or separate pit and then fed slowly to the active system (10 bbls/hour+ depending on the total circulating time).

Note: Do not add ALPLEX directly to untreated seawater as it will not go into solution properly..

3. NEW-DRILL, MIL-PAC, or BIO-LOSE should be premixed in the pretreated brine water and sheared adequately to enhance the performance of the polymers and prevent any possible blinding of the shaker screens.
4. MIL-GEL should be pre-hydrated in fresh water to ensure good filter cake quality prior to adding it to the seawater system.
5. NEW-DRILL should be well sheared prior to drilling to minimize blinding over shaker screens.
6. MIL-PAC LV (0.75 to 1.0 lbm/bbl) can be substituted for BIO-LOSE (2 to 3 lbm/bbl).
7. XAN-PLEX should be used to increase yield point for better hole cleaning.
8. Use the FSE probe to measure the excess ALPLEX concentration.

Note: Due to its strong inhibition characteristics, the initial ALPLEX treatment will depend on the amount of solids in the initial fluid. In unweighted fluid (CEC < 10 meg/100 , less than 2% LGS) the initial ALPLEX treatment should be about 1 lbm/bbl. The desired ALPLEX concentration in the total system should be increased as drilling progresses. This measure will prevent a sharp drop in rheological properties. Use the FSE probe (not mass balance) to accurately determine the ALPLEX concentration.

Treatment and Maintenance

Maintenance of ALPLEX systems is generally dictated and directly proportional to the reactivity of the shale being drilled. The following are maintenance guidelines for an ALPLEX system.

1. The pH of fluid should be maintained above 10.0 with small caustic soda or ALPLEX additions. The pH typically varies between 10 and 11.5 depending on the ALPLEX® concentration.
2. Although the ALPLEX system is solids tolerant, the low gravity solids should be maintained at less than 6%.
3. Use XAN-PLEX for sweeps instead of MIL-GEL.
4. Use caustic soda to raise the pH of ALPLEX fluids.
5. In seawater or high salt ALPLEX systems, use premixed lignite in freshwater for additional filtration control. To avoid pH drop due to additional LIGCO (lignite), compensate with caustic soda using a 4:1 (lignite: caustic) ratio.

6. When the fluid system becomes depleted of ALPLEX®, any or a combination of the following may be observed:
    - The pH of the fluid drops below pH 10.0.
    - The cuttings over the shakers will become soft and sticky. Blinding of the shaker screens may occur.
    - The fluid viscosity and rheological properties will generally increase.
    - Tight spots, excessive torque and drag, and bit balling may develop.

Aluminum Determination by Fluoride Electrode

Equipment and Reagents

1. pH/mv Meter (Orion or instrument capable of using a fluoride electrode and having concentration mode capabilities)
2. Combination Fluoride Electrode with BNC connector - Orion 9609BN (currently supplied with Ionplus A Optimum Results filling solution
3. Reference Electrode Filling Solution - Orion Ionplus A Optimum Results filling solution (Orion 900061) or IONALYZER reference electrode filling solution (Orion 900001)
4. Plastic Pipette - 0.5 or 1.0 ml
5. Plastic Beakers (2) - 150 ml
6. Plastic Graduated Cylinder(2) - 50 ml
7. Pipette (3 ml) or 10cc plastic syringe
8. Potassium Fluoride Solution - 0.0010 M (10 Standard)

    Potassium Fluoride Solution - 0.010 M (100 Standard)
9. Acetic Acid/Potassium Acetate Buffer

Standards Preparation for Instrument Calibration

Note: Graduated cylinders, beakers, and pipettes should be rinsed with distilled water and dried between each use.

---

1. Place 30 ml of 0.0010 M(10 Standard) Potassium Fluoride solution into a plastic graduated cylinder.
2. Pour the 30 ml of 0.0010 M Potassium Fluoride solution into a plastic beaker.
3. Deliver by pipette or 10cc plastic syringe 3 ml of the Acetic Acid/Potassium Acetate Buffer into the plastic beaker of 0.0010 M Potassium Fluoride solution.
4. Swirl the beaker contents to ensure proper mixing. Allow the solution to set for five minutes.
5. Place 30 ml of 0.010 M (100 Standard) Potassium Fluoride solution into a plastic graduated cylinder.

6. Pour the 30 ml of 0.010 M Potassium Fluoride solution into a plastic beaker.
7. Deliver by pipette or 10cc plastic syringe 3 ml of the Acetic Acid/Potassium Acetate Buffer into the plastic beaker of 0.010 M Potassium Fluoride.
8. Swirl the beaker contents to ensure proper mixing. **Allow the solution to set for five minutes.**

Instrument Calibration, Measuring, and Electrode Care:

Electrode Preparation

The electrode is shipped without filling solution in the reference chamber. To fill from the flip-spout bottle:

1. Lift the spout to a vertical position.
2. Insert the spout into the filling hole in the outer sleeve and add a small amount of filling solution to the chamber. Tip the electrode to moisten the O-ring at the top and return electrode to a vertical position.
3. Holding the electrode by the barrel with one hand, use the thumb to push down on the electrode cap, allowing a few drops of filling solution to drain to wet the inner cone.
4. Release sleeve. If sleeve does not return to its original position immediately, check to see if the O-ring is moist enough and repeat steps 2-4 until the sleeve has returned to original position. Add filling solution up to the filling hole.
5. The probe is now ready for use

Add filling solution each day before using electrode. The filling solution level should be at least one inch above the level of sample in the beaker to ensure a proper flow rate. If the filling solution is less than one inch above the sample solution level, electrode potentials may be erratic.

Calibration Procedure for Orion Model 720A

1. Fasten the electrode into the appropriate jack on the meter.
2. Turn the instrument on and wait approximately one minute.
3. Press [1ST] and then press [MODE]. Continue to press [MODE] until the LCD reads “CON” (concentration).
4. Press [1ST], then press [CALIBRATE]. The instrument will display time, date, year, and when last calibrated. The instrument will then display the number of calibrators be used.
5. Place probe in the 0.0010 (10) standard solution.
6. Enter the # of calibrators to be used, in this case 2 , then press [YES]. The instrument will start to measure the concentration. A minute will elapse and the instrument will display “ENTER CONCENTRATION”. Enter (10) and press [YES].
7. Remove probe from the 0.0010 standard solution. Rinse the probe with distilled water and blot with a paper towel. DO NOT WIPE PROBE!
8. Place probe in the 0.010 (100) standard. After 1 minute, the instrument will display “ENTER CONCENTRATION”. Enter (100) and press [YES].
9. The instrument will start to show several displays. **Monitor the mv reading.** It should be within the range of 55-60. (If the mv reading falls outside this range, the electrode should be replaced.)

The instrument is now calibrated and you are ready to proceed with the analysis of your sample.

Calibration Procedure for Orion Model 290A

1. Connect electrode to meter.
2. Press **(power)** key to turn on meter.
3. Press the **(mode)** key until the CONC mode indicator is displayed.
4. Place the Fluoride Selective Electrode into the 10 standard.
5. Press **(2nd cal).** CALIBRATE and the time and date of the last calibration will be displayed. After a few seconds P1 will be displayed indicating the meter is ready for the first standard.
6. When the reading is stable use the scroll keys to enter the value of the standard. To enter a value, press the ∧ or ∨ key. The value will flash. Press the key again and the decimal point will. flash. Position the decimal then press **(yes)**. {Standard value is 10} Continue for each digit on the display. There are 4 1/2 digits plus a polarity sign and decimal point. The display will freeze for three seconds then P2 will be displayed in the lower field.
7. Rinse electrode and place into second standard. When the reading is stable enter the value of the second standard {100} using the ∧ **or** ∨ **and (yes)** keys. The reading will freeze for three seconds then P3 will be displayed.
8. Press **(measure).** The electrode slope will be displayed for a few seconds then the meter will advance to MEASURE mode.
9. Rinse electrode and place into sample. Wait for a stable reading, then record fluoride concentration directly from the main meter display. Record ALPLEX concentration from the **Fluoride electrode correlation chart**.

Sample Preparation for Analysis

1. Place 30 ml of 0.010 M (100 Standard) into a **plastic** graduated cylinder.
2. Transfer the 30 ml of solution to a **plastic** beaker.
3. With a **plastic** pipette, add 0.5 ml of sample (mud filtrate) to the beaker and swirl the contents to ensure proper mixing.
4. With 3ml pipette or 10cc syringe, add 3 ml of Acetic Acid/Potassium Acetate Buffer to the beaker.
5. Swirl the solution to ensure proper mixing.

ALLOW THE SOLUTION TO SIT FOR 5 MINUTES PRIOR TO TESTING.

* Repeat steps 1-5 for each sample analysis.

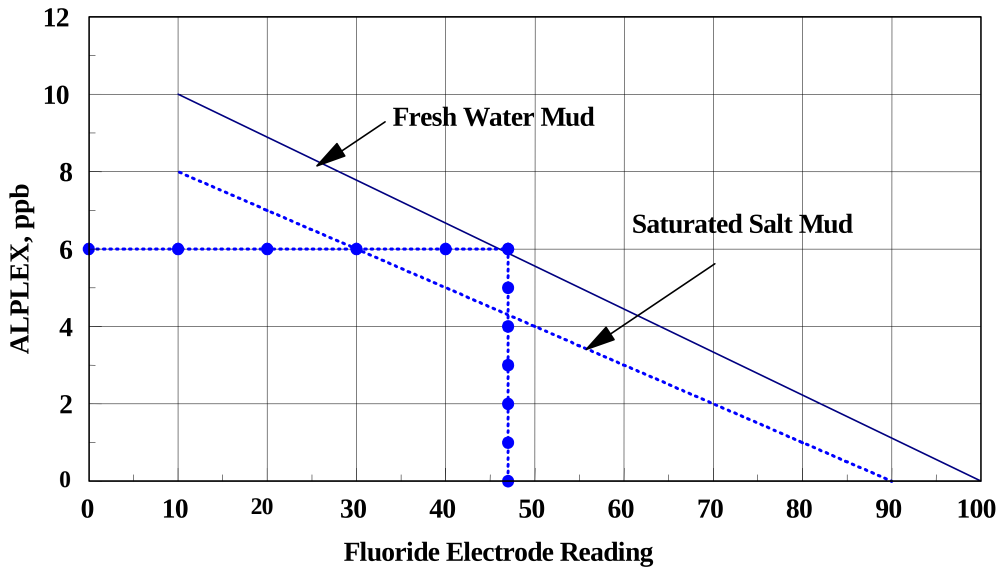
Sample Analysis

1. Rinse the electrode with distilled water between each analysis.
2. Blot probe dry, do not wipe dry.
3. Prepare samples as previously described in “D” above. Place the electrode in the sample and record sample readings after 1 minute.
4. Check calibration every 4 hours by analyzing the 100 standard.

5. Rinse electrode with distilled water and blot dry between each test.

Note: Should your concentration readings be greater than 100, you may have forgotten to add buffer..

Table 3-28 Fluoride Electrode Correlation Chart



Saturated Salt Curve Should Be Used When NaCl Concentration >18%

Example

1. Fresh water mud system is being
2. 0.5 ml of sample is
3. Concentration reading is equal to 47
4. Residual Alplex concentration is equal to 6

PERFORMAX^{SM} – High Performance Water Base Mud

Introduction

The introduction of cloud point glycols (AQUA-DRILL), aluminum complexes (ALPLEX) and finally sealing polymers (MAX-SHIELD and PERFORMAX) by Baker Hughes Drilling Fluids has greatly improved the osmotic effectiveness of water-based drilling fluids. Recent laboratory tests have demonstrated that some polymer emulsions exhibit a synergic effect with aluminum complexes, resulting in improved Pore Pressure Transmission (PPT) performance.

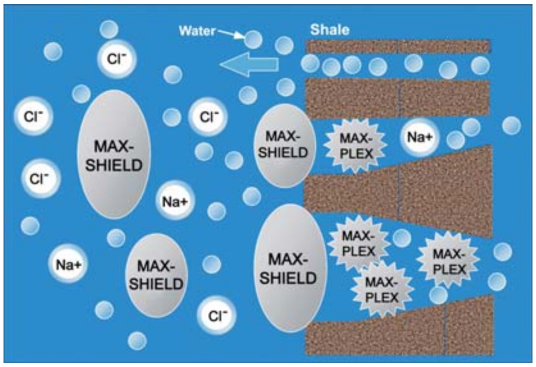
Drilling shales can result in a variety of problems from washout to complete hole collapse. Shales make up over 75% of drilled formations and over 70-90% of borehole problems are related to shale instability. Traditionally, oil-based muds (OBM) are the preferred choice for drilling argillaceous formations. Their application has been justified on the basis of borehole stability, penetration rate, filtration control, filter cake quality, lubricity, and temperature stability. As environmental regulations have restricted the use of diesel and mineral oil-based muds, synthetic and ester-based biodegradable invert emulsion drilling fluids were introduced in the 90’s.

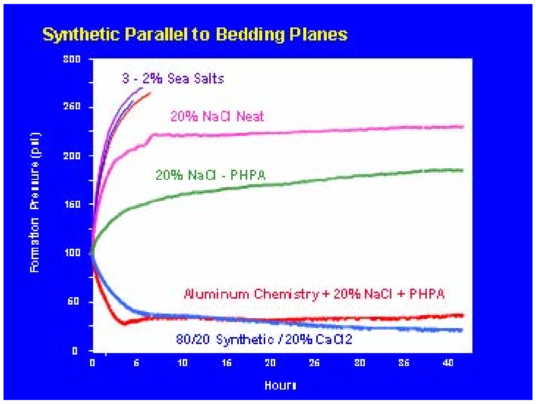
However, the costs associated with the use of environmentally acceptable, invert emulsions drilling fluid systems limit the application of such systems.

Water-based muds (WBM) are attractive replacements from both cost and environmental perspectives. However, conventional WBM systems have failed to meet key performance criteria obtained with OBM in terms of rate of penetration, bit and stabilizer balling, lubricity, filter cake quality, and thermal stability. Past efforts to develop improved WBM for shale drilling have been hampered by a limited understanding of the drilling fluid/shale interaction phenomenon. Recent studies of fluid-shale interactions, however, have produced fresh insights into the underlying causes of borehole instability. Experimental evidence reported by many researchers has shown that the chemical potential driving force, created from the activity difference between the drilling fluid and shale, can counteract the hydraulic driving force (the difference between the mud weight and pore pressure). A theoretical relationship, based on fundamental thermodynamic principles, has been postulated to support the experimental observations that osmotic pressure acts as a negative hydraulic pressure in its influence on water movement.

Overview of the PERFORMAX System

PERFORMAX is Baker Hughes Drilling Fluid’s 3rd generation high-performance water-base drilling fluid that is designed to emulate performance characteristics previously achieved only with emulsion based drilling fluids. These attributes include shale inhibition (reduced pore pressure transmission), cuttings integrity, high rates-of-penetration, and reduced torque and drag. Two features of PERFORMAXthat contribute to wellbore stability are: 1) ultra-fine, deformable sealing polymer particles in MAX-SHIELD (diameter: ~ 0.2 µ) that mechanically seal shale micro-fractures, which physically block further intrusion of drilling fluid filtrate into the shale matrix; and 2) the resin and aluminum complexes in MAX-PLEX, in combination with MAX-SHIELD, produce a semi-permeable membrane at the shale surface and chemically improve the osmotic efficiency, and reduce pressure transmission into shales.





Pore pressure transmission tests clearly show that MAX-SHIELD effectively works in combination with MAX-PLEX to achieve pore pressure transmission characteristics previously achieved only with emulsion-based drilling fluids (oil-based or synthetic-based).

PERFORMAX System Applications

Density:	Tested to a maximum density of 16lbm/gal (1.92 s.g.)
Salinity:	Tested to a maximum temperature of 300°F (149° C)

PERFORMAX™ fluids are compatible with sodium chloride concentrations up to saturation or potassium chloride up to 10% by weight. Sodium and Potassium Formate salts are also compatible.

Table 3-29 PERFORMAX System Products and Functions

PRODUCT	FUNCTION
MAX-SHIELD	Sealing polymer utilized to generate semi-permeable membrane for shale stabilization. Secondary function is as bridging material in pore throats of depleted sands to eliminate differential sticking and lost circulation.
MAX-PLEX	Aluminum and resin complex that works in combination with MAX-SHIELD™ to generate semi-permeable membrane and improve well stability.
NEW-DRILL®	Cuttings encapsulation and improve cuttings integrity
MAX-GUARD™	Amine-based material for suppressing the hydration and swelling of reactive clays and gumbo.
XAN-PLEX® D	A high-molecular-weight xanthan gum polysaccharide that includes an enhanced dispersibility feature used as an effective viscosifier in most waters regardless of salinity or hardness
PENETREX®	Reduce bit balling and increase rates-of-penetration
MIL-PAC™LV	Low-viscosity-grade PAC material to reduce API filtrate
MAX-TROL™	Sulfonated resin for HT-HP filtrate control

PERFORMAX Mixing Procedures at Liquid Mud Plant (LMP)

1. The use of a shearing device is recommended.
2. Remove all trash, solids, etc. from the water- base mixing tank
3. In a separate tank, add **fresh** water and treat hardness to < 200 mg/L with soda ash.
4. Pre-hydrate MILGEL® at a concentration of 30 lbm/bbl with a sufficient volume of water to achieve a concentration 3 lbm/bbl in the final mix. For example, if the total volume of finished mud needed is 2000 bbl. Multiply 2000 bbl by 3 lbm/bbl = 6000 lb. of gel. Divide 6000 lb. by 30 lbm/bbl = 200 bbl pre-hydrated gel required.) Allow gel to hydrate for a minimum of 3 hours after mixing. **Adjust pH of mixture to 10.8 – 11.0 with caustic soda.**
5. Transfer calculated volume of pre-mixed gel to give 3 lbm/bbl in the final volume to the clean mixing tank. For example, if the final volume in mix tank = 300 bbl. 300 bbl. * 3 lbm/bbl = 900 lb. 900 lb. / 30 lbm/bbl = 30 bbl pre-mix.)

If mixing mud system with sacked NaCl, add calculated amount of fresh water to mixing tank.

6. Add the recommended concentrations of products in the following order:
    - XAN-PLEX D
    - NEW-DRILL
    - MIL-PAC LV
    - MAX-SHIELD
    - MAX-GUARD
    - NaCl – continue shearing until salt is dissolved
    - Weighting agent
    - Adjust pH to 10.0 – 10.5 with caustic soda

If using saturated NaCl brine follow above directions to Step #5, then:

7. Add sufficient fresh water to pre-hydrate XAN-PLEX D, NEW-DRILL PLUS, MIL-PAC, and MAX-SHIELD. Allow chemicals to fully hydrate and solubilize.
8. Add calculated amount of saturated NaCl brine. **Check brine for Total Hardness and treat as necessary to reduce hardness**
9. Add NaCl to return salt concentration to 20% by wt.
10. Add MIL-BAR or other weighting agent.
11. Adjust pH to 10.0 – 10.5 with caustic soda

Note: **Do not add MAX-PLEX at the mud plant because it will deplete during transport. MAX-PLEX should be added in pre-hydrated form prior to or during the displacement.**

To prevent “fish eyes”, avoid rapid mixing of polymers unless a high-quality shear device is used. The mud should be blended in the mix tank until homogenous.

If mud tests are required by the operator, take samples and add MAX-PLEX before testing.

Premix Recommendations

The use of pre-mix is recommended to assure solubility and hydration of polymer and other water-soluble components. Below are recommendations for pre-mixes with the PERFORMAX System.

- In seawater or high-salt systems, MAX-PLEX should be added to the active system as a pre-mix at a concentration of 100 lbm/bbl.
- MAX-PLEX can be added directly to the mud system ONLY when using freshwater (low chlorides & hardness) as the makeup water.

- The bentonite content (via MBT) of the system should be less than10 lbm/bbl before adding MAX-GUARD. If not, then clay flocculation will occur as this product reacts with the reactive clays in the system. This will also consume (deplete) the concentration of MAX-GUARD in the system and require that additional product be added to have excess material available when drilling begins.
- NEW-DRILL LV, L or PLUS should be added at concentrations up to a 1.0 lbm/bbl in a freshwater premix, preferably using a shear device. Do not add NEW-DRILL products in pre-mix containing MAX-PLEX because prior work in field tests has indicated that blinding and loss of MAX-PLEX material over shaker screens is increased.
- MILPAC LV can be added to the NEW-DRILL premix at concentrations up 1 lbm/bbl.

Seawater Systems

Seawater should be pretreated with caustic soda and soda ash to a pH of 10.5 and to precipitate calcium and magnesium. MAX-PLEX should never be added directly to untreated seawater because elements in seawater will react with and delete an important component of MAX-PLEX.

System Maintenance

pH	The minimum pH for PERFORMAX™ is pH 10.5. If the pH falls below this level, then excessive depletion of MAX-PLEX™ will result. MAX-PLEX concentrations should be carefully monitored, using the FSE method, when adding products that cause pH to fall below minimum value. These include: LCM materials, lignosulfonates, and lignite. Treat system with caustic soda prior to addition of these materials to counter their pH-reduction effects. If PERFORMAX™ is subjected to temperatures above 230°F, then monitor flowline pH at one to two hour intervals to determine if pH reduction is occurring.
Deflocculants	Deflocculants such as ALL-TEMP® can be used to control rheological properties. However, such additives are acidic in nature and will reduce the pH of the system causing a depletion of MAX-PLEX™ concentration (see pH statement above), therefore treatment with caustic soda to adjust system pH to the proper level is recommended prior to the addition of MAX-PLEX™.
Hardness levels	Soluble Ca+2 and Mg+2 will cause precipitation of a component in MAX-PLEX™. Total hardness should be below 400 mg/L before MAX-PLEX™ is added to the system. Ideally, hardness will be below 100 mg/L. In some situations the presence of aluminum compounds can interfere with total hardness and calcium determinations. If indicator response is suspected, the use of a masking reagent (triethanolamine or tetraethylenepentamine) is recommended.

Cement Contamination	Although PERFORMAX™ is tolerant to cement contamination; drilling cement may cause depletion of the MAX-PLEX™. Citric acid is recommended as a treatment for cement contamination to maintain pH at 10.5 to 11.5. If the system is not displaced, hardness should be reduced below 400 mg/L with soda ash, and MAX-PLEX™ filtrate concentration should be checked by FSE. Increased MAX-PLEX™ treatments may be required in response to cement contamination.
MAX-SHIELD Additions	The particle size of MAX-SHIELD™ is very small and additions of MAX-SHIELD™ can cause a viscosity increase due the material effectively acting like a low gravity solid in the system. Always pilot test before adding MAX-SHIELD™ and other products to the system. Additionally, the rate that MAX-SHIELD™ is added to the system should be from 15 – 20 minutes per 55-gallon drum. The actual rate should be adjusted after pilot testing and monitoring viscosity as the material is added to the system.
MAX-SHIELD Concentration	MAX-SHIELD™ should be maintained at 2% to 4% by volume at all times. The MAX-SHIELD™ concentration should be monitored at all times using the concentrations tracking program on ADVANTAGE Drilling Fluids reporting package.
MAX-PLEX Concentration	The MAX-PLEX™ concentration is measured by a fluoride selective electrode (FSE) method. The rate of MAX-PLEX™ depletion is related to drilling, dilution and formation consumption rates. Variables effecting the depletion of MAX-PLEX include: 1) rate of penetration, 2) hardness levels and 3) pH levels.
MAX-GUARD Concentration	MAX-GUARD™ is a liquid clay hydration suppressant that provides superior clay inhibition and low dilution rates. The recommended concentration of MAX-GUARD™ is 2 - 3% by volume, and will vary based on hole size, rates-of-penetration and reactivity of the formation being drilled.

Handling recommendations for MAX-SHIELD

- All MAX-SHIELD containers which have been opened should be added to the mud. Partially-full containers of MAX-SHIELD should not be returned to warehouse.
- Containers of MAX-SHIELD should not be exposed to extremely cold temperatures or allowed to freeze.

pH Level Recommendation: The pH should be maintained, using caustic soda (NaOH) at 10.6 to 11.3 at all times, while the optimal pH is 11.0. The pH should be monitored at the flowline frequently, particularly when drilling at high rates-of-penetration or when adding products that reduce pH and/or deplete MAX-PLEX. The pH electrode should be calibrated with buffers at pH 7.0, 10.0 and 12.5. Measurement of mud pH should be performed on a 50/50 dilution of whole mud with de-ionized water or whole mud using a high salinity electrode.

Recommended Lubricant: TEQ-LUBE and MIL-LUBE are recommended lubricants for this system. Recommended treatment is 2 to 3% by volume. If other lubricants are to be used, pilot tests should be conducted before the product is added to the mud system. In general, water soluble products will be more compatible with PERFORMAX.

Acid Gases: Lime or gypsum additions, in combination caustic soda, can be used to treat carbon dioxide contamination. Be sure to check the concentration of MAX-PLEX in the system whenever treating with lime or gypsum, since these products deplete the aluminum component in MAX-PLEX. Gypsum may also cause some flocculation of the fluid, but this can be corrected with treatments of 0.5 to 2 lbm/bbl of ALL-TEMP.

MIL-GARD may be used for hydrogen sulfide intrusion.

The PERFORMAX system may be prepared for various applications with salinity as high as saturation for compatible salts. Actual formulations can be adjusted to meet specifications for density, salinity, and temperature applications. Laboratory pilot tests should be prepared following the order of addition and mixing times.

Table 3-30 PERFORMAX System Products and Concentrations

Component	Concentration	Function and Description
Fresh water or Sea water*	—	—
Caustic Soda	0 – 1 lbm/bbl	As required for pH control
Soda Ash	0-.5 lbm/bbl to treat seawater	Removal of soluble calcium
XAN-PLEX™D	0.2 – 0.5 lbm/bbl	Viscosifier
MILGEL® NT	5 – 10 lbm/bbl	Viscosifier for > 250°F
	3 - 8 lbm/bbl	New volume at liquid mud plant
NEW-DRILL® LV	0.3 – 1 lbm/bbl	Cuttings Encapsulate
MAX-SHIELD™	2 – 4 % by volume	Shale inhibitor
MAX-PLEX™	4 – 8 lbm/bbl	Shale inhibitor
MIL-PAC® LV	0 – 2 lbm/bbl	API Fluid loss control
MAX-GUARD™	2 – 3 % by volume	Clay swelling inhibitor
PENETREX®	By injection, up to 3% by volume	ROP Enhancer
NaCl	0 – 109 lbm/bbl	Shale inhibitor
MAX-TROL™	0 – 8 lbm/bbl	HTHP FL control at high salt
MIL-BAR®	As required for density	Weighting agent
LD - S	As required to control foaming	Silicone Defoamer

Contamination and High Temperature Aging

Laboratory testing indicates that the PERFORMAX system remains stable after solids, cement, and carbon dioxide contamination. Aging at 300°F conducted on a low density seawater system showed excellent properties after aging.

Product Compatibility

TEQ-LUBE®, MIL-LUBE® and NF3™ are recommended for increased lubricity and gas hydrate control, respectively. Although the PERFORMAX system is compatible with most standard products use in water-based mud system, some products are not compatible with this system and should not be used. PENETREX® should be added at a steady rate (i.e. 0.25 – 0.5 GPM) with an injection pump while drilling and sliding. The goal is to add the PENETREX continuously so that there is always a small amount of the product exiting the bit.

Return Permeability Testing

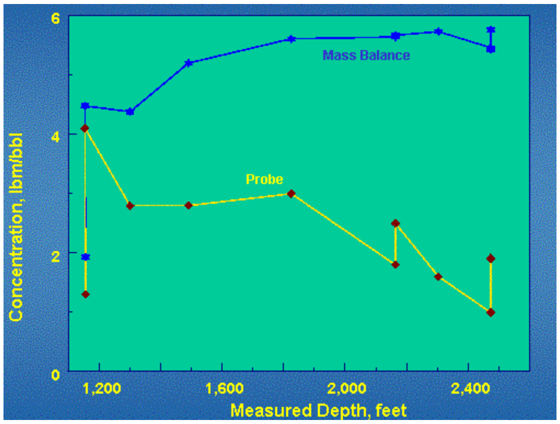
PERFORMAX fluids have been tested for return permeability using LVT 200 mineral oil on a Berea Sandstone core. Return permeability was greater than 90 percent for the 12 lb/gal fluid shown below. However, until reservoir characteristics of the PERFORMAX system are better understood, this drilling fluid system should be used for cased hole completions only. If an open hole completion is anticipated, PERFORMAX should be displaced with a PERF*FLOW*® system.

Table 3-31 Return permeability on Berea Sandstone for 20% NaCl, 12 lb/gal PERFORMAX™

Component	Concentration
NaOH, lbm/bbl	0.4
NEW-DRILL®PLUS, lbm/bbl	0.4
XAN-PLEX® D, lbm/bbl	0.5
BIO-LOSE®, lbm/bbl	2
MAX-TROL™, lbm/bbl	8
MAX-PLEX™, lbm/bbl	6
MAX-SHIELD™, volume %	3
ALL-TEMP®, lbm/bbl	1
NaCl, lbm/bbl	61
MIL-BAR®, lbm/bbl	146
MAX-PLEX™ in API filtrate, cm^3/30 min	3.5
% Return permeability, 200°F, 500 psi	97

MAX-PLEX™ or ALPLEX® Determination by Fluoride Electrode

The concentration of MAX-PLEX in the filtrate can be determined by using a fluoride selective electrode procedure. This method indirectly determines the MAX-PLEX concentration by converting aluminate to aluminum cations, which then react with fluoride anions to produce a mixture of aluminum fluoride species. The fluoride ion excess is correlated to the available MAX-PLEX concentration by means of a chart. An FSE probe must be used to accurately determine the “actual” concentration of MAX-PLEX in the system because the material is depleted (consumed) during drilling. The graph to the right shows a comparison of MAX-PLEX concentration using a mass balance vs. FSE method of determining the available concentration of MAX-PLEX in the system. This example clearly shows that the “actual” concentration of available aluminate in MAX-PLEX (or ALPLEX) cannot be accurately determined using a mass balance approach to determine product concentration. The only accurate method to determine available MAX-PLEX (ALPLEX) is to use the FSE probe.



Equipment and Reagents

1. pH/mv Meter (Orion or instrument capable of using a fluoride electrode and having concentration mode capabilities)
2. Combination Fluoride Electrode with BNC connector - Orion 9609BN (currently supplied with Ion plus A Optimum Results filling solution
3. Reference Electrode Filling Solution - Orion Ion plus A Optimum Results filling solution (Orion 900061) or IONALYZER reference electrode filling solution (Orion 900001)
4. **Plastic** Pipette - 0.5 ml
5. **Plastic** Beakers (2) - 150 ml
6. **Plastic** Graduated Cylinder(2) - 50 ml
7. Pipette (3 ml) or 10cc plastic syringe
8. Potassium Fluoride Solution - 0.0010 M (10 Standard)
9. Potassium Fluoride Solution - 0.010 M (100 Standard)
10. Acetic Acid/Potassium Acetate Buffer

Standards Preparation for Instrument Calibration

Note: Graduated cylinders, beakers, and pipettes should be rinsed with distilled water and dried between each use.

1. Pour the 30 ml of 0.0010 M Potassium Fluoride solution into a plastic beaker.
2. Deliver by pipette or 10cc plastic syringe 3 ml of the Acetic Acid/Potassium Acetate Buffer into the plastic beaker of 0.0010 M Potassium Fluoride solution.
3. Swirl the beaker contents to ensure proper mixing. Allow the solution to sit for five minutes.
4. Place 30 ml of 0.010 M (100 Standard) Potassium Fluoride solution into a plastic graduated cylinder.
5. Pour the 30 ml of 0.010 M Potassium Fluoride solution into a plastic beaker.
6. Deliver by pipette or 10cc plastic syringe 3 ml of the Acetic Acid/Potassium Acetate Buffer into the plastic beaker of 0.010 M Potassium Fluoride.
7. Swirl the beaker contents to ensure proper mixing. Allow the solution to sit for five minutes.

Instrument Calibration, Measuring, and Electrode Care

Electrode Preparation

The electrode is shipped without filling solution in the reference chamber. To fill from the flip-spout bottle:

1. Lift the spout to a vertical position.
2. Insert the spout into the filling hole in the outer sleeve and add a small amount of filling solution to the chamber. Tip the electrode to moisten the O-ring at the top and return electrode to a vertical position.
3. Holding the electrode by the barrel with one hand, use the thumb to push down on the electrode cap, allowing a few drops of filling solution to drain to wet the inner cone.
4. Release sleeve. If sleeve does not return to its original position immediately, check to see if the O-ring is moist enough and repeat steps 2-4 until the sleeve has returned to original position. Add filling solution up to the filling hole.
5. The probe is now ready for use.
6. Add filling solution each day before using electrode. The filling solution level should be at least one inch above the level of sample in the beaker to ensure a proper flow rate. If the filling solution is less than one inch above the sample solution level, electrode potentials may be erratic.

Calibration Procedure for Orion Model 290A

1. Connect electrode to meter.
2. Press **(power)** key to turn on meter.
3. Press the (**mode)** key until the CONC mode indicator is displayed.
4. Place the fluoride selective electrode into the 10 standard.
5. Press **(2nd cal).** CALIBRATE and the time and date of the last calibration will be displayed. After a few seconds **P1** will be displayed indicating the meter is ready for the first standard.
6. When the reading is stable use the scroll keys to enter the value of the standard. To enter a value, press the ∧ or ∨ key. The value will flash. Press the key again and the decimal point will. flash. Position the decimal then press **(yes)**. {Standard value is 10} Continue for each digit on the display. There are 4 1/2 digits plus a polarity sign and decimal point. The display will freeze for three seconds then **P2** will be displayed in the lower field.
7. Rinse electrode and place into second standard. When the reading is stable enter the value of the second standard {100} using the ∧ **or** ∨ **and (yes)** keys. The reading will freeze for three seconds then **P3** will be displayed.
8. Press **(measure).** The electrode slope will be displayed for a few seconds then the meter will advance to MEASURE mode.
9. Rinse electrode and place into sample. Wait for a stable reading, then record fluoride concentration directly from the main meter display. Record MAX-PLEX concentration from the **FLOURIDE ELECTRODE CORRELATION CHART**.

Sample Preparation for Analysis

1. Place 30 ml of 0.010 M (100 Standard) into a **plastic** graduated cylinder.
2. Transfer the 30 ml of solution to a **plastic** beaker.

3. With a **plastic** pipette, add 0.5 ml of sample (mud filtrate) to the beaker and swirl the contents to ensure proper mixing. If mud filtrate is going to be saved for future fluoride electrode testing the filtrate should be retained in a plastic container. The mud filtrate should never be stored in a glass container due to the tendency of the aluminum complex to adhere to the glass surface.
4. With 3ml pipette or 10cc syringe, add 3 ml of acetic acid/potassium acetate buffer to the beaker.
5. Swirl the solution to ensure proper mixing.

Allow the solution to sit for 5 minutes prior to testing.

Repeat steps 1-5 for each sample analysis.

Sample Analysis

1. Rinse the electrode with distilled water between each analysis.
2. Blot probe dry, do not wipe dry.
3. Prepare samples as previously described in "D" above. Place the electrode in the sample and record sample readings after 1 minute.
4. Check calibration every 4 hours by analyzing the 100 standard.
5. Rinse electrode with distilled water and blot dry between each test.

Note: Should your concentration readings be greater than 100, you may HAVE FORGOTTEN to add buffer.

Reinecke Salt Test Procedure for Residual MAX-GUARD™ in PERFORMAX™ Filtrates

Equipment and Materials;

1. Reinecke salt
2. Volumetric flask – 100 ml
3. Deionized water
4. Pipettes
5. Syringes (optional)
6. Sample of MAX-GUARD™

Procedure

1. Prepare a solution of the Reinecke Salt indicator solution by dissolving approximately 3% by weight of the Reinecke salt material into deionized water (or 0.75 g per 24.25 ml water). Small amounts of the solution should be prepared since the shelf life is about 7–10 days at temperatures below 65°F. Shelf life decreases rapidly above this temperature. It is recommended to store the solution in a refrigerator, if possible, when not in use. (Please note: you will see some apparent insoluble materials at the bottom of the container; ignore).
2. In a small vial or bottle, place about 2 ml water, 8 drops of Reinecke salt solution and 0.5 ml of the mud filtrate and shake.

3. If residual MAX-GUARD is present, a precipitate will be observed. A strong precipitate will indicate at least 1 lb/bbl excess.
4. A standard solution of MAX-GUARD in water (at 1 or 2 lb/bbl) could be prepared and tested accordingly. This can give a visual indication of what to expect for the amount of precipitation and compare to the test filtrate results.

Photographs of test results are described below

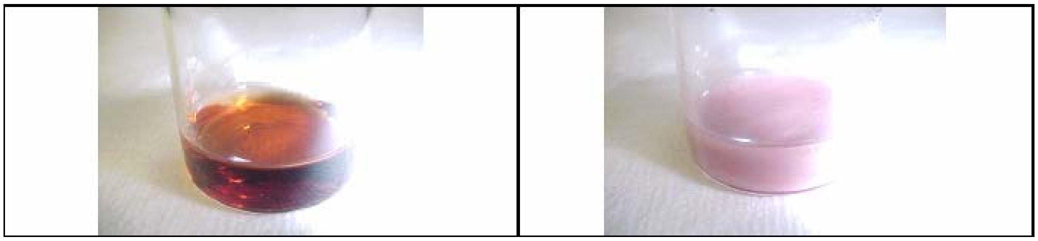


Figure 3-23 Reinecke Salt Results

PERFORMAX filtrate PERFORMAX filtrate:

Tested with Reinecke Salt:

positive results for residual MAX-GUARD

Note: UV measurement of 0.8 lb/bbl residual for above filtrate.

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Chapter Four

Contamination of Water–Base Muds

Chapter 4

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Chapter 4

Contamination of Water-Base Muds

The composition and treatment of drilling fluids depends on the formation encountered or material added during drilling operations. Some of these materials under certain circumstances, along with formation cuttings, can be considered contaminants. This chapter summarizes the various chemical contaminants and describes methods of chemical control and removal of water-soluble contaminants.

Contaminant Overview

If large quantities of contaminants are encountered during drilling, certain factors must be taken into account depending on the contaminant, and the impact it has on the constituents of the drilling fluid resulting in a deviation from the desired fluid properties. These factors are considered individually in the following discussion of each type of contaminant. However, it should be noted that it is not unusual to experience more than one contaminant at a time, which requires an analytical approach to identify and rectify the contaminants.

In general, a contaminant is anything that causes undesirable changes in fluid properties. Any of the liquid, chemical, or solid components of water-base fluids can become a contaminant in some given situation.

Solids are by far the most prevalent contaminant. Commercial bentonite added in excess, drill cuttings, or barite may lead to unacceptable rheological and filtration properties and affect the drilling operation. Water or excess chemical treatment can lead to unacceptable fluid changes and cause unscheduled viscosifier additions.

The contaminants of interest are those which require chemical treatment. Chemical treatments to remove these contaminants are possible for some and impossible for others. The important rule is that treatment must match the contaminant and result in a desired effect on the fluid.

Some contaminants can be predicted and pretreated to control them. The predictable contaminants are cement, bad make-up water, massive salt, anhydrite formations, or gases such as hydrogen sulfide and carbon dioxide in areas where documentation shows a probable presence. These contaminants can be chemically removed in some cases before they can have an overall negative effect on the clays, organic deflocculants, and/or filtration additives. Pretreatment has advantages as long as it is not excessive and does not adversely affect fluid properties. Pre-treating a fluid with sodium bicarbonate before drilling cement is one example. By the same token an over treatment of sodium bicarbonate as a pretreatment can also become a contaminant.

Other contaminants are unpredictable and unexpected, such as those which result from small feed-ins with a gradual build-up of a contaminant. Predicting potential contamination problems while drilling an exploration well is difficult. The contaminant shows its effect by altering the properties of the system and, in part, is determined by the resultant properties. When deflocculants are slightly depleted, or after a long trip when the fluid is allowed to remain stagnant and subjected to elevated downhole temperatures, or after additional contaminant enters the system, changes become evident. It is always necessary to keep complete, accurate records of drilling fluid properties to see the gradual onset of contamination and avoid deterioration of an otherwise good system.

Rig site oven testing provides necessary data for monitoring and treatment purposes. Before reviewing the types of chemical water fluid contaminants and their treatment, you may want to reread Chapter 3, *Water Base Drilling Fluids***,** which contains some fundamental principles and basic definitions of water-base drilling fluid chemistry.

Calcium / Magnesium Contamination

The calcium and magnesium ions can be a major contaminant of water-base drilling fluids. Both are divalent cations which attack clay and high molecular weight polymers by the same mechanism. Calcium can enter the fluid as part of the make-up water or while drilling cement, anhydrite, or gypsum. Also, connate water from penetrated formation and saltwater flows often contain calcium ions and can become sources of calcium contamination. Magnesium can be found in make-up water, formation water, and in formations such as the carnolite salt of the Zechstein formations in the North Sea, and drilling operations in Saudi Arabia. In most sources of cationic contamination the contaminant is a mixture of cations and normally one is more dominate in concentration than the others. As in the case of the Zechstein formation it can vary from almost pure sodium chloride to predominately magnesium and potassium salts.

Calcium contamination changes the nature of freshwater clay-based systems as shown by rheology and/or filtration control problems. The calcium ion tends to replace the sodium ions through Base-Exchange, which results in flocculation and aggregation of the clay particles. The bound layer of water between the clay platelets is also reduced, resulting in diminished hydration or swelling characteristics.

The effects of calcium or magnesium contamination on deflocculated fluids include,

- increased fluid loss values
- increased yield values
- increased gel strengths.

The severity of calcium or magnesium contamination (the degree to which this contaminant will affect the fluid properties) will depend upon,

- the amount of the contaminating ion
- the amount, type, and distribution of solids
- the type and quantity of drilling fluid additives present in the system.

Calcium contamination originating from make-up water, formation water, or anhydrite is usually treated with soda ash (.093 lb_m/bbl per 100 mg/L Ca^{++}) or sodium bicarbonate (0.0735 lb_m/bbl per 100 mg/L Ca^{++}). If the pH is below 10.0, the test specific to calcium should be employed (Betz indicator, NaOH, and triethanolamine solution) to insure magnesium is not present. Approximately 100 mg/L of Ca^{++} should be left in the system to avoid over treatment. Excessive soda ash treatment results in excess soluble carbonates, which could lead to rheological and filtration control problems.

Magnesium, most often encountered when seawater is used as make-up water, has a similar adverse effect on the fluid properties as does calcium. Magnesium can be precipitated with caustic soda as insoluble $Mg(OH_2)$. Theoretically, one-half pound of caustic soda per barrel of fluid will precipitate approximately 430 mg/L of magnesium. Most of the magnesium ion will be precipitated when the pH is increased to the 10.0 pH range. Other sources of magnesium are saltwater flows and field brines. Generally, dilution, additional filtrate control agents, deflocculants and caustic soda are required to restore the drilling fluid properties after magnesium contamination.

Cement Contamination

In most drilling operations cement contamination occurs when the casing is cemented and cement plugs are drilled out. If the plug is drilled while it is still green, the severity of calcium contamination can be very high, as is the case when displacing should the cement return not be diverted before it communicates with the active system. The extent of contamination and its effect on fluid properties depends on solids content and type, concentration of deflocculants, concentration of pretreatment chemical, and the quantity of cement incorporated.

Cement contains compounds of tri-calcium silicate, calcium silicate, and tri-calcium aluminate, all of which react with water to form large amounts of calcium hydroxide $Ca(OH)_2$. It is the calcium hydroxide (lime hydrate) in solution that causes most of the difficulty associated with cement contamination.

Lime in drilling fluids causes chemical reactions which can be detrimental to rheological and fluid loss properties. The presence of OH^- ions increases the pH and the calcium ion affects clay characteristics. Significant pH increases could lead to a *pH shock*. Some polymers such as Xanthan gum or PHPA are sensitive to higher pH levels and their chemical state is altered if pH is too high. If cement contamination reaches a level where it is no longer practical to be treated out, the most contaminated fluid should be discarded. In extreme cases it may be necessary to displace the entire system or convert it to a calcium based fluid (lime mud).

Freshwater, bentonitic systems will be flocculated by cement, resulting in increased rheology and fluid loss. The severity of flocculation depends upon the factors mentioned above. If cement contamination reaches a level where it is no longer practical to treat it out, dump the most contaminated fluid, displace the entire system out, or treat the system as a calcium-based fluid.

To maintain a low-calcium drilling fluid, chemical treatment must be used to remove cement contamination. The aim of treatment is to control pH while removing calcium and excess lime from the system as an inert, insoluble calcium precipitate.

Be aware that 100 lb of cement can potentially yield 79 lb of lime which is then available to react with the drilling fluid. The volume of one sack of cement (94 lb) in most cases is 1.1 cu ft when set. So, if you know the volume of cement drilled, you can make better predictions of the type of treatment. This can be done by assuming the maximum quantity of cement which could be put into the system from drilling the cement. For instance, if the diameter to be drilled is 8.5 in., each foot of hole contains 0.394 cu ft of cement, or 33.7 lb of cement, or 26.5 lb of lime. This is the maximum amount of lime that can be put into the system, assuming that all the cement drilled is incorporated. When cement is completely set, assume 10% is normally available for contamination. When cement is still soft (commonly referred to as “green” cement), as much as 50% of the cement could be dispersed and available to react with the fluid.

To chemically remove 100 mg/L of calcium originating from cement would require approximately 0.0735 lb_m/bbl of bicarbonate of soda or 0.097 lb_m/ bbl of SAPP. Lignite (LIGCO®) will also react with lime to form a calcium salt of humic acid. Approximately 1 lb_m/bbl of lime can be precipitated with 7 to 8 lb of lignite. Treatments in excess of this range are not recommended since calcium salts of humic acids may also create viscosity problems at higher concentrations.

Excess lime can be estimated from the filtrate alkalinity (P_f), fluid alkalinity (P_m), and volume fraction of water by retort analysis (F_w) by the following equation.

$$\text{Excess lime, } lb_m/bbl = 0.26\,(P_m - F_w\,P_f)$$

Pretreating can present a problem, since it is difficult to predict the extent of contamination prior to drilling the cement. Overtreating with bicarbonate of soda or SAPP could be as detrimental to drilling fluid properties as cement contamination. Therefore, it is not advisable to pretreat with more than 0.5 to 0.75 lb_m/bbl of bicarbonate of soda. Materials such as UNI-CAL® and LIGCO are also suitable pretreating agents because they buffer the pH and aid in deflocculating the system.

Consideration also should be given to low-gravity solids content prior to drilling cement since high clay solids content is a primary cause of flocculation when cement contamination occurs. This could be particularly evident in lightly treated or under-treated fluids or high-density fluids. Reduction of low specific gravity solids, if high, is recommended as a defense against severe flocculation.

Because pH values are high when drilling cement, the quantity of calcium ion in solution may not exceed 200 to 400 mg/L. For this reason, much of the cement drilled remains as discrete particles and is available to replace the calcium that has been treated out of solution. High concentrations of excess lime may require many days to remove, particularly if mechanical solids removal devices, i.e., fine screen shakers, hydrocyclones, or centrifuges are not used.

If cement contamination occurs immediately prior to well completion, it may be necessary to replace the fluid in the hole with an uncontaminated drilling fluid to serve as a packer fluid, should testing indicate a high temperature gellation problem.

One approach to avoid over-treatment with bicarbonate of soda or SAPP is to treat only the soluble calcium ion on a circulation basis and treat the lime particles (cement) that subsequently go into solution on additional circulations. Generally, treatments should be discontinued when excess lime approaches the 0.3 to 0.5 lb_m/bbl range.

Sometimes, cement contamination is simply allowed to work its way out of the fluid over several days without “extra” chemical treatment. A well treated fluid could give enough protection against cement contamination and the often observed rheology and filtration control problems. Higher Ca^{++} measurements, relatively high pH values, and relatively higher P_m measurements could be carried for some time without rheology or filtration control problems with a well-treated fluid.

Chemical removal of calcium ion with bicarbonate prevents further contamination, but may not eliminate the rheological problems caused to a dispersed system. It is usually necessary to treat with deflocculants, such as UNI-CAL, UNI-CAL CF, DESCO, or MIL-TEMP® (or ALL-TEMP®) to obtain the desired rheological properties. Materials, such as CHEMTROL® X, LIGCO, prehydrated MILGEL® slurries containing UNI-CAL, CMC, or MIL-PAC™ LV could be used to bring filtration and filter cake characteristics back to the required levels.

A significant problem that may occur as a result of cement contamination is high-temperature solidification. Since testing at ambient temperature might not identify this problem, tests which simulate downhole conditions should be run. The FANN Consistometer, FANN Model 70, and Chandler 7600 XHPHT Mud Viscometer simulate downhole temperature, shear, and pressure conditions, and should be used to support wellsite testing. These tests give an indication of solidification tendencies. To determine remedial treatments, it is recommended that pilot testing procedures include hot rolling and static aging testing when possible. Hot rolling and static aging testing more accurately simulate reactions which occur in the drilling fluid at elevated temperatures.

Oven testing of a fluid can be done at the wellsite and, on many wells, is considered standard operating procedure. Timely test results are the key for making quicker adjustments to the fluid. MIL-TEMP® (or ALL-TEMP®) has been found to be an excellent product in cement contaminated drilling fluids to decrease the gel strength and high-temperature gelation properties. Generally, about 1 to 3 lb_m/bbl of MIL-TEMP® can correct the flow properties of a cement contaminated system. MIL-TEMP is a higher temperature application product and generally is not used for temperatures lower than 250°F to 300°F.

Anhydrite-Gypsum Contamination

Anhydrite and gypsum, both calcium sulfate compounds ($CaSO_4$), are sometimes encountered while drilling. Gypsum is calcium sulfate with water of crystallization ($CaSO_4$+$2H_20$), while anhydrite is the anhydrous form of calcium sulfate (without water). Anhydrite may occur as thin stringers. In some areas, it occurs as massive beds ranging from 100 to 800+ feet thick. Anhydrite has also been associated with salt (stringers, inclusions, overhang, massive salt, etc.) and could signal potential salt contamination.

Anhydrite contamination contributes calcium ions, which could result in flocculation. Unlike cement anhydrite does not cause a pH increase since it supplies a sulfate radical in lieu of an hydroxyl radical. The sulfate radical contributes to flocculation of clay solids only marginally.

In lightly treated fluids, small amounts of anhydrite increase the rheological properties of a fluid. The severity of change depends to a great degree on the bentonite content and solids particle size distribution. When anhydrite goes into solution and soluble calcium increases above 200 mg/L, viscosity may fluctuate noticeably and fluid loss could become more difficult to control. As anhydrite concentrations increase toward a maximum solubility of approximately 600 mg/L Ca^{++}, a *Base Exchange* or change in bentonite characteristics occurs. Flow properties tend to decrease, and fluid loss becomes difficult to control. Conversion to a gypsum-based fluid has occurred. If a gypsum fluid is acceptable, then treatments should be made specifically for a gypsum fluid.

When anhydrite contamination occurs, there are several methods for handling it. The drilling fluid can be maintained as a low-calcium fluid by chemically precipitating most of the calcium from solution, or it can be converted to a gypsum-type system. For smaller amounts of anhydrite contamination, chemical removal of calcium is best achieved by adding soda ash. Approximately 0.093 lb_m/bbl of soda ash is required to precipitate 100 mg/L of Ca^{++} ion, but caution should be exercised to avoid over-treatment. When Ca^{++} ions are reduced to 100 to 150 mg/L, consider stopping soda ash treatment. The reaction between anhydrite and soda ash is as follows.

$$CaSO_4 + Na_2CO_3 \rightarrow CaCO_3\downarrow + Na_2SO_4$$

Remember, pilot testing should support treatment specific to anhydrite contamination.

Soluble sodium sulfate is formed from this reaction and could cause flocculation problems with prolonged treatments. For this reason, it is sometimes necessary to convert to a gypsum-base fluid when massive anhydrite is to be drilled with a freshwater system. Over treatment with soda ash can also cause a carbonate problem.

Salt Contamination

Salt contamination may be a result of make-up water, drilling salt stringers, inclusions, overhangs, massive salt, or saltwater flows. Where solid salt is drilled in large quantities or where economic considerations call for the use of salt make-up water, salt water-base drilling fluid systems are used. In these cases, salt is not a problem. However, in freshwater fluids, salt becomes a contaminant.

Salt and saltwater flow contamination cannot be removed from a drilling fluid by economical chemical means. The harmful effect of salt on freshwater fluids is not so much the chemical reaction effect of the ions as it is the mass ion electrolytic *effect* which changes the charge distribution at the clay surfaces and promotes flocculation. The resulting flocculation causes an increase in rheological properties and fluid loss. With higher concentrations of UNI-CAL®, rheological characteristics tend to remain stable if the solids are in range, although fluid loss may increase.

As high concentrations of salt are encountered, the Na^+ and Cl^- ions become more abundantly attached or congregate near the clay surfaces and, through “mass action,” gradually dehydrate the reactive solids in the fluid. The shrinkage effect on the clays may then cause decreased viscosity and continued increase in fluid loss.

Since salt cannot be precipitated by economical chemical means, salt concentration can be reduced only by dilution with freshwater.

The choice of reconditioning agents for salt contamination in freshwater fluids depends on the severity of contamination. Lightly treated UNI-CAL® drilling fluid systems can usually tolerate up to a concentration of 10,000 mg/L salt as long as the colloidal reactive solids are at a reasonable level for the fluid weight being used. As the salt content increases above 10,000 mg/L, rheological and fluid loss properties become increasingly difficult to control. When higher salt content is expected or accidentally encountered, an increase in UNI-CAL® is necessary. The alkalinity of the system should be slightly higher in salt-contaminated drilling fluids to allow better UNI-CAL® solubility.

Maintaining a salt system is much easier if all chemicals, i.e., deflocculants, filtration control additives, viscosifiers, etc. are presolubilized or prehydrated in a premix tank. When a saltwater flow is encountered, the high concentration of Na^+ ions tends to replace some of the H^+ and Ca^{++} ions at the clay surfaces which slightly reduces the pH and may increase the soluble Ca^{++}.

Fluid loss is often difficult to control with salt contamination. Prehydrated bentonite and polymer-type materials are helpful in this situation but should be added in moderation since they can increase rheological properties.

Almost all saltwater flows contain some cations other than Na^+. Calcium and/or magnesium are commonly present. Their effects have been previously discussed.

Carbonate / Bicarbonate Contamination

Under some conditions, large amounts of soluble carbonates or bicarbonates can accumulate in drilling fluid systems. These ions can adversely affect fluid properties in much the same way as salt or calcium sulfate. Carbonates may come from over-treatment to remove calcium or cement contamination. Carbon dioxide gas could be present in certain formations drilled and the carbonates are formed as a result of the reaction of sodium hydroxide with carbon dioxide.

$$CO_2 + 2NaOH \rightarrow Na_2CO_3 + H_2\uparrow$$

At higher temperatures (≥ 300°F), organics such as lignosulfonate, lignites, etc. yield measurable carbonates which could create fluid problems if not addressed. Barite can also be a source of measurable carbonates. The specific ionic radical present in the mud is a function of pH as presented in Figure 4-1.

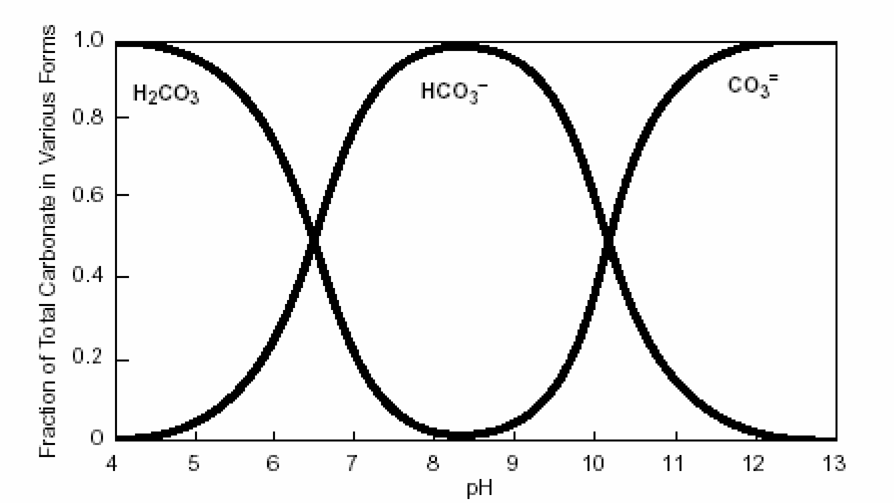


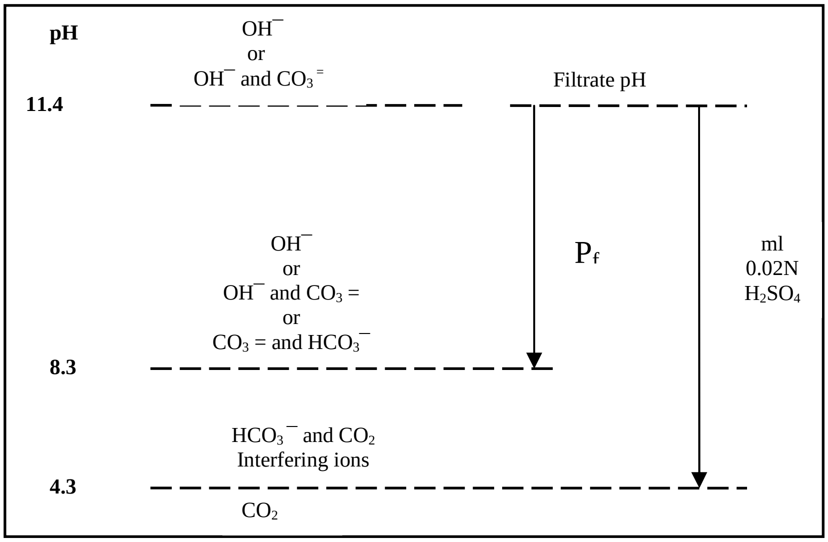
Figure 4-1 **Solution Species Present in Carbonate Systems as a Function of pH – Calculated for K_1=3.5 x 10^{-7} and K_2= 6.0 x 10^{-11}**

Rheological properties are adversely affected in two ways when alkalinity is altered by bicarbonates and carbonates. First, carbonate and bicarbonate anions in the presence of clays will cause increases in gel strength (more noticeable with the ten-minute reading) and yield point. Organic deflocculants such as UNI-CAL® require hydroxyl ions to function properly. An influx of CO_2 will react with hydroxyl ions and take them out of solution so they are not available to react with UNI-CAL®. Heavy carbonate and bicarbonate contamination creates a condition where P_f, pH, and solids phase could appear to be in the desired range, yet viscosity and filtration values do not respond to treatment. Typically, an increasing trend in M_f (5.0 cc N/50 H_2SO_4) may result in high gel strengths which can be due to increasing carbonates and bicarbonates. Difficulty in controlling high-temperature/high-pressure (HT/HP) filtration is also quite evident. Gel strengths will not normally respond to dilution and UNI-CAL® treatments unless an adequate amount of caustic soda has been added to maintain the P_f.

A second problem is caused by field test procedures in detection and remedial steps for carbonate and bicarbonate contamination. In water, the P_f and M_f values can be used to reasonably determine the quantities of hydroxyl ions and bicarbonate/carbonate anions. However, treated drilling fluids contain organic acids which function as buffering agents. This can cause the M_f test procedure to show greater amounts of bicarbonate and carbonate than are actually present.

Therefore, M_f values in excess of five (5) may be indicative of carbonate and bicarbonate anions or could be caused from a highly treated lignosulfonate/lignite fluid as well.

Figure 4-2 **Ions Present at Various pH Levels**



The common alkalinity producing ions which can be present at various pH levels are shown in Figure 4-2 in relation to the P_f and M_f alkalinities.

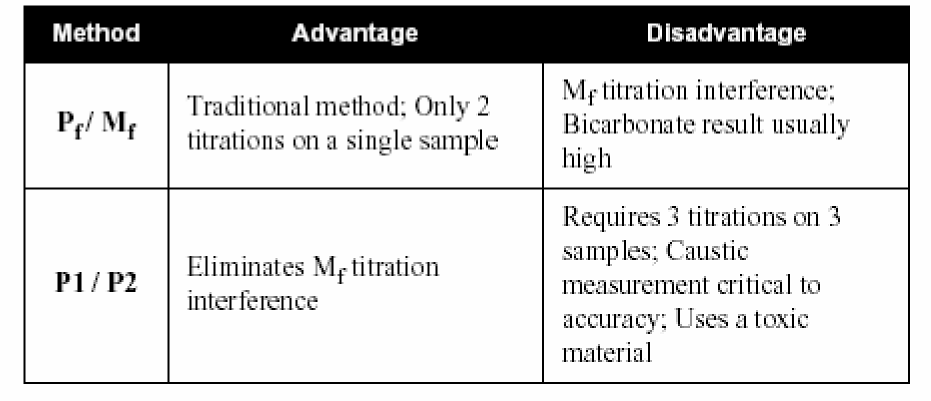
Estimation of Concentration of Carbonates / Bicarbonates

Treatment of carbonates/bicarbonates usually means lime or gypsum and caustic soda additions and requires a reasonably accurate measurement of $CO_3^=/HCO_3^-$ ions. Over treatment with either lime or gypsum at a high temperature could lead to temperature flocculation or solidification. Therefore, caution should be exercised in most cases before treating a $CO_3^=/HCO_3^-$ problem and treatment amounts should be supported with documented pilot testing. Before treatment can start, an estimation of the amounts of carbonates in the mud should be made.

The API has standardized three methods for the measurement of carbonates in drilling fluids. The recommended method is the Garrett Gas Train (GGT) which is the only method of the three which directly measures carbonates. All other methods use alkalinity data to infer the concentration of carbonates and bicarbonates in the fluid. The GGT procedure is discussed briefly in this chapter and a complete description of the test is given in API Bulletin RP 13B-1. The other two methods are the traditional P_f/M_f titration and the P1/P2 titration. The P1/P2 method was developed to overcome limitations in the P_f/M_f method which tends to greatly over estimate the bicarbonate concentration, particularly in highly buffered systems. The P1/P2 titration uses barium chloride to precipitate barium carbonate. Because barium chloride is poisonous and because the titrations are very sensitive, caution must be exercised when the method is used. Figure 4-1 compares the advantages/disadvantages of the two methods.

A fourth alternate mathematical model has been developed using the pH/P_f relation to estimate probable carbonate/bicarbonate concentrations and is illustrated in this chapter.

Table 4-1 Comparisons of the Alkalinity Methods

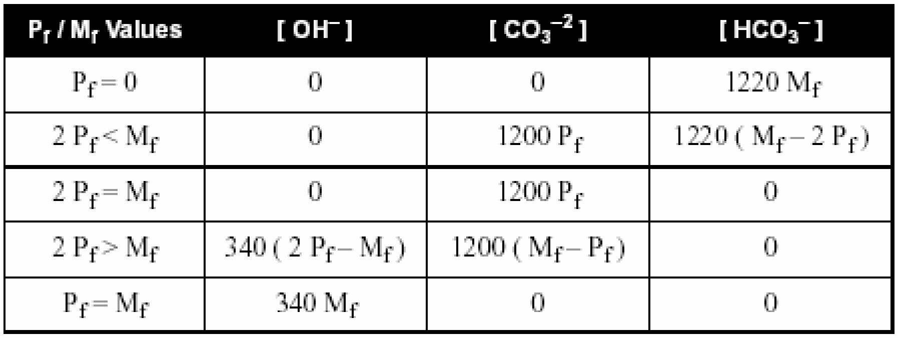


Method	Advantage	Disadvantage
P_f/ M_f	Traditional method; Only 2 titrations on a single sample	M_f titration interference; Bicarbonate result usually high
P1 / P2	Eliminates M_f titration interference	Requires 3 titrations on 3 samples; Caustic measurement critical to accuracy; Uses a toxic material

P_f/M_f Method

The P_f/M_f titrations were historically the first method used to calculate carbonate concentrations. As stated above it tends to be inaccurate because of the buffering of organic acids and dark colored filtrates which make determination of endpoints difficult. Some of the inaccuracy of the Mf endpoint can be eliminated by titrating using a properly calibrated pH meter but this will not eliminate the effects of the buffering agents in the mud.

The calculations for using the P_f/M_f values to determine carbonate and bicarbonate concentrations are shown in Table 4-2.



P_f / M_f Values	[OH^-]	[CO_3^{-2}]	[HCO_3^-]
$P_f = 0$	0	0	1220 M_f
$2\ P_f < M_f$	0	1200 P_f	1220 ($M_f - 2\ P_f$)
$2\ P_f = M_f$	0	1200 P_f	0
$2\ P_f > M_f$	340 ($2\ P_f - M_f$)	1200 ($M_f - P_f$)	0
$P_f = M_f$	340 M_f	0	0

Table 4-2 P_f/M_f Alkalinity Ion Concentrations, mg/L

P1 – P2 Method for Hydroxyl/Carbonate/Bicarbonate Determination.

This carbonate determination method is based on filtrate alkalinity. Two values are determined and designated P1 and P2. P1 is determined by using 1 ml of filtrate mixed with 14 ml of deionized water plus 2 ml of 0.1N sodium hydroxide in a titrating dish. The pH of the mixture should be greater than 11.4. If not then another 2 ml of 0.1 N sodium hydroxide is added. Now 2 ml of barium chloride is added to the titrating dish and then 2 to 4 drops of phenolphthalein. This mixture is then titrated with 0.02N sulfuric acid to a pH of 8.3 or the Pf endpoint. The number of mls required to reach this end point is recorded as the P1 value. To obtain P2, repeat the procedure but with no filtrate. Once P1 and P2 values have been obtained calculate the values of carbonates with the equations below.

Note: Barium chloride in the smallest amount is lethal and extreme caution should be observed to avoid ingestion

When $P_1 > P_2$

$$OH^{-}\left(mg/L\right)=340\times(P_1-P_2)$$

$$CO_3^{=}\left(mg/L\right)=1200\times\left(P_1-(P_1-P_2)\right)$$

When $P_1 < P_2$

$$HCO_3^{-}\left(mg/L\right)=1220\times(P_2-P_1)$$

$$CO_3^{=}\left(mg/L\right)=1200\times P_f$$

Garrett Gas Train Measurement (CO3= / HCO3¯)

The Garrett Gas Train (discussed in the Fluids Testing Procedures Manual and in API Bulletin 13B-1) is the most accurate test to determine $CO_3^{=}$ / HCO_3^{-} concentrations. The test procedure determines total carbonates and does not differentiate between $CO_3^{=}$ and HCO_3^{-}. The procedure utilizes acid (5N sulfuric) to reduce the $CO_3^{=}$ / HCO_3^{-} to CO_2 gas in a known volume of filtrate. The gas is volumetrically passed through a Dräger Tube. A Dräger Tube is a sealed glass tube containing chemicals that react with specific classes of compounds. When the specific compound passes over the chemicals they stain or change colors. In the case of carbon dioxide dräger tubes they stain purple in the presence of CO_2 gas. Using the measured sample volume, the Dräger tube's stain length and a tube factor, the total soluble carbonates can be determined as below. The GGT is also recommended for sulfide (via H_2S) analysis. For $CO_3^{=}$/ HCO_3^{-} determination in mg/L and consequent treatment levels, measurement should be done on the fluid filtrate to show soluble $CO_3^{=}$/HCO_3^{-}. Measurement is sometimes done on the whole fluid, but this is not the preferred approach.

CO_2 (mg/L) = tube stain length x tube factor / ml of filtrate sample

If $CO_3^{=}$/HCO_3^{-} is considered a contaminant, limits are often set whenever measured with a Garrett Gas Train since it is considered more accurate. A range of acceptable $CO_3^{=}$/HCO_3^{-} values is often set at 1000 to 3000 mg/L and should be correlated with the other fluid properties. The Garrett Gas Train should be kept in good working order at all times to ensure accurate measurements.

pH / Pf Method

This technique was developed from a mathematical model of carbonate equilibrium and is a simple test that requires a minimum of time and equipment. Calculation of $CO_3^{=}$/HCO_3^{-} using the pH/P_f model should be done on a routine basis in areas where a carbonate/bicarbonate problem is known to exist. However, it is not without margin of error and the results should only be used as a guideline within the total context of what is happening to the fluid, the hole, and the drilling operation.

Steps should be taken to address a $CO_3^{=}$/HCO_3^{-} problem situation in a reasonable time frame whenever the following occurs.

Viscosity becomes difficult to control.

The ten-minute gel strength reading shows a progressively increasing tendency.

Fluid loss and particularly the HT/HP increases unacceptably and is difficult to control.

Mathematical modeling of fluid chemistry indicates $CO_3^=$/HCO_3^-.

Oven tests show a fluid problem.

Calculated values using the pH/P_f method can reveal a trend or even a sudden occurrence of $CO_3^=$/HCO_3^-, but these values can only be used as a guideline and thorough pilot testing should be done.

Requirements for the pH/P_f method are:

1. Accurate pH – The pH of the filtrate should be determined with a pH meter. The pH of the fluid can be used if filtrate volume is limited.
2. Pf – Alkalinity of the filtrate.
3. Water Fraction – Calculated for unweighted fluids and retort cook-off for weighted fluid.

Equations

1. Hydroxyl concentration in mg/L (OH)

OH^- = 17,000 x $10^{pH - 14}$

2. Carbonate concentration in mg/L ($CO_3^=$)

$CO_3^=$ = 1200 (P_f – (OH / 340))

$$HCO_3 = \frac{CO_3}{10^{pH\,9.7}}$$

Bicarbonate concentration in mg/L (HCO_3^-)

Example calculation using pH/Pf method given the values for pH and Pf

pH = 12.6

Pf = 5.3 cc

OH^- = 677 mg/L

(OH - = 17,000 x 10 pH – 14)

= (17,000 x (1012.6 – 14) = (17,000 x (10 – 1.4) = (17,000 x 0.039810717) = 677 mg/l

CO3= = 3971 mg/L

CO3= = 1200 (Pf – (OH / 340)) = 1200 (5.3 – (677 / 340)) = 1200 (5.3 – 1.9912) =

1200 (3.309) = 3971 mg/l

$HCO3^-$. = 5 mg/L

HCO3– = (CO3=pH – 9.7) = (3971/10 12.6– 9.7) = (3971/10 2.9) = (3971/794.328) = 5 mg/l

Calculation of $CO_3^=$/HCO_3^- using the pH/P_f model should be done on a routine basis in areas where a carbonate/bicarbonate problem is known to exist. However, calculated values should be used within the total context of what is going on with the fluid, the hole, and the drilling operation.

Special Procedure for Low pH Fluids

When the pH is below 9.0 to 9.5 it is difficult to accurately titrate the Pf value. Therefore, the method must be modified in those cases. The procedure is as follows.

1. Increase the pH of a sample of filtrate to 11.5 using CAUSTIC SODA (NaOH) solution and a pH meter. The strength of the caustic soda solution will determine how much will be added. It is recommended that a known Normality solution be made up and used for this procedure. (Forty (40) grams of caustic in one (1) liter of water is a 1 Normal solution.)
2. Titrate and determine the Pf value of this altered filtrate sample and calculate the mg/L of total carbonates from this Pf value by multiplying it by 1200.
3. Calculate the bicarbonates and carbonates in the original filtrate from the equations:

$$Y\left(Total\ Carbonates\right)=P_f\left(Altered\ \ pH\right)\times 1200$$

$$HCO_3^-\left(mg/L\right)=\frac{Y}{1+10^{pH-9.7}}$$

$$CO_3^=\left(mg/L\right)=Y-HCO_3^-$$

where,

Y = total carbonates at 11.5 pH,

pH = original filtrate pH.

Example calculation using pH/Pf method when the pH is low.

Original filtrate pH = 8.8

Pf of altered filtrate (11.5 pH) = 5.0 cc

1. Total Carbonates (Y) (both $CO_3^=$ and HCO_3^-) = 6,000 mg/L

$$Y=P_f\times 1200=5.0\times 1200=6000\,mg/L$$

Bicarbonates = 5329 mg/L

2. $$HCO_3=\frac{Y}{1+10^{(pH-9.7)}}=\frac{6000}{1+10^{(8.8-9.7)}}=\frac{6000}{1+0.125892541}=5329\,mg/L$$

Carbonates = 671 mg/L

3. $$CO_3=Y-HCO_3=6000-5329=671\,mg/L$$

Treatment of Carbonates

Removing carbonates from a mud involves adding some form of soluble calcium. Lime or gypsum is the most common products used to provide this source. Calcium will precipitate the carbonates as calcium carbonate, $CaCO_3$. If the carbonates are in the HCO_3^- form they must be converted to the $CO_3^=$ form before they will precipitate. This means that some form of hydroxyl must be present. This can come from lime ($Ca(OH)_2$)or caustic soda (NaOH). In general, for low pH muds, lime is used to treat out bicarbonates, and for higher pH muds a combination of treatments is used to prevent excessive pH increases. The treatment amounts given below are based on exact chemical reactions. In the field these chemical reactions may not be exact and may take time. Use these treatment amounts as guidelines and verify with accurate pilot testing.

1. For pH's less than 10.0 (over 50% of the carbonates are $HCO3^{-}$) use lime to treat only bicarbonates:

   0.00043 lbs of lime per mg/L of HCO_3^{-}

2. For pH's above 10.0 or to maintain a constant pH while treating out carbonates:

   0.00022 lbs of lime per mg/L of HCO_3^{-}

   0.001 lbs of gypsum per mg/L of $CO_3^{=}$ and ½ of the mg/L of HCO_3^{-}

3. To use gypsum and caustic:

   0.00023 lbs of caustic per mg/L of HCO_3^{-}

   0.001 lbs of gypsum per mg/L of HCO_3^{-} and $CO_3^{=}$

The following guidelines are recommended for treatment of carbonates:

- Determine the amount of carbonates to treat carefully. Use more than one calculation method if possible;
- pilot test;
- when adding lime and gypsum add slowly to allow the chemical reaction to take place;
- add the calculated treatment over several circulations;
- check the mud on each circulation bottoms up and re-calculate the carbonates;
- lignosulfonate additions will keep pH from rising to undesirable levels and help control rheological increases.

Carbon Dioxide (CO2)

Natural gases can contain carbon dioxide with concentrations that range from small amounts to relatively high proportions. Much carbon dioxide is clearly of magmatic origin found in areas where vulcanism is common, with large proportions resulting from local igneous activity. Metamorphism of limestone can result in high concentrations also. Carbon dioxide is also produced by the oxidation of many organic substances and crude oils.

In a water solution the carbon dioxide converts to carbonic acid. This carbonic acid lowers pH and can prove damaging to many polymers. At high concentrations of carbon dioxide the formation of excessive amounts of soluble carbonates occurs and often results in high viscosities, gel strengths, and HT/HP control problems. Often calcium hydroxide [$Ca(OH)_2$] is used to treat out those soluble carbonates with the potential result of scale formation. Nevertheless, calcium hydroxide remains the most common approach to neutralizing this acid. The measurement and treatment of carbonates and bicarbonates was discussed earlier in subsection Carbonate/Bicarbonate Contamination.

Hydrogen Sulfide (H2S) Contamination

Hydrogen sulfide as a contaminant will be briefly discussed here since, in a practical sense, safety is the paramount issue in dealing with H_2S. Certainly, H_2S can have adverse effects on a drilling fluid, i.e., viscosity, filtration control, and fluid chemistry, but its detection at any level should be determined immediately and the safety issue addressed first. High pH fluids and H_2S scavengers have proven effective in controlling H_2S concentration even at very high concentrations. The Garrett Gas Train is necessary to accurately determine soluble sulfides. Chemical treatment should maintain flow properties and filtration properties as required. See Chapter 8, *Corrosion, for guidelines to the treatment of* H_2S *contamination*.

Temperature Flocculation / Deterioration

Many water-base fluids have a temperature limit of ±300°F. This can often be exceeded with the addition of temperature stabilizing additives such as MIL-TEMP®, ALL-TEMP®, or CHEMTROL® X, etc. In planning the fluid to be used in high temperatures, an estimation of bottom hole temperature (BHT) should be used to make sure temperature has a minimal effect on the fluid.

If the following issues are not addressed:

- treatment to address temperature stability
- adequate control of type, distribution, and amount of low specific gravity solids
- provision to counter contaminants as discussed above,

A flocculated, thick fluid off bottom can result which can lead to hole or drilling problems.

Hot rolling and static oven testing a fluid at estimated wellsite BHST should be used to supplement suction pit and flowline fluid checks to counter the effects of high temperatures.

A fluid program that addresses wellbore temperatures at all times in a given well will help in preventing temperature flocculation and deterioration of a fluid. Knowing product temperature limits and how to apply products in high temperature environments is imperative.

Solids Contamination

Throughout this chapter on chemical contamination, severity of fluid contamination is predicated on amount, type, and particle size distribution of solids. Fluids with an unacceptable concentration of low specific gravity solids are more likely to have a severe reaction to chemical contaminants. Solids should be kept to a minimum at all times. Any complete fluids program should include recommendations for solids control equipment and mud dilution. Solids control is discussed in greater detail in Chapter 10, *Mechanical Solids Control*.

Oil / Gas Contamination

In elemental composition, crude oils are mainly carbon and hydrogen with lesser and varying proportions of oxygen, nitrogen, and sulfur. The hydrocarbons in crude oils are generally categorized as aromatics, naphthenes, and paraffins, but include various hybrids. The aromatics are generally referred to as unsaturated with six carbon atoms in each structural ring. Asphaltic type crudes contain asphaltenes and resins. Crude oils can contaminate a water-base drilling fluid, affecting density and possibly viscosity. With high concentrations of crude in a water-base fluid, approved disposal of that fluid could be the appropriate action to take. The fluid properties when affected by excessive crude volumes should be corrected with necessary weight material for density and appropriate additives for adjusting viscosity to desired levels.

Crude oil is always associated with natural gas, a mixture of gases that can contain both hydrocarbons and non-hydrocarbons. Methane is normally the principal hydrocarbon component of natural gas with smaller amounts of the paraffin series present, with some detection of benzene and several naphthenes. Natural gases can contain large amounts of carbon dioxide, nitrogen, and hydrogen sulfide as non-hydrocarbon. In some cases, helium and mercaptans have been detected. Nearly all natural gases contain water vapor from the connate or formation water.

Subsurface hydrocarbons can exist in the gaseous state under certain conditions of pressure and temperature, but separate as a liquid at the surface. Such subsurface hydrocarbon gas existing as surface hydrocarbon liquid is referred to as condensate. Sometimes, natural gas accumulations are found in association with salt water rather than liquid hydrocarbon. Generally, the non-hydrocarbon gases can present problems for the drilling fluid. Both carbon dioxide and hydrogen sulfide are discussed in this chapter.

Chapter Five

Oil/Synthetic Drilling Fluids

Chapter 5

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Chapter 5

Oil / Synthetic Fluids

Oil-base fluids, like other drilling fluids, must be properly applied to derive all the benefits associated with them. There are obvious advantages to using these systems; otherwise they would have ceased to exist in the industry. Likewise, there are disadvantages which limit oil fluids. In situations where oil-base fluids can not be used, synthetic fluids utilizing non-toxic, non-sheening olefin isomers are used. These synthetic-base systems are environmentally-safer alternatives to traditional oil-base systems.

Introduction

The advantages listed below frequently outweigh the disadvantages; oil- and synthetic-base fluids continue to be used in difficult drilling environments and in special applications. The fluids are most commonly prepared as emulsions of brine water in an appropriate oil- or synthetic-base fluid.

In the past, the commonly used oils for drilling fluids were No. 2 diesel, and low-aromatic-content, low-toxicity mineral oils. Crude oil has been used; however, due to safety, health and environmental issues, its use is now rare. Baker Hughes Drilling Fluids (BHDF) CARBO-DRILL® systems use diesel or mineral oil as the base fluid.

The development of systems that use synthetic fluids as a replacement for diesel and mineral oil have eliminated many of the environmental, health and safety issues traditionally associated with oil-base drilling fluids. These synthetic-base fluids have found application in many offshore areas where the discharge of fluid and cuttings from traditional oil muds are restricted. The SYN-TEQ® system, prepared from various environmentally friendly base fluids, is an effective and environmentally acceptable substitute for the CARBO-DRILL system.

A brief summary of the ADVANTAGES and the DISADVANTAGES of oil-base (non-aqueous) drilling fluids follows. Unless specifically indicated otherwise, the information contained in this chapter applies to both oil and synthetic base fluids.

Advantages of Oil-Base Fluids

1. Shale Stability and Inhibition

   Properly conditioned oil-base fluid should have a minimal effect on any shale formation. With correct internal phase salinities, oil fluids provide gauge holes through water sensitive shales combined with long-term borehole stability. This is a true statement as long as tectonic stresses are not a factor.

2. Temperature Stability

   Oil-base fluids have application in wells with high bottom-hole temperatures. Oil-base fluids have shown stability in wells with logged bottom-hole temperatures in excess of 550°F (288°C).

3. Lubricity

   Torque and drag problems related to deviated well-bore, crooked hole, and sidetracks can be reduced considerably with the use of oil-base fluids. The lubricating properties of an oil-base fluid are a result of the chemical nature of the oil-wetting surfactants and the inherent lubricity of the oil itself.

4. Resistance to Chemical Contamination

   Carbonate, evaporite, and salt formations do not adversely affect the properties of an oil-base fluid. CO_2 and H_2S can be easily removed with lime.

5. Gauge Hole in Evaporite Formations

   When drilling salts, the internal (aqueous) phase of the oil-base system becomes saturated. However, as the formation salts saturate the internal phase, it is not uncommon for the internal phase to become super saturated with salt. This will result in the precipitation of excess salts. If calcium chloride is precipitated, this will affect the stability reading negatively, but more importantly, it can cause water-wetting of mud solids and de-stabilize the system. As a reminder, the electrical stability should only be run on screened samples to remove any insoluble salts prior to testing; otherwise a false reading of near zero will be recorded.

6. Solids Tolerance

   Drill solids are inert in oil-base fluids and less dispersible other than from that resulting from mechanical shear; therefore the fluids have a much higher solids tolerance. The key to solids tolerance is less due to volume than it is to particle size and surface area of the solids. This is why oil-base systems are more tolerant of solids resulting in reduced dilution requirements for solids control.

7. Reduced Production Damage

   Oil-base fluids normally have a low fluid loss and the filtrate from a stable mud is generally all oil. The filtrate penetration into the formation would be less than that of filter paper as the well-bore surface area increases incrementally with distance from the well-bore. The filtrate from an oil-mud invades only a short distance into the formation production zone and therefore minimizes damage.

8. Reduced Tendency for Differential Sticking

   A thin, slick filter cake is formed when using an oil-base fluid, minimizing the chance of differential sticking. Note, however, that differential sticking is still possible if drilling highly overbalanced, especially with a high fluid loss system.

9. Drilling Under balanced

   The wellbore stability resulting from the use of oil-base drilling fluids allows, in some instances, drilling with under balanced pressure, thereby increasing the rate of penetration (ROP).

10. Re-Use

    The excellent stability and solids tolerance of a well-conditioned oil-base fluid allows its use in multiple wells. Although the initial make-up cost can be expensive, the re-use of oil-base fluids can actually result in less expense than water-base fluids since the ability to recondition for multiple applications exists.

11. Reduced Cement Cost

    Gauge hole drilling can substantially reduce cement costs. This can be of benefit in two ways – (1) less cement is required; and (2) a more constant flow regime can be achieved resulting in less fluids contamination and a cleaner well-bore prior to cementing, thereby giving a better primary cement job.

12. High Penetration Rate

    The use of lower solids content oil-base drilling fluids, combined with the advent of polycrystalline diamond cutter (PDC) bits, has resulted in the ability to drill with high penetration rates throughout the world. The modification of drilling fluid properties and bit design allows for increased penetration rates in all type of shales, from soft gumbo to the older hard shales.

13. Flexibility

    With the advent of both “relaxed” oil-base fluids and low toxicity oil-base fluids, any size hole, any environment, and any lithology, can be drilled with a specially tailored oil-base fluid.

14. Reduction of Stress Fatigue

    Stress fatigue of tubulars is reduced considerably when using oil-base fluids, i.e. less tubular torque and corrosive attack from formation acid gases.

15. Reduced Corrosion

    Oil fluids are not corrosive since oil, instead of water, is in contact with all tubulars.

Disadvantages of Oil-Base Fluids

1. High Initial Cost per Barrel

    Initial make-up costs can be high. A barrel of oil-base fluid has a high initial cost and maintenance costs can climb substantially depending on the environments encountered. These costs fluctuate with the price of the oil.

2. Mechanical Shear Required

    To achieve the emulsion stability and viscosity required, mechanical shearing is necessary to form a tight emulsion and disperse the organophilic platelets. This can be accomplished by using a high-pressure pump in conjunction with special shearing devices or shearing through the drill bit.

3. Reduced Kick Detection Ability

    H_2S, CO_2, and hydrocarbon gases such as methane (CH_4) are all soluble in oil-base fluids. If gas enters the wellbore, it can go into solution under pressure and as the gas moves up the hole it can break out of solution and expand at a very rapid rate, thus emptying the surface well-bore and reducing the hydrostatic pressure allowing additional kicks to be taken. If this occurs at a shallow depth, it may be too late to prevent a blowout. All kicks in oil-base fluids must be treated as a gas kick and circulated through the choke.

4. Pollution Control Required

    Most areas where oil-base fluid is used have environmental restrictions. Rig modifications may be necessary to contain possible spills, collect or clean cuttings, and handle whole fluid without dumping. Environmentally acceptable disposal procedures must be followed when discarding cuttings and whole mud.

5. High Cost of Lost Circulation

    Lost circulation with is very expensive due to the mud’s cost per barrel. The problem may not be curable. Therefore, it may not be practical to use of oil-base fluids where lost circulation is anticipated. Seepage losses are a common occurrence with oil-base fluids. Formations with low permeability and porosity may exhibit no losses when drilled with a water-base fluid, however, a partial or full loss of returns may occur when drilled with an oil-base fluid. Oil-base fluids, because of their low leak-off values, can act as efficient fracturing fluids.

6. Disposal Problems

   Oil-base fluid cuttings may have to be cleaned before dumping. Some environments require that cuttings be sent to proper disposal areas. Also, whole fluid cannot be dumped. Therefore, if solids need to be reduced, dilution is the only answer. Oil-base fluid volumes only increase. Eventually the oil-base fluid must be disposed of, possibly at considerable cost.

7. Solids Control Equipment

   Oil-base fluids have inherently higher viscosities than water-base fluids. This increased viscosity, combined with the need for oil to dilute during the centrifugation process, results in less than effective solids removal. See Figure 5-22 thru for the recommended solids control equipment configuration.

8. Hole Cleaning

   Hole cleaning is more difficult with oil-base fluids. Some reasons for this are – (1) no cuttings disperse into the fluid as with water-base fluid, requiring larger cuttings to be removed; (2) oil fluids are more Newtonian in behavior than water-base fluids; and (3) oil-base fluids have less thixotropic behavior than water-base fluids.

9. Rig Cleanliness

   Extra effort is required to keep a rig clean when oil-base fluids are used. Special dressing areas, steam cleaners on the rig floor, etc., are required.

10. Special Skin Care for Personnel May be Required

    Prolonged skin exposure to OBM and SBM results in oils being removed from the body, resulting in dry and cracked skin. Proper hygiene and skin moisturizers are required to alleviate this situation.

11. Hazardous Vapors

    As hot oil-base fluid flows across high-speed shaker screens and circulates in fluid pits, toxic hydrocarbons may be released. Therefore, shaker and fluid pit areas must be adequately ventilated.

12. Effect on Rubber

    Oil-base fluids can cause either shrinkage or swelling of normal rubber parts. Therefore, it may be necessary to change out blowout preventer (BOP) rubber components, and the Hydril, etc., to oil-resistant rubber such as Nitrile. Diesel is worse than low-aromatic oils in this respect. Drill pipe rubbers will also need to be replaced. Depending on the base fluid used, shaker bonding polymers may also be negatively affected.

13. Fire Hazard

    Since the oil used in oil-base fluid can burn, extra precautions are required to prevent a fire. Additional gas, smoke, and fire detector and protection devices are necessary, including sealed electric motors and sparkless switches and controls.

14. Special Logging Tools Required

    Resistivity logs do not work in an oil-base fluid environment.

15. Gas Stripping

    Intrusion of gas into an oil-base fluid can cause the weight material to settle. This is referred to as *gas stripping* of barite, whereby the intruding gas changes the wetting characteristics of the barite surface area. This can be a problem when using oil-base fluids on gas wells.

16. Aqueous Contamination

    An influx of water due to surface leaks, rain, or formation has a significant impact on the properties of the system. Dilution is the only recourse to correct the condition and one that is not inexpensive to treat.

Oil-base fluid applications

Drilling

The greatest use for oil-base fluids in the period from 1935 to 1950 was for well completion, mainly in low-pressure or low-permeability zones. When oil-base fluid was used instead of water-base fluid, higher initial production was usually noted. The all-oil filtrate provided an environment in which water-sensitive clays did not hydrate. More recently, the advent of relaxed filtrate, low-solids oil-base fluids, and polycrystalline diamond cutter bits has resulted in exceptional drilling rates and cost savings. Oil-base fluids allow the drilling of reactive formations more efficiently than water-base fluids; such is evident in the North Sea.

Perforating

Oil-base fluid will not seal off perforations as may be the tendency when a freshwater or saltwater clay fluid is used. Bullets and jet charges shot in many water-base systems actually deposit hard solids and clay behind the shot, thereby reducing the effectiveness of the perforation job.

Work over and Completion

Using oil-base fluid in the open-hole section of deep, high-pressure wells simplifies running liners and casing. The fluid provides maximum lubrication of the borehole, reduces torque, and reduces the chances of differential sticking. The procedure aids the operator in the holes where close tolerances are involved or when landing liners in troublesome holes. The same benefits can be seen when running tubing and setting packers.

Coring

Maximum recovery is normally achieved because formation clays do not react with oil-base fluids. The operation is made easier by elimination of core swelling and jamming of the core barrel and differential sticking.

Stuck Pipe Spots

The majority of stuck pipe cases are caused by differential pressure sticking. Other causes are key seating, balled-up bits, hydrated clay, disintegrated shale formations, poor hole cleaning and washouts. Differential sticking can be directly related to low-quality fluid filter cake and/or high pressure differential between the wellbore and formation.

When the pipe becomes partially embedded in the filter cake, it becomes a part of the cake as though it were a fluid solid. It is held to the cake by the pressure difference between the well-bore pressure and the pore pressures in the cake under the pipe. The force required to pull the pipe free is a function of the area of pipe in contact with the cake, the pressure holding it to the cake, and the coefficient of friction between the pipe and cake.

Spotting with either BLACK MAGIC®, or S.F.T. in the zone of sticking is the most successful means of freeing differentially stuck pipe. The asphalt in these systems seals off the water fluid-filter cake, which then dehydrates, dries, shrinks, and cracks. Once cracked, the oil-base fluid penetrates behind the stuck pipe and equalizes the pressure, thus freeing the pipe.

High-Temperature Drilling

Wells where temperatures are above 400°F (204°C) commonly use oil-base fluids. The solids/chemical tolerance of oil-base fluids is much higher than that of most water-base fluids. Also there is less oxidation reduction taking place in an oil-base fluid as the oxygen content is nil compared to that of a water base system. Consequently, certain chemicals/solids are not as highly affected by temperature.

Wellbore Stability

Soft shales can be controlled or hardened by exposure to oil-base fluids which have high-salinity water in the emulsified phase. Transfer of water from the shale to the oil-base fluid is attributed to osmotic forces across the semi-permeable membrane around the emulsified water droplets.

Corrosive Gases

Hydrogen sulfide and carbon dioxide bearing zones, which are hazardous to metal goods and damaging to water-base fluid rheology, are better controlled in an oil environment. The oil coating protects the metal from corrosion, and lime or scavengers can be added to control gases, if necessary.

Salt and Contaminating Formations

Several unsuccessful attempts using water-base fluid were made to drill through the Louann salt formation in North Louisiana. At temperatures above 250°F (121°C) and depths below 12,000 ft (3658 m), plastic flow of the salt was encountered in several wells. High-weight oil-base fluids were used to overcome these problems. In the North Sea, oil-base fluids have been used successfully to drill the Carnallite salt sections. The KCl and $MgCl_2$ salt sections are not washed out when drilled with an oil-base fluid.

Differential Sticking

Earlier, the application of an oil-base fluid for freeing stuck pipe was discussed. The chance of becoming differentially stuck while drilling with an oil-base fluid system is minimal. The oil filtrate, lubricity, low fluid loss, and the cake are ideal for preventing wall sticking.

Drilling Directional Holes

Oil-base fluid is an ideal fluid for directional work because of its thin filter cake, which gives it the ability to maintain a gauge hole and reduce torque.

Packer Fluids

Oil-base fluids are used as packer fluids because they serve as a stable non-corrosive barrier against corrosive formation fluids. In California, a well pack was developed which has a grease-like consistency that prevents transmission of the shock of earth movement to the casing. In Alaska, oil-base fluid casing packs are utilized between the strings of casing that pass through the permafrost zone. This provides insulation to the frozen ground from the warm oil being produced.

Prevent Lost Returns

Lost returns can be prevented when drilling abnormally low pressure gradient formations by using low-density oil-base fluid with less than 8.0 lb_m/gal (0.96 g/cm^3) density.

High Density Fluids

Oil based fluids have a higher tolerance to active and inert solids. Because of this inherit characteristic in combination with surface wetting agents, high density and drill solids tolerant fluids are obtainable with excellent rheological properties.

Oil-based fluid chemistry

Fundamental Chemical Concepts

Matter is composed of small, indivisible particles called *atoms*. Atoms contain a small positively charged core, or *nucleus*, surrounded by negatively charged *electrons*. There are over 100 different types of atoms, and each type represents an *element*. Examples would be oxygen, hydrogen, carbon, sodium, chlorine, etc.

Atoms are attached to one another to varying degrees. When the attraction is strong enough, atoms form *aggregates*. Aggregates bound together strongly enough to behave as units are called *molecules*. Examples are water, sugar, salt, and hydrocarbons (see).

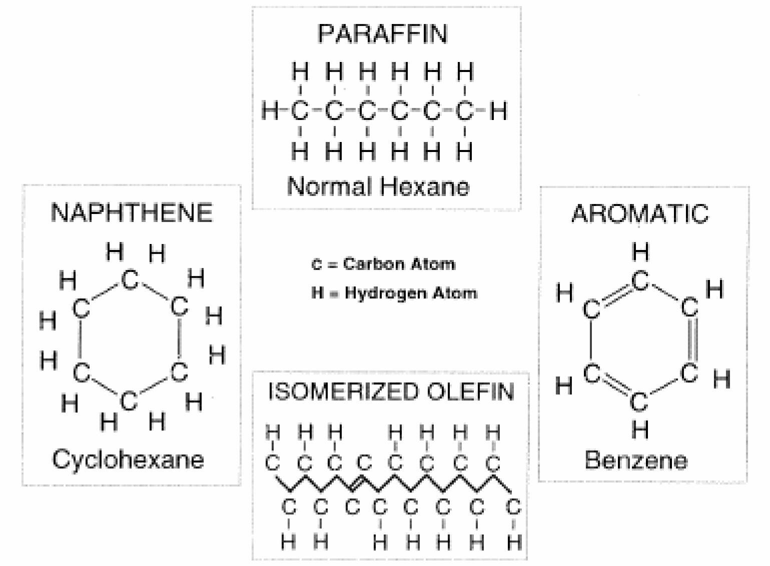


Figure 5-1 Structures of Primary Hydrocarbon Classes and Isomerized Olefin (Synthetic Base)

Atoms in molecules have electrons in what are called *chemical bonds*. When atoms in a molecule have extreme differences in affinity for the electron, we call the bonds *ionic*. The electrons in ionic bonds are transferred from one atom to the other. An example would be sodium chloride or common table salt. In this example, the sodium (represented by the symbol Na) loses an electron and becomes positively charged (represented by Na^+). A charged atom is called an *ion*. Positively charged ions are called *cations*. The chlorine (represented by the symbol Cl) gains an electron and becomes negatively charged (represented by Cl^-). Negatively charged ions are called *anions*. Sodium chloride can be represented as Na^+Cl^- to indicate the electron transferred.

The two electrically charged atoms or ions of opposite charge are highly attracted to one another. This electrical attraction is called *coulombic attraction*. When atoms in a molecule have somewhat similar affinity for the electrons, the bond is *covalent* and the molecules are *nonionic*. The shared electrons are distributed over the atoms. Examples would be molecular hydrogen, molecular nitrogen, and hydrocarbons.

Fundamental Chemical Classes

If the electrons in a chemical bond are shared equally by the atoms, we call the bond *nonpolar*. An example would be molecular nitrogen. When the shared electrons in a molecule favor one atom over the other, the bond and the molecule are *polar*. An example is water. Polar molecules, while electrically neutral, have uneven centers of positive and negative charge due to the uneven electron distribution. Such molecules are called *dipoles*. Hydrogen chloride (gas) is a good example (see Figure 5-2).

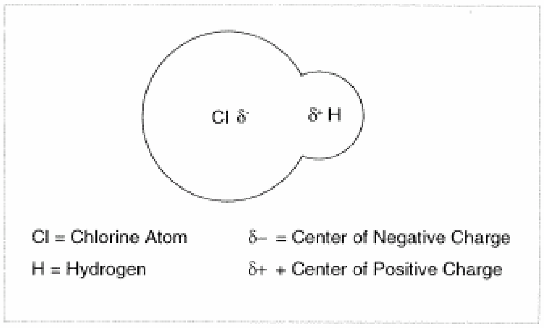


Figure 5-2 Dipolar Hydrogen Chloride Molecule Showing Separation of Charge

The positive end of one dipole is attracted to the negative end of other dipoles. This is referred to as dipole interaction and this phenomenon accounts for much of the strong attraction that polar molecules have for each other (see Figure 5-3).

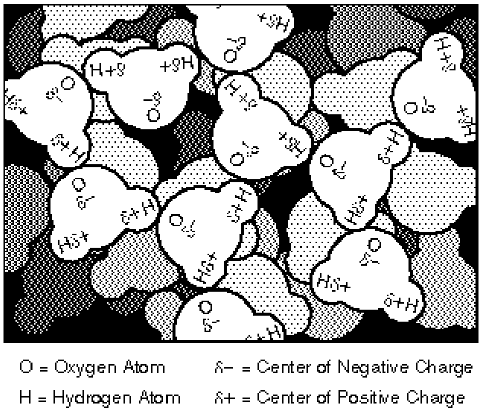


Figure 5-3 Association of Liquid Water

Compounds which have easily replaceable hydrogen ions are called acids (see Table 5-1)

Table 5-1 Common Acids

Name	Formula
Hydrochloric or Muriatic Acid	HCl
Carbonic Acid	H_2CO_3
Hydrofluoric Acid	HF
Acetic Acid	H_3CCOOH
Oleic Acid	$CH_3(CH_2)_7CHCH(CH_2)_7COOH$
Naphthenic Acid	$C_{10}H_7COOH$

Compounds which can react with and accept hydrogen ions are called bases (see Table 5-2).

Table 5-2 Common Bases

Name	Formula
Caustic Soda, Caustic, or Sodium Hydroxide	NaOH
Soda Ash, Sodium Carbonate	
Potash, Pearl Ash, Potassium Chromate	Na_2CO_3
Potassium Hydroxide	K_2CO_3
Lime Hydrate or Lime	
	KOH
	$Ca(OH)_2$

Acids can react with bases to form salt and water. As an example, hydrogen chloride reacts with sodium hydroxide to form sodium chloride plus water. This reaction can be represented by the equation,

$$HCl + NaOH \rightarrow NaCl + H_2O$$

As discussed earlier under ionic bonds, sodium chloride, table salt, can be represented by,

$$Na^+Cl^-$$

The sodium ion and chloride ion are strongly attracted to one another through coulombic attraction. The two ions separate when dissolved in water. The solvent, in this case water, disassociates the salt crystal into its constituent ions (see Figure 5-4). This is possible due to the water molecule dipoles orienting around the individual ions as shown in Figure 5-5

Ions surrounded by clusters of water molecules are called *hydrated ions*, and the process itself, hydration. Hydration is not limited to ions, but occurs with neutral (but polar) molecules as well. Examples are sugar and alcohol.

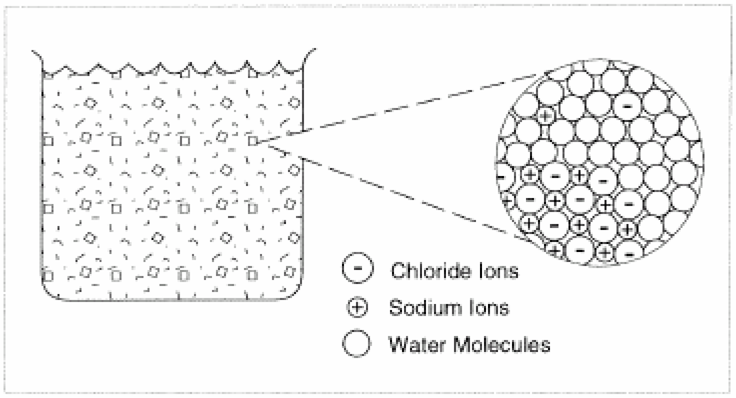


Figure 5-4 Schematic Diagram of Hydrated Sodium and Chloride Ions

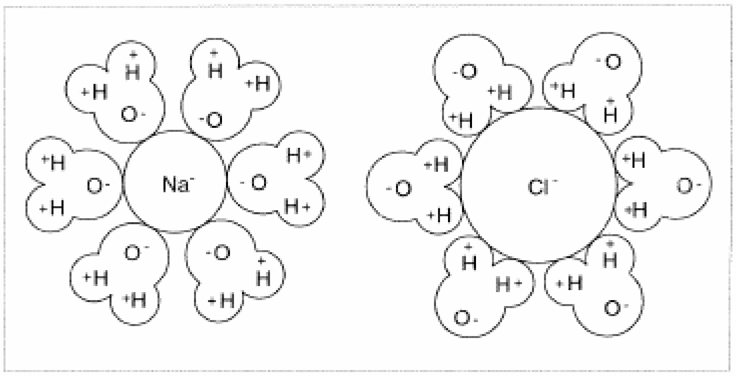


Figure 5-5 Sodium and Chloride Ions Surrounded by Water Molecule Dipoles

Hydration is a specific example of a more general phenomenon called *solvation*. Solvation must occur when one substance, called a solute, dissolves in another substance, usually a liquid, called the solvent. In order to dissolve, the molecules of the solute are surrounded by clusters of molecules of the solvent. This process is called solvation and only occurs when the molecules of the solute are similar in ionic strength to the molecule of the solvent. Examples are salt in water, sugar in water, fats in hydrocarbons. "Like dissolves like" – therefore, molecules which are very dissimilar in charge will not solvate and no solution occurs. Examples are salt in hydrocarbons and water in hydrocarbons.

Compounds which are solvated or hydrated by water, such as salt or sugar, are called *hydrophilic*, meaning water-loving. Compounds which are solvated by oil, such as butter fat, are called *lipophilic*, meaning oil-loving.

Surface Tension

A molecule in the center of a liquid is completely surrounded by other molecules and is attracted equally in all directions. A molecule at the air/liquid surface is attracted inwards, as a result of the lower concentration of attracting molecules in the air relative to the liquid. This will set up an imbalance of force on a surface molecule and energy must be expended in order to move molecules into the surface from the bulk liquid. The amount of energy required to move enough molecules to the surface to create a unit area of surface is called the *surface energy*.

As a consequence of this imbalance of force, the surface of a liquid always tries to contract to the smallest possible area. As a result of this tendency to contract, the surface behaves as if it were under tension (see Figure 5-6). If an imaginary cut were made along the surface, a force would have to be applied to hold the two portions of the surface together. The force would be proportional to the length of the cut and would act at right angles (perpendicular) to the cut. The magnitude of the force per unit length is called the *surface tension* and is numerically equivalent to the surface energy. Surface energy/tension, acting to minimize surface area, causes soap bubbles and water droplets to form spheres (minimum surface area). Surface energy/tension also accounts for the capillary rise of water in small glass tubes.

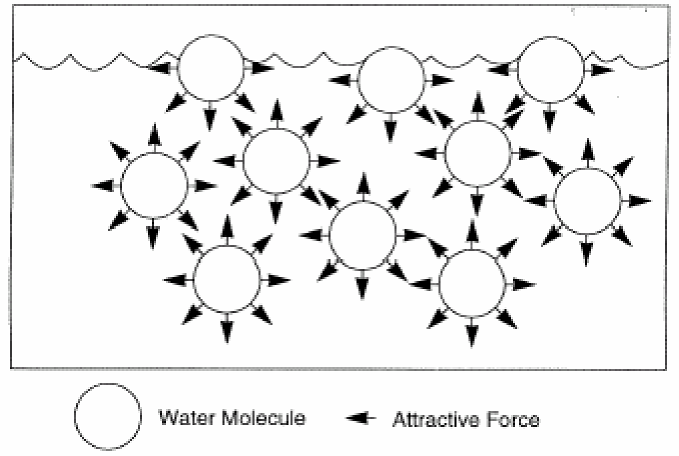


Figure 5-6 Diagram of Attraction Forces in Liquids

Polar molecules, such as water, because of strong dipolar attractive forces between the molecules, show large imbalances of force at the air/liquid surface. This strong imbalance of surface forces results in a high-surface energy/tension for water. Ionic solids, with even stronger ionic and coulombic attractive forces, show even larger imbalances of force at the air/solid surface.

Surface energies/tensions, as a result, are even higher in ionic solids such as glass, quartz, clays, barite, and most mineral solids. High-surface energy/tension liquids, such as water, will interact strongly with high-surface energy (hydrophilic) solids, such as glass, and the attractive forces are sufficient to overcome gravity causing water to rise in glass capillary tubes as shown in Figure 5-7.

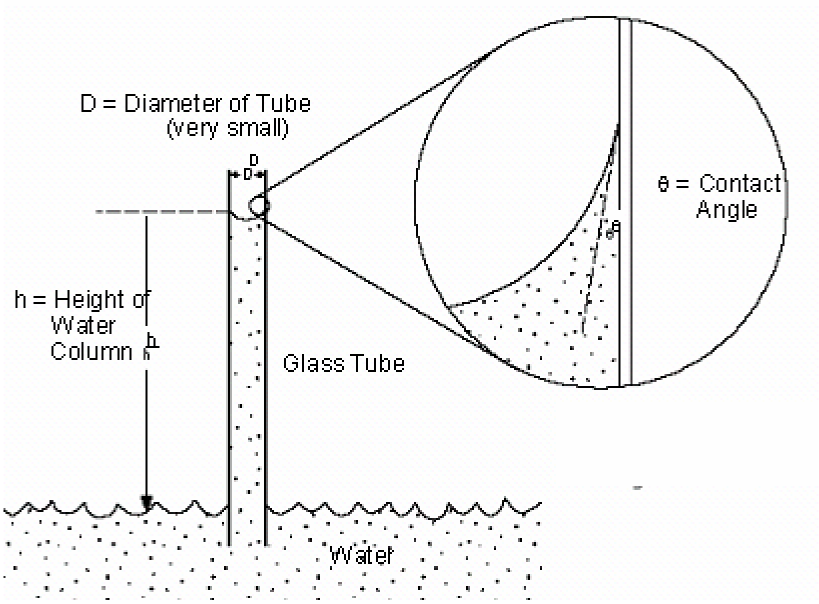


Figure 5-7 Surface Tension Causing the Capillary Rise of Water in a Small Glass Tube

Nonpolar molecules (such as hydrocarbon oils, waxes, and many plastics) show only weak attractive forces between molecules, small imbalances of force at the surface, and have low surface energies/tensions. High surface energy liquids, such as water, will not interact with low-energy surfaces, such as plastic, and will not rise in plastic capillaries. Low-surface energy liquids, such as hydrocarbon oils, will interact only weakly with any surface and show only minimal capillary rise regardless of the capillary material used.

Emulsions

Liquids which are soluble in one another are said to be *miscible*. An example of soluble liquids is water and alcohol. Liquids which are not soluble in each other are *immiscible*. An example would be water and oil.

When immiscible liquids are mixed vigorously, one liquid will be suspended or dispersed as droplets in the other liquid. Such two-phase systems are called *emulsions* (see Figure 5-8). The dispersed or suspended liquid is called the internal, or *dispersed*, phase. The other liquid is called the external, or *continuous*, phase.

The most common types of emulsions are oil in water and water in oil. An example of oil-in-water emulsion is milk. Examples of water in oil emulsions include grease, margarine, and oil-base fluids. The first and most common emulsions studied were oil in water. Water-in-oil emulsions were studied later and sometimes are called *invert* emulsions.

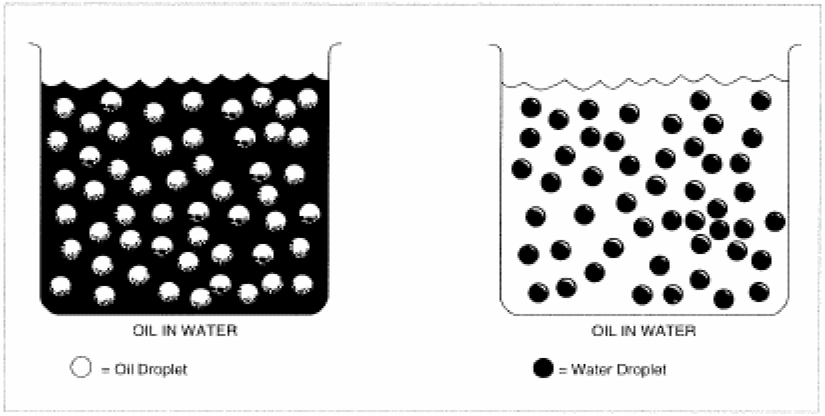


Figure 5-8 Emulsions

Dispersing one liquid as small droplets in another liquid increases the surface area between the two liquids. The surface energy/tension that exists at the interface between two liquids is called the *interfacial* energy or interfacial tension. This interfacial energy/tension tends to minimize the surface area and work must be performed (energy expended) to increase interfacial surface area and overcome these forces. A mixer can form a mechanical emulsion between two pure liquids, such as water and hydrocarbon, but the emulsion breaks and the two phases separate when the agitation ceases. This de-emulsification is due to interfacial energy/tension minimizing interfacial surface area. In order to form a stable emulsion, a third component is necessary.

Surfactants

Surface active compounds are compounds that orient at interfaces or surfaces and lower surface or interfacial energy/tension. Surface active compounds are often called *surfactants*. The most common example is soap, as indicated in Figure 5-9.

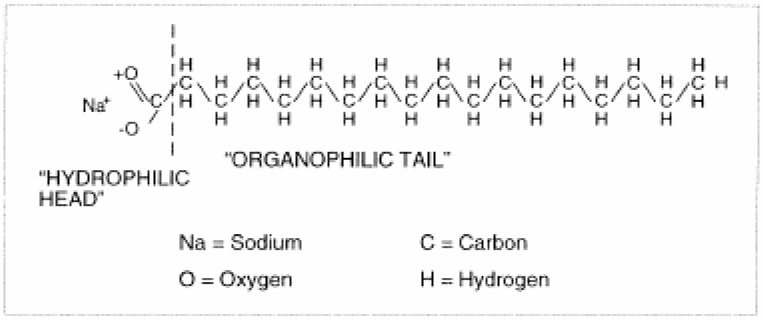


Figure 5-9 Surfactant Structure (Soap)

This compound has both a hydrophilic "head," which is polar and ionized, and an organophilic "tail," which is nonpolar (see Figure5-10). The structure is called amphiphilic to indicate the dual character of these compounds. Surfactants are usually elongated and only partially soluble in either oil or water. The degree to which surfactants are soluble in oil or water can be denoted by the hydrophilic-lipophilic (organophilic) balance (HLB). Surfactants which are more water soluble (hydrophilic) tend to form oil in water emulsions and have high HLB values. For example, Drilling Mud Emulsifier (DME) has an HLB of 7.7. Surfactants which are more oil soluble (organophilic) and form water in oil emulsions, have low HLB values. In addition to the HLB characteristic is the type salt or valence of the hydrophilic portion of the surfactant. Monovalent cations promote oil in water emulsions and Divalent cations promote water in oil emulsions.

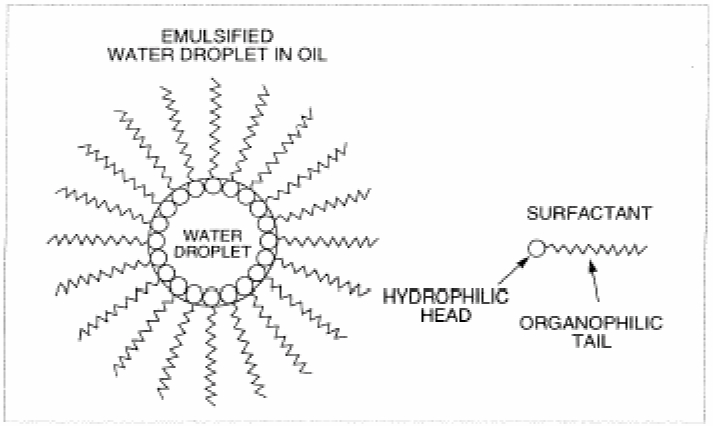


Figure 5-10 Orientation of Surfactants at an Interface

Surfactants orient at interfaces and lower surface energy/tension. This reduces the forces necessary to form new interfacial area and reduces the interfacial area after the emulsion is formed. Surfactants oriented at the interface also form a chemical skin around the emulsified, dispersed phase and mechanically stabilize the interface, thereby helping to prevent droplets from coalescing and breaking when colliding. Small insoluble particles will also do this by forming a mechanical emulsion. Examples of mechanical emulsifiers are lignite and bentonite.

Temperature increases the frequency of droplet collisions and decreases the stability of emulsions. Imposing an electrical field across an emulsion will also tend to break the emulsion, which is the basis of the emulsion stability test for oil-base fluids. Increasing the viscosity of the external phase will decrease the frequency of collisions and stabilize the emulsion.

Dispersions

Powdered solid suspended in a liquid are called a dispersed system, or simply a *dispersion*. The internal or dispersed phase is the solid and the continuous phase is the liquid (see Figure 5-11).

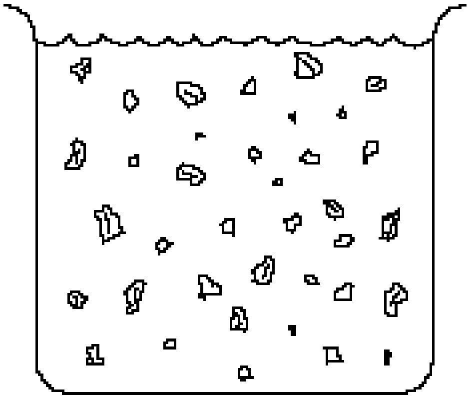


Figure 5-11 Dispersion of a Mineral Powder

The term dispersion is also used to define the process itself which requires the solid particles to be coated by the liquid.

Consider a drop of liquid on a flat solid surface. Three interfaces and three interfacial tensions (γ) are involved – solid/air (S/A), solid/liquid (S/L), and liquid/air (L/A). At equilibrium, it can be shown that,

$$\cos\theta = \frac{\gamma_{S/A} - \gamma_{S/L}}{\gamma_{L/A}}$$

If the contact angle (θ) is greater than or equal to 90°, the liquid is “nonwetting” with respect to the solid. The liquid tends to “bead” on the solid surface as water does on wax (see Figure 5-12). When the contact angle is 0°, the liquid completely wets the solid and, in fact, will spontaneously “spread” on the surface (i.e., water on glass). Surfactants lower the liquid/air surface tension (L/A), as discussed earlier, and reduce the contact angle. Surfactants often adsorb at the solid/liquid surface as well. This adsorbed layer alters the surface of the solid with respect to the liquid.

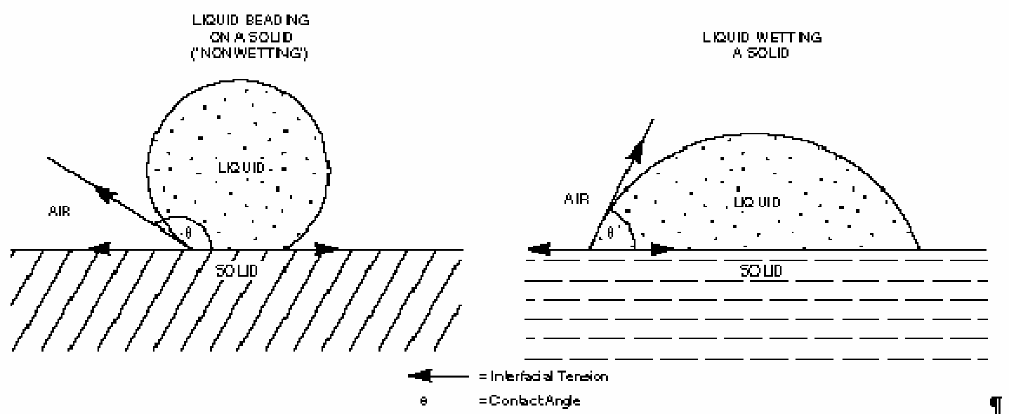


Figure 5-12 Liquids on Solid Surfaces

As indicated by Figure 5-13, the high-surface-energy (hydrophilic) mineral solid is preferentially wet by a high-surface-energy/tension polar liquid, such as water. Even if the surface is initially coated or wet with a low-surface-energy/tension hydrocarbon oil, water will displace the oil and “water-wet” the hydrophilic surface. Just as “like dissolves like” and “like solvates like,” “like wets like.” Adsorbing a surfactant, however, alters the mineral surface with the hydrocarbon tails oriented toward the oil.

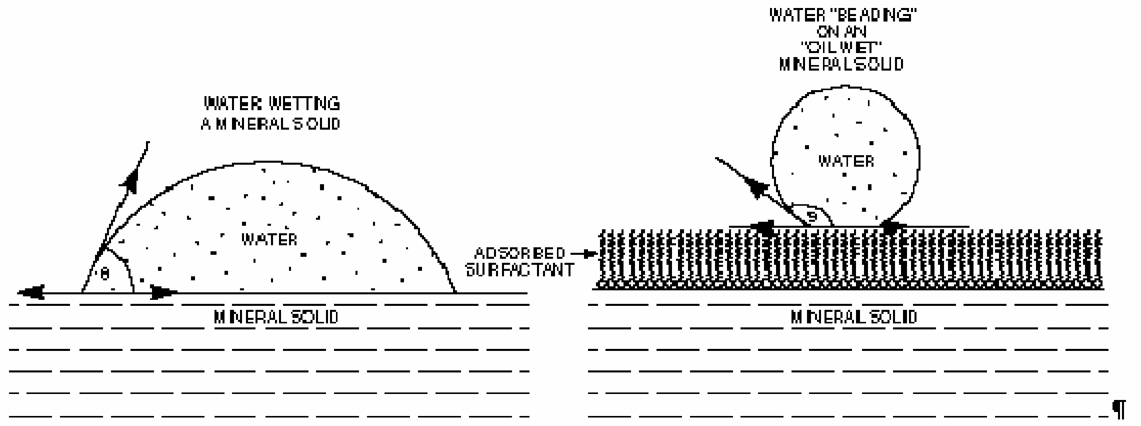


Figure 5-13 Oil Wetting

The surfactant “mimics” a hydrocarbon surface and lowers the surface energy of the mineral. Water, a high-surface energy/tension liquid, will not wet a low-energy surface and will tend to “bead up.” The mineral surface has been rendered “oil-wet.” Examples are waxing the paint on an automobile and using a wetting agent to “oil-wet” barite during weight-up of oil-base fluid systems.

Dispersions, like emulsions, once formed, are subject to particle/particle collisions. These collisions can result in destabilization of the dispersion by flocculation, aggregation, and settling of the solids. Surfactant films help to stabilize dispersions by preventing close approach between particles. Temperature increases the number of collisions and decreases the viscosity of the continuous phase. The latter promotes settling due to Stoke's law and is a particular problem in dispersions.

The most important source of instability occurs in combined emulsions/dispersions. Oil-base fluids can be considered as three-phase oil/water/ionic-mineral solid systems where oil is the continuous phase and water and mineral solids are dispersed. The mineral solids are hydrophilic and will preferentially water-wet. In the absence of surfactants, even if the mineral solid is oil-wet initially, water will tend to displace oil from the surface and water-wet the solids. As the solids water-wet, they stick together, forming larger diameter agglomerates which settle out. Altering the surface of the ionic solid with an adsorbed surfactant layer counteracts this tendency and promotes oil wetting.

General Colloidal Systems

Colloidal systems are defined as emulsions or dispersions in which the diameter of the dispersed phase is of the order of $\leq$ 1 micron (10^{-6} m). The ratio of area to volume in colloidal systems is large (ratios of 10^{6} are not uncommon) and surface effects (surface tension, adsorption, wetting) predominate the physical characteristics. Emulsification requires the creation of new surface area which interfacial tension opposes. While surfactants will minimize the problem, it is never eliminated in practical systems. Common minerals, such as barite, clays, calcite, quartz, etc., are ionic or polar and, as such, are hydrophilic and preferentially water-wet. Adsorbed surfactants alter the surface, but the inherent tendency remains. Dispersed phases are constantly tending to collide with each other leading to coalescence or aggregation. Surfactants are our most important tool for controlling these destabilizing forces and processes.

Non-Aqueous external phase

Base Oils

Hydrocarbon oils are the continuous phase in oil-base fluids. They are non-polar, low-surface energy/tension liquids and interact only weakly with mineral solids. This characteristic is the basis for the use of oil-base fluids as non-reactive, inert drilling fluids. Hydrocarbon oils will not allow clays to swell, which makes them ideal for drilling hydratable shales.

The most commonly used oils today are synthetics where certain environmental regulations prevail, low-aromatic-content, low-toxicity mineral oils, and No. 2 diesel oil. Crude oil has been used in the past but finds little application in today’s modern day oil-mud drilling fluids. Crude is relatively cheap, often available, but may need topping to minimize flammability since a flash point greater than 180°F (82°C) is advised.

- Crude contains native asphaltenes and resins which can interfere with other additives.
- Crude is usually used in “poor boy” oil-base fluids.

No. 2 diesel oil is a moderately-priced, commonly available distillate which contains none of the native asphaltenes or resins in crude and is the most commonly used oil for mixing oil-base fluids. Diesel based systems are generally used today only in land drilling operations. Offshore drilling operations limit the use of diesel base systems due to the toxicity of the base oil. The aromatics in diesel oil can swell rubber gaskets, seals, and pipe rubbers, however, an aniline point greater than 140°F (60°C) (the higher the aniline point, in general, the lower the concentration of aromatics) is recommended. Mineral oils are recommended due to lower toxicity relative to diesel oil. Most of the toxicity of diesel oil is associated with the aromatics, particularly the multi-ring or polynuclear aromatics. Low-toxicity mineral oils have low to very low concentrations of aromatics and those present are predominantly single-ring. Synthetics are the preferred oil in offshore drilling operations where environmental regulations prohibit the discharge of cuttings and/or whole mud to the sea.

All hydrocarbon oils currently used in oil-base fluids are more viscous than water. This probably accounts for the lower penetration rates observed with oil-base fluids (all things being equal) relative to water-base fluids because of the higher viscosity at the bit. The higher viscosity oil also partially accounts for the lower filtration losses observed with oil-base fluids relative to water-base fluids because of Darcy's Law (assuming identical permeability filter cakes). See Table 5-3 for the properties of several oils.

Table 5-3 Base Fluid Properties

Oil	Density at 60°F (15°C) (g/ml)	Initial Boiling Point	Final Boiling Point	Flash Point	Aniline Point	Aromatic Content (wt. %)	Viscosity at 104°F (40°C) (cSt)
Diesel	0.84	383°F 195°C	734°F 390°C	149°F 65°C	154°F 68°C	25 %v/v	3.4
ISO-TEQ C16-18 **(SYN-TEQ sys.)**	0.792	>518ºF >270ºC	NA	273ºF 134ºC	180ºF	NA	3.6
Exxon **ESCAID 110**	0.806	394°F 201°C	459°F 237°C	167°F 75°C	162°F 72°C	0.05	1.63
SIPDRILL 2/0 **(PARA-TEQ sys.)**	0.760	412ºF 211ºC	455°f 235°C	203ºF 95ºC	189°F 87°C	< 0.1	1.75
Total HDF2000	0.808	450°F 232°C	622°F 328°C	221°F 105°C	192°F 89°C	0.4	3.3
Conoco LVT200	0.820	421°F 216°C	518°F 270°C	201°F 94°C	166°F 74°C	1.0	2.1
ALPHA-TEQ	0.778	437°F 225°C	518°F 270°C	237°F 114°C	147°F 64°C	0.1	2.06
EDC 99 DW	0.811	448°F 231°C	509°F 265°C	214°F 101°C	176° 80°C	0.0	2.28
SARAPAR 147	0.76 @ 30°c	NA	NA	248°f 120°C	90°C	NA	2.6

Aniline Point

The Aniline Point is an indicator of the detrimental effects (damage) oil will inflict on the elastomers (rubber compounds) that come into contact with oil-based (non-aqueous) drilling fluids. It is commonly referred to as a test to evaluate base oils that are used in oil muds. The test indicates if a particular oil is likely to damage those parts of the drilling fluid system which are constructed from rubber materials.

The aniline point is called the "aniline point temperature," which is the lowest temperature (°F or °C) at which equal volumes of aniline ($C_6H_5NH_2$) and the oil form a single phase. The aniline point (AP) correlates roughly with the amount and type of aromatic hydrocarbons in an oil sample. A low Aniline Point is indicative of higher aromatic, while a high Aniline Point is indicative of lower aromatic content.

It has been established through field experience that oils exhibiting an Aniline Point of less than 140º F (60º C) will be damaging to the elastomers (rubber parts) of a drilling fluid circulating system. The API has developed test procedures that are the standard for the industry.

Synthetics

Synthetic-base drilling fluids (SBF) use a synthetic type material as the continuous phase. The first SBF was used offshore Norway in March 1990. Since that time, due to the ever-changing environmental status of SBFs, several types of synthetic materials have been used to formulate the synthetic-base fluid. Baker Hughes Drilling Fluids, in April 1994, used an isomerized olefin (ISO-TEQ$^{\text{TM}}$) for the continuous phase of a SBF. This was the first use of the olefin which has now become the industry standard. Like the hydrocarbon-base fluids, the olefin-base fluid will not solvate or swell clays, making them ideal for drilling hydratable shales.

Unlike mineral and diesel oils which are distilled from crude oils, synthetic type materials are usually polymerized from ethylene. Since the synthetics are pure products made from ethylene, they contain no aromatics, thereby lowering the toxicity level normally associated with aromatic compounds. Like hydrocarbon oils, the synthetic type materials are more viscous than water. See Table 5-4 for the properties of several synthetic materials.

Table 5-4 Properties of Synthetic Materials

Oil	Density at 60°F (15°C) (g/ml)	Initial Boiling Point	Final Boiling Point	Flash Point	Aniline Point	Aromatic Content (wt. %)	Viscosity at 104°F (40°C) (cSt)	Pour Point (°C)
LAO (ALPHA-TEQ sys.)	0.778	437ºF 225ºC	518ºF 270ºC	237ºF 114ºC	147ºF 64ºC	0.1	2.06	- 12
CLAIRSOL NS	0.815	500°C 260°C	581°C 305°C	252°F 122°C	190°F 88°C	0.2	3.4	- 18
SYN-TEQ CF (CF-2002)	0.79	482°F 250°C	626°F 330°C	284°F 140°C	180°F 82°C	< 0.001	2.9	<-10
SN – 1890 (SYNTERRA)	0.775			116°C			1.67	- 18

Aqueous (internal) phase

Water contamination is unavoidable in oil-base fluids. Water is picked up at the change out from water-base fluid, from drilling water-bearing sands, and from drilling hydratable shales. Oil-base fluids can be formulated to accommodate additional water. The salinity of the water phase can be controlled with the use of dissolved salts. Calcium chloride ($CaCl_2$) is the most common salt used, although sodium chloride (NaCl) or drillers' salt, seawater, and various brines have been used. The choice is dictated by both the formation and economics.

Aw and Osmosis

Consider the hydrated sodium chloride as shown in Figure 5-14. In addition to the shell of tightly adsorbed water molecules adjacent to the ions, there is more water molecules in the next layer, only moderately less adsorbed. Water molecules in the immediate vicinity of such ions are tied up in hydration and not entirely free to hydrate other ions. This is defined as *bound* water.

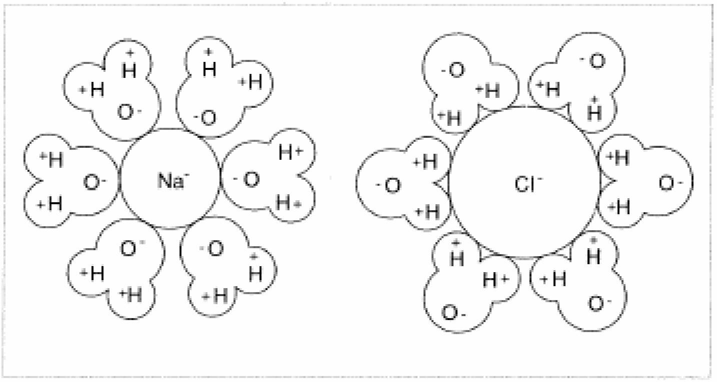


Figure 5-14 Hydrated Sodium and Chloride Ions

As the concentration of ions increases, so does the concentration of water molecules tied up in hydration. As the concentration of water molecules tied up in hydration increases, the concentration of *free* water molecules (not involved in hydration) decreases. The availability of the water molecules in a solution to hydrate additional solutes can be quantified by the “activity” scale. All the water molecules in freshwater are available for hydration and the activity (Aw) is defined as “1”. As salt, or any substance that hydrates, is added, the concentration of hydrated ions or molecules increases and the availability of the brine molecules in the solution to hydrate any additional material decreases the activity (Aw).

If two solutions of different Aw are poured together, diffusional mixing will result in a uniform Aw intermediately between the two. If two solutions of different Aw are separated by a semi-permeable membrane, an unusual situation occurs, as shown in Figure 5-15. A semi-permeable membrane is defined as a thin membrane which will allow water molecules to freely pass, but not salt ions.

Water molecules in the solution of higher Aw will diffuse into the solution with lower Aw, as before, but not the ions. If the chamber with the solution of lower Aw is sealed, then the water diffusing through the membrane increases the pressure in the chamber. This is defined as *osmotic* pressure (Figure 5-15)

Semi-permeable membranes are created between emulsified water droplets in water in oil emulsions and between emulsified water droplets and the formation drilled (see Figure 5-16). The layer of surfactant-rich oil will allow water molecules to pass, but not salt. Unless the Aw values are equal, an osmotic imbalance, or potential, will exist and water will migrate.

As the concentration of salt in the aqueous phase increases and the Aw decreases, less water is available to solubilize and hydrate other materials. Lime, for example, is less soluble in $CaCl_2$ solutions than in water.

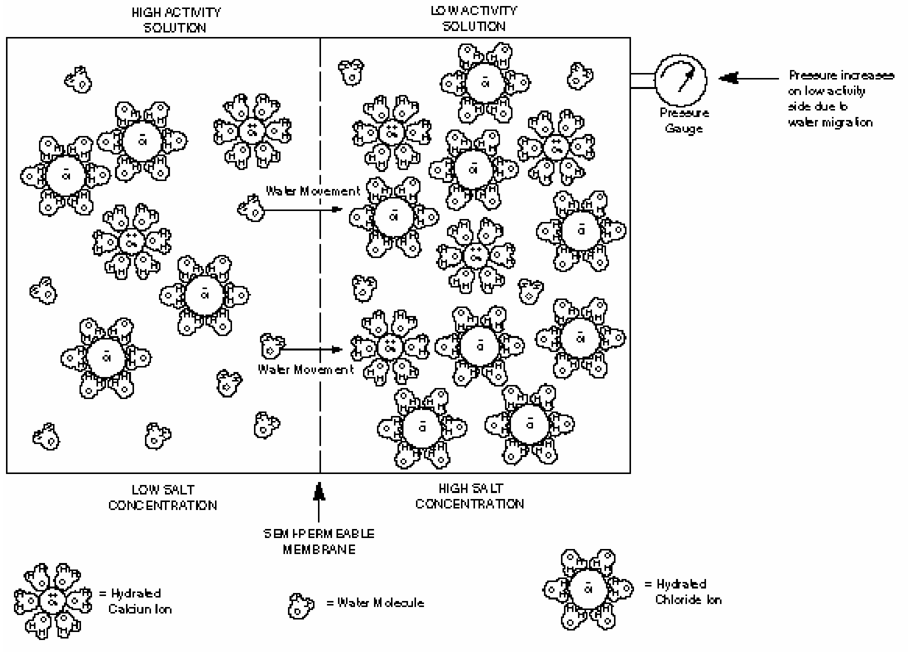


Figure 5-15 Osmosis

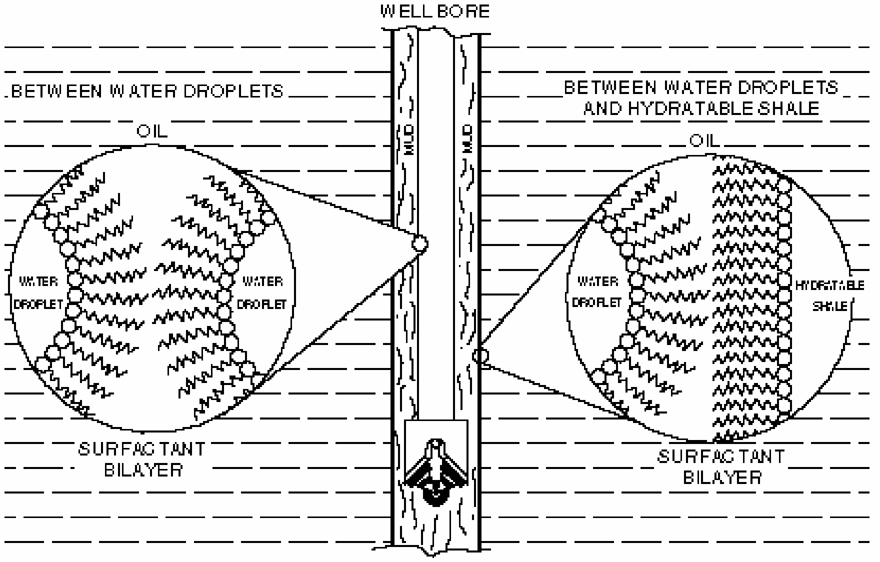


Figure 5-16 Semi-Permeable Membranes

Emulsifiers

Surfactants

Surfactants lower surface energy/tension, as discussed earlier, and are required to emulsify the water/aqueous phase and “oil-wet” the mineral solids. They are amphiphilic compounds with both hydrophilic “heads” and organophilic “tails,” partially soluble in both water and oil.

Surfactants are conveniently classified according to the charge on the hydrophilic “head.” The main classes are *anionic* (negatively charged), *cationic* (positively charged), and *non-ionic* (uncharged). The surfactants used in CARBO-DRILL^{SM}, ISO-TEQ^{TM}, SYN-TEQ™, and SYN-TEQ™ CF systems include CARBO-TEC®, CARBO-MUL® HT, OMNI-MIX^{TM}, OMNI-MUL™ and OMNI-TEC^{TM}. Because most modern invert emulsion fluids now contain more than one emulsifier with different chemical structures but similar functions, they will be discussed separately.

Soaps

The most common anionics are soaps. Soaps were the first surfactants known and are common. They are usually considered in a separate class. Soaps are formed from an alkaline material such as lime [$Ca(OH)_2$] and “long-chain” organic acids, such as stearic acid which is derived from tallow. The lime saponifies the stearic acid and supplies a cation (Ca^{++} in this case), also referred to as a *counter ion*, which balances the negatively charged hydrophilic head (see Figure 5-17).

Calcium soaps are the most commonly encountered soaps in oil-base fluids, or inverts, although magnesium, ammonium, and amine soaps have been used. *Long-chain* organic acid sources include tall oil, asphaltic, naphthalenic, and blown-wax acids. Soaps can be pre-formed and used, or can be formed in the drilling fluid using lime.

Soaps are the cheapest surfactants. Some, such as asphaltics and naphthalenic, occur naturally in some oils. Soaps are good emulsifiers in high pH or water-base drilling fluid systems, but less useful at lower pH. They emulsify freshwater well, but show poor electrolyte tolerance (they lose effectiveness at low Aw). Thermal stability of the molecule is good as is resistance to alkaline hydrolysis (lime will not decompose the molecule), but some soaps gel up at low temperatures. All soaps tend to require additional surfactants at high solids concentration. Tall oil soap (CARBO-TEC or OMNI-TEC) is particularly good at dispersing DENSIMIX®(hematite).

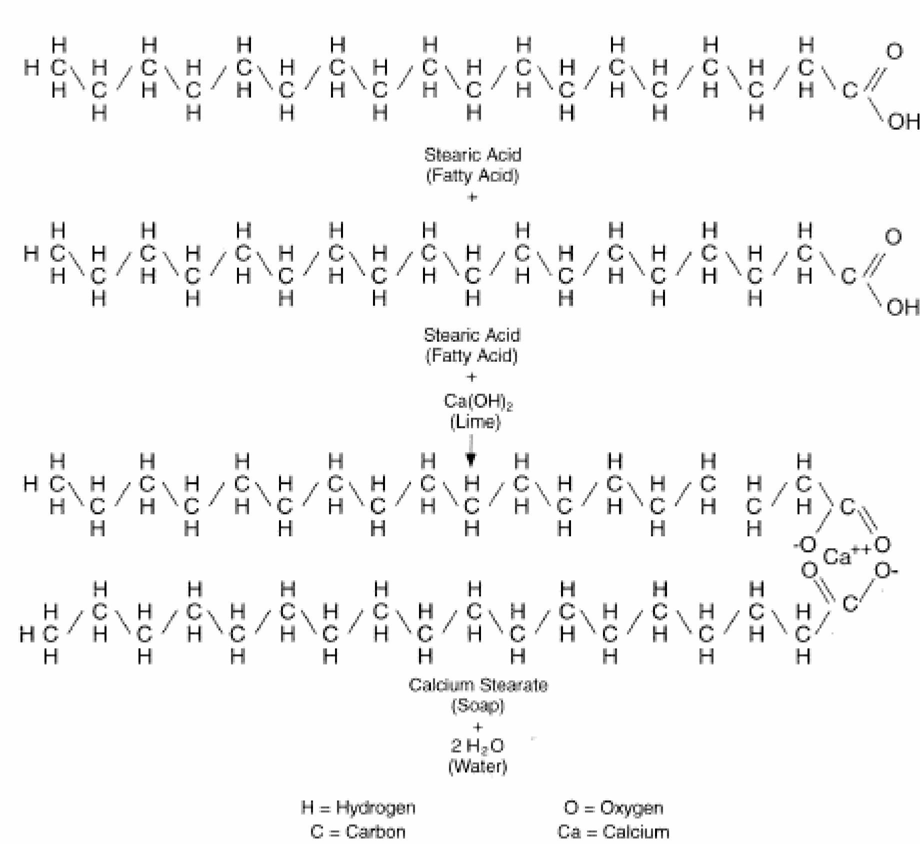


Figure 5-17 Soap Formation

Fatty Acids

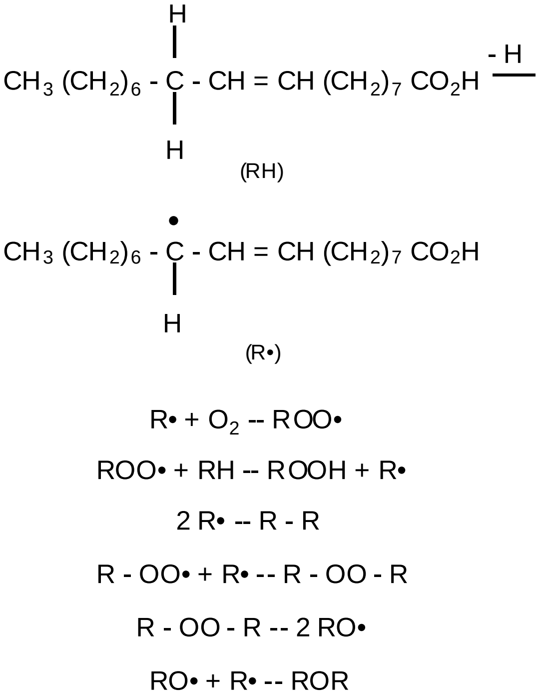
Fatty acids are the basic components for nearly all emulsifiers and wetting agents used in the preparation of invert emulsions. Their demand is due primarily to their low cost and availability in many forms, including crude and refined tall oil, animal pitch, and others.

Tall oil fatty acids are the most common and are obtained as a by-product of the Kraft pulping process, in which alkaline pulping liquor converts fatty and rosin acids present in soft pines to their corresponding sodium salts. These sodium salts are then removed and acidified to yield crude tall oil, which can either be processed into anionic emulsifiers or further refined for use in the manufacture of non-ionic emulsifiers.

Chemical composition of tall oil varies with the geographical source and species of trees used in pulping and in the refining process. Oxidation, isomerization, adduct formation, and polymerization are all factors in the refining process which will influence the final tall oil product.

Anionic Emulsifiers

Anionic emulsifiers, such as CARBO-TEC®, are usually prepared by oxidation of crude tall oil. This oxidation process is shown in Figure 5-18.



$$CH_3\,(CH_2)_6 - \overset{H}{\underset{H}{C}} - CH = CH\,(CH_2)_7\,CO_2H \xrightarrow{-H}$$

(RH)

$$CH_3\,(CH_2)_6 - \overset{\bullet}{\underset{H}{C}} - CH = CH\,(CH_2)_7\,CO_2H$$

(R•)

$R\bullet + O_2$ -- $ROO\bullet$

ROO• + RH -- ROOH + R•

2 R• -- R - R

R - OO• + R• -- R - OO - R

R - OO - R -- 2 RO•

RO• + R• -- ROR

Figure 5-18 Oxidation of Fatty Acids during the Manufacture of Anionic Emulsifiers

The fatty acid of the crude tall oil is converted to a water-insoluble soap by reaction with calcium hydroxide. Soap formation changes the relative solubility of the fatty acid, whereas air oxidation increases the surface activity by introducing hydrophilic oxygen groups.

Anionic emulsifiers are used in vast amounts in the detergent industry. They are excellent at reducing interfacial tension, have good thermal stability, and have resistance to alkaline hydrolysis (some sulfated or sulfonated oils are an exception).

Non-ionic Emulsifiers

Non-ionic emulsifiers, such as OMNI-MUL™, are used to provide emulsion stability in drilling fluids and also to facilitate wetting and dispersion of incorporated solids. These non-ionic emulsifiers tend to be non-ionic, although they can have slightly cationic tendencies.

Cationics tend to adsorb strongly on mineral surfaces and are excellent oil-wetters. They also function excellently when emulsifying concentrated calcium chloride solutions. Thermal stability is moderate and resistance to alkaline hydrolysis is fair to good.

Non-ionics reveal excellent thermal stability and have a high resistance to alkaline hydrolysis. They also exhibit good electrolyte tolerance. Non-ionics are usually mixed with other surfactants to maximize oil-base fluid temperature stability.

One of the most important factors in the formulation of the amide-type non-ionic emulsifier is the selection of the cross-linking agent. Shown below in Figure 5-19 is the manufacturing process for polyamide emulsifiers.

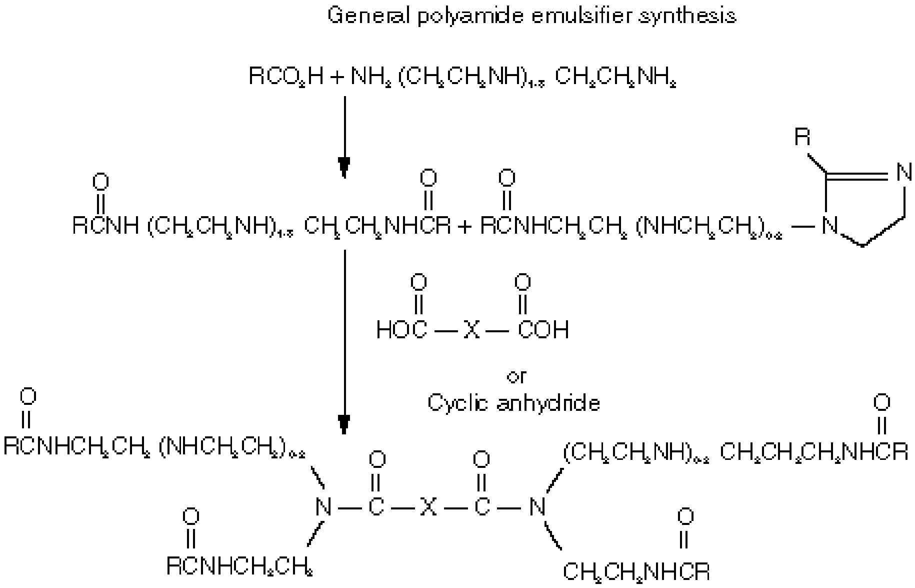


Figure 5-19 General Polyamide Emulsifier Synthesis

Colloids

Organophilic Clay

Organophilic clays (CARBO-GEL® and CARBO-VIS™) are the most common gelling and suspending additives used in oil-base fluids. Organophilic clays are usually formed by reacting a quaternary ammonium chloride (quat) with sodium bentonite. The cationic quat replaces a sodium ion on the surface of the bentonite.

This effectively renders the surface oil wettable and allows the hydrocarbons to wet and penetrate the clay lattice structure and swell the organophilic clay to dispersion. While organophilic bentonite is the most common example, organophilic hectorite and sepiolite can be used as well.

To obtain the full potential rheology of any organoclay, both shear and heat are required. Organoclays are manufactured by either a “dry” or “wet” process. The latter method produces purified clays which are more thermally stable, especially the hectorite base organoclays, which are more consistent in their performance. By varying the quat chemistry and clay type, a wide variety of organoclays are available which can be used with various base oils and in various temperature ranges. Maximum thermal stability of organoclays varies between 285°F (140°C) and 400°F (204°C). The cost of the organoclay grades increases with thermal stability.

Polymers

Several polymers now have application for use in oil-base drilling fluids. These polymers increase fluid carrying capacity, in both diesel and mineral oil systems, and extend the viscosity temperature stability to in excess of 500°F (260°C). Polymers used, include elastomeric viscosifiers (CARBO-VIS^{TM} HT), lightly sulfonated polystyrene polymers, fatty acids, and various dimer-trimer acid combinations.

Asphalt / Gilsonite

Asphalt is a petroleum-derived colloidal gel composed of colloidal asphaltenes, polar aromatics (resins), and oils (see Figure 5-20).

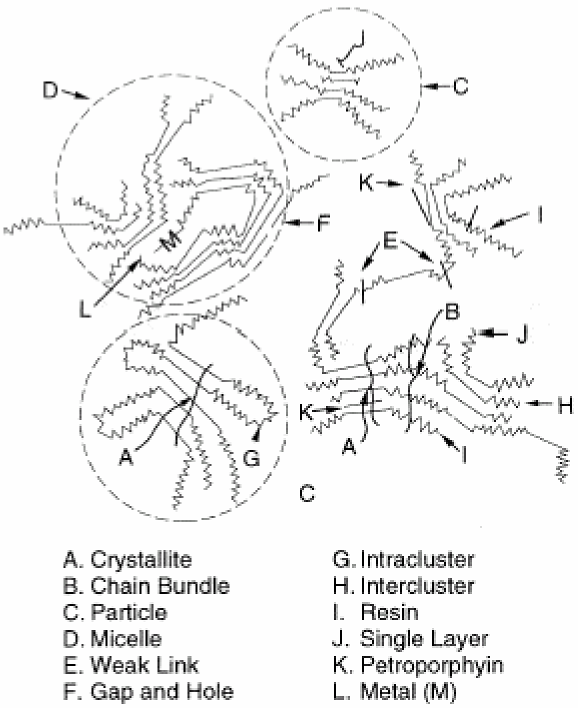


Figure 5-20 Macrostructure of Asphalt

The most commonly encountered are those that are naturally present in crude, gilsonite (a mined product), and blown asphalt. The active components are the asphaltenes. Quality asphaltenes are highly-associating and form *micelles* which are thermally stable.

The primary use of asphalt is for fluid loss control. The concentration used is 1 to 15 lb_m/bbl (2.9 to 42.8 kg/m^3). Asphalt also functions as a shale stabilizer at 5 to 15 lb_m/bbl (14.3 to 42.8 kg/m^3). When used at higher concentrations, such as ≥ 40 lb_m/bbl (114 kg/m^3), it functions as a viscosifier by increasing the base fluid viscosity.

Quality asphalt is relatively cheap, resistant to electrolytes, alkaline hydrolysis, and is an excellent fluid loss control material. Asphalt also has good thermal stability. The cake is soluble in most crude oils, so is somewhat self-cleaning when producing the well.

Amine Lignite

Amine lignites are prepared by reacting quats or amido amines with lignites. Variances in base materials and reaction conditions result in a wide variety of amine lignites, which has a direct influence on their performance and thermal stability. They perform adequately up to 350°F (177°C).

Lime

Acid gases, alkalinity, and corrosion are usually controlled with lime, $Ca(OH)_2$, or quicklime, CaO, in oil-base fluids.

$$CO2 + H2O \rightarrow H2CO3$$

$$H2CO3 + Ca(OH)2 \rightarrow CaCO3 + 2H2O$$

$$H2S + Ca(OH)2 \rightarrow CaS + 2H2O$$

If CO_2 is present, lime additions will be needed only if an anionic emulsifier is being used. Calcium hydroxide is needed to form the calcium soap. Once the soap is formed, any introduction of CO_2 in the fluid will not affect the fatty acid and lime reaction.

If H_2S is introduced to the system, the CaS compound will remain stable as long as there is excess lime present. Basic zinc carbonate can also be used to react with H_2S.

Emulsion based drilling fluids

CARBO-DRILL® Oil-Base Drilling Fluid System

The CARBO-DRILL® oil-base fluid systems are designed for maximum stability and versatility. Three systems make up the CARBO-DRILL system family – CARBO-FAST℠, CARBO-TEC®, and CARBO-CORE® (see Chapter 6, *Reservoir Application Fluids*). Formulations for the CARBO-DRILL system are referenced in Table 5-6 through Table 5-13 at the end of this chapter.

CARBO-DRILL systems can be formulated with low-aromatic mineral oil instead of diesel oil as the external phase for drilling in environmentally-sensitive areas. Mineral oil systems are identified by the S.E.A. designation (i.e., CARBO-TEC® S.E.A., CARBO-FAST℠ S.E.A., and CARBO-CORE S.E.A). Typically, S.E.A. systems will require more organophilic clay and emulsifiers and will exhibit lower electrical stability (ES) values when compared to diesel systems. The CARBO-DRILL systems are very versatile, from relaxed to a very high-temperature stable system. CARBO-TEC S.E.A. is designed specifically to meet environmental requirements for drilling in the North Sea.

CARBO-FAST℠ / CARBO-TEC®

The CARBO-FAST system is prepared as a “relaxed” oil-loss fluid with a low colloid content, and is designed for rapid rates of penetration. Filtrate loss can be controlled over a wide range depending on the control required for a given well.

CARBO-FAST systems can be converted to a CARBO-TEC controlled filtrate loss when low values are required. This is achieved by using the additional products CARBO-TEC, an anionic emulsifier, and CARBO-TROL, an asphaltic filtrate loss control additive. CARBO-TROL A-9, a non-asphaltic filtrate loss control additive, can be substituted if desired.

The CARBO-DRILL systems can incorporate a much higher percentage of water, compared to conventional oil-base drilling fluid. Depending on fluid weight and $CaCl_2$ content, the CARBO-DRILL oil/water ratio can be used to the 45/55 - 60/40 range. Increased water content decreases the amount of oil on cuttings as they are discharged over the shaker, allowing oil-base drilling fluids to meet cuttings discharge criteria in the North Sea. The lower oil/water ratio CARBO-DRILL S.E.A. system is widely used in the North Sea.

In addition to decreasing the amount of oil associated with drill cuttings, the increase in brine content has also been shown to reduce the cost of the oil fluid, since less oil is necessary.

Because of the large volume of water present, the fluid system is composed of specifically designed products. These CARBO-DRILL systems have been designed to cope with the high water content and to exhibit rheology comparable to more conventional oil-base fluid systems. The proper emulsifiers and oil wetting agents result in a stable system with no water in the high-temperature/high-pressure (HT/HP) filtrate. Field and laboratory evidence has shown that the CARBO-DRILL systems can incorporate additional water contamination with minimal increase in rheological properties and little or no water wetting of solids, even when water may be temporarily present in the HT/HP filtrate.

The principal emulsifiers used in the North Sea high water content CARBO-DRILL S.E.A. are CARBO-MUL HT and CARBO-MIX. Field evidence has shown that CARBO-MUL HT/CARBO-MIX emulsifier's combinations are synergistic. The ratio of these products is dependent upon the oil/water ratio, temperature, and fluid density.

System Maintenance

To achieve optimum economics when using emulsifiers and changing oil content, as well as to minimize the plastic viscosity of the fluid, the oil/water ratio is varied with the fluid density.

The CARBO-DRILL systems are more tolerant of water content than most conventional oil-mud systems; however, they become less tolerant to large quantities of low-gravity solids as water content increases. Therefore, drill solids must be controlled. The use of linear motion shale shakers, preferably with the fluid cascaded from coarse mesh shakers (often referred to as scalping shakers) is recommended. Field experience has shown that solids contents up to 120 lb_m/bbl (348 kg/m^3 or 13.2% by volume) can be tolerated. However, fluids containing above 120 lb_m/bbl (348 kg/m^3) low-gravity solids should be diluted with the non to low solid laden CARBO-DRILL SYSTEM. Ideally, the low-gravity solids content should be less than 80 lb_m/bbl (232 g/m^3 or 8.8% by volume).

The base formulations contain emulsifiers to start a system. However, as drilling commences, drill solids accumulation and removal, and increases in fluid density, requires increased additions of emulsifiers and wetting agents. Therefore, the CARBO-DRILL systems must be engineered so that each system is maintained without it becoming an expensive, over-treated fluid system. Water breakout and/or HT/HP increases are direct indicators that additional emulsifiers/wetting agents are required. It is recommended that the HT/HP checks be run every eight hours so that a trend can be developed. Any increases in HT/HP filtrate or detections of water in the filtrate must be treated immediately.

MAGMA-TEQ™ HTHP Non-Aqueous Drilling Fluid System

Increasing demand for drilling deviated HTHP wells in the North Sea area has resulted in the development of a HTHP oil based drilling fluid with unique suspension properties to avoid commonly observed density differentiations under extreme conditions. The stringent environmental and occupational hygiene regulations in the North Sea area also limit the use of commonly used chemistries for oil based HTHP applications. Baker Hughes Drilling Fluid's HTHP oil-based drilling fluid, MAGMA-TEQ™ is a state of the art response to this need.

During the development of this system several new products were created which include a specialized high temperature emulsifier; MAGMA-VERT™, improved fluid loss chemistry and suspension stabilizer; MAGMA-TROL™ and MAGMA-GEL™, a high temperature viscosifier which also acts as a barite sag preventative additive.

The MAGMA-TEQ™ system is stable to temperatures above 400º F and exhibits minimal density differential under dynamic and static conditions. The system can be weighted up to densities above 2.2 s.g. using barite or alternative weighting materials such as Ilmenite, Hematite, or Micromax. Typical O/W ratio is in the 85/15 to 90/10 range. The system is specifically designed for the use of commonly available aromatic-free base oils, and the products in the system exhibit minimal occupational hygiene exposure. Although the system is developed to conform to the environmental regulations of the North Sea area, several of the components of MAGMA-TEQ enhance the fluid properties in higher aromatic base oil environments such as diesel based drilling fluids.

The static barite sag analyses are extremely good and fall well within the sag factors specified by several major oil companies. MAGMA-TEQ also exhibits very low amounts of supernatant oil (syneresis) in samples aged both static and dynamically. Field tests demonstrate that the laboratory formulation properties further improve during drilling conditions; as with other oil mud systems, with repeated shear through bit nozzles and hole temperatures from the drilling operation.

System Maintenance

The system should be maintained in a manner similar to that described for the CARBO-FAST / CARBO-TEC system previously described.

SYNTERRA^{SM} Synthetic Base Drilling Fluid System

SYNTERRA^{SM} was developed to provide an environmentally friendly, non-aqueous synthetic system for use primarily on land operations as an alternative to diesel based drilling fluids. The fluid design is similar to conventional oil-based fluids and has applications in routine drilling as well as more demanding applications, such as HTHP and extended reach drilling. SYNTERRA is not designed for use in drilling offshore if a discharge of cuttings is planned.

The SYNTERRA system employs a unique low-kinematic viscosity synthetic base fluid; SN-1890, to deliver equal to diesel based fluid performance. Some of the benefits of using SYNTERRA include:

Enhanced environmental acceptability

Elimination of fumes commonly associated with diesel-based systems

Occupational hygiene and environmental properties are improved compared to diesel-based systems

Simple, cost-effective formulations

Low kinematic viscosity base fluid for optimal rheology

Thermal stability

Minimal rheology changes with temperature

Good hole cleaning characteristics

Fully compatible with diesel-based systems for blending of the systems as necessary

Some of the applications of SYNTERRA^{SM} include:

Land drilling

Limited discharge sites

Drilling within city limits

Environmentally sensitive areas such as wet lands and reserves

Where an alternative to diesel is desired.

System Maintenance

The system should be maintained in a manner similar to that described for the CARBO-FAST / CARBO-TEC system previously described.

SYN-TEQ Synthetic Base Drilling Fluid System

The SYN-TEQ system provides superior performance and environmental acceptability in one synthetic-based drilling fluid. The system is based upon the use of a low-viscosity olefin isomer. Baker Hughes Drilling Fluids ISO-TEC® base fluid is a nontoxic, isomerized olefin designed specifically for synthetic drilling fluid applications. The ISO-TEC base fluid is a biodegradable fluid and is combined with other specialized fluid additives to form the SYN-TEQ system that offers a safe alternative to traditional oil muds. SYN-TEQ systems can be formulated with low SWR (synthetic/water ratio) for cost savings and overall enhanced well economics.

The SYN-TEQ system offers several environmental and logistical advantages over traditional oil-based muds. Also the system delivers superior lubricity and increased thermal stability. Together, these advantages make SYN-TEQ a preferred drilling fluid where the superior performance of a non-aqueous fluid is desired and where the use of an oil-base fluid is prohibited by environmental concerns. The SYN-TEQ system passes strict environmental testing, including toxicity and biodegradability, designed to evaluate any environmental impact.

System Maintenance

The system should be maintained in a manner similar to that described for the CARBO-FAST / CARBO-TEC system previously described.

SYN-TEQ CF Synthetic Base Drilling Fluid System

The SYN-TEQ CF non-aqueous drilling fluid system is designed specifically to allow the continuous discharge of drill cuttings to the sea. SYN-TEQ CF is compliant with the National Pollutant Discharge Elimination System (NPDES) permit for the Western Gulf of Mexico (2/12/02).

SYN-TEQ CF is formulated with a minimum number of products chosen specifically for individual performance characteristic. The system can be used in any drilling operation requiring superior performance, and is recommended for deepwater operations.

SYN-TEQ CF represents an environmental advance over previous non-aqueous systems using olefins as the base fluid. SYN-TEQ CF is formulated from the base fluid C16/18 isomerized olefins which are acknowledged by the US EPA as being an environmental benchmark in the Gulf of Mexico.

System Maintenance

The system should be maintained in a manner similar to that described for the CARBO-FAST / CARBO-TEC system previously described.

GEO-TEQ™ Synthetic Base Drilling Fluid System

GEO-TEQ is a specially formulated, environmentally responsible synthetic drilling fluid system which addresses the drilling performance, environmental, and geochemical needs desired in synthetic systems. Accordingly, GEO-TEQ uses GT-2500™ as the base fluid, which through its unique composition will not interfere with the interpretation of naturally occurring hydrocarbon components during crude oil analysis. Particularly, GT-2500 enables accurate analysis of the “bio-markers”, Pristane and Phytane, even when the base fluid constitutes as much as 25% of the reservoir sample.

GEO-TEQ™ is a synthetic drilling fluid system specifically designed to allow continued discharge of drill cuttings to the sea and is compliant with the National Pollutant Discharge Elimination System (NPDES) permit for the Western Gulf of Mexico.

System Maintenance

The system should be maintained in a manner similar to that described for the CARBO-FAST / CARBO-TEC system previously described.

Product applications and recommendations

CARBO-GEL®

CARBO-GEL® is a high-purity, wet-process, high-yielding organophilic hectorite clay used as the viscosifying and suspending agent in oil- and synthetic-base fluid systems. Because it is more active than organophilic bentonite clay, CARBO-GEL increases the carrying capacity and hole cleaning characteristics of oil and synthetic-base fluids.

CARBO-GEL is exceptionally effective at maintaining the yield point values in oil and synthetic-base fluids after high-temperature aging.

Concentrations of 1 to 5 lb_m/bbl (2.9 to 14.3 kg/m^3) are usually adequate for most applications. The type of oil determines the concentration limits necessary for building viscosity and for gel-building properties. Good shear is recommended. Low-aromatic oil will require as much as three times the concentration of CARBO-GEL, depending upon the oil type and the water content. Pilot testing is highly recommended when using unfamiliar oil.

Table 5-5 Typical Physical Properties – CARBO-GEL

Appearance	Tan powder
Hygroscopic	No
pH in H_2O	n/a
Bulk Density	45 lbm/ft^3 (720 kg/m^3)

CARBO-GEL® II

CARBO-GEL® II is a gel-forming organophilic clay composed of a selected grade of montmorillonite clay reacted with a high-purity organic compound. As an economical viscosifier, CARBO-GEL II is used to increase yield point and gel strength, thus improving the carrying capacity of low-weight, oil-base fluids. It provides excellent solids suspension and remains stable at temperatures less than 285°F (140°C). The recommended treatment level is 4 to 8 ppb depending on the desired yield point.

Table 5-6 Typical Physical Properties – CARBO-GEL II

Appearance	White/tan powder
Hygroscopic	No
pH in H_2O	Neutral
Bulk Density	55 lbm/ft^3 (881 kg/m^3)

CARBO-MIX™

CARBO-MIX™ is a high activity emulsifier for use in CARBO-DRILL oil-base fluid systems. It will emulsify any chloride brine or water into any base oil, and provides filtration rate control and aids oil-wetting of solids. CARBO-MIX is thermally stable to temperatures in excess of 204°C (400°F).

CARBO-MIX is used as an emulsifier in the CARBO-DRILL S.E.A. oil-base fluid systems with oil/water ratios up to 40/60. In combination with CARBO-MUL® HT, it provides thermally stable, high brine content emulsions. CARBO-MIX can be used in any type of oil-base fluid with any combination of CARBO-MUL HT or CARBO-TEC. Normally, 0.5 to 1.5 gal/bbl (11.9 to 35.7 L/m^3) of CARBO-MIX will be required in a CARBO-DRILL system, depending upon density and total solids content.

Table 5-7 Typical Physical Properties – CARBO-MIX™

Appearance	Black viscous liquid
Flash Point	104°F (40°C) (PMCC)
Pour Point	16°F (9°C)
Density	7.9 lbm/gal (952 kg/m^3)
Viscosity	800 to 1000 cp at 68°F (20°C)

CARBO-MUL® / CARBO-MUL® HT

CARBO-MUL®is an oil-soluble, modified imidazoline (CARBO-MUL® HT is a *high-temperature* polyamide). Both are used as emulsifiers and wetting agents for the CARBO-DRILL family of oil-base fluid systems.

CARBO-MUL is compatible with a wide range of internal phase salinities and can be used to emulsify calcium chloride and sodium chloride brines, seawater, and freshwater in oil-base fluids. CARBO-MUL is substantive (adsorbs on) to mineral surfaces, reducing interfacial surface energy and rendering MIL-BAR, other weight materials, and drill solids oil-wet. CARBO-MUL, unlike soap surfactants, does not require lime hydrate in order to function effectively and is an ideal surfactant for low-colloid, relaxed inverts such as the CARBO-FAST oil-base fluid system.

CARBO-MUL is used as a combination emulsifier/wetting agent in the CARBO-FAST low-colloid/relaxed-filtrate oil-base fluid system, when only modest filtration control is required. No filtration control additives, lime, or other surfactants are typically used in these high-penetration rate systems.

CARBO-MUL is also used as the wetting agent/supplemental emulsifier in the CARBO-TEC controlled-filtrate oil-base fluid system. CARBO-MUL is used in conjunction with CARBO-TEC, lime, and filtration control additives in these more highly treated systems, and can be formulated to withstand temperatures in excess of 400°F (204°C).

CARBO-FAST low-colloid/relaxed-filtrate oil-base fluid systems will require 0.4 to 0.75 gal/bbl (9.5 to 17.9 L/m^3) of CARBO-MUL (used as a primary emulsifier/wetting agent), depending on the bottomhole temperatures, solids content, and type. CARBO-TEC controlled-filtrate oil-base fluid systems will require 0.12 to 1.0 gal/bbl (2.9 to 23.8 L/m^3) of CARBO-MUL applied under similar circumstances. Approximately 1.0 gal (3.8 L) of CARBO-MUL per 25 (100-lb) sacks of MIL-BAR is normally sufficient when used as a wetting agent at weight-up.

Table 5-8 Typical Physical Properties – CARBO-MUL/CARBO-MUL HT

PROPERTY	CARBO-MUL	CARBO-MUL HT
Appearance	Dark liquid	Dark liquid
Flash Point	60°F (16°C) (ASTM D56)	170°F (77°C) (ASTM D56)
Pour Point	10°F (12°C)	23°F (5°C)
Density	7.7 lbm/gal (924 kg/m^3)	8.0 lbm/gal (952 kg/m^3)

CARBO-TEC®

CARBO-TEC® is an anionic emulsifier used with lime hydrate to provide temperature-stable emulsions of water or brines in oil. CARBO-TEC exhibits a high tolerance to contaminants and high temperatures. CARBO-DRILL systems, prepared from CARBO-TEC, have been formulated to withstand temperatures greater than 400°F (204°C).

CARBO-TEC is compatible with a wide range of internal phase salinities and can be used to emulsify calcium chloride and sodium chloride brines, seawater, and freshwater. CARBO-TEC, together with lime hydrate, will provide moderate filtration control in oil-base fluids. CARBO-TEC contains no aromatic solvents.

CARBO-TEC is used in controlled filtration oil-base fluid systems. It requires lime to function effectively, and is used in conjunction with CARBO-MUL HT and filtration control additives in these systems.

CARBO-TEC controlled filtrate oil-base fluid systems will require 0.6 to 1.7 gal/bbl (14.3 to 40.5 L/m^3). Lime should be added as the activator at a concentration of 5 lb_m lime per gallon (0.6 kg/L) of CARBO-TEC.

CARBO-TEC functions as a passive emulsifier in CARBO-CORE systems (see *Chapter 6, Reservoir Application Fluids*). Because lime and water are necessary to activate CARBO-TEC, it will have no emulsification properties in the CARBO-CORE℠ system unless water is incorporated.

Table 5-9 Typical Physical Properties – CARBO-TEC

Appearance	Dark liquid
Flash Point	> 200°F (93°C) (ASTM D56)
Pour Point	13°F (11°C)
Density	8.1 lbm/gal (964 kg/m^3)

CARBO-TEC® HW

CARBO-TEC® HW is a non-ionic emulsifier for the CARBO-DRILL mineral oil-base fluid system. It is compatible with all other products in the CARBO-DRILL system. CARBO-TEC HW has a strong affinity for solid surfaces and provides a high degree of oil-wetting ability in any type mineral oil.

Treatment with CARBO-TEC HW will result in increased emulsion stability and lower plastic viscosities, particularly in heavily solids-laden fluids. CARBO-TEC HW is used to treat fluids where solids levels have risen to high levels and emulsion stability and rheological properties have been compromised as a result. It is particularly effective in high water content oil-base fluids and in high density fluids. Pilot testing is recommended in all cases to avoid over treatment. Over treatment can result in settling of barite. Concentration levels will vary from 0.1 gal/bbl (2.0 L/m^3) in low-weight systems to 0.5 gal/bbl (12.0 L/m^3) in high density, high solids systems.

Table 5-10 Typical Physical Properties – CARBO-TEC HW

Appearance	Dark brown liquid
Flash Point	> 162°F (72°C)
Pour Point	< 14°F (10°C)
Specific Gravity	0.84 S.G. (7.0 lbm/gal)

CARBO-TEC® S

CARBO-TEC® S is an unsaturated polymerized fatty acid blend used to provide supplemental emulsion stability in invert emulsion systems. CARBO-TEC S exhibits a high tolerance to contaminants and high temperatures. CARBO-DRILL systems prepared with CARBO-TEC S have been formulated to withstand temperatures in excess of 204ºC (400ºF). CARBO-TEC S is compatible with a wide range of internal-phase salinities and can be used to help emulsify calcium chloride and sodium chloride brines, seawater, and fresh water.

CARBO-TEC S is a supplemental emulsifier used in the controlled-filtration oil mud system. CARBO-TEC S requires lime to function effectively, and is used in conjunction with CARBO-MUL or CARBO-MUL HT and filtration control additives in these systems. CARBO-TEC S should be added through the hopper or directly to the suction pit if sufficient agitation is available. Concentrations up to 0.6 gal/bbl (14.3 L/m^3) may be required for controlled-filtrate mud systems.

Table 5-11 Typical Physical Properties – CARBO-TEC S

Appearance	Yellow-amber liquid
Flash Point	>93º C (>200º F)
Density	955 kg/m^3 (7.9 lb/gal)

CARBO-TROL®

CARBO-TROL® is a blend of high molecular weight organic polymers and inorganic bridging agents used to improve filtration control in oil-base fluid systems. CARBO-TROL will have a minimal rheological effect on the drilling fluid. CARBO-TROL is compatible with most synthetic and oil-base fluid systems.

Treatments of CARBO-TROL will vary with the type of oil being used, temperatures to be encountered, and desired filtration control properties. Pilot testing is recommended to determine optimum concentration. Treatment levels of 2 to 10 lb_m/bbl (5.7 to 28.5 kg/m^3) should be adequate for most applications.

Table 5-12 Typical Physical Properties – CARBO-TROL

Appearance	Gray powder
Hygroscopic	No
pH in H_2O	Neutral
Bulk Density	49 lbm/ft^3 (784 kg/m^3)

CARBO-TROL® HT

CARBO-TROL® HT is a high-temperature softening-point gilsonite used to improve filtration control in the CARBO-DRILL and CARBO-CORE (no water) oil-base fluid systems with minimal effects on rheological properties.

Treatments of 2.0 to 10 lb/bbl (5.7 to 28.5 kg/m^3) is adequate for most applications. *Example*: A 425°F (218°C) CARBO-DRILL formulation treated with 5 lb_m/bbl (14.3 kg/m^3) CARBO-TROL HT results in the reduction of the 350°F (177°C) HT/HP filtrate from 10.0 to 6.0 cm^3.

Table 5-13 Typical Physical Properties – CARBO-TROL HT

Appearance	Black powder
Hygroscopic	No
Bulk Density	115 lbm/ft^3 (1040 kg/m^3)

CARBO-VIS™

CARBO-VIS™ is an high-yielding organophilic bentonite clay used as the viscosifying and suspending agent in oil- and synthetic-base fluid systems. It increases the carrying capacity and hole cleaning characteristics of oil and synthetic-base fluids by imparting viscosity and gel building characteristics to diesel oil, crude oil, mineral oil, and synthetic fluids. CARBO-VIS can be used to condition CARBO-DRILL or other oil-base fluid systems for use as packer fluids. Concentrations of 1 to 5 lb_m/bbl (2.85 to 14.3 kg/m^3) are usually adequate for most uses. Good shear is recommended for proper blending.

Table 5-14 Typical Physical Properties – CARBO-VIS™

Appearance	Tan powder
Hygroscopic	No
pH in H_2O	n/a
Bulk Density	42 lbm/ft^3 (672 kg/m^3)

CHEK-LOSS®

CHEK-LOSS® is a water-insoluble, ultra-fine, complexed cellulosic material used for controlling seepage and loss of circulation while drilling through depleted or under-pressured zones. CHEK-LOSS can be maintained in a circulating system without bypassing the shale shakers. CHEK-LOSS is effective in bridging micro fractured and permeable formations to control seepage loss.

Table 5-15 Typical Physical Properties – CHEK-LOSS

Appearance	Brown powder
Hygroscopic	No
pH in H_2O	3.5

CHEK-LOSS® PLUS

CHEK-LOSS® PLUS is a water-insoluble, ultra-fine, cellulosic material used for controlling seepage and loss of circulation while drilling through depleted or under-pressured zones. CHEK-LOSS PLUS will not preferentially water-wet when used in conjunction with oil and synthetic-based emulsion systems. This feature minimizes the detrimental effect on the electrical stability often experienced when using other cellulosic fibers. CHEK-LOSS PLUS can be maintained in a circulating system without bypassing the shale shakers. CHEK-LOSS PLUS is effective in bridging micro fractured and permeable formations to control seepage loss.

CHEK-LOSS PLUS reduces filter cake permeability and spurt losses which help prevent differential sticking. CHEK-LOSS PLUS is nontoxic, temperature stable in excess of 204 °C (400 °F), and has minimal effect on fluid rheology. CHEK-LOSS PLUS is functional in both water and oil mud systems.

CHEK-LOSS PLUS can be mixed through the hopper to control seepage losses. Sufficient agitation is necessary to properly disperse CHEK-LOSS PLUS. It can also be used as a sweep or slug in cases of lost circulation. CHEK-LOSS PLUS can be used with HEC, starch, or other polymers in heavy brines for sealing perforations.

The low acidity of CHEK-LOSS PLUS will require a supplemental treatment of soda ash when used in water-based muds (add 0.2 lb/bbl soda ash with each 10 lb/bbl of CHEK-LOSS PLUS). A concentration of 11.4 to 22.8 kg/m³ (4.0 to 8.0 lb/bbl) should be used to control seepage loss. For application as a sweep or slug, 85.5 kg/m³ (30.0 lb/bbl) can be mixed with mud in the slugging pit and spotted across the thief zone.

Table 5-16 Typical Physical Properties – CHEK-LOSS PLUS

Appearance	Brown powder
Hygroscopic	No
pH in H_2O	3.5

MAGMA-GEL™

MAGMA-GEL™ is a specialty product, wet processed organophilic clay used as a gellant/suspension agent in the MAGMA-TEQ HTHP oil-based mud system. MAGMA-GEL is temperature stable to > 425º F (218º C). Its performance is complemented by MAGMA-TROL.

MAGMA-TROL™

MAGMA-TROL™ is a polymeric, oil soluble product designed for HTHP filtrate control and for use in the environmental and occupational hygiene regulated MAGMA-TEQ HTHP oil-based drilling fluid developed for use in drilling deviated North Sea wells. MAGMA-TROL is temperature stable to greater than 1112º F (600º C). It works independently of the base fluid and has a secondary effect benefit of suspension stabilization. MAGMA-TROL has been field tested to 458º F (237º C)

Table 5-17 Typical Physical Properties – MAGMA-TROL

Appearance	White powder, dust
Odor	No characteristic odor
Solubility	Insoluble in water
Specific gravity, 25º C	1.030

MAGMA-VERT™

MAGMA-VERT™ is a specialized, high temperature, modified amide amine used as a supplementary emulsifier in the MAGMA-TEQ HTHP oil-based mud system. MAGMA-TEQ is a specialized system specifically developed for the drilling of HTHP deviated wells in the North Sea. The system and its associated products such as MAGMA-VERT meet the stringent environmental and occupational hygiene regulations established for this area.

OMNI-COTE®

OMNI-COTE® is a thinner and solids dispersing agent for synthetic- and oil-base fluid systems. It is used to lower rheological properties in both CARBO-DRILL and SYN-TEQ systems if the fine solids content becomes excessive.

Treatments with OMNI-COTE will vary depending on the type and quantity of drill solids in the fluid system. Concentrations of 0.1 to 1.0 gal/ bbl (2.38 to 23.8 L/m^3) are typical levels used in the field. All treatments should be pilot tested to determine the optimum level.

Table 5-18 Typical Physical Properties – OMNI-COTE

Appearance	Amber liquid
Solubility	Water insoluble
Specific Gravity, 25º C	1.030

OMNI-LUBE™

OMNI-LUBE™ is an environmentally accepted polymeric fatty acid solution, which will effectively reduce torque and drag in most emulsion based drilling fluids. Results obtained from field applications indicate that the friction in fluids treated with OMNI-LUBE can be lowered by up to 25% compared to untreated fluids, and torque is less erratic. It is a filming type extreme pressure lubricant and is particularly effective in lowering steel-to-steel friction.

OMNI-LUBE is a liquid and will not screen out of the system. As a filming type lubricant, product depletion will occur and will be related to the coating of drill pipe and casing in the wellbore, filter cake in the open hole and cuttings generated by the drill bit. OMNI-LUBE is compatible with most emulsion systems and suitable both in high and low aromatic base fluid environments.

Fluid properties are not adversely affected by additions of OMNI-LUBE and the HTHP fluid loss in emulsion systems treated with OMNI-LUBE will generally be lowered. General engineering practices with respect to pilot testing additions are recommended.

Table 5-19 Typical Physical Properties – OMNI-LUBE™

Appearance	Yellow-brown liquid
Flash Point (ASTM D56)	> 250º C (482º F)
Freezing Point	- 33º C (- 27º F)
Density	970 – 990 kg/m^3 @ 20º C

OMNI-MIX™

OMNI-MIX™ is an anionic emulsifier formulation used in synthetic- and oil-base fluid systems. It is used as a supplemental emulsifier with OMNI-TEC and OMNI-MUL when additional fluid loss control is required or when needed to control water breakout and water wet solids. OMNI-MIX increases emulsion stability and significantly lowers the HTHP fluid loss of any hydrocarbon external phase system. Synthetic-base drilling fluid systems usually require 0.5 to 1.5 gal/bbl (11.91 to 35.71 L/m^3) of OMNI-MIX, depending on density, total solids loading, and temperature design.

Table 5-20 Typical Physical Properties – OMNI-MIX™

Appearance	Black viscous liquid
Flash Point	> 212° F (100° C) (PMCC)
Pour Point	16° F (9° C)
Density	8.0 lbm/gal (952 kg/m^3)
Viscosity	800 to 1000 cp at 68° F (20° C)

OMNI-MUL®

OMNI-MUL® is a high-temperature, environmentally safe, polyamide used as a non-ionic emulsifier and wetting agent in synthetic and oil-base fluid systems. It readily stabilizes fluids under minimal shear, is compatible with a wide range of internal phase salinities, and can be used to emulsify calcium chloride and sodium chloride brines, seawater, and freshwater. OMNI-MUL is substantive (adsorbs on) to mineral surfaces, reducing interfacial surface energy and is a synthetic wetting agent for MIL-BAR, drilled solids, etc. Synthetic-base fluid systems usually require 0.5 to 1.5 gal/bbl (11.9 to 35.7 L/m^3) of OMNI-MUL (used as the primary emulsifier), depending on the bottomhole temperature, density, and drilled solids content.

Table 5-21 Typical Physical Properties – OMNI-MUL

Appearance	Dark brown
Specific Gravity	0.928
Flash Point	> 200° F (93.3° C) (PMCC)
Pour Point	40° F (4.4° C)
pH (5% solution)	3.75

OMNI-PLEX ®

OMNI-PLEX®is an anionic synthetic polymer supplied in emulsion form. It can be used alone or in conjunction with amine-treated organophilic clays. It is compatible with most additives commonly used in low toxicity mineral oil- and synthetic-base drilling fluids and is not affected by gas kicks or H_2S contamination. OMNI-PLEX is thermally stable at temperatures exceeding 400° F (204° C).

OMNI-PLEX increases viscosity levels in low toxicity mineral oil- and synthetic-base invert emulsion drilling fluids. It contributes primarily to YP and gel strength to provide carrying capacity for cuttings and suspension of weighting materials. OMNI-PLEX is added as needed to control low shear rheology. Normally, 1 to 4 ppb is adequate.

Table 5-22 Typical Physical Properties – OMNI-PLEX

Appearance	White liquid
Flash Point	> 250° F (121° C)
Specific Gravity	1.08 - 1.12

OMNI-TEC®

OMNI-TEC®is an anionic emulsifier used with lime hydrate to provide temperature-stable emulsions of water or brines in synthetic and oil-base fluid systems. OMNI-TEC exhibits a high tolerance to contaminants and high temperatures. SYN-TEQ systems, prepared with OMNI-TEC, have been formulated to withstand temperatures in excess of 400°F (204°C).

OMNI-TEC is compatible with a wide range of internal phase salinities and can be used to emulsify calcium chloride and sodium chloride brines, seawater, and freshwater. OMNI-TEC, together with lime hydrate, will provide moderate filtration control in synthetic-base fluids. OMNI-TEC contains no aromatic solvents.

OMNI-TEC is the primary emulsifier used in the SYN-TEQ℠ synthetic-base fluid system. It requires lime to function effectively, and is used in conjunction with OMNI-MUL and filtration control additives in this system. Together with lime, it is recommended for increasing the thermal and electrical stability of all synthetic-base fluid systems.

OMNI-TEC controlled filtrate synthetic-base fluid systems will require 0.6 to 1.7 gal/bbl (14.3 to 40.5 L/m^3). Lime should be added as the activator at a concentration of 5 lb$_m$ lime per gallon of OMNI-TEC (0.6 kg/L).

Table 5-23 Typical Physical Properties – OMNI-TEC

Appearance	Dark, brown liquid
Flash Point	> 400° F (204° C) (PMCC)
Specific Gravity	0.98

OMNI-TROL™ / CARBO-TROL® A-9

OMNI-TROL™ / CARBO-TROL®A-9 are temperature-stable organophilic lignites used to control filtration in oil- and synthetic-base fluid systems. Both provide non-asphaltic filtration control in the CARBO-DRILL/SYN-TEQ family of oil/synthetic fluids. OMNI-TROL / CARBO-TROL A-9 are readily dispersible in all oil and synthetic-base fluids, reduce filtration in oil/synthetic drilling fluids, and stabilize water-in-oil emulsions at temperatures not exceeding 350° F (177° C).

Treatment levels of OMNI-TROL / CARBO-TROL A-9 will vary depending on the type of oil/synthetic fluid used, bottomhole temperatures encountered, and filtration control desired. Concentrations of 5 to 10 lb_m/ bbl (14.3 to 28.5 kg/m^3) should be adequate for most applications.

Table 5-24 Typical Physical Properties – OMNI-TROL / CARBO-TROL

Appearance	Black powder
Hygroscopic	Slightly
pH in H_2O	Neutral
Bulk Density	48 lbm/ft^3 (768 kg/m^3)

6-UP™

6-UP™ is a 100% active liquid rheology modifier. It is used to increase low-shear rheology in all oil-base fluid systems and is effective in improving the 3 rpm and 6 rpm readings of an oil-base fluid without causing an increase in plastic viscosity. 6-UP is compatible with both sodium and calcium chloride internal phases and functions in fluids with oil/water ratios ranging from 40/60 to 90/10. 6-UP is thermally stable at temperatures up to 300° F (149° C) and functions under conditions of both high and low shear.

6-UP can be added directly to the active fluid system, but should be added as the last ingredient (when mixing at the rig site) to achieve full affect. Mix the fluid as normal. Add the 6-UP only after the emulsion has formed and the barite has been fully wetted.

Treatment levels are typically in the range of 0.1 to 0.4 gal/bbl (2 to 10 L/m^3). The final treatment level depends on fluid weight, oil/water ratio, and the level of increase required for the 6 rpm reading. High fluid weights and low oil/water ratios require the smallest treatment levels.

Table 5-25 Typical Physical Properties – 6-UP

Appearance	Pale, yellow liquid
Flash Point	210° F (99° C)
Pour Point	> 32° F (0° C)
Density	0.99 g/mL

Oil mud product safety and handling

Utilize normal precautions of employee protection when handing chemical products. Use of an appropriate respirator, gloves, goggles, and apron are recommended for employee comfort and protection. Material Safety Data Sheets are available and should be reviewed to prior to product use. The liquid oil-base fluid products usually contain flammable or combustible liquids and must not be stored around heat, sparks, or open flames. Empty containers should not be reused.

Field mixing procedures

1. Measure the appropriate amount of base fluid (oil or ISO-TEQ) into the mixing tank and circulate the oil through the hopper and fluid guns.
2. Add CARBO-VIS or CARBO-GEL slowly to the base fluid through the hopper until well dispersed.
3. Add proper amount of OMNI-MUL or CARBO-MUL HT through the hopper until mixed homogeneously with the base fluid. This should take approximately 30 minutes.
4. For CARBO-TEC formulations add the appropriate amount of CARBO-TEC and lime through the hopper and allow mixing for a minimum of 45 minutes.
5. Add brine water slowly through the hopper and allow mixing for 45 minutes.

Note: If the brine water has to be made in the mixing plant by adding sacked salt to water, this would become the first step.

6. For a CARBO-TEC / SYN-TEQ formulation, add the appropriate amount of CARBO-TROL or CARBO-TROL A-9, CARBO-TROL HT, or OMNI-TROL™ through the hopper and allow mixing for a minimum of 45 minutes.
7. Add proper amount of weight material to attain desired fluid weight. To insure proper wetting and dispersion, slow the additions of weight material as fluid weight increases. Periodically during weight-up, check yield point, gels, and emulsion stability to insure proper barite suspension and that a stable emulsion is being formed. Slower additions of weight material may be necessary if inadequate shear exists and emulsion stability is not stable or is decreasing. If problems arise, refer to the troubleshooting information in Table 6-5 located toward the end of the chapter.

Special rig equipment and precautions

1. A fluid-saver box should be installed with a hose connected to the flow line to save fluid lost from connections and tripping the drill string.
2. Pipe wipers will help keep the outside of the drill pipe clean during trips.
3. High-speed shakers and fluid cleaners with the smallest screens possible are highly recommended.
4. If lost circulation is a possibility, a frac tank for oil-base fluid storage on location is recommended.
5. The pits should be covered if located in a rain prone area to prevent water contamination.
6. All water valves should be closed off or disconnected around the pits to prevent inadvertent water contamination.
7. Shaker screens and fluid cleaner screens should be cleaned with spray from an air gun equipped with an oil siphon.

8. Do not use plastic or phenolic resin type materials for lost circulation.
9. Steam cleaners may be needed for general rig clean up. MIL-CLEAN® diluted in water is an excellent cleaner for oil mud coated equipment.
10. Volume control and dilution should be conducted with virgin drilling fluid whenever possible.

Displacement procedures

Displacement can occur either in casing or open hole with cased hole preferred. Prior to displacement, the drilling fluids engineer should make certain all pits and lines are as clean as possible. It is not uncommon to run a slug of base oil through the lines to clean and oil wet them. The trap doors on the pits can be packed with barite if necessary to help prevent leakage.

The water-base fluid to be displaced should be diluted back to reduce yield point and gel strengths. This will help prevent contamination of the oil-base fluid. A *water spacer* of sufficient volume to occupy 500 to 1000 feet of annular volume should be used to chase the water-base fluid up the hole. This will thin the water-base fluid and thicken the oil-base fluid to help hole cleaning and removal of the water-base filter cake. During displacement, the drill pipe should be rotated and reciprocated along with a high pump rate to help prevent channeling. Once displacement commences, the pumps should not be shut down.

The total strokes should be calculated for the spacer to come around to the shaker. This will help locate the interface. The shakers should be bypassed to remove the water-base fluid to a reserve or waste pit. Contaminated oil-base fluid found at the interface should also be discarded (see Table 5-26 Troubleshooting).

Table 5-26 Troubleshooting Emulsion Fluid Systems

Low emulsion stability	Dull, grainy appearance to fluid High HT/HP fluid loss. Free H_2O in HT/HP filtrate. Barite setting out. Blinding of shaker screens. Extreme cases can cause water wetting of solids.	1. Low emulsifier 2. Super-saturated with $CaCl_2$ 3. Water flows 4. Mixing fluid at mixing plant	1. Add CARBO-MUL HT / OMNI-MUL. Add CARBO-TEC and lime if CARBO-TEC system. 2. Dilute back with fresh H_2O and add CARBO-MUL HT / OMNI-MUL. 3. Add CARBO-MUL HT / OMNI-MUL. Can also add CARBO-TEC and lime if CARBO-TEC system. 4. Maximize shear. Check electrolyte content (the higher the content, the harder the emulsion is to form)
Water wetting of solids	Flocculation of barite on sand-content test. Sticky cuttings. Blinding of shaker screens. Settling of barite. dull, grainy appearance of fluid. Low electrical stability (ES). Free H_2O in HT/HP filtrate.	1. Inadequate emulsifiers 2. Water fluid contamination 3. Super saturated $CaCl_2$	1. Add CARBO-MUL HT / OMNI-MUL and OMNI-COTE. 2. Add CARBO-MUL HT / OMNI-MUL and OMNI-COTE. 3. Dilute with fresh H_2O and add CARBO-MUL HT / OMNI-MUL
High filtration	High HT/HP filtrate with increasing free H_2O. Low electrical stability (ES). Fill on connections and trips. Sloughing shale.	1. Low emulsifier content. 2. Low concentration of fluid loss control additives. 3. High bottom hole temperature.	1. Add CARBO-MUL HT / OMNI-MUL. Add CARBO-TEC and lime if CARBO-TEC system. 2. Add CARBO-TROL A-9 / OMNI-TROL and/or CARBO-TROL 3. Add more CARBO-MUL HT / OMNI-MUL. Add CARBO-TEC and lime. Convert to CARBO-TEC system. Add more CARBO-TROL A-9 / OMNI-TROL and CARBO-TROL
High viscosity	High PV, high YP. Increasing funnel viscosity. Increasing retort solids. Increase in water content.	1. High solids content. 2. Water contamination 3. Over treatment w/emulsifiers, especially CARBO-TEC	1. Dilute with oil, maximize solids-control equipment. Add emulsifiers. 2. Add emulsifiers. If severe, also add OMNI-COTE. 3. Dilute with oil
Sloughing shale	Fill on connections and trips. Torque and drag. Cuttings increase across shaker.	1. Drilling under-balanced 2. Excessive filtrate. 3. Inadequate hole cleaning. 4. Activity too low.	1. Increase fluid weight. 2. Add emulsifiers. Add CARBO-TROL A-9 / OMNI-TROL and/or CARBO-TROL. 3. Add CARBO-GEL to increase yield point. 4. Adjust $CaCl_2$ content of internal phase to match formation activity.
Barite setting	Low YP and gels. Settling of barite in heating cup.	1. Poor oil wetting of barite 2. Inadequate suspension. 3. Low ES, high HT/HP	1. Add emulsifiers and /or wetting agents. Slow addition of barite. 2. Add CARBO-GEL or viscosifying polymer. 3. Add emulsifier.
Lost circulation	Pit volume decreases. Loss of returns.	1. Hydrostatic pressure is greater than formation pressure.	1. Add mica or plug. Never add fibrous or phenolic-resin materials. If possible, reduce fluid weight.
Problem mixing fluid at mixing plant	Poor emulsions stability. Barite settling. Dull, grainy appearance to fluid. Fluid very thin with no yield or gel strengths.	1. Inadequate shear. 2. Very cold. 3. Poor wetting of barite. 4. High electrolyte content. Normally greater than 350,000 ppm. 5. Surfactant contamination possible if using $CaCl_2$ brine that has been used as completion or work over fluid.	1. Maximize the shear. 2. Lengthen mixing times. 3. Slow additions of barite. Add CARBO-MUL HT / OMNI-MUL. If severe, add small amount of OMNI-COTE. 4. Dilute back with fresh H_2O. Once emulsion if formed, can add additional $CaCl_2$ to obtain desired activity. 5. Pilot test with known $CaCl_2$ brine to determine if problem does exist

It is recommended that all fluid treatments and mixing procedures be confirmed with the fluids coordinator prior to being initiated. Pilot testing is always recommended prior to commencing actual treatment of the active system.

Solids control with oil mud

The removal of solids in oil muds is different than in a water based mud. Cuttings generated by the bit tend to remain more competent, making the shale shaker a much more efficient solids removal device. At the same time, due to the viscosity of the oil phase, hydrocyclones and centrifuges become less efficient. The waste generated by these devices also contains a high percentage of oil mud which can result in disposal problems.

The problem becomes one of preventing solids build up in the system. It is therefore imperative to maximize the use of solids control equipment to remove as much of the unwanted solids as possible. Drill solids that are not removed by solids control equipment must be diluted. Dilution not only is very expensive, but it creates mud volume control problems.

Oil muds have a very expensive liquid phase. This phase consists of base oil, brine, and surfactants. As we increase the density of oil muds, the cost of the solids phase goes up, but the liquid phase continues to be expensive. This forces us to re-think our usage of equipment. Refer to for an example of oil mud costs vs. density.

In water base muds, the liquid phase is expensive when unweighted. As we weight up, at some density the cost of the barite becomes more expensive that the liquid phase. At higher density, we now concentrate our solids control on barite recovery. This is never the case with oil muds.

Solids

The removal of drill solids is important for the control of any mud system. It is of particular importance in water based fluids because of the magnitude and variety of adverse effects the solids can have on the system. However, in oil based mud systems, solids have historically been only superficially considered. This is primarily the result of the fact that in properly conditioned fluids there are no active drilled solids.

It has become apparent through the use of relaxed filtrate oil based fluids that when rate of penetration is considered, solids have the same detrimental effect in oil based fluids as they do in water based muds. As the solids content increases, the rate of penetration decreases. In addition, if the solids remain in the system, they require treatment with oil wetting agents to maintain fluid properties and stability, thus adding to the expense of the system.

If solids do build up, the standard technique of dumping and diluting is not viable because of the expense involved in dilution and the expense involved with disposal of the waste mud. Treatment of the system to reduce the effects of solids on flow properties is effective to a certain point. Surfactants can be added and the oil-water ratio can be increased to partially offset the effects incorporated solids. Nevertheless, a point will be reached where the colloidal solids content will no longer be affected by surfactants and the oil-water ratio can no longer be effectively increased. When this occurs, the rate of penetration of the fluid will already have been reduced to that of a conventional mud and the control of rheological properties can only be accomplished by dumping mud and diluting with oil.

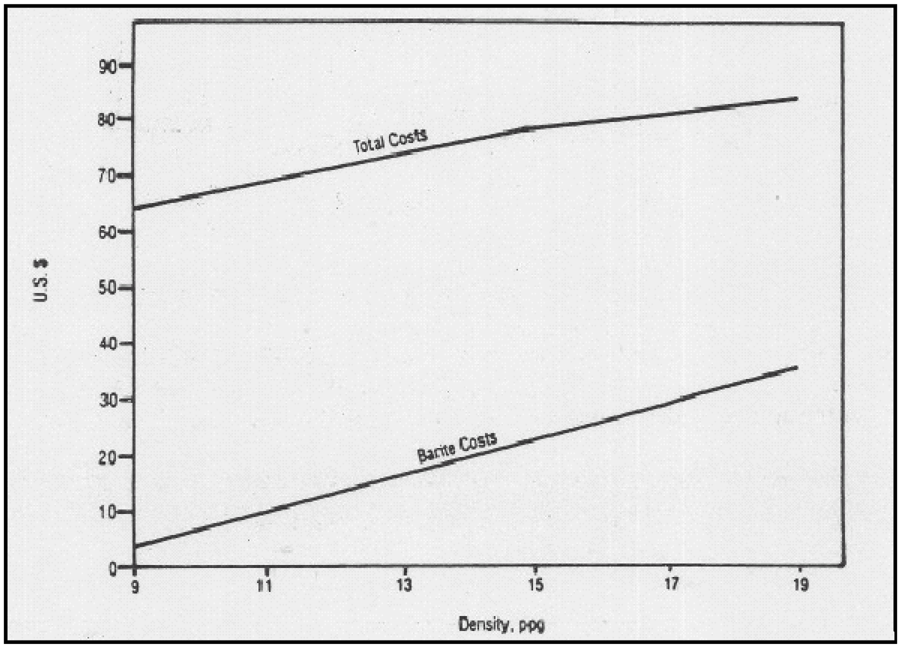


Figure 5-21 Diagram of Costs vs. Mud Weight

As Figure 5-21 indicates, weighted muds have both an expensive liquid and solids phase. We therefore want to save both the liquid phase *and* the barite. This can be a difficult task.

Figure 5-22 shows a flow diagram for a low to unweighted oil mud. The desander may be bypassed, or if run, the underflow could be screened. A mud cleaner would be used to remove sand and save mud. A high volume centrifuge would be used to dispose of solids. All solids should be disposed of, including barite, until the cost of barite is greater than the cost of dilution.

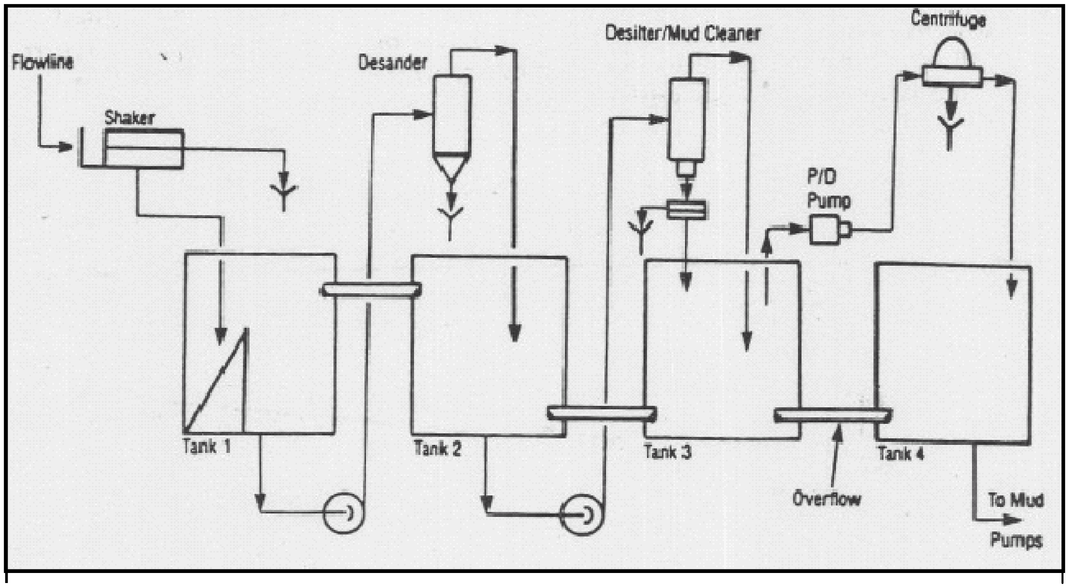


Figure 5-22 Flow Diagram for a Low to Unweighted Oil Mud

When using a weighted oil mud, the flow diagram shown in may be required. The mud cleaner would be run to remove sand and other larger particles. The centrifuge would be run for viscosity control (to remove fine solids).

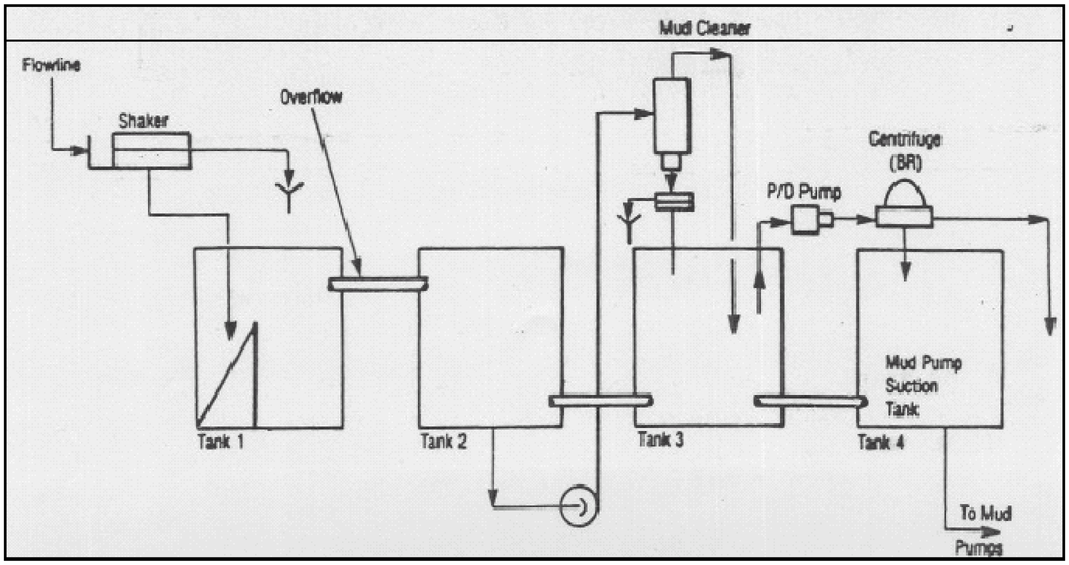


Figure 5-23 Flow Diagram for a Weighted Oil Mud

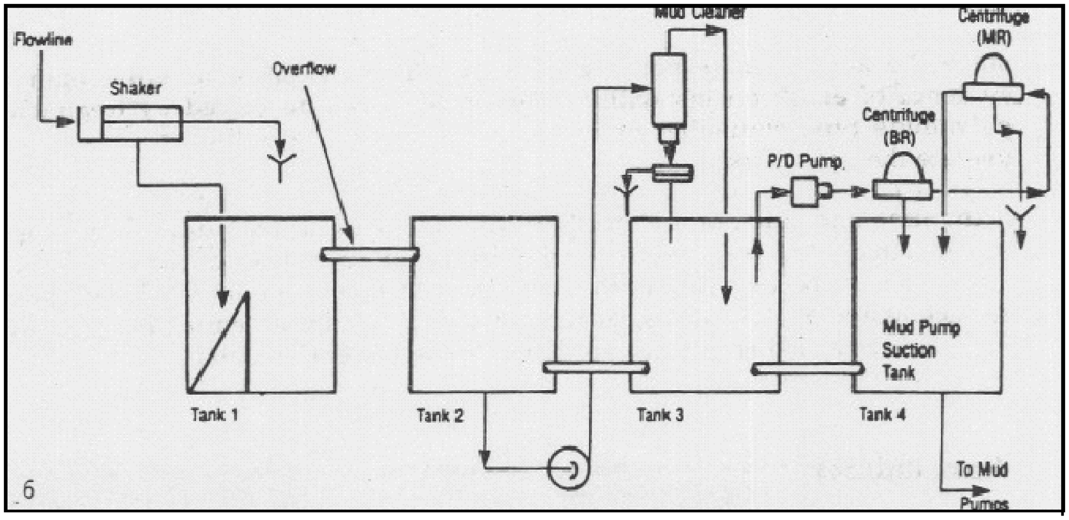


Figure 5-24 Flow Diagram for a Two-Stage Centrifuge for Medium to High Weight Oil Muds

In Figure 5-24 it shows a two-stage centrifuge. The flow diagram is applicable to a medium to high weight oil mud. The concept is to use the first centrifuge to recover barite. The centrifuged mud would then be fed to a second centrifuge which would remove and discard fine solids. The “clean” mud would then be put back into the mud system and also be used for dilution of the first centrifuge. It has been found that as long as the “clean” mud weights 9.0 ppg or less, this procedure is economical. At some point in time, whole mud will have to be removed from the system for viscosity control.

Shakers and centrifuges are the two primary defenses against solids build up in oil muds. Shakers remove a large portion of drill solids, as cuttings remain more competent in oil muds. Shakers and centrifuges discard the least whole mud with the solids they remove.

Salts

Since most salts will not dissolve in oil based fluids, salts take on the aspect of just another solid in the system. Some small quantity of a particular salt may dissolve in the internal phase (i.e. emulsified water) of the mud, but this will be relatively insignificant and will generally have no effect on the stability of the fluid. Depending upon the type of emulsifier used, salts that may dissolve in the water phase may react adversely with the emulsifier. This occurs primarily when massive quantities of magnesium containing salts are encountered.

Formulation Tables

CARBO-DRILL fluid formulation tables

Table 5-27 CARBO-DRILL Products Required to Build 100 bbl of CARBO-TEC Oil Fluid: 70/ 30 and 80/20 Oil/Water Ratios

	Maximum Temperature °F (°C)				
Products	**250 (121)**	**300 (149)**	**350 (177)**	**400 (204)**	**450 (232)**
CARBO-TEC, gal	110	130	170	170	190
CARBO-MUL HT, gal	25	50	62.5	75	125
CARBO-TROL, 50 lb sacks	10	15	20	30	30
MIL-LIME^{TM}, 50 lb sacks	9	11	14	14	16

70/30 OIL/WATER RATIO				
Fluid Weight (lb_m/gal)	**Diesel (bbl)**	**Brine* (bbl)**	**CARBO-VIS^{TM} (50 lb sacks)**	**MIL-BAR (100 lb sacks)**
8.0	66	30	4	0
8.5	65	30	4	27
9.0	64	29	5	55
9.5	63	29	5	82
10.0	61	28	5	109
10.5	60	27	5	136
11.0	59	27	5	164
11.5	58	26	5	191
12.0	56	26	5	218
12.5	55	25	5	245
13.0	54	25	5	272
13.5	52	24	5	299
14.0	51	24	5	327
14.5	50	23	5	354
15.0	48	23	5	381

80/20 OIL/WATER RATIO				
Fluid Weight (lb_m/gal)	**Diesel (bbl)**	**Brine* (bbl)**	**CARBO-VIS (50 lb sacks)**	**MIL-BAR (100 lb sacks)**
16.0	53	14	5	445
16.5	51	14	5	471
17.0	50	14	5	499
17.5	48	13	5	525
18.0	47	13	5	552
18.5	45	12	4	579
19.0	44	12	4	606
19.5	42	12	3	633
20.0	41	11	3	659

**Saturated NaCl or 250,000 ppm* $CaCl_2$ *water*

Table 5-28 CARBO-DRILL Products Required to Build 100 bbl of CARBO-TEC Oil Fluid: 85/15 Oil/Water Ratio

	Maximum Temperature °F (°C)				
Products	**250 (121)**	**300 (149)**	**350 (177)**	**400 (204)**	**450 (232)**
CARBO-TEC, gal	100	115	140	160	180
CARBO-MUL HT, gal	25	50	62.5	75	112
CARBO-TROL, 50 lb sacks	10	20	20	30	30
MIL-LIME^{TM}, 50 lb sacks	8	9	11	13	16

85/15 OIL/WATER RATIO				
Fluid Weight (lb_m/gal)	**Diesel (bbl)**	**Brine* (bbl)**	**CARBO-VIS^{TM} (50 lb sacks)**	**MIL-BAR (100 lb sacks)**
8.0	82	15	9	18
8.5	80	14	9	50
9.0	79	14	9	76
9.5	77	14	9	103
10.0	76	14	9	129
10.5	74	13	9	156
11.0	72	13	9	182
11.5	71	13	9	209
12.0	69	13	9	236
12.5	68	12	8	262
13.0	66	12	8	289
13.5	65	12	8	316
14.0	63	12	8	342
14.5	62	11	8	369
15.0	60	11	7	395
15.5	59	11	7	422
16.0	57	10	7	449
16.5	56	10	7	475
17.0	54	10	7	502
17.5	52	10	7	528
18.0	51	9	5	555
18.5	49	9	5	582
19.0	48	9	5	608

**Saturated NaCl or 250,000 ppm $CaCl_2$ water*

The volumes and densities are accurate to ± 1%. Because it is not possible for a table to show formulations with numerous internal phase salinities and temperature stabilities, it is recommended that a material balance approach be utilized prior to the formulation of large quantities of CARBO-DRILL

Table 5-29 CARBO-DRILL Products Required to Build 100 bbl of CARBO-TEC Oil Fluid: 90/10 and 95/5 Oil/Water Ratios

	Maximum Temperature °F (°C)				
Products	**250 (121)**	**300 (149)**	**350 (177)**	**400 (204)**	**450 (232)**
CARBO-TEC, gal	85	100	125	140	170
CARBO-MUL HT, gal	25	50	62.5	100	125
CARBO-TROL, 50 lb sacks	10	20	20	30	30
MIL-LIME^{TM}, 50 lb sacks	5	6	7	12	14

90/10 Oil/Water Ratio				
Fluid Weight (lb$_m$/gal)	**Diesel (bbl)**	**Brine* (bbl)**	**CARBO-VIS^{TM} (50 lb sacks)**	**MIL-BAR (100 lb sacks)**
7.6	88	10	10	0
8.0	86	10	10	22
8.5	85	10	10	49
9.0	83	10	10	75
9.5	82	9	10	102
10.0	80	9	10	129
10.5	78	9	10	156
11.0	77	9	10	183
11.5	75	8	10	210
12.0	73	8	10	236
12.5	72	8	10	263
13.0	70	8	10	290
13.5	69	8	10	317
14.0	67	8	10	343
14.5	65	8	10	370
15.0	63	7	10	397

95/5 OIL/WATER RATIO				
Fluid Weight (lb$_m$/gal)	**Diesel (bbl)**	**Brine* (bbl)**	**CARBO-VIS™ (50 lb sacks)**	**MIL-BAR (100 lb sacks)**
16.0	62	3	8	471
16.5	61	3	8	499
17.0	59	3	8	526
17.5	57	3	8	553
18.0	56	3	7	579
18.5	54	3	5	606
19.0	52	3	4	633
19.5	50	3	3	660
20.0	49	3	2	687

**Saturated NaCl or 250,000 ppm* $CaCl_2$ *water*

The volumes and densities are accurate to ± 1%. Because it is not possible for a table to show formulations with numerous internal phase salinities and temperature stabilities, it is recommended that a material balance approach be utilized prior to the formulation of large quantities of CARBO-DRILL

Table 5-30 CARBO-DRILL Products Required to Build 100 bbl of CARBO-FAST® Oil Fluid: 70/30 and 80/20 Oil/Water Ratios

	Maximum Temperature °F (°C)				
Product	**250 (121)**	**300 (149)**	**350 (177)**	**400 (204)**	**450 (232)**
CARBO-MUL HT, gal*	40 +	50 +	60 +	70 +	75 +

** + 1 gal additional CARBO-MUL HT / OMNI-MUL™ required per 25 100-lb sacks MIL-BAR®*

70/30 OIL/WATER RATIO				
Fluid Weight (lb_m/gal)	**Diesel (bbl)**	**Brine* (bbl)**	**CARBO-VIS™ (50 lb sacks)**	**MIL-BAR(100 lb sacks)**
8.0	70	30	8	0
8.5	68	29	8	29
9.0	67	29	8	59
9.5	66	28	8	82
10.0	65	28	8	110
10.5	64	27	8	136
11.0	62	27	8	163
11.5	61	26	8	191
12.0	60	26	8	218
12.5	58	25	8	245
13.0	57	24	8	272
13.5	56	24	8	299
14.0	55	23	8	327
14.5	53	23	8	353
15.0	52	22	8	380

80/20 OIL/WATER RATIO				
Fluid Weight (lb_m/gal)	**Diesel (bbl)**	**Brine* (bbl)**	**CARBO-VIS™ (50 lb sacks)**	**MIL-BAR (100 lb sacks)**
15.5	58	14	8	408
16.0	56	14	8	436
16.5	55	14	8	463
17.0	54	13	8	490
17.5	52	13	8	516
18.0	50	12	6	544
18.5	49	12	6	572
19.0	48	12	6	598

**Saturated NaCl or 250,000 ppm* $CaCl_2$

The volumes and densities are accurate to ± 1 %. Because it is not possible for a table to show formulations with numerous internal phase salinities and temperature stabilities, it is recommended that a material balance approach be utilized prior to the formulation of large quantities of CARBO-DRILL

Table 5-31 CARBO-DRILL Products Required to Build 100 bbl of CARBO-FAST Oil Fluid: 85/15 Oil/Water Ratio

	Maximum Temperature °F (°C)				
Product	**200 (93)**	**250 (121)**	**300 (149)**	**350 (177)**	**400 (204)**
CARBO-MUL HT, gal*	40 +	50 +	60 +	70 +	75 +

** + 1 gal addition CARBO-TROL HT /OMNI-MU™ required per 25 100-lb sacks MIL-BAR*

85/15 OIL/WATER RATIO				
Fluid Weight (Lbm/gal)	**Diesel (bbl)**	**Brine* (bbl)**	**CARBO-VIS ™ (50 lb sacks)**	**MIL-BAR(100 lb sacks)**
8.0	84	15	8	18
8.5	82	14	8	50
9.0	81	14	8	76
9.5	79	14	8	103
10.0	76	13	8	129
10.5	74	13	8	156
11.0	73	13	8	182
11.5	71	13	8	209
12.0	70	12	8	236
12.5	70	12	8	262
13.0	68	12	8	289
13.5	67	12	8	316
14.0	65	12	7	342
14.5	64	11	7	369
15.0	62	11	7	395
15.5	61	11	7	422
16.0	59	10	6	449
16.5	58	10	6	475
17.0	56	10	6	502
17.5	54	10	6	528
18.0	53	9	5	555
18.5	51	9	5	608
19.0	50	9	5	608

**Saturated NaCl or 250,000 ppm $CaCl_2$ water*

The volumes and densities are accurate to ± 1 %. Because it is not possible for a table to show formulations with numerous internal phase salinities and temperature stabilities, it is recommended that a material balance approach be utilized prior to the formulation of large quantities of CARBO-DRILL

Table 5-32 CARBO-DRILL Products Required to Build 100 bbl of CARBO-FAST Oil Fluid: 90/10 Oil/Water Ratio

	Manimum Temperature °F (°C)				
Product	**200 (93)**				
CARBO-MUL HT, gal*	40 +	250 (121)	300 (149)	350 (177)	400 (204)

** + 1 gal addition CARBO-TROL HT /OMNI-MU™ required per 25 100-lb sacks MIL-BAR®*

90/10 Oil/Water Ratio				
Fluid Weight, (lb_m/gal)	**Diesel, (bbl)**	**Brine*, (bbl)**	**CARBO-VIS™ (50 lb sacks)**	**MIL-BAR (100 lb sacks)**
8.0	88	9.7	10	36
8.5	86	9.6	10	62
9.0	84	9.4	10	89
9.5	83	9.2	10	115
10.0	81	9.0	10	142
10.5	80	8.9	10	169
11.0	78	8.6	10	195
11.5	76	8.5	10	222
12.0	75	8.3	10	247
12.5	73	8.1	8	275
13.0	72	7.9	8	301
13.5	70	7.8	8	328
14.0	68	7.6	8	354
14.5	67	7.4	8	380
15.0	65	7.2	7	408
15.5	63	7.0	7	434
16.0	62	6.8	7	460
16.5	60	6.7	7	486
17.0	59	6.5	6	513
17.5	57	6.3	6	541
18.0	55	6.1	6	566
18.5	54	6.0	6	593
19.0	52	5.8	6	620

**Saturated NaCl or 250,000 ppm $CaCl_2$ water*

The volumes and densities are accurate to ± 1 %. Because it is not possible for a table to show formulations with numerous internal phase salinities and temperature stabilities, it is recommended that a material balance approach be utilized prior to the formulation of large quantities of CARBO-DRILL

Table 5-33 CARBO-DRILL Products Required to Build 100 bbl 50/50 and 55/45 Oil/Brine Ratios

50/50 OIL/BRINE RATIO								
Fluid Weight, (lb$_m$/gal)	**MINERAL OIL (bbl)**	**BRINE*, (bbl)**	**CARBO-MUL, (gal)**	**CARBO-MIX, (gal)**	**CARBO-TEC HW, (gal)**	**MIL-LIME, (50 lb sacks)**	**CARBO-GEL N, (50 lb sacks)**	**MIL-BAR, (100 lb sacks)**
9.0	45	49	95	54	-	8	1.5	22
9.5	44	48	100	57	-	8	1.5	50
10.0	43	47	105	60	-	8	1.5	77
10.5	42	46	123	70	-	8	1.5	105
11.0	40	45	140	80	-	8	1.5	133
11.5	39	44	147	84	-	8	1.5	161
12.0	37	43	154	88	10	8	1.5	188
55/45 OIL/BRINE RATIO								
13.0	39	37	160	90	20	8	1.5	250
13.5	38	36	175	100	25	8	1.5	276
14.0	35	35	190	110	30	8	1.5	306

**Saturated NaCl or 250,000 ppm* $CaCl_2$ *water*

The volumes and densities are accurate to ±1%. Because it is not possible for a able to show formulations with numerous internal phase salinities and temperature stabilities, it is recommended that a material balance approach be utilized prior to the formulation of large quantities of CARBO-DRILL.

Table 5-34 CARBO-DRILL Products Required to Build 100 bbl of CARBO-CORE Oil Fluid

Fluid Weight, (lb$_m$/gal)	OIL, (bbl)	CARBO-GEL, (50 lb sacks)	ELASTOMERIC POLYMER, (25 lb sacks)	MIL-LIME, (50 lb sacks)	CARBO-TEC, (gal)	CARBO-TROL HT, 50 lb sacks)	MIL-BAR, (100 lb sacks)
7.2	98	31	6.0	2	24	24	-
7.5	97	30	5.0	2	24	23	12
8.0	95	28	4.5	2	24	22	39
8.5	93	26	4.0	2	24	22	66
9.0	92	25	4.0	2	24	22	93
9.5	90	24	4.0	2	24	22	120
10.0	88	22	3.5	2	24	21	147
10.5	86	21	3.0	2	24	21	174
11.0	85	19	3.0	2	24	20	201
11.5	83	18	3.0	2	24	20	227
12.0	81	16	2.5	2	24	19	254
12.5	79	15	2.5	2	24	19	281
13.0	78	14	2.0	2	24	19	308
13.5	76	13	2.0	2	24	18	335
14.0	74	12	2.0	2	24	18	361
14.5	72	11	2.0	2	24	17	388
15.0	71	9	1.5	2	24	17	415
15.5	69	9	1.5	2	24	17	441
16.0	67	8	1.2	2	24	16	468
16.5	65	7	1.2	2	24	16	495
17.0	63	6	1.0	2	24	15	521
17.5	62	6	1.0	2	24	15	548
18.0	60	5	1.0	2	24	15	575
18.5	59	5	1.0	2	24	14	603
19.0	57	4	0.5	2	24	14	630

The volumes and densities are accurate to ±1%. Because it is not possible for a able to show formulations with numerous internal phase salinities and temperature stabilities, it is recommended that a material balance approach be utilized prior to the formulation of large quantities of CARBO-DRILL.

SYN-TEQ fluid formulation tables

Table 5-35 Products Required to Build 100 bbl of SYN-TEQ Fluid: 70/30 and 80/20 Synthetic/Water Ratios (SWR)

	Maximum Temperature ºF (ºC)				
Products Prod	**250 (121)**	**300 (149)**	**350 (177)**	**400 (204)**	**450 (232)**
OMNI-TEC^{TM}, gal	110	130	170	170	190
OMNI-MUL^{TM}, gal	25	50	62.5	75	125
OMNI-TROL^{TM}, 50 lb sacks	10	15	20	30	30
MIL-LIME^{TM}, 50 lb sacks	9	11	14	14	16

70/30 SWR				
Fluid Weight, (lb_m/gal)	**ISO-TEQ, (bbl)**	**Brine,* (bbl)**	**CARBO-GEL, (50 lb sacks)**	**MIL-BAR, (100 lb sacks)**
8.0	66	30	4	0
8.5	65	30	4	27
9.0	64	29	5	55
9.5	63	29	5	82
10.0	61	28	5	109
10.5	60	27	5	136
11.0	59	27	5	164
11.5	58	26	5	191
12.0	56	26	5	218
12.5	55	25	5	245
13.0	54	25	5	272
13.5	52	24	5	299
14.0	51	24	5	327
14.5	50	23	5	354
15.0	48	23	5	381
80/20 SWR				
16.0	53	14	5	445
16.5	51	14	5	471
17.0	50	14	5	499
17.5	48	13	5	525
18.0	47	13	5	552
18.5	45	12	4	579
19.0	44	12	4	606
19.5	42	12	3	633
20.0	41	11	3	659

**Saturated NaCl or 250,000 ppm* $CaCl_2$ *water*

The volumes and densities are accurate to ±1%. Because it is not possible for a able to show formulations with numerous internal phase salinities and temperature stabilities, it is recommended that a material balance approach be utilized prior to the formulation of large quantities of CARBO-DRILL.

Table 5-36 Products required to build 100 bbl of SYN-TEQ Fluid: 85/15 Synthetic/Water Ratio (SWR)

	Maximum Temperature °F (°C)				
Products	**250 (121)**	**300 (149)**	**350 (177)**	**400 (204)**	**450 (232)**
OMNI-TEC™, gal	100	115	140	160	180
OMNI-MUL™, gal	25	50	62.5	75	112
OMNI-TROL™, 50 lb sacks	10	20	20	30	30
MIL-LIME™, 50 lb sacks	8	9	11	13	16

85/15 SWR				
Fluid Weight, (lb_m/gal)	**ISO-TEQ, (bbl)**	**Brine*, (bbl)**	**CARBO-GEL, (50 lb sacks)**	**MIL-BAR, (100 lb sacks)**
8.0	82	15	9	18
8.5	80	14	9	50
9.0	79	14	9	76
9.5	77	14	9	103
10.0	76	14	9	129
10.5	74	13	9	156
11.0	72	13	9	182
11.5	71	13	9	209
12.0	69	13	9	236
12.5	68	12	8	262
13.0	66	12	8	289
13.5	65	12	8	316
14.0	63	12	8	342
14.5	62	11	8	369
15.0	60	11	7	395
15.5	59	11	7	422
16.0	57	10	7	449
16.5	56	10	7	475
17.0	54	10	7	502
17.5	52	10	7	528
18.0	51	9	5	555
18.5	49	9	5	582
19.0	48	9	5	608

**Saturated NaCl or 250,000 $CaCl_2$ water.*

The volumes and densities are accurate to ±1%. Because it is not possible for a able to show formulations with numerous internal phase salinities and temperature stabilities, it is recommended that a material balance approach be utilized prior to the formulation of large quantities of CARBO-DRILL.

Table 5-37 Products Required to build 100 bbl of SYN-TEQ^{SM} Fluid: 90/10 and 95/5 Synthetic/Water Ratios (SWR)

	Maximum Temperature °F (°C)				
Products	**250 (121)**	**300 (149)**	**350 (177)**	**400 (204)**	**450 (232)**
OMNI-TEC^{TM}, gal	85	100	125	140	170
OMNI-MUL^{TM}, gal	25	50	62.5	100	125
OMNI-TROL^{TM}, 50 lb sacks	10	20	20	30	30
MIL-LIME^{TM}, 50 lb sacks	5	6	7	12	14

90/10 SWR				
Fluid Weight, (lb$_m$/gal)	**ISO-TEQ, (bbl)**	**Brine*, (bbl)**	**CARBO-GEL, (50 lb sacks)**	**MIL-BAR, (100 lb sacks)**
7.6	88	10	10	0
8.0	86	10	10	22
8.5	85	10	10	49
9.0	83	10	10	75
9.5	82	9	10	102
10.0	80	9	10	129
10.5	78	9	10	156
11.0	77	9	10	183
11.5	75	8	10	210
12.0	73	8	10	236
12.5	72	8	10	263
13.0	70	8	10	290
13.5	69	8	10	317
14.0	67	8	10	343
14.5	65	8	10	370
15.0	63	7	10	397
95/5 OWR				
16.0	62	3	8	471
16.5	61	3	8	499
17..0	59	3	8	526
17.5	57	3	8	553
18.0	56	3	7	579
18.5	54	3	5	606
19.0	52	3	4	633
19.5	50	3	3	660
20.0	49	3	2	687

**Saturated NaCl or 250,000 $CaCl_2$ water.*

The volumes and densities are accurate to ±1%. Because it is not possible for a able to show formulations with numerous internal phase salinities and temperature stabilities, it is recommended that a material balance approach be utilized prior to the formulation of large quantities of CARBO-DRILL.

Table 5-38 SYN-TEQ Products required to build 100 bbl of SYN-CORE^{SM} Synthetic Fluid

FLUID WEIGHT (lb_m/gal)	ISO-TEQ (bbl)	CARBO-GEL (50 lb sacks)	OMNI-PLEX (gallons)	MIL-LIME^{TM} (50 lb sacks)	OMNI-TEC (gal)	OMNI-TROL^{TM} (50 lb sacks)	MIL-BAR (100 lb sacks)
7.2	98	31	120	2	24	24	
7.5	97	30	110	2	24	23	12
8.0	95	28	105	2	24	22	39
8.5	93	26	100	2	24	22	66
9.0	92	25	90	2	24	22	93
9.5	90	24	90	2	24	22	120
10.0	88	22	80	2	24	21	147
10,5	86	21	75	2	24	21	174
11.0	85	19	70	2	24	20	201
11.5	83	18	60	2	24	20	227
12.0	81	16	55	2	24	19	254
12.5	79	15	55	2	24	19	281
13.0	78	14	50	2	24	19	308
13.5	76	13	50	2	24	18	335
14.0	74	12	45	2	24	18	361
14.5	72	11	40	2	24	17	388
15.0	71	9	35	2	24	17	415
15.5	69	9	30	2	24	17	441
16.0	67	8	25	2	24	16	468
16.5	65	7	20	2	24	16	495
17.0	63	6	12	2	24	15	521
17.5	62	6	12	2	24	15	548
18.0	60	5	12	2	24	15	575
18.5	59	5	12	2	24	14	603
19.0	57	4	12	2	24	14	630

Salt tables

Table 5-39 Properties of Calcium Chloride Solutions at 20°C

Weight Percent	Specific Gravity	Density (lb$_m$/gal)	100% $CaCl_2$ (lb$_m$/bbl)	95% $CaCl_2$ (lb$_m$/bbl)	H_2O Using 100% $CaCl_2$ (gal/bbl)	H_2O Using 95% $CaCl_2$ (gal/bbl)	$CaCl_2$ (mg/L)	Chlorides (mg/L)	Volume[1] Increase Factor 100% $CaCl_2$	Volume[2] Increase Factor 95% $CaCl_2$	Crystal lization Point (°F)	Aw
1.0	1.009	8.42	3.53	3.72	41.93	41.91	10085	6454	1.002	1.002	31.1	0.998
2.0	1.017	8.49	7.13	7.50	41.85	41.81	20340	13018	1.004	1.004	30.4	0.996
3.0	1.026	8.56	10.78	11.35	41.78	41.71	30765	19690	1.006	1.007	29.5	0.993
4.0	1.034	8.63	14.50	15.26	41.69	41.60	41360	26470	1.008	1.010	28.6	0.989
5.0	1.043	8.70	18.27	19.23	41.60	41.48	52125	33360	1.011	1.013	27.7	0.984
6.0	1.051	8.77	22.11	23.27	41.49	41.35	63060	40358	1.013	1.016	26.8	0.979
7.0	1.060	8.84	25.99	27.36	41.38	41.22	74165	47466	1.016	1.019	25.9	0.973
8.0	1.068	8.91	29.94	31.52	41.27	41.08	85440	54682	1.018	1.022	24.6	0.967
9.0	1.077	8.98	33.95	35.74	41.14	40.93	96885	62006	1.021	1.026	23.5	0.959
10.0	1.085	9.05	38.03	40.03	41.01	40.77	108500	69440	1.024	1.030	22.3	0.951
11.0	1.094	9.13	42.18	44.40	40.90	40.63	120340	77018	1.027	1.034	20.8	0.942
12.0	1.103	9.20	46.39	48.83	40.76	40.47	132360	84710	1.030	1.038	19.3	0.933
13.0	1.113	9.28	50.69	53.36	40.65	40.33	144625	92560	1.034	1.041	17.6	0.923
14.0	1.122	9.36	55.05	57.95	40.53	40.18	157080	100531	1.037	1.045	15.5	0.912
15.0	1.132	9.44	59.49	62.62	40.40	40.02	169725	108624	1.041	1.049	13.5	0.900
16.0	1.141	9.52	63.98	67.35	40.25	39.85	182560	116838	1.044	1.054	11.2	0.888
17.0	1.151	9.60	68.55	72.16	40.10	39.67	195585	125174	1.048	1.059	8.6	0.875
18.0	1.160	9.68	73.18	77.03	39.95	39.49	208800	133632	1.051	1.064	5.9	0.862
19.0	1.170	9.76	77.91	82.01	39.80	39.31	222300	142272	1.056	1.068	2.8	0.847
20.0	1.180	9.85	82.72	87.07	39.65	39.13	236000	151040	1.060	1.073	-0.4	0.832
21.0	1.190	9.93	87.59	92.20	39.48	38.93	249900	159936	1.065	1.079	-3.9	0.816
22.0	1.200	10.01	92.53	97.40	39.31	38.73	264000	168960	1.069	1.084	-7.8	0.800
23.0	1.210	10.10	97.55	102.68	39.14	38.52	278300	178112	1.074	1.090	-11.9	0.783
24.0	1.220	10.18	102.62	108.02	38.95	38.30	292800	187392	1.078	1.097	-16.2	0.765
25.0	1.231	10.27	107.82	113.49	38.76	38.08	307625	196880	1.084	1.103	-21.0	0.746
26.0	1.241	10.36	113.09	119.04	38.57	37.86	322660	206502	1.089	1.109	-25.8	0.727
27.0	1.252	10.44	118.44	124.67	38.37	37.62	337905	216259	1.095	1.116	-31.2	0.707
28.0	1.262	10.53	123.85	130.37	38.16	37.38	353360	226150	1.100	1.124	-37.8	0.686
29.0	1.273	10.62	129.39	136.20	37.96	37.14	369170	236269	1.107	1.131	-49.4	0.665
30.0	1.284	10.71	135.00	142.11	37.75	36.90	385200	246528	1.113	1.138	-50.8	0.643
31.0	1.295	10.81	140.70	148.11	37.53	36.64	401450	256928	1.120	1.146	-33.2	0.620
32.0	1.306	10.90	146.48	154.19	37.30	36.38	417920	267469	1.126	1.155	-19.5	0.597
33.0	1.317	10.99	152.32	160.34	37.06	36.10	434610	278150	1.134	1.163	-06.9	0.573
34.0	1.328	11.08	158.25	166.58	36.81	35.81	451520	288973	1.141	1.173	+4.3	0.548
35.0	1.340	11.18	164.32	172.97	36.57	35.53	468825	300048	1.149	1.182	+14.4	0.522
36.0	1.351	11.27	170.47	179.44	36.32	35.24	486360	311270	1.156	1.192	+24.1	0.496
37.0	1.363	11.37	176.76	186.06	36.06	34.95	504310	322758	1.165	1.202	+33.4	0.469
38.0	1.375	11.47	183.13	192.77	35.81	34.65	522500	334400	1.173	1.212	+42.1	0.441
39.0	1.387	11.57	189.53	199.50	35.53	34.33	540735	346070	1.183	1.224	+49.6	0.413
40.0	1.398	11.67	195.99	206.31	35.23	33.99	559200	357888	1.192	1.236	+55.9	0.384

[1] *Volume increase from 100% salt, i.e., from retort.*

[2] *Volume increase from salt and water in the sacked salt.*

Metric Conversions

- $CaCl_2$ (g/L) = $CaCl_2$ (lb_m/bbl) × 2.85714
- H_20 (mL/L) = H_20 (gal/bbl) × 23.8086
- $CaCl_2$ (ppm) = % Wt × 10,000
- Cl^- (ppm) = $CaCl_2$ (ppm) × 0.639
- mg/L = ppm × specific gravity

Formulas

- Salt (lb_m/bbl water) = Volume increase factor × $CaCl_2$ (lb_m/bbl)
- Specific Gravity

  $1.0036\,[0.99707 + 7.923\,(10^{-3})\,(\%\text{ wt }CaCl_2) + 4.964\,(10^{-5})\,(\%\text{ wt }CaCl_2)^2]$
- Volume Increase Factor *

  $1.00293 + 1.04192\,(10^{-3})\,(\%\text{ wt }CaCl_2) + 8.94922\,(10^{-5})\,(\%\text{ wt }CaCl_2)^2$
- Aw

  $0.99989 - 1.39359\,(10^{-3})\,(\%\text{ wt }CaCl_2) - 3.50352\,(1\,0^{-4})\,(\%\text{ wt }CaCl_2)^2$

  % wt $CaCl_2$ = [100% $CaCl_2$ (lb_m/bbl) x % Purity $CaCl_2$]/[S.G. x 350]

  When Using $CaCl_2$ with Purity Other Than 95%.
- New $CaCl_2$ (lb_m/bbl) = 95 × 95% $CaCl_2$ (lb_m/bbl) + % Purity

  New H_2O (gal/bbl) = H_2O (gal/bbl) – [New $CaCl_2$ (lb_m/bbl) – 95% $CaCl_2$ (lb_m/bbl) / 8.345

  Volume increase from salt = 42 + New water **

Example: 35% CaCl2 Brine Using 78% CaCl2

New $CaCl_2$ (lb_m/bbl) = 95 × 172.97 – 78 = 210.67

New H_2O (gal/bbl) = 35.53 – [(210.67 –172.97) / 8.345] = 31.01

Volume increase from 78% salt = 42 + 31.01 = 1.354

* Volume increase from 100% salt, i.e., from retort.

** Volume increase from salt and water in the sacked salt.

Table 5-40 Properties of Sodium Chloride Brines at 20°C

Weight Percent	Specific Gravity (g/cm^3)	Density (lb$_m$/gal)	NaCl (lb$_m$/bbl)	H_20 (gal/bbl)	NaCl (mg/L)	Chlorides (mg/L)	Volume[1] Increase Factor	Aw
1.0	1.007	8.40	3.5	41.87	10070	6108	1.003	0.996
2.0	1.014	8.46	7.1	41.75	20286	12305	1.006	0.989
3.0	1.021	8.52	10.7	41.63	30630	18580	1.009	0.983
4.0	1.029	8.58	14.4	41.46	41144	24957	1.013	0.976
5.0	1.036	8.65	18.2	41.34	51800	31421	1.016	0.970
6.0	1.043	8.70	21.9	41.18	62586	37963	1.020	0.964
7.0	1.050	8.76	25.8	41.02	73500	44584	1.024	0.957
8.0	1.058	8.83	29.7	40.86	84624	51331	1.028	0.950
9.0	1.065	8.89	33.6	40.70	95850	58141	1.032	0.943
10.0	1.073	8.95	37.6	40.54	107260	65062	1.036	0.935
11.0	1.080	9.01	41.6	40.38	118 800	72062	1.040	0.927
12.0	1.088	9.08	45.7	40.19	130512	79166	1.045	0.919
13.0	1.095	9.14	49.9	40.00	142350	86347	1.050	0.910
14.0	1.103	9.20	54.1	39.85	154392	93651	1.054	0.901
15.0	1.111	9.27	58.4	39.66	166650	101087	1.059	0.892
16.0	1.118	9.33	62.7	39.44	178912	108524	1.065	0.882
17.0	1.126	9.40	67.1	39.25	191420	116112	1.070	0.872
18.0	1.134	9.46	71.5	39.03	204102	123804	1.076	0.861
19.0	1.142	9.53	76.0	38.85	216980	131616	1.081	0.850
20.0	1.150	9.60	80.6	38.64	229960	139489	1.087	0.839
21.0	1.158	9.66	85.2	38.43	243180	147508	1.093	0.827
22.0	1.166	9.73	89.9	38.22	256520	155600	1.099	0.815
23.0	1.174	9.80	94.6	37.97	270020	163789	1.106	0.802
24.0	1.183	9.87	99.5	37.74	283800	172147	1.113	0.788
25.0	1.191	9.94	104.4	37.50	297750	180609	1.120	0.774
26.0	1.199	10.01	109.3	37.27	311818	189143	1.127	0.759

[1] There is minimal water in sacked NaCl, therefore, the volume increase from retort and sack additions may be considered the same.

Metric Conversions

NaCl (g/L) = NaCl (lb_m/bbl) × 2.85714

H_20 (mL/L) = H_20 (gal/bbl) × 23.8086

NaCl (ppm) = % wt × 10,000

Cl^- (mg/L) = NaCl (mg/L) × 0.6066

NaCl (mg/L) = Cl^- (mg/L) × 1.65

mg/L = ppm × specific gravity

Formulas

- Salt (lb_m/bbl water) = Volume increase factor × NaCl (lb_m/bbl)
- Specific Gravity

  $$1.0036 [0.99707 + 6.504 (10^{-3}) (\% \text{ wt NaCl}) + 4.395 (10^{-5}) (\% \text{ wt NaCl})^2]$$

- Volume Increase Factor

  $$1.00045 + 2.72232 (10^{-3}) (\% \text{ wt NaCl}) + 8.15591 (10^{-5}) (\% \text{ wt NaCl})^2$$

- Aw

  $$0.99755 - 4.3547 (l0^{-3}) (\% \text{ wt NaCl}) - 1.8205 (10^{-4}) (\% \text{ wt NaCl})^2$$

Table 5-41 Properties of Magnesium Chloride Solutions at 20°C

Weight Percent	Specific Gravity (g/cm)	Density (lb$_m$/gal)	$MgCl_2$ • 6$H_2$0 (lb$_m$/bbl)	$H_2$0 (gal/bbl)	$MgCl_2$ (mg/L)	Chlorides (mg/L)	Volume[1] Increase Factor 100% $MgCl_2$	Volume[2] Increase Factor from Salt	Aw
1.0	1.008	8.41	7.54	41.71	10080	7502	1.001	1.007	0.985
2.0	1.016	8.48	15.15	41.45	20320	15123	1.002	1.013	0.981
3.0	1.024	8.55	22.92	40.87	30720	22863	1.004	1.028	0.978
4.0	1.033	8.62	30.76	40.28	41320	30752	1.006	1.043	0.974
5.0	1.041	8.69	38.82	39.69	52050	38738	1.009	1.058	0.970
6.0	1.050	8.76	46.96	39.06	63000	46887	1.012	1.075	0.964
7.0	1.058	8.83	55.24	38.43	74060	55118	1.014	1.093	0.958
8.0	1.067	8.90	63.60	37.80	85360	63528	1.017	1.111	0.952
9.0	1.076	8.98	72.11	37.17	96840	72072	1.020	1.130	0.943
10.0	1.085	9.05	80.85	36.50	108500	80750	1.023	1.151	0.934
11.0	1.094	9.13	89.73	36.16	120340	89562	1.026	1.161	0.924
12.0	1.103	9.20	98.61	35.83	132360	98508	1.029	1.172	0.913
13.0	1.112	9.28	107.76	35.13	144560	107587	1.033	1.195	0.901
14.0	1.121	9.35	116.90	34.44	156940	116801	1.036	1.220	0.888
15.0	1.130	9.43	126.35	33.73	169500	126149	1.040	1.245	0.875
16.0	1.139	9.50	135.79	33.01	182240	135630	1.044	1.272	0.862
17.0	1.148	9.58	145.53	31.48	195160	145246	1.048	1.334	0.846
18.0	1.157	9.66	155.27	29.95	208260	154995	1.052	1.403	0.830
19.0	1.167	9.73	165.28	29.13	221635	164950	1.057	1.442	0.813
20.0	1.176	9.81	175.28	28.31	235200	175045	1.061	1.484	0.795
21.0	1.186	9.90	185.66	27.47	249060	185360	1.066	1.529	0.778
22.0	1.196	9.98	196.03	26.63	263120	195824	1.071	1.577	0.760
23.0	1.206	10.06	206.78	25.77	277380	206437	1.076	1.630	0.737
24.0	1.216	10.15	217.53	24.91	291840	217199	1.081	1.686	0.713
25.0	1.227	10.24	228.58	24.00	306625	228203	1.087	1.750	0.691
26.0	1.237	10.32	239.63	23.10	321620	239362	1.092	1.818	0.669
27.0	1.248	10.41	251.02	22.18	336825	250679	1.098	1.894	0.647
28.0	1.258	10.50	262.40	21.25	352240	262151	1.103	1.976	0.625
29.0	1.269	10.59	274.12	20.29	367865	273780	1.110	2.070	0.604
30.0	1.279	10.67	285.84	19.32	383700	285565	1.116	2.174	0.582

[1] *Volume increase from 100% salt, i.e., from retort.*

[2] *Volume increase from salt and water in the sacked salt.*

- Metric Conversions

  $MgCl_2$ (g/L) = $MgCl_2$ (lb_m/bbl) × 2.85714

  H_20 (mL/L) = H_20 (gal/bbl) × 23.8086

  $MgCl_2$ (ppm) = % Wt $MgCl_2$ × 10,000

  Cl^- (ppm) = $MgCl_2$ (ppm) × 0.7442

Formulas

- Salt (lb_m/bbl water) = Volume increase factor × $MgCl_2$ (lb_m/bbl)
- Specific Gravity

  $1.00038 + 7{,}95497\ (10^{-3})\ (\%\ \mathrm{Wt\ MgCl_2}) + 4.38583\ (10^{-5})\ (\%\ \mathrm{Wt\ MgCl_2})^2$

- Volume Increase Factor

  $0.999074 + 1.58008\ (10^{-3})\ (\%\ \mathrm{Wt\ MgCl_2}) + 7.66303\ (10^{-5})\ (\%\ \mathrm{Wt\ MgCl_2})^2$

- Aw

  $0.986688 - 1.2334\ (10^{-3})\ (\%\ \mathrm{Wt\ MgCl_2}) - 4.16512\ (10^{-4})\ (\%\ \mathrm{Wt\ MgCl_2})^2$

Typical formulation guidelines by BHDF location

Table 5-42 Typical System Types, Formulations, and Product Usage

Country	Australia	UK	USA	USA	USA	USA
Classification					Primary	Secondary
System Type	Mineral Oil	Mineral Oil	Diesel	HPHT	Synthetic	Synthetic
Base Oil	Sarapar 147	DF-1	Diesel	Diesel	CF-2002	ISO-TEQ C16/18
System Name	CARBO-DRILL	CARBO-SEA	CARBO-DRILL	CARBO-DRILL	SYN-TEQ CF	SYN-TEQ
Salinity, mg/L	100 – 250,000	150 – 200,000				
O/W Ratio	70/30 – 80/20	60/40 – 70/30				
Weight Range, lb/gal	9 to 13.5	10 to 15				
EMULSIFIERS						
CARBO-MUL			3 to 4			
CARBO-MUL HT	14	6		3 to 4		
CARBO-MIX™		4				
OMNI-MUL					8	8
OMNI-TEC					1	1
VISCOSIFIERS						
CARBO-VIS™		3				
CARBO-GEL	8		3 to 4	3 to 4	3 to 4	3 to 4
6-UP™		1				
FILTRATION CONTROL						
CARBO-TROL A-9			2 to 4			
CARBO-TROL HT				3 to 5	3 to 5	3 to 5
PLIOLITE DF01	2					
CARBO-TRO® A-9 HT				2 to 4	2 to 4	2 to 4
WETTING AGENTS						
OMNI-COTE		0.5	1	1	1	1
CARBO-MUL			3 to 4			
CARBO-MUL HT				3 to 4		
OMNI-MUL					3 to 4	3 to 4

Chapter Six

Reservoir Application Fluids

Chapter 6

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Chapter 6

RESERVOIR APPLICATION FLUIDS

This chapter describes the categories of fluids that are used during and after the productive interval is drilled. All of the fluids discussed are designed to maximize well productivity.

INTRODUCTION

Reservoir application fluids are any fluids to which the reservoir will be exposed during drilling, completion and workover operation. These fluids are designed to maximize hydrocarbon production from the production interval(s). This is achieved by minimizing formation damage during drilling and completion operations and maximizing the production potential of the completion methodology. It is first necessary to gain an understanding of hydrocarbon reservoirs before examining their interactions with drilling, completion and workover fluids.

A more thorough understanding of the purpose and application of these fluids requires some knowledge of the earth's geology and of formations from which petroleum products are commercially produced.

PETROLEUM GEOLOGY

Geology is the science of the earth, its origin and development through the past, its size, shape and composition, the processes that are now, or have been at work on its surface, and its interior; also its life forms since its origin. Geology as a science has its own techniques of geological mapping and for reconstruction of past events. It also uses other sciences, such as chemistry, biology, physics and engineering methods and theories.

Geology has the following branches:

- Crystallography
- Mineralogy
- Petrology
- Geochemistry
- Structural Geology
- Geophysics
- Stratigraphy
- Sedimentology
- Paleontology
- Geomorphology

In petroleum geology, one is mainly concerned with sedimentology and stratigraphy, as well as structural geology. Sedimentology is concerned with the origin, transportation, deposition and diagenesis of sedimentary rocks. It includes their description, classification and interpretation. Since sedimentary rocks are the fundamental materials of stratigraphy, the stratigrapher is primarily concerned with sedimentology and palaeontology or the science of life through geological history. The stratigraphic record is a result of sedimentary processes operating through geologic time. A fundamental principle in sedimentation is the law of superposition. “If one series of rocks lies above another, then the upper series was formed after the lower series.” The solution of stratigraphical and structural problems begins with the systematic observation of the sedimentary succession exposed in surface outcrops or made available through drilling. It is important to remember that tectonic activity influences the thickness and character of accumulating sediments. From all the accumulated subsurface information, a stratigraphical column is prepared and subdivided according to geological age. Stratigraphy is the study of rock succession and the interpretation of these successions as sequences of events in the geological history of the earth.

Properties of Sedimentary Rocks

Most sediments are mixtures of two main components, a detrital fraction, brought on site of deposition from the source area, and a chemical fraction, formed at or near the site of deposition. Example: a clastic rock is composed mainly of detrital material.

Texture: Detrital rocks have a fragmental texture, whereas chemical rocks have crystalline textures. Four components give a rock its textural characteristics; the grains, the matrix, the cement, and the pore space. Cement should be distinguished from the matrix. Most common cement materials are silica, calcite, dolomite and siderite.

Particle properties: Described are color, size, shape, roundness, surface texture, orientation, and mineralogical composition. Particle properties describe both clastic and chemical rocks. Large sand grains imply strong transportation currents in a high energy environment, whereas large calcite crystals reflect particular physical and chemical conditions at the deposition areas.

- Particle color is affected mainly by the association of different chemicals, such as iron’s reddish color.

- Particle size is mainly indicative of forces and currents involved in transportation.

- Particle shape is related to the energy and distance to which the particle was subjected before deposition.

Genesis of Sedimentary Rocks (Particles)

A sedimentary rock is the product of provenance (source area or pre-existing rock) and process. Weathering processes breaks down rocks at the earth’s surface to form minute particles. Erosion is the name given to processes which removes the product of weathering. Transport follows, and finally when the energy of the system is exhausted, deposition takes place.

There are three types of weathering and two categories of weathering products.

Chemical:	Selectively oxidizes and dissolves material.
Physical:	Mechanical disaggregation.

(These above categories are called residual sediments)

Biological: Biochemical solution and physical fracturing (result of vegetation).

Erosion has four agents: Gravity, glacial action, running water and wind.

Note that soil is the product of biological weathering. It consists of rock debris and decaying organic matter.

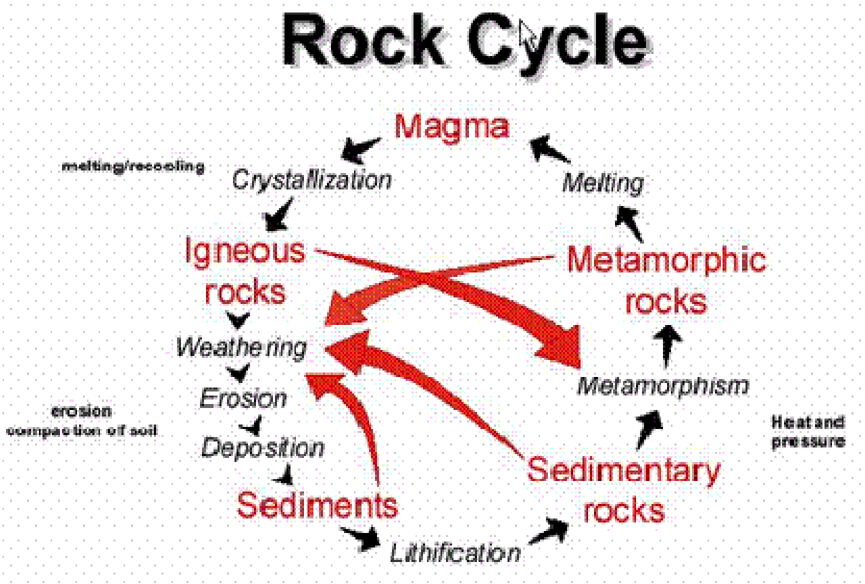


Figure 6 - 1 Rock Cycle

Classification of Sedimentary Rocks

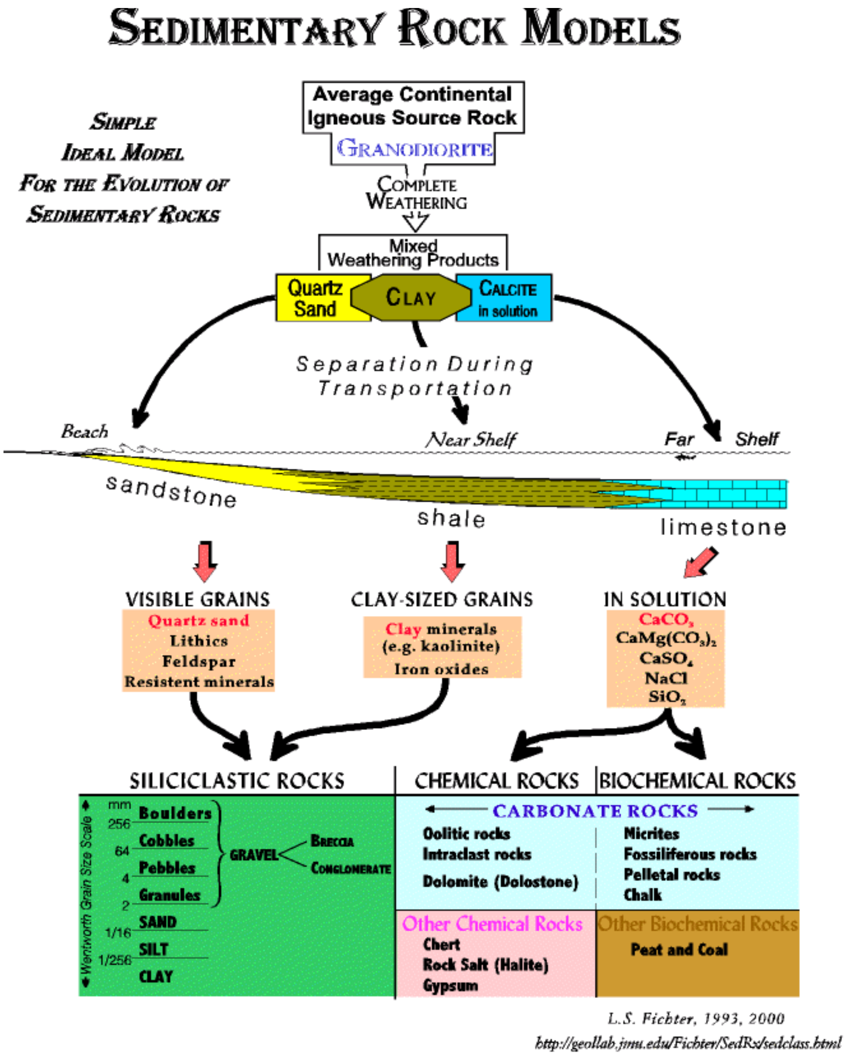
Five generic classes are recognized; chemical, organic, residual, ferruginous and volcanoclastic.

1. Chemical sediments are formed directly by precipitation in a sub-aqueous environment. Types of evaporates and some types of lime muds.
2. Organic sediments are composed of organic matter, both of animal and vegetable origin.
3. Residual sediments are those left in place after weathering.
4. Ferruginous sediments are the derivatives of the land mud rocks, and siliclastics.
5. Volcanoclastic sediments are the product of volcanic activity.

The above classes are sometimes divided into those which have been transported into the depositional environment (allocthonous) and those which are formed within the depositional area (autochthonous).

This classification is important in order to establish some idea about the rocks' origin.

All possible mixtures of compositions and textures occur among sediments and these are studied by proper selection of compositional and textural end members.



L.S. Fichter, 1993, 2000
http://geollab.jmu.edu/Fichter/SedRx/sedclass.html

Figure 6 - 2 Sedimentary Rock Nomenclature

Porosity and Permeability

A good understanding of the morphology and genesis of pores, prediction and detection within the earth’s crust is imperative to the petroleum industry. Porosity and permeability are related properties of any rock or loose sediment.

Porosity of a rock is a measure of its voids and ability to hold a fluid.

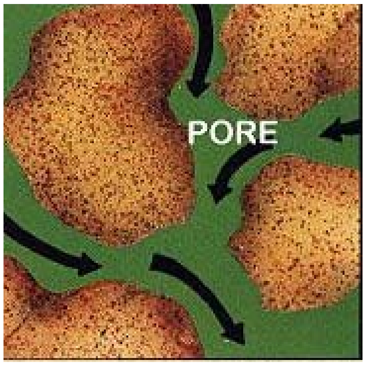
Total porosity is the total volume of void space expressed as a percentage of total volume of rock.

$$\text{Porosity } (\text{Ø}) = 100\,\frac{\text{bulk volume} - \text{grain volume}}{\text{bulk volume}}$$

Effective porosity is the percentage of interconnected pore space.

Permeability is a measure of the ability of a rock to permit fluid flow.

$$K = \frac{Q \times M \times L}{P \times A}$$



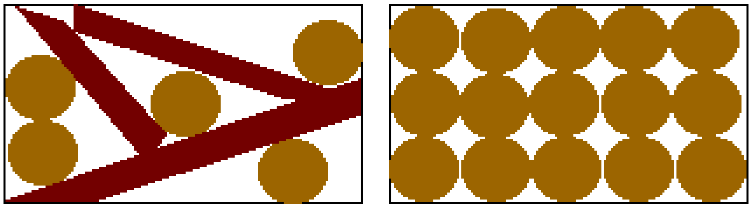
where:

K = Permeability in darcies
L = Length in cm of rock sample
Q = Fluid flow rate in cm^3/sec
M = Viscosity (in centipoises) of test fluid
A = Cross-sectional area of rock sample in cm^2
P = Pressure applied in atmospheres

Most oil and gas is produced from sandstones. Both porosity and permeability are needed for production. Porosity creates the spaces to hold the oil or gas. Permeability allows the oil and gas to flow out of the rock.

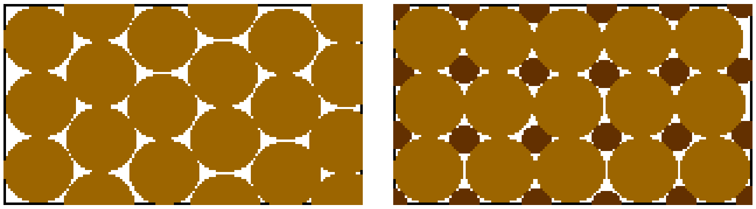
Classification of Porosity

Primary porosity is either inter-granular, between grains, inter-particle, or inside fossil shells. Secondary porosity can be inter-crystalline, as for recrystallized dolomites; fenestral, normal gaps, larger than grain supported interstices; moldic, formed by solution and vuggy or grading into cavernous. Fractured porosity is more difficult to observe. It ranges from microscopically small to cavernous in size. It can be formed either by tectonic activity or some non-tectonic processes, such as immediately beneath unconformities. This would include weathered fractures, especially in limestone.



loosely packed,
well structured material

loosely packed,
uniform particle size



tightly packed,
uniform particle size

tightly packed,
mixed particle sizes

Figure 6 - 3 Grain Packing and Porosity

Theoretically, porosity is independent of grain size, but in practice, porosity generally decreases with increases in grain size. Also generally, porosity and permeability increase with increased sorting. The more spherical the grains, the less the porosity, due to the tendency of closer packing.

Clays have very low porosity due to packing or compaction. Dewatering due to compaction, overburden (weight) increase, and dehydration, will cause a rapid decrease in porosity. Below 6,000 feet, porosity decreases more slowly and is lost due to the re-crystallization of minerals in the pore spaces.

Reservoir Fluids

A key to the analysis of reservoir performance and production are the physical properties of the reservoir fluids, and the variation of these fluids during the recovery and exploitation phase. Petroleum fluids are a complex of naturally occurring hydrocarbon compounds within the porous rock or reservoir.

These fluids may occur as vapor, liquids or solids, or any combination thereof. Their fluid state in the reservoir is a function of the temperature and pressure under which they exist. The chemical composition of petroleum deposits varies widely, but they have one thing in common, they are all predominantly composed of hydrogen (H) and carbon (C) with lesser quantities of sulfur (S), nitrogen (N) and oxygen (O). Broken down, most petroleum deposits exhibit the following composition:

C = 84 - 87%

H = 11 - 14%

S, N, O = 0.1 – 2%

The production or producibility of petroleum reservoirs depends upon the physical characteristics of the fluid within the reservoir. Of primary importance are the fluid viscosity and density, or when vapor and liquid exist, the relative viscosity and density of the mixture. Of equal importance are the volumetric variations of the fluids related to temperature and pressure. These values usually vary during reservoir depletion. Of great importance, therefore, is the correct and accurate sampling of the reservoir fluid and the laboratory analysis of the sample before production.

Reservoir Fluid Types

Generally four types of fluids exist:

1. *Normal Crudes* – These are the hydrocarbon liquids present in the reservoir commonly called "crude oil". The viscosity of these liquids can be as low as 1 cp or as high as 1000 cp or above. Specific gravity can vary from 0.825 up to 1.075, and color varies from amber to greenish black. Volumetric characteristics are related to pressure of the reservoir and can be demonstrated with the cell test.

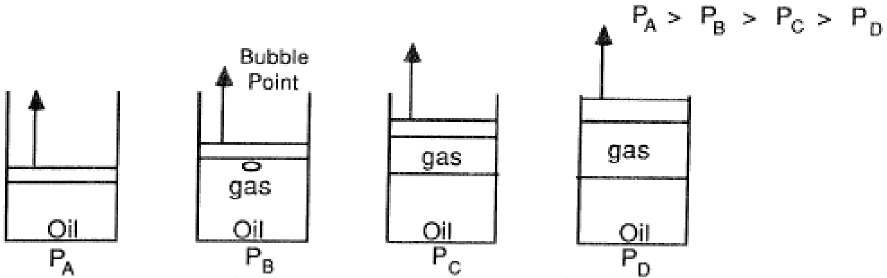


Figure 6 - 4 Normal Crude Oil

If only liquid (oil) is present, P_A, and reservoir pressure is reduced during production, the specific volume of oil increases. Then, at some different pressure, P_B, a bubble of free gas appears. This stage is called the “Bubble Point”. Further reduction of reservoir pressure, P_C and P_D, causes a change to occur. First, the quantity of gas escaping or separating from the oil increases continuously; second, the specific volume of gas increases; and third, the specific volume of reservoir oil decreases with pressure reduction below the bubble point, P_B.

The term used for the escape of gas from the reservoir oil is referred to as “gas coming out of solution”. Basically, the gas is just evaporation of the lighter hydrocarbon compounds; mainly methane and ethane.

Reservoirs themselves can occur at any stage within the P_A – P_D system and are related to pressure and temperature existing within the reservoir section.

If conditions are below the bubble point, geological time would normally have separated the gas from the oil, and the gas will be situated above the oil section in the form of a gas cap in the reservoir.

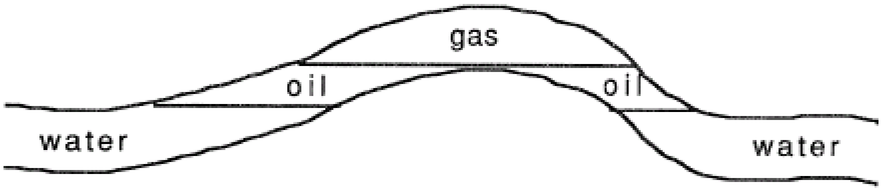


Figure 6 - 5 Oil Reservoir with Gas Cap

2. *Volatile Crude Oils* – These are very similar to the above described oils, but are generally lighter in weight and color, lower in viscosity, and have a larger volume change with pressure. This is entirely due to the volatile aspect, i.e. gaseous solution, therefore, higher compressibility under higher pressure.

   Average viscosity is normally 0.78 to 0.85 cP. Changes due to pressure changes are demonstrated with the same P_A – P_D method.

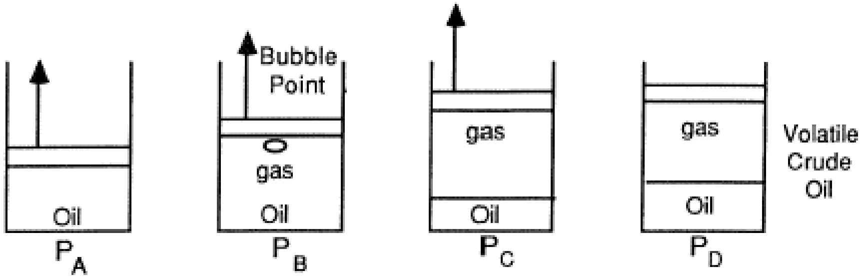


Figure 6 - 6 Volatile Crude Oil

   The difference in behavior is that the larger amounts of gas (free gas) undergo much more shrinkage (compressibility) as pressure declines below the bubble point.

3. *Gas Condensates* – These are hydrocarbon liquids mixed with natural gas instead of crude oils.

Condensates can exist as a very light liquid phase in a gas accumulation. It is a liquid phase that develops from condensation of the heavier components as pressure is reduced during production (or, in small reservoirs, during drilling and/or kick occurrence). The phases are explained in the following P_A – P_D demonstration.

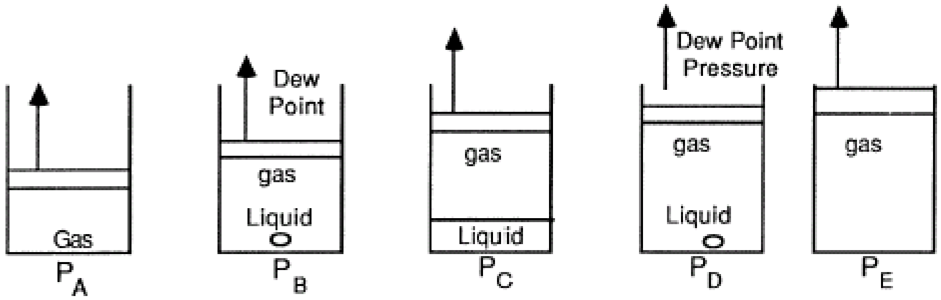


Figure 6 - 7 Gas Condensates

During expansion of the compressed gas when produced, condensate forms a drop of liquid from the heavier hydrocarbon compounds. This point is called the “Dew Point” of a reservoir.

The condensate liquid will reach a maximum depending on the pressure reductions, but then after further reduction, will return to another droplet within the system. This is referred to as the dew point pressure at the reservoir. Any further reduction of pressure after the dew point pressure will result in a single phase gas system with gas expansion in proportion to pressure reduction.

Any reservoir can be, as with oil reservoirs, anywhere between point P_A and P_D. With conditions at or below P_C, the reservoir would be called a normal condensate reservoir. If conditions are above the P_C stage, the term retrograde condensate reservoir is applied. This term implies an increase in liquid (condensate) with a decrease in pressure, rather than a decrease or evaporation under normal conditions.

The viscosity of a gas condensate is normally 0.05 cP or less, but can be as high as 0.5 cP; with a specific gravity of 0.7 to 0.78.

4. *Dry Gas Reservoir* – This refers to a system that contains only light hydrocarbons which exist only in the vapor phase or gas phase under all reservoir conditions.

   A system consisting of only dry gas is usually composed of up to 98% by volume methane. As a result, such reservoirs show an increase in specific volumes due to reduction of reservoir pressures, in agreement with the laws of expansion of compressible fluids.

Physical Properties of Reservoir Fluids

Petroleum, or more commonly, oil, has several physical properties. They are; density, viscosity, shrinkage, and gas in solution.

Density is defined as the weight of oil per unit of volume and is expressed at a particular temperature and pressure. To eliminate the different units used, the petroleum industry has generally adopted the API Unit as the measurement of density. The API unit is derived as follows:

First the Specific Gravity (SG) is obtained by:

$$SG = \frac{Density\ of\ Oil}{Density\ of\ Water}$$

The temperature at which the measurement is taken should also be noted, i.e. at 60°F for both.

$$°API = \frac{141.5}{SG} - 131.5$$

or

$$SG = \frac{141.5}{131.5 + °API}$$

Therefore, if the SG is 1.0 for water, the °API value would be 10°. Oil with an °API value greater than 10° would be lighter than water.

The previously described reservoir fluids have the following ranges API gravity and Specific Gravity.

Type of Fluid	**SG**	**°API**
Crude Oil	0.82 – 1.07	41.1 – 0.7
Volatile Oil	0.78 – 0.85	49.9 – 35.0
Gas/Condensate	0.70 – 0.78	70.6 – 49.9
Fresh Water	1.00	10.0

It can be seen that lighter mixtures have the lower density, SG, and that SG is a function of composition.

°API gravity indicates the market value of the oil. The higher the °API gravity, the more valuable is the oil. This is due to lighter oil containing more valuable products, such as gasoline.

°API gravity is measured with a calibrated hydrometer reading density, specific gravity or °API gravity directly.

Viscosity is basically the physical property which influences the ability of a fluid to flow. Flow rate is inversely proportional to fluid viscosity. A high pressure is needed to displace very viscous oil. Viscosity (μ), like density (ρ), is a function of fluid composition, pressure and temperature. The unit used for viscosity is centipoises (cP).

1 Poise = force in dynes/cm^2 to move a fluid at a rate of 1 cm/sec through an area of 1 cm^2; as a reference water has a viscosity of 1 cp at 68°F or 20°C.

The **Shrinkage** of oil is related to its changes in density, therefore, it is also related to the composition, pressure and temperature of the fluid. Shrinkage is used to measure the change in liquid volume in the reservoir from one pressure to another; for example, as the oil moves from the reservoir to the surface tanks. Normally liquid volumes in a reservoir shrink to a lesser volume as the reservoir pressure declines, except for the retrograde conditions in reservoirs.

Shrinkage is expressed in B_O. B_O is the formation volume factor. The B_O factor is related to the amount of oil in the reservoir and the amount in the tanks on surface.

$$B_O = \frac{Volume\ in\ reservoir}{Volume\ at\ surface}$$

Classification of Oil

Crude oil chemistry is relatively complex with a typical crude oil containing several thousand different compounds belonging to eighteen different hydrocarbon series. A complete chemical analysis of crude oils, in terms of compounds present, is a difficult, if not impossible task. Less complete types of analysis (e.g. by the amounts of lumped elements present) are often useful for determining its physical characteristics.

Difficulty in classifying oils by the chemical composition of their constituents has led to widespread use of simpler, less technical classifications. These classifications focus on differentiating between paraffin base and asphalt base oils. The distinction between paraffin base and asphalt base oils serves only as a broad classification. Most asphaltic oils contain traces of solid paraffins, and most paraffin oils contain some asphaltic residue. Some oils, said to be of “mixed base”, will respond to the tests for both paraffin and asphalt in equal degrees. The tests for classifying oil are described below.

Paraffin base oils are oils in which paraffins predominate. When cooled to low temperatures, these oils yield an appreciable amount of light colored wax that is not readily attacked by acids or dissolved by ether chloroform, or carbon bisulphide.

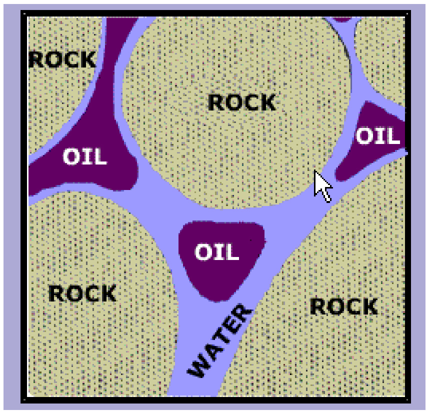
Asphalt base oils are oils in which asphalt predominates. After slow distillation, these oils yield a lustrous, solid residue, usually jet black in color, which exhibits a conchoidal fracture and which dissolves in the previously mentioned solvents.

Often the only classification made on crude oils is made based upon its API° gravity.

Petroleum Reservoirs

Petroleum is produced from the pores between or within the grains of a rock. In order for a rock to be a reservoir, it must contain sufficient porosity and permeability to permit commercial production of hydrocarbons. Porosity is a measure of the percent of pores or voids which a rock contains. The figure below illustrates the position of pores in a typical sandstone reservoir. Oil and gas occurs within the pores or voids between the individual sand grains. Typical sandstone reservoirs contain porosity values of 10 to 35%. Permeability is a measure of the ability of the pore fluid to move from one void to another. Permeability can be envisioned as a “pipeline” between the pores.

The pore in a typical reservoir may contain gas and/or oil. However, all reservoirs contain varying amounts of water. The water may occur as a thin film around the grains or it may be present as droplets. Water free oil has been produced from reservoirs which contain up to 50% water.



Most of the prolific oil production and indeed most of the giant oilfields are in sandstones. Sandstones generally exhibit high primary permeability as well as secondary permeability characteristics. For example, most of the oil and gas produced in Russia is from clastic reservoir rocks. Much of the production from the USA has also been from clastic reservoir rocks. There are some notable exceptions. The Permian Basin of the south-western U.S.A. is a carbonate (limestone) reservoir as are the majority of the huge oilfields in the Middle East.

Sandstones and limestones are two distinct rock types. Compositionally, sandstone is formed through inorganic and clastic processes. Erosion of land surfaces containing all types of existing rocks creates sediments which are transported into a basin where compaction occurs, creating sandstone rock. Looking closely at the sediments, one would see that it contains pebbles, sand grains, and other bits and pieces of rocks. All the sediment of this kind is referred to as clastic rocks, meaning accumulated particles of broken rock and of skeletal remains. The clastic materials are held together in the rock by cement, generally silica.

Limestones (carbonates) are primarily made of the mineral calcite. They are the result of sediment formed by precipitation of minerals from solution in water, either the result of biochemical reactions or by inorganic chemical processes. Inorganic processes mean that calcite is precipitated directly from water; small spheroidal grains, about the size of sand grains, called oolites are found on the floor of oceans. They are composed of calcium carbonate ($CaCO_3$). Oolites found in limestones mean that they were formed in ancient oceans. Cave deposits are also calcite, but they are formed in a wet cave on land.

Biochemically formed limestones are created by the action of plant and animal life that extract calcium carbonate ($CaCO_3$) from the water in which they live. The $CaCO_3$ may be either incorporated into the skeleton of the organism or precipitated directly. Regardless of the mechanism, when the organism dies, it leaves behind a quantity of $CaCO_3$ and over geologic time thick deposits of this material build up. Reefs are examples of such accumulations.

Another precipitant is the mineral $CaMg(CO_3)_2$; it occurs in large concentrations and it forms a rock called dolomite. It is not the result of direct precipitation in sea water, but rather is formed by replacement of pre-existing deposits of calcite.

The manner in which the type of rock creating the reservoir rock was formed is important in understanding the reservoir behavior. The manner in which they were derived creates essential differences as it affects their fundamental properties of porosity and permeability. Primary permeability is dependent upon the manner of formation. Sandstones generally have greater primary permeability than limestone unless the latter is a reef, or similar, structure. Clastic sedimentary rocks tend to be more porous because of the uniqueness of their origin. They are the result of erosion and transportation; these two processes tend to cleanse the material of everything but silica sand grains and they are often of similar size and shape. Carbonates on the other hand, tend to have greater secondary permeability because they are more soluble and reactive. Fractures and faults within carbonates (which are highly soluble) tend to enlarge in size and lateral extent when water flows through these fractures and faults.

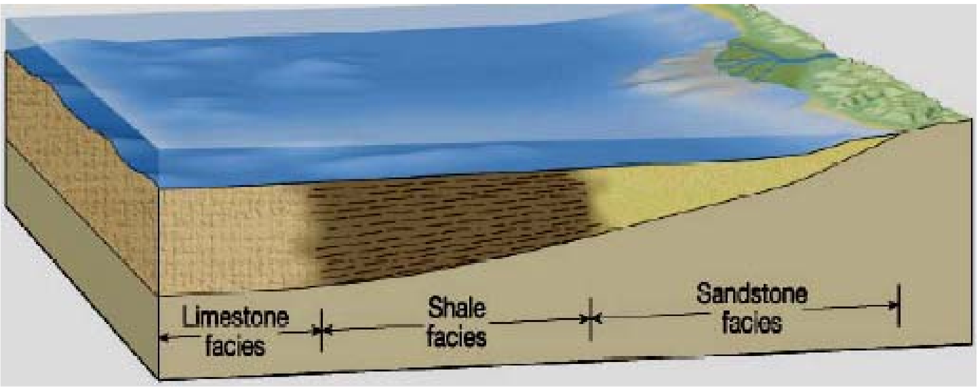


Figure 6 - 8 Marine Sedimentary Depositional Environments

Sandstone Reservoirs

The term sand refers to a particular grain size (62 µm – 2 mm), not to a particular composition. The performance of the sandstone as a reservoir rock, its combination of porosity and permeability, depends upon the degree to which it is truly a sand. Texture should reflect similar sized grains, not a combination of coarse and fine grained material. The best sandstone reservoirs are those that are composed primarily of quartz grains of sand size, silica cement, with minimal fragmented particles.

The quality of the initial sandstone reservoir is a function of the source area for the material, the depositional process, and the environment in which the deposition took place. Sandstone reservoirs are commonly 25 meters (80 ft.) thick, are lenticular and linear spatially, and less than 250 km^2 (100 $mi.^2$) in area. They range in age from the oldest being Cambrian (in Algeria) to the youngest being Pliocene (Caspian region in Ukraine). In the U.S.A., two-thirds of the sandstone reservoirs are Cenozoic in age.

Sandstone reservoirs form extensive stratigraphic traps. Many of the sandstones change composition, e.g. to a shale, within the sandstone unit; at this point they are said to pinch out. Others represent ancient upland river channels that have left sand in the channel that has converted to sandstone. Often these sand channels are stacked one on top of another which means that hydrocarbons are free to migrate between the reservoirs. Other sandstone reservoirs are deltaic in origin, meaning they represent ancient river deltas similar to the Mississippi River delta that extends into the Gulf of Mexico. Successive sandstone layers exist in the subsurface that were created in alternating marine and terrestrial environments. Sandstone reservoir rocks are the result of a number of processes that can occur on dry land as well as beneath the sea.

Carbonate Reservoir Rocks

The most interesting and perhaps impressive aspects of carbonate reservoir rocks are their fossil content. Fossils rage from the very small single cell to the larger shelled animals. Prior to the 1920’s, carbonate reservoir rocks were relatively rare and prior to 1950 they were all regarded as essentially organic rocks. This changed when textural studies of carbonates in Iraq and the Bahamas showed that carbonates are also the result of inorganic processes. Most carbonate rocks are deposited at or in very close proximity to the site of creation. Transportation of material is less common and sorting is essentially non-existent. The “best-sorted” carbonate rocks are oolites in which the “grains” are the same size and shape. Oolites are not “sorted” at all, but they are formed with the sizes and shapes that they have in the carbonate rock and were cemented in place.

Most carbonates begin as skeletal assemblages. They are the accumulation of the remains of carbonate secreting animals and plants. Carbonates may form on gently sloping platforms such as continental shelves in shallow, warm saline water. The resulting rock forms layers of limestone in the subsurface that extend spatially over great distances as in the case of the Michigan Basin or the Cretaceous in Europe. Carbonates may also form as linear or continuous reef trends, as in the case of the Cretaceous reef structure in South Louisiana.

Porosity and permeability are greatly reduced in ancient carbonate reservoir rocks due to compaction and cementation. Porosity tends to increase as a result of secondary processes of leaching and dolomitization of the limestone that occurs after the carbonate rock was formed. Recent carbonate sediments have higher porosity values, but porosity is always reduced during burial and compaction which may reduce the thickness of a limestone bed by 25% under no more than a few hundred meters of overburden. Dolomitization enables a carbonate reservoir rock to resist compaction. Dolomites are normally less porous than limestones at shallow depths, but they retain their porosity better during burial and are less affected by compaction. Therefore they tend to be better reservoir rocks because they contain more voids that hydrocarbons can fill.

Carbonate reservoirs represent a broader range of producibility than do the more common sandstone reservoirs. The most prolific and sustained production rates come from carbonate reservoirs. Carbonate reservoirs can also be at the other extreme in terms of hydrocarbon production. Many carbonate reservoirs will not yield their oil and gas at all unless they are artificially fractured. On average, and despite some outstanding carbonate reservoirs, sandstone reservoirs produce more hydrocarbons per unit volume of reservoir.

Reservoir Traps

Where hydrocarbons exist today in the subsurface depends upon the juxtaposition of source rocks, reservoir fluids, and reservoir traps. There are two types of migration when discussing the movement of petroleum, primary and secondary. *Primary migration* refers to the movement of hydrocarbons from within source rock and into reservoir rock. *Secondary migration* refers to the subsequent movement of hydrocarbons within reservoir rock; the oil and gas has vacated the source rock and has entered the reservoir rock.

A trap consists of an *impervious stratum* that overlies the reservoir rock thereby preventing hydrocarbons from escaping upward and laterally. This impervious stratum is called a *roof*, or *cap*, rock; it intervenes to collect and hold hydrocarbons underground. The roof/cap forms a seal, or barrier, which creates the needed conditions for a *pool*. Trap material must have a lower permeability than the existing rock material through which the hydrocarbons are flowing. The rock forming the seal is also referred to as a capping bed. Porosity controls the volume of hydrocarbons present in a given trap while permeability controls the volume of hydrocarbons that can be extracted from the trap.

Most of the hydrocarbons that form in sediments do not find a suitable trap and eventually flow to the surface along with formation water. It is estimated that less than 0.1% of all organic matter originally buried becomes trapped in an oil pool. The greatest ratio of hydrocarbon pools to volume of sediment is found in rock no older than 2.5 million years and almost 60% of all oil discovered is found in strata of Cenozoic age.

There are three basic types of hydrocarbon traps:

Structural

Structural traps are created when the seal or barrier is concave upward (looking from below). The geometry is formed by tectonic processes after deposition of the reservoir beds involved.

There are two types of structural traps:

1. Folds result in the physical bending (deformation) of the rock units without breaking. The simplest form is an anticline – creating an **Anticline Trap**. The rock units undergo bending very slowly over long periods of geologic time. These types of traps are often found adjacent to mountain ranges.
2. The second type of structural trap is a **Fault Trap**. These are the result of fractures (breaks) within the rock units where one side has moved relative to the other side. Faulting may be the sole cause of the formation of a trap or more commonly, faults form traps in combination with other structural features such as folding which is common along the Gulf coast region of Louisiana. Often an oil field is the result of multiple faulting, forming many structural traps containing hydrocarbons.

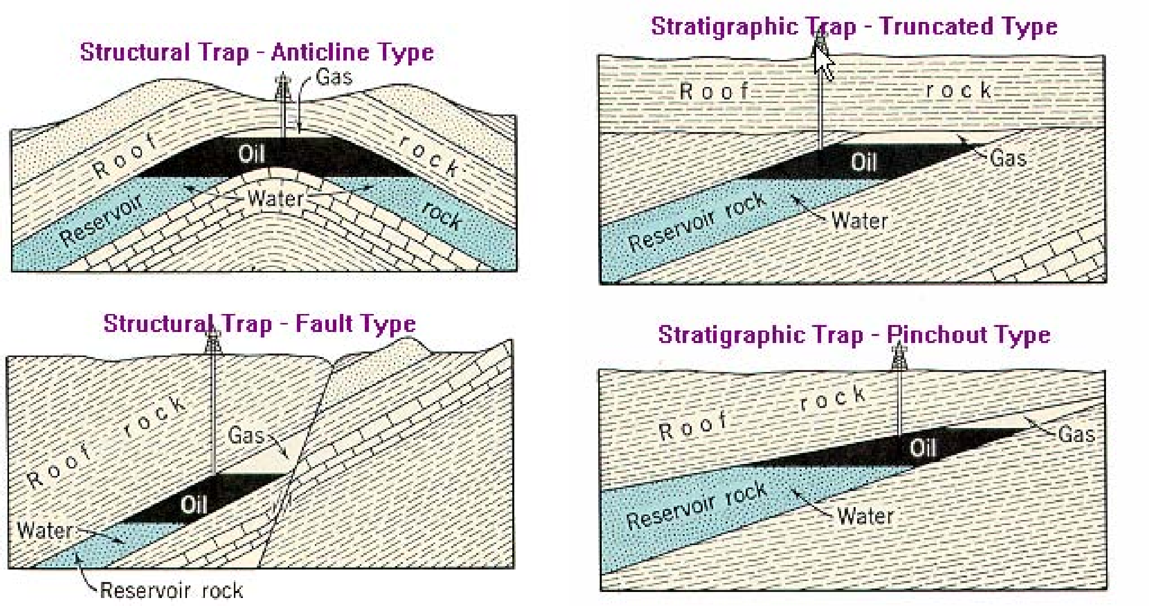


Figure 6 - 9 Structural and Stratigraphic Traps

Stratigraphic

Stratigraphic traps are created when the seal or barrier is formed by changes in lithology or rock type (which also controls porosity and permeability), during the deposition of the reservoir beds involved. Lithological variations may be depositional, as in the cases of reefs, channels, and sand bars. Lithological variations may also be post-depositional in nature; truncations occur where erosion has removed a significant portion of an existing tilted structure followed by deposition of another lithological rock unit, the latter forming the roof rock and thus becoming the capping bed.

Combination Trap

The geometry of a combination trap is the result of a combination of tectonic processes and changes in lithology. A common trap that would be an example of a combination trap is a salt dome. A salt dome is a mass of NaCl (sodium chloride) generally of a somewhat cylindrical shape and with a diameter of about 2 km near the surface, though the size and shape of the dome can vary. This mass of salt has been pushed upward from below through the surrounding rock and sediments into its present position. The source of the salt lies in a deeply buried layer that was formed in the geologic past.

Salt is an evaporite. It exhibits no inherent rock structure. It is subject to deformation resulting from applied pressure and temperature. Salt beds are formed by the natural evaporation of sea water from an enclosed basin. In the North Sea area this occurred during the Triassic period. Subsequently, the precipitated salt layer is buried by successive layers of sediments over geologic time until segments of it begin to flow upward due to increasing overburden pressure toward the surface of the earth. The origin of salt domes is best explained by the plastic-flow theory.

Salt has a density of 2.2 SG under standard conditions. At a depth of about 12,000 feet, the mass of the overlying sediments exerts a compressive, downward force. The combination of this applied pressure (overburden) and accompanying increase in temperature (geothermal) causes a density decrease and salt begins to flow like a plastic substance. A small fracture in the overlying, higher density sediments or a slightly elevated mass of salt above its surroundings would trigger the upward movement. Once this upward salt movement begins, salt from elsewhere in the salt bed moves into the region surrounding the salt plug to replace the salt that is flowing upward to form the salt plug. The upward movement of the salt plug, or dome, continues as long as there is sufficient source of salt "feeding" the dome or until the upward movement is halted by a more rigid formation. Once equilibrium is reached, upward movement of the salt dome ceases, but may begin again if sufficient sediments are added to the weight of the overburden which again increases the load pressure on the parent salt mass. Salt domes come in all sizes and shapes, but all have certain characteristics. For example, they have a cap rock. The cap rock is composed of limestone located at the top of the dome followed by, in descending order, gypsum, anhydrite, and finally rock salt. The average cap rock is between 300 to 400 feet thick, but cap rocks up to 1,000 feet thick are known to exist. Cap rock is created as the salt dome ascends through the overlying materials. The top of the dome dissolves as it rises through the sediments and the residual constituents of the salt become concentrated at the top of the rising plug becoming three layers: limestone, gypsum, and anhydrite. The anhydrite zone represents the less soluble components of the salt that accumulated as the halite was dissolved by pore fluids. The anhydrite zone locally contains abundant celestite that probably formed as the result of interaction with external Sr-bearing brine. The calcite zone formed by bacterial alteration of sulfate accompanying hydrocarbon destruction. The calcite zone contains significant amounts of sulfide minerals and oil. The sulfide-rich calcite zone is dominated by locally massive iron sulfides. These sulfide concentrations resulted from the interaction of deep heated metal-bearing formational brines with bacterially derived reduced sulfur in the ambient cool ground waters.

The cap rock of some salt domes, and sometimes the rock salt itself, is found to overhang, or drape down, the side of the main salt mass. It is commonly found to overhang on one or two sides. The reason for the overhang probably is dependent upon the nature of circulating waters in the sediments through which the dome is ascending. Salt is soluble and dissolves, but the cap rock is not very soluble and is left more intact. Thus the appearance of the cap rock "overhanging" the main salt body is the result of the dissolving of the salt body within the subsurface, but not dissolving the cap rock. Cap rock has all the characteristics of a petroleum reservoir and often contains hydrocarbons. Cap rock also contains free sulfur. Free sulfur is present in cap rock of almost all salt domes, but it appears in commercial quantities only in salt domes that have a thick limestone cap.

FORMATION DAMAGE AND PROTECTION MECHANISMS

Introduction

The objective of a well completion or workover is to establish or re-establish unrestricted communication between the wellbore and an oil or gas producing formation. Any restriction to flow around the wellbore reduces the maximum flow potential and possibly the ultimate hydrocarbon recovery. If the restriction is the result of formation porosity or permeability impairment, it is called formation damage. Other factors that cause a reduction in flow rate into the wellbore are turbulence, partial completion, partial formation penetration (i.e., not drilled deep enough), and poor perforation practices. These are called pseudo-damage because they are not the result of pore-size or permeability reduction. Discussion in this section is limited to factors that cause formation damage and to measures that can be used to protect the formation from damage during drilling, completion and workover operations.

Formation Damage Mechanisms

Formation damage may be the result of physical, chemical, or bacterial alteration of the producing formation rock and/or in-situ fluids from contact either with whole fluids or with components of a drilling and/or completion and workover fluid. The mechanisms of formation damage from invading fluid generally include:

- plugging of pore spaces on the face of the formation by a mud-cake during drilling.
- dispersion of clays or other minerals contained in the rock matrix.
- water-blocking.
- narrowing of fine pore spaces (capillaries) through adsorption of water-soluble polymers.
- dislodgement of fine particulates contained within the pore spaces to lodge in pore throats.
- chemical precipitation of solution salts.
- emulsion formation.
- change in rock wettability.
- presence of sulfate-reducing or slime-producing bacteria and their precipitated by-products.
- swelling of in-situ clays to fill pore spaces.

During drilling, the density of the drilling fluid is usually maintained to give a hydrostatic pressure greater than the formation fluid pressure to prevent a possible well blow-out. Therefore, as new formation is exposed by the drill bit, drilling fluid is forced into the formation by the positive differential drilling fluid column pressure. Particles smaller than the formation pores are introduced into the formation during mud spurt loss, but they rapidly bridge on the pore throats in the near wellbore formation. Particles larger than the formation pores accumulate at the formation face, initiating a mud cake build-up. The invasion of whole drilling fluid is stopped quickly by the mud cake, and only filtrate is allowed to penetrate the formation.

Unless the formation is exceptionally permeable or fractured, the plugging of the formation by drilling fluid solids is very near the wellbore and usually can be by-passed easily by perforating after production casing is set. However, if the casing and formation are perforated in drilling fluid, this formation face damage is transferred into the perforation channel and can become even more difficult to remove than the mud cake on the face. Removal is complicated, because of the tendency of the drilling fluid in the perforations to dehydrate and form a cement-like plug.

A second type of solids plugging can occur when fine drill solids or drilling fluid additives penetrate the formation to depths beyond the near wellbore region. These solids migrate into an ever increasing number of radial passageways. This increase is due to the radial flow geometry. When the well is flowed during production, if the invading particles do not traverse the entry route in reverse, they are likely to become lodged in narrow passageways and block further fluid flow. The problem is exacerbated when unfiltered brine, such as a completion or workover fluid, containing a low solids content is used as a working fluid. After reviewing other models proposed to describe wellbore impairment by internal cake formation in the rock matrix, van Velzen and Leerlooijer, in agreement with Maly, concluded that, for fluids with low solids content, the degree of impairment depends on particle/pore-size ratio and inflow velocity. When inflow velocities are greater than 3.94 inch/minute, the generally accepted “1/3 to 1/7 rule” applies. This rule states that particles larger than one-third of the pore throat diameter will bridge at the pore opening on the formation phase to form an external filter cake, while particles between one-third and one-seventh of the pore throat diameter will invade the formation and be trapped to form an internal plug. However, for low fluid flow velocities (i.e., < 0.8 inch/minute), a “1/3 to 1/7 rule” is probably more applicable. It may be logically concluded from these references that it is better to have either a very dirty or a very clean fluid in contact with the formation rock than a slightly dirty one.

Solids plugging also can occur from the swelling or migration of clays or non-clay minerals within predominantly sandstone formations. Clay and other fine particles are held on the pore surfaces by a variety of forces including, London, van der Waals, electrostatic, Born repulsion, hydrodynamic, and gravitational. These particles can be mobilized when these forces are altered by fluid flow and/or chemically incompatible fluids.

Montmorillonites and mixed-layer clays are typical examples of swelling clays. In the presence of fresher water than that originally contained in the pore space, montmorillonites with a high content of sodium can swell to many times their original volume. This swelling plugs pore openings and reduces porosity and permeability. While smectites are the principal forms of swelling clays, illites also can swell when they coexist with smectites.

Kaolinite has a platelet structure similar to smectites clays but exhibits little or no swelling characteristics. This group of clays usually is attached loosely to the host rock and can be mobilized by the infiltration of fluids with salinities below the critical salt concentration for colloidally induced particle release or with flow rates high enough to exceed the critical shear stress necessary to carry the fine particles away from the pore surfaces. Other clay or mineral types with needle-like or regular crystalline shapes may be affected similarly by the chemistry of invading fluids, whether they are the filtrate of drilling fluid or the whole fluid of completion and workover brines. These mobilized fines then migrate until they are trapped at pore restrictions (the pore throat) and thus reduce the permeability of the rock. Mobilization, migration, and retention of clays and other fine particles have been recognized as the major formation damaging factors in sandstone formations. If these fines are trapped near the wellbore, very significant production losses occur because of the reduction in the number of alternative flow paths into the borehole. The prevention of formation damage by clay swelling and fines migration requires detailed information about the composition of the producing formation and expert planning based on the analysis of the information gathered.

A secondary source of solids that can cause formation damage is the precipitation from solution of insoluble salts or colloidally suspended particulates created when completion or workover fluids contact incompatible connate water. For example, when calcium brines come in contact with connate water containing CO_2, insoluble calcium carbonate ($CaCO_3$) may precipitate and plug near-well-bore pore spaces. Whenever high-density calcium and/or zinc brines are used, formation of salt precipitates is possible when the connate water contains significant amounts of the anions CO_3^{2-}, SO_4^{2-}, S^{2-}, PO_4^{3-}, F^-, or dissolved NaCl. NaCl precipitates because it is less soluble that the corresponding calcium or zinc chlorides or bromides; this precipitation is a problem if it occurs in tight formations where it may be difficult to contact with fresh water to cause dissolution. Also, because of their physical and chemical properties, heavy brines or oil-based drilling fluids filtrates may cause the precipitation of asphaltenes and paraffins from the in-situ hydrocarbons. Dilution of calcium and zinc completion brines with formation connate water may also cause precipitation of the corresponding hydroxide because of the rise in the pH of the diluted solution. Finally, the subject brine may interact with the rock matrix to loosen fines and/or cause precipitation of oxides or silicates.

Formation damage may also be the result of a change in the nature of the fluid wetting the surface of the pore space, i.e., a wettability change. Because of the chemical makeup of the silica (sand) and clays that compose the majority of the world's producing formations, water has a greater affinity for the exposed solid surfaces than does oil. Both the water and the exposed solid surfaces in these formations are polar. Water is attracted to the surface, where it forms a film over and around each surface and particle. Unless the oil in place consists of components other than large molecules of hydrogen and carbon, the hydrocarbon is non-polar and thus is only weakly attracted to the solid surface. Given these conditions, the formation is water-wet. If, however, the hydrocarbon has been oxidized or otherwise contains polar groups, such as carboxyls, amines, amides, sulfonates, and thiols, the partial polarity of the hydrocarbon may actually be such that it is attracted to the rock surface. Water is displaced, and the formation rock is oil-wet.

When the wettability changes, it does so non-uniformly; i.e., some of the pore surfaces remain water-wet and some become oil-wet. Because the relative permeabilities of water and oil are different, and depend on the nature of the fluid wetting the pore surface, a zoning effect results and hydrocarbon productivity is impaired. The formation is more permeable to oil when the formation is water-wet because the oil flows through the center of the pores that compose the larger flow channels while water stays in the narrower channels and along the rock surfaces. Conversely, the formation is more permeable to water when the formation is oil-wet because the water is not restrained by its affinity for the polar surfaces of the rock and is less viscous that the oil.

Sometimes the change from water-wet to oil-wet causes a well that is producing almost no water to begin producing almost all water. Wettability changes can be caused by the presence of surface active agents in the drilling, completion, or workover fluids used to penetrate the productive zone of the formation. Agents such as detergents and lubricants in water based drilling fluids and oil-wetting agents in oil based fluids are the most likely causes of wettability changes. Excessive use of surfactants in completion fluids to prevent emulsion formation between the working fluid and the formation hydrocarbons may also change the characteristic wetting of the formation rock.

The natural tendency of water to wet polar surfaces contributes to another formation damage mechanism called water-block. The significant force of attraction between water molecules and the polar molecules at the surface of a solid is evidenced by the spontaneous rise of water in a glass capillary tube. The height to which the liquid column rises is dependent on its density, surface tension, and the radius of the capillary tube. The maximum height is reached when the hydrostatic pressure of the liquid column equals that of the forces causing the liquid to rise. The hydrostatic pressure is then equal to the *capillary pressure*. Mathematically:

$$gh_L\rho = \frac{2\sigma(\cos\theta)}{r}$$

where,

g = the gravitational constant, ft/sec^2

h_L = equilibrium height of the liquid, feet

ρ = the liquid density, lbm/gal

σ = the liquid surface tension, dynes/cm

θ = the contact angle between the immiscible liquid interface and the solid surface

r – radius of the capillary, inches

The term $gh_L\rho$ is the force driving the liquid into the capillary and is the mathematical description of the capillary pressure. As is apparent from this relationship, the pressure required to remove water from a water-wet formation pore is inversely proportional to the radius of the pore. Capillary pressure promotes the displacement of oil by water but resists the displacement of water by oil. In most reservoirs, native pressures are great enough to overcome capillary pressure. However, in low pressure and tight, low permeability formations, the capillary pressures resisting displacement of water by oil may be significant enough to cause permanent impairment. The problem of water-block is especially serious in the near-wellbore region, where the pressure drop of the oil/water interface approaches zero. The probability of water-block increases as the volume of fluid lost to the formation increases.

Another cause of capillary impairment is in-situ emulsification of in place oil with completion/workover fluids. Even in the absence of commercial surfactants, concentrated salt solutions have an inherent tendency to form mechanical emulsions with crude oil. Stable mechanical emulsions are formed by mixing normally immiscible fluids at high shear rates. In-situ emulsification is possible because, while the total volume of flow may be low, the rate of shear at the constrictions in the flow channels and pore throats is high. Because the viscosity of oil/brine emulsions is very high, their movement through the rock is severely restricted. As the emulsion droplets become trapped in the capillary pore spaces, called an emulsion block, the effective permeability of the formation rock is impaired.

Large, polar, water soluble polymers used for viscosity and filtration control may adsorb on the rock matrix in pore spaces and thus reduce the flow channels available for hydrocarbon movement. Removal of these polymers is difficult both because of the strong attraction and because the polymers are not mutually soluble in water and hydrocarbons. The slime produced by sulfate reducing bacteria is similar to water soluble polymers and has essentially the same effect on permeability. Sulfate reducing bacteria are very resistant to hostile environments, such as salt solutions and high temperatures and pressures. They are ubiquitous environmental organisms that are usually introduced through untreated drilling, completion and workover fluids.

Formation Protection

To ensure the best possible prospect for reducing or eliminating formation damage during drilling, completion and workover activity, a compilation should be made of all the information available on the well and the producing formation. Geological information may be obtained from logs, production formation cores, and mineralogy (with good samples, independent mineralogical analysis is possible). A well history, including depth, bottomhole temperature, type of drilling fluid and/or the nature of any fluids previously in contact with the producing formation, and composition of produced fluids, especially gases, will help immeasurably with planning to prevent formation damage. If practical, a laboratory evaluation should be made of a formation core to determine permeability and fluid compatibility and to ascertain potential detrimental interactions. When all the examinations and analyses are complete, the optimum fluid(s), additives, and procedures designed to minimize formation damage can be recommended.

Even without the extensive analysis recommended, it is generally prudent to follow some generally accepted practices to prevent formation damage during drilling, completion and workover. First, filtered brine usually reduces the chance of both introducing foreign particles into the formation and causing water sensitive clays to swell. Second, use of an empirically selected surfactant helps reduce the chance of emulsion formation, wettability change, and even fines migration. Third, selection of a chemically compatible drill-in/completion/workover fluid reduces the probability of insoluble salt precipitation.

Of all the possible mechanisms to prevent formation damage during drilling, completion or workover, the most significant is the prevention of fluid loss. This sometimes is accomplished by increasing the viscosity of the working fluid. Because flow rate in porous media is inversely proportional to viscosity, increasing the viscosity of the working fluid at bottomhole conditions can significantly reduce the loss of fluid to the formation. The most common practice from preventing loss of fluid to the formation is to use a combination of increased viscosity and salt or calcium carbonate based particles to bridge the pore spaces on the formation face. Both these materials are acid soluble and therefore can be removed by acid treatment if they are not otherwise removed by washing or production of the well.

In a study designed to find and use the best practice for preventing formation damage during workover operations in Prudhoe Bay, Dyke and Crockett reached the following conclusions:

1. The primary cause of formation damage during workovers was the invasion of fine solids and debris from downhole operations, such as near perforation, milling and scraping. Stopping fluid losses prevents the entry of these fines into the formation.
2. Loss control material (LCM) pills, when properly formulated, usually clean up easily from perforations and even more readily from open hole formation face, leaving no formation damage. Badly formulated pills cause severe damage.
3. The loss of clean, i.e. filtered fluids during completion/workover operations has little effect on future productivity when the formation has relatively high permeability.
4. Tight formations that inherently take small amounts of fluid are most likely to be damaged by the loss of fluid. Fluid loss is therefore more important in these wells.
5. In non-fractured wells, viscous pills are capable of reducing, but not stopping, fluid loss. To be effective in stopping fluid loss, graded particulates must be added to the viscous pill to seal the formation.

6. In fractured wells, both coarse and fine solids may cause irreversible damage. If the intent is to stop the loss of fluid, special care must be taken to ensure that any bridging materials added to the LCM contain materials coarse enough to bridge the fractures at the formation face. If, in addition to the bridging materials, fluid dilatency can be achieved, the probability of success in stopping fluid loss is markedly improved.
7. Finally, when working with less than salt saturated fluids, it is prudent to use an antibacterial agent to inhibit the growth of slime producing bacteria so that these bacteria are not injected into the producing formation.

DRILL-IN FLUIDS

Introduction

The rapid growth of extended reach and horizontal wells using open hole completion techniques was a key factor in the popularity of reservoir drill-in fluids. Their popularity has resulted in an emphasis on the practices used while drilling into the reservoir. Now that drilling down to the pay-zone and drilling in the pay-zone are viewed as two distinct steps, oil and gas producers require that service companies demonstrate an expertise in both drilling and completion operations. This cross-functional approach has resulted in a steady improvement in drill-in fluid formulations.

Donovan and Jones described the qualities desired in an optimally formulated drill-in fluid. Their ideal drill-in fluid would:

1. conform to all acceptable health, safety, and environmental standards
2. bridge all exposed pore openings with specially sized bridging material
3. deposit a non-erosive filter cake that is easily and efficiently removed during the completion phase, and
4. retain desirable drilling fluid properties.

Horizontal wells drilled and completed in unconsolidated sand reservoirs have become feasible, due to new technology and completion methods. Wells of this type require sand control such as long open hole gravel packs or the installation of mechanical sand exclusion devices (slotted liners, pre-packed screens, etc.).

Usually the wells are drilled with conventional drilling fluids to the top of the pay-zone and casing is set. The cement is then drilled out to the casing shoe and the shoe tested. The drilling fluid is then displaced with a “low damage potential drilling fluid” generally consisting of polymers, viscosity enhancers, and insoluble particles for building a filter cake. The particles are usually graded salt (NaCl) or graded calcium carbonate ($CaCO_3$).

These compounds are used because they are soluble in under saturated brines or hydrochloric acid. One problem with prior art filter cakes is that they are often difficult to remove requiring high pressures to do so. Under such conditions, damage results to the formation. Such damage is believed to occur because the filter cake invades the formation and becomes “cemented” thereto and must be forcibly removed at high pressure; the forceful removal is thought to cause damage to the permeability of the formation.

After the open hole interval has been drilled to total depth, the gravel pack screen or sand exclusion device is placed in the open hole interval. To do this, it becomes necessary to circulate the drilling fluid from the open hole so that the well can be gravel packed or the sand exclusion setting can be tested. To do this it is necessary to perform a displacement of the drilling fluid with a solids-free completion brine, sometimes viscosified with a water soluble polymer, e.g. xanthan gum derivative. Concern about the physical erosion of the filter cake with the completion fluid is also always an issue. That is, the filter cake should be durable and stable enough to permit the completion or other operation to take place and protect the well bore during the entire operation.

The ideal drilling fluid or drill-in fluid would mechanically seal all pore openings exposed to the wellbore, stay intact during completion operations, then be easily removed by production of oil and gas. Problems arise in designing these fluids because production zones vary in pressure, permeability, porosity, and formation configuration. Generally, fluids used to control fluid leak-off in permeable formations require an initial high pressure spike before removal can begin - from about 300 to 500 psi. This pressure spike is indicative of damage to the original permeability of the permeable formation. It would be desirable if fluids could be devised which would easily form an impermeable filter cake to prevent the loss of expensive completion fluids to the formations and which effectively protect the original permeable formation during various completion operations such as a gravel packing or wellbore workovers. At the same time, however, it is also highly desirable for the filter cake to be easily removable at the beginning of production, causing little or no damage to the formation.

Water-soluble organic polymers, such as HEC, have been used to slow the leak-off rate of a clear fluid into a permeable formation. However, these polymers will not effectively control the leak-off rate. This can only be controlled by bridging the pore opening with rigid or semi-rigid particles of sufficient size and number. Bridging materials used for this purpose (e.g., oil-soluble resins, gel pills, sized salt, and benzoic acid) rely upon breakers or dissolution to remove them. Unfortunately, these methods have not always been effective, resulting in considerable formation damage or unsatisfactory leak-off control.

PERF*FLOW*® System

Baker Hughes Drilling Fluids has developed systems based upon a bridging technique which not only positively controls leak-off of the fluid into the formation, but also provides a bridging zone that can be easily and effectively removed by the produced fluid. **PERF*FLOW*** systems provide effective leak-off control over a wide range of permeabilities. Depending on the type of completion programmed for the well, usually no breakers or fluids to dissolve the bridging solids are required; removal is accomplished by flowing the well.

PERF*FLOW* 's fluid loss control mechanism involves the mechanical bridging of properly sized particles on pore throat openings. The graph below illustrates the particle size distribution of the graded calcium carbonate (MIL-CARB) used in **PERF*FLOW***. Note the broad particle size distribution available to bridge a wide range of permeability, from a few milli-Darcys to over 10 Darcys

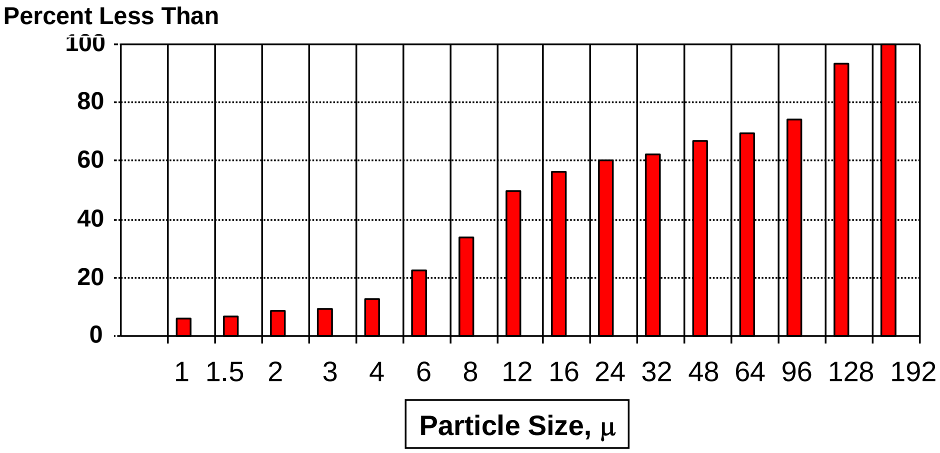


Figure 6 - 10 Particle Size Distribution of MIL-CARB™

PERF*FLOW Systems Application*

Three product compositions are available to prepare **PERF*FLOW*** fluids: W-307, W-306, and **PERF*FLOW* DIF**. W-307 is used in preparing **PERF*FLOW*** fluids utilizing sodium chloride or potassium chloride brines. W-306 and **PERF*FLOW* DIF** are used in preparing **PERF*FLOW*** fluids utilizing potassium chloride, sodium chloride, calcium chloride, calcium bromide and zinc bromide, formate brines or mixtures of these brines.

Standard Systems Formulation

LOW-DENSITY PERF*FLOW* Systems (9.2- 10.5 ppg)

1. Preferred Barrel Formulation:
   - 1 PERF*FLOW* DIF (55 lb/25 kg bag) plus 0.94 bbl of brine
   - 0.94 bbl of brine includes 2% to 4% KCl
   - 1 gal/100 bbls X-CIDE® 102 (25% by volume glutaraldehyde)
2. Optional Barrel Formulation:
   - W-306 (5 or 55 gallon) @ 2.00 gpb to YP = 20 or W-307 (5 or 55 gallon) @ 2.50 gpb to YP = 20
   - 1 MIL-CARB™ (50 lb bag)
   - Final volume contains 2% to 4% KCl; brine volume to 1 bbl
   - 1 gal/100 bbls X-CIDE 102 (25% by volume glutaraldehyde)

HIGH-DENISTY PERF*FLOW* Systems (> 10.5 ppg)

1. Preferred Barrel Formulation:
   - 1 **PERF*FLOW* DIF** (55 lb/25 kg bag) YP = 20
   - 2 to 3 ppb Magnesium Oxide to buffer pH = 8.0

- 0.94 bbl of brine (no KCl)
- 1 gal/100 bbls X-CIDE 102 (25% by volume glutaraldehyde)

2. Optional Barrel Formulation:
   - W-306 (5 or 55 gallon) @ 2.00 gpb to YP= 20
   - 1 MIL-CARB (50 lb bag)
   - 2 to 3 ppb Magnesium Oxide to buffer pH = 8.0
   - Brine volume to 1 bbl
   - 1 gal/100 bbls X-CIDE 102 (25% by volume glutaraldehyde)

Displacement

Prior to building or loading the **PERF*FLOW*** system, all pits and lines should be cleaned and flushed with water/seawater. Cement and float equipment should be drilled with the existing fluid prior to displacing the hole with **PERF*FLOW***. Best results can be achieved if the hole can be circulated with seawater prior to the **PERF*FLOW*** displacement. The circulating rate should be as high as possible with pipe rotation to minimize channeling. Pump a 25 to 30 barrel caustic pill followed by a 25 to 30 barrel high viscosity (3 gal/bbl W-306) pill then follow with the **PERF*FLOW*** system.

Open Hole Displacement for Completion

At total depth, a short trip to the casing should be made and a high viscosity 25 barrel pill pumped and circulated to surface. The drilling assembly should be pulled out of the hole and a hole opener picked up and washed to bottom. The hole and casing can be displaced with a filtered completion fluid at this time. A 20 barrel pill with 3.0 gallons per barrel W-306 in water should be pumped to separate the two fluids. If any tight hole was experienced or concern for lost circulation exists, a **PERF*FLOW*** polymer pill (W-306 without calcium carbonate) can be spotted to cover the open hole plus 500 ft inside the casing. In this case, the workstring should be pulled 250 ft inside the casing. The casing is then circulated until clean brine is returned to the surface. Pull the hole opener out of the hole, then rig up and run in the hole with the completion assembly.

General Guidelines

- The pH should be controlled from 8.0 to 9.0.
- All solids control equipment should be run while drilling cement. Sodium bicarbonate will aid in lowering the pH and will precipitate soluble calcium. Pre-treat the active fluid system with 1 ppb of Sodium bicarbonate before drilling cement.
- High viscosity sweeps will be used throughout the operation. These sweeps should have a yield point greater than 50. All sweeps should be at least 100 barrels to increase their effectiveness.
- Wiper trips are an important tool in gauging hole conditions. A wiper trip at least every 500 ft can detect a build-up of pressure identified by swabbing.
- Packing fraction refers to that state when a fluid begins to exhibit semi-plastic tendencies due to solids. For example, the packing fraction of bentonite in freshwater is approximately 5%

by volume while barite would be about 65% by volume. Balling and lost circulation are frequent problems while drilling conductor, surface or any large diameter hole. Generally, this is a function of the concentration of drilled cuttings in the annulus. High concentrations of active clay (gumbo) cuttings in the annulus result in cuttings adhering together on the bit and pipe. In addition, cuttings increase fluid density and hydrostatic pressure. Factors affecting the cuttings concentration are penetration rate, circulating rate, and cuttings transport efficiency. The following equation provides the maximum penetration rate for a given circulation rate and desired cuttings concentration.

PERF*FLOW Systems: General Engineering Guidelines*

The potentially severe borehole problems intrinsic with horizontal drilling can be minimized dramatically with the selection of a non-damaging drilling fluid system possessing optimum hole-cleaning and lubrication capabilities.

Drilling fluids for vertical wells are often chosen primarily for their ability to control the formation surrounding the reservoir. By modifying the fluid properties and dynamics, these same fluids, in many cases, have been used to drill horizontally.

In this regard, it is important to devote particular attention to the cleaning, lubrication, and maximum pay zone protection capabilities of the fluid system. For gravel packed completion, pay zone protection is extremely important. Damage to the formation will inhibit perforation filling, open hole performance, and reduce well productivity. It is extremely important to obtain a clean interface between the gravel pack sand and the formation sand.

As with vertical wells, deciding which fluid system, or combination of systems, to use in a horizontal application depends upon the geology of the prospect, historical successes and failures, environmental constraints, and the experience of the fluid company and operator.

When planning a drilling fluids program for a horizontal well, it is often advantageous to view the prospect in the same manner as the production engineer – from the downhole objective up. For gravel pack purposes, this usually requires the use of drill-in fluids.

The drill-in fluid should be designed to minimize damage to the reservoir. If the proposed drill-in fluid design conflicts with fluid designs up-hole, then a change in the fluid program may be warranted. The carrying capacity, inhibition, and lubricity of the fluid should suit the formations drilled and the prospective well profile.

PERF*FLOW* DIF fluids were designed to be used as drill-in fluid systems. A drill-in fluid possesses the desirable properties of a good drilling fluid and provides the necessary attributes of a completion fluid. In this respect, **PERF*FLOW* DIF** should be the only fluid the producing formation sees during the final drilling operation. This point, however, brings up the question as to when the fluid should be introduced into the drilling operation.

Even though a **PERF*FLOW* DIF** fluid can be formulated to handle most hole conditions during the drilling operation, it may be more economical and effective to use conventional fluids such as oil-base fluids, PHPA systems, or simple bentonite-base fluids for most of the drilling operation. When to introduce the **PERF*FLOW* DIF** becomes a judgment call on the part of the drilling and production engineers. The following guidelines and comments are provided to assist in making this decision.

Under-reaming Operation

- Where a cased hole exists to the top of the pay zone and it is desired to drill and under-ream for an open-hole completion, **PERF*FLOW* DIF** can be introduced to drill the pilot hole but must be used before starting the under-reaming operation so that the final exposed producing formation sees only the drill-in fluid. In most cases, it may be best to change to the drill-in fluid while in the casing to avoid delay once the drilling operation has started. Displacement would also be more efficient in the cased hole, and exposure of the formation to two different fluids would be avoided.

- Where an old perforated cased hole exists through the pay zone and it is desired to cut a section through the pay zone and to under-ream, the rheological properties and hole cleaning capacity of the **PERF*FLOW* DIF** system can be adjusted to effectively carry steel cuttings out of the hole; thus **PERF*FLOW* DIF** can be used as the cutting fluid. This adjustment, however, will likely require treatment with additional W-306, W-307 or certain products such as BIOZAN® or XANVIS® to obtain higher flow properties than are normally maintained. Therefore, if the existing fluid in the casing is deemed adequate to do the milling operation, then it may be more economical to use it and then change to **PERF*FLOW* DIF** before initiating the under-reaming operation.

Drilling and Completing Horizontal Section

PERF*FLOW* DIF fluid can be used to cut a window and to drill the build section of the horizontal well. Whether to use the **PERF*FLOW* DIF** fluid for this purpose depends upon the same reasoning used in the under-reaming operation. If the existing fluid in the casing is deemed satisfactory for the milling operation and will effectively stabilize the formation to be immediately drilled, then it may be more economical to use that fluid. Where the existing fluid will require extensive treatment or a complete change-out, then consideration should be given to using the **PERF*FLOW* DIF** fluid for this purpose.

Extended Drilling Required from Casing Point/Kick-Off Point

Since **PERF*FLOW* DIF** is to be used as the drill-in fluid, it does not contain any highly active drill solids such as clays. Therefore, using the **PERF*FLOW* DIF** to drill several thousand feet of hole prior to encountering the producing formation may not be the best choice, unless the operator is prepared to replace a significant volume with clean **PERF*FLOW* DIF** fluid prior to drilling into the pay-zone.

Mixing Procedures

Ensure all pits, lines and pumps are clean and have been flushed with water/seawater prior to mixing. Mixing sequence depends on the products being used. When mixing the W-306 or W-307 products, the following mixing order is recommended.

Water / Brine	0.87 - 0.90 bbl
W-306 / W-307	2.0 - 2.5 gal/bbl
MIL-CARB^{TM}	50 lbs/bbl
X-CIDE® 102	0.01 - 0.015 gal/bbl
KCl	1% - 3% (optional)

Product selection of W-306 or W-307 is dependent on the density of the mix water that will be used. In freshwater, KCl, or sodium chloride brines, either the W-306 or W-307 can be used. Once selection of a specific product (W-306 or W-307) has been made, *do not* mix the two products together in the same system as they will not perform up to specification.

In higher brine weights, (above 10.0 ppg NaCl), W-306 is the product of choice. When mixing W-306 in heavy brines (above 11.0 ppg $CaCl_2$), it is recommended to use some type of shearing device that would also increase the temperature of the mix water to the range of 140°F to 150°F.

As noted in the above formulation, KCl additions are optional. KCl additions are recommended for additional inhibition should shale stringers be encountered while drilling the production zone. Also, if time is available, the W-306 and W-307 products should be allowed to disperse in the mix water/brine for 1 to 2 hours before the additions of MIL-CARB^{TM} are made.

The following mixing order is recommended if **PERF*FLOW* DIF** is used:

Water / Brine	0.94 bbl
PERF*FLOW*®	55 lbs/bbl
X-CIDE® 102	0.01 - 0.015 gals/bbl
Magnesium Oxide	3 lbs/bbl
KCl	1% - 3% (optional)

The **PERF*FLOW* DIF** product can be mixed in all ranges of brines. When using divalent salts such as $CaCl_2$, it is recommended to use 3 lbs/bbl of Magnesium Oxide as a pH buffer. Once all the **PERF*FLOW* DIF** has been mixed, and should additional viscosity be required, small additions of W-306 can be added to the system. Prior to these additions, pilot testing should be performed to determine the exact quantity needed.

If displacement volumes are to be mixed on location, care should be taken when mixing the initial volume. Small batch mixes are recommended at first in order to prevent any calcium carbonate from settling out of the system versus trying to mix large volumes of fluid in a poorly agitated fluid tank. Should time constraints prohibit mixing small amounts of fluid, consideration should be given to adding a small quantity ($^1/_8$ to $^1/_4$ lb/bbl) of XANVIS®, BIOZAN®, or XC POLYMER to the mix water before the PERF*FLOW* additions are initiated in order to prevent any calcium carbonate from settling out of the system.

Typical Properties

Brine	**KCl**	**NaCl**	**$CaCl_2$**
Fluid Weight, ppg	9.2	9.7	11.4
Funnel Viscosity, sec/qt	40 - 50	40 - 50	40 - 50
Plastic Viscosity, cP	10 - 20	15 - 25	20 -30
Yield Point (YP), lb/100ft^2	20 - 25	20 - 25	20 -30
Gel Strengths, lb/100ft^2	4 / 7	4 / 7	4 / 7
API Fluid Loss, ml/30 min	< 4	< 4	< 4
pH	8.5 - 9.0	8.5 - 9.0	7.5 - 8.5

Troubleshooting

Problem	Possible Cause	Recommended Action
Increase in API Filtrate	1. Shift in particle size 2. Polymers degrading 3. Bacterial problem	1. Pilot test to determine displacement volume required. 2. Pilot test with W-306™ / 307™ or BIO-LOSE™. 3. Pilot test 1 gallon X-CIDE® 102 per 100 bbls fluid.
Increase in Rheological Properties	1. Shift in particle size 2. Incorporated solids	1. Pilot test to determine displacement volume required. 2. MBT increased, pilot test for displacement volume.
Decrease in Rheological Properties	Polymers degrading	Pilot test with W306/307, XANVIS®, BIOZAN® or XAN-PLEX D Polymer to determine treatment level.
Slugging Pipe for trip	Air entrapment	Add 1/8 to 1/4 gallon LD-8® per 10 bbls of slug volume. Use salt for some portion of the slug weight
Sliding	BHA Configuration Hole Geometry	Add 3% TEQ-LUBE®
Foaming	High Surface Tension	Elevate pH to 9.0. Add defoamer LD-8®
Stuck Pipe	Aggressive build rate	Consult stuck pipe pills section of manual

CLEAR-DRILL® Fluids

Introduction

To balance the formation pressures experienced down-hole, conventional drilling fluids are required to cover a wide density range. In the majority of cases, the required fluid density has been achieved by the addition of insoluble minerals, typically barite, which are suspended in the fluid by a viscosifier. The **CLEAR-DRILL** family of drilling fluids departs from this standard technology by utilizing a variety of highly soluble formate salts to achieve the required density. By selecting the correct salt, any density in the range 1.0 (8.34 ppg) to 2.35 S.G.(19.6 ppg) can be achieved with a solids-free system.

The advantages of a solids-free system are significant. The plastic viscosity of a fluid is greatly affected by the quantity of suspended solids. Consequently, clear brine systems will exhibit lower plastic viscosities than conventional fluid systems. This will result in lower equivalent circulating densities (ECD) and lower pressure losses downhole, resulting in greater drilling efficiency. These two effects are particularly important in slim hole drilling where, because of the narrower pipe and annulus diameters, the reduction of downhole pressure losses and ECDs is essential to ensure good rates of penetration while preventing fracturing of the formation.

Environmental considerations are playing an increasingly significant part in drilling activities throughout the world, and drilling fluids have come under particularly close scrutiny, both onshore and offshore, in terms of their environmental potential. The **CLEAR-DRILL** system has been developed partly in response to environmental pressures for cleaner drilling fluid systems. This has been achieved by utilizing biodegradable salts with very low acute toxicity in conjunction with benign polymers and by eliminating the routine use of weighting materials, many of which contain quantities of heavy metals such as lead, cadmium, and mercury.

Clearly, no system can be acceptable solely on environmental grounds; a high level of performance must also be present. Fluids in the **CLEAR-DRILL** system provide optimum rheological properties, excellent stability and a very high degree of inhibition to reactive shales. The absence of barite helps to ensure that the **CLEAR-DRILL** fluids are non-damaging to the pay zone, thus eliminating the need for more complicated “drill-in” fluids. Other salts such as sodium chloride or potassium chloride can be used as bridging materials, providing the necessary fluid loss control with materials which are readily removed during the well clean-up operation. The **CLEAR-DRILL** system comprises three brines: sodium formate, potassium formate, and cesium formate. All these salts can be used either to formulate solids-free drilling fluid systems or in conjunction with conventional weighting materials to build regular drilling fluids.

Function of Formates

The use of clear brines for drilling is not a new idea. Sodium chloride and calcium chloride have been available for many years and the former, in particular, has been widely used as the basis for low-weight drilling fluids. These brines however, have significant limitations. Sodium chloride is limited to a maximum density of 1.2 S.G. (10.0 ppg) while calcium chloride brines suffer from a high degree of incompatibility with the majority of polymers used in conventional drilling fluids. The use of highly soluble salts to provide density rather than insoluble weighting materials can have a major effect on solids loading within the system. The benefit of a clear brine system increases with increasing density as shown in the figure below.

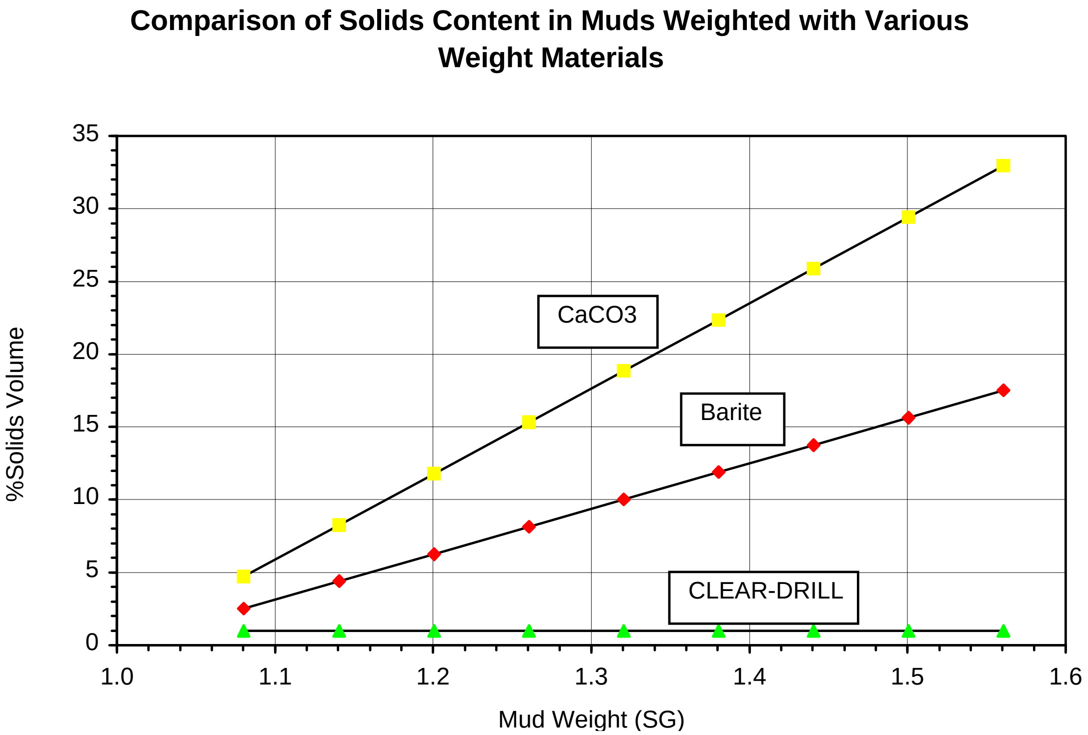


Figure 6 - 11 **Comparison of Solids Content in Fluids Weighted with Various Weight Materials**

In order to provide drilling fluids based on clear brines which can cover a wide range of densities and exhibit a high degree of compatibility with viscosifying and fluid loss polymers, other salts are needed. Formates were selected because of their very high solubilities and, initially, as a result of their excellent compatibility with xanthan polymers. The relationship between formate salts and xanthan polymers is synergistic in terms of thermal stability; the higher the formate salt concentration, the higher the temperatures at which xanthan polymers retain their viscosity. This relationship is illustrated in the figure below.

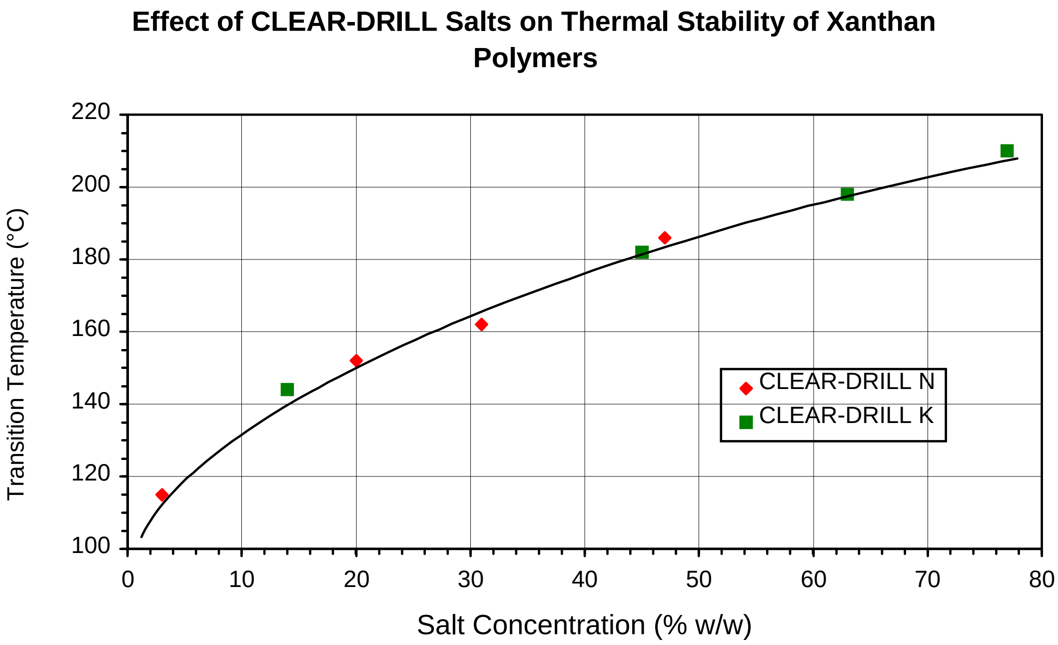


Figure 6 - 12 Effect of CLEAR-DRILL Salts on Thermal Stability of Xanthan Polymers

Further investigation revealed that formates are compatible with all commonly used drilling fluid polymers. Sodium and potassium formates are readily available and the use of these products on their own, or in combination, can provide brines with densities up to approximately 1.58 S.G. (13.2 ppg).

A further advantage of formates is that they will not react with any cations to produce insoluble salts, thus minimizing the possibility of producing precipitates downhole upon contact with formation water. In particular, all the divalent metal formates are readily soluble in water. Additionally, the toxicity of formates is generally very low, both to mammalian and aquatic species, thus enabling environmentally benign fluids to be formulated for use in sensitive areas. The complete absence of chlorides from the system allows easy disposal of waste fluid into fresh water systems, a significant benefit when drilling on land.

Description of System Components

CLEAR-DRILL® N

CLEAR-DRILL N (sodium formate) is a crystalline white powder, highly soluble in water, giving mildly alkaline brines up to a density of 1.35 S.G. (11.2 ppg). The product can also be supplied as a concentrated brine.

- System applicability: **CLEAR-DRILL N**
- Temperature limitations: Stable at 250°C (482°F)

CLEAR-DRILL® K

CLEAR-DRILL K (potassium formate) is a crystalline white powder, highly soluble in water giving mildly alkaline brines up to a density of 1.58 S.G. (13.2 ppg) The product can also be supplied as a concentrated brine.

- System applicability: **CLEAR-DRILL K**.
- Temperature limitations: Stable at 250°C (482°F)

CLEAR-DRILL® C

CLEAR-DRILL C (cesium formate) is a crystalline white powder, highly soluble in water giving alkaline brines up to a density of 2.35 S.G.(19.6 ppb). It is commercially available.

- System applicability: **CLEAR-DRILL C**
- Temperature limitations: Stable at 250°C (482°F)

Weighting Materials in CLEAR-DRILL® Brines

Conventional weighting materials can be used in **CLEAR-DRILL** brines to provide fluids above the normal density ranges available for the solids-free systems **with the exception of barite in CLEAR-DRILL K solutions with densities above 1.30 SG (10.8 ppg, 45% by weight)**. Calcium carbonate, hematite (DENSIMIX), and manganese tetraoxide (MICROMAX) can all be utilized. High concentrations of **CLEAR-DRILL K** (i.e. above 1.50 S.G. (12.5 ppg)) result in the partial solubilization of barium sulphate to provide levels of soluble barium up to 2,000 mg/l, depending on time of exposure, temperature and barite availability. This phenomenon has not been observed in lower density **CLEAR-DRILL K** solutions, or in other formate solutions even at saturation.

Products Used in CLEAR-DRILL Fluids

XAN-PLEX® D / Xanthan Gum Polymer

XAN-PLEX D Polymer is the primary viscosifier for all systems where temperatures are not expected to exceed 150°C (302°F). These polymers provide the best rheological profile of any commonly available polymer and result in shear-thinning fluids under dynamic flow with good gel structures under static conditions. In addition, there is a marked degree of synergy between xanthan polymers and concentrated formate solutions which results in a demonstrable increase in the upper temperature limit for these products.

- System applicability: **ALL**
- Temperature limitations: Up to 150°C (302°F)

KEM-SEAL®

KEM-SEAL is a synthetic copolymer of AMPS and alkylacrylamide and has proven thermal stability to temperatures in excess of 250°C (482°F). **KEM-SEAL** also provides filtration control under high temperature conditions and is resistant to most types of contamination.

- System applicability: **ALL**

- Temperature limitations: Up to 250°C (482°F). For high temperature applications where prolonged exposure to conditions over 150°C (302°F) will occur, then KEM-SEAL is used as the primary viscosifier.

MIL-PAC™ LV

MIL-PAC LV can be added in significant quantities to a CLEAR-DRILL fluid to obtain the required filtration control without contributing to viscosity.

- System applicability: **ALL**

- Temperature limitations: Up to 120°C (248°F). For low to moderate temperature applications, up to 120°C (248°F), **MIL-PAC LV** is the normal additive for fluid loss control in formate-base systems. For higher temperatures, **MIL-PAC LV** is replaced with KEM-SEAL®.

Calcium Carbonate

Calcium carbonate can be used as a bridging agent or as a weighting material. Dolomite (calcium magnesium carbonate) or graded, ground marble can also be used.

- System applicability: **ALL**

- Temperature limitations: Stable at 250°C (482°F)

MICROMAX

MICROMAX (manganese tetraoxide – Mn_3O_4) is a water-insoluble, acid soluble, dispersible weighting material for drilling fluids with ideal properties for providing high density fluids. The material has a specific gravity of approximately 4.8 @ 20°C, resulting in a roughly 15% volume reduction of solids compared to barite. Although somewhat harder than barite, MICROMAX is slightly less abrasive than barite because the particle shape is predominantly spherical, thus providing a higher density while avoiding the abrasivity problems normally associated with hematite. The particle shape and size (typically less the one micron) are also responsible for non-impairment of return permeabilities and the low impact that the product has on plastic viscosity as particle-to-particle interactions are minimized.

- System applicability: **ALL**
- Temperature limitations: Stable at 250°C (482°F)

Standard Laboratory Formulations and Properties

These data represent a cross-section of the laboratory work carried out Shell Oil Company's laboratories in The Hague and in Baker Hughes Drilling Fluids' laboratories as part of a joint venture research project between Shell and Baker Hughes Drilling Fluids.

	1.20 SG	1.32 SG	1.44 SG	1.56 SG	1.68 SG	2.24 SG
CLEAR-DRILL N, g	128.1	219.8	-	-	-	-
1.58 SG CLEAR-DRILL K Brine, ml	-	-	257.0	327.0	237.4	
2.25 SG CLEAR-DRILL C Brine, ml	-	-	-	-	65.1	345.0
Water, ml	292.0	242.9	93.0	23.3	-	-
XC® Polymer, g	1.0	0.5	0.75	0.5	0.5	1.0
MIL-PAC™ LV, g	2.0	2.0	2.0	2.0	1.0	1.0
KEM-SEAL®, g	-	-	-	2.0	-	-
Citric Acid, g	-	-	-	-	1.0	2.0
Soda Ash, g	0.5	0.5	0.5	0.5	0.5	0.5
W.O.™ 30 , fine, g	10.0	10.0	10.0	10.0	10.0	10.0

Table 6 - 1 Laboratory Fluid Formulations

Properties	1.20 SG	1.32 SG	1.44 SG	1.56 SG	1.68 SG	2.24 SG
Fann 600 rpm	48	57	47	55	29	45
Fann 300 rpm	32	34	30	35	19	31
Fann 200 rpm	25	26	23	24	15	25
Fann100 rpm	18	16	15	15	10	18
Fann 6 rpm	5	4	4	4	3	6
Fann 3 rpm	4	3	3	3	2	5
Gels (lbs/100 ft^2)	5/6	3/5	4/5	3/5	3/6	6/7
PV (cP)	16	23	17	20	10	14
YP (lbs/100 ft^2)	16	11	13	15	9	17
pH	10.5	10.2	10.6	11.0	10.2	10.8
API Filtrate, ml	4.0	0.7	1.8	0.4	3.5	3.0
HT/HP (250°F/121°C), ml	14	20	17	14	20	20

Table 6 - 2 Initial Properties of Laboratory Fluid Formulations

Post H/R (250ºF/121°C)	1.20 SG	1.32 SG	1.44 SG	1.56 SG	1.68 SG	2.24 SG
Fann 600 rpm	36	45	50	60	31	45
Fann 300 rpm	25	27	33	37	20	30
Fann 200 rpm	20	20	25	29	16	24
Fann 100 rpm	14	12	17	18	11	16
Fann 6 rpm	4	3	5	4	4	5
Fann3 rpm	3	2	4	3	3	4
Gels (lbs/100 ft^2)	4/4	2/3	4/6	3/5	4/6	4/5
PV (cP)	11	18	17	23	11	15
YP (lbs/100 ft^2)	14	9	16	14	9	15
pH	10.2	10.0	10.3	10.8	10.2	11.3
API Filtrate, ml	5.5	5.5	3.2	2.5	3.6	3.4
HT/HP (250F/121°C), ml	22	26	20	19	22	20

Table 6 - 3 Properties of Laboratory Formulations after Hot Rolling

BIO-LOSE® 90 SYSTEM

Introduction

The **BIO-LOSE 90** system was developed by Baker Hughes Drilling Fluids for use as a low solids horizontal drilling fluid which would provide low dynamic fluid loss and rheological parameters which are compatible with long horizontal sections. Its primary use is in fractured formations, both sand and calcareous. The primary viscosifier used is DRISPAC®, with BIO-LOSE® added to control filtration. BIO-LOSE is a non-fermenting chemically modified starch which does not require any biocides and can be used over a wide pH range in most water-base fluids. The third product required in the make-up of a **BIO-LOSE 90** system is MIL-BREAK 943, which will prevent any emulsification from occurring as drilling progresses. When mixed according to Baker Hughes Drilling Fluids guidelines, no further additives will be required.

Rheological Properties

The **BIO-LOSE 90** system can easily be adjusted to the operator’s specifications if changes in rheological properties are required. The Yield Point is usually maintained at 6 to 8 lb/100 ft^2 to ensure the system will be in turbulent flow.

Filtration Control

Under normal conditions, the API Filtrate ranges from 5.0 to 6.0 cc/30 min. A very tight filter cake will be formed and laboratory tests have shown the dynamic filtrate to be very low. The concentration of BIO-LOSE required is 13 to 14 kg/m^3 (6.0 – 6.5 lbm/gal).

Reservoir Considerations

After drilling over 180 wells with the **BIO-LOSE 90** system, Baker Hughes Drilling Fluids has found this fluid system to be compatible with formation fluids. Laboratory testing is available and return permeability tests have been conducted on this fluid system with favorable results. The presence of an emulsification inhibitor ensures that minimal formation damage will occur as the reservoir is penetrated.

Fluid Density

The **BIO-LOSE 90** system can be maintained in a density range of 8.5 to 8.6 lb/gal if adequate solids control equipment is available. The solids content of the fluid should be monitored closely and if the level climbs above 2%, consideration should be given to discarding some fluid. In most cases, Baker Hughes Drilling Fluids recommends that the hole volume be displaced with fresh fluid every 500 to 600 ft of new hole.

Directional Tools

In the **BIO-LOSE 90** system, there are no additives which could prove detrimental to the directional drilling equipment. If a bridging agent is required, Baker Hughes Drilling Fluids recommends the addition of various grades of calcium carbonate, which will not affect the performance of downhole tools. Drilling fluid losses have been minimal when using the **BIO-LOSE 90** system without any bridging agent – even when drilling a carbonate zone where the primary porosity comes from micro-fracturing.

Recommended Fluid Properties

Fluid Density	8.5 – 8.6 lb/gal
Funnel Viscosity	35 - 45 sec/qt
Yield Point	4 – 8 lb/100 ft^2
pH	7.5 - 8.0
API Filtrate	4.0 - 6.0 cc/30 min.
MILBREAK 943	0.5% - 1.0% by volume

OMNI*FLOW*® DIF SYSTEM

System Benefits

The **OMNI*FLOW* ®DIF** system is a specially formulated, invert emulsion, drill-in and completion fluid using an approved external phase oil. This system is designed to minimize formation damage by using carefully selected surfactants at minimal concentrations to avoid emulsion blocking. MIL-CARB bridging agent has been chosen for the system as its wide particle size distribution is suited for bridging most reservoirs. **OMNI*FLOW*® DIF** system's simple formulation is designed for easy filter cake lift off. **OMNI*FLOW*® DIF** system's organic continuous phase and internal phase activity make the system ideal for long term control of sensitive shales encountered before and while drilling the reservoir. Characteristically for an invert emulsion system, the **OMNI*FLOW* DIF** system exhibits minimal pore-pressure penetration and is stable at high downhole temperatures and pressures. **OMNI*FLOW*®** **DIF** is formulated to maximize low shear-rate viscosity, an essential requirement for optimal hole cleaning.

System Components

The following products are utilized in the **OMNI*FLOW* ® DIF** system.

Component	Product
External Phase	Synthetic or Mineral Oil
Brine Phase	Brine (usually $CaCl_2$)
Viscosifier	CARBO-GEL
Emulsifier	OMNI-MUL
Addition Filtration Control	DFE-433
Bridging Agent	MIL-CARB
Weighting Agent	MIL-BAR

Table 6 - 4 OMNI*FLOW* DIF Products

OMNI-MUL® is an emulsifier specially selected for the system. A concentration of 1 gal/bbl (23.81 L/m^3) of this product provides sufficient emulsification and aids in filtration control while not contributing significantly to formation damage. The concentration of **OMNI-MUL®** may have to be increased in formulating fluids for high temperature/high density applications.

DFE-433: Generally, at temperatures below 250°F (121°C) no filtration control agents are required as the system has inherently low filtration values due to the emulsifier and bridging agent combination. However, at higher temperatures, especially approaching 300°F, the addition of **DFE-433** may be required to control filtration to within acceptable levels. Laboratory tests show that **DFE-433** has marginal effect on the lift-off pressures and return permeability results.

CARBO-GEL® is the recommended viscosifier for the **OMNI*FLOW*® DIF** system. Concentrations of up to 8.0 ppb (22.9 Kg/m3) have been laboratory tested and no adverse effects on lift-off pressures or return permeability results have been noted.

MIL-CARB®: A concentration of 50ppb (143 Kg/m^3) of **MIL-CARB®** should be maintained in the system for effective bridging.

Continuous Phase (Base Oil) : OMNI*FLOW* ® DIF may be formulated with any type of synthetic or mineral oil or diesel. The choice of oil makes no difference to the lift-off pressures and return permeability results.

Salinity of Brine Phase

Any salinity may be used in formulating **OMNI*FLOW*® DIF**. The level of salinity in the system should be chosen in the normal way for invert emulsion fluids. If required, the salinity of the brine phase may be increased to allow a reduction in barite concentration. Care should be taken not to increase salinity to a concentration greater than saturation, particularly for $CaCl_2$ brine.

Densities

The system can currently be formulated to a maximum density of 14.5 ppg (1.74 sg). In formulations with densities above 14.0 ppg (1.68 sg), excess barite tends to plug both gravel and screens. Adjusting the OWR in order to reduce the barite concentration does not improve return permeability results.

Drilled Solids

Maintaining the drilled solids content at <5% (v/v) is recommended. Dilution with fresh **OMNI*FLOW* DIF** is recommended if the drilled solids concentration rises above this level.

Typical Fluid Formulation and Properties

11.0 ppg (1.32 sg) OMNIFLOW DIF Formulation		
External Phase	Synthetic Base Oil	0.58 bbl
Brine Phase	$CaCl_2$ Brine (1.32 sg)	0.249 bbl
Viscosifier	CARBO-GEL	6.0 lb/bbl
Emulsifier	OMNI-MUL	1.0 gal/bbl
Bridging Agent	MIL-CARB	50.0 lb/bbl
Weighting Agent	MIL-BAR	118.0 lb/bbl

Table 6 - 5 Typical OMNIFLOW DIF Formulation

Property	**Typical Value**
Density (s.g.)	1.32
S/W Ratio	70/30
600 rpm	72
300 rpm	45
6 rpm	10
3 rpm	9
PV (cP)	27
YP (lbs/100ft^2)	18
Gels (lbs/100ft^2)	8/10
HTHP (@121°F), ml	2.0 - 4.0

Table 6 - 6 Typical OMNI*FLOW* DIF Formulation

CARBO-CORE

Native State Drilling and Coring Fluids

The **CARBO-CORE** system is a no-water-added oil-base fluid system used as a native state coring and drilling fluid. It is used whenever potential invasion of water or oil filtrate with surfactants, into producing reservoirs must be avoided. The **CARBO-CORE** system is temperature stable, even after contamination with water. Should contamination be severe, it can be converted to a CARBO-FAST or CARBO-TEC® system.

A drilling fluid that minimizes changes in water/formation wettability and water saturation in a producing reservoir will result in maximum permeability and oil production. Invasion of water filtrate into producing reservoirs can alter connate water saturation. Invasion of oil filtrate, containing strong surfactants, can possibly alter the wettability characteristics of the formation. A naturally water-wet sand may become oil-wet if the filtrate contains strong surfactants.

The alteration of water saturation and/or wettability characteristics can result in errors in predicting and evaluating reservoir performance based on core data. In some cases these actions may also decrease production after the well is completed.

No-water-added oil-base coring fluids have been used previously to retrieve unaltered cores for laboratory analysis. These cores are used to better define water saturation, connate water salinities, and oil water contacts. Cores that are recovered are also used to determine reservoir permeability and porosity as well as for laboratory flow tests to better define the reservoir characteristics. This technology is now present as the drilling fluid, **CARBO-CORE**.

Lease crude has been used, and is preferable as a drilling or coring fluid when unaltered cores are required. However, density requirements, or the lease crude characteristics, may make its use impracticable.

CARBO-CORE is prepared with minimum surfactants and a near zero water content, using mineral or diesel oil.

Components

Base Oils

CARBO-CORE fluids may be prepared with lease crude, No. 1 diesel, No. 2 diesel, mineral oil, or a combination of oils to meet individual requirements. If lease crude is used, it must be free of emulsion breakers and filming amine corrosion inhibitors, which can alter wettability characteristics. *Lease crude must also have an aniline and flash point above the desired minimum.* High viscosity lease crude may be blended with mineral oil or diesel to the desired viscosity range. No. 1 diesel oil or mineral oil is more desirable than No. 2 diesel, since No. 2 diesel may contain additives that may cause formation contamination. Pilot testing is recommended prior to the use of various oils due to their solubility and viscosity differences.

Water Phase

CARBO-CORE systems are prepared without water. However, 2% to 5% water may be incorporated during displacement of a water-base fluid. However, if the water content is in excess of 5% to 10%, depending upon the type of shale and/or cores being drilled, the system should be displaced, diluted, or converted to a standard controlled activity **CARBO-DRILL®** system.

Mixing Procedures

Because water content is contrary to the design of the **CARBO-CORE** system, special care must be taken when mixing and displacing the system.

The mixing tank should be clean and all lines flushed with diesel or a used **CARBO-DRILL** system which is then discarded. Pump the required amount of base oil, add the emulsifier and add the required amount of viscosifiers. The application of heat, up to 180°F (82°C), will increase dispersion of product, evaporate water, decrease mixing time, and result in a more stable system overall. The calculated amount of **CARBO-TROL® HT** should be added as quickly as possible, based upon the mixing system available.

After a satisfactory dispersion, with adequate viscosity, has been made, weight material may be added to obtain the desired density. If additional viscosity is necessary, *small* additions of viscosifiers may be used.

Displacement

Because a low to zero water content is desired in this system, the displacement procedure can have a tremendous effect upon the overall system performance. Ideally, casing should be run and the cement plug be pumped with the **CARBO-CORE** fluid.

If this is not possible, displacement prior to drilling out of casing is highly recommended. Displacement at high flow rates while rotating and reciprocating the drillpipe will minimize water contamination. In situations where water content *must* be maintained near zero, displacements have been made using a standard **CARBO-DRILL** oil-base fluid to displace the water-base fluid, followed by the **CARBO-CORE** system.

Water Contamination

The **CARBO-CORE** system has proven to be temperature stable even after contamination with water, as indicated in the figure below. Because the rate of osmotic transfer of water from the fluid to the shale increases as the water content increases, small quantities of water should not greatly affect the stability of the shale.

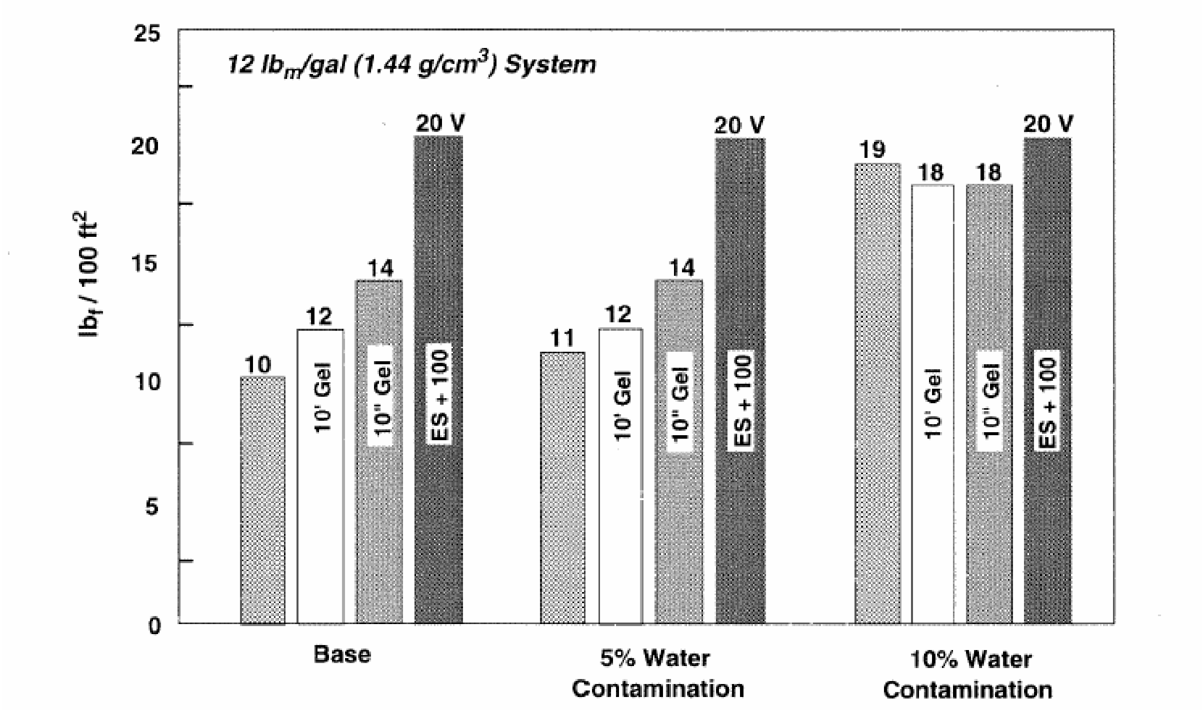


Figure 6 - 13 No-Water-Added CARBO-CORE Typical Flow Properties

However, should water contamination exceed 5% to 10%, it is recommended to dilute with oil, displace the system with new fluid, or simply convert the **CARBO-CORE** to a conventional **CARBO-DRILL**^{SM} system. This can be accomplished with the addition of calcium chloride to reduce the activity of the water phase to a desired range. Further additions of **CARBO-MUL**$^{®}$ **HT** and **CARBO-TEC**^{TM} will maintain fluid stability as the water content increases.

COMPLETION FLUIDS

Introduction to Clear Brines

Proper completion fluid selection is an important parameter directly related to the success of any well. The invasion of dirty fluids into the formation will cause damage or severe impairment to the productivity or injectivity of a well. Clear solids-free brines have gained widespread acceptance as part of a general practice for completion and workover applications due to their ability to meet the following desired properties and performance.

- Non-damaging to the formation
- Density ranges to provide sufficient hydrostatic pressure
- Economical
- Commercially available
- Environmentally safe and friendly
- Low corrosion rates
- Stable under in-situ conditions

The term *brines* refers to solutions prepared from dissolved salts in water or naturally occurring seawater or formation waters. Brines are considered non-formation damaging because they can deliver the appropriate density desired and can be filtered to remove particulates which would cause potential damage. The selection of appropriate brine based on the above criteria will deliver a system which minimizes hydration and dispersion of formation clays and is compatible with most additives used during completion and workover. The additives typically used in completion and workover are surfactants, viscosifying agents, bactericides, corrosion inhibitors, etc.

Clear brines are used for a wide variety of completion and workover applications.

- Packer fluids
- Kill fluids
- Under-reaming fluids
- Drill-in fluids
- Drilling fluids
- Perforating fluids
- Gravel packing fluids

Factors of most importance when selecting a brine for a particular application is density, formation damage, crystallization, and, of course, economics. Many different types of salt can be used. Some can be used as an individual salt to achieve the desired properties or can be utilized as mixed salt type brine systems. Costs, density, and formulations can be drastically different based on the brine type and crystallization point desired. Generally, the higher the density and lower crystallization point desired, the higher the cost. Consequently, it is imperative to formulate the proper brine density and its desired properties at optimum cost.

Effects of Temperature and Pressure

Temperature

- Volume expansion
- Density decrease
- Crystallization

Pressure

- Compressibility
- Well control

Brine Density, lb/gal	Expansion	Compressibility
8.4 - 9.0	0.00017	3.8 E-6
9.1 - 11.0	0.00025	1.5 E-6
11.1 - 14.5	0.00033	1.4 E-6
14.6 - 17.0	0.00040	1.4 E-6
17.1 - 19.2	0.00048	1.5 E-6

Table 6 - 7 Brine Density Due to Thermal Expansion

Average Temperature = (BHST + Surface Temperature) ÷ 2

Average Density = Density @ 68°F (20°C) - ((Avg. Temp. – 68°F) × Correction Factor)

Density Correction due to Compression

Hydrostatic Pressure [Bars] = (Depth [m] × Avg. S.G. × 0.0981)

Average Pressure = Bars ÷ 2

Pressure Correction = S.G. + (Avg. Bars × Correction Factor)

Calculations for Density Adjustments

Increase Density for Single Salt Brines

1. Determine weight and volume of system to be weighted.
2. Using the data from the formulation tables, determine the following:

Brine Density lb/gal	bbl Water/bbl	lb Salt/bbl
D original	W_o	S_o
D final	W_f	S_f

3. From this data, the required additions can be calculated as follows:

$$Salt\ additives = \frac{V_O(W_O S_f - S_O)}{W_f}$$

where V_o = original volume (bbl)

Example

Increase 400 bbl of 9.5 lb/gal $CaCl_2$ to 10.5 lb/gal $CaCl_2$.

Brine Density lb/gal	bbl Water/bbl	lb Salt/bbl
9.5	.954	65.1
10.5	.904	125

$$\text{CaCl}_2 \text{ addition} = 400\left[\frac{(.954)(125)}{.904} - 65.1\right] = 26{,}725 \text{ lbs}$$

$$\text{Final volume} = 400\left[\frac{.954}{.904}\right] = 422 \text{ bbl}$$

Therefore, 400 bbl of 9.5 lb/gal $CaCl_2$ fluid and 26,725 lbs 94-97% $CaCl_2$ will yield 422 bbl of a 10.5 lb/gal fluid.

Increase Density of a $CaCl_2$/$CaBr_2$ Fluid with Dry Calcium Bromide

1. Determine weight and volume of system to be weighed.
2. Using the data from the formulation tables, determine the following:

Brine Density lb/gal	bbl Water/bbl	lb 94% $CaCl_2$/bbl	lb 95% $CaBr_2$/bbl
D original	W_o	Cl_o	Br_o
D final	W_f	Cl_f	Br_f

From this data, the required additions can be calculated as follows:

$$\text{Water addition} = \frac{V_o(Cl_oW_f - W_o)}{Cl_f}$$

$$\text{CaBr}_2 \text{ addition} = \frac{V_o(Cl_oBr_f - Br_o)}{Cl_f}$$

$$\text{Final volume} = V_o\left[\frac{Cl_o}{Cl_f}\right]$$

Example

Increase 400 bbl of 13.4 lb/gal fluid to 14.0 lb/gal with concentrated 95% $CaBr_2$.

Brine Density lb/gal	bbl Water/bbl	lb 94% $CaCl_2$/bbl	lb 95% $CaBr_2$/bbl
13.4	.762	149.2	154.5
14.0	.738	134.0	206.1

$$\text{Water addition} = 400\left[\frac{(149.2)(.738)}{134.0} - .762\right] = 23.9\ \text{bbl}$$

$$CaBr_2\ \text{addition} = 400\left[\frac{(149.2)(206.1)}{134.0} - (154.5)\right] = 29,991\ \text{lbs}$$

$$\text{Final volume} = 400\left[\frac{149.2}{134.0}\right] = 445\ \text{bbl}$$

Therefore, 400 bbl of 13.4 lb/gal fluid and 23.9 bbl of water and 29,991 bbl of 95% $CaBr_2$ will yield 445 bbl of a 14.0 lb/gal fluid.

Increase Density with Heavier Liquid Brine

1. Determine the following:

   D_o = Original brine density

   D_h = Density of heavier brine

   D_f = Final brine density

   V_o = Original brine volume

2. From this data, the required additions can be calculated as follows:

$$\text{Volume of heavy brine} = \frac{V_o(D_h - D_o)}{D_h - D_f}$$

Final Volume = V_o + volume of heavy brine

Example

Increase 400 bbl of 13.2 lb/gal fluid to 13.7 lb/gal using a 15.1 lb/ gal brine.

$D_o = 13.2$

$D_h = 15.1$

$D_f = 13.7$

$V_o = 400$

$$\text{Volume of brine to add }(15.1) = \frac{400(13.7 - 13.2)}{15.1 - 13.7} = 142.9\ \text{bbl}$$

Final volume = 400 + 142.9 = 542.9 bbl.

Therefore, 142.9 bbl of 15.1 lb/gal brine blended with 400 bbl of 13.2 lb/gal fluid yields 542.9 bbl of 13.7 lb/gal fluid.

Decrease Density with Lighter Liquid Brine

1. Determine the following:

D_o = Original brine density

D_l = Density of lighter brine

D_f = Final brine density

V_o = Original brine volume

2. From this data, the following additions can be calculated:

$$Volume\,of\,light\,brine = \frac{V_o\left(D_o - D_f\right)}{D_f - D_1}$$

Final Volume = V_o + volume of light brine

Example

Decrease 400 bbl of 14.5 lb/gal fluid to 13.0 lb/gal with a 9.5 lb/ gal brine.

D_o = 14.5

D_l = 9.5

D_f = 13.0

V_o = 400

$$Volume\,of\,brine\,to\,add\,(13.0) = \frac{400(14.5 - 13.0)}{13.0 - 9.5} = 171bbl$$

Final volume = 400 + 171 = 571 bbl.

Therefore, 171 bbl of 9.5 lb/gal brine added to 400 bbl of 14.5 lb/gal fluid yields 571 bbl of 13.0 lb/gal fluid.

Increase Density after Dilution with Fresh Water

1. Determine weight and volume of original system (D_o, V_o)

2. Determine density of the diluted brine and estimate the volume.

D_d = Density of diluted brine (lb/gal)

V_e = Estimated volume brine (bbl)

3. Using data from the formulation tables, determine the following:

   D_o = Brine density (lb/gal)

   W_o = bbl water/bbl

   Cl_o = lb 94% $CaCl_2$/bbl

   Br_o = lb 95%/bbl

4. Determine amount of fresh water incorporated into system:

$$W_d = \frac{V_e(D_o - D_d)}{D_o - 8.335}$$

5. Determine materials required to increase density back to the original density:

$$CaCl_2 \text{ required} = \frac{(W_d)Cl_o}{W_o}$$

$$CaBr_2 \text{ required} = \frac{(W_d)Br_o}{W_o}$$

$$\text{Final volume} = \frac{V_e + W_d}{W_o}$$

Example

400 lbs of a 14.5 lb/gal brine while being used in a well became diluted with fresh water. The density of the diluted brine was found to be 14.1 lb/gal and the volume estimated at 450 bbl. How much $CaCl_2$ and $CaBr_2$ are required to increase density back to the original?

Vo = 400 bbl

Ve = 450 bbl

De = 14.1 lb/gal

D_o = 14.5 lb/gal

W_o = .718 bbl

Cl_o = 121.3 lb

Br_o = 248.9 lb

6. Amount of fresh water incorporated:

$$W_d = \frac{450(14.5 - 14.1)}{14.5 - 8.335} = 29.2 \text{ bbl}$$

$$\text{CaCl}_2 \text{ addition} = \frac{(29.2)121.3}{.718} = 4{,}933 \text{ lbs}$$

$$\text{CaBr}_2 \text{ required} = \frac{(29.2)248.9}{.718} = 10{,}122 \text{ lbs}$$

$$\text{Final volume} = \frac{450 + 29.2}{.718} = 667 \text{ bbl}$$

Therefore, 4,933 lbs of $CaCl_2$ and 10,122 lbs of $CaBr_2$ added to 450 bbl of 14.1 lb/gal fluid will yield 667 bbl of original 14.5 lb/gal brine

Salt Solubility vs. Freeze Depression

Crystallization

Ice Crystals

Fresh water ice crystals begin to form when the solution drops below the freeze depression curve. In other words, salts dissolved in water below their maximum solubility limit for that solution depress the freezing point of the solution.

Salt Crystals

These crystals occur when a particular salt is added above its maximum solubility at a particular temperature, or when the temperature drops below the curve at which the salt can be in solution.

Problems

Several potential problems can be caused by the formation of ice and salt crystals.

- Density will begin to decrease as ice forms or salt comes out of solution and is removed as the fluid circulates over the shakers.
- Formation damage can occur as salt crystals plug the pore throats.
- Viscosity increases with crystallization due to solids crowding.

Corrosion Data (mils per year)

30 Day Test N-80 Steel

		Temperature (°F)			
		70°	150°	250°	350°
Brine Type	Density lbs/gal	Cor. Rte, mpy	Cor. Rte, mpy	Cor. Rte, mpy	Cor. Rte, mpy
NaCl	10.0	0.5	1.5	0.2	0.1
NaBr / NaCl	11.2	0.4	0.7	0.1	0.1
$CaCl_2$	11.6	0.1	0.2	0.7	1.9
$CaCl_2$ / $CaBr_2$	13.6	0.3	0.9	1.6	3.0
$CaCl_2$ / $CaBr_2$	15.1	0.1	0.5	2.4	6.6

Note: *No corrosion inhibitor*

Table 6 – 8 Corrosion Rate vs Temperature in 30-Day Test N-80 Steel

Compatibility of Various Additives with Different Salt Types

Monovalent Salts	**Divalent Salts**
Oxygen Scavengers	Oxygen Scavengers
Scale Inhibitors	Scale Inhibitors
Magnesium Oxide	Magnesium Oxide
Sodium Hydroxide	Viscosifiers (HEC, W-306, and starches)
$Ca(OH)_2$ (Lime)	Defoamers
Defoamers	
Many different Viscosifiers	
Other Surfactants	

Salt Tables

The following salt tables came from three sources.

The potassium chloride table is from the *CRC Handbook of Chemistry and Physics*, 62nd edition.

The sodium chloride table is from Staples and Nuttall, *Journal of Physical Chemistry Reference Data*, 1977, Volume 6.

The calcium chloride table is from Clarke and Grew, *Journal of Physical Chemistry Reference Data*, 1985, Volume 14.

The tables are divided into the following columns.

1. **Percent wt** = the anhydrous solute weight percent, g solute/100 g solution.
2. **Specific gravity** = the ratio of the mass of a body at 20°C to the mass of an equal volume of water at 4°C.
3. **Density, lb_m/gal** = specific gravity converted to pound per gallon units. The density of water is assumed to be 8.33 lb_m/gal.
4. **lb_m of salt/bbl of solution** = the pounds of salt in a barrel solution of the given density.
5. **Gallons of water per barrel of solution** = the gallons of water to make up one barrel of solution of the given density.
6. **Salt, mg/L** = the concentration of salt in mg/L of solution.
7. **Chlorides, mg/L** = the concentration of chlorides in mg/L.
8. **Volume increase factor** = the volume increase that will occur when the specified weight of salt is added to the specified volume of fresh-water. The value in 8 is used for retort corrections.
9. **Crystallization point, °F** = the crystallisation point of a solution containing the specified concentration of salt.
10. **Aw** = the activity of the solution. This value has also been called Formation Activity Coefficient (FAC) in previous manuals. This value, regardless of the term applied to it, is a measure of the fluid's potential to absorb water.

Salt	% by Weight (as dry salt)	Max. Density (ppg)
KCl	24.2%	9.7
NaCl	26.0%	10.0
HCOONa	73.8%	11.1
NaBr	44.7%	12.7
HCOOK	75.0%	13.1
$CaCl_2$	37.6%	11.6
$CaBr_2$	51.9%	14.2
$CaCl_2$/$CaBr_2$	17.5% $CaCl_2$ / 46.1% $CaBr_2$	15.1
$CaBr_2$/$ZnBr_2$	22.8% $CaBr_2$ / 52.8% $ZnBr_2$	19.2
$ZnBr_2$	77.0% $ZnBr_2$	21.0

Table 6 - 8 Operational Densities of Various Salts

Salt	Typical pH Values **
11.1 ppg HCOONa	8.0 to 8.5
11.6 ppg $CaCl_2$	6.5 to 7.5
13.0 ppg HCOOK	8.0 to 8.54
14.2 ppg $CaBr_2$	6.5 to 7.5
15.1 ppg $CaCl_2$ / $CaBr_2$	6.0 to 7.0
16.0 ppg $CaCl_2$ / $CaBr_2$ / $ZnBr_2$	4.5 to 5.0
17.0 ppg $CaCl_2$ / $CaBr_2$ / $ZnBr_2$	3.5 to 4.0
18.0 ppg $CaCl_2$ / $CaBr_2$ / $ZnBr_2$	2.5 to 3.0
19.0 ppg $CaCl_2$ / $CaBr_2$ / $ZnBr_2$	1.5 to 2.0

*** pH measured directly on undiluted brine*

Table 6 - 9 Typical pH Values of Various Salt Mixtures

Density, lb/gal (70°F)	Sp. Gr.	NaCl, (100%) lbm/bbl	$CaCl_2$, (94-97%) lbm/bbl	Fresh Water, bbl
10.1	1.21	88	29	0.887
10.2	1.22	70	52	0.875
10.3	1.24	54	72	0.875
10.4	1.25	41	89	0.876
10.5	1.26	32	104	0.871
10.6	1.27	25	116	0.868
10.7	1.28	20	126	0.866
10.8	1.30	16	135	0.864
10.9	1.31	13	144	0.862
11.0	1.32	10	151	0.859
11.1	1.33	8	159	0.854

Table 6 - 10 Formulation of Sodium Chloride/Calcium Chloride Solution using Sacked NaCl (100%) and $CaCl_2$ (94-97%)

1 Percent Weight	2 Specific Gravity	3 Density (lb_m/gal)	4 KCl (lb_m/bbl)	5 H_20 (gal/bbl)	6 KCl (mg/L)	7 Chlorides (mg/L)	8 Volume Increase Factor	9 Crystallization Point (°F)
1.0	1.005	8.37	3.5	41.8	10000	4756	1.005	31.2
2.0	1.011	8.42	7.1	41.6	20200	9606	1.009	30.3
3.0	1.017	8.47	10.7	41.4	30500	14506	1.013	29.5
4.0	1.024	8.53	14.4	41.3	41000	19499	1.017	28.6
5.0	1.030	8.59	18.1	51.1	51500	24493	1.022	27.8
6.0	1.037	8.64	21.8	40.9	62200	29582	1.026	26.9
7.0	1.044	8.69	25.6	40.7	73000	34718	1.031	26.1
8.0	1.050	8.75	29.4	40.5	84000	39950	1.035	25.2
9.0	1.057	8.80	33.3	40.4	95100	45229	1.039	24.3
10.0	1.063	8.86	37.3	40.2	106300	50556	1.045	23.4
11.0	1.070	8.90	41.2	40.0	117700	55977	1.050	22.4
12.0	1.077	8.97	45.3	39.8	129200	61447	1.055	21.4
13.0	1.084	9.03	49.4	39.6	140900	67011	1.061	20.4
14.0	1.091	9.08	53.5	39.4	152700	72623	1.066	20.0
15.0	1.097	9.12	57.6	39.1	164600	78282	1.072	18.5
16.0	1.104	9.20	61.9	38.9	176700	84038	1.078	17.0
17.0	1.111	9.26	66.1	38.7	188900	89840	1.084	16.0
18.0	1.119	9.32	70.5	38.5	201300	95737	1.090	15.0
19.0	1.126	9.38	74.9	38.3	213900	101730	1.097	14.0
20.0	1.133	9.44	79.3	38.0	226600	107770	1.104	13.0
21.0	1.140	9.51	83.9	37.8	239500	114000	1.111	22.0
22.0	1.147	9.56	88.4	37.6	252400	120040	1.117	34.0
23.0	1.155	9.64	93.1	37.4	265700	126473	1.125	48.0
24.0	1.162	9.68	97.7	37.1	278900	132643	1.132	59.0

Table 6 - 11 Physical Properties of Potassium Chloride Solutions @ 20^{0}C

** There is minimal water in sacked KCI, therefore, the volume increase from retort and sack additions may be considered the same.*

Metric Conversions

- KCl (g/L) = KCl (lb_m/bbl) x 2.85714
- H_20 (mL/L) = H_20 (gal/bbl) x 23.8086
- KCl (ppm) = % wt x 10,000
- mg/L = ppm x specific gravity
- Cl^- (mg/L) = KCl (mg/L) x 0.476
- KCl (mg/L) = Cl^- (mg/L) x 2.101
- K^+ (mg/L) = Cl^- (mg/L) x 1.103
- Cl^- (mg/L) = K^+ (mg/L) x 0.907

Formulas

- *Salt (lb_m/bbl water)* = Volume increase factor × KCl (lb_m/bbl)
- *Specific Gravity* = $1.00056 + 1.22832\ (10^{-6})(Cl^{-}, mg/L)$
- *Volume Increase Factor* = $1 + (2.775 \times 10^{-7})(Cl^{-})^{1.105}$

1 Percent Weight	2 Specific Gravity	3 Density (lb_m/gal)	4 $NaCl_2$ (lbm/bbl)	5 H_2O (gal/bbl)	6 NaCl (mg/L)	7 Chlorides (mg/L)	8 Volume[a] Increase Factor	9 Crystallization Point (°*F)*	10 Aw
1.0	1.007	8.40	3.5	41.87	10070	6108	1.003	31.0	0.996
2.0	1.014	8.46	7.1	41.75	20286	12305	1.006	30.0	0.989
3.0	1.021	8.52	10.7	41.63	30630	18580	1.009	28.8	0.983
4.0	1.029	8.58	14.4	41.46	41144	24957	1.013	27.7	0.976
5.0	1.036	8.65	18.2	41.34	51800	31421	1.016	26.5	0.970
6.0	1.043	8.70	21.9	41.18	62586	37963	1.020	25.3	0.964
7.0	1.050	8.76	25.8	41.02	73500	44584	1.024	24.1	0.957
8.0	1.058	8.83	29.7	40.86	84624	51331	1.028	22.9	0.950
9.0	1.065	8.89	33.6	40.70	95850	58141	1.032	21.5	0.943
10.0	1.073	8.95	37.6	40.54	107260	65062	1.036	20.2	0.935
11.0	1.080	9.01	41.6	40.38	118800	72062	1.040	18.8	0.927
12.0	1.088	9.08	45.7	40.19	130512	79166	1.045	17.3	0.919
13.0	1.095	9.14	49.9	40.00	142350	86347	1.050	15.7	0.910
14.0	1.103	9.20	54.1	39.85	154392	93651	1.054	14.1	0.901
15.0	1.111	9.27	58.4	39.66	166650	101087	1.059	12.4	0.892
16.0	1.118	9.33	62.7	39.44	178912	108524	1.065	10.6	0.882
17.0	1.126	9.40	67.1	39.25	191420	116112	1.070	8.7	0.872
18.0	1.134	9.46	71.5	39.03	204102	123804	1.076	6.7	0.861
19.0	1.142	9.53	76.0	38.85	216980	131616	1.081	4.6	0.850
20.0	1.150	9.60	80.6	38.64	229960	139489	1.087	2.4	0.839
21.0	1.158	9.66	85.2	38.43	243180	147508	1.093	0.0	0.827
22.0	1.166	9.73	89.9	38.22	256520	155600	1.099	2.5	0.815
23.0	1.174	9.80	94.6	37.97	270020	163789	1.106	5.2	0.802
24.0	1.183	9.87	99.5	37.74	283800	172147	1.113	+1.4	0.788
25.0	1.191	9.94	104.4	37.50	297750	180609	1.120	+15.0	0.774
26.0	1.199	10.01	109.3	37.27	311818	189143	1.127	+25.0	0.759

Table 6 - 12 Physical Properties of Sodium Chloride Brines @20° C

a. *There is minimal water in sacked NaCl, therefore, the volume increase from retort and sack additions*

Metric Conversions

- NaCl (g/L) = NaCl (lb_m/bbl) × 2.85714
- H_20 (mL/L) = H_20 (gal/bbl) × 23.8086
- NaCl (ppm) = % wt × 10,000
- Cl^- (mg/L) = NaCl (mg/L) × 0.6066
- NaCl (mg/L) = Cl^- (mg/L) × 1.65
- mg/L = ppm × specific gravity

Formulas

- Salt (lb_m/bbl water)

Volume increase factor × NaCl (lb_m/bbl)

- Specific Gravity

$1.0036\ [0.99707 + 6.504\ (10^{-3})(\%\ wt\ NaCl) + 4.395\ (10^{-5})(\%\ wt\ NaCl)^2]$

or $1 + 1.94\ (10^{-6})(Cl^{-}, Mg/L)^{0.95}$

- Volume Increase Factor

$1.00045 + 2.72232\ (10^{-3})(\%\ wt\ NaCl) + 8.15591\ (10^{-5})(\%\ wt\ NaCl)^2$

or $1 + 5.88\ (10^{-8})\ (Cl^{-}, Mg/L)^{1.2}$

- Aw

$0.99755 - 4.3547\ (10^{-3})(\%\ wt\ NaCl) - 1.8205(10^{-4})(\%\ wt\ NaCl)^2$

Density lb/gal	Specific Gravity @ 60°F	lbs NH_4Cl per bbl Brine	bbls Water per bbl Brine	% Weight NH_4Cl
8.4	1.007	7.0	0.990	1.98
8.45	1.013	10.5	0.981	3.00
8.5	1.020	19.0	0.969	5.30
8.6	1.031	30.0	0.940	8.40
8.7	1.044	42.0	0.919	11.50
8.8	1.055	53.0	0.900	14.40
8.9	1.068	65.0	0.881	17.40
9.0	1.079	77.0	0.860	20.40
9.1	1.128	88.0	0.840	23.00
9.2	1.103	100.0	0.819	25.90
9.5	1.139	135.0	0.750	33.90

Table 6 - 13 Physical Properties of Ammonium Chloride (NH_4Cl) Solutions

1 % wt	2 Specific Gravity	3 Density (lb$_m$/gal)	4a 100 CaCl$_2$ (lb$_m$/bbl)	4b 95% CaCl$_2$ (lb$_m$/bbl)	5a H2O Using 100% CaCl$_2$ (gal/bbl)	5b H2O Using 95% CaCl$_2$ (gal/bbl)	6 CaCl$_2$ (mg/L)	7 Chlorides (mg/L)	8a* Volume Increase Factor 100% CaCl$_2$	8b** Volume Increase Factor 95% CaCl$_2$	9 Crystal lisation Point (°F)	10 AW
1	1.009	8.42	3.53	3.72	41.93	41.91	10085	6454	1.002	1.002	31.1	0.998
2	1.017	8.49	7.13	7.50	41.85	41.81	20340	13018	1.004	1.004	30.4	0.996
3	1.026	8.56	10.78	11.35	41.78	41.71	30765	19690	1.006	1.007	29.5	0.993
4	1.034	8.63	14.50	15.26	41.69	41.60	41360	26470	1.008	1.010	28.6	0.989
5	1.043	8.70	18.27	19.23	41.60	41.48	52125	33360	1.011	1.013	27.7	0.984
6	1.051	8.77	22.11	23.27	41.49	41.35	63060	40358	1,013	1.016	26.8	0.979
7	1.060	8.84	25.99	27.36	41.38	41.22	74165	47466	1.016	1.019	25.9	0.973
8	1.068	8.91	29.94	31.52	41.27	41.08	85440	54682	1.018	1.022	24.6	0.967
9	1.077	8.98	33.95	35.74	41.14	40.93	96885	62006	1.021	1.026	23.5	0.959
10	1.085	9.05	38.03	40.03	41.01	40.77	108500	69440	1.024	1.030	22.3	0.951
11	1.094	9.13	42.18	44.40	40.90	40.63	120340	77018	1.027	1,034	20.8	0.942
12	1.103	9.20	46.39	48.83	40.76	40.47	132360	84710	1.030	1.038	19.3	0.933
13	1.113	9.28	50.69	53.36	40.65	40.33	144625	92560	1.034	1.041	17.6	0.923
14	1.122	9.36	55.05	57.95	40.53	40.18	157080	100531	1.037	1.045	15.5	0.912
15	1.132	9.44	59.49	62.62	40.40	40.02	169725	108624	1.041	1.049	13.5	0.900
16	1.141	9.52	63.98	67.35	40.25	39.85	182560	116838	1.044	1.054	11.2	0.888
17	1.151	9.60	68.55	72.16	40.10	39.67	195585	125174	1.048	1.059	8.6	0.875
18	1.160	9.68	73.18	77.03	39.95	39.49	208800	133632	1.051	1.064	5.9	0.862
19	1.170	9.76	77.91	82.01	39.80	39.31	222300	142272	1.056	1.068	2.8	0.847
20	1.180	9.85	82.72	87.07	39.65	39.13	236000	151040	1.060	1.073	-0.4	0.832
21	1.190	9.93	87.59	92.20	39.48	38.93	249900	159936	1.065	1.079	-3.9	0.816
22	1.200	10.01	92.53	97.40	39.31	38.73	264000	168960	1.069	1.084	-7.8	0.800
23	1.210	10.10	97.55	102.68	39.14	38.52	278300	178112	1.074	1.090	-11.9	0.783
24	1.220	10.18	102.62	108.02	38.95	38.30	292800	187392	1.078	1.097	-16.2	0.765
25	1.231	10.27	107.82	113.49	38.76	38.08	307625	196880	1.084	1.103	-21.0	0.746
26	1.241	10.36	113.09	119.04	38.57	37.86	322660	206502	1.089	1.109	-25.8	0.727
27	1.252	10.44	118.44	124.67	38.37	37.62	337905	216259	1.095	1.116	-31.2	0.707
28	1.262	10.53	123.85	130.37	38.16	37.38	353360	226150	1.100	1.124	-37.8	0.686
29	1.273	10.62	129.39	136.20	37.96	37.14	369170	236269	1.107	1.131	-49.4	0.665
30	1.284	10.71	135.00	142.11	37.75	36.90	385200	246528	1.113	1.138	-50.8	0.643
31	1.295	10.81	140.70	148.11	37.53	36.64	401450	256928	1.120	1.146	-33.2	0.620
32	1.306	10.90	146.48	154.19	37.30	36.38	417920	267469	1.126	1.155	-19.5	0.597
33	1.317	10.99	152.32	160.34	37.06	36.10	434610	278150	1.134	1.163	-6.9	0.573
34	1.328	11.08	158.25	166.58	36.81	35.81	451520	288973	1.141	1.173	+4.3	0.548
35	1.340	11.18	164.32	172.97	36.57	35.53	468825	300048	1.149	1.182	+14.4	0.522
36	1.351	11.27	170.47	179.44	36.32	35.24	486360	311270	1.156	1.192	+24.1	0.496
37	1.363	11.37	176.76	186.06	36.06	34.95	504310	322758	1.165	1.202	+33.4	0.469
38	1.375	11.47	183.13	192.77	35.81	34.65	522500	334400	1.173	1.212	+42.1	0.441
39	1.387	11.57	189.53	199.50	35.53	34.33	540735	346070	1.183	1.224	+49.6	0.413
40	1.398	11.67	195.99	206.31	35.23	33.99	559200	357888	1.192	1.236	+55.9	0.384

Table 6 - 14 Properties of Calcium Chloride Solutions @ 20°C

Metric Conversions

- $CaCl_2$ (g/L) = $CaCl_2$ (lbm/bbl) × 2.85714
- H_2O (mL/L) = H_2O (gal/bbl) × 23.8086
- $CaCl_2$ (ppm) = % wt × 10,000
- Cl^- (ppm) = $CaCl_2$ (ppm) × 0.639
- mg/L = ppm × specific gravity

Formulas

- *Salt (lb_m/bbl water)*
- Volume increase factor × $CaCl_2$ (lb_m/bbl)

- *Specific Gravity*
- $1.0036\,[0.99707 + 7.923\,(10^{-3})(\%\ \text{wt}\ CaCl_2) + 4.964\,(10^{-5})(\%\ \text{wt}\ CaCl_2)^2]$

- *Volume Increase Factor* *
- $1.00293 + 1.04192\,(10^{-3})(\%\ \text{wt}\ CaCl_2) + 8.94922(10^{-5})(\%\ \text{wt}\ CaCl_2)^2$

- *Aw*

$0.99989 - 1.39359\,(10^{-3})(\%\ \text{wt}\ CaCl_2) - 3.50352\,(10^{-4})(\%\ \text{wt}\ CaCl_2)^2$

$$\%\ \text{wt}\ CaCl_2 = \frac{100\%\ CaCl_2(\ lb_m/\text{bbl})\ \times \%\ \text{Purity}\ CaCl_2}{S.G \times 350}$$

When Using $CaCl_2$ with Purity other than 95%

New $CaCl_2$ (lb_m/bbl) = 95 x 95% $CaCl_2$ (lb_m/bbl) ÷ % Purity

$$NewCaCl_2,(gal/bbl) = H_2O,(gal/bbl) - \left[\frac{NewCaCl_2,(gal/bbl) - 95\%\,CaCl_2,(gal/bbl)}{8.345}\right]$$

Volume increase from salt (gal) = 42 ÷ New water **

Example: 35% $CaCl_2$ Brine Using 78% $CaCl_2$

New $CaCl_2$ (lb_m/bbl) = 95 x 172.97 ÷ 78 = 210.67

$$\text{New}\ H_2O(\text{gal/bbl}) = 35.53 - \left[\frac{210.67 - 172.97}{8.345}\right] = 31.01$$

Volume increase from 78% salt = 42 ÷ 31.01 = 1.354

** Volume increase from 100% salt, i.e., from retort*

*** Volume increase from salt and water in the sacked salt.*

Ve* 10^4	Density lb/gal	Specific Gravity @ 68°F	bbl 11.6 $CaCl_2$ per bbl Brine	bbl Water per bbl Brine	Crystalliztion Point, °F	Weight % $CaCl_2$
	8.4	1.01	0.022	0.978	+31	1.0
	8.5	1.02	0.052	0.948	+30	2.0
	8.6	1.03	0.083	0.917	+28	4.0
	8.7	1.04	0.113	0.887	+27	5.0
	8.8	1.06	0.144	0.856	+25	6.0
	8.9	1.07	0.174	0.826	+23	7.0
3.33	9.0	1.08	0.203	0.797	+21	9.0
	9.1	1.09	0.233	0.767	+19	10.0
	9.2	1.10	0.264	0.736	+17	11.0
	9.3	1.11	0.294	0.706	+15	12.0
	9.4	1.13	0.325	0.675	+12	14.0
3.00	9.5	1.14	0.356	0.644	+9	15.0
	9.6	1.15	0.390	0.610	+6	16.0
	9.7	1.16	0.420	0.580	+3	17.0
	9.8	1.17	0.450	0.550	1	19.0
	9.9	1.19	0.480	0.520	6	20.0
2.89	10.0	1.20	0.510	0.490	11	21.0
	10.1	1.21	0.540	0.460	16	22.0
	10.2	1.22	0.571	0.429	22	23.0
	10.3	1.23	0.601	0.399	28	25.0
	10.4	1.25	0.632	0.368	34	26.0
2.6	10.5	1.26	0.663	0.337	41	27.0
	10.6	1.27	0.694	0.306	48	28.0
	10.7	1.28	0.724	0.276	55	29.0
	10.8	1.29	0.755	0.245	51	30.0
	10.9	1.31	0.785	0.215	31	31.0
2.4	11.0	1.32	0.820	0.180	15	32.0
	11.1	1.33	0.850	0.150	0	33.0
	11.2	1.34	0.880	0.120	+12	34.0
	11.3	1.35	0.910	0.090	+23	35.0
	11.4	1.37	0.940	0.060	+34	36.0
2.39	11.5	1.38	0.970	0.030	+43	37.0
	11.6	1.39	1.00	0.000	+53	38.0

Table 6 - 15 Preparation of Calcium Chloride ($CaCl_2$) Solutions Using Liquid 11.6 lb/gal $CaCl_2$

* Determined by ASTM methods

Ve = expansion factor gal/gal/°F; used with density adjustment calculations.

Example:

To prepare 10 bbl of 11.0 lb/gal $CaCl_2$ *from 11.6 lb/gal liquid* $CaCl_2$*:*

Add 10 × 0.264 = 2.6 bbl of 11.6 lb/gal $CaCl_2$ *to 10 × 0.736 bbl of fresh water.*

Density lb/gal	bbl Water per bbl Brine	bbl KBr per bbl Brine	% KBr	Crystallization Point, °F (LCTD)
8.3	1.000	-	-	32
8.6	0.985	15.1	4.2	30
8.7	0.980	21.9	6.0	30
8.8	0.974	28.1	7.6	29
8.9	0.967	34.8	9.3	28
9.0	0.962	40.8	10.8	27
9.1	0.956	47.0	12.3	27
9.2	0.954	52.6	13.6	26
9.3	0.947	58.6	15.0	26
9.4	0.942	64.7	16.4	25
9.5	0.937	70.6	17.7	24
9.6	0.932	76.6	19.0	23
9.7	0.928	82.3	20.2	22
9.8	0.922	88.5	21.5	22
9.9	0.916	94.8	22.8	21
10.0	0.911	100.8	24.0	19
10.1	0.905	106.9	25.2	18
10.2	0.901	112.7	26.3	17
10.3	0.895	119.0	27.5	16
10.4	0.888	125.4	28.7	15
10.5	0.883	131.4	29.8	14
10.6	0.878	137.6	30.9	12
10.7	0.872	143.8	32.0	13
10.8	0.865	150.6	33.2	20
10.9	0.858	157.0	34.3	27
11.0	0.854	162.6	35.2	33
11.1	0.847	169.2	36.3	41
11.2	0.842	175.5	37.3	49
11.3	0.835	181.2	38.3	57
11.4	0.829	188.2	39.3	66
11.5	0.824	194.2	40.2	75

Table 6 - 16 Preparation of Potassium Bromide Based Solutions Using Granular Concentrated KBr

Example:

To prepare 10 bbl of 10 lb/gal KBr:

10 × 0.911 = 9.1 bbl water

10 × 100.8 = 1,008 lbs KBr

Add 1,008 lbs KBr to 9.1 bbl water.

Brine Density at 60^{o}F (lb$_m$/gal)	11.6 lb$_m$/gal CaCl$_2$ (bbl)	14.2 lbm/gal CaBr$_2$ (bbl)	94 to 97% CaCl$_2$ (Flakes or Pellets) (lb)	Crystallization Point (^{o}F)
11.7	0.9714	0.0246	3.5	+45
11.8	0.9429	0.9429	6.9	+51
11.9	0.9143	0.0738	10.4	+52
12.0	0.8857	0.0984	13.9	+54
12.1	0.8572	0.1229	17.4	+55
12.2	0.8286	0.1475	20.8	+55
12.3	0.8000	0.1722	24.3	+56
12.4	0.7715	0.1967	27.8	+56
12.5	0.7429	0.2213	31.2	+57
12.6	0.7143	0.2459	34.7	+58
12.7	0.6857	0.2705	38.2	+58
12.8	0.6572	0.2951	41.7	+58
12.9	0.6286	0.3197	45.1	+59
13.0	0.6000	0.3443	48.6	+59
13.1	0.5714	0.3689	52.1	+60
13.2	0.5429	0.3935	55.5	+60
13.3	0.5143	0.4181	59.0	+60
13.4	0.4851	0.4432	62.6	+61
13.5	0.4572	0.4672	66.0	+61
13.6	0.4286	0.4919	69.4	+62
13.7	0.4000	0.5165	72.9	+62
13.8	0.3714	0.5411	75.4	+63
13.9	0.3429	0.5656	79.8	+63
14.0	0.3143	0.5903	83.3	+64
14.1	0.2857	0.6149	86.8	+64
14.2	0.2572	0.6394	90.3	+64
14.3	0.2286	0.6640	93.7	+65
14.4	0.2000	0.6886	97.2	+65
14.5	0.1715	0.7132	100.7	+65
14.6	0.1429	0.7378	104.2	+66
14.7	0.1143	0.7624	107.6	+66
14.8	0.0858	0.7869	111.1	+67
14.9	0.0572	0.8116	114.6	+67
15.0	0.0286	0.8361	118.0	+67
15.1	0.0000	0.8608	121.5	+68

Table 6 - 17 Calcium Chloride-Calcium Bromide Solution Requirements Using 11.6 lbm/gal CaCl$_2$ Brine, 14.2 lbm/gal CaBr$_2$ Brine, and Sacked CaCl$_2$ (Formulation per 1 bbl)

Conversions

ppm $CaCl_2$ = % wt × 10,000

ppm Cl^- = ppm $CaCl_2$ × .64

Formulas

When using 78% $CaCl_2$

$$\left(lb_m / bbl\right) = 95\%\ CaCl_2 \times 1.218$$

$$New\,H_2O,(gal/bbl) = H_2O,(gal/bbl) - \left[\frac{78\%\,CaCl_2,(lb_m/bbl) - 95\%\,CaCl_2,(lb_m/bbl)}{8.345}\right]$$

$CaCl_2$ / $CaBr_2$ Density at 60°F (15° C)		lb $CaCl_2$ per bbl Brine	bbl 14.2 $CaBr_2$ per bbl Brine	bbl Fresh Water per bbl Brine
lb_m/gal	lb_m/ft^3			
11.7	87.52	193.39	0.0254	0.8163
11.8	88.26	191.00	0.0507	0.7924
11.9	89.01	188.42	0.0762	0.7683
12.0	89.76	185.85	0.1016	0.7443
12.1	90.51	183.28	0.1269	0.7203
12.2	91.26	180.70	0.1524	0.6963
12.3	92.00	178.13	0.1778	0.6723
12.4	92.75	175.56	0.2032	0.6483
12.5	93.50	172.99	0.2286	0.6243
12.6	94.25	170.41	0.2540	0.6003
12.7	95.00	167.83	0.2794	0.5762
12.8	95.74	165.27	0.3048	0.5523
13.0	97.24	160.12	0.3556	0.5042
13.1	97.99	157.54	0.3810	0.4802
13.2	98.74	154.97	0.4064	0.4562
13.3	99.48	152.40	0.4318	0.4322
13.4	100.23	149.82	0.4572	0.4082
13.5	100.98	147.26	0.4826	0.3842
13.6	101.73	144.68	0.5080	0.3602
13.7	102.48	142.12	0.5334	0.3361
13.8	103.22	139.54	0.5589	0.3121
13.9	103.97	136.98	0.5842	0.2882
14.0	104.72	134.40	0.6069	0.2641
14.1	105.47	131.84	0.6351	0.2401
14.2	106.22	129.26	0.6604	0.2161
14.3	106.96	126.68	0.6858	0.1921
14.4	107.71	124.11	0.7113	0.1681
14.5	108.46	121.54	0.7366	0.1441
14.6	109.21	118.97	0.7620	0.1201
14.7	109.96	116.39	0.7875	0.0961
14.8	110.70	113.82	0.8128	0.0721
14.9	111.45	111.25	0.8382	0.0481
15.0	112.20	108.67	0.8637	00.241
15.1	112.95	106.10	0.8891	0.0000

Table 6 - 18 Preparation of Calcium Bromide Based Solutions Using Solid 94% $CaCl_2$ and Liquid 14.2 lbm/gal $CaBr_2$

Example:

To prepare 10 bbl of 13.0 lb_m/gal $CaBr_2$ from minimum 94% solid $CaCl_2$ and 14.2 lb_m/gal liquid $CaBr_2$:

Add 10 × 160.1 = 1600 lbs of solid $CaCl_2$ to 10 × 0.35 = 3.5 bbl of 14.2 lb_m/gal $CaBr_2$ and 10 × 0.50 = 5.0 bbl of fresh water.

Brine Density		bbl Fresh Water per bbl Brine	lb 95% $CaBr_2$ per bbl Brine
lb_m/gal	lb_m/ft^3		
11.0	82.28	0.889	150.8
11.1	83.03	0.887	155.9
11.2	83.78	0.884	160.9
11.3	84.52	0.878	167.4
11.4	85.27	0.869	174.5
11.5	86.02	0.867	179.6
11.6	86.77	0.864	184.7
11.7	87.52	0.863	188.9
11.8	88.26	0.849	198.3
11.9	89.01	0.849	202.6
12.0	8976	0.848	207.0
12.1	90.51	0.840	214.1
12.3	92.00	0.831	225.8
12.4	92.75	0.830	230.3
12.5	93.50	0.821	237.7
12.6	94.25	0.819	242.4
12.7	95.00	0.810	250.0
12.8	95.74	0.808	254.8
12.9	96.49	0.797	266.5
13.0	97.24	0.796	267.4
13.1	97.99	0.794	272.3
13.2	98.74	0.791	277.3
13.3	99.48	0.789	282.4
13.4	100.23	0.778	290.4
13.5	100.98	0.775	295.6
13.6	101.73	0.772	300.8
13.7	102.48	0.761	309.0
13.8	103.22	0.758	314.3
13.9	103.97	0.755	319.7
14.0	104.72	0.751	325.1
14.1	105.47	0.748	330.5
14.2	106.22	0.744	335.9
14.3	106.96	0.740	341.5

Table 6 - 19 Preparation of Sodium Bromide Based Solutions Using 95% Dry $CaBr_2$

Example:

To prepare 10 bbl of 13.0 lb_m*/gal* $CaBr_2$ *from 95% solid* $CaBr_2$*:*

Add 10 × 267.4 = 2,675 lbs of 95% $CaBr_2$ *to 10 × 0.796 = 7.9 bbl of fresh water.*

Density (lb_m/gal)	bbl 10.0 NaCl per bbl Brine	bbl 12.4 NaBr per bbl Brine	Crystallization Point (°F) (LCTD)
10.0	1.000	0.000	30
10.1	0.958	0.042	*
10.2	0.917	0.083	*
10.3	0.875	0.125	*
10.4	0.833	0.167	*
10.5	0.792	0.208	*
10.6	0.750	0.250	*
10.7	0.708	0.292	*
10.8	0.667	0.333	*
10.9	0.625	0.375	*
11.1	0.583	0.417	*
11.2	0.500	0.500	*
11.3	0.458	0.542	*
11.4	0.417	0.583	*
11.5	0.375	0.625	*
11.6	0.333	0.667	*
11.7	0.292	0.708	*
11.8	0.250	0.750	*
11.9	0.208	0.792	23
12.0	0.167	0.833	28
12.1	0.125	0.875	32
12.2	0.083	0.917	36
12.3	0.042	0.958	39
12.4	0.000	1.000	46

Table 6 - 20 Preparation of Sodium Bromide Based Solutions Using 10.0 lbm/gal NaCl Solution and 12.4 lb/gal NaBr Solution

** Data being reconfirmed*

Example:

To prepare 10 bbl of 11.0 lb_m/gal NaBr:

10 × 0.583 = 5.8 bbl 10.0 lb_m/gal NaCl

10 × 0.417 = 4.2 bbl 12.4 lb_m/gal NaBr

Add 5.8 bbl of 10.0 lb_m/gal NaCl to 4.2 bbl 12.4 lb_m/gal NaBr.

Density lb$_m$/gal	bbl Water per bbl Brine	bbl NaCl per bbl Brine	lb NaBr per bbl Brine	Crystallization Point, °F (LCTD)
10.0	0.886	110.0	0	30
10.1	0.883	106.0	9.3	*
10.2	0.880	102.0	18.6	*
10.3	0.877	97.8	27.9	*
10.4	0.874	93.7	37.1	*
10.5	0.871	89.6	46.4	*
10.6	0.868	85.6	55.7	*
10.7	0.865	81.5	65.0	*
10.8	0.862	77.4	74.3	*
10.9	0.859	73.4	83.6	*
11.0	0.856	69.3	92.8	*
11.1	0.853	65.2	102.0	*
11.2	0.850	61.2	111.0	*
11.3	0.847	57.1	121.0	*
11.4	0.844	52.9	130.0	*
11.5	0.841	48.8	139.0	*
11.6	0.838	44.8	149.0	*
11.7	0.835	40.7	158.0	*
11.8	0.832	36.6	167.0	*
11.9	0.829	32.6	177.0	*
12.0	0.826	28.5	186.0	37
12.1	0.823	24.4	195.0	41
12.2	0.820	20.4	204.0	47
12.3	0.818	16.3	214.0	49
12.4	0.815	12.2	223.0	53
12.5	0.812	8.1	232.0	56
12.6	0.809	4.1	242.0	60
12.7	0.806	0	251.0	63

Table 6 - 21 Preparation of Sodium Bromide Based Solutions Using Solid NaCl, Granular Concentrated NaBr, and Water

** Data being reconfirmed*

Example:

To prepare 10 bbl of 11.0 lb$_m$/gal NaBr:

10 × 0.856 = 8.6 bbl water

10 × 69.3 = 693 lbs NaCl

10 × 92.8 = 928 lbs NaBr

Add 693 lbs NaCl and 928 lbs NaBr to 8.6 bbl of water.

Brine @ 20°C (68° F)		Requirements for 1 bbl Brine		Requirements for 1 M^3 of Brine		Crystal Point**	
ppg	S.G.	H_2O gals	NaBr lbs	H_2O/M^3s	NaBr kgs	°F	°C
8.4	1.007	41.81	4.08	0.996	11.65	31.0	-0.6
8.5	1.019	41.66	9.60	0.992	27.38	30.0	-1.1
8.6	1.031	41.51	15.07	0.988	42.99	29.0	-1.7
8.7	1.043	41.35	20.60	0.984	58.77	29.0	-1.7
8.8	1.055	41.18	26.15	0.981	74.62	28.0	-2.2
8.9	1.067	41.02	31.70	0.977	90.44	26.0	-3.3
9.0	1.079	40.85	37.39	0.973	106.68	25.0	-3.9
9.1	1.091	40.69	42.92	0.969	122.45	24.0	-4.4
9.2	1.103	40.51	48.55	0.965	138.52	23.0	-5.0
9.3	1.115	40.34	54.20	0.961	154.64	22.0	-5.6
9.4	1.127	40.17	59.84	0.956	170.72	21.0	-6.1
9.5	1.139	39.99	65.52	0.952	186.92	20.0	-6.7
9.6	1.151	39.81	71.21	0.948	203.15	19.0	-7.2
9.7	1.163	39.64	76.91	0.944	219.42	18.0	-7.8
9.8	1.175	39.46	82.58	0.939	235.62	16.0	-8.9
9.9	1.187	39.27	88.33	0.935	252.01	15.0	-9.4
10.0	1.199	39.09	94.05	0.931	268.34	14.0	-10.0
10.1	1.211	38.90	99.81	0.926	284.75	12.0	-11.1
10.2	1.223	38.72	105.56	0.922	301.18	11.0	-11.7
10.3	1.235	38.53	111.33	0.917	317.62	10.0	-12.2
10.4	1.247	38.34	117.09	0.913	334.07	8.0	-13.3
10.5	1.259	38.16	122.86	0.909	350.52	6.0	-14.4
10.6	1.271	37.97	128.62	0.904	366.96	5.0	-15.0
10.7	1.283	37.78	134.41	0.900	383.48	4.0	-15.6
10.8	1.295	37.59	140.19	0.895	399.98	2.0	-16.7
10.9	1.307	37.40	146.02	0.890	416.62	0.0	-17.8
11.0	1.319	37.20	151.87	0.886	433.30	-2.0	-18.9
11.1	1.331	37.00	157.71	0.881	449.96	-3.0	-19.4
11.2	1.343	36.80	163.58	0.876	466.72	-5.0	-20.6
11.3	1.354	36.61	169.40	0.872	483.32	-7.0	-21.7
11.4	1.366	36.41	175.28	0.867	500.08	-9.0	-22.8
11.5	1.379	36.21	181.14	0.862	516.79	-11.0	-23.9
11.6	1.391	36.02	186.98	0.858	533.47	-14.0	-25.6
11.7	1.402	35.81	192.83	0.853	550.16	-16.0	-26.7

Table 6 - 22 Sodium Bromide Brine Requirements (using 95% NaBr)

***Due to variances in salt impurities and nucleation sites, it is recommended to reconfirm the crystal points prior to field use.*

Table 6 - 23 CLEAR-DRILL N Brine Table

HCOONa (Wt%)	HCOONa (g/L)	Initial H_20 (mL/L)	Density (S.G.)	Density (ppg)	Correc. Factor	Sodium (mg/L)	lbs HCOONa /bbl H_2O	Activity
0.5	5.01	999.2	1.0024	8.360	1.0008	1694	1.76	0.996
1.0	10.05	996.6	1.0049	8.371	1.0034	3397	3.53	0.992
1.5	15.11	994.2	1.0076	8.392	1.0059	5109	6.32	0.989
2.0	20.20	991.7	1.0102	8.415	1.0083	6829	7.13	0.986
2.5	25.32	989.4	1.0129	8.438	1.0107	8560	8.96	0.982
3.0	30.47	987.0	1.0157	8.461	1.0131	10301	10.81	0.979
3.5	35.65	984.7	1.0186	8.485	1.0155	12051	12.67	0.979
4.0	40.86	982.4	1.0215	8.509	1.0179	13813	14.56	0.972
4.5	46.10	980.2	1.0245	8.534	1.0202	15586	16.46	0.968
5.0	51.38	977.9	1.0275	8.559	1.0226	17367	18.39	0.965
5.5	56.68	975.7	1.0306	8.585	1.0249	19161	20.33	0.961
6.0	62.02	973.4	1.0337	8.611	1.0273	20966	22.30	0.958
6.5	67.39	971.2	1.0368	8.637	1.0297	22782	24.29	0.955
7.0	72.80	968.9	1.0400	8.663	1.0321	24609	26.30	0.951
7.5	78.24	966.7	1.0432	8.690	1.0345	26447	28.33	0.948
8.0	83.71	964.4	1.0464	8.716	1.0369	28297	30.38	0.946
8.5	89.21	962.1	1.0496	8.743	1.0394	30157	32.46	0.941
9.0	94.75	958.8	1.0528	8.770	1.0419	32030	34.55	0.938
9.5	100.32	957.4	1.0560	8.797	1.0444	33913	36.67	0.935
10.0	105.83	956.1	1.0593	8.824	1.0470	35808	38.82	0.932
10.5	111.57	952.7	1.0626	8.851	1.0496	37714	40.99	0.928
11.0	117.24	950.3	1.0668	8.878	1.0523	39631	43.18	0.925
11.5	122.96	947.8	1.0691	8.906	1.0550	41560	45.40	0.922
12.0	128.68	945.4	1.0724	8.933	1.0578	43600	47.64	0.919
12.5	134.46	942.9	1.0758	8.960	1.0606	45451	49.91	0.916
13.0	140.26	940.4	1.0789	8.987	1.0634	47413	52.20	0.913
13.5	146.10	937.8	1.0822	9.015	1.0663	49387	54.53	0.909
14.0	151.97	935.2	1.0855	9.042	1.0693	51372	56.87	0.906
14.5	157.88	932.6	1.0888	9.070	1.0723	53368	59.25	0.903
15.0	163.81	930.0	1.0921	9.097	1.0763	55375	61.65	0.900
15.5	169.79	927.3	1.0964	9.125	1.0784	57394	64.09	0.897
16.0	175.79	924.5	1.0987	9.152	1.0816	59424	66.55	0.893
16.5	181.83	921.8	1.1020	9.180	1.0848	61466	69.04	0.890
17.0	187.91	919.1	1.1053	9.207	1.0880	63519	71.56	0.887
17.5	194.01	916.3	1.1086	9.235	1.0914	65583	74.11	0.884
18.0	200.16	913.5	1.1120	9.263	1.0947	67660	76.69	0.880
18.5	206.33	910.6	1.1153	9.291	1.0982	69748	79.30	0.877
19.0	212.56	907.7	1.1187	9.318	1.1016	71848	81.95	0.873
19.5	218.79	904.9	1.1220	9.346	1.1052	73960	84.63	0.870
20.0	226.08	901.9	1.1254	9.374	1.1087	76084	87.34	0.866

CLEAR-DRILL N Brine Table continued

HCOONa (Wt%)	HCOONa (g/L)	Initial H_20 (mL/L)	Density (S.G.)	Density (ppg)	Correc. Factor	Sodium (mg/L)	lbs HCOONa /bbl H_2O	Activity
20.5	231.40	899.0	1.1288	9.403	1.1124	78220	90.09	0.863
21.0	237.75	896.0	1.1322	9.431	1.1160	80369	92.87	0.859
21.5	244.15	893.0	1.1358	9.459	1.1198	82530	95.69	0.856
22.0	250.58	890.0	1.1390	9.488	1.1236	84704	98.54	0.852
22.5	257.05	887.0	1.1424	9.517	1.1274	86892	101.43	0.848
23.0	253.56	883.9	1.1459	9.546	1.1313	89092	104.36	0.844
23.5	270.11	880.9	1.1494	9.574	1.1362	91305	107.32	0.840
24.0	276.69	877.8	1.1529	9.604	1.1392	93532	110.33	0.836
24.5	283.32	874.7	1.1564	9.633	1.1433	95773	113.37	0.832
25.0	289.99	871.5	1.1600	9.663	1.1474	98027	116.46	0.828
25.5	296.70	868.4	1.1635	9.692	1.1515	100296	119.58	0.823
26.0	303.46	865.2	1.1671	9.722	1.1557	102579	122.75	0.819
26.5	310.25	862.1	1.1708	9.752	1.1600	104876	125.96	0.814
27.0	317.09	858.9	1.1744	9.783	1.1643	107188	129.22	0.810
27.5	323.97	855.7	1.1781	9.813	1.1687	109515	132.62	0.805
28.0	330.90	852.4	1.1818	9.844	1.1731	111857	135.87	0.800
28.5	337.87	849.2	1.1855	9.875	1.1776	114213	139.26	0.795
29.0	344.89	845.9	1.1893	9.907	1.1822	116586	142.70	0.790
29.5	351.95	842.5	1.1931	9.938	1.1868	118973	146.19	0.785
30.0	359.08	839.3	1.1969	9.970	1.1914	121376	149.73	0.780
30.5	366.22	836.0	1.2007	10.002	1.1962	123794	153.32	0.775
31.0	373.42	832.7	1.2046	10.034	1.2010	126228	156.96	0.770
31.5	380.66	829.3	1.2085	10.066	1.2059	128678	160.66	0.764
32.0	387.96	826.9	1.2124	10.099	1.2108	131143	164.41	0.759
32.5	396.29	822.5	1.2163	10.132	1.2158	133623	168.22	0.753
33.0	402.68	819.0	1.2202	10.165	1.2210	136119	172.08	0.748
33.5	410.11	815.6	1.2242	10.198	1.2262	138630	176.00	0.742
34.0	417.58	812.1	1.2282	10.231	1.2314	141157	179.98	0.736
34.5	425.10	808.5	1.2322	10.264	1.2368	143698	184.02	0.731
35.0	432.66	806.0	1.2362	10.297	1.2423	146253	188.12	0.725
35.5	440.26	801.4	1.2402	10.331	1.2479	148823	192.29	0.719
36.0	447.90	797.7	1.2442	10.364	1.2536	151407	196.52	0.713
36.5	455.59	794.0	1.2482	10.397	1.2594	154004	200.82	0.708
37.0	463.30	790.3	1.2522	10.431	1.2654	156613	205.19	0.702
37.5	471.06	786.5	1.2562	10.464	1.2714	159236	209.62	0.696
38.0	478.85	782.7	1.2601	10.497	1.2776	161868	214.13	0.691
38.5	486.57	778.8	1.2641	10.530	1.2840	164512	218.71	0.685
39.0	494.52	774.9	1.2680	10.562	1.2905	167165	223.37	0.680
39.5	502.40	770.9	1.2719	10.595	1.2972	169827	228.10	0.675
40.0	510.29	766.8	1.2757	10.627	1.3041	172497	232.91	0.670
40.5	518.21	762.7	1.2795	10.658	1.3111	175173	237.81	0.665
41.0	526.14	758.5	1.2833	10.690	1.3184	177855	242.78	0.660

CLEAR-DRILL N Brine Table continued

HCOONa (Wt%)	HCOONa (g/L)	Initial H_20 (mL/L)	Density (S.G.)	Density (ppg)	Correc. Factor	Sodium (mg/L)	lbs HCOONa /bbl H_2O	Activity
41.5	534.09	754.2	1.2870	10.720	1.3259	180540	247.84	0.656
42.0	542.04	749.9	1.2906	10.750	1.3336	183227	252.99	0.651
42.5	549.99	745.4	1.2941	10.780	1.3415	185916	258.23	0.647
43.0	557.93	740.9	1.2975	10.808	1.3497	188601	263.56	0.643
43.0	557.93	740.9	1.2975	10.808	1.3497	188601	263.56	0.643
43.5	565.87	736.3	1.3009	10.836	1.3581	191284	268.98	0.640
44.0	573.79	731.6	1.3041	10.863	1.3669	193962	274.51	0.636
44.5	581.69	726.8	1.3072	10.889	1.3759	196633	280.13	0.633
45.0	589.58	721.9	1.3101	10.913	1.3863	199293	286.86	0.630
45.5	597.40	716.9	1.3130	10.937	1.3950	201941	291.68	0.628
46.0	605.19	711.7	1.3156	10.959	1.4051	204574	297.61	0.626
46.5	612.92	706.5	1.3181	10.980	1.4155	207188	303.66	0.624
47.0	620.59	701.1	1.3204	10.999	1.4264	209782	309.82	0.622
47.5	628.19	695.6	1.3225	11.016	1.4377	212350	316.10	0.620
48.0	635.71	689.9	1.3244	11.032	1.4494	214891	322.50	0.619
48.5	643.13	684.1	1.3260	11.046	1.4617	217400	329.02	0.618
49.0	650.45	678.2	1.3274	11.058	1.4746	219874	335.67	0.617
49.5	657.65	672.1	1.3286	11.067	1.4878	222307	342.45	0.616

Table 6 - 24 CLEAR-DRILL K Brine Table

HCOOK (Wt%)	HCOOK (g/L)	Initial H_20 (mL/L)	Density (S.G.)	Density (ppg)	Correc. Factor	K (mg/L) (Potassium)	lbs HCOOK/ bbl H_2O	Activity
0.5	5.02	999.9	1.0032	8.358	1.0001	2331	1.76	0.996
1.0	10.06	998.0	1.0063	8.382	1.0020	4677	3.53	0.994
1.5	15.14	996.0	1.0094	8.408	1.0040	7037	5.32	0.993
2.0	20.25	994.0	1.0124	8.433	1.0061	9411	7.13	0.991
2.5	25.39	991.8	1.0154	8.459	1.0082	11799	8.96	0.989
3.0	30.55	989.7	1.0164	8.484	1.0106	14201	10.81	0.987
3.5	35.75	987.4	1.0214	8.508	1.0127	16616	12.67	0.986
4.0	40.97	985.1	1.0243	8.533	1.0161	19044	14.56	0.984
4.5	46.23	982.8	1.0273	8.567	1.0175	21486	16.46	0.982
5.0	51.51	980.4	1.0302	8.581	1.0200	23841	18.39	0.980
5.5	56.82	978.0	1.0331	8.606	1.0225	26409	20.33	0.978
6.0	62.16	975.5	1.0359	8.629	1.0261	28890	22.30	0.975
6.5	67.52	973.0	1.0388	8.653	1.0277	31384	24.29	0.973
7.0	72.92	970.5	1.0417	8.677	1.0304	33892	26.30	0.971
7.5	78.34	967.9	1.0446	8.701	1.0331	36412	28.33	0.969
8.0	83.79	966.3	1.0474	8.725	1.0359	38946	30.38	0.968
8.5	89.27	962.7	1.0503	8.749	1.0387	41493	32.46	0.964
9.0	94.78	960.1	1.0531	8.772	1.0416	44063	34.55	0.961
9.5	100.32	957.4	1.0560	8.798	1.0445	46627	36.67	0.959
10.0	105.88	954.7	1.0588	8.820	1.0476	49214	38.82	0.956
10.5	111.48	951.9	1.0617	8.844	1.0505	51815	40.99	0.954
11.0	117.11	949.2	1.0646	8.868	1.0535	54430	43.18	0.951
11.5	122.76	946.4	1.0675	8.892	1.0566	57058	45.40	0.948
12.0	128.45	943.6	1.0704	8.916	1.0597	59700	47.64	0.946
12.5	134.16	940.8	1.0733	8.940	1.0629	62357	49.91	0.943
13.0	139.91	938.0	1.0762	8.965	1.0661	65028	52.20	0.940
13.5	145.68	935.1	1.0791	8.989	1.0694	67713	54.53	0.937
14.0	151.49	932.3	1.0821	9.014	1.0726	70413	56.87	0.934
14.5	157.33	929.4	1.0851	9.039	1.0760	73128	59.25	0.931
15.0	163.21	928.5	1.0881	9.063	1.0793	75858	61.65	0.928
15.5	169.11	923.6	1.0911	9.088	1.0827	78603	64.09	0.925
16.0	175.05	920.7	1.0941	9.114	1.0862	81363	66.55	0.922
16.5	181.02	917.7	1.0971	9.139	1.0896	84139	69.04	0.918
17.0	187.03	918.8	1.1002	9.164	1.0931	86930	71.56	0.915
17.5	193.07	911.8	1.1033	9.190	1.0967	89737	74.11	0.911
18.0	199.14	908.9	1.1064	9.216	1.1003	92561	76.68	0.908
18.5	205.25	905.8	1.1095	9.242	1.1039	95401	79.30	0.905
19.0	211.40	902.9	1.1126	9.268	1.1076	98257	81.95	0.901
19.5	217.58	899.8	1.1158	9.295	1.1113	101130	84.63	0.897
20.0	223.80	896.8	1.1190	9.321	1.1151	104019	87.34	0.894
20.5	230.06	893.8	1.1222	9.348	1.1189	106926	90.09	0.890
21.0	236.34	890.7	1.1254	9.375	1.1227	109850	92.87	0.886

CLEAR-DRILL K Brine Table continued

HCOONa (Wt%)	HCOONa (g/L)	Initial H_20 (mL/L)	Density (S.G.)	Density (ppg)	Correc. Factor	Sodium (mg/L)	lbs HCOONa /bbl H_2O	Activity
21.5	242.67	887.6	1.1287	9.402	1.1266	1121791	95.69	0.882
22.0	249.04	884.5	1.1320	9.429	1.1305	116750	98.54	0.878
22.5	255.44	881.4	1.1363	9.457	1.1345	118726	101.43	0.874
23.0	261.88	878.3	1.1386	9.485	1.1386	121721	104.36	0.870
23.5	268.36	875.2	1.1420	9.513	1.1426	124733	107.32	0.866
24.0	274.88	872.0	1.1453	9.541	1.1467	127763	110.33	0.862
24.5	281.44	868.9	1.1487	9.569	1.1509	130812	113.37	0.858
25.0	288.04	865.7	1.1522	9.598	1.1552	133880	116.46	0.854
25.5	294.68	862.5	1.1556	9.626	1.1594	136966	119.58	0.849
26.0	301.36	859.3	1.1591	9.666	1.1638	140071	122.75	0.845
26.5	308.08	856.0	1.1626	9.684	1.1682	143194	125.96	0.841
27.0	314.84	852.8	1.1661	9.714	1.1726	146337	129.22	0.836
27.5	321.65	849.5	1.1696	9.743	1.1772	149499	132.52	0.832
28.0	328.49	846.2	1.1732	9.773	1.1817	152680	135.87	0.827
28.5	336.38	842.9	1.1768	9.802	1.1864	155880	139.26	0.823
29.0	342.30	839.6	1.1804	9.832	1.1911	159100	142.70	0.818
29.5	349.27	836.2	1.1840	9.863	1.1958	162340	146.19	0.813
30.0	356.29	832.8	1.1876	9.883	1.2007	165599	149.73	0.809
30.5	363.34	829.4	1.1913	9.923	1.2056	168877	153.32	0.804
31.0	370.44	826.0	1.1950	9.954	1.2106	172176	156.96	0.799
31.5	377.58	822.6	1.1987	9.985	1.2157	175494	160.66	0.794
32.0	384.76	819.1	1.2024	10.016	1.2209	178833	164.41	0.789
32.5	391.98	815.6	1.2061	10.047	1.2261	182191	168.22	0.786
33.0	399.25	812.1	1.2099	10.078	1.2314	185569	172.08	0.780
33.5	406.56	808.5	1.2136	10.109	1.2368	188967	176.00	0.775
34.0	413.92	804.9	1.2174	10.141	1.2423	192386	179.98	0.770
34.5	421.32	801.3	1.2212	10.173	1.2479	196824	184.02	0.765
35.0	428.76	797.7	1.2250	10.204	1.2536	199283	188.12	0.760
35.5	436.24	794.0	1.2289	10.236	1.2594	202762	192.29	0.756
36.0	443.77	790.3	1.2327	10.268	1.2653	206261	196.52	0.750
36.5	451.34	786.6	1.2366	10.300	1.2713	209780	200.82	0.745
37.0	458.96	782.9	1.2404	10.333	1.2773	213320	205.19	0.740
37.5	466.62	779.1	1.2443	10.365	1.2835	216879	209.62	0.735
38.0	474.32	775.3	1.2482	10.398	1.2899	220459	214.13	0.730
38.5	482.06	771.4	1.2521	10.430	1.2963	224059	218.71	0.725
39.0	489.85	767.6	1.2560	10.463	1.3028	227679	223.37	0.719
39.5	497.68	763.7	1.2600	10.495	1.3095	231320	228.10	0.714
40.0	505.56	759.7	1.2639	10.528	1.3163	234981	232.91	0.709
40.5	513.48	755.7	1.2679	10.581	1.3232	238662	237.81	0.704
41.0	521.44	751.7	1.2718	10.594	1.3303	242363	242.78	0.699
41.5	529.45	747.7	1.2758	10.627	1.3376	246084	247.84	0.694
42.0	537.50	743.6	1.2798	10.660	1.3448	249826	252.99	0.689

CLEAR-DRILL K Brine Table continued

HCOONa (Wt%)	HCOONa (g/L)	Initial $H_2$0 (mL/L)	Density (S.G.)	Density (ppg)	Correc. Factor	Sodium (mg/L)	lbs HCOONa /bbl H_2O	Activity
42.5	545.58	739.5	1.2837	10.694	1.3523	253587	258.23	0.684
43.0	553.73	735.3	1.2877	10.727	1.3599	257369	263.56	0.678
43.5	561.91	731.2	1.2917	10.760	1.3677	261171	268.98	0.673
44.0	570.13	726.9	1.2958	10.794	1.3756	264993	274.51	0.668
44.5	578.40	722.7	1.2998	10.827	1.3838	268836	280.13	0.663
45.0	586.71	718.4	1.3038	10.861	1.3920	272697	285.85	0.658
45.5	595.06	714.1	1.3078	10.894	1.4005	276580	291.68	0.653
46.0	603.46	709.7	1.3119	10.928	1.4091	280482	297.61	0.648
46.5	611.90	705.3	1.3159	10.962	1.4179	284405	303.66	0.643
47.0	620.38	700.8	1.3200	10.996	1.4269	288348	309.82	0.638
47.5	628.91	696.4	1.3240	11.029	1.4360	292312	316.10	0.632
48.0	637.48	691.8	1.3281	11.063	1.4454	296296	322.50	0.627
48.5	648.10	687.3	1.3322	11.097	1.4550	300300	329.02	0.622
49.0	654.76	682.7	1.3362	11.131	1.4648	304325	335.67	0.617
49.5	663.48	678.1	1.3403	11.166	1.4747	308370	342.45	0.612
50.0	672.21	673.5	1.3444	11.199	1.4850	312436	349.37	0.607
50.5	681.00	668.7	1.3485	11.233	1.4954	316522	358.43	0.602
51.0	689.84	664.0	1.3526	11.267	1.5081	320630	363.63	0.597
51.5	698.72	659.2	1.3567	11.302	1.5170	324758	370.98	0.592
52.0	707.65	654.4	1.3609	11.336	1.5281	328908	378.48	0.587
52.5	716.62	649.5	1.3650	11.370	1.5396	333079	386.15	0.581
53.0	725.64	644.7	1.3691	11.405	1.5512	337272	393.97	0.576
53.5	734.71	639.7	1.3733	11.439	1.5632	341486	401.96	0.571
54.0	743.82	634.8	1.3774	11.474	1.5754	345722	410.13	0.566
54.5	752.98	629.8	1.3816	11.509	1.5879	349981	418.48	0.561
55.0	762.19	624.7	1.3858	11.544	1.6007	354262	427.01	0.556
55.5	771.45	619.7	1.3900	11.579	1.6138	358566	436.73	0.551
56.0	780.76	614.6	1.3942	11.614	1.6272	362893	444.65	0.546
56.5	790.12	609.4	1.3984	11.649	1.6409	367243	453.78	0.541
57.0	799.54	604.2	1.4027	11.684	1.6550	371618	463.12	0.535
57.5	809.00	599.0	1.4070	11.720	1.6694	376016	472.68	0.530
58.0	818.52	593.8	1.4112	11.756	1.6841	380440	482.46	0.526
58.5	828.09	588.5	1.4155	11.791	1.6992	384888	492.49	0.520
59.0	837.71	583.2	1.4199	11.827	1.7147	389363	502.75	0.514
59.5	847.40	577.8	1.4242	11.864	1.7306	393864	513.27	0.509
60.0	857.14	572.5	1.4286	11.900	1.7469	398391	52706	0.504
60.5	866.94	567.0	1.4330	11.937	1.7635	402946	535.11	0.498
61.0	876.80	561.6	1.4374	11.973	1.7807	407529	546.45	0.493
61.5	886.72	556.1	1.4418	12.010	1.7982	412141	558.08	0.487
62.0	896.71	550.6	1.4463	12.048	1.8162	416783	570.02	0.482
62.5	906.76	545.0	1.4508	12.085	1.8347	421454	582.28	0.476
63.0	916.88	539.5	1.4564	12.123	1.8537	426167	594.87	0.471

CLEAR-DRILL K Brine Table continued

HCOONa (Wt%)	HCOONa (g/L)	Initial H_20 (mL/L)	Density (S.G.)	Density (ppg)	Correc. Factor	Sodium (mg/L)	lbs HCOONa /bbl H_2O	Activity
63.5	927.07	533.8	1.4599	12.181	1.8732	430893	607.81	0.465
64.0	937.32	528.2	1.4646	12.200	1.8932	435661	621.10	0.459
64.5	947.66	522.5	1.4692	12.239	1.9138	440463	634.77	0.453
65.0	958.06	516.8	1.4739	12.278	1.9349	445300	648.83	0.447
65.5	968.55	511.1	1.4787	12.318	1.9567	450173	663.30	0.441
66.0	979.11	505.3	1.4835	12.358	1.9790	455083	678.19	0.436
66.5	989.76	499.5	1.4884	12.398	2.0020	460032	693.53	0.429
67.0	1000.49	493.7	1.4933	12.439	2.0267	465020	709.33	0.423
67.5	1011.31	487.8	1.4982	12.480	2.0500	470049	725.61	0.416
68.0	1022.22	481.9	1.5033	12.522	2.0751	476121	742.41	0.409
68.5	1033.23	476.0	1.5084	12.565	2.1009	480237	759.74	0.403
69.0	1044.33	470.0	1.5135	12.608	2.1275	486397	777.63	0.396
69.5	1055.54	464.1	1.5188	12.651	2.1549	490805	796.11	0.389
70.0	1066.84	458.0	1.5241	12.695	2.1832	495861	815.20	0.381
70.5	1078.26	452.0	1.5294	12.740	2.2124	501167	834.94	0.374
71.0	1089.79	445.9	1.5349	12.788	2.2425	506525	855.35	0.366
71.5	1101.43	439.8	1.5405	12.832	2.2736	511937	876.49	0.358
72.0	1113.20	433.7	1.5461	12.879	2.3058	517405	898.38	0.350
72.5	1126.09	427.5	1.5518	12.927	2.3390	522931	921.07	0.341
73.0	1137.10	421.3	1.5677	12.976	2.3734	528517	944.59	0.333
73.5	1149.25	416.1	1.5636	13.026	2.4090	534164	969.01	0.324
74.0	1181.54	408.8	1.5697	13.075	2.4459	539876	994.36	0.314
74.5	1173.98	402.6	1.5758	13.126	2.4841	545655	1020.71	0.305
75.0	1186.56	398.2	1.5821	13.179	2.5238	551503	1048.11	0.294

Table 6 - 25 Properties of 85% Calcium Nitrate Solutions (at 25°C)

Percent Weight	Specific Gravity (g/cm^3)	Density (lb/gal)	85% $Ca(NO_3)_2$	H_2O Using 85% $Ca(NO_3)_2$ (L/m^3)	$Ca(NO_3)_2$ (mg/L)	Calcium (mg/L)	Volume Increase Factor 85% $Ca(NO_3)_2$	A_w
1	1.005	8.39	10	997	10089	2080	1.002	0.998
2	1.012	8.45	20	993	20043	4191	1.007	0.995
3	1.019	8.5	30	989	30762	5327	1.011	0.993
4	1.026	8.56	41	985	41349	8490	1.016	0.990
5	1.033	8.62	51	980	52105	10680	1.021	0.988
6	1.040	8.68	62	976	63036	12897	1.025	0.985
7	1.047	8.74	73	972	74143	15142	1.030	0.983
8	1.054	8.80	84	968	85429	17416	1.034	0.980
9	1.061	8.85	95	963	96898	19718	1.039	0.977
10	1.068	8.91	106	959	108552	22050	1.044	0.974
11	1.075	8.97	118	954	120395	24411	1.049	0.972
12	1.082	9.03	129	950	132429	26802	1.054	0.969
13	1.090	9.09	141	945	144657	29224	1.059	0.966
14	1.097	9.15	152	940	157083	31676	1.064	0.963
15	1.104	9.21	164	935	169708	34160	1.069	0.960
16	1.111	9.27	175	930	182538	36676	1.074	0.956
17	1.119	9.34	189	925	195573	39224	1.080	0.953
18	1.126	9.40	201	920	208818	41805	1.086	0.950
19	1.134	9.46	214	915	222274	44419	1.092	0.948
20	1.141	9.52	226	910	235946	47067	1.098	0.942
21	1.149	9.58	239	905	249836	49748	1.104	0.939
22	1.156	9.65	252	899	263948	52464	1.111	0.935
23	1.164	9.71	265	894	278283	56215	1.117	0.931
24	1.171	9.78	279	888	292846	58001	1.124	0.927
25	1.179	9.84	292	882	307538	60823	1.132	0.922
26	1.187	9.91	306	876	322664	63681	1.139	0.918
27	1.195	9.97	320	871	337925	66576	1.147	0.913
28	1.203	10.04	334	865	353426	69508	1.155	0.909
29	1.211	10.10	348	858	369169	72477	1.163	0.904
30	1.219	10.17	362	852	385156	75484	1.172	0.898
31	1.227	10.24	377	846	401392	78530	1.181	0.893
32	1.235	10.31	392	839	417878	81614	1.190	0.888
33	1.243	10.38	406	833	434618	84738	1.200	0.882
34	1.252	10.44	421	826	451615	87901	1.210	0.876
35	1.260	10.51	437	820	468872	91105	1.220	0.870
36	1.268	10.59	452	813	486392	94349	1.231	0.864
37	1.277	10.66	468	806	504178	97634	1.242	0.857
38	1.286	10.73	484	799	522232	100961	1.253	0.851
39	1.294	10.80	500	791	540558	104329	1.265	0.844

Properties of 85% Calcium Nitrate Solutions (at 25°C) continued

Percent Weight	Specific Gravity (g/cm^3)	Density (lb/gal)	85% $Ca(NO_3)_2$	H_2O Using 85% $Ca(NO_3)_2$ (L/m^3)	$Ca(NO_3)_2$ (mg/L)	Calcium (mg/L)	Volume Increase Factor 85% $Ca(NO_3)_2$	A_w
40	1.303	10.87	516	784	559159	107740	1.278	0.837
41	1.312	10.95	532	776	578038	111193	1.291	0.829
42	1.321	11.02	549	769	597197	114690	1.304	0.821
43	1.33	11.10	566	761	616640	118230	1.318	0.814
44	1.339	11.17	583	753	636370	121815	1.332	0.805
45	1.348	11.25	600	745	656389	125444	1.347	0.797
46	1.357	11.33	617	737	676701	129117	1.362	0.788
47	1.367	11.41	635	729	697308	132837	1.377	0.779
48	1.376	11.49	653	720	718214	136602	1.394	0.770
49	1.386	11.57	671	712	739421	140413	1.410	0.760
50	1.396	11.65	689	703	760933	144271	1.428	0.751

WORKOVER FLUIDS

Many functions of a workover fluid are the same as functions of a drilling fluid. A workover fluid must:

- Provide sufficient hydrostatic pressure to prevent formation fluids from entering the wellbore
- Be able to clean the hole with reasonable pump pressures and annular velocities
- Prevent excessive fluid (filtrate or whole workover fluid) losses to the formation
- Be stable at the maximum well temperature
- Provide maximum protection against formation damage.

The likelihood of a well being damaged can be much greater during workover operations than during drilling operations. In the past it was a common practice to use drilling fluid materials (barite, clays, filtration control agents, and chemicals) for preparing and maintaining workover fluids. This practice has resulted in formation damage and loss of productivity in a significant percentage of the wells worked over with these fluids.

Completion operations such as acidizing and fracturing, which are designed to open up a formation and increase production, also increase the potential for invasion of the formation by the workover fluid when remedial work is required.

Damage to the formation occurs when:

- solids contained in the workover fluid lost to the formation plug pores and reduce its effective permeability

- swelling of expandable clays in the producing formation is caused by the invading fluid
- there is particle movement within the sandstone
- the fluid lost to the formation forms a viscous emulsion with formation fluids or changes the interfacial tension resulting in reduced production
- enough fluid is lost to the formation to flush the hydrocarbons away from the wellbore, thus allowing water from a water drive to enter the wellbore

For a well to return to full production after workover operations, the fluid lost to the formation during workover should be minimized and the solids and chemicals lost to the formation must be removed.

Simply producing the well may be sufficient to flush these solids from the formation face. The smaller clay and barite particles, however, are carried deep into the formation where they lodge and cannot be flushed out, thus permanently impairing the productivity of the well.

Heavy Brines

Many of these problems can be avoided by using solids-free workover fluids. By using diesel oil (a fire hazard) or various brines (sodium chloride, calcium chloride, calcium bromide, or zinc bromide), it is possible to have solids-free workover systems with a density range of 7.0 to 19.2 lb_m/gal. The maximum operational densities in pounds per gallon which may be achieved with various salts are shown in the tables above. The use of these brines as workover and completion fluids has increased dramatically over recent years due to their non-damaging characteristics. In addition to heavy brines being used as workover fluids, they are also used as packer fluids, perforating fluids, and gravel pack fluids.

Calcium chloride has a greater solubility than sodium chloride and, at higher concentrations of these mixed salts, the sodium chloride can come out of solution. As much sodium chloride as possible should be used for a given weight to reduce cost when these two salts are used.

The properties of calcium chloride solutions can be found in the preceding tables. The material requirements for preparing chloride and bromide solutions are also found in the preceding tables.

The solubility of calcium bromide increases with temperature, and much of it may precipitate from higher density solutions if the solution is allowed to cool. Requirements of a calcium chloride and calcium bromide solution can be found in the preceding tables.

Unfortunately, solids-free workover fluids cannot do everything that is required of a workover fluid. They do not have the carrying capacity needed to clean the hole, and they have no filtration control or means of controlling lost returns. In addition, when calcium bromide or zinc bromide is needed for density requirements, these fluids can be very expensive.

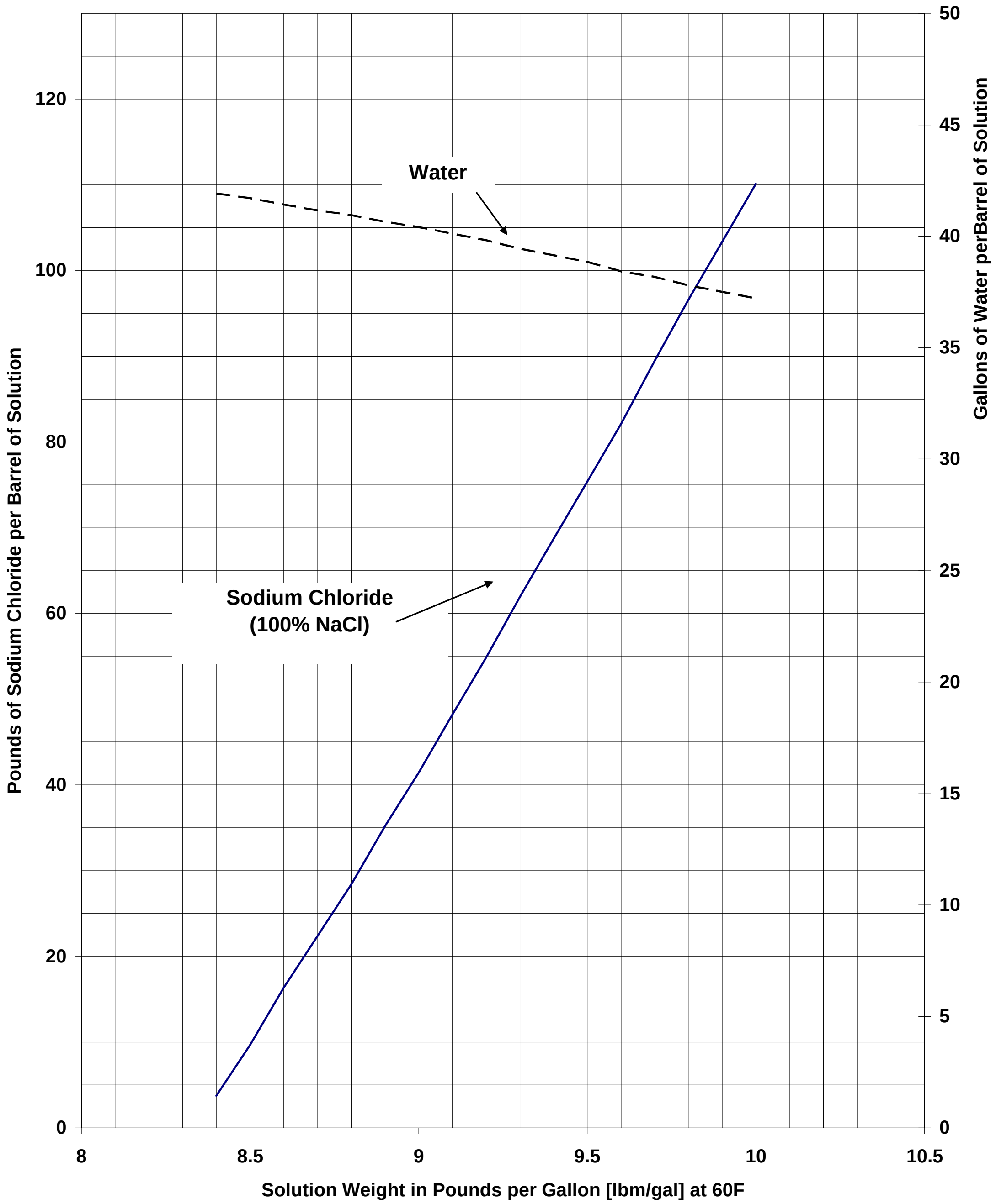


Figure 6 - 14 **Material Requirements for Preparing Sodium Chloride Solutions**

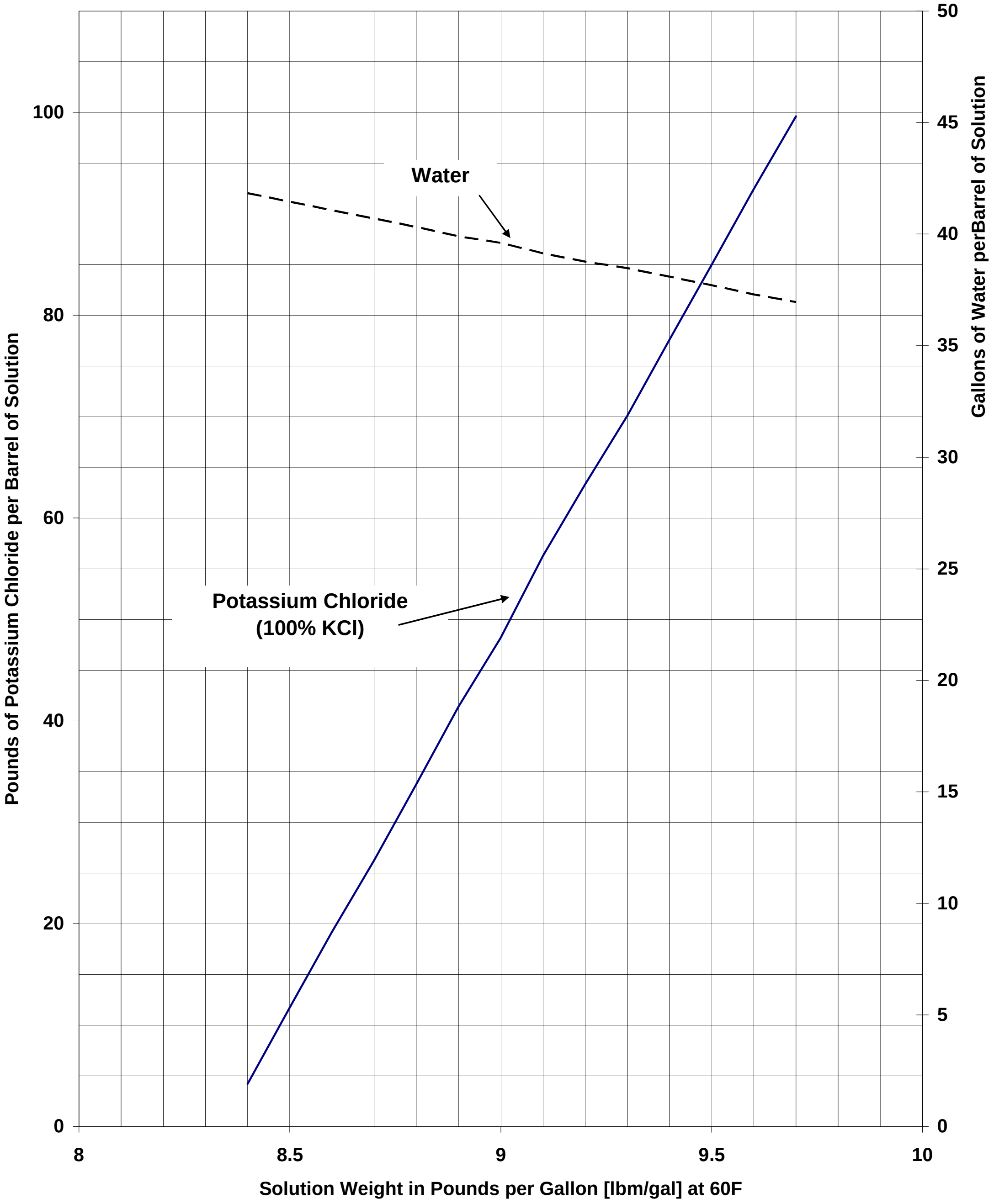


Figure 6 - 15 Material Requirements for Preparing Potassium Chloride Solutions

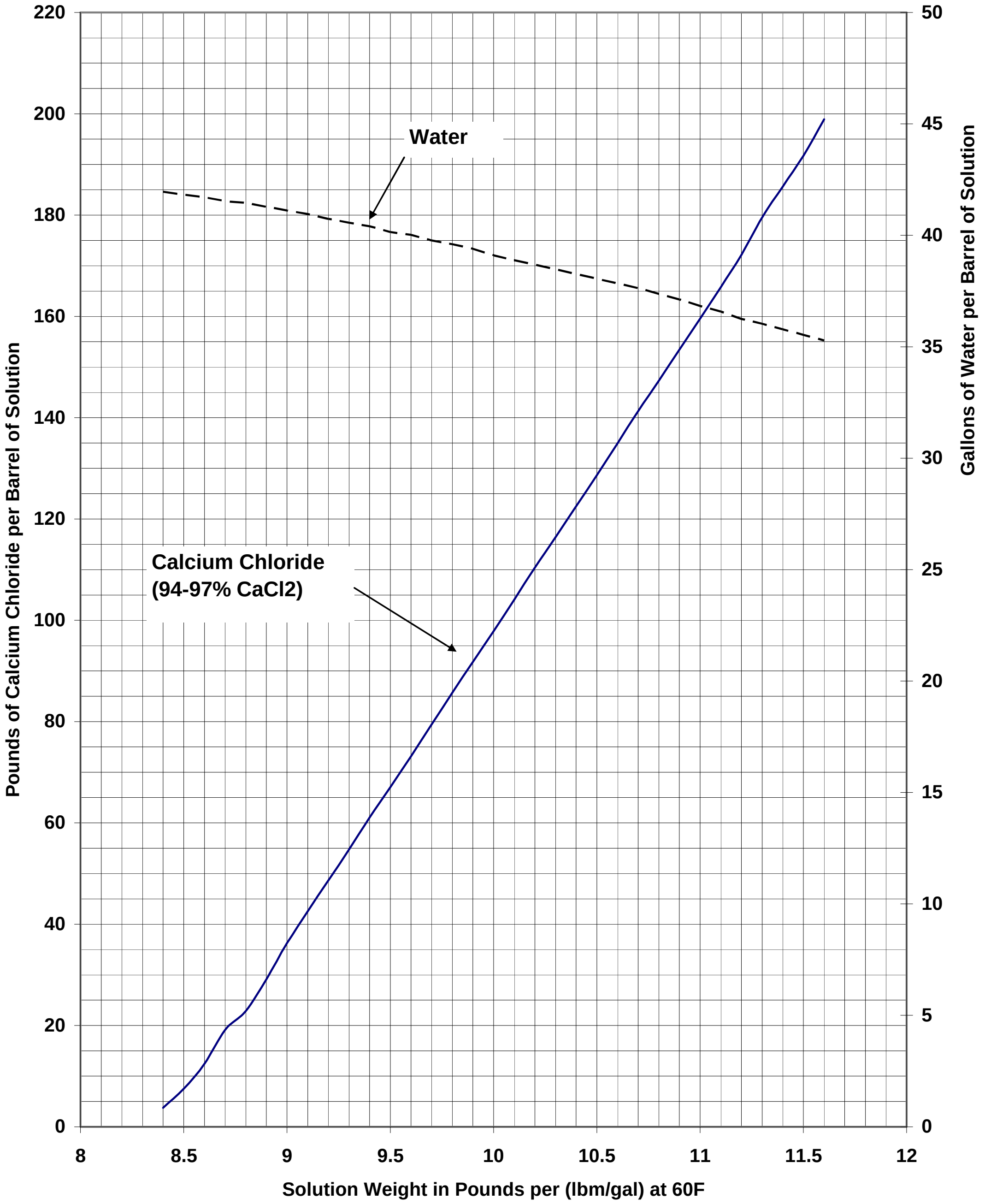


Figure 6 - 16 Material Requirements for Preparing Calcium Chloride Solutions

Workover Products

Various materials have been used in an effort to give the desired characteristics to brine workover fluids while retaining the solids-free benefits. These materials have had varying degrees of success.

Hydroxy Ethyl Cellulose (HEC) is a non-ionic viscosifier widely used in workover applications. Baker Hughes Drilling Fluids markets this compound under the trade name **W.O.™ 21L. HEC** hydrates in almost all types of brines and is also effective in reducing filtration.

HEC is made by reacting alkali cellulose with ethylene oxide in the presence of isopropyl alcohol. HEC is made in several viscosity grades depending on the number of side chains and the molecular weight. HEC is almost completely acid soluble. HEC, like guar gum, is susceptible to bacterial degradation. The use of an antifoaming agent, such as **W.O.™ DEFOAM**, may be necessary when adding HEC to brine solutions.

Xanthan gum, or **XAN-PLEX D**, is a high molecular-weight natural polysaccharide produced by the bacterial fermentation of the micro-organism *Xanthomonas campestreis*. This polymer is slightly anionic and shows good solubility in sodium chloride, potassium chloride, and to a lesser extent, calcium chloride brines.

The main advantage of xanthan gum as a viscosifier over guar gum or HEC is that the gel structure that is formed with xanthan gum in solution is superior, thereby resulting in greater hole cleaning efficiency. Although xanthan gum is somewhat susceptible to bacterial degradation, a biocide is not required in most applications.

Guar gum has been used widely as a viscosifier for workover fluids. Guar gum is a non-ionic, branched-chain, high molecular-weight polysaccharide which is obtained from the seeds of the guar plant. Guar gum is soluble in almost any type of water except zinc bromide due to its non-ionic nature. Though its physical appearance in solution would indicate that it has near solids-free characteristics, it too can plug formations in much the same manner as clays.

Recent modifications of guar gum have resulted in a material with a lower residual content (after acidizing). These derivatives, hydroxypropyl guars, have greatly improved the performance of guar gum. Guar gum also swells when exposed to certain chemicals such as isopropyl alcohol, which is used in some sand fixation processes. Guar gum is susceptible to bacterial degradation. Use of a biocide, such as **DRYOCIDE™**, is recommended.

To obtain fluid loss control in a brine workover or completion fluid, it may be necessary to add solid fluid-loss control agents. The most common additive used is sized calcium carbonate, such as **W.O.™ 30**. Calcium carbonate comes in fine, medium, and coarse grades depending on the pore size or fractures present in the producing zones. Calcium carbonate is acid soluble, thus offering protection against the plugging of producing formations. Other fluid-loss control agents used in workover and completion fluids include oil-soluble fluid-loss resins, sized NaCl crystals, and iron carbonate.

Lost circulation materials (LCM) for workover and completion fluids include calcium carbonate, oil soluble resins, or fluid loss blends that are normally formulated into pills of 20 to 50 bbl. Baker Hughes Drilling Fluids markets calcium carbonate as **W.O.™ 30** (fine and coarse) and **MIL-CARB™**. All of these materials are normally acid soluble. Fluid loss blends generally include carbonates, viscosifying polymer, and dispersing agents.

These pills may contain up to 50 lb_m/bbl of the particular LCM material chosen and are usually pumped directly across from the thief zone and allowed to sit for at least two hours before circulation is attempted. This procedure is repeated until circulation is regained.

Both calcium chloride and calcium bromide are non-corrosive, but oxygen can dissolve in these brines causing oxygen corrosion. Oxygen scavengers such as **NOXYGEN™** will effectively remove oxygen from these types of brines. Brines containing zinc will be acidic, thus they are corrosive. Film forming inhibitors (such as **AMI-TEC™**) are the additives of preference for combating this type of corrosion.

BRINE-PAC®, because it is effective against corrosion by oxygen, carbon dioxide, and hydrogen sulfide, is a convenient all-purpose corrosion additive. Corrosion will increase as greater temperatures are encountered.

Mixing heavy brines can generate considerable heat and care must be taken to prevent the inhalation of any dust particles from the dry products. The use of protective goggles, masks, rubber gloves, and protective aprons should be mandatory for all rig personnel working with heavy brines. These brines are hygroscopic and can dry out skin and irritate eyes. Emergency showers and eye wash stations should be provided on the rig floor and pits. All personnel should be familiar with the Material Safety Data Sheets (MSDS) of all products.

Other Workover Fluids

Alternative workover fluids to heavy brines that have been utilized in the past include acid soluble carbonate materials such as calcium carbonate or iron carbonate (siderite) which are used as weighting agents. When using calcium carbonate, densities up to 14 lb_m/gal can be achieved while densities of up to 18 lb_m/gal (2.1 S.G.)can be obtained using iron carbonate as the weighting agent. Advantages of these types of workover additives include lower cost, resistance to crystallization, and greater fluid loss control.

Oil-base fluids can also be utilized as workover fluids in certain applications. The advantage of oil-base fluids over water-base fluids is that the oil filtrate does not damage water-sensitive formations, and low-density fluids can be formulated for depleted production zones. Conventional oil-base fluid formulations for drilling applications have disadvantages for workover situations including oil-wetting of producing zones caused by surfactants in the fluid, emulsion blockage, and solids invasion.

WELLBORE DISPLACEMENT AND CLEAN-UP PRODUCTS AND PROCEDURES

Introduction

Transfer of the completion/workover fluid to the wellbore by displacing the fluid already present is one of the most important procedures of the completion/workover operation. The objective of the displacement is to replace all of the fluid in the wellbore, usually drilling mud, so that a minimal amount of displacing fluid is contaminated. Displacements typically follow a simple two step procedure comprising the conditioning the current wellbore fluid and then displacing with completion fluid (direct displacement) or by first displacing with water {sea or fresh) followed by the completion fluid (indirect displacement). The purpose of conditioning the drilling fluid is to disperse and evenly distribute into the wellbore fluid any solids that may be clinging to the casing wall, the formation face, and transfer pipes. The rheological properties of the fluid to be displaced can then be adjusted to make it flow more easily when the actual displacement takes place.

During the drill-in phase, wellbore sections become exposed to mud and mud particles. Drilled solids become attached to the casing and become a part of the filter cake in the open wellbore. Regardless of the type of completion, these foreign particles, if not removed from the wellbore, may damage the reservoir and the completion assembly. Some completion methods will require a more thorough cleansing process than others.

The procedures described below are generalized recommendations.

Displacement Objectives

The basic displacement objective is the same regardless of the completion type or procedure. For example, if a drilling fluid is being displaced to drill-in fluid, contamination of the drill-in fluid may occur and spacers must be incorporated to avoid intermingling. Likewise, when a drilling fluid or drill-in fluid is displaced to clear brine, the solids-free brine will become contaminated and similar safeguards are required.

A successful displacement should accomplish the following:

- Remove mud and unwanted debris from the open-hole, casing and riser (if applicable).
- Maintain the integrity of the mud and completion fluid interface.
- Minimize rig time.
- Minimize brine filtration and expense.
- Minimize waste and disposal costs.
- Minimize the need for stimulation and promote a clean, undamaged and productive wellbore.

Pre-Displacement Considerations

A. Cleaning the Wellbore
B. Indirect versus Direct Displacement
C. Forward versus Reverse Circulation
D. Clean-out String Bottom Hole Assembly
E. Conditioning the Mud System
F. Surface Pits and Equipment Cleanup
G. Design of Displacement Pills

Cleaning the Wellbore

It is always desirable to have a clean wellbore. Historically, some problems have been encountered, especially during the completion phase, due to insufficient displacement and well clean up.

- Junk and solids can both prevent future well intervention activity or interfere with the running of perforating guns
- Solids and junk both result in the inability to run the completion process, typically by early setting of packers
- Solids and gunk have both caused problems functioning CIV/FIV type valves requiring bailer runs or coiled tubing intervention
- Gunk offers a serious risk to formation damage if serious losses occur
- Debris on top of wire line plugs can prevent their recovery

The objective of the clean out operation is to remove all kinds of debris from the well. An absolute definition of debris is hard to give, but can generally be described under three categories*:*

Solids generated during the well construction process typified by:

- barite from settled mud
- cuttings from cement and formation because of poor hole cleaning
- steel shavings from milling operations
- scale and rust from poorly conditioned tubulars

Junk introduced to the well e.g.:

- solids from surface equipment due to poor surface clean-out
- foreign materials from BOP and seal stacks
- cement plugs and float equipment after drill out
- perforation debris
- dropped objects from drill floor

Gunk formed from the fluids used in the well:

- pipe dope
- synthetic mud at low temperature
- gelled oil based mud from mixing with water

The first step in the well clean up process is to clean the casing (and possibly the riser). To help evaluate the relative effectiveness of methods to clean a wellbore, a short description of the displacement objective is in order.

The following figures illustrate the likely condition of the wellbore after drilling. (The figure and the following description, is primarily for open hole, but the description will also be fully applicable for cased holes). Not only is this section of the hole filled with drilling mud (typically one that has been conditioned prior to pulling out of the hole with the drill bit), but there is also a bed of drill solids on the low side of a horizontal wellbore. In addition, there is a static filter cake (dehydrated fluid) on top of the dynamic cake. This static cake is made up of polymer residue and trapped drill solids. To remove this material, the drilling fluid must be displaced from the hole with clear brine or seawater and then, the filter cake must be scoured. Displacement of the drilling fluid is best accomplished through the use of a viscous “push pill” followed by clear fluid. The purpose of the viscous push pill is to remove as much mud as possible in a “piston-like” process. To achieve this, the pill should have a yield point 1 to 2 times higher than the mud being displaced. This is typically achievable with a 1.5-ppb xanthan gum system. To further ensure a piston-like displacement, the density should be ~0.1 to 0.2 ppg heavier than the drill-in fluid.

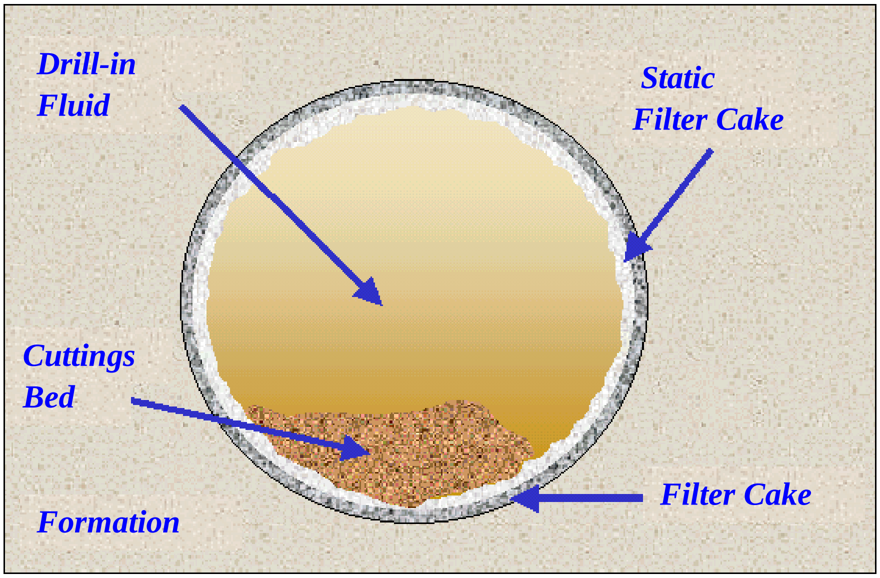


Figure 6 - 17 Condition of Horizontal Wellbore Prior to Displacement

Once the drill-in fluid has been displaced, the filter cake must be scoured. The figure below illustrates this process. Critical to the success of hole cleaning is to maximize the fluid velocity near the wellbore wall. For this reason it is important to fully maintain turbulent flow if possible. To assist in remaining turbulent, low viscosity fluids are desired for this process. While low viscosity fluids help to maximize velocity near the wall, it is commonly assumed that their use also makes it somewhat more difficult to remove solids from the wellbore. To carry solids completely out of the wellbore, elevated flow velocities are required.

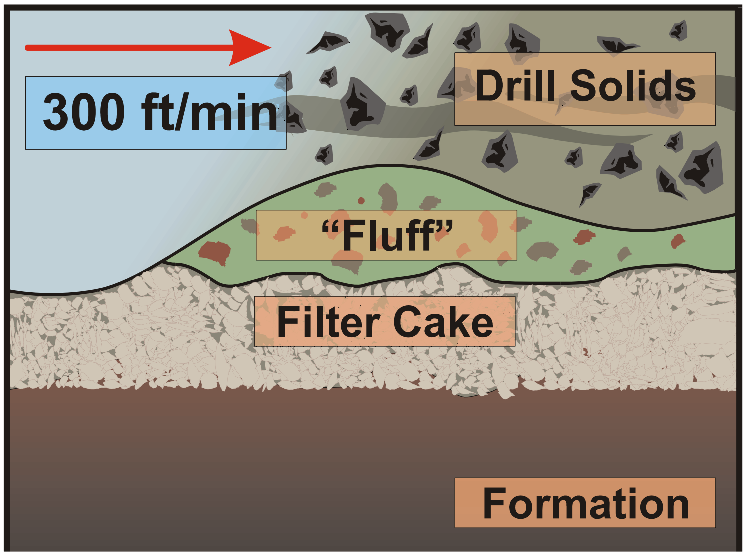


Figure 6 - 18 Scouring of the Filter Cake

Numerous laboratory studies have been conducted concerning the flow velocity required to completely remove drill solids from a high-angle wellbore. The general conclusions from all of these studies indicate that there is a critical velocity (CTFV-**C**ritical **T**ransport **F**luid **V**elocity) that must be exceeded to ensure a complete sweep of the wellbore. If the fluid velocity is below this value (SCFF – **S**ub-**C**ritical **F**luid **F**low), cuttings will start to accumulate in the wellbore. This accumulation continues until the flow velocity over the top of the cuttings bed exceeds the CTFV, at which time an equilibrium condition is created.

It has been determined that through these testing programs, the most difficult wellbore angle to clean is between 65° and 75°. However, the increase in required flow velocity only varies slightly over the complete range of well deviations for 55° to 90°. Since the transport mechanism changes from rolling to lift, studies indicate that the critical velocity is significantly lower at wellbore deviations from vertical to about 50°.

To summarize, it was observed in flow loop simulations that the removal of a cuttings bed with a viscosified fluid was in fact detrimental in high angle wellbores (assuming zero to low drill pipe rotation), and that low viscosity fluids are more beneficial.

Based on these studies and in-house work, Baker Hughes Drilling Fluids has settled on a value of 5 ft/sec (300 ft/min) as the recommended flow velocity to clean out the wellbore for particles. In addition, this displacement rate has been tested and proved effective in numerous field applications, especially before screen and gravel placement.

Indirect versus Direct Displacement

There are two general types of displacement used in the oil industry today. One is an indirect displacement and the other is a direct displacement. Each type has its advantages and disadvantages. Utilize BHDF's **DISPLEX** Simulation Model to determine the pill volumes required for spacer contact times and flow rates.

Indirect Displacement

An indirect displacement is usually associated with a displacement of the mud system to seawater (or drill water) in a drilling liner or production casing before displacing to the next fluid system.

For example, if oil-based drilling mud is in use, the operator may wish to displace and clean the drill string and casing with seawater before displacing to brine. The seawater would be preceded by a series of spacers and solvents to clean and water-wet the casing. With this method, a thorough cleansing can occur with minimal product usage due to the circulation of inexpensive water. Later, the displacement to the clean brine will occur without contamination.

For indirect displacements, a good cement bond log is necessary because high differential pressures on the casing could cause a breakdown of cement or collapse of the casing.

Indirect displacements may also be recommended for the production casing. In this instance, the drill-in fluid would be displaced to drill-water before finally being displaced to clear brine. Caution must also be exercised in this displacement because a possible reduction in hydrostatic pressure across the production interval could lead to casing collapse.

Improved direct displacement techniques (specialized spacers) and increased daily rig costs have reduced the use of indirect displacements.

The indirect displacement involves the use of forward or reverse circulation. The complete displacement process includes two phases; (1) displacement of the drilling fluid in the wellbore to seawater or drill water and (2) displacing the seawater to the next drilling fluid or brine.

Deviated wellbores represent unique hole cleaning challenges. As wellbore inclination increases, axial particle slip shifts to radial particle slip, causing the cuttings to fall to the low side of the borehole, thus increasing the transport difficulty.

As hole angles approach horizontal inclinations, displacements in deviated wells utilize increasingly greater spacer volumes and high annular velocities to move mud debris out of the wellbore. Some operators are more willing to displace the casing to seawater or drill water (an indirect displacement) because the larger water volumes are inexpensive and longer pump times are possible. The second phase, displacement to the drilling fluid or brine, is intended to clean and water-wet the casing and requires less pump time.

Water-Base System (WBM) to Brine

General Procedure

Pre-Displacement

Run the workstring to bottom and condition the mud.

Displace the WBM to Water

Pump a viscous push pill containing Xanthan Gum spaced between the mud and seawater. The spacer viscosity should be ~150-300 sec/qt and formulated by adding 3 lb Xanthan Gum per bbl seawater. The volume of the viscous push pill should cover approximately 1000 feet of annulus.

Follow the pill with seawater and circulate and filter to the operator-specified limit.

Displace Seawater to Brine

Pump viscosified seawater containing **CASING WASH^{TM} 100**. Circulate at least one hole volume.

Follow with a viscous Seawater/ Xanthan Gum spacer between brine and seawater. The viscous spacer should cover 500 to 2000 feet of widest annular diameter.

Follow with filtered brine until operator’s turbidity requirements are achieved.

Oil-Base/Synthetic-Base System to Brine

General Procedure

Invert emulsion systems having highly aromatic oils will contain hydrocarbons in the slop water. Proper containment will be necessary to avoid unlawful discharge of these fluids. Additionally, all spacers should be disposed of as per regulations, or the operator’s specific requirements. See attached additional information on proposed treatment of oil-contaminated water and brine.

Pre-Displacement

Run the workstring to bottom and condition the mud.

Displace the OBM/SBM out of the casing with seawater/drill water

Pump a 50 bbl spacer of base oil or synthetic fluid before the seawater. This spacer is optional but can be recovered in the OBM/SBM.

Push Pill

Follow the base oil spacer with a Spacer/Push Pill. Viscosify and weight up a seawater spacer to 0.2 ppg heavier than the mud. The spacer viscosity should be 1 to 2 times the mud viscosity. The volume should cover at least 1000 feet of largest annular diameter. The density, viscosity and surfactant (**FLOW-CLEAN^{TM}**) in the spacer will help push oily debris out of the wellbore and initiate the water-wetting process.

Seawater Flush

Follow the spacer with seawater for two wellbore volumes.

Water-Wetting Spacer

FLOW-SURF^{TM} or **FLOW-SURF^{TM} PLUS** will chemically detach, dissolve and remove the mud residue from all casing surfaces, out of the wellbore and finalize the water-wetting process. Typical concentration of solvent is 5-10%.

Volume is determined and optimized based on surface area of tubulars, saturation volume, Reynolds number, annular velocity, contact time and pump rate. Normally spacer volume is 1000 to 2000 ft of the largest annular volume. Contact time required is normally 2.5 to 10 minutes.

Viscous Spacer

Viscous Xanthan Gum / Seawater spacer between **FLOW-SURF^{TM}** spacer and filtered brine.

Volume = ± 1000 feet of largest annular diameter.

Clean Brine

Follow the viscous spacer with clean brine and filter to operator’s turbidity requirements.

Direct Displacement

A direct displacement may be defined as one that uses a series of relatively small spacers between the original drilling fluid and the next fluid system, i.e. drill-in fluid or clear brine. This method is often favored because the rig time (cost) is reduced. Improved procedures and solvents have advanced significantly, reducing the number of spacers required to clean the open-hole and casing effectively.

A direct displacement differs from an indirect displacement, primarily by omitting the displacement to seawater step. The direct displacement utilizes very effective solvent and surfactant spacers to clean and water-wet the casing so that you can “directly” displace the wellbore to the final displacement fluid in a single operation.

Water-Base System to Brine

Pre-Displacement

Once the well has reached TD, circulate a minimum of one bottoms-up and short trip into the casing. Go back to bottom and circulate a minimum of one bottoms-up. If well conditions are stable, clean the mud pits and surface equipment by flushing sufficiently with seawater/drillwater to remove all residue of drilling mud.

Weighted Lead Spacer

This spacer is designed to push the mud out of the wellbore. The spacer density should be slightly heavier (0.2 ppg) than the mud being displaced. YP = 1.5 times the YP of the mud. Spacer volume is based on the wellbore geometry and sufficient to cover 500 to 1000 feet of the largest annular diameter.

Circulating Rate

Pump at the maximum safe rate with the minimum rate determined by the wellbore configuration. Pump by conventional (forward) circulation. Rotate and reciprocate the pipe while pumping but do not reciprocate pipe while spacers or interface is near the end of the workstring. **Do not shut down during displacement**.

Casing Cleanup Spacer

CASING-WASH™ 100 is used to chemically remove the mud and other materials from the metal surfaces and carry them out of the wellbore. The volume is calculated at 0.5% to 1% of the casing volume and is mixed in water or brine at 5-8% by volume. The highest concentration is recommended when the fluid being displaced contains oil or other hydrocarbon additives.

Viscosified Spacer

This high yield point spacer will carry any remaining solids out to the casing or open hole and prevent contamination of the completion fluid. The spacer volume is based on wellbore configuration – usually filling 500 to 1000 feet of the largest annular volume.

Filtered Brine

Filtered completion brine should be circulated one full circulation or until cleanliness specifications are met. Dispose of the spacers as per established procedures.

Oil Based System to Brine

Optional Lead Spacer

50 bbl of mineral or diesel oil can provide a good cleansing action on the casing and remove a significant amount of debris. This is a cost effective procedure but is optional depending on capabilities at the rig-site to recover and store the contaminated oil for future use.

Push Pill

Follow the base oil spacer with Spacer/Push Pill. Viscosify and weight up a seawater spacer to 0.2 ppg heavier than the mud. The yield point should be a higher (1.5 times greater) to promote a good displacement without the commingling of the base oil or mud with the spacer. The volume should cover at least 1000 feet of largest annular diameter. The density, viscosity and surfactant in the spacer will help push oily debris out of the wellbore and initiate the water-wetting process. This pill should contain **FLOW-CLEAN™.**

Water-Wetting Spacer

FLOW-SURF™ or **FLOW-SURF™ PLUS** will chemically detach, dissolve and remove the mud residue from all casing surfaces, flush out of the wellbore and finalize the water-wetting process. Typical concentration of solvent is 5-10%.

Volume is determined and optimized based on surface area of tubulars, saturation volume, Reynolds number, annular velocity, contact time and pump rate. Normally spacer volume is ±1000 ft of the largest annular volume. Contact time required is normally 2.5 to 10 minutes.

Viscous Spacer

Viscous Xanthan Gum / Seawater spacer between A-312N spacer and filtered brine.

Volume = ±1000 feet of largest annular diameter.

Clean Brine

Circulate the filtered completion brine for one circulation or until cleanliness specifications are met. Dispose of all spacers as per regulations.

General Displacement Considerations

The displacement of mud from an annulus is a complex physical phenomenon. The main driving forces, which can be used to enhance the displacement, are:

- fluid viscosity and density
- pump rate and frictional forces
- circulation of fluid

High pump rates will nearly always be better (even in laminar flow); they reduce the boundary layer thickness on the casing wall. Turbulence is best to ensure 100% access of the clean up pills. It is recommended to use circulating sub to allow higher flow rates.

In deviated wells the eccentricity of the displacement string reduces displacement efficiency and rotation and/or reciprocation is crucial for effective displacement. As steel surface is getting water wet, the effectiveness of pipe rotation may be diminished. If Advantage Torque and Drag simulation indicates high torque, it should be programmed to use friction reducer additive in the displacement fluid.

Displacement must not stop once pills are in the annulus. Even very short stoppages will allow fluids to mix and increase the interface. Interfaces between fluids also increase with hole angle.

Circulate to warm mud and use fine shakers when possible. At low temperature (<40°C/104°F) oil based mud can get very viscous with synthetic based muds becoming the most viscous. Circulating the mud to warm it reduces this problem.

Forward versus Reverse Circulation

Advantages and Disadvantages

With reverse circulation the elevated flow velocity up the smaller ID workstring enhances debris removal, and the lower workstring volume as compared to the annular volume, allows for a shorter bottoms-up time, which in turn allows for closer monitoring of the bottom hole conditions.

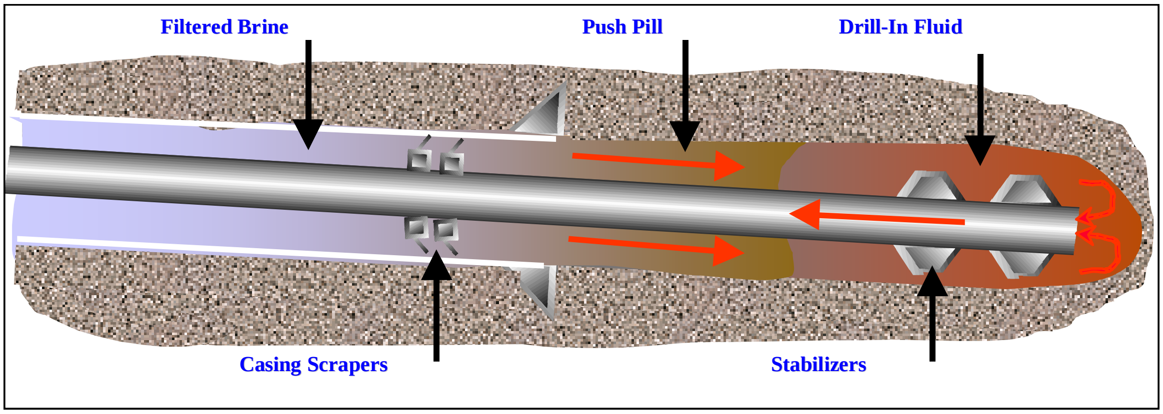


Figure 6 - 19 Reverse Circulation

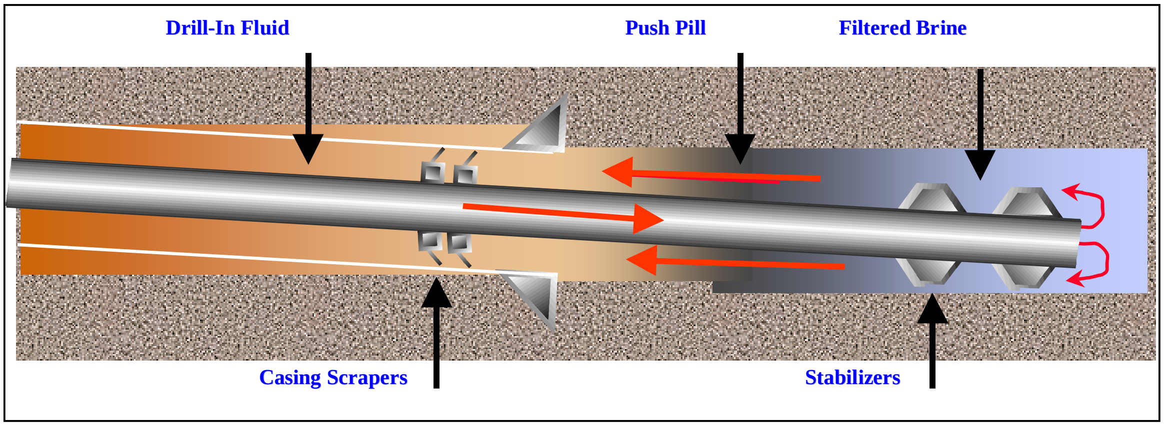


Figure 6 - 20 Forward Circulation

However, there is a serious drawback to the reverse circulating technique. *First*, the drawback is that the friction pressure from pumping the entire length of the workstring at a high rate is imposed at the bottom of the wellbore, rather than at the surface. *Secon*, it also eliminates the possibility of rotating the workstring during displacement due to the closed BOP.

Clean-out String Bottom Hole Assembly

The following equipment can be used to clean and remove debris from the inside of casing:

Casing scrapers should be used on the workstring in accordance with the casing schematic for each casing. Each casing section should have a scraper/brush placed not more than 100 feet above each casing shoe. These devices will help remove any solids that may adhere to the casing walls so the displacement fluid can move them out of the hole. A casing scraper should create maximum contact with internal diameter of casing, and be of a one-piece design with full drill pipe strength with no weak internal connections. Casing scrapers should enable rotation at rates up to 50 rpm, but conventional scrapers are not built for extended rotation or drilling, i.e. extensive rotation at the same spot should be avoided. Rotation and reciprocation of the drill pipe is recommended during displacement and clean up. Casing brushes are not considered necessary if an effective scraper is selected. If a brush is used it should be redressed after each application. Non-rotating scrapers are also available.

Circulating subs should be used to enable high circulating rates. There are two major different types of circulating subs: ball drop type and weight-set sub.

The ball drop type is the most common used. The circulation ports are opened by dropping a chrome-steel ball down the drill string, and then starting the mud pumps. With 1000 – 2000 psi fluid pressure, the ball shears the pin holding the sleeve, the ball and sleeve then drop, opening the ports and diverting the downhole flow. (See figure below)

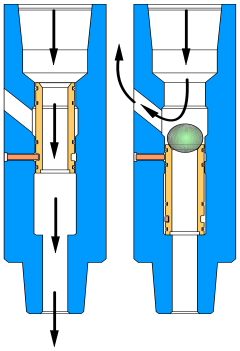


Figure 6 - 21 Ball drop circulating sub

Once the flow has been diverted, it can not be re-diverted and the ability to circulate to the bottom of the well is lost. This type of circ. sub allows rotation and reciprocation of the clean out string while circulating. Circulating subs should be installed above mud-motor and at every casing size increase, where Advantage Hydraulic simulations indicate that it will be necessary to achieve high enough circulating rate. A multifunction ball opening circulating sub is available in the market, but the failure rate has been high in some regions.

The weight-set circulating tool relies on maintaining weight set down on the tool to maintain the circulation path, all circulation is at one point. These tools should be run with the clutch option allowing drill pipe to be rotated independently of the pipe inside the liner. This tool can be actuated as many times as required.

Junk catcher should be used if there is any concern about debris or junk in the well. Baker Oiltools has a Junk catcher called 'The Wellbore Custodian'. This is designed to seek out junk, collect it and the carry it to surface. The fluid passing through is being filtered through stainless steel screen. When RIH the tool will act as a boot basket allowing collection of large debris using fluid flow as it passes through the tool. When pulling out of hole, the bypass is closed and the tool now diverts fluid through the filter media capturing the debris.

Magnets should be used to remove ferrous steel debris and swarf (metal filings, shavings, etc.). The downhole magnet is used to assist with cutting and milling debris removal where either low annular velocity, or with well fluids that have poor carrying capacity, is used. Typical locations of the magnets are just above the scrapers.

Conditioning the Mud System

A well-conditioned fluid will be easier to displace from a wellbore. The mud should be circulated and conditioned at normal flow line temperatures while reducing its viscosity and gels, but not to the point where it can no longer suspend weight material. When adjusting the rheology, the flow characteristics of the mud improve, making it easy to circulate and evenly disperse the solids prior to removal.

Surface Pits and Equipment Clean-up

Attention should be made to ensure the well and / or circulating system is not re-contaminated after the clean up. It is important that all areas coming into contact with the well are cleaned prior to the well clean up.

Pit management and cleaning is a critical element for providing clean brine all through the well. With increasing restriction on pit access and pressure on time, management of pits and cleaning needs to be carefully considered by the rig team. Draft plan including pumping schedules and pit requirements must be discussed with all relevant personnel.

Right pit washing tools will reduce the requirement for pit entry and reduce waste generated. The effectiveness of these systems relies on use of an effective detergent at ambient surface temperatures. All areas that require cleaning shall be cleaned by circulating a detergent pill for a minimum of 20 minutes, and then flushed with sea / drill water.

Pit cleaning not only carries HSE risks associated with pit entry and waste volumes generated, poor cleaning of pits and surface lines can seriously affect clean up efficiency. Effective isolation between pits is very important to avoid contamination.

The suggested checklist is a guideline for checking out equipment / areas that should be cleaned. The list has to be adjusted to the actual and relevant equipment on rig.

AREA / EQUIPMENT	**CLEANED PRIOR TO PUMPING**	**CLEANED DURING PUMPING**
Pits – (All where Completion fluid will be stored)		
Sand traps		
Degasser		
Mud Cleaner		
Mud Ditches		
Pumps		
Header Box		
Shakers		
Gumbo		
Poor Boy		
Trip Tank		
Trip Tank Fill Line		
Trip Tank Overflow Line		
Standpipe Manifold		
Top Drive		
Chicksans		

Choke Manifold		
Buffer Tank		
Choke & Kill Manifold		
Mud Pump Charging Pumps		
Mixing Pumps		
Rig Pumps		
Choke Lines		
Upper Kill Line		
Lower Kill Line		
Reverse Circulating Line		
Overboard Lines		
Pit Gun Lines (All)		
Transfer Lines:		
To & From All Pits		
To & From Filter Unit		
Diverter		
Equalizing Lines		
Lines to Drill floor		
Hole Fill Pump		
Pop Off Lines		
Bleed Off Lines		
Kill Pump		
Solids Handling Equipment		
Hose to Boat		
Relief Overboard (Cmt.)		
Mud Cleaner Pump		
H.P. Suction Manifold		
Transfer line to cmt. unit		
Strainers		

Surface Cleaning Procedure

a) Pump the surface volume of mud into containers suitable for transfer to final destination. Remove any solids build-up in pits, corners and discharge areas by mechanical means. A vacuum system will greatly enhance the solids cleanup of the surface equipment. Also, with a high temperature/high-pressure washer, external areas can be cleaned thoroughly. Mix 1-2 drums of detergent into 100-150 bbls of water and flush all hoses, lines and pumps thoroughly, taking returns back to the same pit. Pump this at the maximum safe rate.

b) Using the same fluid as in Step a) above and with the pipe rams closed, pump through all choke/kill lines, manifold and rig floor standpipe equipment to thoroughly remove all OBM or SBM residue. Pump at the maximum safe rate. Dispose of as per operator procedures.

Design of Displacement Pills

To ensure effective mud displacement and water wetting of the casing, the displacement pills need to be designed carefully, especially when oil based muds are in use. Major functions for these pills are:

- disperse and thin the drilling fluid
- compatible with the drilling fluids

- lift out debris and junk
- water wet pipe surface
- remove pipe dope
- effectively displace mud

The best fluid for thinning the mud is the continuous phase of the mud. 50-75 bbl of the base oil can be pumped in the case of oil based muds. For water based mud pumping 50 bbl of water as the first displacement pill will effectively thin the mud. Before any displacement the compatibly of the spacers with the mud and the ability to water wet steel surfaces should be checked at room temperature and 85° C (185° F) to confirm compatibility (in deep water lower temperature tests may be necessary). All tests should be done on field mud samples to ensure mud is representative. In high mud weight the risk of inducing barite sag needs to be considered, because displacement pills can thin the mud to the point it can no longer support barite.

Water pumped without surfactants to displace oil muds (e.g. for an inflow test) prior to clean up, can form gunk, which are not broken down by subsequent clean up pills. Aggressive solvents are required to remove gunk and pipe dope.

XAN-PLEX^{TM} D and Xanthan Gum are the preferred materials for mixing viscous pills. When mixed in calcium brines, these require special procedures by lowering pH before adding the polymer, and then raise pH to get the fluid viscous. HEC-viscosified fluids do not have good solids support. Polymers should be checked for suitability at the anticipated bottom hole temperature.

Lead Spacer (Push Pill) Systems

The function of a lead spacer is to move the drilling fluid from the wellbore without contacting other incompatible fluids. Moving a system from a wellbore is best accomplished by utilizing a high pump rate, pipe rotation and a viscous (weighted) spacer. The high viscosity helps maintain the integrity of the spacer by enabling it to stay in “plug” or laminar flow at high pump rates. The spacer must be large enough to allow for 5 to 10 minutes contact time based on the pump rate. Pipe rotation helps break up the gelled pockets of mud that may accumulate in some sections of the annulus, especially in highly deviated wellbores. If required, the density of the lead spacer should be adjusted for well control reasons and should be at least or slightly more dense than the fluid being displaced. Although the lead spacer may be in plug flow, the middle spacer systems are moving in turbulent flow and will remove any residual debris. It is recommended that each spacer cover at least 1000 feet of the annulus at its largest diameter.

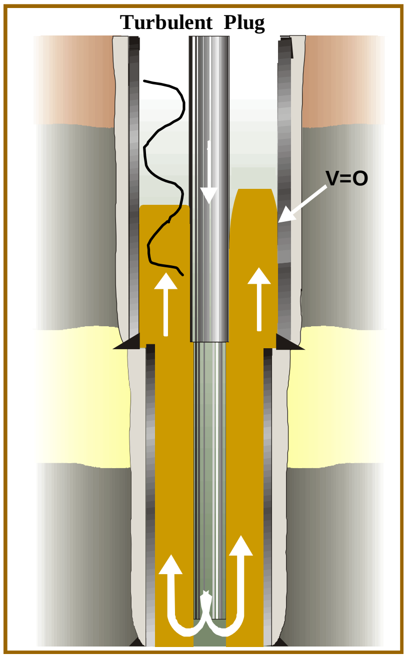


Figure 6 - 22 Plug and Turbulent Flow Regimes

Contact Time

Spacer contact time in the wellbore is determined by the volume and type of spacer, the annular flow rate, the fluid and density being displaced and the wellbore configuration. Contact time is critical in the cleanup process because removal of debris occurs gradually as a spacer flushes past the wellbore surface. In most applications, the contact time may vary somewhere between 2.5 to 10 minutes. The concentration of the solvent in the spacer also plays a significant role in cleanup, especially in the removal of oil-base and synthetic-base residue. In these and other applications, the volume of the spacer and the displacement rate determine the contact time. Usually the displacement rate is based on the annular flow rate needed to achieve turbulent flow, however, hole or rig conditions may limit the pump output. Once the volume is calculated for optimum contact time at the agreed-upon displacement rate, the appropriate solvent concentrations can be optimized. For the removal of oil/synthetic debris, concentration requirements are calculated based on the surface area of the wellbore (casing or open-hole). Programs are available to calculate precise contact time requirements for specific applications.

HSE needs to be considered for all chemicals used. Mixtures of displacement pills and mud have to be separated from the active mud and packer fluid for disposal (zero discharge issues).

Well Cleanliness Determination

The determination of how clean the well is usually based on the cleanliness of fluids returning from the wellbore. The most common measures are normal turbidity units (NTU) and solids content, neither actually relate to what is left in the well. Junk baskets or equivalent equipment do give some positive indication of solids removal. Other indicators of a clean well are torque and drag (related to the increasing friction coefficient because of the fluid coating the casing walls being washed away) and cleanliness of the clean up string when pulled to surface. Rust in return from the pumped seawater or brine (if oxygen scavenger is not used) is also an indicator of a clean well.

Turbidimeter (nephelometer)

The measurement of brine clarity (solids content) is not a direct measurement of the concentration of suspended particles but a measurement of the scattering effect that such particles have on light. On-site measurement of brine turbidity with a portable nephelometer is quick and easy. Field testing has shown that this turbidity method is a useful way to evaluate brine quality and is most often used to decide when to stop displacement to brine after clean up.

The procedure only places a relative value on the presence or absence of solids in a particular sample. The unit of measurement for turbidity is called a nephelometer turbidity unit (NTU). The absolute NTU value of brine is specific to each fluid and can be only used for comparison values to the same fluid. The absolute NTU reading is dependent on fluid color, solids distribution, air entrapment, etc. Each operator or completion procedure will have specific requirements for NTU reduction. Typical requirements are 50 – 100 NTU.

The field use of a turbidimeter is recommended as a guide only. For example, during filtration, when the NTU values are no longer falling, no further gains in fluid quality will be made without making some change to the filtration process.

Solids Content

Measurements of solids content can be taken using a portable electrical centrifuge. For most operations, a solids content of < 0.05% is acceptable. For gravel packing this should be reduced to 0.02%

NTU and solids content are not directly related. Solids content will only assess materials collected at the bottom of the test tube during centrifuging.

These tests use sample sizes of a few mls and it is difficult to draw conclusions about a well with an annular volume of 500 bbl. 0.1% vol/vol solids is equal to more than one ft^3 of solids deposited for tubing contents of 200 bbl.

When clear fluids are pumped without adding oxygen scavenger, rusty coloured fluid will, after some circulation, return to surface. Corrosion products in return fluids give high NTU values. To deal with the problem of rust (as a result of oxidation of water wet steel surfaces) impacting turbidity readings, a little acid (HCl) should be added after the initial reading. When the well is displaced to packer fluid, it should always be inhibited with oxygen scavenger.

Where the string is rotated during clean up the increase in torque can be used as an indicator of clean well. The coefficient of friction in sea water/brine is more than twice that of OBM. Typical friction factors for OBM is 0.12-0,15 and 0.20-0.29 for seawater/brine.

For critical wells, e.g. high angle wells/where milling has occurred/previous problems with debris etc, it is recommended to use ‘Wellbore Custodian’ or similar junk basket. If the junk basket is pulled full it should be re-run.

Visual inspection of the clean up string after pulling out of the hole will give a good indication of the cleanliness of the well. If it is mud free and water wet, the mud displacement and clean out has been successful. If the string is mud coated, a junk basket should be run.

End of Well Reporting and Performance Measures

Effective reporting of well clean up is crucial for developing best practice and looking for opportunities to improve or reduce cost.

Key elements for reporting are:

- Daily events to include all time associated with clean up
- Record of measurements (e.g. NTU/solids content)
- Tracking of performance (e.g. time to reach NTU target/interface volumes)
- Lessons learned
- Target time vs. actual
- Tracking of brine, i.e. volumes received, built, lost, sent for reclamation

A report should capture the following areas:

- Fluid designs and properties
- Flow rates
- Pill volumes
- Volumes circulated
- Interface volumes
- Equipment used
- Materials used and costs
- Pipe movement during displacement
- Time breakdown
- Fluids cleanliness vs. time during circulation
- Surface clean up
- Target vs. actual for cost and time
- Pipe movement and torque measurements

Identification of performance parameters to be measured should include:

HSE Related:

- Days Away from Work Injuries
- Recordable Injuries and Illnesses
- All Accidental, uncontained spills or discharges
- Total Manhours on site for this service and operation

Cost Related:

- Total Completion Fluids Cost
- Planned Cost
- Filtering Related Cost
- Total Cased Hole Volume
- Total Spacer Fluids Pumped and Cost
- Total Completion Fluid Volume and Cost
- Completion Fluid Type
- Completion Fluid Density
- Completion Fluid Turbidity Requirement (NTU's)
- Completion Fluid Solids Requirements (Vol%)

Efficiency Related:

- Total Non-Productive Rig Time (NPT) Hours Related to this Service
- Total Non-Productive Rig Cost (NPC)
- Total NPT Incidents related to this service, (Number of Occurrences (> 0.5 hrs)

Quality Related:

- People Related Failure, Number of Occurrences
- Mechanical (Equipment) Failure, Number of Occurrences
- Design Limit Related Failure, Number of Occurrences
- Objectives Defined, Number
- Objectives Met, Number

Examples of performance to be measured:

- Brine returns NTU to be as low as possible above value of fluid in pits
- Clean returns after circulating as few hole volumes as possible
- Minimize interface volumes between pills

DISPLEX™ Displacement Software

Displacements of drilling or drill-in fluids to clear brine are critical for most completion operations. Without a well-planned displacement to the completion fluid, completion tool setting failures or wellbore damage may compromise a project's objectives. A wellbore clean up of casing and open-hole section requires careful planning from a chemical, rheological and mechanical perspective. In addition, the calculations required to accurately model an efficient displacement are multifarious because of varying trajectories, tubular configurations, circulating sub requirements, wellbore intervals, fluid properties and requisite pump rates.

Furthermore, in cases where geometry differences require varying pump rates due to multiple spacer systems, a single accurate planning tool helps the operator implement a safer displacement process. Using more accurate rheological models, such as the Herschel Bulkley model for drilling fluids, helps predict the pressure losses more accurately. Not withstanding these complexities, the displacement parameters must be modeled so that every operation, including cased and open-hole intervals, utilize the proper chemistry and mechanical energy to safely clean and remove unwanted wellbore debris.

Baker Hughes Drilling Fluids utilizes proprietary displacement software (DISPLEX™) for planning and executing displacement operations. Each displacement fluid (mud, spacer and brine) can be individually customized based on the rheological behavior. Available models to choose from are the Bingham Plastic, Power Law and Hershel Bulkley models. The individual characterization of each spacer allows for proper pressure management during the displacement process. Complex rheological models, such as Hershel Bulkley, more accurately describe the rheological behavior of thixotropic fluids such as the drilling fluid and viscous push pills while the others, such as the Bingham model, accurately model the Newtonian fluids.

A list of capabilities and benefits of this modeling software are given below:

- A detailed pressure analysis table enables the user to adjust the pumping schedule to achieve maximum displacement rates without exceeding the formation fracture pressure.
- Flow-in and flow-out information is continuously available.
- ECD and pressure profiles with respect to time and depth are generated in tabular or in simulation mode.

- Pressure, ECD and flow profile information relative to time and volume is recorded.
- Forward and reverse circulation scenarios are available, including back pressure options.
- Up to nine (9) fluids in the annulus and drill string may be included.
- Five (5) different pump rates per spacer system are allowed, including separate fluids in the choke, kill and booster lines.
- Each fluid can have different flow properties and use a different rheological model.
- The model will show and account for free fall and allows for back pressure if needed to either control the free-fall or provide automatic calculation for maintaining the pressure for well control.
- A “circulation sub” in the work string may be modeled for pressure and flow control.
- Minimum required pump rates calculated to move fluids in a turbulent flow regime.
- Color coding of the data allows for easy identification of problems.
- A full 2D, dynamic flow pattern simulator allows the user to visualize the simulation process.
- Last-minute changes in the displacement program are easily entered at the rig locations to account for any operational modifications or, in the case of pump failure, the pump schedule can be easily re-calculated and adjusted for new parameters.
- Open-hole displacement modeling allows different clean-up spacers for both the open-hole and casing.
- Multiple fluid densities may be input to provide a safe overbalance. Animation features visually verified for fluid top during the entire process.
- Models deepwater operations and provides flexibility for pumping multiple spacer systems at different rates to clean the casing and the riser. Choke, kill and boost lines can be used for either pumping down or taking returns as the process dictates.
- A volume calculator provides all the pertinent information about the wellbore. This reduces the planning time and possibility of error regarding contact time and spacer volumes.

Baker Hughes Drilling Fluids has developed a suite of spacer/displacement products as described below.

Pickling of Tubulars

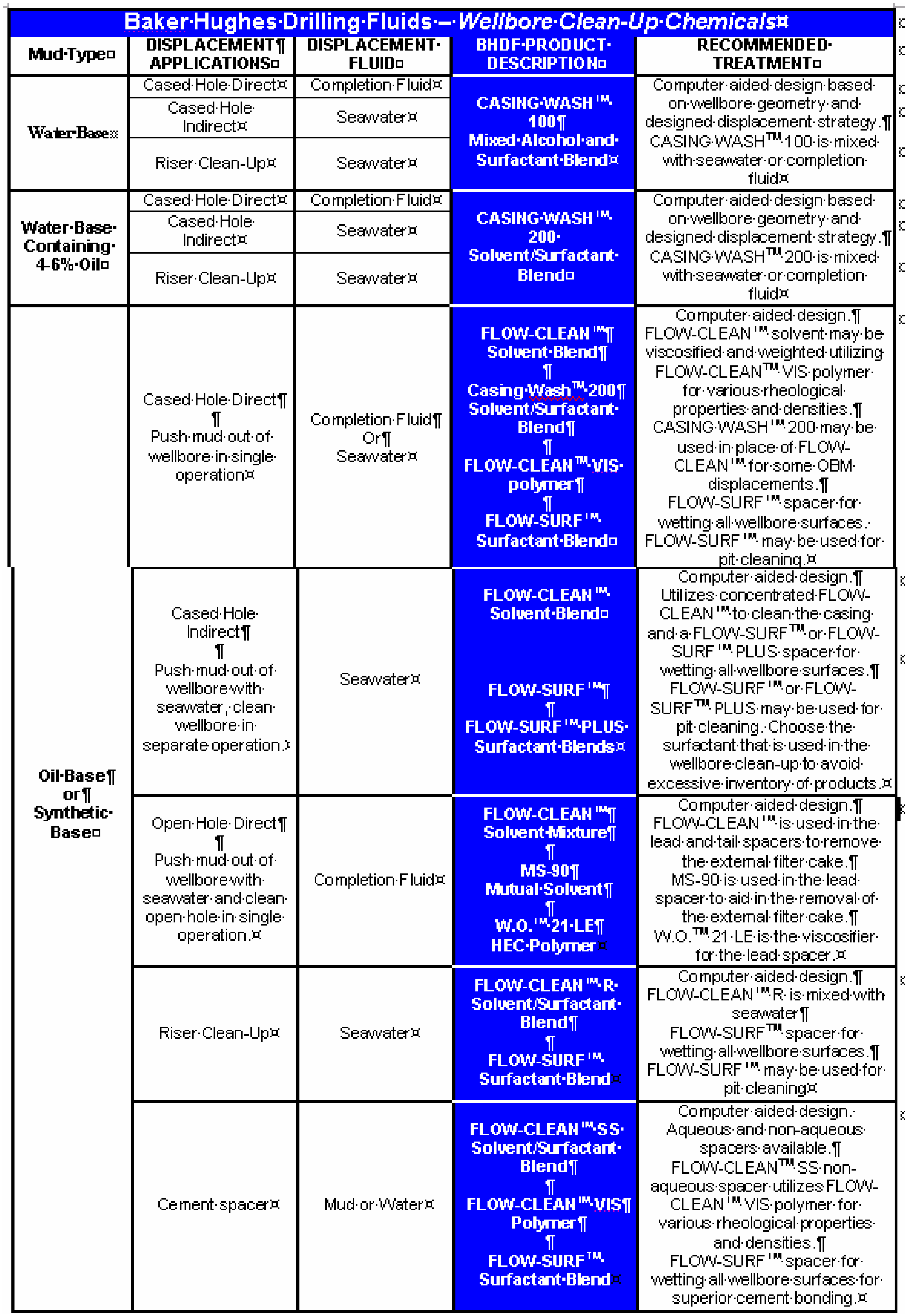
Baker Hughes Drilling Fluids has developed **DOPE-FREE™** and **DOPE-FREE™ Zn**. These are highly effective pipe pickling solvents with proven success in dissolving a wide range of pipe dopes from downhole tubulars. They may be used to completely remove oil, grease and residue from the casing, work string, tubulars, pits and lines.

DOPE-FREE™ in combination with the pipe pickling acid works to eliminate stubborn pipe scale, rust, cement, mud contamination and other foreign debris that can cause major well bore damage and even costly failures during well completion operations.

DOPE-FREE™ is primarily used to pickle the workstring or tubing during the preparation for a completion operation.

Recommended Treatment

Each fluid should be pumped separately to the end of the workstring at the desired pump rate, and reversed out. A minimum of three (3) tubing volumes of brine should be reverse circulated after the acid treatment. A typical sequence and volume of the treating fluids are: 1) 210 gal of DOPE-FREE. 2) 420 gal of 15% HCl containing: • 1 gal of corrosion inhibitor • 2 gal of silt suspending agent • 20 lb of Iron sequestering agent. Capture the pickling acid solution at surface and dispose of according to local, state and federal regulations.



Baker Hughes Drilling Fluids — *Wellbore Clean-Up Chemicals*

Mud Type	DISPLACEMENT APPLICATIONS	DISPLACEMENT FLUID	BHDF PRODUCT DESCRIPTION	RECOMMENDED TREATMENT
Water Base	Cased Hole Direct	Completion Fluid	CASING WASH™ 100 Mixed Alcohol and Surfactant Blend	Computer aided design based on wellbore geometry and designed displacement strategy. CASING WASH™ 100 is mixed with seawater or completion fluid
	Cased Hole Indirect	Seawater		
	Riser Clean-Up	Seawater		
Water Base Containing 4-6% Oil	Cased Hole Direct	Completion Fluid	CASING WASH™ 200 Solvent/Surfactant Blend	Computer aided design based on wellbore geometry and designed displacement strategy. CASING WASH™ 200 is mixed with seawater or completion fluid
	Cased Hole Indirect	Seawater		
	Riser Clean-Up	Seawater		
	Cased Hole Direct Push mud out of wellbore in single operation	Completion Fluid Or Seawater	FLOW-CLEAN™ Solvent Blend Casing Wash™ 200 Solvent/Surfactant Blend FLOW-CLEAN™ VIS polymer FLOW-SURF™ Surfactant Blend	Computer aided design. FLOW-CLEAN™ solvent may be viscosified and weighted utilizing FLOW-CLEAN™ VIS polymer for various rheological properties and densities. CASING WASH™ 200 may be used in place of FLOW-CLEAN™ for some OBM displacements. FLOW-SURF™ spacer for wetting all wellbore surfaces. FLOW-SURF™ may be used for pit cleaning.
Oil Base or Synthetic Base	Cased Hole Indirect Push mud out of wellbore with seawater, clean wellbore in separate operation.	Seawater	FLOW-CLEAN™ Solvent Blend FLOW-SURF™ FLOW-SURF™ PLUS Surfactant Blends	Computer aided design. Utilizes concentrated FLOW-CLEAN™ to clean the casing and a FLOW-SURF™ or FLOW-SURF™ PLUS spacer for wetting all wellbore surfaces. FLOW-SURF™ or FLOW-SURF™ PLUS may be used for pit cleaning. Choose the surfactant that is used in the wellbore clean-up to avoid excessive inventory of products.
	Open Hole Direct Push mud out of wellbore with seawater and clean open hole in single operation.	Completion Fluid	FLOW-CLEAN™ Solvent Mixture MS-90 Mutual Solvent W.O.™ 21 LE HEC Polymer	Computer aided design. FLOW-CLEAN™ is used in the lead and tail spacers to remove the external filter cake. MS-90 is used in the lead spacer to aid in the removal of the external filter cake. W.O.™ 21 LE is the viscosifier for the lead spacer.
	Riser Clean-Up	Seawater	FLOW-CLEAN™ R Solvent/Surfactant Blend FLOW-SURF™ Surfactant Blend	Computer aided design. FLOW-CLEAN™ R is mixed with seawater FLOW-SURF™ spacer for wetting all wellbore surfaces. FLOW-SURF™ may be used for pit cleaning
	Cement spacer	Mud or Water	FLOW-CLEAN™ SS Solvent/Surfactant Blend FLOW-CLEAN™ VIS Polymer FLOW-SURF™ Surfactant Blend	Computer aided design. Aqueous and non-aqueous spacers available. FLOW-CLEAN™ SS non-aqueous spacer utilizes FLOW-CLEAN™ VIS polymer for various rheological properties and densities. FLOW-SURF™ spacer for wetting all wellbore surfaces for superior cement bonding.

PACKER FLUIDS

Packer fluids are fluids, either clay-laden or without solids, which are left in the annular space between the tubing and casing.

Packer fluids for the most part have been drilling fluids conditioned to be left in the hole on completion of the well. Under normal situations of low temperatures and normal pressures, this approach has usually been satisfactory. Not until the advent of lime fluid in the late 1940s and early 1950s did packer fluids attain industry attention. Lime fluids, when exposed for prolonged periods of time to high temperature, may set to a non-pumpable solid state from the chemical reaction of clays, silica, lime, and caustic soda, which forms the cement-like substance tobermorite. This condition becomes severe at about 250°F. Such fluids prevent unseating of the tubing from the packer and pulling of the tubing during workover operations. Literally, these “set” fluids have to be drilled out.

The problem of lime fluids focused considerable attention on packer fluid requirements. Since then, a number of approaches to the design of packer fluids have evolved.

Requirements of a Good Packer Fluid

The primary purpose of packer fluids is to provide sufficient hydrostatic pressure to protect the casing from excess formation pressures. Hydrostatic pressure is obtained by using soluble salts such as $NaCl$, $CaCl_2$, $CaBr_2$, $ZnBr_2$, and insoluble materials such as barite and calcium carbonate.

A packer fluid should be *thermally stable* at bottomhole temperatures. It should have sufficient gel properties for adequate suspension of barite in weighted systems, but be easily sheared down during pumping or pulling operations.

The packer fluid should be *non-corrosive*. It should not form scales or produce gaseous by-products such as H_2S or CO_2. It should not react with metal to produce inter-granular crystallization or changes in the metallurgical structure of the steel.

A packer fluid should be *free of solids settling* on the packer. Gel properties in solids systems must be controlled to prevent sedimentation. Salt solutions must not form scales or produce insoluble sediments which could settle on the packer.

Types of Packer Fluids

Clear Brines

Brine solutions are sometimes used as completion and packer fluids instead of conventional drilling fluid systems. There are two primary advantages to salt brines.

1. A clean, particle-free medium minimizes formation damage during completion operations (cleaner perforations, good sand control, more successful plastic squeeze jobs, etc.).

2. Fluids do not settle or solidify in the tubing-casing annulus to complicate workover jobs. Also, a reliable circulating fluid capable of retaining any formation pressures in the

well is available at all times. All brines discussed in the previous sections are commonly used for this application.

Conditioned Drilling Fluids

This category probably represents the largest group used as packer fluids. Conditioning drilling fluids for use as packer fluids is generally done as a matter of economics rather than performance. Since an investment has been made in the drilling fluid, why not use it as a packer fluid? In the early 1960s, lime fluids, for the most part, were replaced with systems like UNI-CAL® and low pH gypsum fluids. Solidification was less of a problem with these systems, and the industry felt they could serve as packer fluids if properly conditioned.

The primary advantages of using an existing drilling fluid for a packer fluid are availability and economics. Considerable expenditures are necessary when a new system is prepared because of material costs, rig time, and disposal of the existing fluid.

Gelation and formation damage are potential problems when existing drilling fluids are put into packer fluid service. This is because of the high concentrations of colloidal solids which are generally present. These solids can be tolerated while drilling since the system can be conditioned periodically. Under static conditions, however, gelation may progress to the point that the fluid cannot be pumped when remedial work is required. Also, if cement and/or saltwater enter the system during workover operations, colloidal solids can flocculate and severely affect rheological properties.

The inert solids (barite and sand) contained in a drilling fluid are not acid-soluble and may result in permanent blockage of the production zone. Also, drilling fluids usually are relatively low in electrolyte content, thus the filtrate could contribute to clay swelling and permeability damage.

Since the well was drilled with the fluid, it is not likely that further surface or near surface damage to the formation will occur. On the other hand, perforating and fracturing expose undamaged formations. This work should be done with a solids-free or acid-soluble system, if at all possible.

The initial cost advantages of utilizing an existing drilling fluid as a completion and/or packer fluid is quite appealing. Long range costs related to drilling fluids (excessive gelation, settling, formation damage, etc.) should be considered, however, before selecting them as packer fluids.

If existing drilling fluids are to be used as packer fluids, the following steps should be taken prior to placing them in the hole.

1. Reduce low-gravity solids by centrifuging or diluting to a maximum of 4%.

2. Adjust the pH of the fluid to 11.5 to 12.5 with caustic soda.

3. Add additional deflocculant to compensate for that lost through dilution and centrifuging.

4. Add **SALT WATER GEL®** and/or **MILGEL®** to increase viscosity to the desired level.

5. Treat the fluid with an oxygen scavenger (**NOXYGEN™**) and a biocide. **MUD-PAC®** contains a biocide and corrosion inhibitor suitable for this purpose.

6. Run static aging tests at operational temperature.

SALT WATER GEL Packer Fluids

A number of low energy suspension systems to be used as packer fluids have been investigated in the laboratory as well as in the field. The most satisfactory results have been obtained from the **SALT WATER GEL** packer fluid. Although this type of system may exhibit some subsidence in the fluid column, no difficulties in workover operations have been reported.

The addition of an oxygen scavenger (**NOXYGEN**) and a biocide is recommended as a precautionary measure against corrosion and bacterial degradation.

Material requirements for 1 bbl of **SALT WATER GEL** packer fluid for varying densities are contained in the table below.

Fluid Weight (lb_m/gal)	Lime (lb_m/bbl)	SALT WATER GEL (lb_m/bbl)	MIL-BAR (lb_m/bbl)	Water (gal/bbl)
14	0.25	8	307	32.9
14	0.25	10	301	32.8
14	0.25	12	296	32.7
16	0.25	8	420	29.8
16	0.25	10	418	29.7
16	0.25	12	416	29.6
18	0.25	8	528	26.6
18	0.25	10	527	26.5
18	0.25	12	527	26.5

Table 6 - 26 Formula for 1 bbl of SALTWATER GEL of Varying Density

GEL-CMC Freshwater Packer Fluids

GEL-CMC packer fluids have been used on operations with bottomhole temperatures up to 275°F. These fluids perform well because they can be pumped out when workover operations are required. These packer fluids utilize freshwater, **MILGEL®, CMC** (medium viscosity), **MIL-BAR®, NOXYGEN™** (oxygen scavenger), and caustic soda. A bactericide can be added for additional corrosion protection.

The composition and mixing procedure for various densities are shown in the table below. To the measured amount of water required, add caustic soda, **MILGEL**, **CMC (MV),** and **MIL-BAR**. For fluid weights above 14 lb_m/gal, start with a portion of the water required to avoid settling on the initial addition of **MIL-BAR**.

Fluid Weight Desired (lb_m/gal	Suggested Funnel Viscosity (sec/qt)	Fresh Water (bbl)	Caustic Soda (lb)	MILGEL (lb)	CMC (MV) (lb)	MIL-BAR (lb)
11	45 - 55	0.91	0.36	10.9	1.82	145
12	50 - 60	0.87	0.35	9.5	1.73	200
13	55 - 65	0.82	0.33	8.3	1.66	255
14	55 - 75	0.79	0.32	7.1	1.58	310
15	60 - 80	0.76	0.30	6.0	1.51	365
16	65 - 85	0.72	0.29	5.0	1.44	420
17	75 - 90	0.68	0.27	4.1	1.37	475
18	75 - 100	0.65	0.33	3.3	1.31	530
19	75 - 100	0.61	0.43	2.5	1.22	585
20	75 - 100	0.57	0.46	1.7	1.15	640

Table 6 - 27 Formula for Preparing One Barrel of Weighted Freshwater Packer Fluid Using MILGEL and CMC (MV)

Conversion of CARBO-DRILL Fluids to a Packer Fluid

The **CARBO-DRILL**® oil-base fluid system will make an excellent packer fluid with minor conditioning. Since oil-base fluids are electrical insulators, corrosion will be minimal in the **CARBO-DRILL** system. The **CARBO-DRILL** system is also significantly more temperature stable than water-base fluids. In addition, the **CARBO-DRILL** system environment is not conducive to bacterial growth.

When using the **CARBO-DRILL** system as a packer fluid, it should be treated with approximately 0.25 gal/bbl of **CARBO-MUL® HT** for added temperature and emulsion stability. If the bottomhole temperature exceeds 350°F, 0.25 to 0.50 gal/bbl of **CARBO-TEC™** and the appropriate amount of lime should also be added.

The **CARBO-DRILL** system used must have adequate yield point and gel strengths to support barite and drill solids for long periods of time. Enough **CARBO-GEL®** should be added to provide a 25 to 40 lb_f /100 ft^2 yield point. Be sure the newly added **CARBO-GEL** has had adequate shear through the bit to insure maximum yield. Pilot testing is very useful in estimating the amount of **CARBO-GEL** needed.

If there is a chance of CO_2 or H_2S intrusion, enough lime should be added to provide for 4 to 6 lb_m/bbl excess lime. If H_2S is expected, a hydrogen sulfide scavenger (**MIL-GARD®)** can also be added.

SOFTWARE FOR COMPLETIONS AND WORKOVERS

Baker Hughes Drilling Fluids has developed software specifically for use on completion and workover operations. This software is designed for use during the planning and operations phases of these operations.

Bridgewise™

Bridgewise™ is a bridging technology designed by Baker Hughes Drilling Fluids to maximize hydrocarbon recovery from reservoirs.

Bridgewise calculates the *optimum blend* of available calcium carbonate additives required to effectively bridge reservoir pore openings of known size. By utilizing a particle size distribution (PSD) database, **Bridgewise** allows the user to select the appropriate concentration and product ratio to provide maximum formation protection. This proprietary calculator is primarily used as a reservoir drill-in well planning tool, but in areas where there is a history of loss of circulation, **Bridgewise** may be used to select an appropriate LCM blend.

Features and Benefits

- Includes a choice of bridging rules
  - Abrams 1/3 Rule
  - Kaeuffer SQRT Rule
  - Vickers Rule
- Selects fit-for-purpose products
  - Acid soluble products
  - LCM materials
  - User defined products
- Uses core data for PSD (Particle Size Distribution) selection
  - Pore size in µm (microns)
  - Winland permeability/porosity
  - Permeability
- Utilizes a PSD database
  - **MIL-CARB** Series
  - **FLOW-CARB** series
  - Locally analyzed product
- Allows S.I. or Oilfield Units

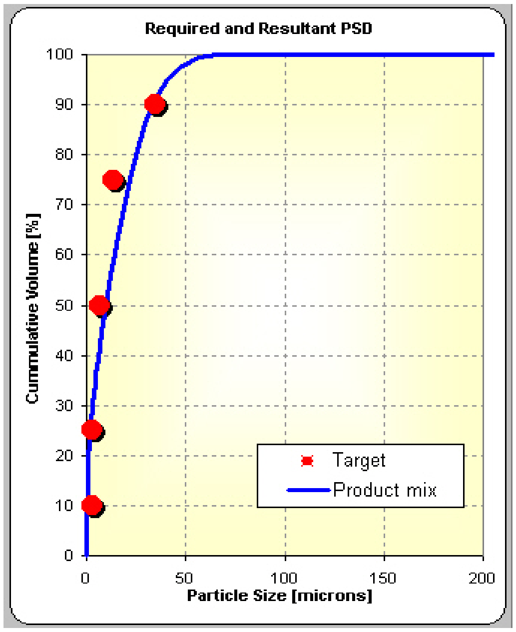
Bridging Rules

Several calculation methods (rules) are available and can be used to compare the recommended output values of each. However, scores of tests comparing spurt and total filtration volumes and formation damage lead Baker Hughes Drilling Fluids to introduce the “Vickers Rule”. This rule offers an improvement over the often used Abrams and Kaeuffer Rules by selecting a more effective PSD of graded calcium carbonate for the entire range of expected pore sizes.

The Vickers Rule has been validated in numerous laboratory tests.

Lab Validation

Bridgewise calculations have been validated in the permeability lab using cores of known pore size. Bridging efficiency evaluations based on long-term mud-off times (24-48 hours) were used to demonstrate the performance of various PSD blends.



In a recent drill-in fluid evaluation, tests were conducted on a field core having a pore diameter range between 3 to 35 µm (d50 = 20 µm). **Bridgewise** calculations suggested that **MIL-CARB** and **FLOW-CARB 10** would be the optimum product mix for this core. The core was tested and similar cores were tested with blends suggested by the Abrams and Kaeuffer rules. The lab results confirmed that the Vickers Rule provided the best recommendation for controlling spurt and total filtrate volumes relative to the other PSD blends. More significantly, after 48 hour dynamic and static exposure tests were completed, higher regain permeability results were also achieved.

Clear Brine ESD Calculator (Equivalent Static Density)

Introduction:

When planning for a completion, or while on location, the brine engineer must be able to predict the effective hydrostatic pressure exerted by the brine completion fluid in the wellbore. He must know what fluid density to procure in order to have the effective downhole density required to balance formation pressures under static conditions. Brine fluids can expand and therefore their densities are reduced as fluid temperatures increase. Since the temperature of the wellbore increases with depth, the effective hydrostatic pressure of the brine column changes as the temperature changes. Conversely, brine fluids are somewhat compressible, offsetting some of the effect of thermal expansion. Thus, the net change in the brine column density must be calculated in advance to ensure adequate well control and to minimize client completion fluid costs.

The temperature/pressure correction software program for clear brine developed by Baker Hughes Drilling Fluids is known as the Clear Brine ESD Calculator. Baker Hughes Drilling Fluids' Technology Group developed this calculator in response to the needs of field operations.

Background:

Before the development of the ESD Calculator, the industry used theoretical models to calculate the changes in density of brine due to temperature and pressure changes. The results derived from these models have not always been in close agreement with experimentally determined values at elevated temperatures and pressures for most of the brine blends used in the field. Furthermore, the change in density versus temperature and pressure are different for each brine type or blend.

In 1984, Dow Chemical (Krook and Boyce, SPE 12490, 1984) developed experimental data for input into a working method for determining the effect of temperature and pressure on brine density. The model used the following equation.

$$\Delta P_t = (\Delta P_d \times 10^{-3})\beta - (\Delta T \times 10^{-2})\,\alpha$$

Where:

ΔP_t = Change in density resulting from temperature and pressure, lb/gal

ΔP_d = Pressure difference, psi

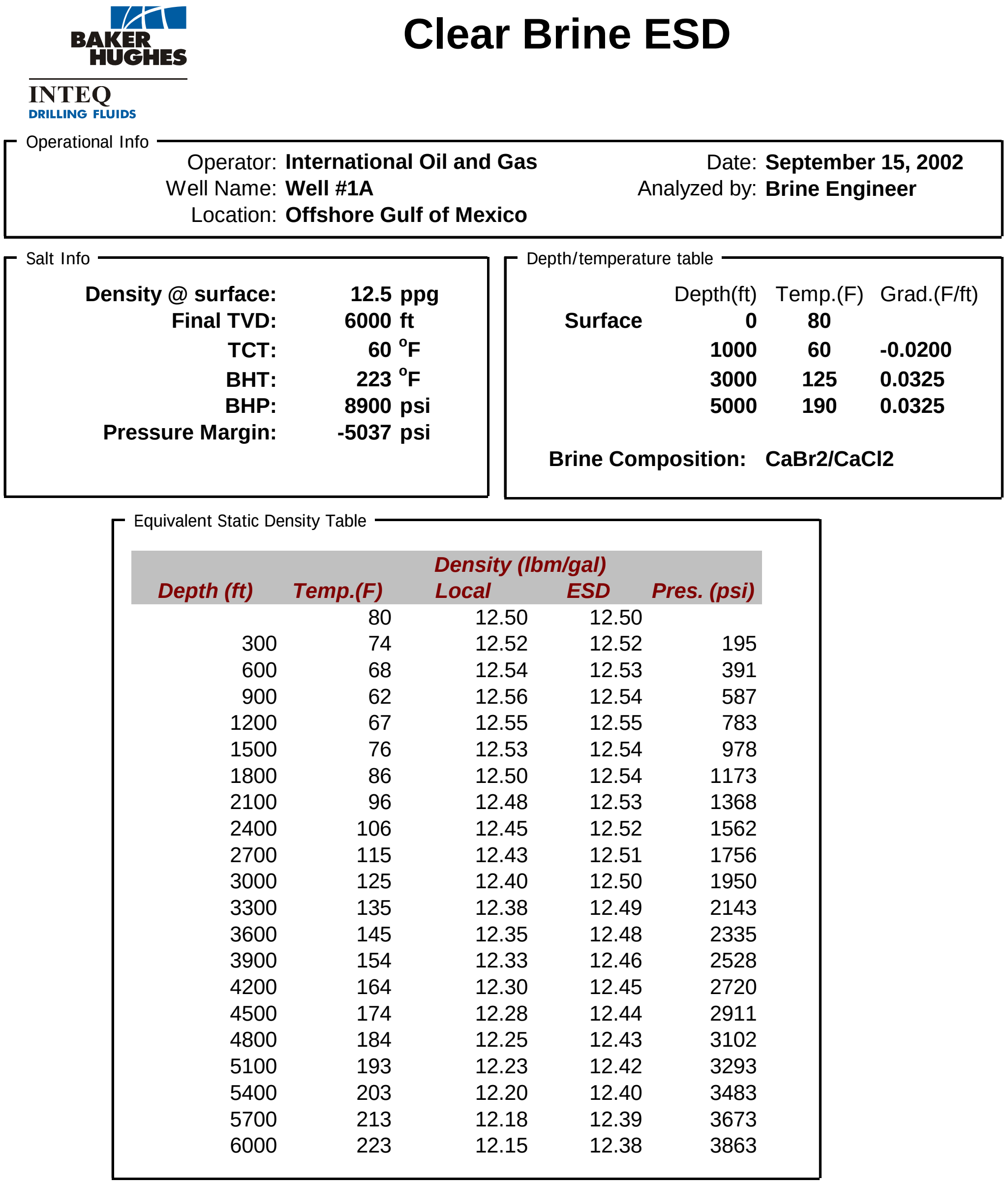
ΔT = Temperature difference, °F

β = Compressibility factor, lb/gal/100 °F

α = Expansion factor, lb/gal/1000 psi

If the values of α and β are known for a particular brine, the change in density can be calculated. Although the industry had taken a step forward in estimating clear brine downhole densities, the compressibility and expansion factors for most mixed-salt brine combinations were unavailable. The ESD Calculator has resolved this issue and developed a database of compressibility and expansion factors for most of the mixed-salt brine compositions. To complete the program, the Baker Hughes Drilling Fluids ESD Calculator provides calculated density values at 20 different TVD increments along the wellbore.

Program Usage:



BAKER HUGHES
INTEQ
DRILLING FLUIDS

Clear Brine ESD

Operational Info

Operator: **International Oil and Gas**
Well Name: **Well #1A**
Location: **Offshore Gulf of Mexico**
Date: **September 15, 2002**
Analyzed by: **Brine Engineer**

Salt Info

Density @ surface:	**12.5 ppg**
Final TVD:	**6000 ft**
TCT:	**60 °F**
BHT:	**223 °F**
BHP:	**8900 psi**
Pressure Margin:	**-5037 psi**

Depth/temperature table

	Depth(ft)	Temp.(F)	Grad.(F/ft)
Surface	**0**	**80**	
	1000	**60**	**-0.0200**
	3000	**125**	**0.0325**
	5000	**190**	**0.0325**

Brine Composition: **CaBr2/CaCl2**

Equivalent Static Density Table

		Density (lbm/gal)		
Depth (ft)	***Temp.(F)***	***Local***	***ESD***	***Pres. (psi)***
	80	12.50	12.50	
300	74	12.52	12.52	195
600	68	12.54	12.53	391
900	62	12.56	12.54	587
1200	67	12.55	12.55	783
1500	76	12.53	12.54	978
1800	86	12.50	12.54	1173
2100	96	12.48	12.53	1368
2400	106	12.45	12.52	1562
2700	115	12.43	12.51	1756
3000	125	12.40	12.50	1950
3300	135	12.38	12.49	2143
3600	145	12.35	12.48	2335
3900	154	12.33	12.46	2528
4200	164	12.30	12.45	2720
4500	174	12.28	12.44	2911
4800	184	12.25	12.43	3102
5100	193	12.23	12.42	3293
5400	203	12.20	12.40	3483
5700	213	12.18	12.39	3673
6000	223	12.15	12.38	3863

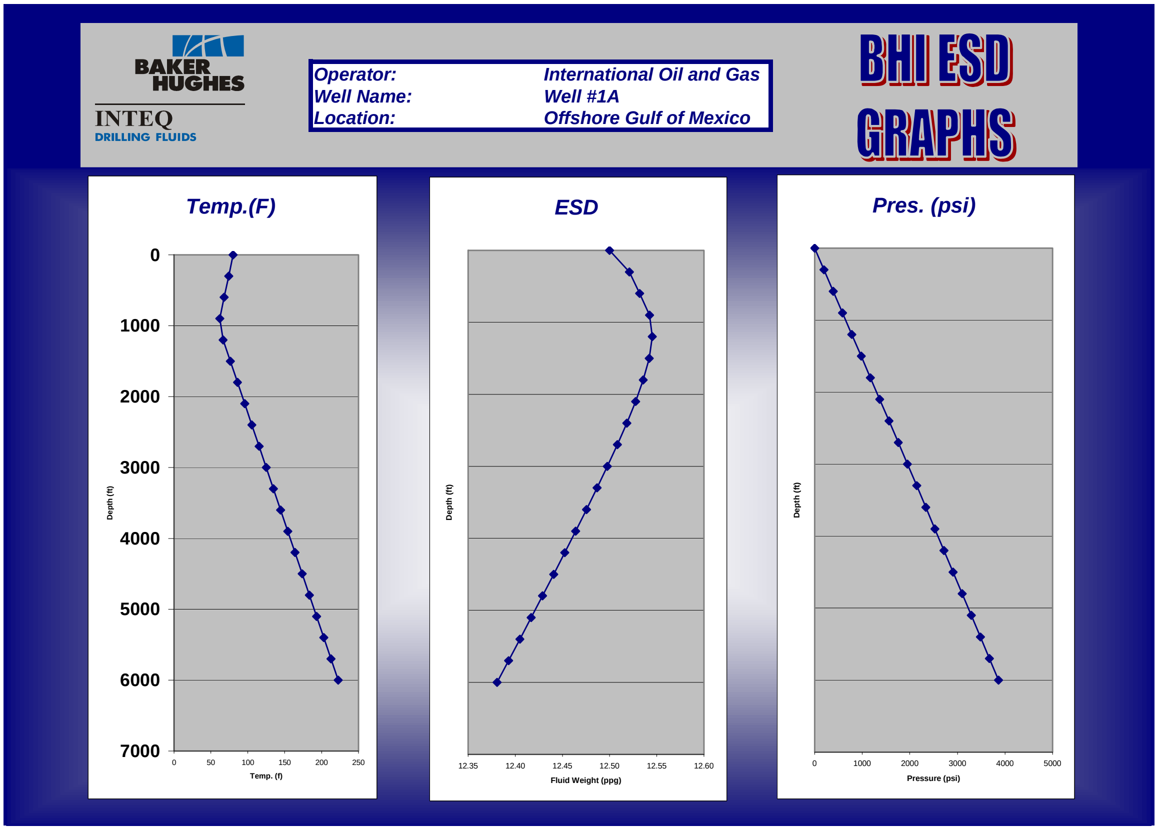
Table 6 - 28 Example Results From Baker Hughes Drilling Fluids ESD Calculator

Using the ESD Calculator is very simple and requires only basic input information. There are three categories for user input. They are as follows:

- Operational information,
- Salt information *(Salt TCT is taken into account for mixed brines)* , and
- Depth/temperature/brine composition information.

Once the data is entered in the category sections, the program generates a tabular printout of the ESD versus depth. This form can be printed for use in a brine program or for general information. In addition to the Equivalent Static Density Table, a graph can be printed indicating the change in

ESD and Brine Pressure versus Depth. An example of each output is given below.



Operator: International Oil and Gas
Well Name: Well #1A
Location: Offshore Gulf of Mexico

Figure 6 - 23 Graphical Results Obtained from Baker Hughes Drilling Fluids ESD Calculator

DISPLEX

DISPLEX is state-of-the-art displacement and spacer management software that closely monitors downhole pressures and pump rates to ensure optimum contact time for an effective wellbore and casing clean-up. Some of its features are:

- Multiple fluids and spacer capability
- 3D wellbore visualization
- Multiple rheological model options
- Open hole completion
- Spacer contact times
- Flow profiles (turbulent or laminar)
- Surface equipment limitations

- Pump pressures
- Deepwater application

Spacers

- User can choose one spacer or multiple spacer fluids.
- If "multiple spacer fluids" option is selected:
- In annulus - up to 9 different fluids with fluid interface locations and their individual rheological properties
- Inside pipe - up to 9 different fluids with fluid interface locations and their individual rheological properties
- Inside choke/kill/boost lines – 1 fluid and its rheological properties

DISPLEX Simulation for UNOCAL INDONESIA

The attached **DISPLEX** simulation was executed for UNOCAL INDONESIA for the purpose of demonstrating its benefits with respect to wellbore clean-up and cost savings from proper spacer selection, optimized contact time, proper displacement rates and reduced circulation time.

For this simulation, some pipe size selections were estimated but this does not reduce the value of the output. There are several scenarios available to choose from with respect to the rig and location. The example illustrated below is a deepwater scenario where the 2-step method has been used. The 2-step method for deepwater applications uses the DISPLEX program to clean the bottom casing strings up to the top of the riser through the coke and kill lines. Once the clean-up spacers and brine have reached the surface (Stage 1 completed), then an additional clean up spacer system is pumped back down the choke and kill lines to clean the riser (Stage 2).

Because of field success in deepwater clean up applications, the following spacer sequence has been selected:

- Base oil spacer – begins the cleaning and is recycled into the used oil-based mud. **DISPLEX** calculated the flow rate for this spacer to be in turbulent flow for best cleaning.
- Viscosified mud spacer – pushes debris up the hole dislodged by the turbulent base-oil spacer.
- Lead solvent cleaner (Viscosified and Weighted **FLOW-CLEAN**) – continues the cleaning process. This pill is non-aqueous.
- Second solvent cleaner (neat **FLOW-CLEAN**) – continues the cleaning process. To this point the wellbore has not seen any aqueous solution which is the key to using small pill volumes.
- Water-wetting spacer (**FLOW-SURF** or **CASING WASH 300**) – water-wets the casing. This spacer represents the first time the wellbore is contacted with water (brine).
- Final viscous sweep (HEC viscosified brine) – sweeps any remaining solids up the hole
- Completion brine

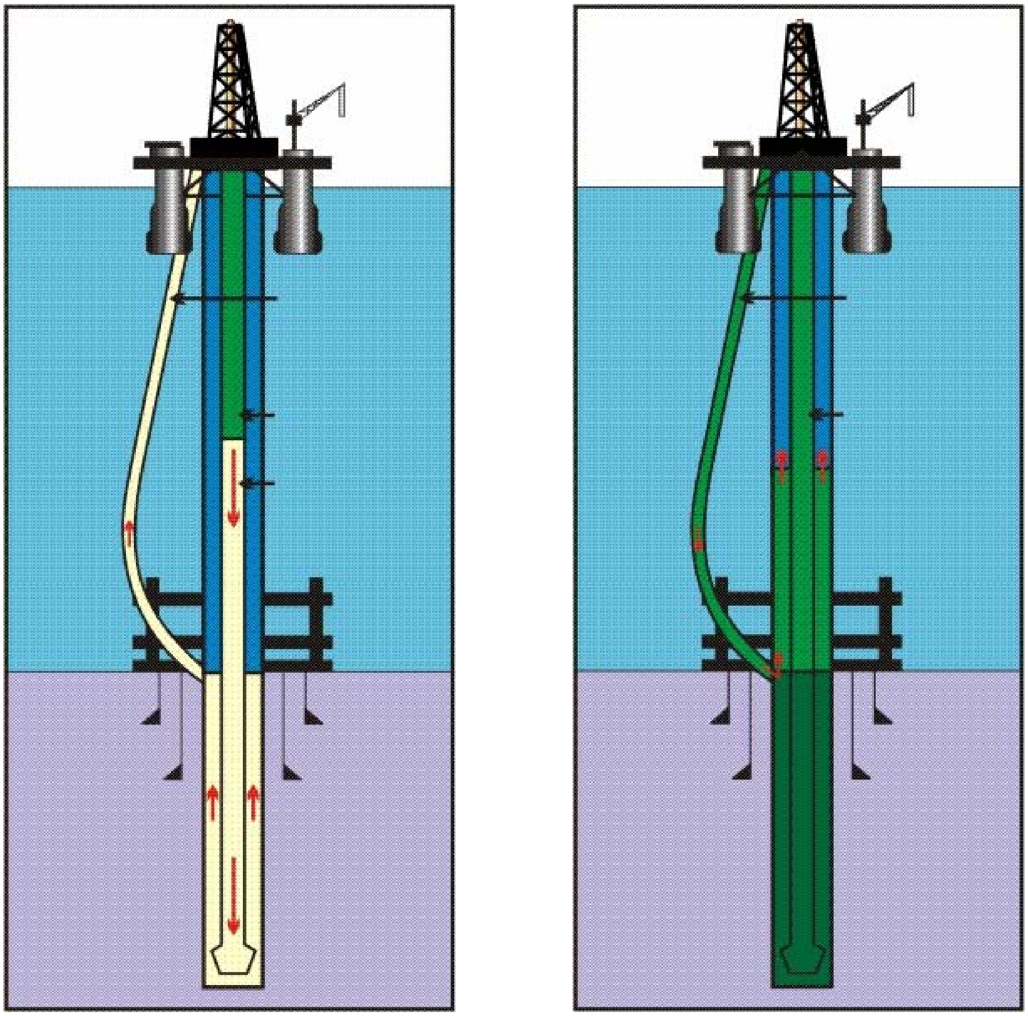
As mentioned for Stage 1, the spacer system will be circulated to the surface via the kill and choke lines. Stage 2 of the displacement is for riser cleaning, and in this case, the riser cleaning pill is circulated down the kill line, choke and booster lines and finally up the riser, isolating the previously cleaned casing. **DISPLEX** will calculate the time, strokes, pump pressure and pump rate required circulate the various pills to surface so that the various spacers are in the proper flow regime (laminar or turbulent). For reduced rig time and more efficient cleaning, turbulent flow rates for the spacers and brine have been chosen.

Below are found diagrams of various stages in the displacement for this WSA C06 (WSAP-16) applications. In a separate file, are found the **DISPLEX** printout of all the pumping schedules for this simulation.

Figure 6 - 24 DISPLEX Simulation for Deepwater Applications

Operation 2

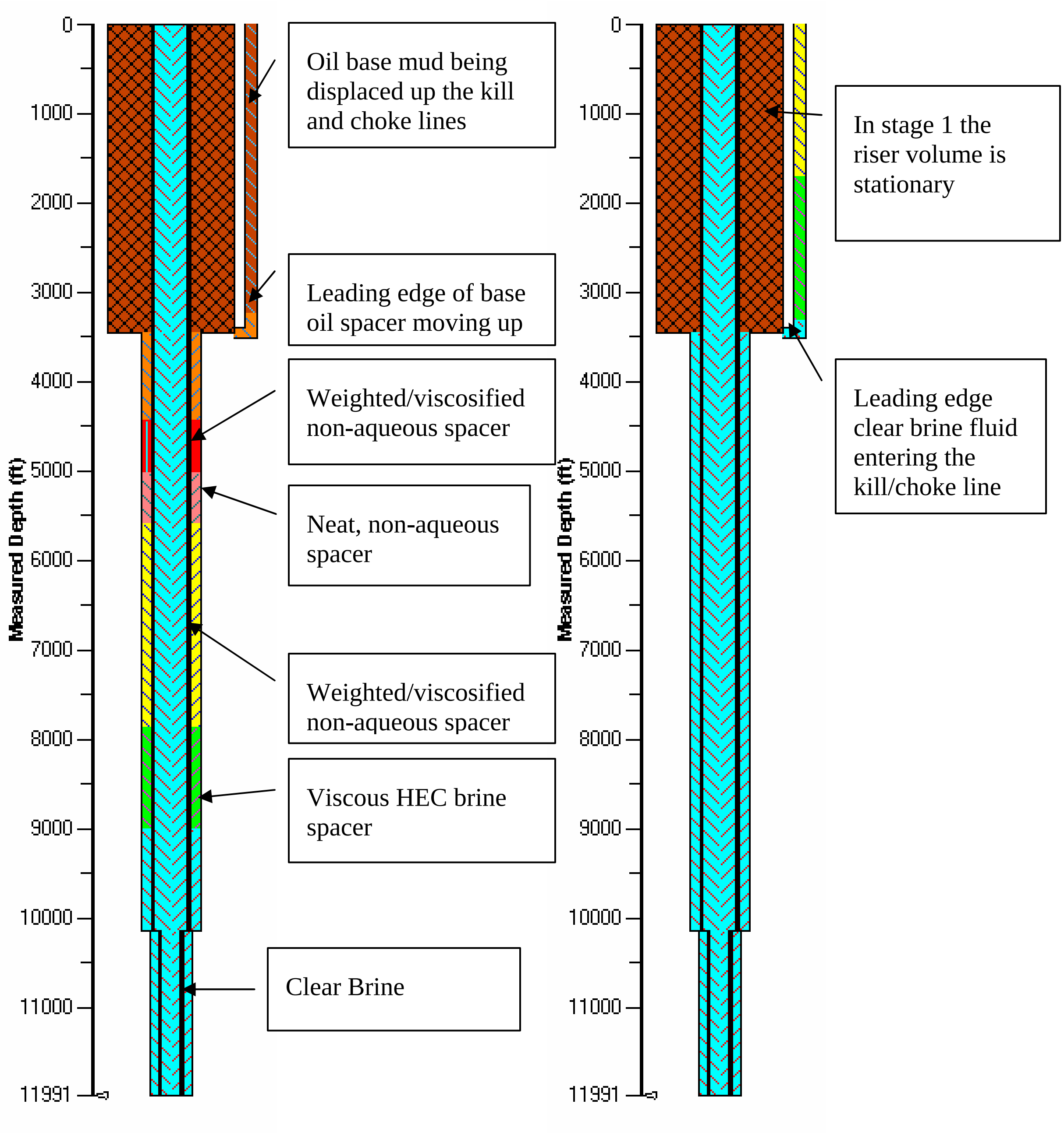
Stage 1 **Stage 2**



Pumping down the work string, (left figure) to clean casing and pumping down the kill/choke/booster lines (right figure) for the riser clean-up.

Figure 6 - 25 Simulation of WSA C06 (WSAP-16) Wellbore Displacement and Clean-up

Casing Clean-Up



Oil base mud being displaced up the kill and choke lines

Leading edge of base oil spacer moving up

Weighted/viscosified non-aqueous spacer

Neat, non-aqueous spacer

Weighted/viscosified non-aqueous spacer

Viscous HEC brine spacer

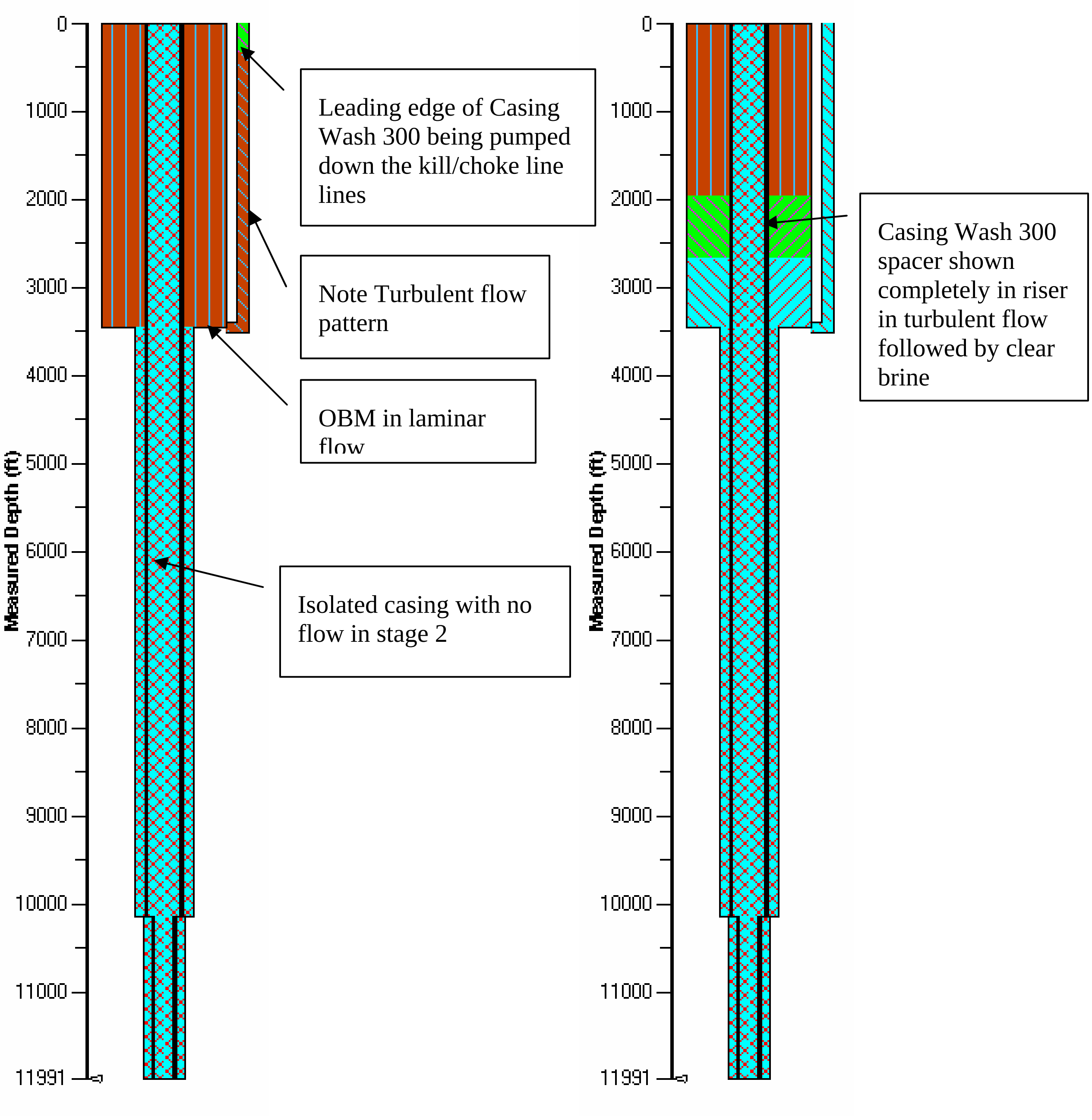
Clear Brine

In stage 1 the riser volume is stationary

Leading edge clear brine fluid entering the kill/choke line

Figure 6 - 26 Simulation of WSA C06 (WSAP-16) Wellbore Displacement and Clean-up

Riser Clean-Up



Leading edge of Casing Wash 300 being pumped down the kill/choke line lines

Note Turbulent flow pattern

OBM in laminar flow

Isolated casing with no flow in stage 2

Casing Wash 300 spacer shown completely in riser in turbulent flow followed by clear brine

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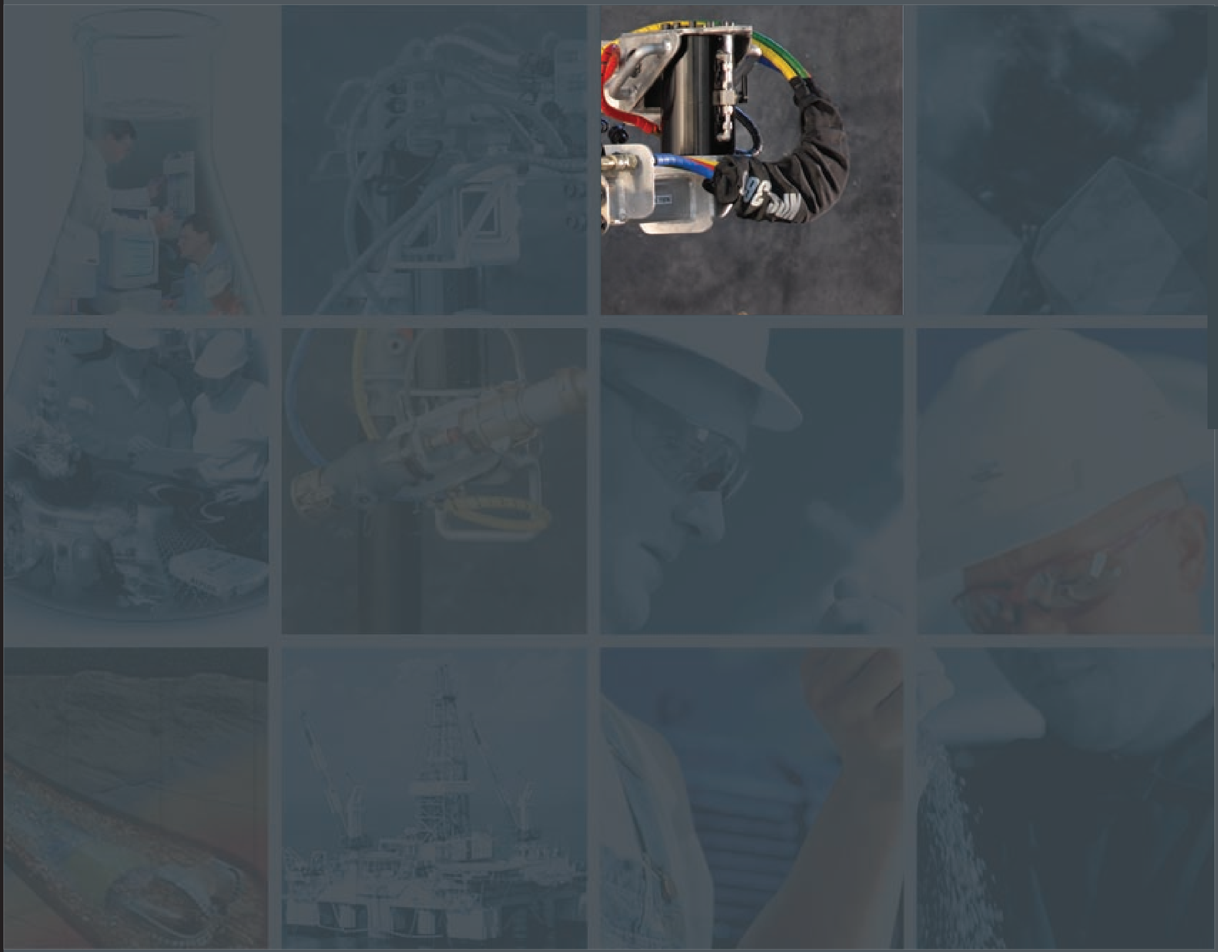

Chapter Seven

Borehole Problems

Chapter 7

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Chapter 7

BOREHOLE PROBLEMS

Wellbore problems are the result of many circumstances, not the least of which is misinformation resulting from inadequate planning. Drilling fluids are not the sole cause of wellbore problems; they are however, the first line of defense to correct them.

HOLE STABILITY PROBLEMS

Introduction

The maintenance of wellbore stability is one of the most critical considerations in any drilling operation. As a minimum, an unstable wellbore will reduce drilling performance and in the worst case could result in the loss of the hole through borehole collapse.

Wellbore instability can occur as a result of mechanical effects, chemical effects, or a combination of both. In simple terms, mechanical effects are usually related to drilling fluid density (drilling fluid density too high or too low) or drilling practices (rate of penetration, inadequate hole cleaning, vibration effects, torque and drag and frequency of trips), whereas chemical effects are drilling fluid type related (inappropriate drilling fluid type or inhibition level for the formation being drilled). The following sections give more detail on this, and provide a guide to minimize wellbore instability in the planning, implementation and drilling phases.

Common Misconceptions

Before detailing aspects of hole stability problems some popular misconceptions must be dispelled.

- Many in the industry believe that well control purposes alone dictate the required mud weight. They also assume that hole collapse is simply a result of drilling with insufficient drilling fluid density. Thus, the perception is that drilling with a nominal overbalance for well control will also ensure hole stability. The logic behind these beliefs is flawed. Weak formations may need overbalance in excess of 1000 psi to prevent hole collapse, whereas some mudstones can be drilled problem free in “underbalanced” conditions.

- It is common to assume that increasing drilling fluid density is always the answer to hole instability problems. This is not always correct. Increasing drilling fluid density can amplify problems. For instance, more rapid failure could occur in fractured rocks, whereas in some porous formations the resulting higher filtration rates and thicker filter cakes could promote differential sticking.

- Many believe that the use of an invert emulsion drilling fluid will prevent any problems occurring while drilling in shales. Hole instability can still occur particularly if the drilling fluid density or water phase salinity is inappropriate.

- It must be recognized that drilling fluid recommendations based on theoretical models are liable to be unreliable and often require "fine tuning" to give sensible, practical drilling fluid densities. Area experience is a better guide.

- Too great of an emphasis is often placed on annular velocity in the process of hole enlargement. Reducing API filtrate and increasing inhibition and overbalance will often have more beneficial effects than reducing annular velocity.

The Mechanisms of Wellbore Instability – Mechanical Aspects

Unconsolidated Formations

This type of formation would usually be associated with top hole intervals, but may also be encountered in fault zones or in unconsolidated reservoirs. Unconsolidated formations have no cohesive strength. Consequently when they are drilled with a clear fluid that exerts no confining stress on the wall of the hole the formation will slough into the hole. Most commonly the unconsolidated formation will be sand. However, in some tectonically active areas, a fault zone will be encountered that contains rock flour and unconsolidated rubble.

Preventative and Remedial Action

- Drilling this type of formation with a drilling fluid that has good filtration characteristics will produce a filter cake on the rock. The pressure drop across this cake will impart cohesive strength and a gauge, or near gauge, hole can often be achieved. The drilling fluid should contain bridging solids (usually calcium carbonate or fibrous seepage loss material) to promote the rapid build-up of a filter cake. If a cake is not quickly established the turbulent flow at the bit will produce washed out hole.

- Use the minimum flow rate that will clean the hole to prevent the erosion of the filter cake.

- Consider the use of a drilling fluid with good low shear rate viscosity so that high pump rates are not required. Xanthan gum polymer (**XAN-PLEX® D**) and mixed metal hydroxide (**MMH**) have an application in these cases.

- Do all that is possible to avoid the mechanical removal of the filter cake – minimize trips, minimize reaming and back-reaming, avoid rotating stabilizers next to the unconsolidated formation.

- The use of a drilling fluid known to have enhanced fracture sealing capabilities may help to stabilize fault zone rubble beds. Specific drilling fluid systems and additives can be designed for this application.

Competent Formations

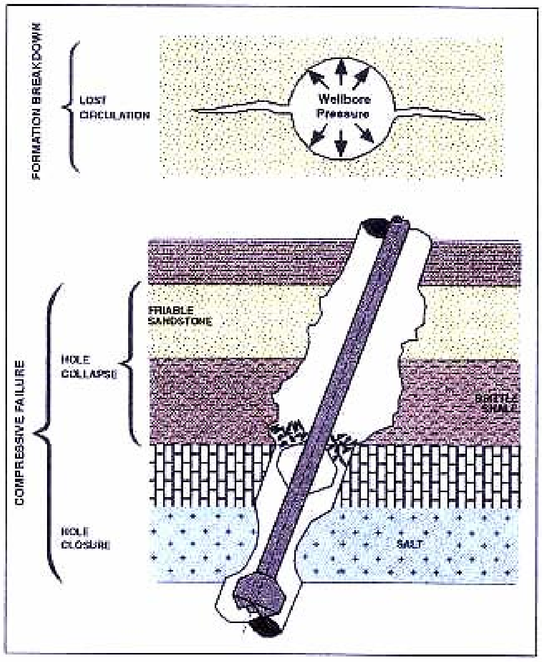
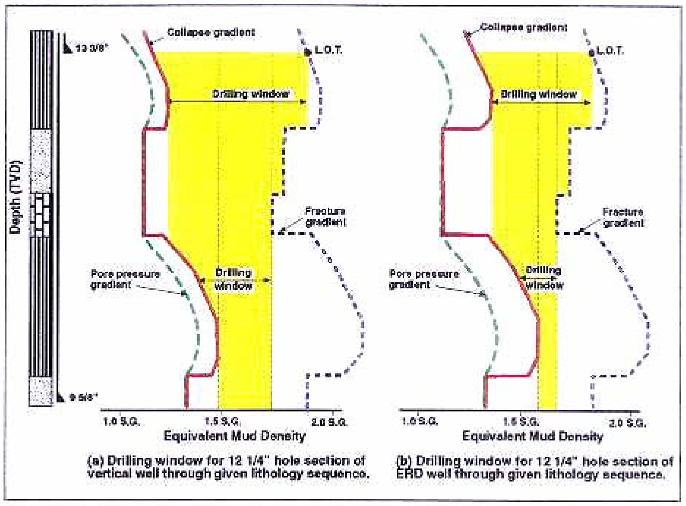


Figure 7 - 1 Forms of Mechanical Instability

There are two extremes of mechanical hole instability, referred to as compressive failure and formation breakdown (Figure 7 - 1). Compressive failure occurs when the drilling fluid density is too low – this results in hole closure (tight hole) or hole collapse. In contrast to this, formation breakdown occurs if the drilling fluid density is too high. Drilling fluid pressure may induce a fracture or open a natural fracture system, leading to massive mud losses.

In general, hole sections containing shales/mudstones will collapse if given insufficient support, and sands/carbonates will lead to mud losses and/or differential sticking if drilled with too high an overbalance.

To drill a hole section with little or no instability problems requires the maximum drilling fluid density tolerated by the sand/carbonates to exceed the minimum drilling fluid density required to support the mudstones. These upper and lower bounds to the drilling fluid density define the "mud weight window" (see Figure 7 - 2). The wider the window the easier the well is to drill. Conversely, the narrower the window the more difficult it is to contain the drilling fluid density within the stable region, and hence the risk of wellbore instability is much greater.



(a) Drilling window for 12 1/4" hole section of vertical well through given lithology sequence.

(b) Drilling window for 12 1/4" hole section of ERD well through given lithology sequence.

Figure 7 - 2 Defining "Mud Weight Window"

In certain highly tectonically stressed regions (e.g. foothills of the Casanare region in Colombia) the collapse gradient in the shales can exceed the fracture gradient in the sands, even for nominally vertical wells. In such cases there is no drilling window and it is impossible to select a drilling fluid density to simultaneously avoid both losses and collapse. Hence, one or both forms of instability must be tolerated to some extent.

In general a mud weight window will exist. The "width" of the window will depend on a number of operator controlled factors, but primarily well inclination. Increased well inclination will usually reduce the width of the mud weight window (Figure 7 - 2), thus increasing the risk of straying from the region of safe mud weights. Hence, Extended Reach Drilling (ERD) wells are typically more prone to instability than other more conventional wells drilled in the region.

Another factor strongly influencing the integrity of the hole is the open hole time. Even stable shales are seldom stable for an indefinite period and the longer the open hole time the greater the risk that instability will occur. This is particularly the case when using water based drilling fluids. Increased hole section length and therefore increased open hole time are a natural consequence of drilling ERD wells. Where possible, a gradual increase in drilling fluid density can be effective in combating this time element and can stabilize the formation for a longer period.

When assessing ERD options in a region previously drilled with conventional wells, the primary hole stability consideration is to assess the impact of trajectory on the mud weight window. If conventional drilled wells have proven difficult to drill due to a narrow mud weight window, then serious thought must be given as to whether a casing program can be designed to combat the increased risks projected in the ERD well.

Preventative Action – Mechanical

Pre Drilling

The purpose of any data collection is to attempt to define the optimum drilling window for offset wells and to project that window to planned wells. Without any offset well data then there is little value in any wellbore stability study.

The data of most value are:

- Drilling and Completion reports from offset wells (which may contain much of the other information listed below).
- Details of any formation stress tests including Leak Off Test (LOT) and Formation Integrity Test (FIT).
- Daily mud properties.
- Details of any drilling fluid losses encountered.
- Details of any pipe sticking and/or excess reaming.
- Composite logs, dipmeter or borehole geometry logs, any caliper logs, density logs and sonic logs.
- Description of any major faulting in the region (normal, strike-slip, etc).

Planning Stage

Well Inclination

- Allow for increases in drilling fluid density of between 0.5 ppg and 1.0 ppg per 30 degrees inclination through shale/mudstone sections to combat hole collapse. Only local experience will determine at which end of the scale to be.

- No increase in drilling fluid density with hole inclination is necessary across permeable formations, e.g. sands. Formations with reasonable matrix permeability can usually be drilled with nominal overbalance, regardless of well trajectory or formation strength.

- Be aware that the fracture gradient may reduce with increased angle.

Fracture Gradient

- Recognize that the fracture gradient for a hole section is more likely to be controlled by a carbonate or sand rather than the shale within which the LOT was performed (see Figure 7 - 2).

- On ERD wells, drilling high pressure reservoirs may prove extremely difficult due to a very tight mud weight window between taking a kick and experiencing losses. The extent and effect of ECDs need careful consideration at the planning stage.

- During appraisal, consider performing micro-fracture tests (essentially a LOT taken beyond the point of breakdown) to better determine the fracture gradient in formations that may prove to be critical in an ERD well.

Regional Stress State

- Process any dipmeter or borehole imaging log data to determine *in situ* stress directions. This may help to interpret any problems seen during the drilling operation and thus hasten corrective actions.

- In highly tectonically stressed regions, drilling up dip of the major faults may provide a larger mud weight window than drilling down dip, cross dip or vertically.

- The *in situ* stress state near a salt diapir is highly disturbed, such that well trajectories which approach the diapir normal to its surface provide a larger mud weight window than trajectories tangential to its surface.

Casing Program

- Having planned for an increased drilling fluid density to control shales in an ERD well, assess whether the planned casing setting depths still provide sufficient mud weight window.

- In ERD wells the drilling fluid density required to drill a normally pressured reservoir is often significantly less than that required to prevent collapse in the cap rock. The setting of the production casing should minimize or exclude the presence of cap rock in the reservoir hole section, thus allowing the reservoir to be drilled with a normal overbalance.

General

- Oil-based drilling fluids often allow a lower drilling fluid density to be used to prevent collapse in shales. This provides a larger mud weight window.

- The risk of instability in highly laminated shales may be reduced when adopting a trajectory normal to bedding.

Symptoms and Remedial Action

- The onset of cavings from a formation while it is being drilled may indicate underbalance conditions. An increase in drilling fluid density or a reduction in ROP may help.

- The onset of cavings more than a few hours after drilling a shale indicates that the benefit of the initial overbalance has been lost. This is a result of the migration of filtrate into the formation causing near wellbore pressure increases. An increase in drilling fluid density and/or a reduction in API filtrate are likely to help.

- Often an improvement in LOT value can be observed as the section is drilled. Consider repeating the LOT where low values have originally been obtained.

- Even in normally stressed regions the mud weight window may be influenced by well azimuth. Be prepared to increase the drilling fluid density in wells with azimuths sub-parallel to the maximum horizontal stress direction.

- Controlling API filtrate to a minimum is particularly important in ERD wells and all hole sections, not simply in the reservoir section.

- Swab and surge pressures may trigger instability in weak or highly fractured shales. Particular care is required when running in and pulling out of hole sections with such formations present. Pressure While Drilling (PWD) measurements indicate that surge pressure equal to 1.5 ppg (0.18 S.G.) can be generated not just when tripping, but also on connections made with a top drive.

- Unless absolutely necessary, do not reduce the drilling fluid density while drilling if a shale is present in the open hole section, otherwise the risk of hole instability is greatly increased. If operational difficulties necessitate a drilling fluid density reduction then the slower this is done the better.

The Mechanisms of Wellbore Instability – Chemical Aspects

Chemical wellbore instability is due to chemical interaction between the formation being drilled and the drilling fluid. This can occur in two main types of formation:

- Shales
- Salt formations

In both cases, it is an interaction with *water* which causes instability. **Thus, chemical stability is always minimized by using oil based drilling fluids.**

When shales react with water, they can soften, disperse, swell and crack. These effects can cause a wide range of operational problems such as tight hole, hole enlargement, ledging, bit balling and caving.

To minimize these problems, it is important to characterize the shale type at the planning stage of a well, and to use an appropriately designed drilling fluid.

In salt formations, chemical instability occurs if the formation is soluble in water. The use of an incorrectly formulated fluid will lead to uncontrollable washouts in these situations. Formation types which exhibit this behavior are:

- Halite ($NaCl$)
- Carnallite ($KMgCl_3.6H_2O$)
- Bischofite ($MgCl_2.\ 6H_2O$)
- Sylvite (KCl)
- Polyhalite ($K_2Ca_2Mg(SO_4)_4.\ 2H_2O$)

Preventative Action – Chemical

Pre Drilling

- When planning a well, first decide if shales or salts will be encountered. Offset well data and drilling fluid reports will be particularly useful.

- Design the casing/well program to minimize the length of time reactive formations are exposed to the drilling fluid. Because shales have very low permeability ($10^{-9} – 10^{-6}$ D), they may appear stable for a time, but water can penetrate leading to time delayed effects. This process is known as pore pressure transmission and can be countered by the use a cloud point glycols, silicate and aluminate based drilling fluids.

- Characterize shale types by XRD (X-ray Diffraction) analysis. This technique should also be supported by laboratory inhibition tests, which are best done on preserved shale.

- Watch out for inter-bedded formations (e.g. salt stringers in shale or reactive shale in competent shale). A drilling fluid system compatible with both formation types will be required.

- The best way to minimize chemical instability in shales or salt sections is to use an oil based drilling fluid. High performance water based drilling fluids should be given serious consideration as alternatives. A cost/benefit analysis should aid the final selection process.

- Do not rely on chemical - mechanical wellbore stability models to design the drilling fluid. There is invariably insufficient input data, and they do not take account of specific chemical reactions.

Oil-Based Drilling Fluid –Engineering Comments

- Oil-based mud (OBM) water phase salinity must be at least as high as the pore fluid salinity of the shale. This will prevent water entering the shale by osmosis.
- When drilling salt formations, OBM salinity should be high (e.g. 300,000 mg/l chloride), to minimize salt dissolution into the water phase of the drilling fluid.
- Synthetic-based mud (SBM) (pseudo oil based drilling fluids) should be considered where environmental constraints restrict the use of conventional oil. Shale inhibition is equally effective in these systems.
- In micro-fractured shales, use a very low HPHT filtrate drilling fluid (< 3 ml), and add fracture sealing additives.

Water-Based Drilling Fluid –Engineering Comments

- If water-based mud (WBM) is to be used, carry out a screening program at an early stage to allow optimization.
- Water based drilling fluids are less lubricating generally than oil based drilling fluids, therefore expect higher torque in high angle wells. It may be necessary to add lubricants to the system.
- In salt sections, it is important to match the fluid to the type of salt. Salt saturated drilling fluids (NaCl) are used for simple halites; mixed salt systems are available for complex salts such as Carnallite.
- Use a low filtrate drilling fluid (e.g. API < 5ml, HPHT (250°F < 14 ml) in micro-fractured shales, and add fracture sealing additives.

Symptoms and Remedial Action

Having planned the well using all available data, the risk of mechanical and/or chemical borehole instability will be limited. It is important that should instability occur it should be identified and suitable remedial action should be adopted.

Indication of the condition of the hole can be inferred from torque and drag measurements, the condition and quantity of cuttings seen at the shale shakers and variations in drilling fluid volumes.

- When drilling shales, monitor cuttings quality as a qualitative measure of inhibition. Very soft cuttings will mean insufficient chemical inhibition or, in the case of OBM, would suggest that the water phase salinity is too low.
- High torque values would suggest tight hole, possibly requiring an increase in drilling fluid density or an increase in inhibition to reduce the swelling of clays.
- A sudden appearance of large or increased volume of “cuttings” at the shale shakers is indicative of wellbore caving.

- An unplanned increase in drilling fluid rheological properties could be due to a build up of fine solids in the drilling fluid which in turn could be an indication of poor inhibition or hole washout.

- The downhole loss of whole drilling fluid would indicate that the formation was being fractured by the use of too high a drilling fluid density.

- Difficulty running in the hole could be attributed to ledges, swelling clays or caving formations.

The caliper log can be run at section TD. The gauge of the hole will give an indication of whether drilling fluid density and inhibition was at a correct level for that interval. If an oriented 4-arm caliper is used, information on stress orientations can be obtained. A typical indication of stress induced borehole instability is the presence of an oval rather than a circular hole. Information regarding the two horizontal *in situ* stresses can be deduced from this type of log. Knowing the direction of the stresses is valuable when planning development wells as the well directions least prone to hole problems can be established.

Special Cases

Salt Formations

- Drilling near a salt diapir (salt intrusion as in salt dome) presents a special case because of the altered *in situ* stresses near to the diapir. The behavior of wells within a few hundred meters of a diapir may be totally different to wells only a kilometer or so away. In general hole problems are accentuated near a diapir.

- The maintenance of gauge or near gauge hole is important when drilling massive salt formations. Greatly washed out hole will probably result in a poor cement job. This in turn will allow salt behind the casing to creep, impinging on the casing and, in extreme cases cause the casing to buckle.

- Stuck pipe is a common problem when drilling salt formations. Salt formations tend to creep and impinge on the drillstring. The only way to stop this process is to drill with a drilling fluid density equivalent to overburden gradient (approximately 19 ppg in the Southern North Sea and 17 ppg in the Gulf of Mexico). In practice the rate of creep can often be reduced to acceptable levels at lower drilling fluid densities, typically 14.0 ppg. The use of eccentric bits to slightly increase the diameter of the hole has proved beneficial in some operations. Figure 7 – 3 describes the approximate mud weight to control salt creep as a function of hole temperature and hole depth.

- Drilling massive salt sections with OBM/SBM generally produces an in-gauge hole. In many cases, the creep of the salt results in the drill bit becoming stuck. Pumping a slug (5 – 10 bbl) of fresh water down the drill pipe past the bit generally frees the bit. The small volume of water should not affect the stability of the OBM, but the system should be treated with additional salt to bring the water phase salt concentration back to required levels.

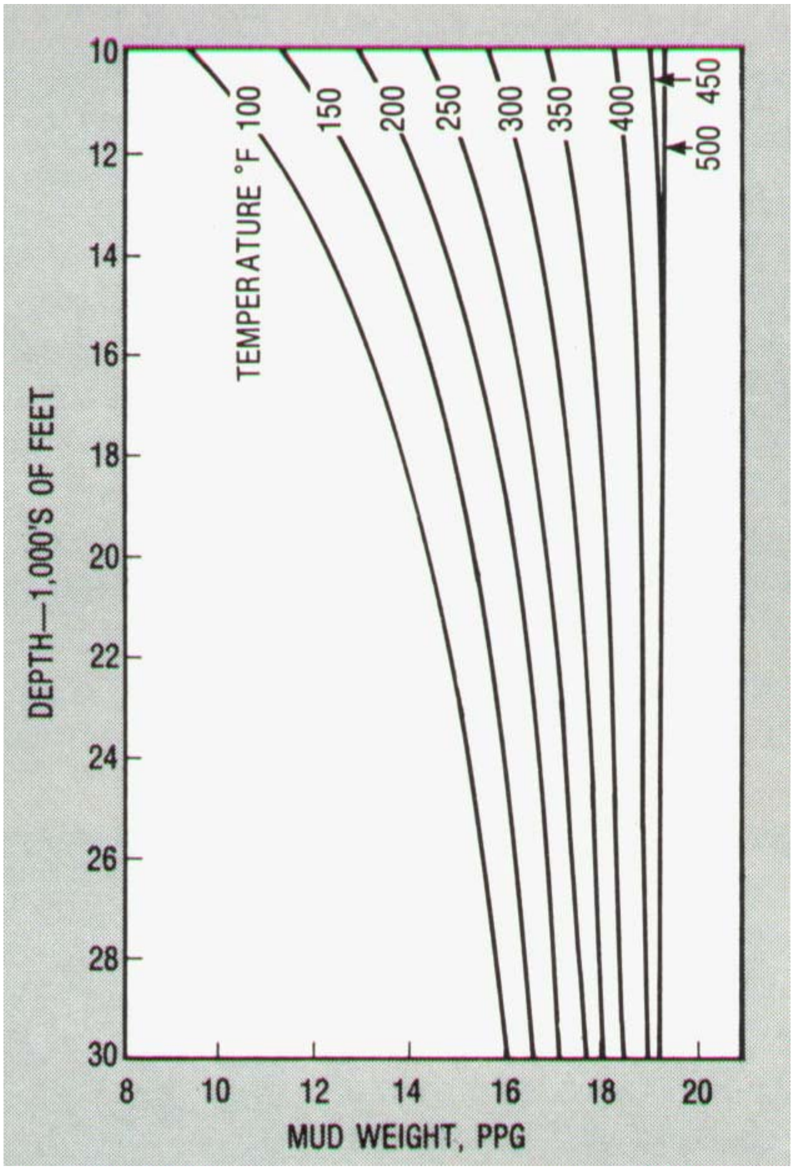


Figure 7 - 3 Approximate Mud Weight Required to Control Salt Creep

Coal Formations

Coal is a very brittle formation with low compressive strength. It is usually highly fractured and in areas of high tectonic stress can instantly collapse into the borehole when the horizontal stress is relieved by the bit – stuck pipe is often the end result. High drilling fluid densities can rarely be used to stabilize the coal formation because of their inherent low fracture gradients. The recognized technique to drill coal is to limit penetration rates so that the stresses are given a chance to equilibrate and so that the blocky pieces of coal can be removed from the hole. Good hole cleaning is essential – it may be necessary to modify the cleaning capacity of the drilling fluid while drilling coal. The properties can be restored to normal when the coal has been drilled. Alternatively viscous, weighted sweeps can be used to enhance hole cleaning – this is particularly appropriate if the coal seam is anticipated to be thin.

Should the pipe become stuck in coal, and circulation is possible, experience shows that spotting a high pH pill around the coal can help to free the pipe.

Where the coal seam is not tectonically stressed and geological information regarding the seam is required care must be taken with fluid properties and drilling practices. Seat earths and marine bands both provide valuable information about the coal but both are easily washed out. When coring with water based drilling fluids a low filtrate should be utilized and jet velocity should be minimized. There is some evidence that these fractured rocks can be stabilized with products such as Gilsonite and **SULFATROL®**.

INHIBITIVE WATER BASED DRILLING FLUIDS

There has been extensive research into inhibitive drilling fluids in an attempt to control wellbore instability by means of shale control. Shale control continues to dominate research due to the fact that shale instability remains one of the largest contributors to troublesome drilling and increased costs.

“Today's definition of an inhibitive fluid is much broader than simply the inhibition of the swelling of highly expanding clays such as Montmorillonite. It means a fluid that exhibits minimal reactivity with the borehole and more specifically with the broad range of shales and other argillaceous formations.” This statement by B.G. Chesser of Baker Hughes Drilling Fluids typifies the type of thinking that has guided the evolution of inhibitive fluid systems over the years.

The goal of inhibitive water based drilling fluid design is generally to prevent hydration/swelling of the clay minerals and to minimize pore pressure transmission.

Shale Hydration

All classes of clay minerals absorb water, but smectites take up much larger volumes than do other classes, because of their expanding lattice. For this reason, most of the studies on clay swelling have been made with smectites, particularly with montmorillonite.

Two swelling mechanisms are recognized: crystalline and osmotic. Crystalline swelling (also called surface hydration), results from the adsorption of mono-molecular layers of water on the basal crystal surfaces – on both external, and, in the case of expanding lattice clays, the inter-layer surfaces. The first layer of water is held on the surface by hydrogen bonding to the hexagonal network of oxygen atoms. Consequently, the water molecules are also in hexagonal coordination. The next layer is similarly coordinated and bonded to the first, and so on with succeeding layers. The strength of the bonds decreases with distance from the surface, but structured water is believed to persist to distances of 75 – 100 Å from an external surface.

The structured nature of the water gives it quasi-crystalline properties. Thus, water within 10 Å of the surface has a specific volume about 3% less than that of free water. (Compared with the specific volume of ice, which is 8% greater than that of free water.) The structured water also has a viscosity greater than that of free water.

The exchangeable cations influence the crystalline water in two ways. First, many of the cations are themselves hydrated, i.e., they have shells of water molecules (exceptions are NH_4^+, K^+, and Na^+). Second, they bond to the crystal surface in competition with the water molecules, and thus tend to disrupt the water structure. Exceptions are Na^+ and Li^+, which are lightly bonded and tend to diffuse away.

When dry montmorillonite is exposed to water vapor, water condenses between the layers, and the lattice expands. The energy of adsorption of the first layer is extremely high, but it deceases rapidly with succeeding layers.

Osmotic swelling occurs because the concentration of cations between the layers is greater than that in the bulk solution. Consequently, water is drawn between the layers, thereby increasing the c-spacing and permitting the development of diffuse double layers. Although no semi-permeable membrane is involved, the mechanism is essentially osmotic, because it is governed by a difference in electrolyte concentration. Osmotic swelling causes much larger increases in bulk volume than does crystalline swelling.

Shale Hydration Inhibition

To minimize the effects of water on shale, two aspects of the hydration can be modified. One is to replace sodium and calcium ions on the exchange sites of the swelling clay, montmorillonite, with a cation (very often potassium) or with an amine such as those in **CLAY-TROL™** and **MAX-GUARD™.** The second approach is to encapsulate shale cuttings with PHPA (**NEW-DRILL®**) and thus hinder their physical degradation. This encapsulation makes it easier for the surface solids equipment to remove these solids from the drilling fluid.

Various inhibitive systems are formulated with water soluble salts such as: sodium chloride, potassium chloride, potassium carbonate, calcium sulfate, calcium chloride and calcium hydroxide. The cations contained in these systems are adsorbed onto the clay surface through a cation exchange process. The adsorption of these cations onto the clay surface reduces the ability of the clay to hydrate and swell. The reduction in clay swelling is due to the amount or thickness of the water film associated with that particular cation.

When clays containing low order replacement cations (monovalent cations) are exposed to water, the cations hydrate and dissociate from the clay surface forcing the clay platelets apart. The distance that the platelets separate is governed by the hydration radius of the cation. A higher replacement order cation having a smaller hydration radius and a greater affinity for the clay structure can now displace the low order cation reducing the separation between the platelets and reversing the swelling tendency.

The most commonly occurring cations may be ranked according to their replacement power as follows,

$$\underrightarrow{Li^+,\ Na^+,\ K^+,\ Mg^{++},\ Ca^{++},\ Al^{+++}}$$

Increasing Order of Replacement

Potassium chloride systems have been used with a great deal of success around the world while calcium-base systems (lime and gypsum fluids) have been used with varying degrees of success.

The mechanisms by which PHPA polymers stabilize shale cuttings are adsorption, bridging, and flocculation. The long chain polymer can attach itself to shale particles through adsorption, sometimes referred to as encapsulation. This encapsulation process forms bridges between many shale particles and thus links these particles together preventing or greatly limiting dispersion. The encapsulation action of this polymer enhances the physical integrity of shale cuttings. It therefore gives more strength against mechanical degradation while the cutting is in transport out of the wellbore.

The hydrated layer formed when the polymer adsorbs onto the shale particles is permeable, and other water molecules will eventually react with the shale particles causing shale hydration and swelling. This process could lead to disintegration, but due to the presence of the PHPA polymer, the shale particle remains intact. This suggests that the benefits gained from PHPA are indeed of a mechanical nature and the ability of this polymer to reduce swelling is a kinetic effect.

Pore Pressure Transmission

The most important factor in maintaining shale stability is preventing pressure increases in the shale matrix. Pore pressure increases, and differential pressure support decreases, when drilling fluid filtrate invades the shale. Wall support is lost with the reduction in differential pressure and the shale can then easily slough into the annulus. Shale (borehole) stability is achieved when pressure increases in the matrix are reduced and differential pressure support is maintained. The problem of pressure invasion is exacerbated by shales having low permeability, which slows the rate at which pressure can dissipate. This typically confines the added pressure in the shale to the vicinity of the near-wellbore surface.

Pressure transmission in emulsion systems is managed by the generation of a semi-permeable membrane and the osmotic potential pressure difference between the shale and emulsion fluid. Sources of the semi-permeable (selective) membrane of OBM/SBM proposed in the literature include the oil film and emulsifiers/surfactants surrounding the emulsion. Calcium chloride in the internal phase reduces water-phase activity and creates an osmotic pressure differential at the borehole wall. Additionally, pressure invasion in emulsion systems is suppressed by the capillary entry pressure that must be overcome in order to force oil into the water-wet pore throat.

Conventional water based drilling fluids are poor in drilling weak rocks like shales. These require an effective radial support stress, provided by drilling fluid overbalance, for stability. Overbalance, however, also drives the flow of drilling fluid filtrate and diffusion of drilling fluid pressure into the shale, causing a number of destabilizing effects. The most profound of these is near-wellbore pore pressure elevation which destroys effective drilling fluid pressure support. The *in situ* stresses may now overcome the strength of the shale, causing plastic deformation and failure. OBM and SBM are restricted from invading shales due to capillary threshold pressures. Improvement of WBMs involved reducing the filtrate flow J_v into shales, which can be described by:

$$J_v = k\,(\Delta P - \sigma \Delta \Pi) / \eta$$

Where:

k = shale permeability,

η = filtrate viscosity,

ΔP = the hydraulic overbalance,

σ = the membrane efficiency

$\Delta\ \Pi$ =- the osmotic pressure defined by:

$$\Delta\ \Pi = \frac{RT}{\overline{V}_w}\ ln \left[\frac{a_w^{sh}}{a_w^{df}} \right]$$

where:

T = temperature,

R = the gas constant,

$\overline{V}_w$ = the partial molar volume of water,

a_w^{sh} and a_w^{df} = the shale and drilling fluid water activities respectively.

These equations show that there are four methods for reducing $J_{v:}$

1. Reducing the flow of drilling fluid filtrate by increasing the filtrate viscosity η ;

2. Reducing the flow of drilling fluid filtrate by reducing the shale permeability k ;

3. Balancing the flow of drilling fluid filtrate into the shale driven by overbalance ΔP by a backflow of pore water driven by the combined osmotic pressure $\sigma\ \Delta\ \Pi$;

4. Combining the above mechanisms.

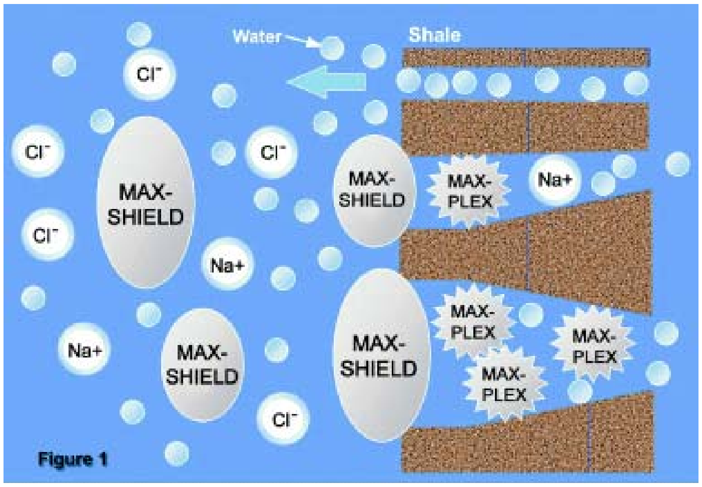
Pore Pressure Transmission Inhibition

Emulsion drilling fluids are the ultimate membrane generating systems and provide superior drilling performance primarily because of their ability to reduce pressure transmission in shale. Preventing pressure invasion in shale using WBM is a formidable obstacle due to the technical difficulty of generating an efficient membrane while remaining cost-competitive with OBM/SBM. A significant technology gap in High Performance Water Based Drilling Fluid (HPWBM) occurs when the system cannot generate a membrane approaching that of OBM/SBM. **PERFORMAX™** is designed to closely emulate the shale stabilizing mechanisms of an emulsion system by generating a selective membrane and creating an osmotic pressure difference between the drilling fluid and the shale.

The mobility of solutes in shale determines membrane efficiency of drilling fluids. The shale essentially acts as a semi-permeable (selective) membrane because the clay-rich matrix hinders the movement of solutes. The shale matrix can be made more selective, thus further reducing the mobility of solutes, by decreasing shale permeability.

Other water based drilling fluids also generate selective membranes using various products including cloud point glycols, silicates and **ALPLEX®**. In **PERFORMAX™** a two-prong approach is used to generate the membrane. This is done by reducing shale permeability using both mechanical and chemical means. **MAX-SHIELD™**, a deformable sealing polymer, having an extremely small particle size, is used to mechanically bridge micro-fractures on the exterior of the shale matrix.

Figure 7 - 4 Mechanics of MAX-SHIELD™



The polymer is stable and maintains its particle size distribution even in the presence of high salt concentrations. The particle size of the polymer is such that the polymer bridges fractures on the shale surface. The deformable nature of the polymer allows it to mould itself along the fracture which improves bridging (plugging) efficiency.

Aluminum chemistry (**MAX-PLEX™**) is used to form an internal bridge via precipitation within the shale matrix. The aluminum complex is soluble at the drilling fluid pH, but precipitates as it enters the shale matrix due to a reduction in pH, reaction with multi-valent cations, or a combination of both.

Silicate Based Drilling Fluids

Drilling fluids based on soluble silicates for the control of “heaving shale” were first introduced in the 1930’s. These drilling fluids, based on high concentrations of soluble silicates (i.e. 20 – 50% v/v) were successful in drilling over 100 wells in the Gulf Coast area, but were difficult to control because of high rheological properties, which caused their use to be discontinued until they were re-introduced in the late 1960’s. At this time it was found that most shales could also be stabilized with more dilute solutions (less than 20% v/v, typically 5 – 10% v/v) of sodium and potassium silicates, the latter systems being the more effective. Adding simple salts (e.g. KCl, K_2CO_3, NaCl) or non-ionic solutes (e.g. glycerol, ethylene glycol) contributed significantly to shale stability. This additional stabilizing effect was attributed to shale dehydration *through an osmotic gradient* generated by the solutes. Three wells were drilled with these fluids but they did not achieve acceptance. In the 1990’s silicates re-emerged. The following developments enabled re-introduction of these fluids:

- Understanding of the causes of the problematic control of rheological properties of previous silicate drilling fluids.
- The availability of compatible, high-performance polymer-based rheological property modifiers and filtration control agents.
- Advances in solids removal equipment.
- A better understanding of wellbore stability problems in general. It is now better appreciated that drilling success is not governed by drilling fluid chemistry alone, but also involves such critical factors as drilling fluid density, hole cleaning capacity, swab/surge etc.

Liquid sodium or potassium silicates are solutions of water soluble glasses, which are primarily manufactured by fusing either soda ash (Na_2CO_3) or potash (K_2CO_3) with silica (SiO_2) sands at high temperatures (1000 - 1200°C):

$$M_2CO_3 + nSiO_2 \quad \rightarrow \quad M_2O \,.\, n(SiO_2) + CO_2$$

Where M is either Na^+ or K^+ and n identifies the molecular ratio (i.e. the number of SiO_2 molecules relative to one M_2O molecule) and is typically in the range 1.5 – 3.3 for commercial; products.

The pH of silicate solutions is a function of the molecular ratio, but is always high; pH decreases with increasing ratio, i.e. when the silicate becomes more siliceous and less alkaline. When pH is lowered artificially (e.g. by the addition of acid) in relatively high concentration silicate solutions, the anionic silicate oligomers will polymerize and gel. Gelation is most rapid at neutral pH. Gelation times are lowered by the presence of mono-valent salts. Most importantly, silicates react almost instantaneously with dissolved polyvalent cations such as Ca^{2+} and Mg^{2+} to form insoluble precipitates.

Soluble silicate starts out as monosilicate which polymerizes rapidly to form negatively charged oligomers. At a pH of 11 – 12 (which is the pH of field drilling fluid formulations), polymerization halts because of mutual repulsion when relatively small oligomers have been formed. Such oligomers are still small enough to penetrate the tiny pores in the shale fabric (typically a few nanometers in diameter), transported by diffusion or hydraulic flow. Having entered the shale pore network, the following may happen:

1. Pore fluid pH is close to neutral ($pH \approx 7$) in virtually all shales. When the oligomers are diluted down to this neutral pH, they may overcome their mutual repulsion and coagulate, forming 3-D gel networks.

2. In all shale pore fluids, there are free polyvalent ions present (e.g. Ca^{2+} and Mg^{2+}), that will instantaneously react with the oligomers to form insoluble precipitates.

The gelled / precipitated silicates now become a means of stabilizing shales, as they:

a) Provide a physical barrier that prevents further drilling fluid filtrate invasion and pressure penetration. Thus, the wellbore and shale formation are effectively (pressure) isolated. Note that the gelation / precipitation process occurs very rapidly and is completed before significant fluid loss and pressure invasion has occurred.

b) Enhance the efficiency of the shale-drilling fluid membrane. Silicates are well known for their membrane building potential. To prevent destabilizing osmotic water flow from the drilling fluid to the shale the water activity of the silicate-based drilling fluid should be at least balance the shale activity (i.e. $a_w^{df} \leq a_w^{sh}$).

The presence of solutes, in particular simple monovalent salts like NaCl and KCl, , is synergistic in various ways:

- Monovalent cations like Na^+ and K^+ may exchange at the shale clay surfaces for Ca^{2+} and Mg^{2+}, which then become available for precipitating silicate.

- High salt concentration helps in the deposition of silicates as a gel by lowering characteristic gel times.

- Solutes can be used to balance the drilling fluid and shale activities (i.e. $a_w^{df} = a_w^{sh}$) to prevent osmotic water flow from the drilling fluid to the shale. It may be desirable to lower the water activity of the drilling fluid even further (i.e. $a_w^{df} \le a_w^{sh}$) using an excess of solutes. The resulting dehydration and pore pressure decrease may benefit shale stability.

Cloud Point Glycols

The organics typically used in high-performance water-based drilling fluid systems are to reduce filtrate losses, provide suspension properties, improve lubrication and to stabilize water-sensitive formations such as shales. In the 1990's polyglycols were introduced for stabilization. Polyglycol chemistry, characteristics and benefits of their use in drilling are well documented. Most of the applications gave been with the use of a supplemental inorganic electrolyte, typically potassium chloride, to aid in performance. This has allowed the use of less expensive polyglycols in many cases. The use of chloride salts is undesirable in land-based drilling due to disposal problems and where the high conductivity from the electrolyte interferes with the sensitivity of induction logs during exploratory drilling. Use of an alternative electrolyte, such as potassium acetate or formate is feasible.

Polyglycol Chemistry and Application

Polyglycols, as used in the drilling industry, are oligomers of polypropylene glycol or polyethoxylated and propoxylated short chain alcohols such as butanol. The chameleonic or TAME (Thermally Activated Mud Emulsion) polyglycols are the most widely used. They are characterized by their inverse solubility in water with temperature. These polyglycols are typically miscible with water at lower temperatures but, when heated, will eventually separate into two distinct liquid phases as the polyglycol becomes partially insoluble in the aqueous phase (See figure above). The temperature at which this occurs is defined as "Cloud Point" or "Cloud Point Temperature" (CPT) due to the scattering of the light by droplets of the polyglycol-rich phase which separate. This phenomenon is reversible as the separated phase re-dissolves once the temperature is lowered below the CPT. The exact CPT of a polyglycol

Figure 7 - 5 **Temperature Sequence of Glycol Cloud Point Formation**

solution is a function of the specific polyglycol used, its concentration and the presence of other dissolved materials, especially electrolytes.

The CPT for a given polyglycol and aqueous phase forms a locus of CPT's with concentration, or CPT curve, as shown in the figure below. Below the curve the polyglycol forms a single solution in water, but if the temperature of the solution is increased above the curve the solution will separate into two disticnt phases. The composition of the two phases is defined strictly by the temperature of the system and is given by the temperature of an isotherm (any horizontal line in the figure below) with the curve at the two points.

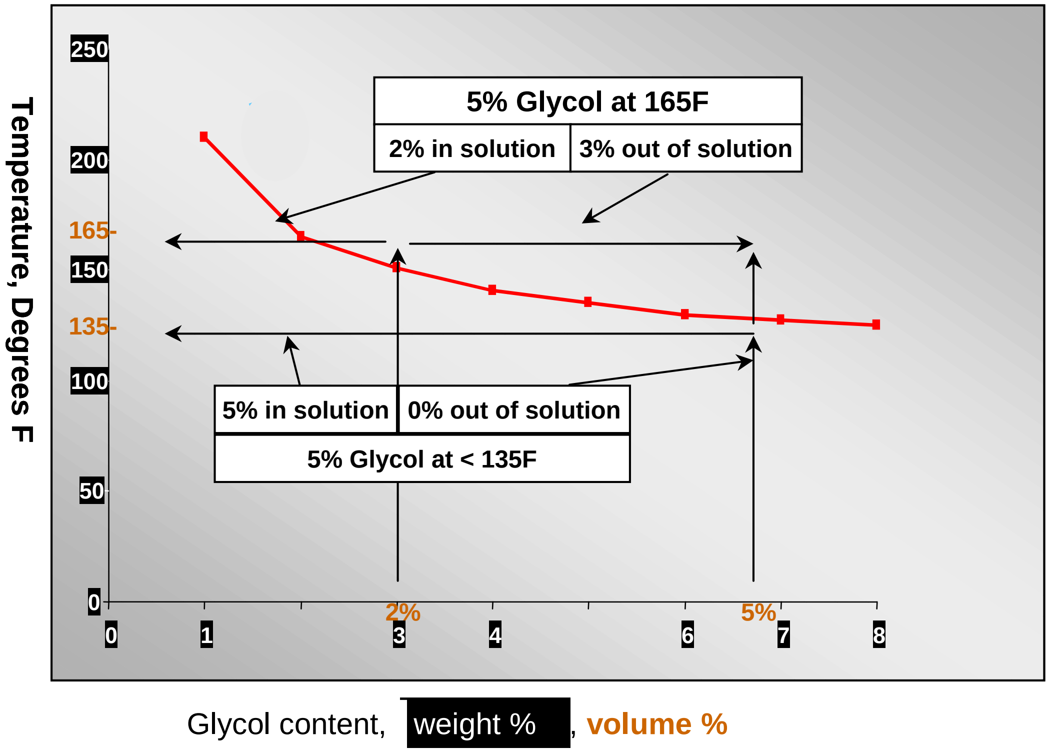


Figure 7 - 6 Phase Conditions of Cloud Point Formation

Baker Hughes Drilling Fluids' proprietary software GLY-CAD will perform CPT calculations and is the recommended tool for designing CPT glycol fluids.

The significance of the CPT is somewhat controversial, as the exact mechanism by which polyglycols stabilize clays and shales is debated. Polyglycols form complexes with clays. This fails to account for the wide variability in efficiency seen in various polyglycols. Most of the laboratory studies showing efficient and effective shale stabilization as well as the successful field applications have used polyglycol solutions at or near their CPT. This clearly suggests that the CPT is important, but the exact mechanism is elusive. Laboratory studies eventually provided insight into the importance of CPT and provided a mechanism by which chameleonic or TAME polyglycols provide highly efficient shale stabilization.

Polyglycol Shale Stabilization Mechanism

Below the CPT, the soluble polyglycols viscosify the drilling fluid filtrate. This filtrate will invade the shale, but the rate of invasion is retarded by the viscosity enhancement. When the temperature is above the CPT, the polyglycol solution becomes thermodynamically unstable, triggering phase separation of the polyglycols to form a concentrated emulsion. In this macro-molecular state, the polymers can no longer enter the shale and are also very ineffective at closing off the shale pore throats. Therefore, they do not have an effect on reducing fluid invasion of shales. Note, however, that not all of polyglycol will cloud out at the CPT. In fact, just above the CPT the majority of the polyglycol product remains in solution and determines the viscosity of the continuous phase. The dissolved fraction of polymers will enter the shale pore system unrestricted, and again the rate of pressure transmission is retarded by a factor equal to the filtrate viscosity enhancement. The soluble polyglycol fraction will only cloud-out if temperature is raised far beyond the CPT. As an example, for a certain 5% polyglycol solution with a CPT of 60°C, 100% phase separation will not occur unless temperature is raised above 90°C.

The discussions above emphasize the role of viscosity, and may be an explanation why good results have been obtained in the field with clouding polyglycols used far below or above the cloud point, and polyglycols that have no CPT. It should be noted, however, that relatively high concentrations (>10% v/v) of polyglycols are necessary to obtain the desired viscosity effects.

Under realistic downhole circulating conditions, a drilling fluid at bottom-hole circulating temperature (BHCT) contacts a shale at a higher bottom-hole static temperature (BHST), i.e. a drilling fluid/shale temperature gradient exists. Thus when a drilling fluid invades a shale, it heats up, thereby changing temperature dependent fluid properties.

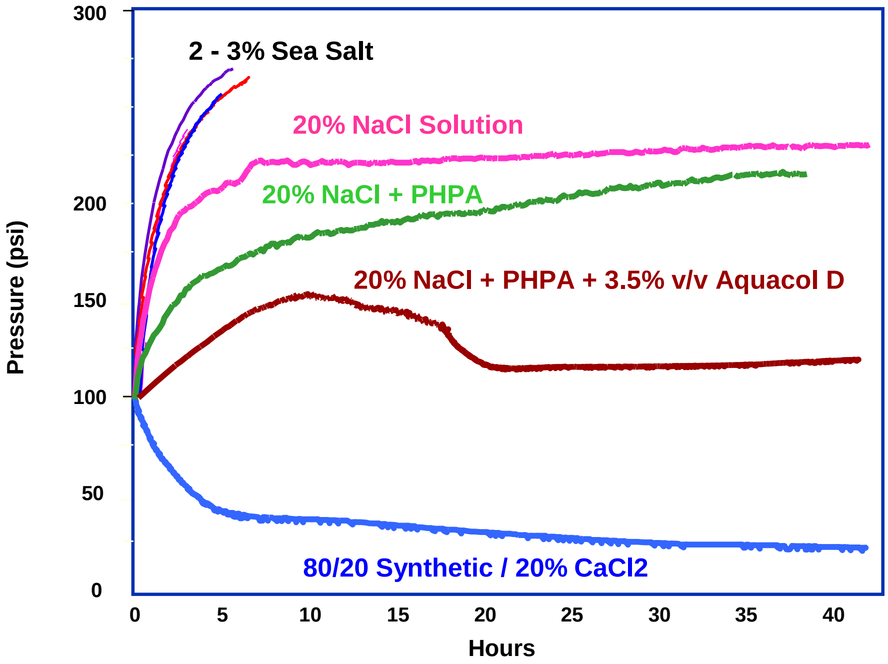


Figure 7 - 7 Typical PPT Data For Various Fluids

The above figure shows pore pressure transmission results from various fluids. The 20% NaCl + PHPA + 3.5% v/v **AQUA-COL™ D** is a cloud point glycol fluid designed to cloud out in the simulated drilling fluid/shale temperature gradient. A lower pore pressure build-up was obtained with the polyglycol fluid than with the other water based fluids. The difference is too great to be attributed to viscosity effects. It is believed that the following mechanism explains this difference. A polyglycol solution is designed with a CPT that coincides with the BHCT, i.e. at the bit the polymers are just starting to cloud out. This solution invades the shale under the influence of hydraulic and diffusion gradients, and will experience temperature elevation due to the higher Bottom Hole Static Temperature (BHST). Temperature induced phase separation now occurs and emulsions are formed in situ, filling the shale pores. Possible, phase separation forces the polymers onto the shale surfaces, coating them and changing their wettability. The fraction of polymers deposited in situ now becomes a barrier that restricts further fluid invasion and drilling fluid pressure penetration. Thus, the wellbore and shale pore system are isolated and the shale is effectively stabilized.

Design Criteria for Polyglycol Drilling Fluids

1. The polyglycol molecules should be small enough to invade the shale pore network to form an emulsion in situ. Typically, the molecular weight of the additives should be in the range 500 – 2000 a.w.u. High molecular weight (>100,000) polyglycols are restricted from entering shales due to their size, and will therefore not be effective in closing off the shale pores.

2. The polyglycols should display cloud point behavior.

3. The CPT of the polyglycol solution should be tailored to coincide with the BHCT, in order to fully exploit the temperature gradient between the wellbore and the formation (BHST). The CPT may be changed in several ways:

   - As polyglycols with different chemical composition will have different CPTs, the right polyglycol may be chosen for the set of circumstances;

   - The CPT can be influenced by changing salt content of the drilling fluid;

   It is noted that matching the CPT to BHCT may be difficult when a long shale section is drilled with continuously increasing BHCTs. There are two ways to tackle this problem:

   - The drilling fluid contains a blend of polyglycols with different cloud points, such that glycols will cloud out at every BHST encountered;

   - The salt content of the drilling fluid is depleted while drilling the section : lowering the salinity will raise the CPT of the polyglycols.

   Note: All of the above are most easily adjusted by use of GLY-CAD.

LOSS OF CIRCULATION

Reference is made in this section to: **Prevention and Control of Lost Circulation: Best Practices,** Reference Manual 750-500-104, by Atlantic Richfield & Baker Hughes Drilling Fluids, February 1999.

Loss of circulation is the loss of whole drilling fluid to exposed formations. This will occur where there is a permeable zone with openings of sufficient size to permit entrance of whole fluid, and/or the hydrostatic pressure is greater than the formation fracture pressure.

Improved drilling fluid technology, a greater understanding of hydraulics, and drilling practices have greatly reduced the incidence of loss of circulation in most areas. However, in spite of continued research to improve technology, loss of circulation problems still adversely affect many drilling operations. Resulting treatments, extra casing strings, increased drilling time, and drastically altered drilling programs greatly increase the overall drilling cost on these wells.

In general, the two classes of loss of circulation are,

- those inherent to the formation or natural loss of circulation
- those of a mechanical nature caused by poor drilling techniques

There are four types of loss of circulation zones in these classes.

1. Zones of *normal strength* which have been fractured by the use of high-density or high-viscosity drilling fluids or by pipe handling pressure surges
2. Zones that are *naturally fractured* or containing joints and fissures
3. Zones that are coarsely permeable, such as gravels and some conglomerates
4. Zones that are *cavernous*, such as limestones and dolomites, with vugular or “honeycomb” porosity large enough to take whole drilling fluid

Loss of circulation into all of these zones can be precipitated by improper control of drilling fluid density, flow properties, or pressure fluctuations. Field studies have shown that excessive drilling fluid pressure fluctuations are often the main cause of loss of circulation. Factors that influence the magnitude of pressure fluctuations include fluid rheological properties, speed of pipe movement (surge pressure), relative diameter of the components (drillstring to borehole diameter), and volumetric flow rate.

Pressure surges cannot be blamed for all loss of circulation, although this is a key variable. For example, drilling fluid may be lost to fractures or cavernous formations that cannot support a normal hydrostatic head. Conversely, in some areas high hydrostatic pressures that are necessary to control high formation fluid pressures cause loss of circulation in adjacent formations. Preventive measures must be tailored to the area and the nature of the loss.

Preventive Measures

Prevention of lost circulation is very important due to the difficulties in curing the problem once it occurs. Measures to combat loss of circulation should include the following:

- Use minimum drilling fluid densities consistent with formation pressures and borehole stability requirements.

- Evaluate area well data and drilling parameters to aid in proper placement of casing strings. In many areas, it is possible to estimate formation pressures with shale density, drilling rates ("d" exponent), and log data. If pore pressure is known, it is generally possible to predict the fracture gradient accurately.

- Loss of circulation problems to known porous or finely fractured zones may be pre-treated with a fine bridging material such as **MIL-PLUG®, MILMICA®, LC-LUBE**, **MIL-CARB™,** and/or **CHEK-LOSS®.** However, fine shaker screens will remove a large percentage of these additives from the fluid system. Occasionally, shaker screens are bypassed in order to keep these products in the system without having to continuously replace what the shaker screens are discarding. This practice is detrimental to solids control but, at times, can be justifiable. To prevent the build-up of solids in the fluid system, lost circulation pills are spotted in the area of loss in an attempt to cure the problem. When circulated out of the hole, the lost circulation material is removed from the system at the shale shakers. **It should be recognized that the addition of these and other LCM may contribute to increased drilling fluid rheological properties, thereby increasing pressure loss and the aggravation of lost circulation. The application of LCM under these conditions should be carefully considered.**

- Surge pressures, circulating pressure losses, and pressures occurring while breaking circulation after trips could contribute to loss of circulation. The surge pressures should be calculated using ADVANTAGE^{SM} engineering software on critical operations to determine safe pipe-running speeds and to predict effects of fluid rheological properties. Annular friction losses while circulating may require alteration of flow properties and circulating rate to prevent losses.

On deep, hot holes, gelation of drilling fluid may cause loss of returns during attempts to break circulation. Tests with the Fann Consistometer, Fann Model 70/75 Viscometer, high temperature high pressure aging cells and shearometers can be utilized to predict the degree of gelation and assist in determining proper corrective treatment. When breaking circulation, upward movement and rotation of drillstring will reduce pressures. Standpipe chokes (hand adjustable choke installed on standpipe with bypass line discharging into mud pit) if installed, would be useful to aid in breaking circulation with a slow, gradual increase in standpipe pressure. Procedures for predicting surge/swab pressures are outlined in the section dealing with basic hydraulics equations.

Annular restrictions due to balled bits, collars, and stabilizers are not uncommon while drilling gumbo shales. Reduction in annular size, regardless of the cause, can impose additional pressure against the formation which may result in loss of circulation. Preventive measures to be considered are;

- Use of fluid additives such as MIL-LUBE®, BIO-DRILL®, PENETREX®, or the environmentally friendly TEQ-LUBE® or LUBE 622 minimizes the build-up of clay solids on the drillstring and bit.

- Controlled penetration rates may be necessary in troublesome zones.

- Improved hydraulics may alleviate bit balling in some cases.

- *Inhibitive* fluids such as **CARBO-DRILL®**, **SYN-TEQ®**, **ALPLEX®**, **PERFORMAX™** and potassium-base and/or calcium-base drilling fluids (lime and gypsum fluids) may provide sufficient protection against swelling and sticky shale. Plastic deformation (flow of shales into wellbore) may be controlled or minimized with these systems. In most cases, however, it is necessary to increase drilling fluid density to restrain plastic flow of shales.

- Wellbore deviation also must be considered as a factor in wellbore constriction. In deviated wellbores of 30 degrees and higher the cuttings bed forms on the low side of the annulus and with improper hole cleaning the cuttings bed will build, reducing the annular opening. These beds travel up the wellbore in dune-type movements. That is, as the bed reaches a given height of deposition it will be washed higher up the wellbore to be deposited until a deposition height reaches a sufficient height to be washed again. This movement of the cuttings bed causes pressure fluctuations within the annulus, due to varying wellbore diameter restrictions. These cuttings beds are unstable and tend to “avalanche” (slide back down the hole). These avalanches can, in the worst case, cause packing-off of the annulus. It is recommended to run hole cleaning simulations in ADVANTAGE in order to identify, and if possible remedy, the formation of cuttings beds.

Another possible cause of annular restriction is wall cake build-up. This problem is normally associated with low annular velocities, high filtrate values, and permeable formations. It can generally be alleviated by reducing the API Filtrate (thinner wall cake) and/or the differential between fluid hydrostatic and formation pressures.

Seepage Loss

Seepage loss **(<25 bbl/hr WBM or, <10 bbl/hr OBM)** is usually associated with permeable formations such as loosely cemented, porous sands encountered in younger sediments. This type of loss is sometimes remedied with fine lost circulation material (LCM) such as **MILMICA®, MIL-PLUG®, CHEK-LOSS® MIL-CARB™** and **SOLUFLAKE™** (acid soluble) accompanied by the viscosifier **MILGEL®** as necessary. Some lost circulation materials are effective as bridging agents. These include coarse granular materials. Fibrous and flake materials are adequate filter cake building materials. Most effective applications of LCM are accomplished by combining various amounts of bridging and filter cake building materials. In some areas, fluid is flocculated (thickened) with lime or cement to control loss in highly permeable zones (gravel, coarse sand). This practice should be used with discretion because filtrate and wall cake thickness may be increased by the addition of lime, and back pressure caused by the decreased annular clearance can result in increased fluid losses.

Seepage loss can often be cured by pulling the drill string inside the casing and waiting six to eight hours. This approach may be enhanced if fine bridging materials are added to the drilling fluid left in the hole. Excessive penetration rates coupled with low circulation rates may result in high annular drilling fluid densities which can promote loss of circulation. For example, drilling

20 feet per minute with a 17½ inch bit and a flow rate of 500 gal/min could result in a fluid density increase from 10.0 to 13.6 lb_m/gal in the annulus. While this may be an extreme example of a fluid density increase when drilling large diameter holes at a high penetration rate, it effectively describes the situation. Remedial procedures for this problem would be (1) decrease penetration rate, (2) increase pump rate, or (3) circulate several minutes after drilling each drill pipe joint down. Real time annular pressure sensors have proven extremely useful in monitoring these conditions.

Partial Loss

Partial loss **(25–100 bbl/hr WBM or, 10–30 bbl/hr OBM)** is generally associated with coarsely permeable zones (gravel beds or vugular limestones), faulty cement jobs, and induced or existing fracturing. As noted earlier, a defective cement job is normally solved by cement squeezes. Loose to coarsely permeable and finely fractured zones may be cured by adding materials such as medium **MILPLUG®, MIL-SEAL™, MIL-CEDAR FIBER™, Kwik-Seal, MIL-FIBER®, MILFLAKE®**.. and **SOLUFLAKE™** (acid soluble). If loss is severe, mix a concentration of lost circulation material (30 to 40 lb_m/bbl of **MIL-SEAL**, for example) into a portion of the system and spot opposite the loss zone. After spotting this material, pull into the casing and wait six to eight hours.

Another technique which has been successful with partial fluid loss is squeezing the loss zone with high filter loss slurries such as **SOLU-SQUEEZE** or Diaseal M. The addition of 10 to 20 lb_m/bbl of **MIL-SEAL** to this slurry will generally improve the chances of success. Mixing procedures for Diaseal M are given in Table 7-1. When applying a high fluid loss slurry, squeeze slowly (½ to 1½ bbl/min) with low squeeze pressures (50 to 100 psi). Normally, final squeeze pressures should not exceed 0.1 psi per foot of depth. Obviously, for low squeeze pressures, it is desirable to have an accurate, low-pressure gauge for reading annular pressures.

Density (lbm/gal)	Diaseal M		MIL-BAR®. (sacks)	Water (bbl)
	(lb)	(sacks)		
9	50	1.00	0.0	0.87
10	50	1.00	0.6	0.84
11	47	0.94	1.2	0.80
12	42	0.84	1.8	0.77
13	38	0.76	2.3	0.74
14	34	0.68	2.9	0.70
15	31	0.62	3.5	0.67
16	28	0.56	4.0	0.63
17	25	0.50	4.6	0.60
18	22	0.44	5.2	0.56
Example: 100 bbl of 14 lb_m /gal Diaseal M slurry required 68 sacks Diaseal M, 290 sacks MIL-BAR, 70 bbl water, and MIL-PLUG if desired				

Table 7 - 1 Formula for Preparing One Barrel Diaseal M Weighted Slurry with Fresh Water, Bay Water, or Sea Water

If water-absorbing materials such as **MIL-SEAL™** are employed, it is advisable to add a reduced quantity of Diaseal M and observe the effect of lost circulation material on viscosity prior to adding the remainder.

	Water or Oil			SOLU-SQUEEZ			MIL-BAR®		
[1]Density, lbm/gal	FW, bbl	SSW, bbl	Oil, bbl	FW, lbs	SSW, lbs	Oil, lbs	FW, lbs	SSW, lbs	[2]Oil, lbs
10.0	0.90	-	0.876	85.2	-	85.2	60	-	115
12.0	0.83	0.88	0.805	71.6	83	71.6	180	90	230
14.0	0.76	0.81	0.735	58.6	71	58.6	290	220	342
16.0	0.69	0.74	0.666	47.8	59	47.8	400	340	454
18.0	0.62	0.66	0.596	36.8	46	36.8	520	460	564

Table 7 - 2 Formula For Preparing One Barrel SOLU-SQUEEZE Weighted Slurry with Fresh Water, Saturated Salt Water (SSW), or Oil

Note 1: Depending on rig mixing equipment minor modifications to the formulation may be required. At mud weights below 12 lbm/gal, viscosity can be increased with small amounts of XAN-PLEX D. At higher mud weights, viscosity can be reduced with water dilution if necessary. Pilot test for optimum results.

Note 2: At mud weights above 14 lbm/gal, depending upon rig mixing equipment, small amounts of OMNI-COTE may needed to help oil wet the SOLU-SQUEEZ pill. Always pilot test as over - treatment with OMNI-COTE can cause barite settling. At low mud weights, small additions of CARBO-GEL can be added if viscosity is too low.

Severe (or Total) Loss of Returns

Severe or Total drilling fluid loss **(>100 bbl/hr WBM or, >30 bbl/hr OBM)** may occur as a result of a faulty cement job around the casing shoe, induced or natural fractures, or coarsely permeable zones such as gravel or reef structures. Total loss may be cured with cement (neat or bentonite cement for 14.5 to 15.5 lb_m/gal slurries and gilsonite cement for slurries with densities below 14.5 lb_m/gal).

Four basic squeeze slurries designed for the most severe or total loss of returns are: (1) Diesel Oil Bentonite Cement, (2) Water Organophilic Clay Plug, (3) **MAGNE-SET®,** and (3) **X-LINK™.** Details of each squeeze follows:

Loss to faulty cement jobs can best be remedied by squeeze cementing. However, in some cases (such as inability to pull out of hole for squeeze tool due to kicking formation), it may be necessary to utilize a squeeze slurry. Loss to induced fractures (hydrostatic head of fluid column exceeds fracture gradient) may best be remedied by the use of soft plugs, diesel oil-bentonite-cement squeezes, or diesel oil-bentonite squeezes. Diesel oil-bentonite-cement squeezes are prepared by adding 2 sacks of cement and 2 sacks of **MILGEL®** for each barrel of diesel. Final volume of this mixture is 1.39 bbl. When this slurry is spotted and enters the thief zone, it comes in contact with the water-base fluid which causes the bentonite to hydrate forming a plastic plug.

DIESEL OIL BENTONITE CEMENT SQUEEZE

Procedure for mixing and spotting diesel-bentonite squeeze slurry is as follows.

1. Pull out of hole and locate loss zone with temperature or radioactive survey. Run in hole open-ended to top of loss zone.

2. Mix slurry volume equivalent to or greater than open-hole volume below point of loss. For 100 bbl of slurry, add 154 sacks of **MILGEL**, 154 sacks of cement, and 72 bbl of diesel.

3. Pump 5 bbl of diesel in front of slurry to serve as a buffer between drilling fluid and squeeze slurry. Start pumping slurry and continue until slurry reaches bit (follow slurry with another 5 bbl diesel spacer). After slurry reaches the bit, close preventers and begin pumping drilling fluid into annulus at rate of 2 bbl/min while displacing slurry, from drillpipe, at a rate of 4 bbl/min. After pumping ½ of slurry, reduce pump to ½ speed (1 bbl/min annulus and 2 bbl/min on drillpipe). After pumping ¾ of slurry, attempt "hesitation" squeeze pressure of approximately 100 to 500 psi. Under-displace slurry so that approximately 1 bbl remains in drillpipe.

4. Pull out of hole and wait eight to ten hours to allow slurry to set.

Diesel oil-bentonite squeezes (400 lb of **MILGEL** per bbl of diesel) are run in a similar manner, but will have a lower set strength than diesel oil-bentonite-cement squeezes.

WATER ORGANOPHILIC CLAY PLUG

In oil based drilling fluids, the reverse of an oil bentonite plug is used, the water organophylic clay plug (reverse gunk squeeze). In oil based drilling fluids, a clay which has been chemically treated to render it oil dispersible is used to provide viscosity. This Organophylic clay will not yield in water but will yield in oil in the presence of water. Thus, if a high concentration of Organophilic clay dispersed in water is pumped to the loss zone, on contact with oil based drilling fluid, it will form a strong solid material.

1. The gel used in the reverse gunk-squeeze will yield with OBM, and should therefore not come into contact with OBM until the gunk exits the drill string. Preventing OBM from entering the batch tank and associated lines is imperative.

2. For the reverse gunk squeeze to work properly, the bit must be located just above the loss zone so that the gunk will yield in the loss zone.

3. Pumping OBM down the annulus, simultaneously with pumping down the drill string, will ensure that the gunk mixes with the OBM, and prevents the gunk from being squeezed into a zone above the bit, which could stick the drill string.

4. Performing an open hole squeeze with the drill string across permeable zones can result in differential sticking of the drill string. Therefore, it is important to keep the squeeze pressure on the annulus low, and minimize the time the drill string is stationary. Do not reciprocate the drill string while the annular preventer is closed, as the gunk may mix across the BHA and stick the pipe.

5. This type of pill cannot be reversed out of the pipe.

Mixing Procedure

1. Ensure that the cementing unit and cementing batch tank are clean.
2. Mix reverse gunk pill in the cementing batch tank:

Formulation (typical) for 1 bbl mix:

Water	0.55 bbl
Defoamer	0.15 gallons
Soda Ash	1.22 lbs
Bentone 128	210 lbs

Placement of the Plug

- Run in hole with open ended drillpipe and place the bottom of the drillpipe +/- 1 joint above the thief zone. Pump the gunk pill down the open ended drill pipe, with 5 bbl water spacer ahead and behind as spacer. If well-bore pressure or conditions prevent the drill string being pulled out of the hole, those involved should evaluate the possibility of displacing this mix through the drill string and bit.
- Displace with drilling fluid until the water ahead reaches the bottom of the drillpipe.
- Close the annular preventer.
- Squeeze gunk with the two cement unit pumps;
  - Pump No.1: Pump down DP at 2 BPM
  - Pump No.2: Pump down annulus at 0,5 BPM
- Squeeze down total gunk pill volume (until all water is cleared from the drill pipe).
- Pull drill pipe well above gunk.
- Hold the squeeze pressure for 30 to 60 minutes.
- Carefully place weight on the gunk pill to test the pill firmness. A maximum period of 3 hours should be given for the gunk to set up.

MAGNE-SET® SQUEEZE SYSTEM

Description

MAGNE-SET, used as an alternative to cement plugs, offers these advantages in addition to quick-mixing. **MAGNE-SET** can be mixed in the mud pits or slug tank.

- This material may be spotted with the drill bit in place.
- **MAGNE-SET** has very little effect on the fluid system.
- **MAGNE-SET** contains no diesel and does not affect the toxicity of the fluid system as diesel would.

Table 7-3 and Table 7-4 give slurry formulations.

Slurry Volume (bbl)	Water Volume (bbl)	MAGNE-SET (sacks)
10	6	64
20	12	128
25	15	160
30	18	192
35	21	224
40	24	256
45	27	288
50	30	320

Table 7 - 3 MAGNE-SET Slurry Formulations

Bottomhole Temperature (°F)	Pounds per Barrel			
	MAGNE-SET	Accelerator	Retarder	Thinner
90 - 110	106	54	4	—
110 - 130	123	37	5	—
130 - 150	139	21	1	—
150 - 170	160	—	—	—
170 - 190	160	—	6	—
190 - 210	160	—	11	3

Table 7 - 4 MAGNE-SET Additive Concentrations - Sacks per 25 bbl

Recommended Treatment (MAGNE-SET®)

For most lost circulation problems, a slurry of 25 or 50 bbl of **MAGNE-SET** is sufficient. A small extra quantity should be mixed to allow for any residual slurry that cannot be pumped from the tank or pit.

Mixing Procedure

1. Add water to a clean pit or tank.
2. Dissolve the proper amount of **MAGNE-SET** retarder in the water.
3. Dissolve the proper amount of **MAGNE-SET®** thinner in the water/**MAGNE-SET** retarder solution.
4. Add **MAGNE-SET** powder to the solution until weight is 14.0 lb_m/gal. If foaming occurs, add **W.O.™ DEFOAM**.

5. Mix for approximately five minutes after addition of last sack. Mix until the material forms a smooth blend.

6. When **MAGNE-SET** accelerator is used, it should be added last to the slurry, mixed just enough for proper dispersion, and pumped downhole in a *non-stop* operation.

Note: *The weight of the blended slurry should be 14.0 lb_m /gal to assure optimum performance. The weight is reduced by adding water and increased by adding MAGNE-SET.*

Typical Pumping Procedure

1. If possible, locate the lost circulation zone.
2. Pull drillstring above the lost circulation zone.
3. Pump the **MAGNE-SET** slurry into the drillpipe.

Note: *Clean the empty tank or pit with water, or flush with fluid from the active system.*

4. Using fluid from the drilling fluid system, pump the **MAGNE-SET** slurry down to the lost circulation zone. Pump slurry at maximum rate.
5. If required by hole conditions, the **MAGNE-SET** slurry can be squeezed into the formation using standard squeeze procedures.
6. Pull up above the top of the **MAGNE-SET** slurry.
7. Allow **MAGNE-SET** to cure for eight hours, keeping the annulus full if possible.

X-LINK® SYSTEM

Baker Hughes Drilling Fluid's **X-LINK™** system combines advanced, cross-linking polymers with bridging agents to provide quick, reliable control of fluid loss. In addition, **X-LINK** offers a proven means of controlling the more severe circulation losses resulting from large fractures or vugular spaces.

X-LINK pills are temperature-activated and setting time is controlled through the addition of accelerator (**X-LINK® ACR**) or retarder (**X-LINK® RTR**) during mixing, thereby eliminating the risk of premature setting at the surface or while pumping through the bottom hole assembly.

Mixing Procedure

The mixing of an **X-LINK** pill does not require any specialized equipment and can be accomplished at the rig site. A 40 lb. bag of **X-LINK** makes one barrel of pill. Set-up time is controlled by the well's bottom hole temperature (BHT). It is vital that the well's temperature profile be known prior to the **X-LINK** application. A supplemental retarder is required for use in wells possessing bottom hole temperatures greater than 150º F (65° C). In addition, an accelerator is available for cold water applications. **X-LINK** pills can be used in water, synthetic- or oil-base drilling fluids.

In the event an **X-LINK** pill is mixed but not pumped, it can be bled back into the active mud system. If no accelerator is used, there is no danger from gelation in the tank provided retarder was used in the formula. If an accelerator was used, the pill can be diluted with water to a 1% solution to eliminate cross-linking.

Once the **X-LINK** pill sets, it is easily drilled or reamed and can be removed from the mud system over conventional shale shakers.

Temperature, °F	X-LINK, lbs/bbl	Accelerator, lbs/bbl	Retarder, lbs/bbl	Retarder, gal/bbl	Pumpable Time, min	Set Time, min
60	40	0.3			27	90
120	40	0.078			80	150
150	40		5.85	0.53	90	180
200	40		10.4	0.95	90	180
250	40		15.6	1.42	90	180
300	40		17.6	1.60	90	180

Table 7 - 5 Formulation for One (1) Barrel of Un-weighted X-LINK as Function of Temperature

Temp	200º F				250º F				300º F			
Density, lb//gal	H_2O, bbl	X-LINK, sks	RTR, gal	MIL-BAR, sks	H_2O, bbl	X-LINK, sks	RTR, gal	MIL-BAR, sks	H_2O, bbl	X-LINK, sks	RTR, gal	MIL-BAR, sks
12	87	87	86	192	87	87	117	191	87	87	138	190
13	83	83	82	247	83	83	112	246	83	83	132	245
14	80	80	78	303	80	80	107	302	80	80	126	301
15	76	76	75	359	76	76	102	359	76	76	120	357
16	72	72	71	414	72	72	97	413	72	72	114	413
17	68	68	67	470	68	68	92	469	68	68	108	468

Table 7 - 6 Formulations to Build 100 Barrels of Weighted X-LINK Plug

Other Types of Remedial Techniques

Extremely severe drilling fluid losses, such as those encountered while drilling cavernous zones and depleted reservoirs may require specialized techniques, such as drilling with air, drilling with stiff foam, drilling with aerated fluid (using either an injection string run on outside of the casing string or using concentric drillpipe), drilling with a mud-cap, or drilling blind until the loss zone is cased off. With the exception of drilling blind, the methods noted above require special equipment and preparation and should be planned before drilling operations begin.

It should be noted that severe corrosion problems may be encountered with aerated fluids if preventive measures are not taken.

Lost Circulation Prevention by “Stress Cage” Technique

Induced losses occur when the drilling fluid density, required for well control and to maintain a stable wellbore, exceeds the fracture resistance of the formations. A particular challenge is the case of depleted reservoirs. There is a drop in pore pressure as the reserves decline, which weakens hydrocarbon-bearing rocks, but neighboring or inter-bedded low permeability rocks (shales) may maintain their pore pressure. This can make the drilling of certain depleted zones virtually impossible – the drilling fluid density required to support the shale exceeds the fracture resistance of the sands and silts. The potential prize is clear if a way can be devised to strengthen the weak zones and thereby access these difficult reserves. In fact, the value of wellbore strengthening is much more wide-ranging and includes the following applications/benefits:

- Access to additional reserves (depleted zones)
- Reduced drilling fluid losses in deepwater drilling
- Loss avoidance when running casing or cementing

- Elimination of casing strings
- An alternative option to expandable casing

Various studies have investigated wellbore strengthening with a view to preventing drilling fluid losses. One method suggests using temperature changes to alter the stress state around the wellbore. Drilling fluid heaters can be used to heat the circulating fluid and increase the near-wellbore stresses, thereby giving a strengthening effect. However, this method might be difficult to control and would not be suitable in wells with an already high bottom hole temperature. In an alternative approach a method was developed to allow small fractures to form in the wellbore wall, and to hold them open using bridging particles near the fracture opening. The bridge must have a low permeability that can provide pressure isolation. Provided the induced fracture is bridged at or close to the wellbore wall this method creates an increased hoop stress around the wellbore, which is referred to as a “stress cage” effect. The aim is to be able to achieve this while drilling by adding appropriate materials to the drilling fluid. Short fractures are best and so it is necessary to arrest the fracture growth very quickly as the fracture starts to form. This means high concentrations of bridging additives will be preferable. The additives need to be physically strong enough to resist the closure stresses, and sized to bridge near the fracture mouth to produce a near wellbore stress cage. Assuming an opening width of 1 mm, the particle size distribution of the fluid would need to range from the colloidal clays up to values approaching 1 mm, to give a smooth particle size distribution and produce a low permeability bridge.

In permeable rocks the particle bridge need not be perfect because fluid that passes through the bridge will leak away from within the fracture into the rock matrix. Thus, there will be no pressure build-up in the fracture and the fracture cannot propagate. Achieving a stress cage effect in permeable rocks is straightforward. If the drilling fluid contains particles that are too small to bridge near the fracture mouth, the fracture could still become sealed by the build-up of a filter cake inside. Fracture gradients observed in sands are usually higher than predicted by theoretic models, probably due to the presence of solids in the drilling fluid and the deposition of filter cake.

In low permeability rocks such as shale the bridge will need to have an extremely low permeability to prevent pressure transfer into the fracture and fracture propagation. “Ultra-low fluid loss muds” with HPHT filtrates as low as 0.1 ml are thought be beneficial to wellbore strengthening. The driving force for bridge formation across a shale fracture needs to be considered carefully. The initial rush of fluid into the fracture when it forms will deposit the bridging solids at the fracture mouth, but a pressure difference across the bridge is required to hold it in place. Pressure decay into the shale matrix behind the bridge will be minimal especially with oil-based drilling fluids, which have an added sealing action due to interfacial tension (capillary pressure) effects. In water-based drilling fluids, there may be a slow pressure leak-off into the shale, but the challenge would then be to produce water based drilling fluid with an ultra-low filtrate so that the bridge at the fracture mouth has a sufficiently low permeability.

- Laboratory studies and field experience have shown calcium carbonate and graphitic blends (**LC-LUBE**) as one of the best ways to reduce mud losses into fractures.

- The fluid should contain a smooth/continuous range of particle sizes ranging from clay size (around 1 micron) to the required bridging width.

- Ideal packing theory (the d ½ rule) is useful for selecting the optimum size distribution in low density drilling fluids.

- High particle concentrations are best and at least 30 ppb of bridging mix is required for an efficient seal.
- In the laboratory fracture sealing has been successful up to 300°F and 4000 psi overbalance pressure in some tests.
- Drilling fluid density is not a critical factor in forming a successful bridge.
- The bridging material can be used in pills if the section can first be drilled with a drilling fluid density below the fracture gradient, and then subsequently strengthened by squeezing a pill across the weak zone.

On the Brent field in the UK North Sea, in the depleted reservoir zone, experience has shown that the use of **LC-LUBE** can add approximately 900 **-** 1250 psi to the fracture propagation pressure. Recommended **LC-LUBE** concentration in the active system is 6 – 20 ppb, though on Brent 20 ppb was used.

DRILLSTRING STICKING

The primary causes of stuck drillpipe include:

- differential-pressure sticking
- key seating
- junk in hole and/or collapsed casing
- wellbore instability (sloughing shale or plastic deformation of shale or salt)
- inadequate hole cleaning due to rheological properties, hydraulics, or hole enlargement.

Many instances of stuck pipe are a result of wall sticking (differential pressure sticking) which usually occurs in the drill collars and bottomhole assembly because of the increased surface area exposed to the wellbore. This section will deal primarily with this problem and related preventive and remedial measures.

Differential pressure or wall sticking is the result of the force holding the pipe against a permeable zone while the pipe is motionless. This force is roughly equivalent to the differential between hydrostatic and formation pressures and the surface area upon which the force is acting. Also important, but more difficult to define, is the friction which exists between the pipe and filter cake. The friction coefficient will vary with the fluid’s chemical composition and the type of solids in the filter cake (coefficient is considerably higher for barite than for bentonite).

The equation suggested by Outmans to describe sticking force is,

$$F = f \times A \times S$$

where,

F = friction between drillstring and wall cake, or the total pulling force in pounds that would be necessary to pull pipe free,

A = area of contact between filter cake and pipe (in.^{2}),

S = pressure existing between pipe and wall cake in psi. During sticking process, this pressure will range from 0 initially to that differential pressure which exists between the hydrostatic of the fluid column and the formation.

f = coefficient of friction between the pipe and wall cake (laboratory data indicates coefficient of friction values ranging from approximately 0.07 for invert emulsions to approximately 0.40 for low solids, native fluids).

The above equation indicates that the sticking force may be reduced by altering the following physical properties of a drilling fluid.

- Control fluid densities at lowest practical level consistent with control of formation pressure and borehole stability.
- Monitor filtration and wall cake properties with emphasis on a thin wall cake. Evaluate effect of time and temperature on the wall cake. The filter cake thickness of two fluids may be equal in an API filtrate test (100 psi for 30 minutes), whereas the cake thickness could vary greatly with an increase in time, pressure, or temperature. Static conditions produce filter cakes of greater thickness as compared to dynamic conditions where the filter cake continues to erode due to fluid flow.
    - Control drilled solids at the lowest practical level.
    - Utilize additives which aid in reducing friction coefficient and sticking coefficient.
- Severe conditions may dictate the use of an oil/synthetic fluid system such as **CARBO-DRILL®/SYN-TEQ®**. This type of fluid offers maximum protection against wall sticking.

Other preventive measures against differential sticking are, (1) reduce area of contact between collars and wall cake with spiral collars and/or stabilizers, and (2) minimize interruption of pumping, particularly when the drillstring is not in motion.

Most instances of differentially stuck pipe are preceded by increases in torque and drag. Many lubricants have been developed to minimize torque and drag, which in turn should reduce the chances of differential sticking. Some of these lubricants are shown in Table 7-6 and will be discussed in more detail under the section titled, **Lubricity**.

Product	Initial Recommended Treatments	Maintenance
LUBRI-FILM®	4 lb_m/bbl	Dependent upon fluid dilution
MIL-LUBE™	0.5% to 2.0%	Dependent upon fluid dilution
AQUA-MAGIC®	1.0% to 8.0%	Dependent upon fluid dilution

Table 7 - 7 Lubricants

Spotting Fluids

Baker Hughes Drilling Fluids offers a variety of spotting fluids which are designed for use in every drilling environment. These spotting fluids may be used in either weighted or un-weighted systems.

- **BLACK MAGIC® –** a compound with a premium-grade, high melting point asphalt in diesel oil. Barite is added at the rigsite to the liquid solution.
- **BLACK MAGIC® LT** – contains a premium-grade asphalt compounded in a low-toxicity mineral oil. Barite is added at the rigsite to this liquid solution.
- **BLACK MAGIC® SFT®–** (Sacked Fishing Tools) is a dry mixture of optimum size air-blown asphalt, lime, fatty acids, and dispersants in a powdered form. This sack product is stored at the rigsite and mixed with low-toxicity mineral oil, #2 diesel, or synthetic fluids.
- **BIO-SPOT®–** a non-toxic, oil free, water soluble spotting fluid concentrate. **BIO-SPOT®** can be mixed rapidly and contributes virtually no toxicity to water-base fluid systems. **BIO-SPOT** is recommended for use when the use of oil and toxic surfactant blends are undesirable.
- **MIL-SPOT™ 2** – a liquid blend of a long chain fatty acid pitch, an emulsifier, and gellant. MIL-SPOT 2 can be used in #2 diesel, low-toxic mineral oils or synthetic fluids.
- **MIL-FREE** - a liquid concentrate containing a long-chain fatty acid compound reacted with a surfactant. Can be used with any base oil and is recommended for freeing differentially stuck pipe in water-base drilling fluids when an un-weighted spotting fluid can be safely used.

Spotting Fluid Placement

The success of spotting fluids frequently depends upon time elapsed between sticking and placement of the spotting fluid. If the spotting fluid can be placed adjacent to the area of sticking within half an hour, the pipe may come free within one to two hours. If several hours have elapsed prior to placement of spotting fluid, 10 to 15 hours may be required for the pipe to come free. For this reason, spotting fluid materials should be kept on the rig and mixing facilities should be available to facilitate prompt placement.

Even with prompt placement, it is essential that the spotting fluid is placed in the zone of sticking and that the fluid does not migrate too rapidly. When spotting diesel oil and **MIL-FREE®** in low-density fluids, it would be advisable to calculate annular volume around drill collars and double this calculated quantity. This extra volume will compensate for hole enlargement. It will also allow a slight under displacement of drillpipe so that 1 to 2 bbl/hr of solution can be pumped to compensate for migration.

When stuck pipe occurs with weighted fluids, a spotting fluid should be used with a density equal to or slightly higher than the drilling fluid in the annulus to avoid migration. Time elapsed between sticking the pipe and placement of the spotting fluid has such a drastic effect on the ability of the spotting fluid to free the pipe that consideration should be given to spotting an un-weighted pill if possible.

Grogan Technique

Accurate placement of spotting fluid is difficult when hole enlargement has occurred and the spotting fluid must be placed some distance above the drill collars. Grogan outlined one technique for spotting a fluid which is lighter than the drilling fluid in use. This procedure utilizes the casing pressure observed after displacing spotting fluid from the drillstring and the relative gradients of drilling fluid and spotting fluid. For example, a casing pressure of 200 psi is noted after displacing a 6.8 lb_m/gal spotting fluid into the annulus containing 10.8 lb_m/gal drilling fluid.

Calculated length of column of spotting fluid would initially be equivalent to observed casing pressure divided by fluid gradient, less spotting fluid gradient.

Subsequently after pumping drilling fluid equivalent to volume of spotting fluid, a casing pressure of 150 psi is observed, which would indicate that the column length is 721 feet [150 lb / (.562 – .354) = 721 ft] and that the top of column is 1682 feet off bottom. This procedure can be continued until placement of spotting fluid is achieved. When spotting fluid density equals drilling fluid density, this technique will not apply and it will be necessary to use more than the calculated volume to compensate for error caused by hole enlargement.

Remedial Procedures Using Spotting Fluids

If the drillpipe becomes stuck, it must first be determined where the pipe is stuck. This may be accomplished by the following practices.

- *Stretch Indication* – The drillpipe is pulled into tension with the amount of stretch and force required to stretch the pipe recorded. Then, a calculation can be made which will give an approximation as to where the pipe is stuck. This is not an accurate test especially in a deviated hole as it may give false results.
- *Freepoint Indicator Tool* – An electric wireline tool called a freepoint tool is run inside the drillpipe on wireline. The pipe is worked up and down and torqued up as the tool is run down the hole. When the tool no longer indicates pipe movement, the point of differential sticking has been located. This is the most accurate means of determining exactly where the drillstring is stuck.

One method of freeing stuck pipe is to spot oil/synthetic which contains a surfactant. **MIL-FREE®.** is used only as an un-weighted spotting fluid in water-base fluids. Approximately 2 gallons of **MIL-FREE** is added to each barrel of oil/synthetic that is required to cover the zone of stuck pipe.

Recommended Treatment (BLACK MAGIC SFT)

For 100 bbl of prepared **BLACK MAGIC® SFT**, thoroughly mix the following amounts of materials, shown in Table 7-8, to obtain the desired fluid weights.

Density (lb_m/gal)	Base Oil* (bbl)	BLACK MAGIC SFT (sacks)	Water (bbl)	MIL-BAR® (sacks)
Un-weighted	70	136	12	0
10.0	64	124	11	135
12.0	62	113	7	240
14.0	57	102	6	345
16.0	54	91	3	455
18.0	49	81	3	560
** Base Oil: Low-toxicity mineral oil, #2 diesel or synthetic (140°F Aniline Point Minimum)*				

Table 7 - 8 BLACK MAGIC® SFT Material Requirements - Formulation per 100 bbl

Mixing Procedure

1. Clean mixing pit and flush pump with water.
2. Add oil as per chart.
3. Add **BLACK MAGIC® SFT** through hopper with agitation.
4. Add water and agitate to a smooth blend.
5. Add **MIL-BAR** and agitate to a smooth blend.
6. To increase viscosity, add **BLACK MAGIC® SFT**.
7. To reduce viscosity, add oil.

Recommended Treatment (MIL-SPOT 2)

1. Prior to mixing, thoroughly clean a slug tank with drillwater or seawater and flush out mixing lines.
2. Fill the slug tank with the required amount of oil as determined from Table 7-9.
3. Add the required amount of **MIL-SPOT 2** spotting fluid, followed by the required amount of seawater or drillwater.
4. Add **MIL-BAR** to achieve desired fluid weight. All materials can be mixed as fast as required.
5. Barite varies in quality and different barites, especially flotation varieties, can have a marked effect on rheological properties. Pilot test if barite is poor quality.

Fluid Density (lbm/gal)	Diesel Volume (bbl)	MIL-SPOT 2 (55-gal drum)	Water (Seawater or Drillwater) (bbl)	MIL-BAR (lb)
8.0	29.0	4	14.6	1925
10.0	26.7	4	13.7	6600
12.0	26.4	4	10.5	11,750
14.0	26.0	4	6.9	17,650
16.0	24.9	4	4.5	22,750
18.0	23.4	4	2.5	27,900

NOTES:

1. The relative volumes of oil/water must be adhered to for each density.

2. To obtain fluid densities between those listed in the table is a simple case of extrapolation.

3. All these fluids are designed for yield point values of ± l6 lb_f /100 ft^2. Increasing oil content decreases viscosity; increasing water content increases viscosity, but also increases tendency of solids to become water wet.

4. Employ maximum agitation in the slug pit when mixing barite.

Table 7 - 9 MIL-SPOT 2 Material Requirements - Formulation per 50 bbl

Recommended Treatment (BIO-SPOT)

Spot at least enough **BIO-SPOT** spotting fluid to cover the entire stuck pipe interval, but preferably not less than 100 bbl (see Table 7-10).

Density (lb_m/gal)	BIO-SPOT (bbl)	Water (bbl)	MIL-BAR (sacks)
8.7	100	0	0
10.0	95	0	74
12.0	87	0	185
14.0	80	0	297
16.0	65	7	410
18.0	50	14	523

Table 7 - 10 BIO-SPOT Materials Requirement - Formulation per 100 bbl

Mixing Procedure

1. Thoroughly clean mixing pit. Flush pump and mixing lines with water and drain, if possible, to minimize dilution of the **BIO-SPOT** fluid.
2. Add correct volume of **BIO-SPOT** concentrate for desired volume and fluid density.

3. Add correct volume of water (if required) and agitate until thoroughly blended.
4. Add **MIL-BAR** (or weight material) to the desired density and agitate until thoroughly blended and smooth.

> ***Note:*** *Weighted spotting fluid at this point should be pumpable yet have sufficient body to suspend weight material. If spotting fluid is not pumpable, treat lightly with* ***UNI-CAL®.***

5. If the chloride concentration of the drilling fluid is greater than 60,000 mg/L, placement of a 25 to 40 bbl freshwater **NEW-DRILL®** spacer ahead of the **BIO-SPOT** as well as behind the **BIO-SPOT** is recommended. Spacers are not required if the chloride concentration is less than 60,000 mg/L.
6. Pump spotting fluid at normal pumping rates.

Alternate Methods for Freeing Stuck Pipe

Other methods of freeing stuck drill strings include the following.

Altering Fluid Density

Reducing drilling fluid density may result in freeing stuck pipe. This method would not be feasible if pressure reduction allowed formation fluids to enter the wellbore. Often it is also time consuming and expensive.

Drillstem Test Tool

Stuck pipe has also been freed by utilizing a drillstem test (DST) tool above the point of sticking and releasing pressure below packer. This sudden reduction in pressure may, however, result in unstable shales falling into the wellbore and an influx of formation fluids from permeable zones. This technique should be used with extreme caution.

U-Tube Technique

The *U-Tube Technique* offers the advantage of speed without the inherent cost involved in reduction of drilling fluid density. Basically, the U-Tube method involves displacing a portion of the fluid in the upper part of the drillstring with a lighter fluid such as diesel oil or water, then allowing annulus fluid to flow back on the drillpipe side until equilibrium is obtained. The hydrostatic pressure reduction desired by lowering fluid level in the annulus can be calculated.

Example

While drilling at 8000 feet, the drillstring stuck while running a survey. Hole size is 8½ inch and drillpipe is 4½ inch. Casing size is $9^{5}/_{8}$ inches and is set at 3000 feet.

Drilling fluid density is 10.6 lb_m/gal, and it is desired that hydrostatic pressure be reduced by 250 psi on bottom. Water is to be used to lighten hydrostatic on the drillpipe side.

$$V_w = \frac{P_h\left[\frac{C_a}{W_m} + \frac{C_{dp}}{W_m - W_d}\right]}{0.052} = \frac{250\left[\frac{0.0538}{10.6} + \frac{0.0142}{10.6 - 8.34}\right]}{0.052} = 54.6$$

$$\boldsymbol{P}_{\max} = 0.052\left[\left(\boldsymbol{W_m} - \boldsymbol{W_d}\right)\left(\frac{\boldsymbol{V_w}}{\boldsymbol{C_{dp}}}\right)\right] = 0.052\left[(10.6 - 8.34)\left(\frac{54}{0.0142}\right)\right] = 446.9$$

$$\boldsymbol{V_a} = \boldsymbol{P_h}\left(\frac{\boldsymbol{C_a}}{0.052 \times \boldsymbol{W_m}}\right) = 250\left(\frac{0.0538}{0.052 \times 10.6}\right) = 244.0$$

where,

V_w = bbl of light fluid to be pumped into drillpipe

P_h = desired pressure reduction at 8000 ft

C_a = annular capacity between drillpipe and casing in bbl/ ft

W_m = fluid weight (lb_m/gal)

C_{dp} = Capacity of drillpipe in bbl/ft

P_{max} = pressure required to displace required volume of light fluid

V_a = amount of light fluid which will flow back to obtain equilibrium

W_d = weight of the displacement fluid.

A reduction of 250 psi in bottom hole pressure would result in an equivalent drilling fluid density of 10.0 lb_m/gal at total depth.

Caution should be exercised with this method, since a drop in fluid level could reduce hydrostatic pressure to a value less than formation pressure allowing a kick. In the above example, fluid level is lowered 454 feet which would result in an equivalent drilling fluid density of 9.0 lb_m/gal at the casing shoe.

If the well flows, it will be necessary to circulate out through the choke utilizing a balanced bottomhole pressure technique. Caution should be exercised if reverse circulation is attempted since all circulating pressure losses below the casing shoe (annular friction loss from casing to bit and friction losses through nozzles, collars, drillstring, etc.) would be imposed at the casing shoe and could induce lost returns.

The primary advantages of this technique are that drilling fluid properties do not have to be altered and hydrostatic pressure can be reduced slowly, minimizing the possibility of hole sloughing or kicks. Also, with this method the displacing fluid does not normally come into contact with the wellbore.

If remedial procedures do not free stuck pipe, it may be necessary to wash over the fish. It should be noted that wash pipe would have greater tendency to stick than the drillstring, therefore, drilling fluid properties (downhole filtrate and rheological properties) should receive special consideration.

Other Causes of Drillpipe Sticking and Remedial Correction

Key Seating

Key seating is another possible cause of pipe sticking. Key seats are the result of sharp hole angle changes causing the drillpipe rotation to wear a groove on one side of the hole. This groove would be the approximate diameter of the drillpipe or tool joints. When pulling out of the hole, the drill pipe and tool joints may pull through the groove, but the larger diameter drill collars would become stuck.

To avoid key seating, the most important thing to do is minimize abrupt angle changes. When drilling directional wells, the rate of deviation change (dogleg severity) should be controlled to avoid any sharp changes in direction or angle. String reamers can be used to smooth out abrupt angles.

The development of a key seat may not occur over the course of one bit run, but rather over a number of bit runs. Evidence of key seat development can be observed when the drill pipe encounters increasingly excessive drag in the same section of hole on repetitive trips.

When key seating does occur and the pipe becomes stuck, the following corrective measures are suggested.

- Work pipe downward (if possible) while pumping.
- Avoid excessive pull on the drill string as this will in all probability compound the problem by pulling pipe further into the key seat.
- Increase the concentration of friction reducing materials in the fluid (see Table 7-6).
- In some cases a special “driving” tool consisting of a length of casing concentric around a second joint of smaller diameter casing with the annulus full of cement (for weight) is used to “hammer” the drill string downward and out of the key seat. The inside length of casing has an ID large enough to slide over a drill pipe guide and impact on a robust seat (“anvil”) mounted on a sub inserted into the stuck drill pipe.

Foreign Objects

Foreign objects entering the wellbore may also result in stuck pipe. In this case, friction reducing materials will probably not help. Working the pipe up and down and rotating when possible are primary remedial actions.

Formation Caving

Formation caving can also result in stuck drillstrings. The severity of sticking is affected by quantity and size of cavings and how well the drilling fluid is cleaning the hole. The remedial action to be taken is to start circulating to clean the hole and run sweeps to improve cleaning action.

Fluid Density

Insufficient drilling fluid density can also be a contributing factor. Care should be taken, however, in how much the drilling fluid density is increased since differential sticking and loss of circulation can result from excessive hydrostatic pressure.

LUBRICITY

Control of drilling fluid lubricity becomes extremely important in holes experiencing severe torque and drag. These problems are most pronounced in a directional or excessively deviated hole, and considerable effort has been directed to their solution. The application of extreme-pressure (EP) lubricants in drilling fluids was first conceived in 1958. These lubricants were originally introduced to increase bit life but, as work progressed, noticeable reductions of torque and drag expanded the development of lubricants for aqueous fluids.

The problem associated with developing effective lubricants derives from the fact that some lubricating products form a good boundary layer of protection but, under extreme pressures and the associated high temperatures produced from friction, these lubricants breakdown. A comprehensive testing of lubricants should include the use of an EP tester in combination with a sticking coefficient apparatus. The EP tester cannot simulate conditions that are found when the drillpipe contacts filter cake, but an approximation can be made using a stickometer which uses actual filter cake to conduct the test.

Laboratory experience indicates that the Falex Lubricant Tester is a reliable laboratory test to predict effectiveness of lubricants under extreme pressure conditions (see Fluids Testing Procedures Manual). With the Falex Tester, properties are evaluated by comparing torque measurements at varying increments of loading among a series of test samples, including a base sample. Reductions in torque as compared to the base fluid are generally indicative of lubricant effectiveness. The Falex Lubricant Tester has been modified for use with drilling fluids. This device measures the torque generated between two steel surfaces in the presence of drilling fluid. The readings are converted into coefficient of friction.

Laboratory measurements are valid in selecting lubricants, but these results alone will not always predict effectiveness under downhole conditions. Variables such as temperature, quantity and nature of solids generated and long-term effect of the drilling fluid in use are often difficult to analyze. The ultimate test is obviously the results achieved under actual drilling conditions.

Some general conclusions obtained from laboratory data and substantiated by field experience are noted below.

- Minimum concentrations of drilled solids generally result in improved lubricity.
- The effectiveness of diesel oil as an EP lubricant is greatly reduced when it is tightly emulsified in a system. Diesel oil offers maximum lubricity when added continuously in small quantities to the suction pit while drilling. The information on diesel oil obtained from laboratory testing using the lubricity tester differs from results obtained using the sticking coefficient instrument. This device indicates that emulsified oil in a water-base fluid system does impart lubricity. This is most likely due to the oil becoming embedded in the filter cake and thus lubricating the filter cake. Diesel oil emulsified with a surfactant to preferentially oil-wet metal surfaces will thereby impart fair lubricity. Surface-active materials are generally

restricted, to an un-weighted or non-dispersed drilling fluid since they tend to promote flocculation.

- Asphaltic materials offer limited lubricity. Maximum effectiveness as a lubricant is attained when used in a fluid which contains a percentage of diesel oil. These materials are employed primarily to assist in stabilizing sloughing shale sections.

Baker Hughes Drilling Fluids offers a selection of lubricants designed to function in a variety of conditions. What follows is a brief description of these products.

LUBRI-FILM® is an extreme-pressure lubricant which promotes formation of an insoluble lubricant film on the surface of metal. This film of metallic “soap” provides lubrication at loads much greater than those of general borehole lubricants. **LUBRI-FILM** is particularly well suited for deep, hot holes where friction and wear between casing and drillpipe are of primary concern. Since **LUBRI-FILM** deposits a tenacious, long-lasting film, it can provide lubricity for extended periods with no maintenance additions. Most borehole lubricants, on the other hand are dependent on frequent additions to maintain lubricity.

Benefits derived from **LUBRI-FILM**, other than improved lubricity, are the corrosion protection afforded by the metallic soap film. Increased bit life of 30% to 100% has also been observed after additions of **LUBRI-FILM**.

Note: *Unlike some EP lubricants, LUBRI-FILM contains no sulfur which may produce sulfide cracking.*

MIL-LUBE™ provides and extreme pressure lubrication. **MIL-LUBE** is effective over a wide range of loading conditions. **MIL-LUBE** is a blend of surfactants and modified fatty acids designed for use in all types of water-base drilling fluids. Under extreme pressure conditions, **MIL-LUBE** forms a lubricating film on metal surfaces that resists removal. Sticking coefficient is reduced with **MIL-LUBE**, thus minimizing differential sticking. When using **MIL-LUBE**, the pH of the drilling fluid should be controlled at 9.5 or below which will give the best performance and resistance to greasing-out or high-temperature degradation.

AQUA-MAGIC™ was designed for use in environmentally-sensitive areas. **AQUA-MAGIC** is a very low-toxicity lubricant which *will not* create a sheen on receiving waters or on U.S. EPA (Environmental Protection Agency) laboratory sheen tests. **AQUA-MAGIC** may be used in un-weighted or weighted, freshwater or seawater fluids. **AQUA-MAGIC** is most efficient at a pH of 9.5 or below.

CARBO-DRILL®/SYN-TEQ® and similar oil/synthetic fluid systems offer the highest degree of lubricity that can be achieved with drilling fluids. In some extremely high angle and crooked holes, oil-base fluids have been introduced to reduce drag and torque to acceptable levels.

TEQ-LUBE® II is an environmentally-acceptable composition which will effectively reduce torque and drag in most water-base drilling fluids. It contains water-dispersible, extreme pressure lubricants and a specially selected glycol carrier. Because it is water-soluble, **TEQ-LUBE® II** will not sheen. **TEQ-LUBE® II** will function up to very high tool joint contact loads and provides an effective lubricant in a wide range of water-base drilling fluids and conditions.

OMNI-LUBE is an environmentally acceptable polymeric fatty acid solution which will effectively reduce torque and drag in most emulsion-based drilling fluids. Results obtained from field tests of **OMNI-LUBE** indicate that friction can be lowered by up to 25% as compared to untreated fluids, and torque is less erratic.

LC-LUBE is chemically inert, sized graphite which can be used effectively as a general borehole lubricant. It is environmentally acceptable and is applicable in water-, synthetic-, or oil-based fluids. **LC-LUBE** can also be effective in reducing the probability of stuck pipe. It has little effect on the rheological properties of drilling fluid. It has high compressive strength and because of its excellent bridging properties, it is also used to control loss of circulation (partial and seepage losses) in drilling fluids.

LC-GLIDE is a spherical, synthetic-graphite product used for torque and drag reduction during drilling, wireline and casing running operations. Its spherical shape provides a high performance alternative to glass and copolymer beads typically used for torque and drag reduction. It has an advantage over the beads in that when it is crushed it becomes graphite particles which still have lubricious properties, whereas when the beads are crushed the resultant particles are not lubricious.

LUBE-622 is a non-toxic, biodegradable lubricant which can be used effectively in salt based systems.

MIL-GRAPHITE is environmentally acceptable graded graphite used primarily to enhance lubricity and sliding and is applicable in water, synthetic, or oil-based fluids.

The **PENETREX®** family of products is designed to reduce bit-balling and improve penetration rates in water-based systems up to 400% over untreated systems. Products making up this family are: **PENETREX** for offshore operations**, PENETREX L** for land operations**,** and **PENETREX NS,** for North Sea applications.

HIGH BOTTOM HOLE TEMPERATURES

Mechanisms of Thermal Degradation

From the drilling fluid point of view high temperatures can be considered as those above which conventional drilling fluid additives begin to thermally degrade at an appreciable rate. The degradation leads to loss of product function, and system maintenance becomes difficult and expensive. The majority of drilling fluid treatment chemicals derived from natural products begin to degrade at temperatures between 250 and 275°F. However, many systems designed for hot wells are based on clay and contain lignosulphonates and ignites and can exhibit temperature stability up to approximately 350°F. However, management of these drilling fluids above 300°F can be difficult and expensive.

Thermal degradation can be simplistically thought of as the result of putting so much energy into a chemical substance that some portion of its structure can break off or change form. Similar results can be effected at lower temperatures by the presence of certain chemicals. Oxygen (from air) can promote oxidation; water (present in the drilling fluid) can promote hydrolysis. Whatever the cause, or particular chemical reaction involved, the end result is that at higher temperatures formerly stable drilling fluids become difficult to control. Unfortunately elevated temperatures are usually not the only stresses experienced by drilling fluids in high BHT wells. Often chemical contaminants such as the acid gases hydrogen sulfide and carbon dioxide are also present. Very frequently high drilling fluid densities and considerable drilling depths are part of the overall picture. Long trip times, which leave static, solids laden drilling fluid exposed to high levels of contaminants, put many high temperature drilling fluids in exceptionally challenging environments. Thermal degradation of drilling fluid additives (generating CO_2), can result in unstable rheological and filtration properties.

High temperatures both disperse and flocculate bentonite suspensions. Hydration of Montmorillonite (the major constituent of commercial bentonite) increases with temperature and pressure and an increased number of clay platelets are split from aggregated stacks. A greater number of particles are then present in the suspension and the viscosity of the suspension increases. The split of aggregated stacks presents fresh surfaces for the adsorption of hydroxyl ions producing a consequential drop in pH. This combination of increased surface area and drop in pH will tend to increase flocculation within the suspension. Under downhole conditions this creates a demand for alkali and deflocculant additions. If sufficient deflocculant is not present, or the deflocculant itself is thermally degrading, severe flocculation or gelation can occur. This condition is most commonly reached on a trip and problems re-establishing circulation can be created. The actual temperature that triggers thermal flocculation depends on the fluid’s composition. The type of bentonite, the type and concentration of drilled solids, the type and concentration of deflocculant and the ionic composition of the liquid phase, all have an effect on the flocculation process. The reaction of calcium ions with colloidal clays in a high alkalinity environment can result in the formation of cement-like calcium-alumino-silicates. In these situations extremely high gels can develop and, in the worst case, the drilling fluid may solidify.

Temperature effects on polymer drilling fluids are mainly due to the effects of temperature on the constituent polymers. In most cases polymer drilling fluids are low solids fluids and all have a degree of inhibition to clay hydration. The problem of increased clay hydration, seen in bentonite drilling fluids, is rarely a problem in polymer systems. The polymers are, however, susceptible to thermal degradation. Cleavage of the polymer chain can be accompanied by chemical modification of the attached groups. The two primary reactions responsible for polymer breakdown are oxidation and hydrolysis. Both of these processes can be controlled, to some degree, by the maintenance of pH in the range 9.5 – 10.5 and by the use of oxygen scavengers.

The polar interactions between charged clays and polymers that take place in water based drilling fluids do not occur in the non polar phase of a non-aqueous-based drilling fluid. Only relatively weak hydrogen bonding can occur. These weak forces are readily broken by increases in temperature so thermal degradation of non-aqueous-based drilling fluids is not common.

Temperature Limits

The following tables give approximate decomposition temperatures, or practical thermal application limits, for water based drilling fluids products and systems. Correctly formulated non-aqueous-based drilling fluids can perform effectively on wells with bottom hole temperatures as high as 500°F (275°C).

Drilling Fluid Products		
Generic Type	**Temp Limit °F**	**Temp Limit °C**
Guar Gum	225	107
Starch	250	120
Biopolymers	250 – 275	120 – 135
HT Starch	275	135
CMC and PAC	275	135
Lignosulphonate	250 – 325	120 – 160
Standard Lignite	300 – 350	150 – 175
Modified Lignite	350 – 450	175 – 230
Synthetic Polymers	400 - 500	205 - 260

Table 7 - 11 Drilling Fluids Products Temperature Limitations

Drilling Fluid Systems		
Generic Type	**Temp Limit °F**	**Temp Limit °C**
Non Dispersed Polymer	275	135
NDP – High Temperature Formulation	350	175
Bentonite/FCL	300	150
Bentonite/FCL/Lignite	350	175
Bentonite/Modified Lignite/polymer Blends	400	205
Synthetic Polymers (PHPA, PA, SSMA, VSA, etc.)	400 - 500	205 - 260

Table 7 - 12 Drilling Fluids Systems Temperature Limitations

Extending Temperature Limits

To increase the temperature stability of drilling fluids products and systems it is necessary to inhibit the mechanisms that cause product failure and/or to substitute parts of a system that are the first to lose product function.

The life of polymers can be extended by minimizing the reactions that cause severing of the polymer chains. Primarily these reactions are hydrolysis and oxidation. Hydrolysis can be minimized by maintaining a pH in the range 9.5 – 10.5 and oxidation can be avoided by the use of an oxygen scavenger. This approach alone will extend the thermal stability of most systems by approximately 25°F. Some heavy metals are believed to catalyze the breakdown reactions and products are available that “mop up” these elements. When polymers are used in formate brines their thermal stability is increased by as much as 50°F. This is largely due to the formate brines being powerful antioxidants.

Drilling Fluid Properties

Both temperature and pressure can have significant effects on drilling fluid properties.

Density

It is important to realize that drilling fluid density can vary significantly with temperature. This variation is represented by a decrease in density with increasing temperature and is due to the volumetric thermal expansion of the fluid phase. This is particularly true of oil based drilling fluids as the oil continuous phase has a greater coefficient of expansion than does water.

Rheological Properties

In commonly utilized oilfield drilling fluids all rheological properties decrease with increasing temperature. However under downhole conditions this effect may be reduced by increased pressures and may be completely reversed (i.e. viscosity will increase) by the increased hydration and flocculation of commercial clays and drilled solids. The presence in the wellbore of contaminants such as calcium, magnesium and carbon dioxide can, under high temperature conditions, cause the rheological properties of a water based drilling fluid to increase to such an extent that it become un-pumpable. The viscosity of oil based and synthetic fluids also increases with applied pressure.

Filtrate

Both API and HPHT filtrate increase with increasing temperature. This is largely due to loss of product function, and to changes in filter cake compressibility with changing temperatures.

Above differential pressures of 100 psi pressure increases alone have little effect on clay based drilling fluid filtrate indicating the effects of compressible filter cakes.

In general, polymers maintain their filtration control function well beyond the temperature at which they lose any viscosifying capabilities. This is due to the fact that even short, broken polymer chains are capable of functioning as filtrate control agents but not as viscosifiers.

Alkalinity

Temperature increases the rate and extent of most chemical reactions. The increased yield of clays results in more sites being available for reaction with ions, particularly hydroxyl ions. The end result of this is a reduction in alkalinity and an increase in flocculation. In oil based drilling fluids increased reaction of lime with surfactants greatly increases with temperature and reductions in drilling fluid alkalinity are common, particularly after lengthy trips. Often the performance of the drilling fluid will be hindered by a lack of a sufficient excess of lime.

Methylene Blue Test (MDBT)

When using a water based drilling fluid the MBT is one of the most meaningful tests available to indicate the general condition of the drilling fluid. The results of this test give an indication of the amount and size of active clays in the drilling fluid. In normal wells a non-dispersed polymer drilling fluid should, for example, have an MBT no greater than 20 lb/bbl. In high density drilling fluids 15 lb/bbl. should be considered the upper limit. High temperatures can rapidly increase the yield of commercial bentonite and reactive solids; this in turn will produce a rapid increase in values obtained from MBT tests. Drilling fluids with high MBTs are susceptible to contaminants that would not normally cause problems in low solids drilling fluids (e.g. calcium, carbonates, etc.).

Flash Point

When using an oil based drilling fluid on HPHT wells, the flowline temperature can approach the flash point of the base oil particularly when drilling deep 12 ¼” intervals. Usually bottom hole temperatures are too low to cause a problem in 17 ½” hole and circulation rates in smaller hole diameters allow the drilling fluid time to cool as it comes up the annulus. High return drilling fluid temperatures can have adverse effects on elastomers, can produce undesirable volumes of fumes and present a fire risk. Careful management of surface pits can facilitate cooling of the drilling fluid, but the effect is usually minimal. Some operators advocate the use of mud coolers (heat exchangers) and there is some evidence that, in the right application, this approach can prove effective.

Symptoms and Remedial Action

Symptoms

Typical symptoms of problems associated with high temperatures are:

- High viscosity and gel strengths
- Increased filtrate
- Decreased alkalinity

These problems may manifest themselves as:

- Difficulty in breaking circulation
- Difficulty in running tools to bottom
- Difficulty in degassing circulated drilling fluid
- Differential sticking tendency

The first indications of thermal deterioration of the drilling fluid system will be seen in bottoms up samples after trips. Trips tend to be lengthy on HPHT wells and the drilling fluid will have been exposed to near bottom hole temperature for long periods. It is important that bottoms up drilling fluid is tested and the results used as an indicator of future problems should remedial treatment not be made.

Remedial Action – Water Based Drilling Fluid

- **Increased Rheological Properties**

- **Add water** – due to increased surface area of clays, increased downhole filtration and surface evaporation drilling fluids at high temperature rapidly become dehydrated.

- **Decrease solids content** – reducing the percentage of low gravity solids in the drilling fluid will facilitate the control of rheological properties and improve product performance.

- **Add deflocculants** – If bottoms up samples indicate that the drilling fluid is becoming excessively viscous it might be beneficial to increase the concentration of deflocculant/dispersant. Alternatively substitute the existing product for one better suited to the bottom hole temperature. Baker Hughes Drilling Fluids' additives to improve the thermal stability of water-base systems are **MIL-TEMP®**, a low-molecular-weight co-polymer, and **ALL-TEMP®**, a sulphonated synthetic inter-polymer. Additions of **MIL-TEMP** or **ALL-TEMP** (0.3 to 3 lb_m/bbl) to existing water-base fluids aid in stabilizing rheological and filtration properties under severe temperature conditions. Laboratory and field data indicate that these materials are effective at temperatures above 600°F. Care must be exercised when increasing product concentration. Most chemicals will take up free water and this can negate any beneficial affects of deflocculation.

- **Increased Filtrate**

- **Add HTHP filtrate reducer** – if it is apparent that the filtrate cannot be controlled economically with existing products a more thermally stable product should be used. Often this appears an expensive option but usually proves cost effective. Baker Hughes Drilling Fluids' additives for filtration control at high temperatures are:
    - **PYRO-TROL®,** an AMPS/AM co-polymer. Has minimal effect on rheological properties. Normal treatments are 0.75 – 2.0 lb_m/bbl.
    - **KEM-SEAL® PLUS**, an AMPS/AAM co-polymer. In fresh water will increase viscosity. In brines effect on viscosity is appreciably less. Normal treatment levels are 0.25 – 2.0 lb_m/bbl.
    - **CHEMTROL® X**, a lignite/polymer blend. Has a minimal effect on viscosity. At temperatures greater than 400°F, caution should be exercised due to CO_2 from thermal degradation. Normal treatment levels are 1.0 to 10.0 lb_m/bbl.

Remedial Action – Oil Based Drilling Fluid

- **Increased Rheological Properties**

- **Add base oil** – increased filtrate and surface evaporation reduces the total oil content of the drilling fluid and, if not replaced, will in effect, "dehydrate" the system.

- **Add oil wetting agents** – by ensuring that all solids are oil wet the inter-particle reactions between them are reduced. This results in reductions in viscosity and gel strengths. Care must be taken when adding wetting agents. They are usually concentrated products that prove very effective thinners for clay based rheological properties in oil based drilling fluids. Over treatment can reduce suspension characteristics to levels that will promote inefficient hole cleaning and may allow barite sag to occur.

- **Increased HPHT filtrate**

- Often increases in HPHT filtrate can be readily, and economically, remedied by the addition of sufficient lime to restore a good (2 – 3 lb_m/bbl) excess in the drilling fluid. If this is not effective, increased levels of emulsifiers may be required. Ultimately the addition of a dry powder filtrate reducer (**MAGMA-TROL™)** may be required.

Planning

The successful application of a fluid in an HPHT environment is greatly influenced by pre-job planning. Prior to drilling an HPHT interval contingencies must be in place to ensure that the potential fluid problems, common on HTHP wells, can be anticipated and corrected.

Drilling Fluid Selection

The type of drilling fluid that will be chosen for a particular application will depend very much on factors other than just the ultimate bottom hole temperature.

The location of the well may have an influence on selection. If the well is to be drilled in a particularly remote or environmentally sensitive area the use of a non-aqueous-based drilling fluid, the commonly preferred option for high temperature applications, may be restricted.

The anticipated formations and contaminants are important factors in drilling fluid selection. Highly dispersed water based drilling fluids may not, for example, be appropriate to drill reactive shales or formations where CO_2 or brine flows are predicted. CO_2 can have dramatic negative effects on water based drilling fluids that do not contain lime. However water based drilling fluids, heavily treated with lime can be particularly difficult to stabilize at high temperatures. Polymer based drilling fluids are subject to degradation by various means at high temperature.

It can be seen that neither clay nor polymer based fluids are ideal for high temperature environments. However, by careful choice of materials, relative to the anticipated environment, water based drilling fluids can be run, with some difficulty, on wells with BHT up to 500°F.

Non-aqueous-based drilling fluids have a distinct HSE disadvantage for HPHT applications in that gas is soluble in these fluids under downhole conditions. Gas is not soluble in water based drilling fluids.

Water based drilling fluids are much less effected by temperature and pressure than non-aqueous-based drilling fluids. This makes hydraulic modeling and ECD control appreciably more straightforward in water based fluids.

It is therefore essential that an appropriate drilling fluid system is selected for HPHT applications and that, as part of the planning process, the formulation of the chosen system is optimized for the anticipated downhole environment and contaminants.

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Chapter Eight

Corrosion

Chapter 8

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Chapter 8

CORROSION

Corrosion is the destruction of a metal by chemical or electrochemical reaction with its environment.

INTRODUCTION

Corrosion is a severe and costly problem in the drilling industry. Because the tubular goods are mostly iron and many drilling fluids are water-based, corrosion is inevitable. Four conditions must be met, however, before corrosion can occur.

1. An anode and a cathode must exist.
2. The anode and cathode must be immersed in a conductive medium.
3. A potential difference between the anode and cathode exists.
4. There must be a coupling to complete the electrical circuit.

The anode and cathode exist on the drillpipe itself. The drilling fluid may serve as the electrolytic medium, and the coupling is created by the drillpipe steel. The potential difference is due to the crystalline structure and different metals used in the drilling pipe alloy.

FACTORS AFFECTING CORROSION RATE

Several factors affect the rate at which corrosion proceeds. Most of these factors are interrelated and have a compound effect on the corrosion rate. The basic relationships are as follows:

Temperature

Two different effects occur.

1. As temperature increases, the corrosion rate increases. If all other factors remain constant, the corrosion rate doubles for each 55°F (13°C) increase in temperature.
2. Increasing temperature decreases the solubility of corrosive gases (O_2, CO_2, H_2S), thus decreasing the corrosiveness of the fluid due to these gases. Note that "solubility" here refers to the solubility of gas at surface pressure, and does not include chemical reactions of gases such as CO_2 and H_2S with the fluid.

Pressure

Increasing pressure increases the solubility of most corrosive gases. Entrained, or trapped air rapidly goes into solution in the fluid as the pressure increases, when the fluid is pumped downhole. This dramatically affects the oxygen content of the fluid, increasing corrosiveness.

pH

Generally, for steel components, corrosion rate decreases as pH increases. At ambient temperatures, as the pH increases, corrosion rates rapidly decrease. Rates are much slower in alkaline fluids than in acidic fluids. Little reduction in corrosion rate is obtained as pH is increased above 10.5 (see Figure 8 - 5).

For aluminum drill pipe and components, corrosion rates increase with increasing; pH. This is due to the formation of soluble aluminum compounds at high pH. If aluminum components are used in the drill string, the pH should be maintained in the range of 6 – 9.

Dissolved Salts

The effect of salt concentration is twofold.

1. As salt concentration increases, conductivity rises increasing the corrosion rate (see Figure 8 - 1).

2. Increasing the salt concentration, however, reduces oxygen solubility, (see Figure 8 - 2), thereby decreasing corrosion rate. The overall effect is a brief rise in corrosion rate due to conductivity until the salt concentration reaches approximately 18,000 mg/L (Cl^-). Above this range, as salt concentration increases, oxygen solubility and corrosion rates decrease (see Figure 8 - 3 and Figure 8 - 4).

CORROSIVE AGENTS AND TREATMENTS

Oxygen (O_2)

1. Source – Atmosphere. Water additions, solids removal, gas separation equipment and mixing equipment generally increase oxygen content.

2. Reactions – Oxygen corrosion of Iron (Fe) is cathodic depolarization reaction. Basically, this is what happens when water and oxygen are present.

	Cathode	Anode
1st Step	$O_2 + 4H^+ + 4e^- \rightarrow 2H_2O$	$Fe \rightarrow Fe^{++} + 2e^-$
2nd Step	Combined: $2Fe + O_2 + 4H^+ \rightarrow 2Fe^{++} + H_2O$	
Fe^{++} can be further oxidized: $4Fe^{++} + O_2 + (4 + 2x)\ H_2O \rightarrow 2FeO_3 + H_2O + 8H^+$		

Note: *Oxygen is required to drive the reaction at the Cathode to supply (OH^-) for the reaction at the Anode.*

3. Attack Types – Pitting, localized (deep pits) or general (evenly distributed shallow pits are characteristic). Oxygen results in an etching form of corrosion attack..

4. Treating Agents

   - **NOXYGEN™ L** – Liquid ammonium bisulfite $(NH_4)HSO_3$
   - **AMI-TEC™** – Film-forming amine (see CO_2 Treating Methods)
   - **KD-40™** – Film-forming organophosphate corrosion inhibitor.
   - **KD-700™** – Film-forming organophosphate corrosion inhibitor which also acts as a scale inhibitor.

5. Treating Methods **–** Inject via chemical pump into the pump suction. Adjust injection rates to maintain the sulfite at 75 to 125 mg/L sulfite residual (at the flowline). Where filtrate calcium levels are untreatable, or excess lime is present, maintain only an indication of sulfite residual.

Carbon Dioxide (CO_2)

1. Source – Formations and bacterial degradation of certain fluid additives.

2. Reactions.

   - $CO_2 + H_2O \rightarrow H_2CO_3$ (Carbonic Acid)
   - $H_2CO_3 + Fe^{++} \rightarrow FeCO_3 + H_2$

3. Attack Type – Severe pitting (worm-eaten appearance).

4. Treating Agents.

   - Caustic soda – NaOH.
   - Lime – $Ca(OH)_2$.
   - **AMI-TEC™** – Film-forming amine.

- **KD - 700™** – Scale inhibitor

5. Treating Methods – Where the intrusion of CO_2 is not severe, neutralization with caustic soda and lime, or gypsum by maintaining a pH of 10.0 or higher may be the easiest and most cost-effective method. If lime or gypsum is used, **SCALE-BAN™** should also be used to inhibit the deposition of calcium carbonate scale on the drillpipe. This type of scale can aggravate oxygen corrosion cells. Therefore, **NOXYGEN™** treatments may have a favorable effect at reducing corrosion.

When a CO_2 influx has become severe, or where neutralization requires large treatments, several steps may be necessary to minimize the corrosive effect on the drillstring.

- When possible, raise the fluid weight to stop the influx.
- **MIL-TEMP®** or **ALL-TEMP®** treatments can be extremely effective at controlling rheological properties which will minimize the entrapment of CO_2 and O_2. The **MIL-TEMP®** or **ALL-TEMP®** will also minimize the flocculating effects of lime additions which are essential to precipitate carbonates and balance alkalinities.

Use **AMI-TEC™**, **KD–700™** or **SCALE BAN™** to form a protective film on the drillstring. **AMI-TEC™** should be used with solids-laden fluids. Treatment is accomplished by pumping a 25 to 35 gal “batch” down the drillpipe on a regular basis. A “batch” is prepared by mixing **AMI-TEC™**, diesel oil and/or **ISO-TEQ®** in a 1:5 to 1:20 ratio depending on the level of protection required. The batch size (number of gallons) depends on the length of the pipe to be coated and the annular diameter. **KD-700™** may be used in all water-based drilling fluids. **KD-700™** contains an organophosphate filming agent.

In order to effectively maintain an inhibitive film with amines, tourly treatments are recommended.

Note: *Entrainment of excessive amounts of amines into drilling fluids may result in flocculation of the system, therefore avoid over-treatment.*

- Continue to treat with caustic soda and lime to neutralize the acid gas. In addition, treat the system with **SCALE-BAN™** to prevent scale deposition. Treatment with **SCALE-BAN™** is 3 to 5 gal per 1000 bbl initially, and 1 to 2 gal each day thereafter.
- Testing Procedures – Monitor alkalinities and pH periodically to ensure that carbonates are precipitated and solubility of carbon dioxide is minimized. The Garrett Gas Train for carbonates is necessary to properly monitor the fluid system quantitatively.

Hydrogen Sulfide (H_2S)

WARNING!

Hydrogen Sulfide Gas is *highly poisonous* and *extremely corrosive*. Small concentrations in air may be fatal in just a few minutes (See Table 8-1). When H_2S is expected, thoroughly familiarize yourself with protective measures in advance.

1. Source – Formations are the primary source with bacterial and thermal degradation of fluid additives contributing minor amounts.

2. Reaction – $H_2S + Fe^{++} + H_2O \rightarrow FeS + 2H^+$

3. Attack Type – Severe pitting, hydrogen embrittlement or sulfide stress corrosion cracking, also generalized pitting and black sulfide coating. Black sulfide coating is apparent as a black powder or scale on the drillstring.

4. Treating Agents

   - Caustic soda – NaOH
   - Lime – $Ca(OH)_2$
   - **MIL-GARD®** – $2ZnCO_3 \times 3Zn(OH)_2$
   - **MIL-GARD® L** – Zinc ammonium NTA
   - **MIL-GARD® FE** – Iron based scavenger designed to be used where zinc compounds are not environmentally acceptable

5. Treating Methods – The most effective method of controlling H_2S involves the use of **MIL-GARD®** (to scavenge sulfides) in conjunction with pH control, using caustic soda and/or lime, to minimize embrittlement.[1]

   MIL-GARD® preventative treatment is recommended at 2-3 lb_m/bbl (1 lb_m/bbl = 500 mg/L sulfide)

   MIL-GARD® FE preventative treatment is recommended at 0.05 gal/bbl (0.12 vol%). Treatments of 0.1 gal/bbl (0.24%) will treat approximately 100 ppm H_2S.

6. Caustic soda and/or lime should be used in the fluid system to establish an alkaline environment. In an alkaline environment, H_2S is reduced to soluble sulfides which have less of a tendency to cause hydrogen embrittlement (see Figure 8 - 6). However, since soluble sulfides present in the system are corrosive and will revert to H_2S if a reduction in pH occurs, do not rely on this approach for total control.

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[1] *Chemical Scavengers for Sulfides in Water-Base Drilling Fluids*, Garrett, R. L., Clark, R. K., Carney, L.L., and Grantham, C.K., SPE 7499, Journal of Petroleum Technology, June 1979.

H_2S (%)	0 – 2 Minutes	2 – 15 Minutes	15 – 30 Minutes	30 Minutes - 1 Hour	1 – 4 Hours	4 – 8 Hours	8 – 48 Hours
0.005 0.010				Mild conjuctivitis; respiratory tract irritation			
0.010 0.015		Coughing, irritation of eyes, loss of sense of smell	Disturbed respiration; pain in eyes; Sleepiness	Throat irritation	Salivation and mucous discharge; sharp pain in eyes; coughing	Increased symptoms	Hemorrhage and death
0.015 0.020		Loss of sense of smell	Throat and eye Irritation	Throat and eye irritation	Difficult breathing; blurred vision; light shy	Serious irritating effects	
0.025 0.035		Irritation of eyes loss of sense of smell	Irritation of eyes	Painful secretion of tears; weariness	Light shy; nasal catarrh; pain in eyes; difficult breathing	Hemorrhage and death	
0.035 0.045		Irritation of eyes loss of sense of smell	Difficult respiration coughing Irritation of eyes	Increased irritation of eyes and nasal trac; dull pain in head weariness; light shy	Dizziness; weakness; increased irritation; death	Death	
0.050 0.060	Coughing; collapse; unconsciousness	Respiratory disturbances; irritation of eyes Collapse	Serious eye irritation; palpitation of heart; few cases of death	Severe pain in eyes and head; dizziness; trembling of extremities; great weakness and death			
0.060 - 0.070 0.080 - 0.100 0.150	Collapse; Unconsciousness, Death	Collapse; Unconsciousness, Death					

Table 8- 1 The effects and Symptoms of H_2S Exposure

MIL-GARD®, **MIL-GARD® FE,** or **MIL-GARD® L** are used to effectively scavenge all forms of sulfide present in the system. The reaction of **MIL-GARD®** with sulfides is irreversible, forming insoluble zinc sulfide (ZnS), and will occur within a pH range of 3.4 to 14.

7. Recommended Treatment

- NaOH and/or $Ca(OH)_2$ for pH 10.0 or above.

- **MIL-GARD®**: 2 to 3 lb_m/bbl (1 lb_m/bbl = 500 mg/L sulfide)

or

MIL-GARD® L: 55 gallons per 1000 bbls of drilling fluid to scavenge 50 – 80 ppm H_2S.

or

MIL-GARD® FE : 0.1 gal/bbl (0.24%) will treat approximately 100 ppm H_2S.

Note: *MIL-GARD® L should be used in clear fluids such as drillwater and brines, as MIL-GARD® will settle. Maintain excess MIL-GARD® in the system when H_2S is suspected or known to be present. Use the Garrett Gas Train to monitor excess MIL-GARD® concentration.*

In the event **MIL-GARD®** is unavailable, the next best method to treat for H_2S involves pH control using lime, a filming amine to coat the pipe such as **AMI-TEC™** , or **KD–700™**, and **SCALE-BAN™** to prevent scale deposition. Control the pH at 10.5 or above using lime. Do not use caustic soda alone, because caustic reacts to form sodium sulfide (Na_2S) which is extremely soluble and H_2S may be released from the fluid if the pH drops. Lime is recommended instead because it forms calcium sulfide (CaS) which is not as soluble and may precipitate from the system. Use **AMI-TEC™** or **KD-700™** to provide a film on the drillpipe to protect against sulfide corrosion.

Note: *The use of the Garrett Gas Train and sulfide indicating Dräger Tubes is necessary to properly monitor the fluid system for quantitative information on sulfides. Techniques utilizing lead acetate paper discs are used only to indicate the presence of sulfides in relative concentration.*

When testing for the presence of sulfides in a fluid, it is extremely important that the filtrate used be as fresh as possible. In addition, the filtrate should be taken from a sample of fluid freshly collected at the flowline. Minimize exposure of the fluid or filtrate to the atmosphere as this reduces the accuracy of the test.

CORROSIVITY OF VARIOUS FLUIDS

- *Non-dispersed* – Oxygen entrapment and high dissolved oxygen contents caused by high gel strengths and yield points cause these fluids to be regarded as corrosive. This is exacerbated by these fluids often having a low pH.

- *Low Solids* – Corrosive due to the same rheological conditions as with *Non-Dispersed* fluids.

- *Polymer Fluids* – Usually have lower pH and may contain salts which increase the fluid conductivity. Also, these fluids often have rheological properties which allow entrapment of oxygen, resulting in high oxygen content. **NEW-DRILL®** and **PYRO-DRILL®** fluids routinely have low corrosion rates. This phenomenon has been observed even when operating in the more corrosive environments. Some polymers are natural O_2 scavengers; others are scale inhibitors, etc.

- *Saturated Salt Fluids* – Oxygen solubility is low but conductivity is high; chlorides increase pitting attack. These fluids may have moderately high oxygen contents due to O_2 entrapment.

- *Dispersed* – Slightly corrosive; less oxygen entrapment due to lower gel strengths and yield points. In addition, most dispersants have some oxygen scavenging ability.

- *Lignosulfonates* – Slightly corrosive due to same conditions indicated in *Dispersed*. Lignosulfonates are, to a certain degree, natural oxygen scavengers. In addition, lignosulfonate fluids usually have a pH high enough (9.0 or greater) to greatly reduce corrosion. However, where salts are present, conductivity may be increased, thereby increasing corrosivity.

- Synthetic and Oil-Based Fluids – Considered non-corrosive

Note: *Aluminum drillpipe forms an aluminum oxide coating or film that protects it from corrosion in many environments. This film is quite stable in neutral conditions but is attacked by alkalinities. Therefore, when using aluminum drillpipe, the pH of the fluid should be at 9.0 or below.*

USE OF CORROSION COUPONS

Ring Coupons

The most effective method of measuring the corrosivity of a drilling fluid involves the use of pre-weighed ring coupons. These rings are sized to fit into the relief groove in the tool joint box. These rings are placed in the drillstring and exposed to the fluid for a period of time during the drilling operation. After exposure to the system for a minimum of 40 hours, the rings are retrieved, cleaned, and reweighed in the laboratory to within 1/10 milligram. The difference between the initial and final weights (or the weight lost) is attributed to corrosion, and the corrosion rate is calculated and reported as lb_m/ft^2/year or mils/year. The term mils/year refers to the loss of metal in thousandths of an inch per year. Two types of rings are available, bare uncoated steel and steel rings having a hard plastic backing. See Table 8 - 2.

		Factors		Coupon Dimensions		
Series	Ring Size	mils/yr	Series	Ring Size	mils/yr	Series
 F H	3½" E.H. 3½" I.F. 4" F.H.	 280 252	 F H	3½" E.H. 3½" I.F. 4" F.H.	 280 252	 F H
	4" I.F. 4" E.F.	Same as 4½" E.H. Same as 3½" I.F				
K N P	4½" F.H. 4½" E.H. 4½" I.F.	207 195 193	203 192 189	$2^{15}/_{16}$" $3^{5}/_{16}$" $3^{13}/_{16}$"	3½" $3^{13}/_{16}$" $4^{3}/_{16}$"	$^{7}/_{16}$" $^{7}/_{16}$" $^{7}/_{16}$"
R	5" F.H.	219	215	$3^{17}/_{32}$"	$4^{1}/_{32}$"	$^{5}/_{16}$"
	5" E.H	Same as 4½" I.F.				
V	5½" F.H.	188	184	$4^{1}/_{32}$"	$4^{5}/_{8}$"	$^{11}/_{32}$"
	5½" E.H.	Same as 5" I.F.				
X	5½" I.F.	148	145	$4^{7}/_{8}$"	$5^{19}/_{64}$"	$^{7}/_{16}$"
	6" E.H.	Same as 5½" I.F				

Table 8- 2 Ring Factors and Formulas (for all metal rings)

Ring Placement and Scheduling

Placement – Corrosion coupons (rings) are normally placed in the crossover sub above the drill collars, and/or in the kelly saver sub, or fluid saver sub above the TIW valve.

Scheduling – Ring coupons should be run in the drillstring for a minimum of 40 hours. In every instance, the time must be reported as accurately as possible, even if the coupon is left in the string for several days.

Handling of Corrosion Rings

1. Leave the ring in the shipping envelope until immediately prior to placement in the drillstring. **DO NOT HANDLE THE RING PRIOR TO RUNNING IT.**

2. Wipe the recessed area inside the box end of the tool joint clean of excess fluid and pipe dope.

3. Carefully place the ring down into the recess with the beveled side down. Care should be taken to be sure that the ring lays flat within the recess, to avoid mechanical damage when the joint is made up.

4. Record on the shipping envelope the location of the ring coupon and the date and time of placement in the string. Run the ring coupon in the drillstring for a minimum of 40 hours, but not more than 120 hours.

5. If the string is out of the hole for an extended time, remove the ring coupon and replace it with a new corrosion ring coupon when trip-back in the hole in begins.

6. After the run, carefully remove the ring coupon, preventing any mechanical damage that could cause a weight loss.

7. Immediately upon its removal from the string, wash off any excess fluid and fluid solids adhering to the ring coupon. Wipe dry and apply a light coat of grease or heavy oil to the ring coupon to protect it from atmospheric corrosion. *Do not use pipe dope.*

8. Rewrap the ring coupon and record on the shipping envelope the requested information. Be sure to record the date and time the ring coupon was installed and removed as well as the fluid type and any corrosion control techniques and treatments in effect during the ring coupon run. Ship the ring coupon to the processing lab as soon as possible.

Calculation of Corrosion Rate

The corrosion rate, based on weight loss (from corrosion coupon analysis), is calculated as follows.

$$Corrosion\,Rate, lb_m \;/\; ft^2 \;/\; yr = \frac{(K)(Weight\,Loss, gm)}{Exposure\,Time, hr}$$

$$Mils \,/\, yr = lb_m \;/\; ft^2 \;/\; yr \times 24.6$$

Where:

K = a constant used for the area of the ring coupon exposed and is printed on the shipping envelope.

Note: *Constants for plastic coated rings are significantly different and should not be interchanged.*

CORROSION TREATMENT TIPS

Oxygen Scavengers

NOXYGEN™

NOXYGEN™ is a liquid and is packaged in 55 gal drums. Best application is by chemical injection pump into the suction line. Initial injection rate should be as high as the pump will allow, reducing the rate as necessary to obtain the required sulfite residual at the flowline. Maintain 75 to 125 mg/L sulfite residual. Large diameter boreholes with high circulation rates will require higher chemical injection rates. All fittings and valves on the chemical injection equipment should be of good quality stainless steel. All fittings should be air tight. Avoid copper and brass fittings.

Film-Forming Amines

O.D.	Weight/ft T & C Nominal	I.D.	(1000) Linear Feet per Gallon	Minimum Slug 10,000 ft or Less in Gallons	Additional Slug/ 1000 ft Below 10,000ft
3½"	09.50 13.30 15.50	2.992" 2.764" 2602"	2.7382 3.2082 3.6201	08.0	1.00
4"	11.85 14.00 15.70	3.476" 3.340" 3.240"	2.0283 2.1973 2.3348	12.0	1.25
4½"	13.75 16.60 20.00	3.958" 3.826" 3.640"	1.5644 1.6745 1.8501	15.0	1.50
5"	16.25 19.50	4.408" 4.276"	1.2614 1.3407	19.0	2.00
5½"	21.90 24.70	4.778" 4.670"	1.0738 1.1240	23.0	2.50

Table 8- 3 Amine Quantities for Slug Treatment

AMI-TEC™

AMI-TEC™ may be applied by spraying, dipping, or by "batch" treatments. During trips when spraying is not feasible, it is possible to treat the pipe by placing 15 to 20 gal of amine/diesel or amine/**ISO-TEQ®** "batch" in the annulus below the flowline, and 5 to 10 gal of "batch" inside the pipe after it will "pull dry." In this manner, the pipe may be coated inside and out on trips. **AMI-TEC™** is oil-soluble and water-dispersible. The addition of **AMI-TEC™** to a fluid system can cause severe rheological problems and the above recommended treatment with this material should minimize its entrainment in the fluid.

KD-700™

KD-700™ is designed to prevent oxygen related corrosion and inhibit the formation of carbonate-based scale. It may be used in water-based drilling fluids, aerated drilling fluids, and in mist drilling applications. **KD-700**™ is a water-soluble, oil/synthetic dispersible compound and may be mixed in solids-free drilling fluid (brines, etc.) in closed systems. This product is organophosphate-based and is stable at temperatures up to 350°F. **KD-700**™ forms a strong, protective film on metal surfaces and protects tubular goods from oxygen related corrosion. Also, it is effective against acid gas corrosion. It has little to no effect on fluid rheological properties. **KD-700**™ disperses readily in drilling fluids and may be added through the mud hopper. The recommended initial concentration of **KD-700**™ depends on the corrosivity of the drilling environment. For drilling fluid systems, typical rates are in the table below.

Corrosivity of Drilling Environment	**Initial Treatment, gal/100 bbl fluid**	**KD-700™, ppm in mud filtrate**
Low	5	250
Moderate	10	450
Severe	15	850

Table 8- 4 KD-700 Treatment Levels in Water-Based Drilling Fluids

KD-40™

KD-40™ is a water soluble corrosion inhibitor designed to prevent oxygen related corrosion in water-based drilling fluids, aerated drilling fluids and in mist and foam drilling applications. **KD-40**™ is an organophosphate formulation that forms a strong, protective film on metal surfaces. **KD-40**™ has little or no effect on fluid rheological properties and is effective in fresh water and brine water systems under 400 ppm Ca^{+2} or Mg^{+2}. **KD-40**™ prevents oxygen related corrosion and is effective against acid gas corrosion. **KD-40**™ is effective to 400°F. **KD-40**™ disperses readily in drilling fluids and should be added through the mud hopper or chemical barrel. Treatment rates depend on the corrosivity of the drilling environment. Residual levels of **KD-40**™ can be determined with an organophosphate analytical test kit.

Corrosivity of Drilling Environment	**Initial Treatment, gal/100 bbl fluid**	**KD-40, ppm in mud filtrate**
Low to Moderate	2 - 5	150 - 300
Severe	7 - 12	450 – 700

Table 8- 5 KD-40™ Treatment Levels in Water-Based Drilling Fluids

Scale Inhibitor

SCALE-BAN™

SCALE-BAN™ is a chemical inhibitor that interrupts and deforms the normal crystalline growth pattern of carbonate scales. **SCALE-BAN**™ is required in very low concentrations; as little as 3 to 5 ppm in the system is effective at inhibiting scale formation. Visual inspection of the drillpipe will indicate if treatment levels are sufficient.

When scale is formed, oxygen concentration cells develop beneath the scale, and severe localized pitting develops. **SCALE-BAN**™ is suggested anytime carbonate gas may be present or when lime is used in significant quantities in the circulating system. Where scale deposits are already present on the pipe, sandblasting or other cleaning is required to remove the scale. **SCALE-BAN**™ *will not* remove existing scale from the pipe.

PACKER FLUID TREATMENT

Packer fluids are fluids left between casing and tubing. Casing packs are fluids left between casing and open hole. While these fluids may be left in place for a variety of reasons, the principal reasons are (1) to inhibit corrosion and extend the life of the tubular goods, and (2) to provide **a** hydrostatic column for control of pressures in the event of a casing or tubing leak.

Packer fluids are formulated from three types of basic fluids – water-base drilling fluids, brine water, and oil or synthetic fluids. The techniques for formulating a packer fluid are as follows.

Water-Base Drilling Fluid

1. Raise the gels to prevent the settling of solids for the extended periods over which the fluid will be stagnant. A high temperature-high pressure Cameron test cell can be used to provide a stable test environment.

2. Raise the pH to 11.0 with caustic soda.

3. Blend 2 - 5 gal of **KD-40**™ corrosion inhibitor uniformly into each 100 bbl of fluid for low to moderate corrosion rate protection. This concentration will yield 150 – 300 ppm **KD-40**™ in the mud filtrate. For high corrosion rates, increase the concentration of **KD-40**™ to 7 – 12 gal per 100 bbl of packer fluid. This concentration of **KD-40**™ will yield 450-700 ppm **KD-40**™ in the mud filtrate. Residual levels of **KD-40**™ corrosion inhibitor in the filtrate can be determined with an organophosphate analytical test kit. The quantity of **KD-40**™ used will depend on the type and severity of the corrosion problems expected and on the fluid type used.

4. Corrosion rates should be monitored with drill pipe corrosion coupons.

Brine Water

1. To raise the pH for NaCl and KCI to 10.0 - 10.5, use caustic soda (NaOH) or caustic potash (KOH). To raise the pH for high-density brines (i.e., $CaCl_2$, $CaBr_2$, $ZnCl_2$, and $ZnBr_2$) and combinations of these brines, do not use caustic soda to try to raise the pH. Instead, use small amounts of lime ($CaOH_2$) and raise the pH only when absolutely necessary.

2. Add **BRINE-PAC®** to the brine water at a concentration of 55 gal per 150 - 200 bbl brine. In severely corrosive areas it may be necessary to increase the concentration of **BRINE-PAC®.** Do not use **BRINE-PAC®** with brines containing solids.

3. Do not circulate or aerate brine water containing **BRINE-PAC®** as this will expend the oxygen scavenger.

4. In areas where H_2S is a problem, add 6 to 12 lb_m/bbl of **MIL-GARD® R** to control sulfide corrosion.

5. **BRINE-PAC® 2000** is a high temperature corrosion inhibitor for high density brines such as calcium and zinc bromide. It is stable up to 450°F and completely soluble in high density calcium and zinc brines. **BRINE-PAC® 2000** forms a tough long lasting coating on metal surfaces to resist penetration of dissolved organic gases, hydrogen sulfide and carbon dioxide. The recommended treatment is 10 – 15 gallons per 100 bbl of brine.

6. **BRINE-PAC® 1500** is a filming amine type corrosion inhibitor for treatment of low to no solids brines. It is water soluble and is effective in fresh water and sodium, potassium and

calcium brines at temperatures up to 300°F. **BRINE-PAC® 1500** forms a tough long lasting coating on metal surfaces to resist penetration of dissolved organic gases, hydrogen sulfide and carbon dioxide. The recommended treatment is 5 – 15 gallons per 100 bbl of brine

Invert Emulsion Fluids

1. In oil or synthetic fluids, the external phase (oil) is nonconductive and, therefore, basically non-corrosive. Chemical inhibitor additions to oil fluids are not necessary.

2. Increase the emulsion stability of the system with treatments of **CARBO-TEC® / OMNI-TEC™** and lime. This will provide the stability required for long-term packer fluid service.

3. Raise the yield point and gel strengths with **CARBO-GEL®** to prevent solids settling and minimize segregation. For high-temperature applications, **CARBO-GEL® / CARBO-VIS™** can be supplemented with **CARBO-VIS™ HT**. Cameron cell testing can be used to provide a formulation with stable properties.

4. Increase the excess lime concentration to 5 lb_m/bbl as a precautionary measure against possible H_2S intrusion. **MIL-GARD® (***not* **MIL-GARD® R)** may also be added.

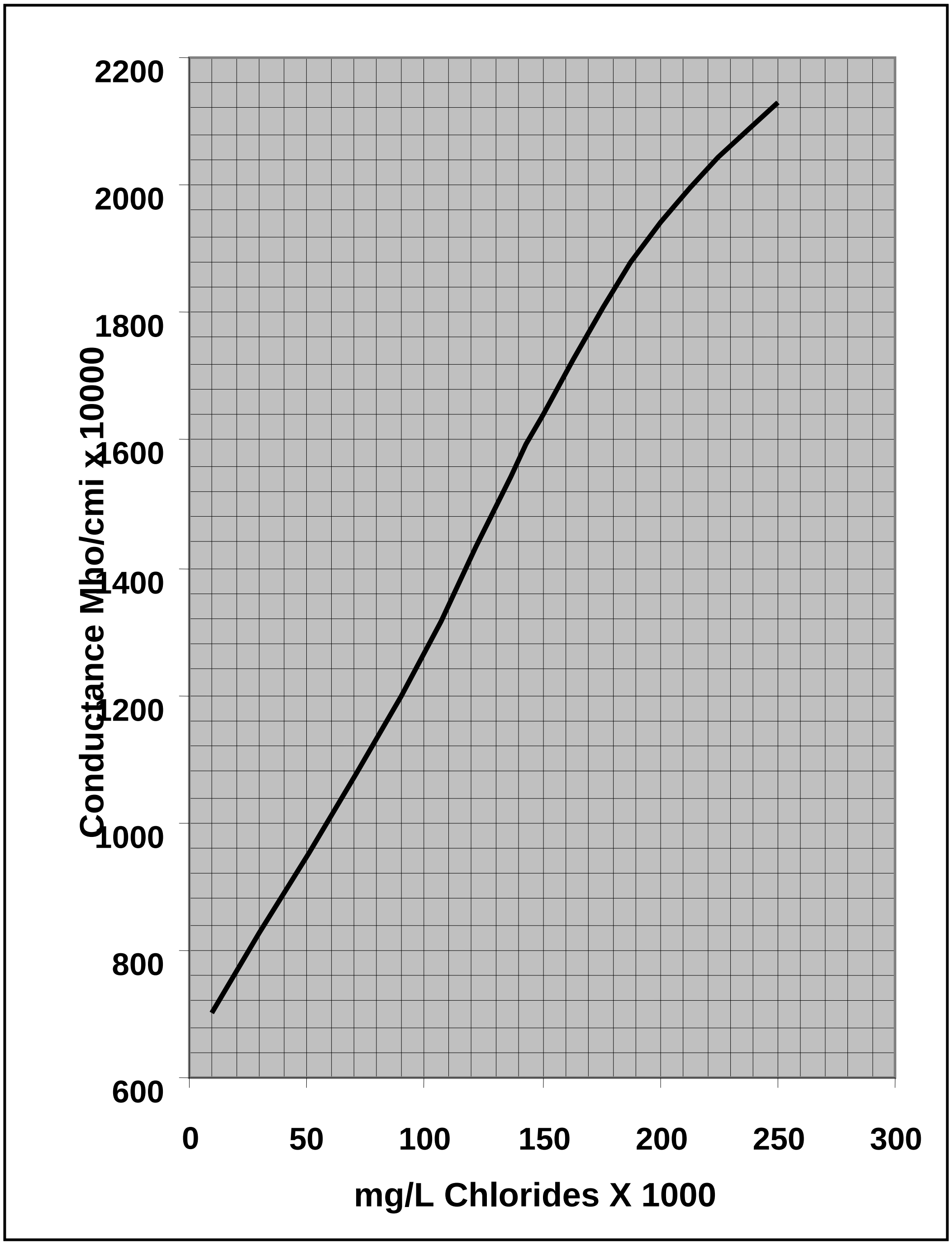


Figure 8- 1 **Conductivity of Brines**

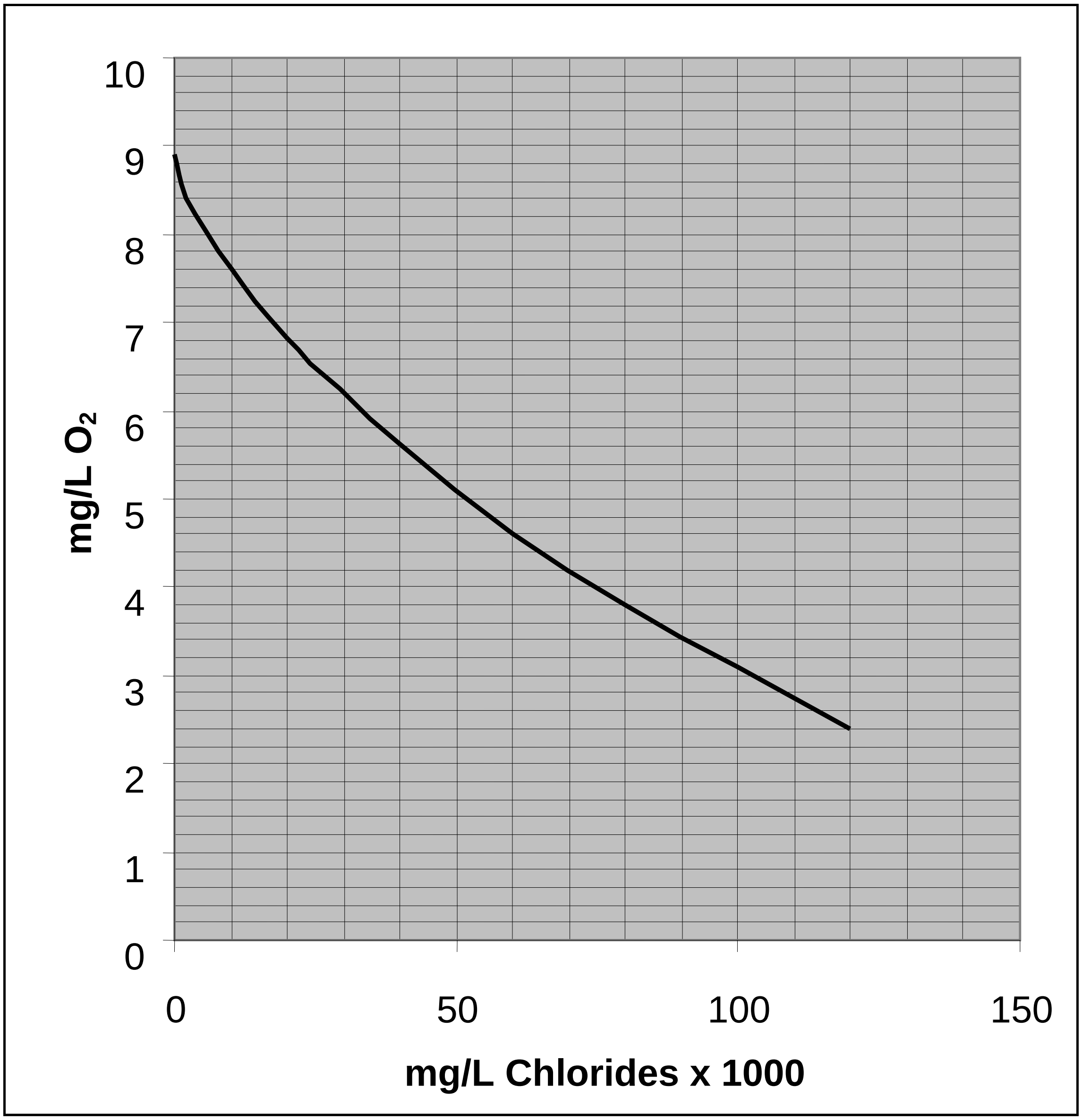


Figure 8- 2 **Oxygen Solubility versus Salinity**

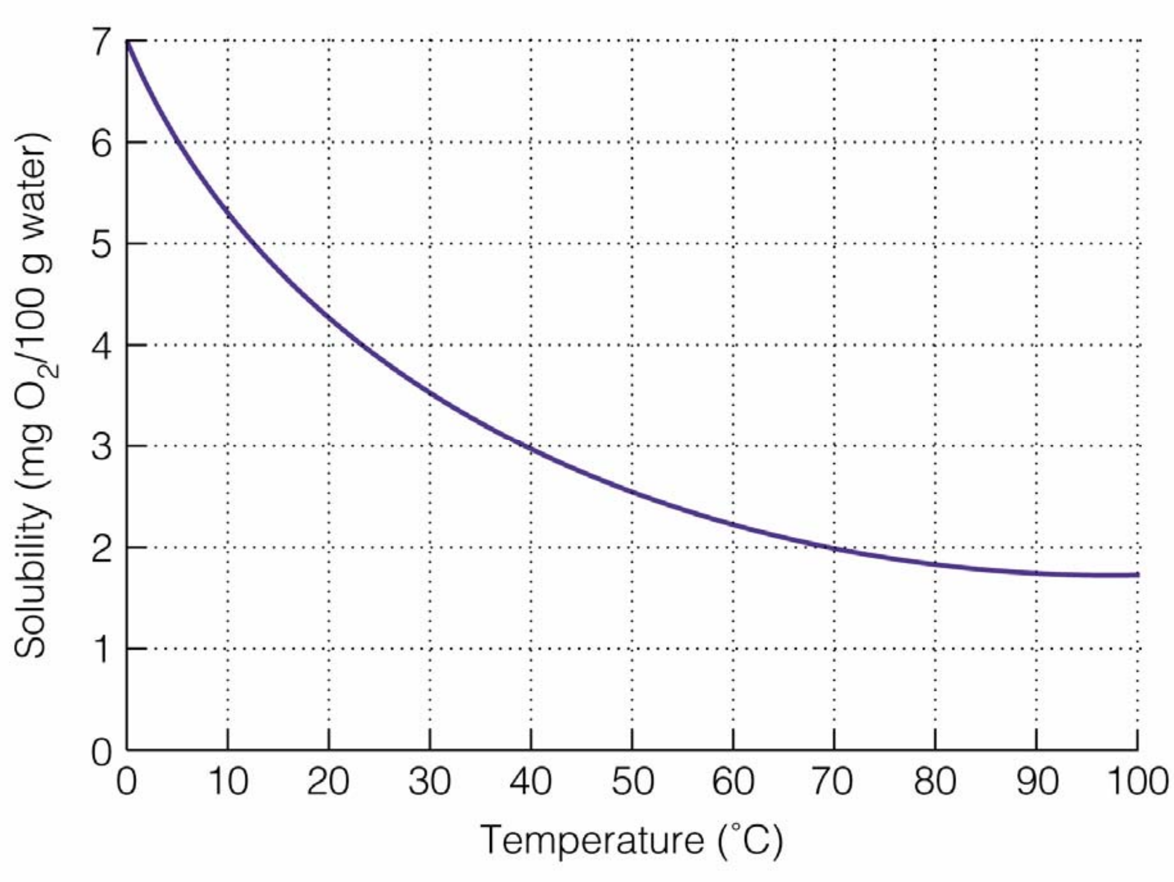


Figure 8- 3 **Oxygen Solubility In Fresh Water Versus Temperature (at one atmosphere)**

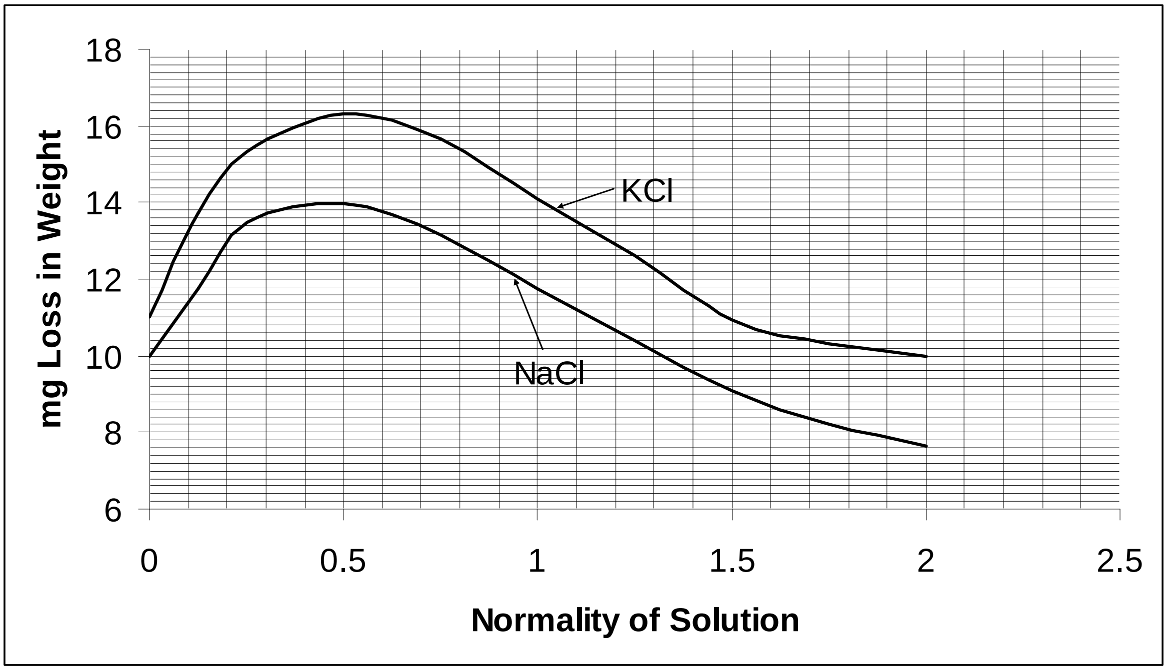


Figure 8- 4 **Salt (KCl & NaCl) Concentration vs. Corrosion Rate**

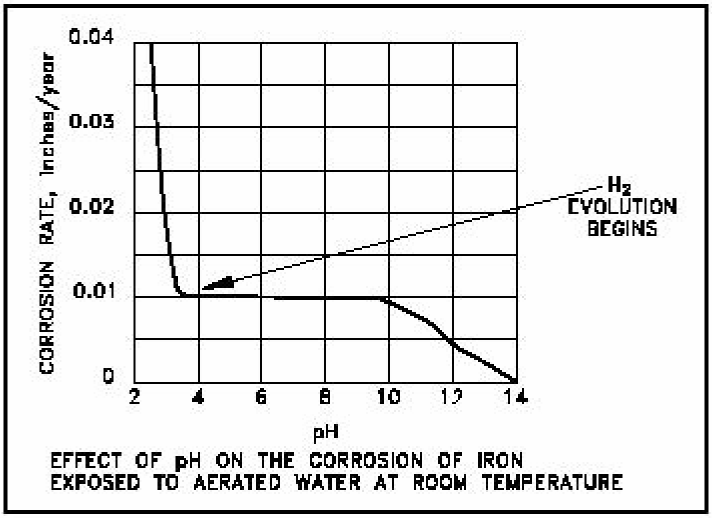


Figure 8- 5 Effect of pH on Corrosion of Iron

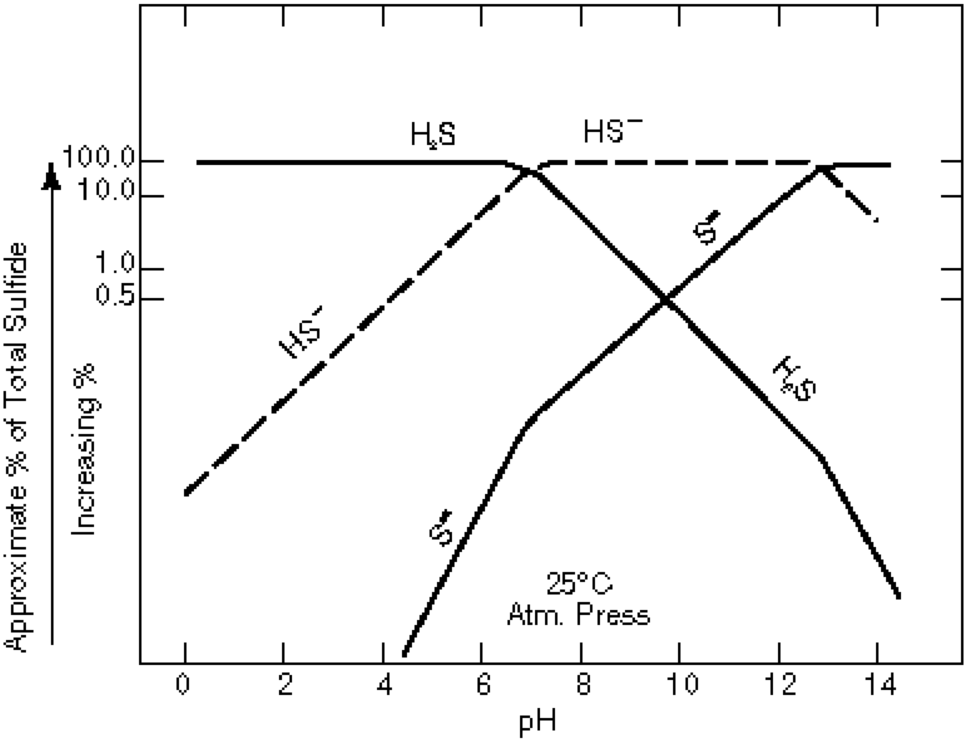
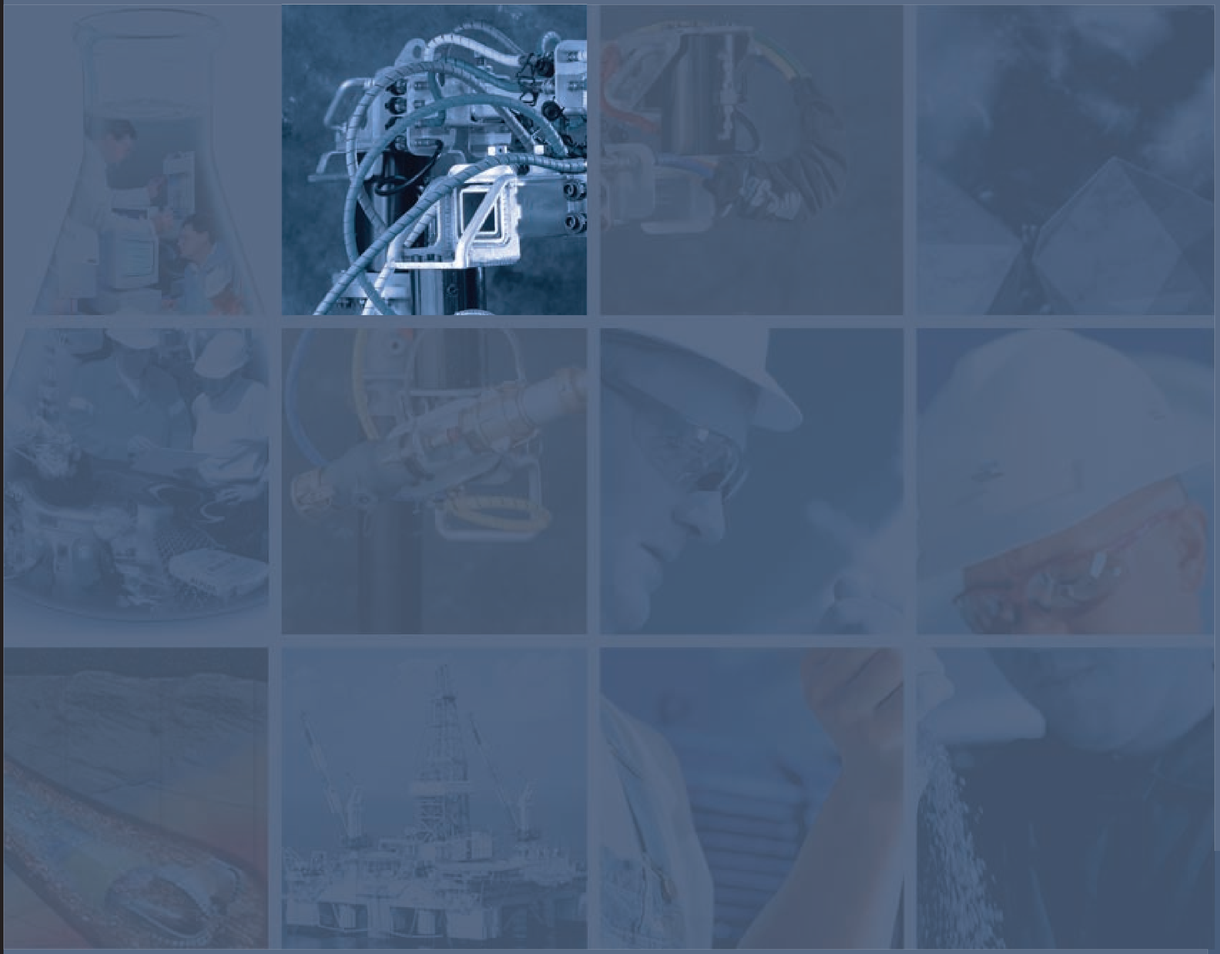


Figure 8- 6 Approximate Distribution of H_2S, HS^-, and $S^=$ as a Function of pH



Chapter Nine

Hydraulics

Chapter 9

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Chapter 9

HYDRAULICS

A detailed understanding of the role drilling fluids hydraulics play in drilling operations is required to adequately support drilling operations. Drilling fluids personnel must understand the different concepts, models, and sets of equations which can be used to plan, optimize, and calculate the hydraulics of a drilling operation. They must also be aware of the strengths and limitations of the engineering software used for hydraulics simulations.

INTRODUCTION

Hydraulics calculations are recommended to be carried out using ADVANTAGE^{SM} Engineering Software. This is the most accurate tool available to Baker Hughes Drilling Fluids personnel for performing hydraulics and hole cleaning simulations. The contents of this chapter are related to ADVANTAGE^{SM} Hydraulics and Hole Cleaning.

The calculation of the various hydraulic parameters of a drilling operation are very important in order to control the many variables of the drilling fluid in such a manner that the well can be completed safely, with minimum damage to the borehole formations, and at the lowest possible cost. The optimization of any particular hydraulic parameter will primarily depend upon the location of the drilling operation. For example, it is pointless to maximize bit hydraulic horsepower or impact force when drilling in soft formations where the penetration rate is limited by the time required to make a connection in the drillstring.

It is common practice to calculate a number of hydraulic parameters and include this information on the fluid report. If any of these parameters are not optimal, alterations to fluid properties, pump rate, or even bit nozzles may be made to compensate. This comprehensive approach is desirable and is the main reason for developing computer programs such as ADVANTAGE^{SM} Hydraulics and Hole Cleaning. The following sections describe the hydraulic parameters and corresponding equations used in a drilling operation.

RHEOLOGY

Rheology is the study of flow and deformation of matter, including liquids and solids. It is critical to remember this definition and be aware that it is not possible to measure, increase, decrease, or optimize rheology. Instead we can do this to viscosity or to rheological properties.

Rheological Terms

To better understand the impact of rheological properties, Figure 9-1 can be used to provide a definition of some basic rheological terms. This illustration depicts the forces acting on a liquid between two one square meter plates, which are separated by one meter. The bottom plate is stationary and the top plate is moved at a rate of one meter per second. The amount of force required to do this is measured in Newtons. **Shear Stress (τ)** is defined as the force required to move a given area of the fluid. In this case one Newton is required for each square meter of area.

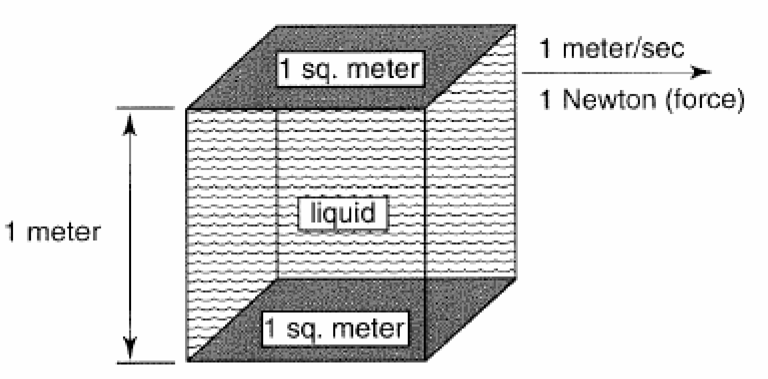

Figure 9 - 1 Diagram for Rheological Definitions

The units of shear stress are Newtons per square meter, also known as Pascals. Alternative units for shear stress are dynes per square centimeter and pounds force per square inch. **Shear Rate ($\dot{\gamma}$)** is defined as the rate of movement of the fluid between the plates. It is determined by dividing the velocity difference between the plates by the distance between them. This can also be called the velocity gradient. In this case, the shear rate or velocity gradient is one meter per second per meter of fluid and is thus measured in reciprocal seconds (sec^{-1}). **Viscosity (η)** is defined as the ratio of shear stress over shear rate. Consequently, the units are Newton seconds per square meter or Pascal seconds. Another common unit is the Poise (dyne second/centimeter^2). One centipoise is equal to one milliPascal second (1cP = 1 Pa.s). NOTE: in oilfield literature, μ is most often substituted with η to designate viscosity.

Generalized Flow Curves

Figure 9-2 illustrates the viscosity versus shear rate curve for water, a simple Newtonian fluid. For a Newtonian fluid, viscosity is independent of shear rate.

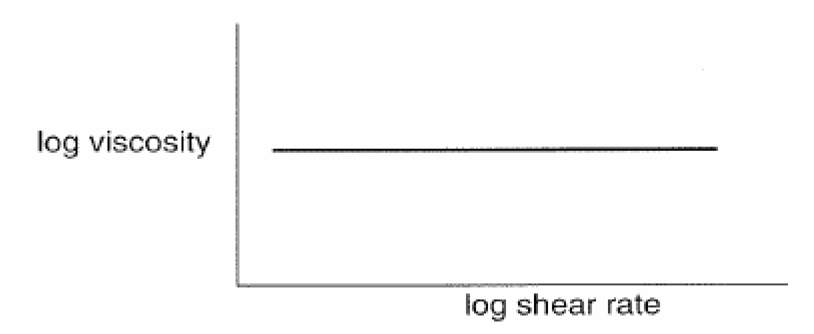

Figure 9 - 2 Viscosity of a Simple Newtonian Fluid

When a water-soluble polymer is added to water, the curve changes dramatically, as indicated in Figure 9-3.

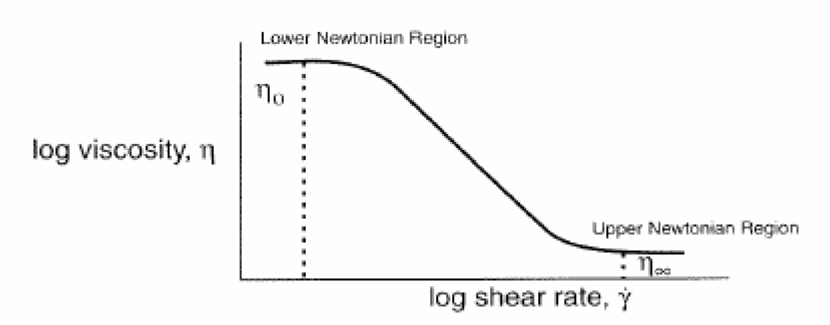

Figure 9 - 3 Viscosity of a Non-Newtonian Fluid

Of significance, there is usually a region at both low and high shear rates where viscosity is independent or nearly independent of shear rate, and a section in between that exhibits strong shear rate dependence. This middle region is usually referred to as the power law region. In some fluids, it can be difficult to reach shear rates that are high or low enough to observe the upper and lower Newtonian regions.

Fluids are generally classified as Newtonian (shear rate independent) or Non-Newtonian (shear rate dependent). Newtonian fluids follow a simple relationship between shear stress and shear rate. Their viscosity is a constant as described by the slope of the line in a linear plot of shear stress versus shear rate (Figure 9-2). Air, water and light hydrocarbon oils are examples of Newtonian fluids.

$$\tau = \mu \, \dot{\gamma} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (1)$$

where:

τ = Shear stress

μ = Viscosity

$\dot{\gamma}$ = Shear rate

The viscosity of Non-Newtonian Fluids at a specific shear rate can also be defined by Equation 2; however, for these fluids, viscosity will vary depending on the shear rate.

Rheological Models

Several mathematical models have been developed to describe the shear stress/shear rate relationship on Non-Newtonian fluids. These models are used to characterize flow properties in an effort to determine the ability of a fluid to perform specific functions. Misapplication of rheological data can result in an over-simplification or exaggeration of fluid features, accompanied by the failure to perform a specific task. In order to optimize fluid performance, an in-depth discussion of data acquisition, rheological models and their inherent limitations is necessary.

Rheological evaluation of oil field fluids is generally accomplished using concentric cylinder viscometers. Typically, these instruments provide a limited number of shear rates ranging from 5.1 to 1022 sec^{-1}. Data generated with these instruments are analyzed using empirical models developed to describe the flow of Non-Newtonian fluids. The most frequently applied models are the Bingham Plastic, Power Law and Herschel-Bulkley models. While the Bingham model may have sufficed during the evolution of clay based drilling fluids, it is deficient when describing the overall behavior of polymer or invert emulsion drilling fluids. Furthermore, the presence of an upper and lower Newtonian region, coupled with a region of power law behavior (Figure 9-3), makes the interpretation and application of rheological data a challenging task. This is further complicated by the fact that the onset of Newtonian behavior varies, depending on the viscosifier or fluid system under consideration (Figure 9-4).

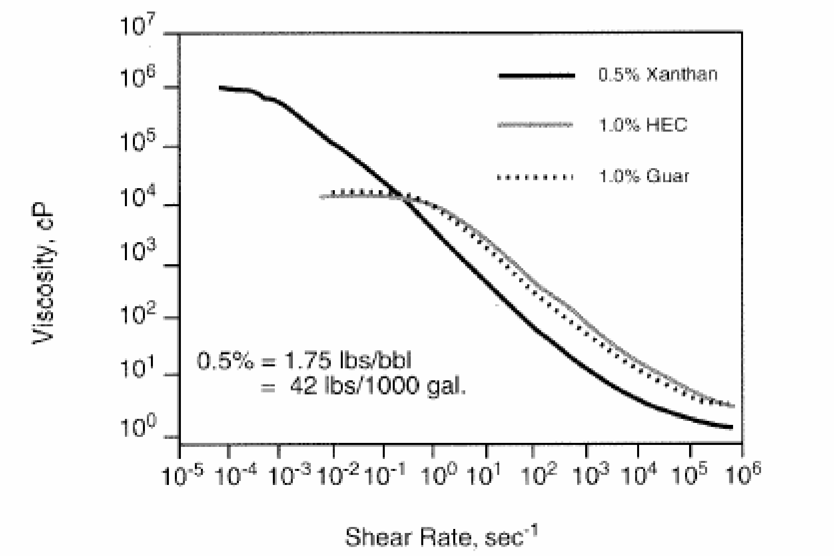

Figure 9 - 4 Viscosity Profiles of Xanthan, HEC and Guar, in 2% KCl, 75°F

Power Law Model

One of the more widely used models for describing the behavior of oil field fluids is the power law model. This model (Equation 2) is valid for the linear, i.e. center section, of the curve shown in Figure 9-3. In the power law model, the viscosity term from the Newtonian model is replaced with a constant, *K*, termed the *consistency index*, which serves as a viscosity index of the system. The consistency index has the unusual set of units, Force-sec^n/Area. In addition, the shear rate term is raised to the nth power, thus the term power law. The factor, *n*, is called the *power law index* which indicates the tendency of the fluid to shear thin. As the value of the flow behavior index deviates from one, the fluid becomes increasingly non-Newtonian.

$$\tau = K\dot{\gamma}^n \quad \ldots\ldots (2)$$

where:

τ = Shear stress
K = Consistency index
$\dot{\gamma}$ = Shear rate
n = Power law exponent

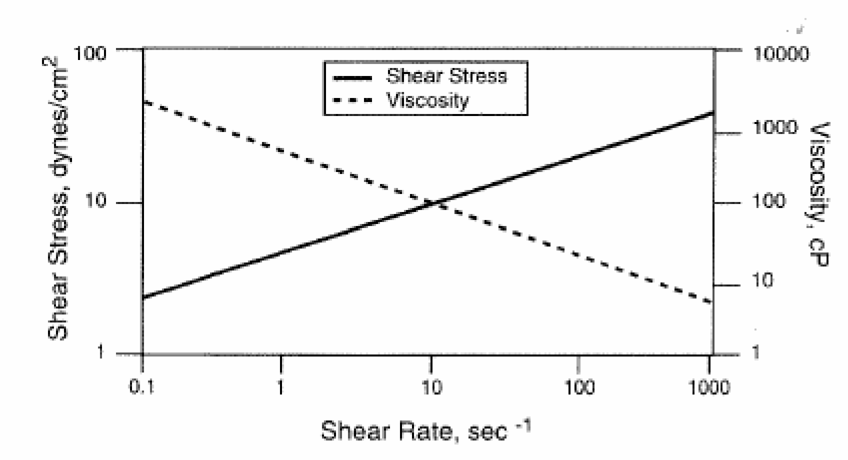

Figure 9 - 5 Idealized Power Law Fluid

When the log of the shear stress is plotted against the log of the shear rate (Figure 9-5), a straight line with a slope equal to *n* and an intercept (at a shear rate of one) equal to log *K*, results. A plot of the log of the viscosity versus log of the shear rate also results in a straight line.

Most polymer solutions and invert emulsion drilling fluids are pseudoplastic. In this case, increased shear rate causes a progressive decrease in viscosity. This is due to alignment of the polymer chains, or structural elements of the fluid, along the flow lines. For pseudoplastic fluids, the value of the flow behavior index, *n*, ranges from about 0.1 to < 1.0. When the *n* value is equal to 1.0, the power law reduces to the Newtonian model. The further that *n* is reduced from 1.0 the more the fluid deviates from Newtonian behavior. Although this is one of the most popular models used, no known fluid exhibits power law behavior over the entire range of shear rate conditions. Therefore, the primary drawback is the limited shear rate range over which it is valid. Care must be taken to use data within the power law region to accurately calculate parameters (*n* and *K*). For example, with xanthan gum, calculating *n* and *K* from 600 rpm (1022 sec^{-1}) and 300 rpm (511 sec^{-1}) on a concentric cylinder viscometer, will result in inaccurately high *n* and low *K* values as compared to values obtained at lower shear rates. As a result, at shear rates below 1.0 sec^{-1}, predicted viscosities using these inaccurate *n* and *0* values will be much lower than measured values (Figure 9-6).

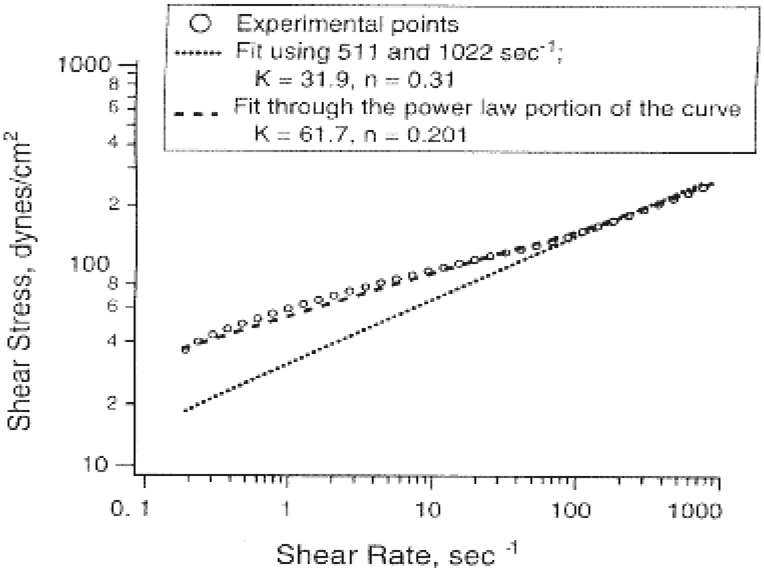

Figure 9 - 6 Application of Power Law for 2.5 lb/bbl Xanthan Gum in 3% KCl Using Data from 1022 and 511 sec^{-1}

This example illustrates the need to apply this model within the power law region of a particular fluid to assure accurate predictions of viscosity.

Bingham Plastic Model

The other two parameter model which has been widely used in drilling fluid applications is the Bingham Plastic model (Equation 3). Fluids that exhibit Bingham Plastic behavior are characterized by a yield point (τ_0) and a plastic viscosity (μ_p) that is independent of the shear rate (Figure 9-7).

$$\tau = \tau_0 + \mu_p \dot{\gamma} \quad \text{.......} \quad (3)$$

where:

τ = Shear stress

τ_0 = Yield point

μ_p = Plastic viscosity

$\dot{\gamma}$ = Shear rate

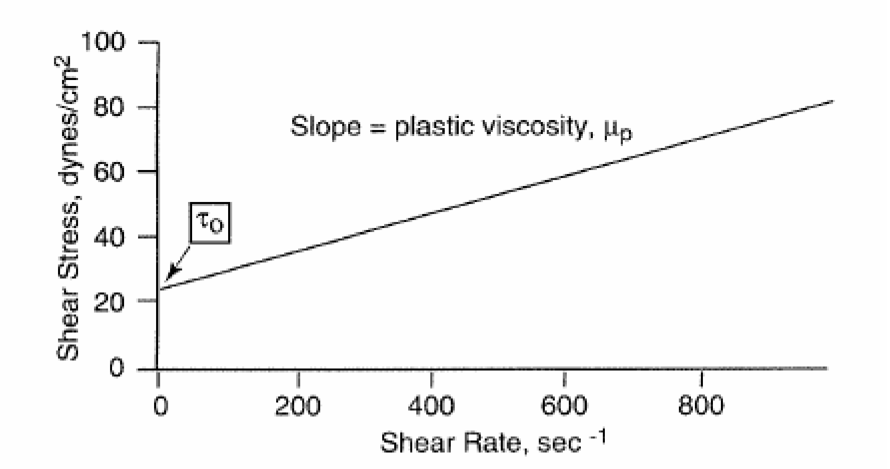

Figure 9 - 7 Idealized Bingham Plastic Fluid

The presence of a yield stress means that a certain critical shear stress must be exceeded before flow can begin. If the fluid exhibits a linear increase in shear stress with shear rate after the yield value is exceeded, it is called a Bingham Plastic fluid. While some fluids exhibit a yield point, most oil field fluids show shear rate dependence after flow is initiated. This model is interesting but not very useful in describing the behavior of polymer or invert emulsion fluids. In the oil field, the Bingham Plastic model has been used to describe the behavior of some clay based drilling fluids and a few cement slurries. An extension of the Bingham Plastic model to include shear rate dependence is the Herschel-Bulkley model, described later.

There are several models that involve the use of three or more adjustable parameters. It is necessary to include a third parameter to describe the flow of fluids in the upper or lower Newtonian region as well as the power law region.

Herschel-Bulkley Model

Fluids that exhibit a yield point and viscosity that is stress or strain dependent cannot be adequately described by the Bingham Plastic model. The Herschel-Bulkley model (Figure 9-8) corrects this deficiency by replacing the plastic viscosity term in the Bingham Plastic model with a power law expression (Equation 4).

$$\tau = \tau_0 + K\dot{\gamma}^{n} \quad \ldots\ldots\ldots\ldots\ldots\ldots \quad (4)$$

where:

τ = Shear stress

τ_0 = Yield point

K = Consistency index

$\dot{\gamma}^{n}$ = Power law expression

This model is useful for describing a wide range of fluids used in oil field operations. The model is reduced to the power law if there is no yield stress and to the Bingham model if $n = 1$. The primary limitation of this and all other models that cannot be linearized is curve fitting to evaluate model parameters. Computers and non-linear curve fitting techniques have overcome this problem. Many publications have shown the usefulness of the three parameter Herschel-Bulkley model and this model is generally accepted as the best available for describing the flow properties of drilling fluids.

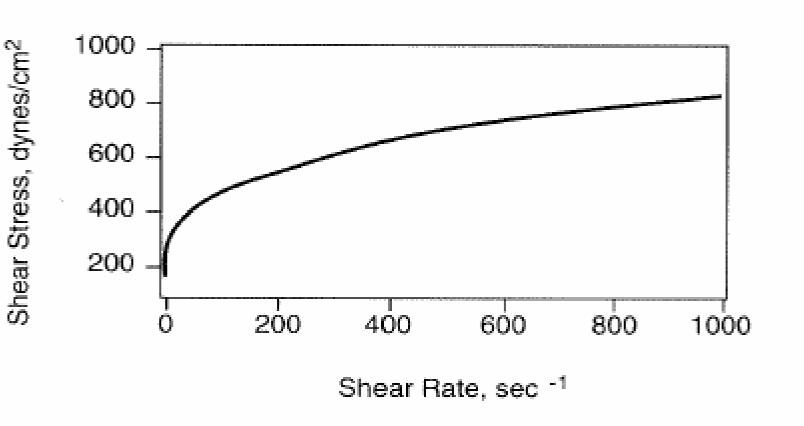

Figure 9 - 8 Idealized Herschel-Bulkley Fluid

Robertson-Stiff Model

The Robertson-Stiff equation, like the Herschel-Bulkley model, is a three variable model. Like the Herschel Bulkley model it has been found to provide very close approximations for pressure losses in the circulating system in most drilling situations. The Newtonian, Bingham Plastic and power law models are specific cases of the Roberson-Stiff model.

In ADVANTAGE^{SM} a least squares method is used to determine the rheological parameters for the Robertson-Stiff model also. This considers all the available Fann readings to determine the rheological parameters for the Robertson-Stiff model. If Plastic Viscosity and Yield Point are entered instead of Fann readings, the Fann readings at 300 and 600 [RPM] can be recalculated. Additionally, the 10sec gel strength can be used to approximate the Fann reading at 3 [RPM].

$$\tau = K \times (\gamma_0 + \gamma)^n \quad \text{...(5)}$$

where:

τ = Shear stress

K = Consistency index

γ_0 = Shear rate intercept

γ = Shear rate

n = Power law index

Rheological Models in ADVANTAGE

In ADVANTAGE Reporting it is possible, and recommended, to input at least Fann readings for 600, 300, 200, 100, 6 and 3 rpm. The 10 second, 10 minute and 30 minute gel strengths are also entered. From these numbers the Plastic Viscosity and Yield Point are derived along with *n* and *k* for the power law model.

The hydraulics equations in ADVANTAGE^{SM} Reporting are API 13-D equations and utilize the power law. These equations do not account for the effect of temperature and pressure on fluid density and rheological properties. This means that in most situations that the results will contain inaccuracies. It is important to be aware of this and the causes of the inaccuracies.

In ADVANTAGE^{SM} Engineering there are two hydraulics models – the BP model and the BHI model. These two models and the rheological models they use will now be discussed separately.

BP Model

The desired input parameters are the Fann readings – preferably at least the 600, 300, 200, 100, 6 and 3 rpm readings - plus the 10 second and 10 minute gels. If only Plastic Viscosity and Yield Point are entered instead of the Fann readings the Bingham model will be used for hydraulics equations. If the Fann readings are entered, then Herschel Bulkley will be used for pressure loss calculations. The cuttings concentration in the drilling fluid is not taken into account in ECD calculations. **The BP model does not allow for temperature and pressure effects on fluid density and rheological properties.**

BHI Model

The Robertson-Stiff and Herschel Bulkley models most accurately model drilling fluids, with the Herschel Bulkley being the recommended model for calculating pressure losses. It is not advisable, nor technically correct, to change models in order to get the best fit between modeling results and field data.

In the BHI model it is possible to use Fann 35 data or Fann 75 data, though the latter is more accurate, especially when using invert emulsion drilling fluids. In **Spreadsheet Hydraulics** the Fann 35 readings are used and system and bit pressure losses are calculated at ten different flow rates using the selected model. The **Calc. Fann Fit** button can be selected in order to check which model best fits the viscometer readings. The default model in the hole cleaning mode for annular pressure loss calculations is the Herschel Bulkley model. A selected model can be used to calculate drill string and drill bit pressure losses. In **System Mud Hydraulics with Hole Cleaning** Herschel Bulkley is used for annular pressure loss calculations using the input flow rate. In the **HT-HP** mode Fann 70 / 75 data must be entered corresponding to the temperature and pressure conditions in the well. When hole cleaning is taken into account the Herschel Bulkley model is used to calculate annular pressure losses, but the manually selected model is used for all other pressure losses. In this mode either spreadsheet Hydraulics or System Mud Hydraulics may be selected.

DRILL STRING AND ANNULAR HYDRAULICS

This section on drill string and annular hydraulics is designed to create a basic understanding of how the various calculations are carried out. The discussion below is based on the use of the power law rheological model. In ADVANTAGE Engineering, the rheological model can be selected and this directly affects hydraulics calculations as different values are derived for the various factors using the different models. The most commonly used models are the Herschel-Bulkley and Roberson-Stiff models, and of these the Herschel-Bulkley is recommended as it is capable of fitting data from power law fluids, Bingham Plastic fluids and power law fluids with a yield stress.

Fluid Velocity

The flow of drilling fluid through the surface equipment, drill string, and annulus may be considered to be flow through a series of circular pipes. The diameter and cross-sectional area in each portion of the circulating system vary from one part to the other. If the volumetric flow rate through the circulating system remains constant, then the speed or velocity of the drilling fluid changes in relation to the cross-sectional area for that particular part of the system. The highest velocities occur where the diameter is the smallest. The fluid velocity is the first and most important step in making hydraulic calculations in the drilling operation.

For **fluid velocity in the drill string,**

$$V_p = \frac{0.408Q}{D^2}$$

where:

V_p = fluid velocity in pipe, ft/sec

Q = volumetric flow rate, gal/min

D = inside diameter of the pipe, in.

For **fluid velocity in the annulus,**

$$V_a = \frac{0.408Q}{(D_2)^2 - (D_1)^2}$$

where:

V_a = annular velocity, ft/sec

Q = volumetric flow rate, gal/min

D_2 = hole diameter, in.

D_1 = outside diameter of the drill pipe/collar/etc, in.

Note that the above equations describe average flow rate in the drill string and the annulus. In the annulus on a directional well there will be a series of velocities in the annulus. Figure 9-9 illustrates the fluid velocity distribution in an eccentric annulus with a rotating inner cylinder. This is the type of flow pattern to be expected in a deviated well.

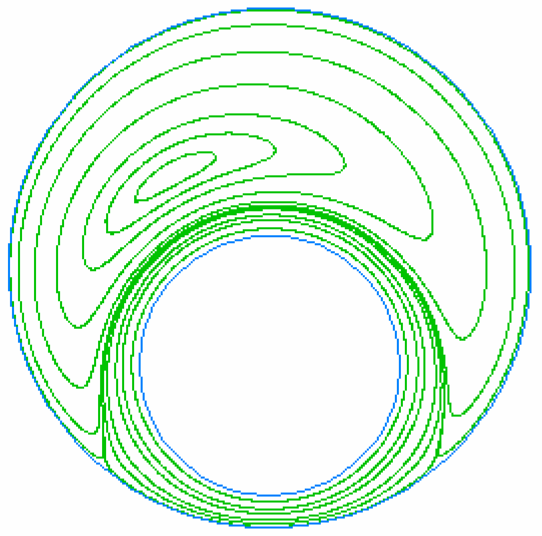

Figure 9 - 9 Flow in an Eccentric Annulus with Inner Cylinder Rotation

Power Law Constants, *n* and *K*

As described above, the consistency factor, *K*, describes the thickness of the fluid and is somewhat analogous to the effective viscosity. The flow behavior index, *n*, indicates the degree of non-Newtonian behavior. These two constants can be calculated from any two values of shear rate/shear stress relationships. When readings are obtained from a V-G meter at 600 rpm, 300 rpm, and 3 rpm, two sets of *n* and *K* can be developed corresponding with fluid flow inside the drill pipe and fluid flow in the annulus. This is done to improve the accuracy of hydraulic calculations in the drill pipe or annulus since the Power Law Model does not exactly describe the behavior of drilling fluids.

To obtain the **power law constants corresponding to fluid flow inside the drill pipe,** the 600 rpm and 300 rpm readings are used.

$$n_{\mathrm{p}} = 3.32 \log\left(\frac{\theta_{600}}{\theta_{300}}\right)$$

$$= \frac{5.11 \times \theta_{600}}{1022^{n_{\mathrm{p}}}}$$

To obtain the **power law constants corresponding to fluid flow in the annulus**, the 300 rpm and 3 rpm (or initial gel strength) readings are used.

$$n_a = 0.5 \log\left(\frac{\theta_{300}}{\theta_3}\right)$$

$$K_{\mathrm{a}} = \frac{5.11 \times \theta_{300}}{5.11^{n_{\mathrm{a}}}}$$

where,

n = flow behavior index, dimensionless

K = consistency factor, poise.

Effective Viscosity

Since all drilling fluids are shear-thinning to some degree, the viscosity of the fluid changes with a change in the shear rate. In order to calculate other hydraulic parameters, the effective viscosity at a given rate of shear must be known. By definition, effective viscosity is the viscosity of a Newtonian fluid that exhibits the same shear stress at the same rate of shear.

The equation for **effective viscosity** in pipe is:

$$\mu_{e_p} = 100K_p\left[\frac{96V_p}{D}\right]^{n_p - 1}$$

where,

μ_{e_p} = effective viscosity inside pipe, cp

K_p = power law constant, poise

V_p = bulk fluid velocity in pipe, ft/sec

D = inside diameter of the pipe, in.

n_p = power law constant for pipe

The equation for **effective viscosity in the annulus is**:

$$\mu_{e_a} = 100K_a\left[\frac{144V_a}{D_2 - D_1}\right]^{n_a - 1}$$

where:

μ_{ea} = the annular effective viscosity, cp
K_a = power law constant, poise
V_a = annular fluid velocity, ft/sec
D_2 = hole diameter, in.
D_1 = outside pipe diameter, in.
n_a = power law constant for annulus

Reynolds Number

After calculating the effective viscosity, μ_e, as a function of fluid velocity and power law constants, the Reynolds Number is calculated to determine the flow regime of the fluid (i.e., laminar, transitional, or turbulent flow).

The equation for **Reynolds Number** inside the pipe is:

$$Re_p = \frac{928(V_p)(D_p)\rho}{\mu_{e_p}\left[\frac{3n_p + 1}{4n_p}\right]^{n_p}}$$

where:

Re_p = Reynolds Number inside the pipe
V_p = fluid velocity inside the pipe, ft/sec
D_p = inside diameter of the pipe, in.
ρ = fluid density, lb_m/gal
μ_{e_p} = effective viscosity inside pipe, cp
n_p = power law constant for pipe

To obtain the Reynolds Number in the annulus:

$$Re_a = \frac{928V_a(D_2 - D_1)\rho}{\mu_{e_a}\left[\frac{2n_a + 1}{3n_a}\right]^{n_a}}$$

where:

Re_a = Reynolds Number in the annulus
V_a = fluid velocity in the annulus, ft/sec

D_2 = hole diameter, in.

D_1 = outside pipe diameter, in.

ρ = fluid density, lb_m/gal

μ_{e_a} = effective viscosity in the annulus, cp

n_a = power law constant for the annulus

Flow Regime and Critical Reynolds Number

As discussed in the **Rheology** section of Chapter 2, fluid flow may be laminar, transitional, or turbulent. In the experiments conducted by Osborne Reynolds in 1883, he found in observing the flow of water in a circular pipe that the onset of turbulent flow began at a calculated Reynolds Number of 2000 and was completely turbulent flow at a Reynolds Number of 4000. He then defined a Reynolds Number between 2000 and 4000 as transitional flow – neither completely laminar nor turbulent.

Since drilling fluids don't behave exactly like the flow of water, the Reynolds Numbers at which flow changes from laminar to turbulent flow is not the same as water. The following equations have been developed to determine the critical Reynolds Number (*Rec*) at which the flow regime changes.

Laminar Flow

$$Rec < 3470 - 1370n$$

Transitional Flow

$$3470 - 1370n \leq Rec \leq 4270 - 1370n$$

Turbulent Flow

$$Rec > 4270 - 1370n$$

Critical Flow Rate

In the drilling operation, it is usually desirable to have laminar flow in the annulus. In order to have laminar flow, the critical Reynolds Number for laminar flow ($3470 - 1370n_a$) in the annulus must not be exceeded. It is then easy to calculate the critical flow rate for the critical Reynolds Number in two steps.

First, obtain the **critical velocity** by solving the following equation:

$$V_c = \left[\frac{\left(3470 - 1370_{n_a}\right)(100)K_a\left[\frac{2n_a + 1}{3n_a}\right]^{n_a}}{928\rho\left(D_2 - D_1\right)\left[\frac{144}{D_2 - D_1}\right]^{1-n_a}} \right]^{\frac{1}{2-n_a}}$$

Where:

V_c = critical annular velocity, ft/sec.

Then solve for Q_c,

$$Q_c = 2.45(V_c)[(D_2)^2 - (D_1)^2]$$

where:

Q_c = critical flow rate, gal/min

Fanning Friction Factor

The Fanning Friction Factor (f) expresses the resistance to flow of a fluid at the pipe wall and is a function of the Reynolds Number and of the surface conditions at the wall.

Laminar flow in pipe,

$$f_p = \frac{16}{Re_p}$$

Transitional flow in pipe,

$$f_p = \left[\frac{Re_p - (3470 - 1370n_p)}{800}\right] \times \left[\frac{a}{(4270 - 1370n_p)} - \frac{16}{3470 - 1370n_p}\right] + \frac{16}{3470 - 1370n_p}$$

where:

$$a = \frac{\log n_p + 3.93}{50}$$

$$b = \frac{1.75 - \log n_p}{7}$$

Turbulent flow in pipe,

$$f_p = \frac{a}{Re_p^b}$$

where:

$$a = \frac{\log n_p + 3.93}{50}$$

$$b = \frac{1.75 - \log n_p}{7}$$

Laminar flow in annulus,

$$f_a = \frac{24}{Re_a}$$

Transitional flow in annulus,

$$f_a = \left[\frac{Re_a - (3470 - 1370n_a)}{800}\right] \times \left[\frac{a}{(4270 - 1370n_a)^b} - \frac{24}{3470 - 1370n_a}\right] + \frac{24}{3470 - 1370n_a}$$

where:

$$a = \frac{\log n_a + 3.93}{50}$$

$$b = \frac{1.75 - \log n_a}{7}$$

Turbulent flow in annulus,

$$f_a = \frac{a}{Re_a^{\ b}}$$

where:

$$a = \frac{\log n_a + 3.93}{50} \quad \text{and} \quad b = \frac{1.75 - \log n_a}{7}$$

Friction-Loss Pressure Gradient

The total pressure required to circulate the drilling fluid includes not only the pressure drop across the bit nozzles, but also the friction losses throughout the surface system, drillstring, and annular sections. The appropriate friction factor (from previous section) is substituted into the Fanning equation to determine the friction-loss pressure gradient. The appropriate values must be used for each section of pipe or annulus sections with different diameters.

Friction-Loss gradient in pipe:

$$\frac{P_p}{L_m} = \frac{(f_p)(V_p)^2(\rho)}{25.81D}$$

where:

$\frac{P_p}{L_m}$ = pressure loss per measured depth, psi / ft

and,

f_p = friction factor (laminar, transitional, or turbulent)

V_p = bulk velocity in pipe, ft/sec

ρ = fluid density, lb_m/gal

D = inside diameter of pipe, in.

Friction-loss gradient in annulus:

$$P_a = \frac{P_a}{L_m} \times \text{Annular Length}$$

$$\frac{P_a}{L_m} = \frac{(f_a)(V_a)^2(\rho)}{25.81(D_2 - D_1)}$$

where:

$$\frac{P_a}{L_m} = \text{pressure loss per measured depth, psi / ft}$$

and,

f_a = friction factor (laminar, transitional, or turbulent)

V_a = bulk velocity in annulus, ft/sec

ρ = fluid density, lb_m/gal

D_2 = hole diameter, in.

D_1 = outside pipe diameter, in.

Equivalent Circulating Density

The pressure required to overcome the total friction losses in the annulus, when added to the hydrostatic pressure of the fluid, gives the **Equivalent Circulating Density** (ECD) as follows.

$$ECD = \frac{\Sigma P_a}{(.052)(TVD)} + \rho$$

where:

ECD = equivalent circulating density, lb_m/gal

ΣP_a = sum of the friction loss in all annular intervals, psi

TVD = true vertical depth, ft

ρ = fluid density, lb_m/gal

Note: Temperature and pressure affect both the density of fluids and their rheological properties, both of which affect the ECD.

BIT HYDRAULICS

Conventional bits incorporate a number of nozzles through which the drilling fluid is forced at high velocity. This fluid velocity results in hydraulic forces that affect penetration rate, bit cleaning, and other parameters. While it is desirable to have most, if not all, of these parameters at an optimum value, such gains must not be made at the expense of some other detrimental effect. For example, maximizing penetration rate may not necessarily result in the lowest cost per foot of drilled hole. Other factors such as reduced bit life or pack-off of drilled cuttings in the annulus may increase cost. As with all hydraulic parameters, bit hydraulics should be used in an overall hydraulic evaluation of the drilling operation. Optimizing bit hydraulics tends to be more critical with water based drilling fluids than with invert emulsion drilling fluids.

Nozzle Velocity

The velocity of the drilling fluid is determined by the circulation rate and the total area of the nozzles in the bit. Even if the jet nozzles are of different sizes, the velocity is the same through each. In other words, the velocity is independent of the individual diameters of the nozzles due to the mechanics of fluid flow through an orifice.

First calculate the **total nozzle area**.

$$A_t = \frac{(J_1)^2 + (J_2)^2 + \ldots + (J_n)^2}{1303.8}$$

where:

A_t = total nozzle area, in^2.

J_n = nozzle size, 32nds of an inch (i.e., 11, 12, etc.)

Then **nozzle velocity:**

$$V_n = \frac{Q}{3.117 A_t}$$

where:

V_n = nozzle velocity, ft/sec

Q = flow rate, gal/min

A_t = total nozzle area, in.^{2}

Pressure-Drop Across Bit

When the drilling fluid passes through the jet nozzles, a pressure-drop due to friction losses occurs. This pressure-drop has a number of important applications, such as optimizing hydraulic horsepower or impact force of the fluid on the formation and improving chip removal and bit cleaning. The bit nozzles are designed to maximize the portion of pressure loss in the circulating system that may be used to perform work on the formation. Analysis of pressure-drop through an orifice such as a jet nozzle can be complicated; however, nozzle coefficients have been empirically determined that account for turbulence and velocity through the orifice. The total pressure-drop across the bit is derived from an energy balance called **Bernoulli's Equation** and includes a nozzle coefficient of 0.95. It is calculated by,

$$P_n = \frac{156(\rho)Q^2}{[(J_1)^2 + (J_2)^2 + \ldots + (J_n)^2]^2}$$

where:

P_n = total pressure-drop across bit, psi

ρ = fluid density, lb_m/gal

Q = flow rate, gal/min

J_n = nozzle size, 32nds of an in. (i.e., 11, 12, etc.).

Hydraulic Horsepower and Impact Force

Hydraulic horsepower is the product of pressure and flow rate, whereas impact force is the product of fluid density, flow rate, and velocity. Both horsepower and impact are measures of the amount of work from the drilling fluid available at the bit, although derived differently. Additionally, both parameters are affected by the circulation pressure losses in all parts of the circulation system.

Hydraulic horsepower at the bit is given by:

$$\mathrm{HHP} = \frac{\mathrm{QP_n}}{1714}$$

where:

HHP = hydraulic horsepower, hp

Q = flow rate, gal/min

P_n = total pressure-drop across bit, psi.

Some operators prefer to analyze the **ratio of hydraulic horsepower to hole area**. This is calculated by:

$$\mathrm{HHP/in^2} = \frac{(1.2732)\mathrm{HHP}}{\mathrm{D^2}}$$

where:

HHP/in^2 = hydraulic horsepower per $in.^2$

D = hole size or bit size, in.

Impact force is given by:

$$\mathrm{F_i} = \frac{\rho(\mathrm{Q})\mathrm{V_n}}{1932}$$

where:

F_i = impact force, lb_f

ρ = fluid density, lb_m/gal

Q = flow rate, gal/min

V_n = nozzle velocity, ft/sec.

Jet Selection

When optimizing a hydraulics program, it is sometimes desirable to maximize either the hydraulic horsepower or the impact force within the constraints of minimum and maximum flow rates and maximum standpipe pressure. A detailed derivation of maximizing either parameter is not given here, however, a common assumption is that maximum hydraulic horsepower occurs when 65% of the total available standpipe pressure is developed at the bit. Correspondingly, maximum impact force occurs when 48% of the total available standpipe pressure is developed at the bit. It can be easily seen that maximizing both hydraulic horsepower and impact force cannot be done simultaneously. The calculation for maximizing either hydraulic horsepower or impact force involves finding a total nozzle area required to develop the specified pressure loss at the bit, and then simply selecting the required number and available nozzle sizes that give the total nozzle area. It should be noted that the jet nozzles need not be all of the same size.

It is sometimes necessary to run a bit with large nozzles in order to circulate lost circulation material. This frequently causes a great decrease in hydraulic horsepower or impact force. Downhole motors, MWD and LWD equipment all contribute significantly to drill string pressure losses. These pressure losses may be so great as to restrict the ability to optimize bit hydraulics. However, in many cases, it is possible to maintain reasonably good hydraulics by reducing the number of nozzles. For example, two $^{16}/_{32}$ in. nozzles have approximately the same area as three $^{13}/_{32}$ in. nozzles.

To find the **total jet area for maximum hydraulic horsepower or impact force,**

$$A_t = \frac{Q}{2.96\left[\frac{(1238.5)CP}{\rho}\right]^{1/2}}$$

where:

A_t = optimum total nozzle area, in.^{2}

Q = flow rate, gal/min

P = available standpipe pressure, psi

ρ = fluid density, lb$_m$/gal

C = Constant: 0.65 for maximum HHP,

0.48 for maximum impact force,

0.59 for HHP-Impact compromise.

Once the total jet area is obtained, simple algorithms are used to back-calculate jet sizes. The following algorithms show how jet sizes can be obtained for any number of jets.

$$J_1 = \left[\frac{1303.797}{N} A_t\right]^{1/2}$$

$$J_2 = \left[\frac{1303.797}{N-1}\left(A_t - \frac{(J_1)^2}{1303.797}\right)\right]^{1/2}$$

$$J_3 = \left[\frac{1303.797}{N-2}\left(A_t - \frac{(J_1)^2 + (J_2)^2}{1303.797}\right)\right]^{1/2}$$

$$J_4 = \left[\frac{1303.797}{N-3}\left(A_t - \frac{(J_1)^2 + (J_2)^2 + (J_3)^2}{1303.797}\right)\right]^{1/2}$$

$$J_{N-3} = \left[\frac{1303.797}{4}\left(A_t - \frac{(J_1)^2 + ... + J_{N-4}^2}{1303.797}\right)\right]^{1/2}$$

$$J_{N-2} = \left[\frac{1303.797}{3}\left(A_t - \frac{(J_1)^2 + ... + J_{N-3}^2}{1303.797}\right)\right]^{1/2}$$

$$J_{N-1} = \left[\frac{1303.797}{2}\left(A_t - \frac{(J_1)^2 + ... + J_{N-2}^2}{1303.797}\right)\right]^{1/2}$$

$$J_N = \left[\frac{1303.797}{1}\left(A_t - \frac{(J_1)^2 + ...+ J_{N-1}^2}{1303.797}\right)\right]^{1/2}$$

where:

N = the number of jets desired

J_1, J_2, etc. = the jet size in 32nds of an in., which must be rounded to the nearest whole number (i.e., 11, 12, etc.).

ADVANTAGE^{SM} Engineering programs contain the necessary tools to recommend bit nozzle sizes.

SWAB AND SURGE

Tripping into or out of a wellbore involves movement of the drillstring within a non-circulating fluid column. Many blowouts have occurred when tripping out of the hole, while lost-returns problems are often associated with trips back into the hole. The common factor in both cases is the movement of the drillstring and its effect on hydrostatic pressure, typically at the last casing seat and at total measured depth. Swab and surge pressures are caused by the combined effects of viscous drag of the drilling fluid on the drillstring and annular velocity due to displacement of the drilling fluid by the drillstring.

The key variables influencing swab and surge pressures are:

- Wellbore geometry – Such factors as gauge hole, cuttings beds and washouts can have a very strong effect on the wellbore geometry.
- Fractures pressures, pore pressures and depleted zones – These determine how high/low pressure surges a wellbore will safely tolerate.
- Drilling fluid density and rheological properties – Gel strengths are considered in calculations and directly impact the pressure necessary to initiate fluid flow.
- Tripping speed – This is the most easily controlled variable and is the one that is used by ADVANTAGE^{SM} Engineering to limit swab and surge pressures.

Swab and surge pressures can be calculated by a method similar to that used for calculating annular circulating pressures. The greatest problem is determining fluid flow rate in the annulus when the pipe is open-ended since the distribution of flow between pipe bore and annulus cannot be found by any simple method. However, assumptions can be made which will simplify the analysis.

If an assumption is made in which the pipe is closed, or the entire fluid flow rate is in the annulus, then the analysis will lead to swab or surge pressures equal to or probably exceeding the true swab or surge pressures.

Alternatively, to assume the pipe is open-ended and fluid levels in pipe and annulus remain equal is a rarely justifiable and subsequent swab and surge pressure calculated will usually be too low. Another alternative procedure considers the pipe bore and annulus where a U-tube fluid level in the pipe and annulus are not equal – where the sum of pressure losses in the pipe bore and bit equals the sum of pressure losses in the annulus. This procedure requires a trial and error solution due to the uncertainty of the fluid level in the pipe bore.

Finally, when calculating swab or surge pressures, the calculated value should be checked against the pressure required to break the gel strengths of the fluid. If the calculated swab or surge pressure is less than the sum of the pressures required to break the gel strengths, the gel-breaking pressure should be used.

ADVANTAGE^{SM} Engineering contains swab and surge calculation modules. This is Baker Hughes Drilling Fluids' recommended tool for performing swab and surge analysis. The discussion below explains some of the background to swab and surge calculations.

Equivalent Fluid Velocity

When moving the drillstring through a stationary fluid column, an equivalent fluid velocity due to the speed of pipe movement can be calculated. Since the combination of fluid movement and viscous drag has an effect on the swab or surge pressure, Burkhardt's constant is introduced in order to account for the viscous drag effect. It is common practice to assume Burkhardt's constant is equal to 0.45, as any error introduced by this assumption will be on the side of safety.

To find the **equivalent fluid velocity in the annulus:**

$$V_m = \left(0.45 + \frac{(D_1)^2}{(D_2)^2 - (D_1)^2}\right) V_p$$

where:

V_m = equivalent fluid velocity, ft/min

D_1 = outside diameter of the pipe, in.

D_2 = hole diameter, in.

V_p= average maximum speed of pipe movement, ft/min

The **average speed of pipe movement**, V_P, can be determined by one of the following methods:

1. Measurement of the time required to run or pull one stand of pipe from slips to slips, divided into 1.5 times the stand length.

$$V_p = \frac{90L_s}{t}$$

where:

L_s = stand length, ft

t = time from slips to slips, sec

2. Measurement of the time required for the middle joint of a three-joint stand to pass through the rotary table divided into the joint length.

$$V_p = \frac{60L_j}{t}$$

where:

L_j = joint length, ft

t = time through rotary table, sec

Flow Regime

The possibility of turbulent flow in the annulus must be considered in surge and swab calculations. The equivalent fluid velocity may be compared to the critical flow rate for the annular section of interest previously calculated if the fluid properties or pipe diameters have not changed. If changes have occurred, calculate a new *critical flow rate* by following the steps outlined earlier.

Surge or Swab Pressure

The appropriate Fanning Friction Factor for annular flow and Friction-Loss Pressure Gradient are used to obtain the surge or swab pressure loss in each interval.

Equivalent Fluid Weight

In order to be meaningful, the surge or swab pressure and resulting equivalent fluid weight must be compared to some fracture gradient or pore pressure. The pressure drops in each annular interval are summed together, very similar to the steps used to obtain the Equivalent Circulating Density. When running pipe in the hole, the **equivalent fluid weight due to the surge pressure** is:

$$\text{EMW} = \rho + \frac{\sum P_a}{(0.052)(\text{TVD})}$$

When pulling pipe out of the hole, the **equivalent fluid weight due to the swab pressure is,**

$$\text{EMW} = \rho - \frac{\sum P_a}{(0.052)(\text{TVD})}$$

where:

EMW = equivalent fluid weight, lb_m/gal

ρ = fluid density, lb_m/gal

$\sum P_a$ = sum of the pressure loss in each annular interval, psi

TVD = true vertical depth, ft

If the equivalent fluid weight due to the surge pressure exceeds the fracture gradient, at some point in the open hole, loss of circulation may occur. Likewise, if the equivalent fluid weight due to swab pressure is less than the formation pore pressure, at some point in the open hole, a kick, or even a blowout, may occur.

These preceding steps and equations are useful approximations for surge and swab calculations when the time required running or pulling pipe can be measured. For planning purposes, it would also be useful to calculate the time required so as not to exceed a fracture gradient or pore pressure. This type of calculation is done through iterations of time (t) and is one of the programs contained within ADVANTAGE^{SM} Engineering.

Gel-Breaking Pressure

When pipe is started back in the hole after a trip, the fluid will have been at rest for some period of time. The pressure required to break the downhole gel strength of the fluid can be significant, especially if the gel strengths are progressive. The primary reason for measuring 30-minute gel strength is to determine the progressive or fragile nature of the gel strengths. If the gel strengths are significantly high and progressive, the resulting surge or swab pressure could lead to well control problems.

Gel strengths are a function of many factors, including time and temperature. By utilizing the 30-minute gel strength, the time factor can be partially taken into account for fragile gels, as long as the fluid is temperature stable at the bottomhole temperature. If the calculated swab or surge pressure is less than the sum of the gel-breaking pressures for each section of annulus, the gel-breaking pressures should be used.

To find the **gel-breaking pressure:**

$$P_g = \frac{4L\tau_g}{1200(D_2 - D_1)}$$

where,

P_g = gel breaking pressure, psi

L = Length of annular section, ft

τ_g = 30-minute gel strength, lb_f /100 ft^2

D_2 = hole diameter, in.

D_1 = outside pipe diameter, in.

The equivalent fluid weight is calculated using the earlier equations.

CUTTINGS TRANSPORT

One of the primary functions of a drilling fluid is to bring drilled cuttings to the surface. Inadequate hole cleaning can lead to a number of problems including fill, packing-off, stuck pipe, and excessive hydrostatic pressure.

The ability of a drilling fluid to lift cuttings is affected by many factors, and there is no universally accepted theory which can account for all observed phenomena. Some of these parameters are fluid density and rheological properties, annulus size and eccentricity, annular velocity and flow regime, pipe rotation, cuttings density, and size and shape of the cuttings.

Figure 9-10 shows some general features of cuttings transport in laminar flow. If the particles are of irregular shape, they are subjected to a torque caused by the shearing of the fluid. If the drillpipe is rotating, a centrifugal effect causes particles to move toward the outer wall of the annulus in straight holes and helps keep cuttings moving, which minimizes the cuttings bed in horizontal holes. Nonetheless, cuttings transport rates are strongly dependent on particle size and shape, which, during a drilling operation, are both irregular and variable.

The only practical way to estimate cuttings transport or slip velocity of cuttings is to develop empirical correlations based on experimental data. Even with this approach, there is quite a wide disparity in the results obtained by different authors.

Particle slip velocity calculations are based upon particle Reynolds Numbers, drag coefficients, and size of cuttings. Simplifications are made that allow the slip velocity to be determined.

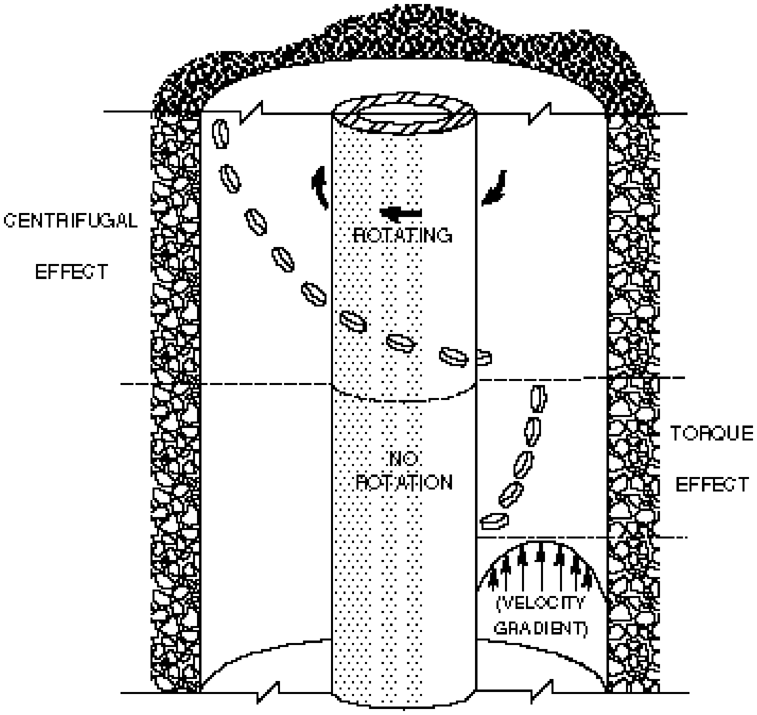

Figure 9 - 10 Cuttings Transport

ADVANTAGE^{SM} Engineering is the recommended tool for conducting hole cleaning simulations and calculations. The discussion below describes some of the theories involved in cuttings transport.

Laminar Flow Condition

Find the **boundary shear rate,**

$$\gamma_b = \frac{186}{D_c\sqrt{\rho}}$$

where,

γ_b = boundary shear rate, sec^{-1}

D_c = particle diameter, in.

ρ = fluids density, lb_m/gal

Find the **shear stress developed by the particle:**

$$\tau_p = 7.9\sqrt{T(20.8-\rho)}$$

where,

τ_p = particle shear stress, lb_f /100 ft^2

T = particle thickness, in.

ρ = fluid density, lb_m/gal

Find the **shear rate developed by the particle** using the annular power law constants for the fluid:

$$\gamma_p = \left(\frac{\tau_p}{K_a}\right)^{\frac{1}{n_a}}$$

where,

γ_p = particle shear rate, sec^{-1}

τ_p= particle shear stress, lb_f /100ft^2

n_a = annular flow behavior index

K_a = annular consistency factor, poise

If $\gamma_p < \gamma_b$, the **slip velocity** is determined by:

$$V_s = 1.22\tau_p\left[\frac{(\gamma_p)(D_c)}{\sqrt{\rho}}\right]^{1/2}$$

where,

V_s = slip velocity, ft/min

τ_p = particle shear stress, lb_f /100 ft^2

γ_p = particle shear rate, sec^{-1}

D_c = particle diameter, in.

ρ = fluid density, lb_m/gal

If $\gamma_p > \gamma_b$, the slip velocity is determined by the equation below, **slip velocity of a particle in turbulent flow**.

Turbulent Flow Condition

Find the **particle shear stress:**

$$\tau_p = 7.9\sqrt{T(20.8 - \rho)}$$

where:

τ_p = particle shear stress, lb_f /100 ft^2

T = particle thickness, in.

ρ = fluid density, lb_m/gal.

Slip velocity of a particle in turbulent flow is:

$$V_s = \frac{16.62\,\tau_p}{\sqrt{\rho}}$$

where:

V_s = slip velocity, ft/min

τ_p = particle shear stress, lb_f /100 ft^2

ρ = fluid density, lb_m/gal

Cuttings Transport

The **cuttings transport** for each different hole geometry is obtained by subtracting the slip velocity of the cuttings from the annular velocity in that particular section of the hole by:

$$V_t = V_a - V_s$$

where:

V_t = cuttings transport, ft/min

V_a = annular velocity × 60, ft/min

V_s = slip velocity, ft/min

Transport Efficiency

Perhaps more important than an actual cuttings transport value is the **cuttings transport efficiency**, which is simply the ratio of cuttings transport to annular velocity, defined by:

$$E_t = \frac{V_t}{V_a} \times 100 = \left(1 - \frac{V_s}{V_a}\right) \times 100$$

where,

E_t = transport efficiency, %.

Note: *If the slip velocity is zero, the transport efficiency is 1, or 100%.*

Cuttings Concentration

Due to the slip velocity of cuttings in the annulus, the concentration of cuttings in the annulus depends upon the transport efficiency as well as the volumetric flow rate and the rate at which cuttings are generated at the bit (ROP and hole size). Experience has shown that cuttings concentration in excess of five (5) volume % can lead to a pack-off, tight hole, or stuck pipe. When drilling in soft formations, where pipe connections in the drillstring are made as rapidly as possible, the cuttings concentration may easily exceed 5%, if ROP is uncontrolled. The **cuttings concentration** is calculated by:

$$C_a = \frac{(ROP)D^2}{14.71(E_t)Q} \times 100$$

where,

C_a = cuttings concentration, vol %

D = hole diameter, in.

E_t = transport efficiency, %

Q = flow rate, gal/min

ROP = rate of penetration, ft/hr

The ROP is obtained by measuring the time it takes to drill a length of pipe and dividing that length by the time. For instance, a stand length for a top-drive is 100 ft and it is drilled down in 20 min, then the ROP is 100 ft/20 min × 60 min/hr = 300 ft/hr.

When the cuttings concentration exceeds five (5) volume %, the effect on hydrostatic pressure and equivalent circulating density can be substantial. The change in hydrostatic pressure depends upon the density of the cuttings as well as the concentration of the cuttings in that section of hole. The effective fluid weight due to the cuttings concentration in that section of hole is calculated by,

$$\rho_e = (SG_c)(8.34)\left(\frac{C_a}{100}\right) + \rho\left(1 - \frac{C_a}{100}\right)$$

where:

ρ_e = effective fluid weight due to cuttings concentration, lb_m/gal

SG_c = specific gravity of the cuttings

C_a = cuttings concentration, vol %

ρ = fluid density, lb_m/gal

SUMMARY

ADVANTAGE^{SM} Engineering is Baker Hughes Drilling Fluids’ preferred tool for carrying out all hydraulics and hole cleaning analyses. The hydraulics calculations in ADVANTAGE^{SM} Reporting use API equations and are less accurate than those used in ADVANTAGE^{SM} Engineering.

HYDRAULICS EXAMPLE

The following is a manually worked example demonstrates the steps involved in performing hydraulics calculations.

Drilling a deviated hole, with the following information:

- 4½" drillpipe, 16.60 lb_m/ft; I.D. = 3.326"
- 300 ft. of 7¼" drill collars; I.D. = 2.8125"
- Last casing $13^{3}/_{8}$" 61 lb_m/ft; I.D. = 12.515"
- Hole size $9^{7}/_{8}$"
- $9^{7}/_{8}$" HTC J33 bit; Jets = three #12
- Fluid density = 15.3 lb_m/gal.
- PV = 32 cps
- YP = 19 lb_f /100 ft^2
- Initial gel = 5, (use as 3 rpm reading)
- 10-min gel = 12
- 30-min gel = 15
- Flow rate = 375 gal/min.
- Maximum available standpipe pressure = 3500 psi
- Fracture gradient at shoe = 16.5 lb_m/gal
- Fracture gradient at TD = 17.0 lb_m/gal
- Pore pressure at shoe = 14.0 lb_m/gal
- Pore pressure at TD = 14.7 lb_m/gal

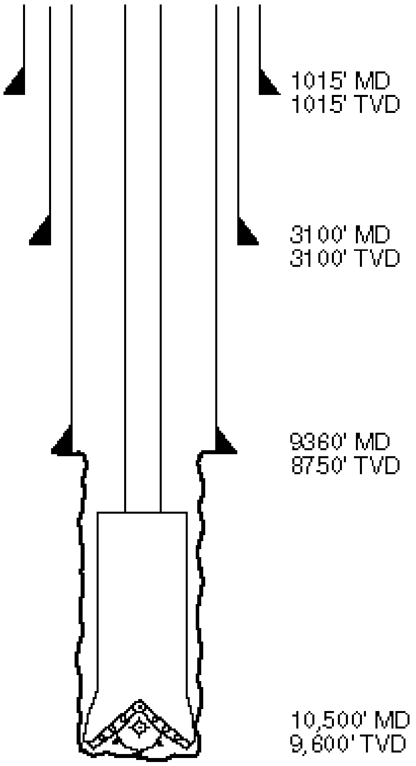

Figure 9 - 11 Well Schematic

1. Find fluid velocity in drillpipe, drill collars, and annulus:

- Drillpipe

$$V_p = \frac{0.408Q}{D^2} = \frac{0.408(375)}{(3.826)^2} = 10.45\, ft/\sec$$

- Drill collars

$$V_p = \frac{0.408(375)}{(2.8125)^2} = 19.34\, ft/\sec$$

- Annulus of drill collar and open hole

$$V_a = \frac{0.408Q}{(D_2)^2 - (D_1)^2} = \frac{0.408(375)}{9.875^2 - 7.25^2} = 3.40 \text{ ft/sec}$$

- Annulus of drillpipe and open hole

$$V_a = \frac{0.408(375)}{9.875^2 - 4.5^2} = 1.98 \text{ ft/sec}$$

- Annulus of drillpipe and casing

$$V_a = \frac{0.408(375)}{12.515^2 - 4.5^2} = 1.12\ \text{ft/sec}$$

2. Find the power law constants *n* and *K*.

$\theta_{600} = 83$

$\theta_{300} = 51$

$\theta_3 = 5$

- Inside drillpipe and drill collar

$$n_p = 3.32\log\frac{\theta_{600}}{\theta_{300}} = 3.32\log\frac{83}{51} = 0.70$$

$$K_p = \frac{5.11 \times \theta_{600}}{1022^{n_p}} = \frac{5.11 \times 83}{1022^{0.70}} = 3.32$$

- Annulus

$$n_a = 0.5\ \log\frac{\theta_{300}}{\theta_3} = 0.5\ \log\frac{51}{5} = 0.50$$

$$K_a = \frac{5.11 \times \theta_{300}}{511^{n_a}} = \frac{5.11 \times 51}{511^{0.50}} = 11.53$$

3. Find the effective viscosity.

- Drillpipe

$$\mu_{e_p} = 100K_p\left[\frac{96V_p}{D}\right]^{n_p - 1} = 100(3.32)\left[\frac{96(10.45)}{3.826}\right]^{0.70-1} = 62.45\ \text{cp}$$

- Drill collar

$$\mu_{e_p} = 100(3.32)\left[\frac{96(19.34)}{2.8125}\right]^{0.70-1} = 47.34\ \text{cp}$$

- Annulus of drill collar and open hole

$$\mu_{e_a} = 100K_a\left[\frac{144V_a}{D_2 - D_1}\right]^{n_a - 1} = 100(11.53)\left[\frac{144(3.40)}{9.875 - 7.25}\right]^{0.50-1} = 84.43\ \text{cp}$$

- Annulus of drillpipe and open hole

$$\mu_{e_a} = 100(11.53)\left[\frac{144(1.98)}{9.875 - 4.5}\right]^{0.50-1} = 158.31\ \text{cp}$$

- Annulus of drillpipe and casing

$$\mu_{e_a} = 100(11.53)\left[\frac{144(1.12)}{12.515 - 4.5}\right]^{0.50-1} = 257.03\ \text{cp}$$

4. Calculate the Reynolds Number.

- Drillpipe

$$Re_p = \frac{928(V_p)(D_p)\rho}{\mu_{e_p}\left[\frac{3n_p + 1}{4n_p}\right]^{n_p}} = \frac{(928)(10.45)(3.826)(15.3)}{(62.45)\left[\frac{3(0.70) + 1}{4(0.70)}\right]^{0.70}} = 8465$$

- Drill collar

$$Re_p = \frac{(928)(19.34)(2.8125)(15.3)}{(47.34)\left[\frac{3(0.70) + 1}{4(0.70)}\right]^{0.70}} = 15{,}192$$

- Annulus of drill collar and open hole

$$Re_a = \frac{928V_a(D_2 - D_1)\rho}{\mu_{e_a}\left[\frac{2n_a + 1}{3n_a}\right]^{n_a}} = \frac{(928)(3.40)(9.875 - 7.25)(15.3)}{(84.43)\left[\frac{2(0.5) + 1}{3(0.5)}\right]^{0.50}} = 1300$$

- Annulus of drillpipe and open hole

$$Re_a = \frac{(928)(1.98)(9.875 - 4.5)(15.3)}{(158.31)\left[\frac{2(0.5) + 1}{3(0.5)}\right]^{0.50}} = 827$$

- Annulus of drillpipe and casing

$$Re_a = \frac{(928)(1.12)(12.515 - 4.5)(15.3)}{(257.03)\left[\frac{2(0.5) + 1}{3(0.5)}\right]^{0.50}} = 429$$

Variable	Re	Flow
Drill pipe	8465	Turbulent
Drill collar	15192	Turbulent
Drill collar – open hole	1300	Laminar
Drill pipe – open hole	827	Laminar
Drill pipe – casing	429	Laminar

Table 9 - 1 Reynolds Number Summary

5. Find the flow regime in each section.

- Pipe

$$Re_c = 3470 - 1370(n_p) = 3470 - 1370(0.70) = 2511$$
$$Re_c = 4270 - 1370(n_p) = 4270 - 1370(0.70) = 3311$$

- Annulus

$$Re_c = 3470 - 1370(n_a) = 3470 - 1370(0.50) = 2785$$
$$Re_c = 4270 - 1370(n_a) = 4270 - 1370(0.50) = 3585$$

6. Calculate the critical flow rate for the annular sections of the open hole.

- Annulus of drill collar and open hole

$$V_c = \left[\frac{(3470 - 1370n_a)(100)K_a \left[\frac{2n_a + 1}{3n_a}\right]^{n_a}}{928\rho(D_2 - D_1)\left[\frac{144}{D_2 - D_1}\right]^{1 - n_a}} \right]^{\frac{1}{2 - n_a}}$$

$$V_c = \left[\frac{[3470 - 1370(0.5)](100)(11.53)\left[\frac{2(0.5) + 1}{3(0.5)}\right]^{0.5}}{928(15.3)(9.875 - 7.25)\left[\frac{144}{9.875 - 7.25}\right]^{1 - 0.5}} \right]^{\frac{1}{2 - 0.5}} = 5.58 \text{ ft/sec}$$

$$Q_c = (2.45)V_c\left[(D_2)^2 - (D_1)^2\right] = (2.45)(5.58)(9.875^2 - 7.25^2) = 615 \text{ gal/min}$$

- Annulus of drillpipe and open hole

$$V_c = \left[\frac{[3470 - 1370(0.5)](100)(11.53)\left[\frac{2(0.5) + 1}{3(0.5)}\right]^{0.5}}{928(15.3)(9.875 - 4.5)\left[\frac{144}{9.875 - 4.5}\right]^{1 - 0.5}} \right]^{\frac{1}{2 - 0.5}} = 4.40 \text{ ft/sec}$$

$$Q_c = (2.45)(4.40)(9.875^2 - 4.5^2) = 833 \text{ gal/min}$$

7. Calculate the Fanning Friction Factor.

- Drillpipe (Turbulent)

$$a = \frac{\log n_p + 3.93}{50} = \frac{\log(0.70) + 3.93}{50} = 0.0755$$

$$b = \frac{1.75 - \log n_p}{7} = \frac{1.75 - \log(0.7)}{7} = 0.2721$$

$$f_p = \frac{a}{(Re_p)^b} = \frac{0.0755}{8465^{0.2721}} = 0.0064$$

- Drill collar (Turbulent)

$$f_p = \frac{0.0755}{15{,}192^{0.2721}} = 0.0055$$

- Drill collar-open hole (Laminar)

$$f_a = \frac{24}{Re_a} = \frac{24}{1300} = 0.0185$$

- Drillpipe-open hole (Laminar)

$$f_a = \frac{24}{827} = 0.0290$$

- Drillpipe-casing (Laminar)

$$f_a = \frac{24}{429} = 0.0559$$

8. Calculate the Friction-Loss Pressure Gradient.

- Drillpipe

$$\frac{P_p}{L_m} = \frac{f_p(V_p)^2(\rho)}{25.81D} = \frac{(0.0064)(10.45^2)(15.3)}{(25.81)(3.826)} = 0.1083 \text{ psi/ft}$$

There is 10,200 ft of drillpipe.

$$P_p = (0.1083 \text{ psi/ft})(10{,}200 \text{ ft}) = 1105 \text{ psi}$$

9. Find the equivalent circulating density.

$$ECD = \frac{\Sigma P_a}{(.052)(TVD)} + \rho = \frac{14.5 + 10.5 + 49}{(.052)(9600)} + 15.3 = 15.45 \text{ lb}_m\text{/gal}$$

Bit Hydraulics

1. Calculate total nozzle area.

$$A_t = \frac{(J_1)^2 + (J_2)^2 + (J_3)^2}{1303.8} = \frac{12^2 + 12^2 + 12^2}{1303.8} = 0.3313 \text{ in.}^2$$

2. Calculate nozzle velocity.

$$V_n = \frac{Q}{3.117A_t} = \frac{375}{(3.117)(0.3313)} = 363 \text{ ft/sec}$$

3. Calculate pressure-drop across bit.

$$P_n = \frac{156(\rho)Q^2}{[(J_1)^2 + (J_2)^2 + (J_3)^2]^2} = \frac{(156)(15.3)(375)^2}{(12^2 + 12^2 + 12^2)^2} = 1799 \text{ psi}$$

Note: *The standpipe pressure should be equal to all of the friction loses downhole plus the pressure drop across the bit. In this example, standpipe pressure = 1105 + 130 + 14.5 + 10.5 + 49 + 1799 = 3108 psi*

4. Calculate hydraulic horsepower and impact force.

$$\text{HHP} = \frac{Q(P_n)}{1714} = \frac{(375)(1799)}{1714} = 394 \text{ hp}$$

$$\text{HHP/in.}^2 = \frac{(1.2732)\text{HHP}}{D^2} = \frac{(1.2732)(394)}{(9.875)^2} = 5.14 \text{ hp/in.}^2$$

$$F_i = \frac{(15.3)(375)(363)}{1932} = 1078 \text{ lb}_f$$

5. Calculate total nozzle area to maximize HHP or Impact Force. For maximum HHP, C = 0.65.

$$A_t = \frac{Q}{2.96\left[\frac{(1238.5)(C)(P)}{\rho}\right]^{1/2}} = \frac{375}{2.96\left[\frac{(1238.5)(.65)(3500)}{15.3}\right]^{1/2}} = 0.2952 \text{ in.}^2$$

For maximum impact, C = 0.48

$$A_t = \frac{375}{2.96\left[\frac{(1238.5)(.48)(3500)}{15.3}\right]^{1/2}} = 0.3435 \text{ in.}^2$$

6. Select jet sizes.

For 3 jets, N = 3; maximum HHP

$$J_1 = \left[\frac{1303.797}{N}A_t\right]^{1/2} = \left[\frac{1303.797}{3}(0.2952)\right]^{1/2} = 11.3 \rightarrow 11$$

$$J_2 = \left[\frac{1303.797}{N-1}\left(A_t - \frac{(J_1)^2}{1303.797}\right)\right]^{1/2} = \left[\frac{1303.797}{3-1}\left(0.2952 - \frac{11^2}{1303.797}\right)\right]^{1/2} = 11.49 \rightarrow 11$$

$$J_3 = \left[\frac{1303.797}{N-2}\left(A_t - \frac{(J_1)^2 + (J_2)^2}{1303.797}\right)\right]^{1/2} = \left[\frac{1303.797}{3-2}\left(0.2952 - \frac{11^2 + 11^2}{1303.797}\right)\right]^{1/2} = 11.59 \rightarrow 12$$

Therefore, for maximum HHP with 3500 psi on the standpipe, we would choose 3 jets of 11, 11, and 12.

For jets, N = 2; maximum HHP

$$J_1 = \left[\frac{1303.797}{N}A_t\right]^{1/2} = \left[\frac{1303.797}{2}(0.2952)\right]^{1/2} = 13.87 \rightarrow 14$$

$$J_2 = \left[\frac{1303.797}{N-1}\left(A_t - \frac{(J_1)^2}{1303.797}\right)\right]^{1/2} = \left[\frac{1303.797}{2-1}\left(A_t - \frac{14^2}{1303.797}\right)\right]^{1/2} = 13.74 \rightarrow 14$$

Therefore, for maximum HHP with 3500 psi on the standpipe, we would choose 2 jets of 14 and 14.

Exercise: Calculate the jet sizes required for 3 jets and 2 jets for the total nozzle area for maximum impact force in the above example.

Answer: 3 jets: 12, 12, 13
2 jets: 15, 15

Practice: Calculate the jet sizes for HHP-impact compromise for a PDC bit with five jets.

Answer: 9, 9, 9, 9

Swab and Surge

Exercise: Following the preceding example calculations, calculate the EMW due to running pipe in the hole after a trip.

Are the gel strengths progressive or fragile?

Cuttings Transport

Laminar Flow in Annulus

Assume: Particle thickness, T = ³⁄₈ in. = 0.375 in.
Particle diameter, D_c = ¾ in. = 0.750 in.

1. Find the boundary shear rate.

$$\gamma_b = \frac{186}{D_c\sqrt{\rho}} = \frac{186}{0.75\sqrt{15.3}} = 63.4\ \text{sec}^{-1}$$

2. Find the shear stress developed by the particle.

$$\tau_p = 7.9\sqrt{T(20.8-\rho)} = 7.9\sqrt{(0.375)(20.8-15.3)} = 11.35\ \text{lb}_f/100\ \text{ft}^2$$

3. Find the shear rate developed by the particle.

$$\gamma_p = \left(\frac{\tau p}{K_a}\right)^{\frac{1}{n_a}} = \left(\frac{11.35}{11.53}\right)^{\frac{1}{0.50}} = \gamma_b = 0.97\ \text{sec}^{-1}$$

4. $\gamma_p < \gamma_b$, slip velocity is determined by,

$$V_s = 1.22\tau_p\left[\frac{\gamma_p D_c}{\sqrt{\rho}}\right]^{1/2} = (1.22)(11.35)\left[\frac{(0.97)(0.75)}{\sqrt{15.3}}\right]^{1/2} = 5.97 = 6.0\ ft/\min$$

5. Calculate the cuttings transport for casing drillpipe annulus.

$$V_t = V_a - V_s = (1.12\ \text{ft/sec} \times 60\ \text{sec/min}) - 6.0 = 61.2\ \text{ft/min}$$

6. Calculate the transport efficiency.

$$E_t = \frac{V_t}{V_a} \times 100 = \frac{61.2}{(1.12)(60)} \times 100 = 91\%$$

or

$$E_t = 1 - \left(1 - \frac{V_s}{V_a}\right) \times 100 = \left(1 - \frac{6.0}{(1.12)(60)}\right) \times 100 = 91\%$$

Cuttings Concentration

We have timed a stand of pipe 93 ft long drilled down in 14 minutes with a top drive.

1. Calculate the ROP.

   Operator wants to make some hole!

2. Calculate the cuttings concentration in the annulus after drilling down this stand.

$$C_a = \frac{(ROP)D^2}{14.71(E_t)Q} \times 100 = \frac{(398.6)(9.875)^2}{14.71(91)(375)} \times 100 = 7.7\%$$

3. Calculate the effective fluid weight due to this enormous cuttings concentration. Assume SG_c = 2.2.

$$\rho_e = (SG_c)(8.34)\left(\frac{C_a}{100}\right) + \rho\left(1 - \frac{C_a}{100}\right) = (2.2)(8.34)\left(\frac{7.7}{100}\right) + 15.3\left(1 - \frac{7.7}{100}\right) = 15.53\,lb_m / gal$$

What do you need to recommend to the Drilling Foreman?

NOMENCLATURE

A_t	Area, total
C	Nozzle constant
C_a	Cuttings concentration
D	Diameter
D_1	Outside diameter, pipe
D_2	Hole diameter
D_c	Diameter, particle
D_p	Inside diameter, pipe
ECD	Equivalent circulating density
EMW	Equivalent fluid weight
E_t	Efficiency, transport
f_a	Friction factor, annulus
f_p	Friction factor, pipe
F_i	Impact force
HHP	Hydraulic horsepower
J	Nozzle size
K	Consistency factor
K_a	Consistency factor, annulus
K_p	Consistency factor, pipe
L	Length
L_j	Length, joint
L_m	Length, measured
L_s	Length, stand
n	Flow behavior index
n_a	Flow behavior index, annulus
n_p	Flow behavior index, pipe
N	Number of nozzles
P_a	Pressure loss, annulus
P_g	Pressure, gel breaking
P_n	Pressure loss, nozzle
P_p	Pressure loss, pipe
Q	Flow rate, bulk
Q_c	Flow rate, critical
ROP	Rate of penetration
Re_a	Reynolds Number, annulus

Re_c	Reynolds Number, critical
Re_p	Reynolds Number, pipe
SG_c	Specific gravity, cuttings
t	Time
T	Thickness, particle
TVD	True vertical depth
V_a	Velocity, annular
V_c	Velocity, critical
V_m	Equivalent velocity, fluid
V_n	Velocity, nozzle
V_p	Velocity, pipe
V_s	Velocity, slip
V_t	Transport, cuttings
γ	Shear rate
γ_b	Shear rate, boundary
γ_p	Shear rate, particle
θ_3	3 rpm reading
θ_{300}	300 rpm reading
θ_{600}	600 rpm reading
μ_{e_a}	Effective viscosity, annulus
μ_{e_b}	Effective viscosity, pipe
ρ	Fluid density
ρ_e	Fluid weight, effective
τ	Shear stress
τ_g	Gel strength, 30 min.
τ_p	Shear stress, particle

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Chapter Ten

Mechanical Solids Control

Chapter 10

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Chapter 10

MECHANICAL SOLIDS CONTROL

Drilling fluid maintenance costs can decrease greatly when proper solids control techniques are utilized. A drilling fluids engineer must be thoroughly knowledgeable of available solids control techniques in order to maximize drilling fluid performance and minimize costs

DRILLING FLUIDS

Adverse effects caused by drilled solids account for a major portion of drilling fluid maintenance expenditures. Drilled solids are the number one contaminant of all drilling fluids. Considering that a 12¼ in. gauge hole drilled to 10,000 ft would result in 1,327,000 lb or more of drilled solids, the above statement is not surprising. Overall drilling costs can also be severely affected by the quantity of drilled solids incorporated into the system. These effects include the following:

- Increased drilling fluid maintenance costs.
- Greater difficulty in maintaining optimum rheological properties.
- Increased frequency/opportunity of differential sticking.
- Reduced penetration rate.
- Decreased bit life and increased rate of wear on pump parts.
- Increased circulating pressure losses, and consequently increased possibility of lost circulation.
- Increased tendency for a well to swab on trips, possibly contributing to pressure control problems.

A solids control program should consider the drilling fluid as well as the formations to be drilled prior to selecting equipment for a particular operation. Care should be taken to operate the selected equipment efficiently and in the correct sequence to prevent overloading any individual unit.

It would be desirable in most cases to remove all drilled solids. Although this is possible with the use of chemical enhancement prior to separation, it is not always the most economical approach. The goal of a solids control system is to achieve the balance between mechanical solids separation and dilution that will result in drilled solids being maintained at an acceptable level with minimum cost, while maintaining property specifications. This is achieved when the cost of the required dilution fluid is at a minimum.

Classification of Solids

Solids can be classified into categories based on specific gravity and particle size.

- *Specific Gravity (S.G.)* – Solids in drilling fluids can be separated essentially into two density groups, high and low specific gravities. High specific gravity will refer to those solids with a specific gravity of 4.2 and above. High specific gravity materials are used for drilling fluid density increases, the most commonly used of which are barite (4.2 s.g.), and hematite (5.0 s.g.). Low specific gravity solids may range from a low of 1.6 to 2.9 for dense lime. Drilled solids have a specific gravity in the range of 2.1 to 2.8. Most solids analysis calculations use 2.6 as the assumed S.G. of all drilled solids.

- In a drilling fluid containing only low-gravity solids and fresh water, the concentration of solids will be a function of fluid density. The same relationship exists if a drilling fluid is composed only of barite and water. If a drilling fluid contains low-gravity and high-gravity solids, then the solids content will vary between the two ranges at a particular density. Figure 10-1 illustrates the effect of specific gravity and solids concentration on fluid density.

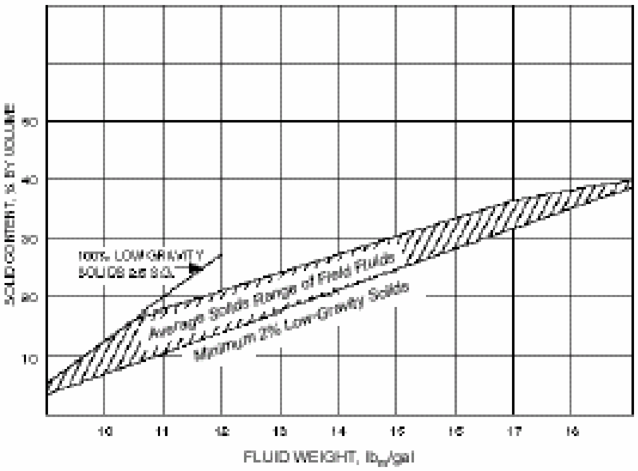

Figure 10 - 1 Average Solids Range of Water-Base Drilling Fluids (Freshwater)

- *Particle Size* – Fluid solids are measured in microns because of their small size. A micron (µ) is a unit of measure in the metric system and is $^{1}/_{1000}$ of a millimeter. To better illustrate the relative size of a micron, there are 25,400 microns to the inch. API classification of solids by size range is listed in Table 10-1. Commercial clays such as **MILGEL$^{®}$** contain predominantly particles which are smaller than 2 microns, or colloidal in size.

Particle Size, microns	Particle Classification	Sieve Size
Greater than 2000	Coarse	10
2000 to 250	Intermediate	60
250 to 74	Medium	200
74 to 44	Fine	325
44 to 2	Ultra-Fine	400
Less than 2	Colloidal	–

Table 10 - 1 API Classification by Particle Size

Even though drilled solids initially may be relatively coarse, they rapidly disintegrate into smaller particles due to chemical dispersion and mechanical action of the bit and drillstring. The rate of disintegration will vary with formation, type of drilling fluid, bit exposure time, annular transport time, annular circulating rate, degree of deviation, and mechanical abrasion from the drillstring. Disintegration can be shear dependent. It is extremely important to remove as many of the drilled solids as possible on the first circulation.

Low Gravity Solids Concentration

Most fresh water-base drilling fluids use bentonite for viscosity and filtration control. Low density fresh water drilling fluids may contain approximately two (2) volume % bentonite or about 18 lbs/bbl to achieve desirable properties. As mud density increases, the concentration of bentonite required decreases. Polymer based fluids may not use bentonite for this purpose by the substitution of other synthetic materials to achieve similar controls.

Experience has shown that the low gravity solids concentration should be controlled and maintained at specific levels for optimum fluid performance. Experience with the economics of solids control has indicated that the specific level for low gravity solids concentration falls between 4 and 6 percent. Since bentonite concentration can be approximately 2 volume %, this leaves room for only 2 - 4 volume % drill solids.

Various publications have addressed the issue of drilling and mud economics. The subjects of “dilution” vs. “displacement” have been considered. Since waste disposal has become a major economic factor in drilling operations today, emphasis has been placed on the proper selection and operation of mechanical solids control equipment. This has resulted in concentrating the volume of “dry” drill solids requiring disposal and therefore has minimized the need for building large volumes of dilution mud to achieve optimum fluid performance.

Dr. Leon Robinson presents an economic analysis that bears repeating. In his article[1], Robinson states that since drilling fluid costs vary greatly, a particular well situation needs to be analyzed. That involves the cost of fluid associated with each barrel of discarded drill solids which can be calculated. Using the data in Figure 10 - 2, if the drilling fluid target solids is 4 volume % and the system has a 60% removal efficiency, 9.6 bbl of drilling fluid will be discarded with each barrel of drilled solids discarded. Assuming a $50/bbl fluid cost, 1000 bbl of drilled solids would require $480,000 for new drilling fluid.

If the drilling fluid target solids can be increased to 6 volume % and the removal efficiency increased to 70%, only 4.7 bbl of drilling fluid must be built for each barrel of discarded drill solids. Again, for a $50/bbl fluid, the same 1000 bbl of drilled solids discarded would cost $235,000.

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[1] Robinson, L., *How to Optimize Solids Control Economics, Efficiency,* Handbook by Derrick Equipment Co., “Solids Control Manual for Drilling Personnel”.

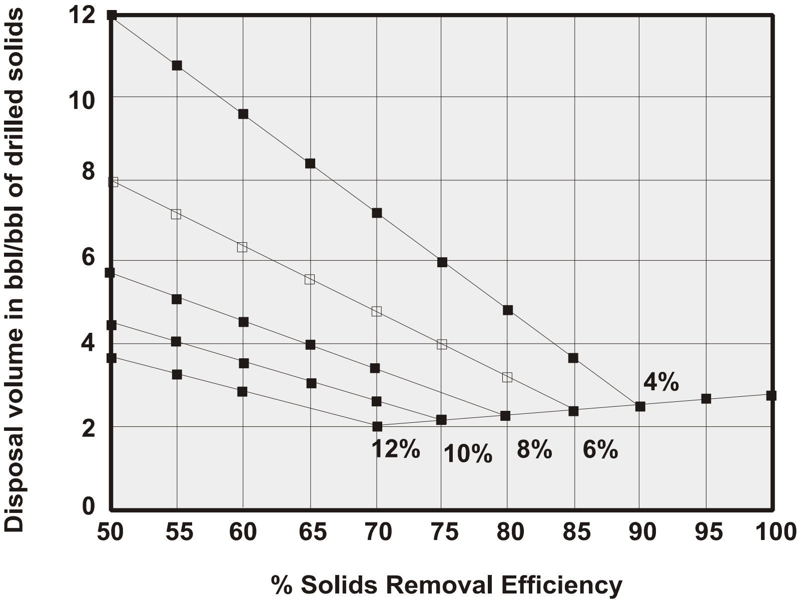

Figure 10 - 2 Drilling Fluid Required if Discard Stream From All Solids Processing Equipment Averages 30% by Volume Solids

The Methylene Blue Test (MBT) is used to determine the Cation Exchange Capacity (CEC) of fresh water-base drilling fluid. The test measures the concentration of all active clays present in the drilling fluid. Correcting the test results for commercial bentonite concentration allows the concentration of all other clays to be estimated. Using the MBT test allows the concentration of drilled solids to be estimated and the drilling fluid treated/processed accordingly to achieve a predetermined drilled solids concentration. Efforts to reduce the drill solids concentration to lower levels can result in unnecessary drilling fluid maintenance expense.

Oil or synthetic-based systems, along with certain polymer systems, because of their inherently inhibitive nature, do not experience the same low gravity solids problems particular to fresh water-base drilling fluids.

The API Recommended Practices 13C contains a field method for evaluating the total efficiency of the drilling fluid processing system in water-based fluids. This procedure depends upon accurate dilution volume information. The API procedure uses the dilution volume over a given interval to compute a dilution factor, DF, which is the volume ratio of actual mud dilution required to maintain a desired solids concentration with no solids removal equipment. The dilution factor is used to determine the total solids removal efficiency of the system. The API procedure is as follows:

1. Over a desired interval length, obtain accurate water additions and retort data.
2. From the retort data, calculate:
    - a. The average drilled solids concentration in the mud, ks.
    - b. The average water fraction of the mud, kw.

3. Calculate the volume of drilled solids, Vm:

$$Vm = \frac{Vw}{kw}$$

4. Calculate the volume of drilled solids, Vc:

$$Vc = 0.000971 \times D^2 \times L \times W$$

5. Calculate the dilution volume required if no solids were removed Vd:

$$Vd = \frac{Vc}{ks}$$

6. Calculate the dilution factor, DF:

$$DF = \frac{Vm}{Vd}$$

7. Calculate the total solids removal performance, Et:

$$Et = (1 - DF)$$

Multiply the result by 100 to calculate a percentage

The accuracy of the API procedure depends somewhat on a relatively constant solids concentration in the mud, constant surface circulating volume, and consistent averaging techniques over the interval of interest. The total solids removal performance by this method should be reported at frequent intervals during the course of drilling the well..

EFFECTS OF SOLIDS ON RHEOLOGICAL PROPERTIES

A brief review of the effects of drilled solids on the flow properties of water-base drilling fluids is necessary to assist in determining the effectiveness and need of solids control.

Plastic viscosity is largely due to mechanical friction between solid particles in the drilling fluid, and to a lesser degree the friction between solid and liquid. The plastic viscosity value depends primarily on the size, shape and concentration of solids in the system, and the viscosity of the liquid phase. Day-to-day trends in plastic viscosity can give an indication of an increasing degree of fineness within the solids concentration and can be utilized as a guide in determining the necessity for centrifuging and dilution.

Yield point and gel strength indicate the degree of attractive forces existing between particles in the system. Chemical treatment is usually indicated when high yield and gel values are present. Dilution or mechanical removal of solids may also reduce yield and/or gels. These attractive forces are related to the distance between the particles. Either of these actions will result in increased particle separation.

Dispersion of Surface Area - Removal of particles of very fine size produces greater viscosity reductions than does the removal of an equivalent volume of coarser particles due to differences in surface area. For example, a cubic foot of formation has 6 ft^2 of surface area, whereas this same piece of formation broken up into cubic micron-size particles would have a combined surface area of 1,828,800 ft^2 or 42 acres. The volume % solids that would result from incorporation of these particles in a fluid would be the same in both cases, but a considerable change in the volume of water to wet the surface would occur. Obviously, a solids problem can develop without an increase in solids volume if the particles are degraded into smaller sizes. Table 10-2 describes the increase in surface area as a solids cube is broken down into smaller pieces.

Number of Cube Divisions	Total Number Pieces	Individual Cube Size, inches	Total Surface Area, square inches
0	1	1	6
1	8	1/2	12
2	64	1/4	24
3	512	1/8	48
4	4096	1/16	96
5	32768	1/32	192
6	262144	1/64	384
7	2.0972×10^6	1/128	768
8	1.6772×10^7	1/256	1536
9	1.3421×10^8	1/512	3072
10	1.0737×10^9	1/1024	6144
15	3.5184×10^{13}	1/32768	1966081

Table 10 - 2 The Disintegration of Solids

Current Solids Control Techniques

The methods by which drilled solids can be removed are as follows:

- Displacement – reduces solids by discarding the solids laden fluid and replacing it with a drilled solids free fluid
- Dilution - additions of clean/clear fluids which is the most expensive method of controlling drill solids
- Mechanical removal – accomplished with shale shakers, desanders, desilters, centrifuges, etc.
- Settling – restricted to low-viscosity, low-density fluids and requires a large settling pit to allow particles the necessary time to settle out of suspension.

The higher the concentration of drill solids in a discard, the more favorable the displacement or mechanical removal method. The purpose of mechanical control is to minimize dilution requirements by discarding solids in the highest concentration possible. The basic mechanical solids removal equipment available falls into two categories – screening devices and enhanced settling devices.

Dilution vs. Displacement[2]

Dilution, as previously stated, is the most expensive and therefore the least desirable method for controlling drill solids. In this case, a program of continuous dilution results in the dilution of the already diluted fluid in each circulation cycle. Continuous fluid treatment to control chemical concentrations, rheological and filtration properties, and density maintenance is required. A more practical and economic method once considered is *displacement.* In this case, a measured volume of the drilled solids contaminated drilling fluid is dumped and replaced with an equal volume of drilled solids free fluid having the proper density, chemistry, rheological, and filtration characteristics. In order for this procedure to be cost effective, the surface volume should be maintained at minimum levels.

The concept of *dilution* vs. *displacement* economics has taken on other significance since the disposal of fluids/solids/drilled cuttings came under more strict environmental regulation. Current practices involve the minimization of all drilling fluids/solids waste. The application and effective operation of mechanical solids removal equipment will minimize fluid dumping requirements. Mechanical solids removal equipment should be sized and operated to remove maximum drilled solids possible on a “first pass” basis. This will minimize the opportunity for drilled solids being broken down into smaller sizes by repeated passage through the circulating system. This practice will minimize dilution and dumping requirements.

The various types of solids removal equipment are described below.

Vibrating Screen Separators

Vibrating screens (shale shakers) are the first mechanical devices in the solids control system to process the fluid. Maximizing the removal of solids at this point will increase the efficiency of the remainder of the solids equipment utilized.

In unweighted fluid systems, maximum removal with shakers will reduce the solids loading on the desander, thus lowering the chance of an overload condition, which in turn, will lower the chance of overloading the downstream desilter. The cascading effect of a solids control system points out the importance of having each piece of equipment operate to its maximum potential, thus allowing the downstream units to do the same. Since the operation of the shaker affects the remainder of the equipment, it must be sized and utilized correctly for the system to remove the maximum amount of solids.

Fine screen shakers should be used on any operation where optimum solids control is desired, but they are particularly suited for operations employing weighted fluids, high-cost fluid-phase fluids, and oil-base fluids. When weight material is carried in the fluid system, the options for removing solids without removing the weight material are limited to screening and centrifuging. If weighted

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[2] Beasley, R.D. and Dear, S.F. III, *A Process Engineering Approach to Drilling Fluids Management*, SPE 19532, Presented at the 64th Annual Technical Conference, San Antonio, TX, October 8-11, 1989

oil fluids are used, then even centrifuging is not feasible because of economic and environmental reasons. Dual centrifuging an oil or synthetic is done to *strip and clean* mud plant fluids In this case, it is very important to have optimum solids removal at the shale shaker. It would be contrary to sound engineering practices to spend thousands of dollars for an oil-base fluid system or any inhibited system to retain "cuttings integrity" without utilizing the most efficient solids control equipment available. An inhibited system (such as **CARBO-DRILL**$^{\mathbf{SM}}$ or **NEW-DRILL**$^{®}$**)** cannot achieve its full potential and be cost-effective if the cuttings are re-circulated and ground down into very fine particle sizes.

Two basic designations are used for shakers presently in the field – rig (scalper shaker) and high-speed shakers. Normal operation of scalper shakers would typically employ the use of screens in the 10- to 40-mesh range. The removal of large drill cuttings at this stage will increase the efficiency of the downstream *high-speed* shakers. The term *high-speed* refers to a unit that is capable of operating with fine screens. These units also are commonly referred to as *linear motion*, *premium*, and *high-efficiency* shakers. The term high-speed had its origin with some of the early improved shakers that operated with speeds in the range of 3600+ rpm. Although very few shakers have this speed on the vibrator shaft at present, the term stuck. Linear motion refers to the action that the vibrating assembly transmits to the screen deck, in this case a reciprocating motion. Figure 10-2 demonstrates three typical screen motions.

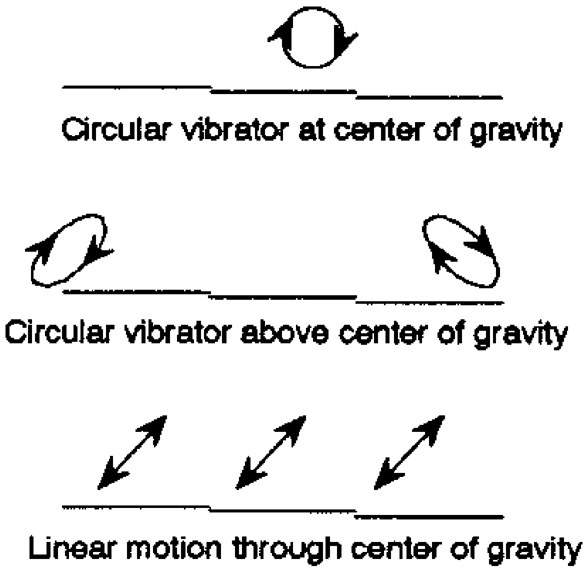

Figure 10 - 3 Typical Screen Motions

Regardless of the particulars of the machine, the most important point to remember is that the goal is to remove the maximum amount of solids, and this is done by running a screen with the smallest openings. If we assumed the average particle size of formation solids (in fluid returns) was 80% finer than 838 microns and 70% larger than 178 microns, theoretically only 20% could be removed with the 20-mesh screen, whereas 70% could be rejected with the 80-mesh screen.

Fine shaker screens come in a multitude of designations, and no single measurement adequately describes a screen's solids removal capabilities and throughput. *Mesh* is the linear measurement of the number of openings per inch. The *aperture* is the actual opening dimension which controls the maximum size particle that can pass through a screen. Two screens with the same mesh, if woven with different diameter wires, will have different apertures.

The current API screen designation system states that no fewer than the following minimum elements be stated:

- Equivalent Aperture in microns
- Conductance (Kilodarcies/mm)
- Non-blanked area (ft^2)
- Manufacturer' Designation / Part Number

Optional but recommended information includes:

- Manufacturer's name
- Country of manufacture or assembly

This description is sufficient for single-layered screens, but with the advent of multiple-layered screens and bonded screens, this designation falls short in describing the effective cut point of a screen, the ability to pass fluid and the actual screen area available to pass fluid.

A new description is recommended to be attached to all screen panels and will call for,

- cut point at D-50 and D-95
- conductance
- percentage of total screen area available for screening.

A D-50 *cut point* is defined as the point measured in microns where 50 volume % of the solids are larger than the size specified and 50% are smaller than the specified micron size. D-95 indicates that 95% are smaller and 5% are larger than the micron size specified. See Figure 10-4 for some typical solids distribution curves and the indicated D-50 points.

Conductance is defined as the permeability of the screen cloth divided by the thickness of the cloth, and is usually given in kilodarcys per millimeter (kd/mm). Permeability of the screen is a function of the opening size and the wire geometry. Basically, it is a measure of the ease with which fluid will flow through the screen. No units will be indicated on screen conductance designation, as this will be a relative measurement.

Commonly manufactured screen cloths come in square mesh and rectangular mesh. These are used to build screens in many combinations from single layers, for the coarser meshes, to every conceivable combination of square and rectangular meshes stacked together. The square mesh removes more randomly shaped solids than a rectangular mesh having the same minimum aperture dimension. For the same minimum aperture on one dimension, the rectangular screen has a higher fluid capacity since the percent open area is greater. Also, the rectangular screen can be woven of heavier wires, thus offering a potential for longer screen life. This longer life and increased throughput versus lower solids removal potential are typical tradeoffs to be considered when selecting a screen.

Table 10-3 lists U.S. Test Sieve Numbers. These sieve numbers each have a standard opening size given in microns. The sieve number refers to the mesh count of the given screen. Cut points of screens will be referred to commonly either using the sieve number or the micron cut point.

Test Sieve No.	Opening, *µm*	Test Sieve No.	Opening, *µm*
5	4000	60	250
6	3350	70	212
7	2800	80	180
8	2360	100	150
10	2000	120	125
12	1700	140	106
14	1400	170	90
16	1180	200	75
18	1000	230	63
20	850	270	53
25	710	325	45
30	600	400	38
35	500	450	32
40	425	500	25
45	355	635	20
50	300		

Table 10 - 3 ASTM Sieve Designation[3]

The number usually given in screen designations can be misleading. It can refer to micron opening size, number of openings per inch, U.S. Test Sieve equivalent opening size, sum of wires in each direction, or average cut point related to U.S. Test Sieve screens.

Two common screen cloths used for the manufacture of screens are *market grade* (MG) and *tensil bolting cloth* (TBC). These terms refer to wire sizes used in the manufacturing of the screens, market grade being a coarser wire than tensil bolting cloth. Some manufacturers use wire diameters finer than tensil bolting cloth to achieve a greater open area on the screen while maintaining the mesh count. This results in a weaker wire that will pass larger solid particles.

Solids Removal by Centrifugal Force

All mechanical devices for solids control, excluding vibrating screens, depend upon particle separation by size and specific gravity of particles. Examination of the equation describing the settling rate of particles indicates that the settling velocity of a particle depends upon particle size, particle density, liquid density, liquid viscosity and the gravitational force induced. The relationship of these factors is demonstrated by **Stokes' equation for settling velocity**.

$$V = \frac{G\left(d^2\right)\left(D_S - D_M\right)}{\mu}$$

where,

V = settling rate, cm/sec

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[3] ISO API RP 13C July 2004

G = the gravitational constant, cm/sec^2

d = the diameter of the particle, cm

D_S = density of the particle, S.G.

D_M = density of the fluid, S.G.

μ = viscosity of the fluid, centipoise

In general,

- The smaller of two particles of the same specific gravity has a lower settling velocity.
- The heavier of two particles of equal diameter will settle faster.
- The higher the fluid density, the lower the settling velocity.
- The higher the viscosity, the lower the settling velocity.

For example, it can be calculated that a barite particle (4.2 specific gravity and 4-microns in diameter) will settle at approximately the same rate as a low-gravity particle (2.6 specific gravity) having a diameter of 6 microns.

Hydrocyclones

Hydrocyclones are used for desanding, desilting and salvaging barite. Figure 10-4 is a cross-sectional view illustrating the operating principle of a hydrocyclones.

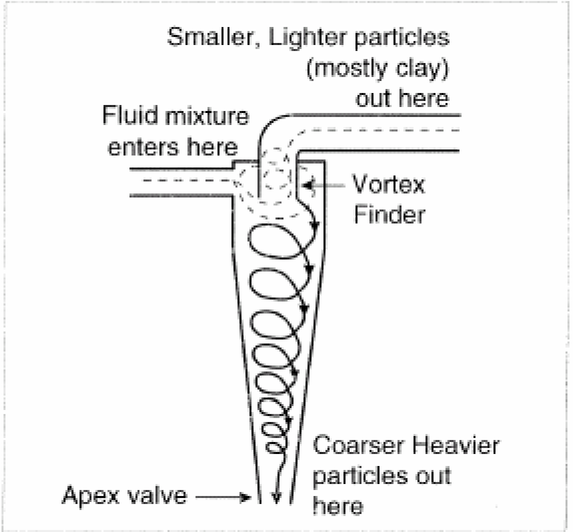

Figure 10 - 4 Cross-Sectional View of Hydrocyclone Operation

Desanding hydroclones are usually 6 inches or larger in diameter. As the name implies, desander hydroclones are designed to handle large volumes of fluid and remove essentially all low-gravity particles above 74 microns, the sand designation size. The desander is economical and performs very well in low solids, inexpensive drilling fluids.

Desanders, operated with a spray discharge, will normally make a 30-micron median cut on low-gravity solids in low-density drilling fluids. Median cut implies that there is a 50-50 chance for particles of 30 microns and above to be ejected through the underflow opening, normally called the *apex valve*. Median cut is called the D-50 cut point. A 30-micron median cut on low-gravity solids would be equivalent to a 20-micron median cut on barite. Since quality barite normally contains 40% of particles greater than 20 microns in size, it would be economically impractical in most cases to desand a weighted drilling fluid. An exception to this would be in higher viscosity drilling fluids where the median cut point would be greatly increased. In these cases, it may be practical to desand a weighted drilling fluid for short intervals providing the barite content of the underflow is closely monitored.

Hydroclones are normally rated using water which provides the minimum viscosity possible. This results in reported cut points that are comparable from one unit to the next, but do not give realistic numbers that can be related to a drilling fluid. Because the cut point is directly proportional to the viscosity of the fluid, the actual performance on a viscosified fluid will be much higher than the manufacturer's specifications. Remember, cut points mentioned here are based on optimum conditions.

Twelve inch diameter desander cyclones are the most common and will process approximately 500 gal/min with 75 ft feed head. This is equal to 35 psi when a 9 lb_m/gal is being processed. Sufficient cyclones should be utilized to process 1.25 to 1.5 times the maximum circulating rate. The back flow in the fluid pit, caused by this excess of processing capacity from the desander discharge pit to the suction pit, will ensure that all of the fluid is processed. In each and every case where hydrocyclone solids processing equipment is being utilized, fluid back flow is important

Desilters are hydroclones which are normally 4 in. in diameter and will process 50 to 80 gal of fluid per minute per cone depending on manufacturer. Feed head requirements range from 75 to 96 ft with the most common requirement being 75 ft. Desilters with a spray discharge will make a 16- to 18-micron median cut on low-gravity solids. A sufficient number of cones should be provided to process 1.25 to 1.5 times the circulating rate for maximum efficiency.

It is most important that desilters be employed at the start of an operation and run almost continuously until a weighted drilling fluid is required. If desilting is delayed or utilized only part-time, the recycled drilled solids will rapidly degrade into particle sizes too small to be removed by the desilter.

The general operating parameters for hydrocyclones is presented in Table 10 – 4 as follows:

2"			4"			6"			12"		
Press (psi)	Head (ft)	Vol (gpm)	Press (psi)	Head (ft)	Vol (gpm)	Press (psi)	Head (ft)	Vol (gpm)	Press (psi)	Head (ft)	Vol (gpm)
35	75	20	35	75	60	35	75	100	35	75	500

Table 10 - 4 Recommended Hydrocyclone Feed Head Requirements (Pressures based on 9 lbm/gal fluid)

The quantity of solids removed from an unweighted system by a hydrocyclone can be calculated as follows.

$$W_S = 97(D_\mu - 8.33)(Q_\mu)$$

where,

W_s = lb solids removed per hour per cone

D_μ= density of underflow, lb_m/gal

Q_μ = underflow rate, gal/min.

Smaller diameter hydrocyclones (usually 2 inches in diameter) have been used for barite salvage. Under ideal conditions, these cones will make a D-50 cut on barite in the 4- to 6-micron range and a 7- to 10-micron out on low-gravity solids. Barite recovery efficiency is less than that obtained with a centrifuge which should give D-95 cut in the 4- to 6-micro range.

Figure 10-4 illustrates approximate performance curves for various diameter hydrocyclones. These curves are for low-gravity solids in unweighted drilling fluids.

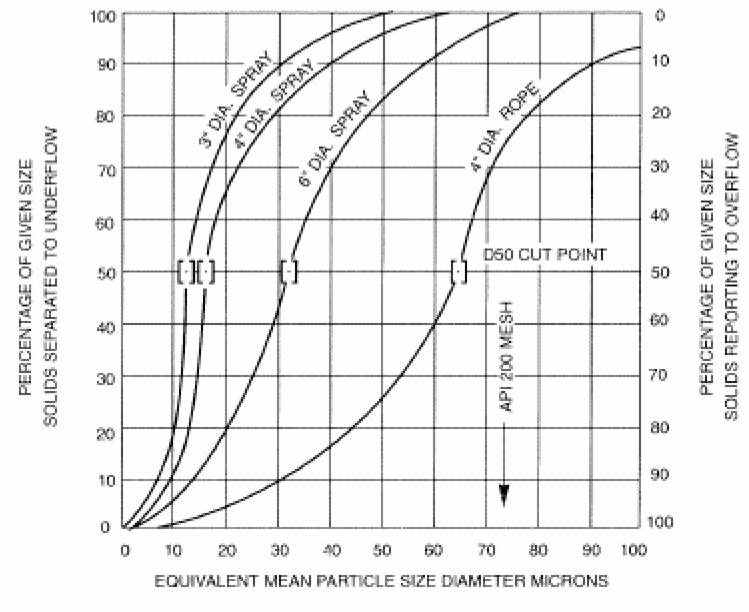

Figure 10 - 5 Typical cyclone Performance (Comparison by Size)

Fluid (Mud) Cleaners

The hydroclone/screen combination consists of a bank of desilters which are mounted over a fine mesh vibrating screen (140- to 200-mesh). The desilter underflow is processed by the fine screen. Particles removed by the screen are discarded and the fluid processed through the screen is returned to the active system. The effluent or desilter overflow is also returned to the active system. The fluid cleaner is essentially a fine screen shaker. Its primary purpose is to remove that portion of sand-sized or larger particles that pass through the rig shaker. Ideally, a 200-mesh screen would be desirable on the fluid cleaner, however, a 140- to 150-mesh screen is generally necessary to minimize barite losses.

Fluid cleaners are not recommended on low-weight systems which can utilize a desilter, since the desilter will remove more solids down in the fine range. On the other hand, on unweighted systems with very expensive liquid phases, the fluid lost at the desilter underflow may be economically prohibitive (oil fluids, polymer-KCl fluids, etc.). In these cases, a fluid cleaner may be of assistance in the control of drilled solids.

The fluid cleaner is not a centrifuge and does not replace a centrifuge on weighted systems. However, this device does fill a gap if premium shakers are not employed with a weighted drilling fluid. Rig shakers may only be able to use an 80-mesh screen which removes drilled solids larger than 178 microns. The centrifuge removes drilled solids smaller than 4- to 6-microns, so it is apparent that a particle that passes through the 80-mesh screen will be retained in the system until it is ground down to the 4 to 6 micron range. Utilizing a fluid cleaner with 200-mesh screens would give a 74-micron cut and fill the gap.

Removal of particles in the 74 to 178 micron range with the fluid cleaner could produce the following benefits.

- Improved filter cake quality (less coarse drilled solids) results in a less-permeable, less-porous cake. Improved cake quality (thinner and tougher) can minimize wall sticking and reduce frictional forces between drillstring and wellbore.

- A decreased concentration of drilled solids contributes to improved rheological properties and reduced fluid maintenance costs.

Centrifuges

Centrifuges use centrifugal force, as do hydroclones, to shorten and/or control the settling time required to separate solids from liquids. Centrifuges utilize an external force to rotate a separation chamber and increase centrifugal force. This G-force can be calculated using the following formula.

$$G = 0.0000142(r^2)(d)$$

where,

G = G-force

r = revolutions per minute

d = inside diameter of the bowl in inches.

Practical application of the barite recovery centrifuge for processing drilling fluids considers the following.

1. It is a common misconception that centrifuges separate low-gravity solids from barite, but this would only be possible if all barite in a system was above 3 to 4 microns and all low-gravity solids were below the 4 to 6 micron range. Under field operating conditions, approximately 10% of barite is below 3 microns in size and 20% to 50% of low-gravity solids are below 6 microns in size. The solids removed with a centrifuge are the very fine particles which have a greater relative effect on rheology than the coarser particles.

2. Centrifuging will not eliminate the need for water. Water will still be required to replace that lost through the centrifuge and to the wellbore. Dilution requirements will however, be reduced and drilling fluid maintenance cost reduction can be expected. This is particularly true in areas where reactive formation solids are prevalent.

3. Day-to-day trends in plastic viscosity can give an indication of how fast solids concentration is increasing and can be used as a guide for operating the centrifuge and/or addition of water. Bentonite content, as measured by Cationic Exchange Capacity (CEC) using the Methylene Blue Test (MBT), and solids content, as determined by retort analysis, can also be of assistance in determining the need for centrifuging and/or water additions.

There are basically three types of decanting centrifuges. The types are grouped depending on the G-force, rpm, cut point, and feed capacity.

1. *Barite Recovery Centrifuge* – Used primarily for viscosity control. These centrifuges operate in an rpm range of 1600 to 1800 rpm and generate a G-force from 500 to 700 Gs. Cut point will be between 6 to 10 microns for low-gravity solids and 4 to 7 microns

for high-gravity solids. Feed rates normally run from 10 to 40 gpm depending on the density of the whole fluid. This centrifuge will strip barite above the cut point from the fluid and discard the liquid phase with the remaining fine solids.

2. *High Volume Centrifuge* – Used primarily for discarding low-gravity solids from the fluid. It is so named because processing rates range from 100 to 200 gpm. Normal rpm ranges from 1900 to 2200 rpm. G-forces average about 800 Gs. The cut point attained is from 5 to 7 microns on unweighted fluid applications.
3. *High Speed Centrifuge* – Used for removal of low-gravity solids from unweighted fluid systems and as second centrifuge in dual-centrifuging applications. This group of centrifuges turn from 2500 to 3300 rpm. G-forces created by these units range from 1200 to 2100 Gs. Cut point can be as low as 2 to 5 microns. Feed rates will range from 40 to 120 gpm depending on application and the fluid to be processed.

The term dual-centrifuging comes from the use of two centrifuges in tandem. Effluent from a barite recovery unit is used to feed the second centrifuge. The benefit of this operation is that some solids can be removed from the low end of the size range without the loss of the fluid phase.

For example, if the barite recovery unit is making a cut at 8 microns, then the fluid feed to the second centrifuge will basically have solids 8 microns and smaller. The second centrifuge should be capable of achieving higher Gs than the first and make a cut in the 2- to 5-micron range. The fluid phase is returned to the fluid and the solids discarded from the system. As demonstrated, this combination of centrifuges does not remove the ultra-fine and colloidal solids from the system, but it does remove solids that may be degradating down to that range. This will prolong the need for dilution and displacement of the fluid. Dual centrifuging has possible economic justification in situations where environmental restrictions will not allow reserve pits, or where the liquid phase of the fluid has high economic value. It needs to be remembered, though, that the use of these units will not solve any solids problems with the fluid, only delay them.

The principle of the decanting centrifuge is illustrated in Figure 10-6

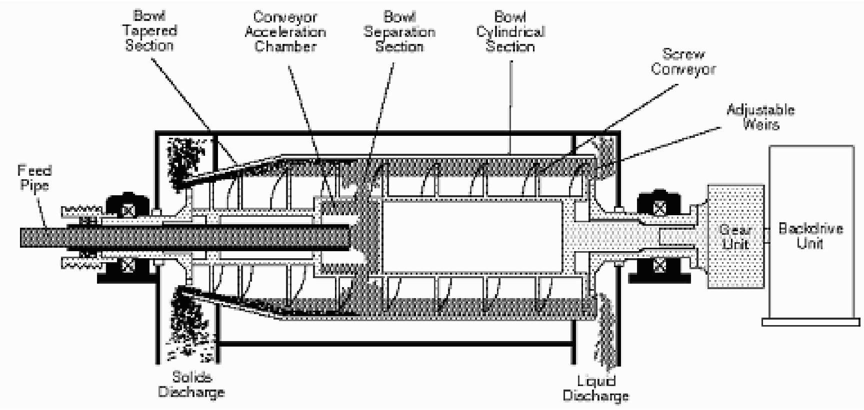

Figure 10 - 6 Solid Bowl Decanting Centrifuge

Some suggested guidelines for operation of barite recovery decanting centrifuges are:

1. *Effluent viscosity* – 35 to 37 sec/qt.
2. *Effluent density* – 9.5 to 9.7 lb_m/gal. It may be greater if excessive quantities of barite are near colloidal.
3. *Underflow density* – usually 20 to 23 lb_m/gal. It may be less depending on volume of low-gravity solids in the barite size range.
4. *Bowl speed* – 1600 to 1800 rpm
5. *Dilution of feed fluid* – 25% to 75% (10.5 to 11.5 lb_m/gal). Dilution rate increases as viscosity and density increase.
6. *Process rate* – see Figure 10-7.
7. *Percentage of low gravity solids removed* - normally 30% to 60%.
8. *Chemical removal* – underflow of decanting centrifuge will contain 15% to 30% of chemicals present in original drilling fluid.
9. *Volume decrease* – 70% to 85% of fluid centrifuged. Depends on volume of solids in the recoverable range.
10. ***ALWAYS WASH OUT THE CENTRIFUGE THOROUGHLY PRIOR TO SHUT DOWN***

Figure 10-7) illustrates comparative processing capabilities for decanting centrifuges and concentric cylinder (RMS) centrifuges.

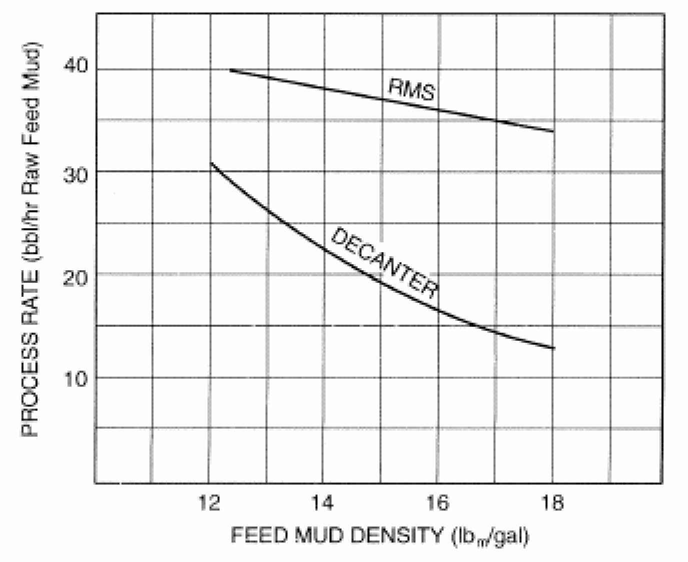

Figure 10 - 7 Process Rate of Barite Recovery Decanting Centrifuge

RMS Centrifuge

There is an alternative to the use of a decanting-bowl centrifuge for barite recovery. It is the RMS-type centrifuge. This type unit is particularly applicable where rig-up restrictions will not allow use of a decanting-type unit. Although this unit is capable of handling more fluid, it tends to not make as fine a cut on the barite as a decanting unit does. Also, because the returned phase is wetter, it will contain a higher percentage of undesirable solids.

General Operation of the RMS Centrifuge

The separation chamber of the centrifuge consists of a stationary case and a perforated cylinder which revolves concentrically within the case. The combined discharge from two metering pumps supplies a fluid/water mixture which is introduced to the separator chamber annulus between the stationary case and the rotating perforated cylinder. As the diluted mixture enters the case, the rotation exposes all solid particles to centrifugal force, moving them away from the rotor and toward the case wall. The condensed phase moves through the case along the walls and exits at the underflow port. The lighter phase moves toward the center of the perforated cylinder and exits through the overflow tube.

Figure 10-8 is a schematic of an RMS separation chamber.

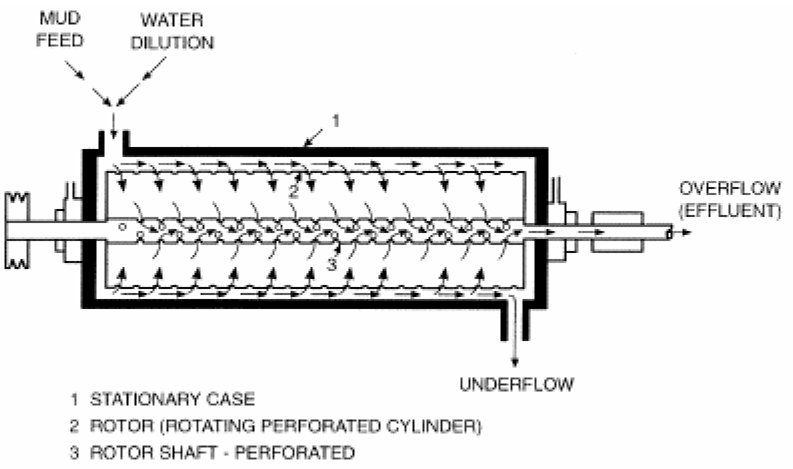

Figure 10 - 8 RMS Separation Chamber

Closed-Loop Systems

Closed-loop systems describe any operation where no reserve pit is utilized. This is commonly due to environmental restrictions, but may be caused by space limitations, cost to build and close the pit, or expense of the liquid phase. Depending on the economics of disposing of excess fluid and cuttings, the system may consist of no additional equipment on the rig to a full-blown system that includes all the mechanical equipment necessary to achieve maximum solids removal and a dewatering operation to finish the removal of all excess solids.

The function of a closed-loop operation, where disposal costs are high, is to minimize the haul-off by condensing the discards to the minimum volume. For instance, if 9 lb_m/gal fluid is hauled off, then you would only be removing 45.5 lb of solids for each bbl removed. If you would condense these solids by use of a centrifuge to 40% by volume solids, then for each bbl hauled off, 363.9 lb of solids would be removed. To achieve this same pounds of removal with whole fluid would require hauling 8 bbl of fluid. This would represent an 8 to 1 savings in hauling cost and disposal cost.

The term closed-loop system, when only mechanical equipment is employed to remove the solids, is more often than not a misnomer. That is, there is a limit on how long the operation of the fluid system can go before fluid has to be displaced due to solids build up. The fact is, mechanical equipment screens, centrifuges, etc. cannot economically remove solids that are in the colloidal size range. If the closed-loop system is rated at 85% solids removal efficiency, then the other 15% of the solids will have to be removed by displacing whole fluid. Not “opening up” the loop to remove these excess solids is a common operational problem and will result in a fluid system that has flow properties and fluid loss that are hard to control. This in turn causes chemical additions above normal to counteract the excess of colloidal solids and the “loop” will ultimately have to be “opened” to discard the excess solids.

Figures 10-9 and 10-10 depict the arrangement of mechanical solids removal equipment on a closed-loop system for unweighted and weighted fluid systems respectively. The addition of the dewatering system will make the closed-loop complete and allow it to truly reflect the name “closed-loop system.” This is achieved by removing the excess solids that remain in the fluid after the mechanical processing.

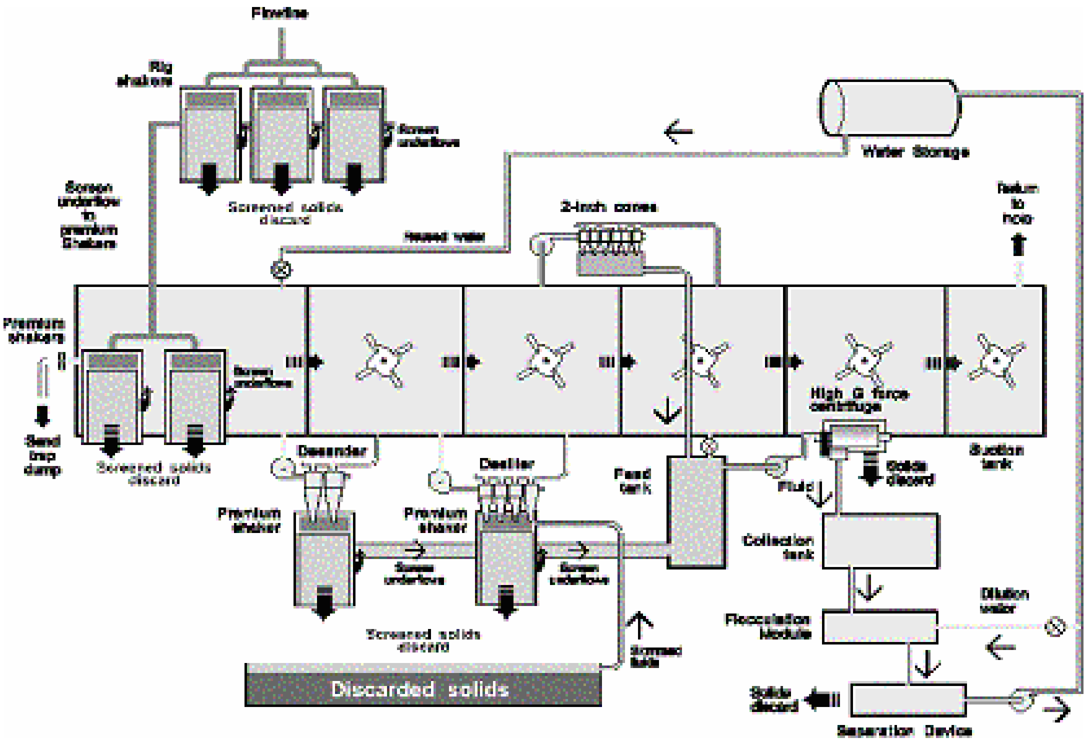

Figure 10 - 9 Closed Loop Solids System – Unweighted Fluid

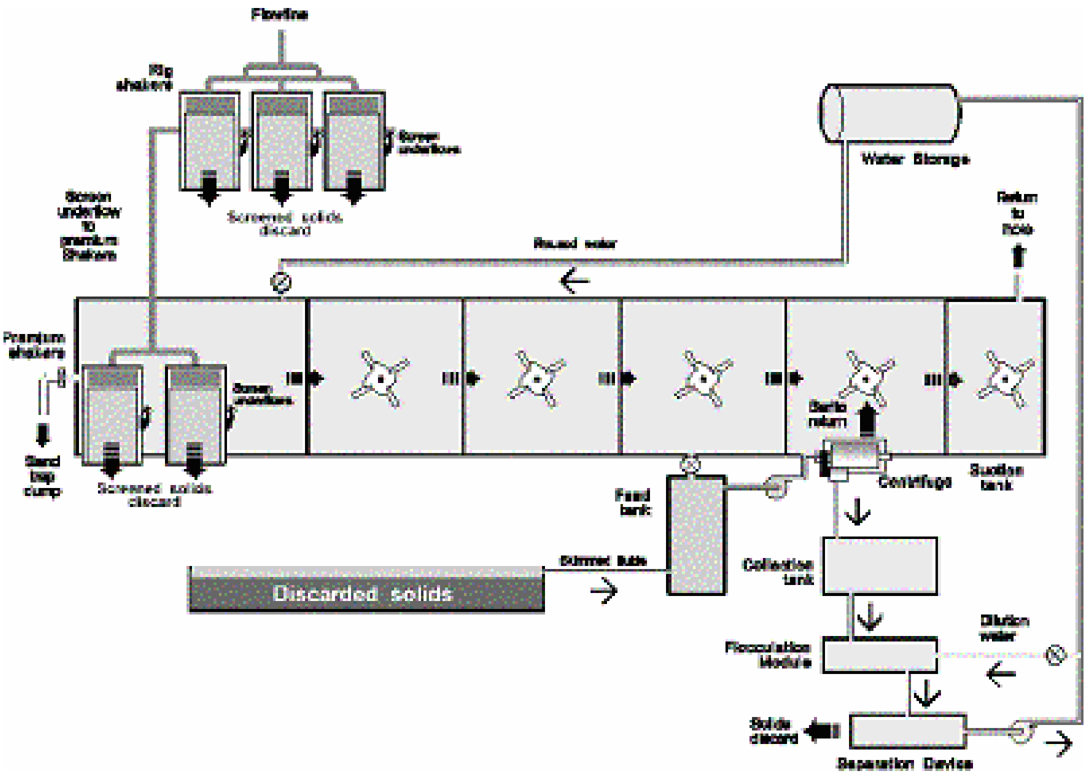

Figure 10 - 10 Closed Loop Solids System – Weighted Fluids

Typical Equipment Configurations

Figures 10-11, 10-12, 10-13, and 10-14 describe the proper arrangement of equipment for common drilling situations. Note that the figures also indicate the positioning of the weirs between the compartments to control the flow direction of the fluid being processed.

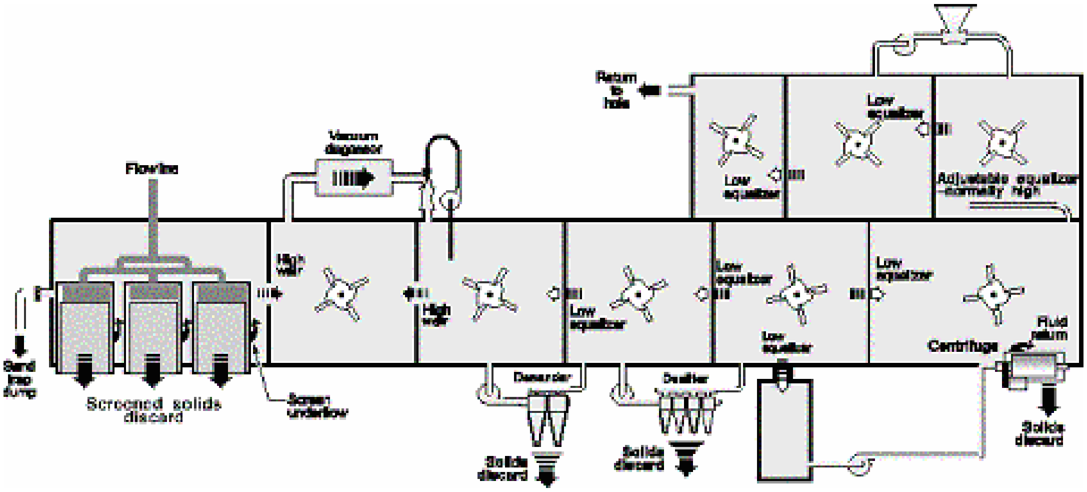

Figure 10 - 11 Unweighted Fluid: Centrifuge Processing Active System

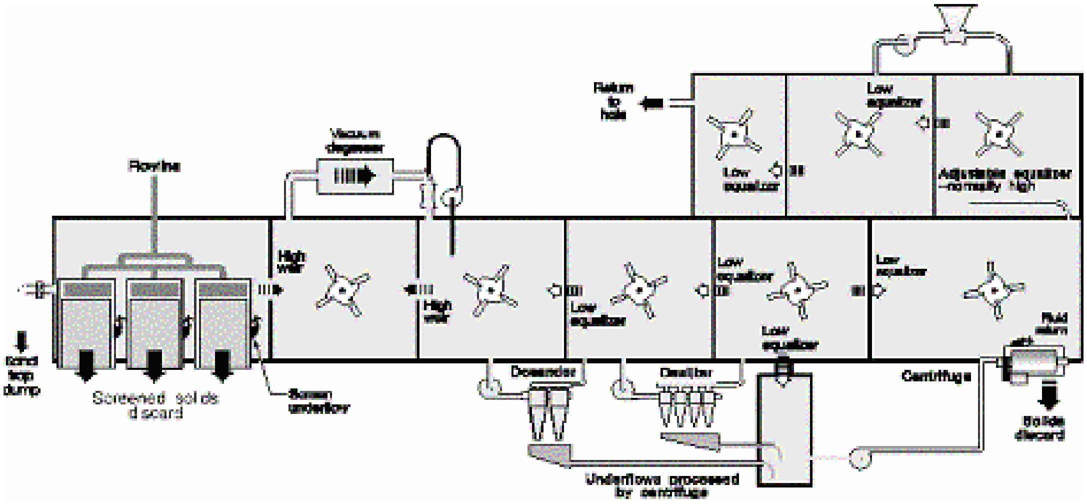

Figure 10 - 12 Unweighted Fluid: Centrifuge Processing Hydrocyclone Underflow

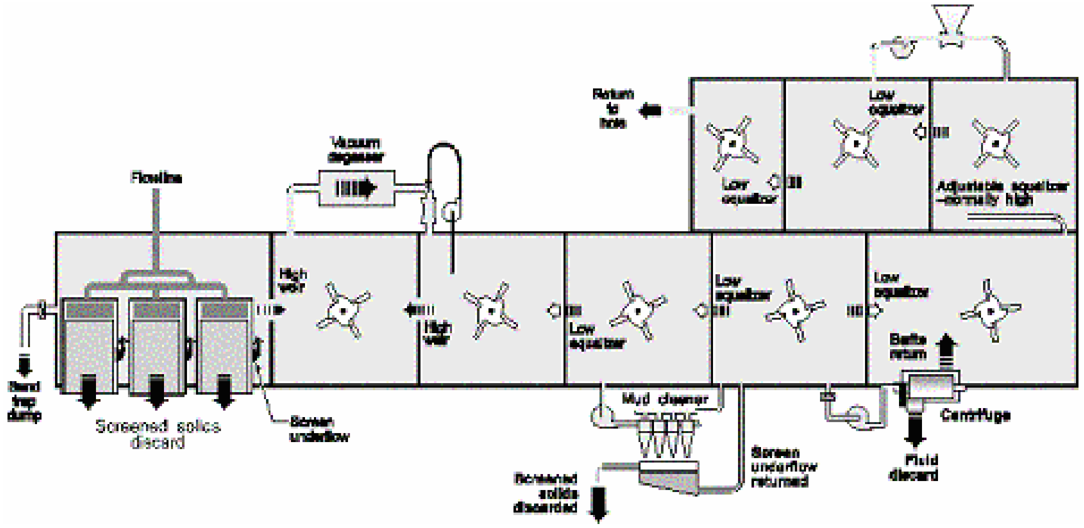

Figure 10 - 13 Weighted Water-Base Fluid: Single-Stage Centrifuging (Barite Recovery)

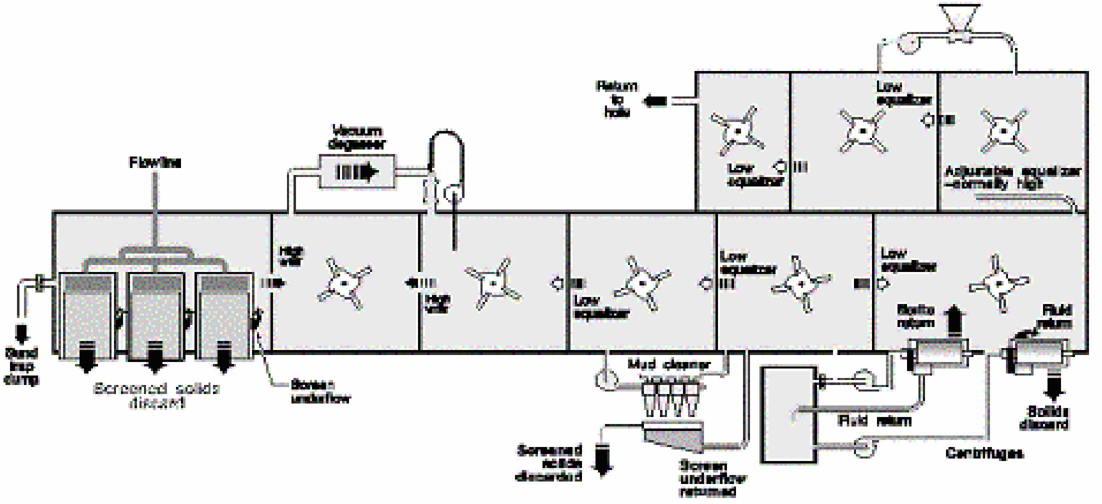

Figure 10 - 14 Weighted Fluid: Two Stage Centrifuging

The dewatering system operates by destabilizing the fluid chemically, which causes coagulation of the solids, and then by chemically *flocking* the solids. “Flocked” solids and liquid are then separated by use of a centrifuge or screwpress to achieve maximum concentration of the solids in the discard and maximum return of the solids-free liquid to the fluid system.

The benefits vary when utilizing a dewatering system depending on the fluid type. Besides the primary benefit of reduced haul-off, reduction in fluid maintenance can be realized for two reasons, (1) the amount of solids carried in the fluid can be controlled without total dependence on chemical thinners and, (2) any soluble materials in the liquid phase will be returned to the system after the flocculation process. However, it should be noted that some additives are removed depending on the ionic charge of the chemical flocculants and the concentration used. This will reduce the cost of fluid built to replace that lost with the solids.

Calculations Used in Solids Control Evaluations

The following equations are based on the fact that the specific gravity (S.G.) of the fluid is equal to the sum of the specific gravity times the volume fraction of each of its components. In these simplified equations, the fluid will consist of three basic components – liquid, low-gravity solids, and high-gravity solids.

$$S_M = (V_W)(S_W) + (V_{LG})(S_{LG}) + (V_{HG})(S_{HG})$$

1. Average specific gravity of solids in water-base fluids.

- Freshwater fluid

$$S_a = \frac{\lfloor 0.12(D_m)\rfloor - V_w}{V_s}$$

- Saltwater fluid

$$S_a = \frac{[0.12(D_m)] - [(V_{wc})(S_w)]}{V_{sc}}$$

$$V_{sc} = 1.0 - V_{wc}$$

Volume of saltwater corrected (V_{wc}) and specific gravity of the water (S_w) are obtained from the appropriate salt table in Chapter 6, **Reservoir Application Fluids**.

2. Volume fraction solids in freshwater fluid containing all low-gravity solids (2.6 S.G.)

$$V_s = 0.075(D_m - 8.33)$$

3. Volume fraction of barite (4.2 S.G.) and low-gravity solids

$$V_b = 0.625(S_a - 2.6)(V_{sc})$$

$$V_{\lg} = V_{sc} - V_b$$

4 Volume fraction of hematite (5.0 S.G.) and low-gravity solids

$$V_h = 0.417(S_a - 2.6)(V_{sc})$$

$$V_{\lg} = V_{sc} - V_h$$

NOMENCLATURE

Cl	Total chloride in mg/L (titration value)
D_m	Fluid density, lb_m/gal
S_a	Specific gravity of solids (average)
S_m	Specific gravity of fluid
S_w	Specific gravity of water
V_b	Volume of barite, MIL-BAR®
V_h	Volume if hematite, DENSIMIX®
V_{hg}	Volume of high-gravity solids*
V_{lg}	Volume of low-gravity solids*
V_s	Volume of solids*
V_{sc}	Volume of solids corrected for NaCl*
V_w	Volume of water*
V_{wc}	Volume of water corrected to include NaCl*
** Expressed as a decimal fraction.*	

Chapter Eleven

Horizontal & Extended Reach Drilling

Chapter 11

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Chapter 11

HORIZONTAL & EXTENDED-REACH DRILLING

Horizontal and Extended Reach Drilling techniques are commonly used in the development phase of oil and gas fields. These types of operations present many challenges in drilling fluid design.

INTRODUCTION

Horizontal and extended-reach drilling are not new technologies. Variations of these techniques were in use 50 years ago. With current state-of-the-art equipment, wells that were once considered marginal and uneconomical potentially become high-return development projects.

Compared to a vertical well, a horizontal hole or extended reach well in a productive formation increases the total percent of the wellbore drilled through the pay zone, resulting in these benefits.

- Accelerated production rates
- Total recovery improvement
- Through reductions in pressure gradients, water and gas coning problems are limited.

Operators make use of these technologies to improve and accelerate the replacement of reserves. According to several surveys of oil and gas producers worldwide, over 50% of wells drilled in the near future will utilize horizontal and extended-reach technologies.

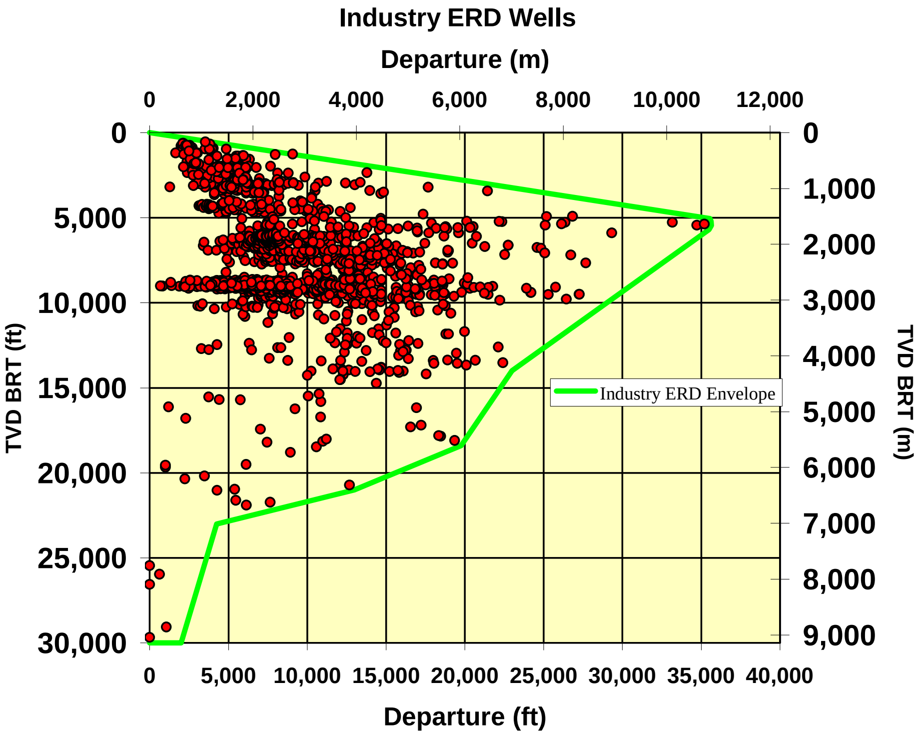
Horizontal and *extended-reach* terms are often used synonymously, but in fact they are fundamentally different. One definition of a horizontal well states that a well is considered horizontal if the producing reservoir is penetrated with the intent of never leaving that stratum.

Therefore, a well does not have to be 90° to be classified as a horizontal well. A prospect can be defined as an extended-reach well when the wellbore is over 60° to 70° with a horizontal displacement of 10,000 ft. Such wells are drilled with a single-bend or steerable motor that can be rotated from the surface. No formal accepted definitions have been established however, and the above examples are meant to show the differences only.

EXTENDED REACH DRILLING

Extended Reach Drilling (ERD) has evolved from simple directional drilling to horizontal, lateral, and multi-lateral step-outs. ERD employs both directional and horizontal drilling techniques and has the ability to achieve horizontal well departures and total vertical depth to deviation ratios beyond the conventional experience of a particular field. ERD can be defined in terms of reach/true vertical depth (TVD) ratios. An extended reach well is commonly defined as a well having a reach to TVD ratio in excess of 2:1. Relative difficulty is a function of both reach/TVD ratio and absolute TVD, commonly referred to as Aspect ratio.

Constraints to successful ERD include downhole drill string and casing movement, applying weight to the drill bit, possible buckling of casing or drill string, and running casing successfully to the bottom of the well. Tension may be a primary concern in vertical wells, but in ERD, torsion may be the limiting factor. Running normal weight drill pipe to apply weight to the bit in ERD can lead to buckling of the drill pipe and rapid fatigue failure. Conventional drilling tools are prone to twist-off, because of unanticipated failure under the high torsional and tensile loads of an extended reach well. Torque can be significantly reduced with the use of non-rotating drill pipe protectors. Advanced equipment for an ERD well may include wider diameter drill pipe, additional mud pumps, enhanced solids control, higher capacity top drive, more generated power and invert emulsion drilling fluids. ERD requires longer hole sections, which require longer drilling times. The result is increased exposure of destabilizing fluids to the wellbore. The superiority of invert emulsion drilling fluids versus water based-fluids in ERD is widely recognized. Conventional water based fluids may not provide the inhibition or confining support of invert emulsion drilling fluids.



Courtesy, K&M Technology

Figure 11 - 1 Medium-Radius Applications Industry ERD Wells.

Extended reach drill string design involves a) determining expected loads, b)selecting drilling string components, c) verifying each component's condition, d) setting operating limits for rig team, and e) monitoring conditions during drilling. Economic issues in drill string planning include availability, logistics, and cost. Rig and logistics issues include storage space, accuracy of load indicators, pump pressure/volume capacity, and top drive torque output. Hole issues include hole cleaning, borehole stability, hydraulics, casing wear, and directional objectives.

Extended reach drilling from land locations has been used instead of offshore locations in several locations including the BP development at Wytch Farm, England, and the TOTAL project in Tierra Del Fuego.

HORIZONTAL TECHNIQUES

The industry has categorized three directional techniques as they relate to the radius formed by the curve of the well. These are long-radius, medium-radius, and short-radius. A fourth technique, ultra-short radius, is used much less frequently. A discussion of all of these techniques follows.

Long-Radius Technique

A long-radius well can be defined as a borehole with at least one hole section in which well inclination is increased at 1° to 10°/100 ft. Most of these wells are drilled with conventional downhole hardware. The kick-off point may be near the surface to allow the target to be reached at the correct depth. Due to the length of the build section, several hole sizes and casing strings may be necessary before the long-radius well reaches its objective. Long-radius wells are not normally taken to the horizontal due to excessive drag and torque.

For example, a build rate of 4°/100 ft results in a radius departure of 1432 feet before the well reaches horizontal.

The length of the radius equates to the measured depth that must be drilled to reach a given inclination. With a 4°/100 ft build rate noted above, controlled drilling of more than 2250 feet is required.

An explanation of these calculations follows: The drilling of 2250 feet to achieve a deviation of 90^0 which puts the drilling on a horizontal plane represents drilling ¼ of a complete circle. The circumference of a circle is defined by $2\pi r$. Four (4) x 2250 = 9000. Dividing 9000 by 2π gives 1432.

Medium-Radius Technique

A medium-radius lateral can be defined as a borehole with at least one hole section in which a well inclination is increased at 10° to 20°/100 ft. A majority of the horizontal wells use this technique. Medium-radius wells suit a wide variety of applications (see Figure 11-2), and have been successfully drilled off-shore in the North Sea, across the Gulf Coast, in the Rockies, and on the north slope of Alaska.

The nature of a reservoir has some effect on the suitability of medium-radius drilling, but much less so than with long-radius. Fractured reservoirs, like the Austin Chalk, may be the most economical use of the medium-radius technique to date.

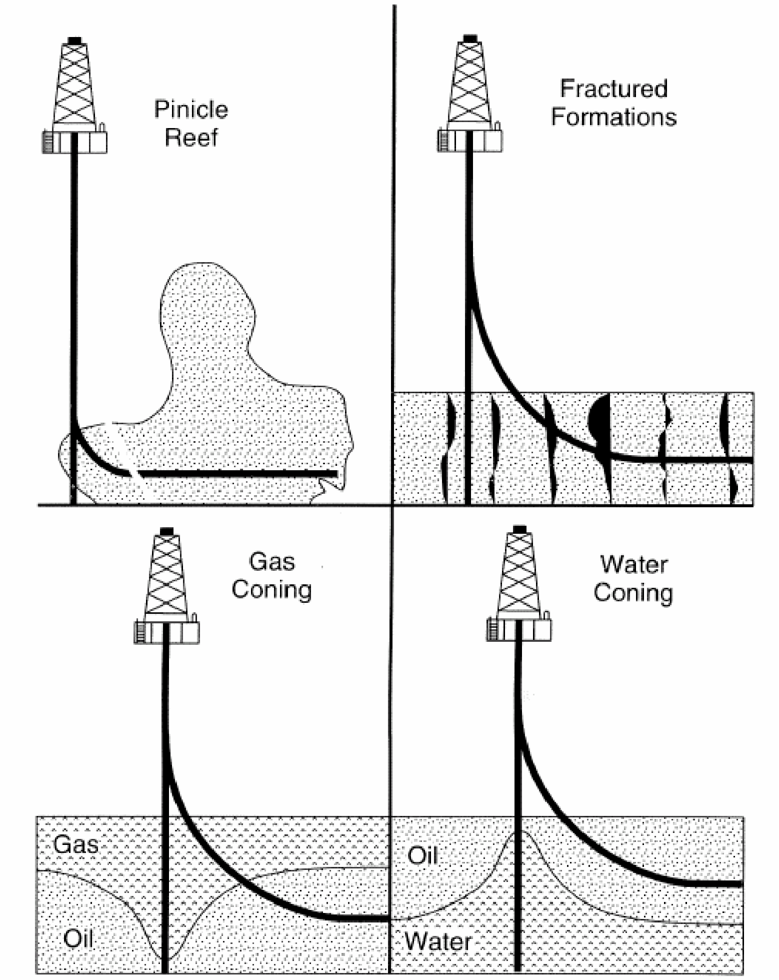


Figure 11 - 2 Schematics of Medium-Radius Applications.

The reduced vertical depth needed for medium-radius wells is an advantage of this technique. A medium-radius well requires less lease space to reach a horizontal target than a long radius well. A typical medium-radius curve requires less than 500 feet of departure, while a long-radius curve requires over 1400 feet.

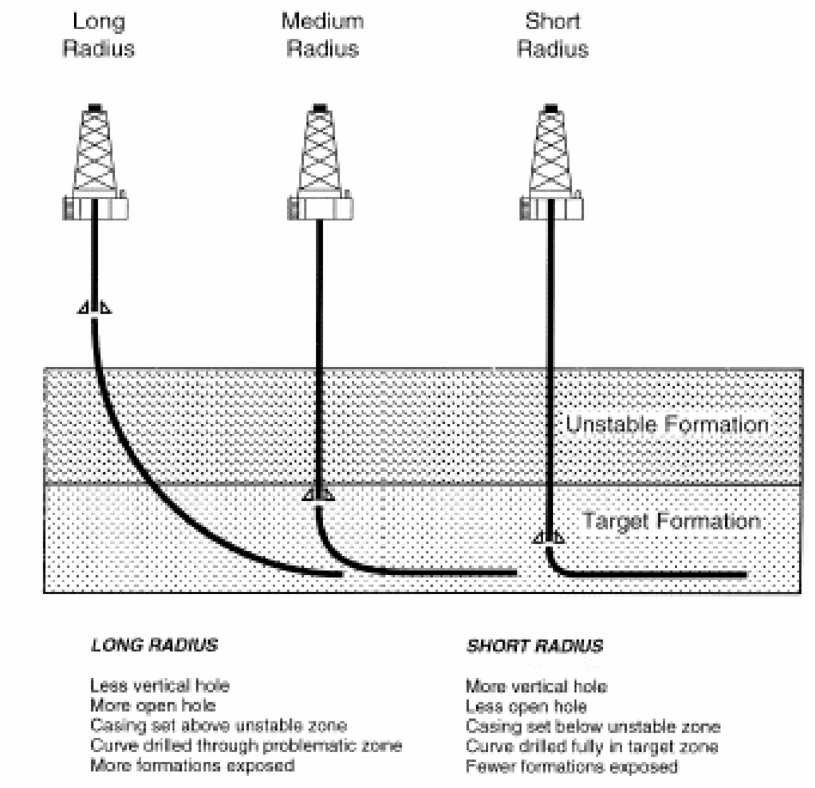


Figure 11 - 3 Schematics of Wellbore Radius in Unstable Formations

Other advantages include reduced torque and drag. Also, no special equipment is necessary as in the case of the short-radius well. As a result, more equipment is available for these types of wellbores.

An unstable or problematic formation yields the most unpredictable variation in build rate and vertical target accuracy. This situation is one of the most influential factors in determining which horizontal technique to use.

Many troublesome zones are normally penetrated in the vertical section of a medium-radius well, and can be cased off before drilling the build and lateral sections. The shorter length of curved wellbore has proven less troublesome to operators than extended-reach wells (see Figure 11-3).

Short-Radius Technique

Short-radius drilling encompasses a wider range of build rates than any of the others discussed. Short-radius drilling is best defined by the use of flexible or articulated tooling to drill doglegs ranging from 1° to 3°/ft.

The best use of this technique is for wells in leases of limited size. A short-radius and/or re-entry well could be turned to lateral and completed with less displacement than a typical long-radius well at 45°. This would make short-radius drilling quite attractive on leases less than 80 acres in size. Problems with this technique involve small hole sizes, downhole tool problems, and being able to hit a small target with consistency. Other difficulties involve completion techniques.

The small departure and limited depth required for short-radius wells makes them suitable in formations topped with problem-causing lithology or reservoirs.

For example, in a thin lime bed topped with 1500 feet of heaving shale, a long-radius well would develop most, if not all, inclination in the trouble zone, while a short-radius well develops little or no angle in the shale. Thus, in a short-radius well, a troublesome zone can be cased off before critical hole drilling begins (see Figure 11-3).

Ultra-Short Radius Technique

The newest method of horizontal drilling is the ultra-short radius technique. This method uses high-pressure fluid to jet a semi-horizontal borehole, the radius of which turns in a matter of inches rather than feet.

The ultra-short radius technique uses specialized equipment and requires some wellbore enlargement in the vicinity of the lateral target. Hole sizes ranging from 2 in. to 6 in. are a function of formation and the jetting head used, while lateral departure is limited to several hundred feet.

In limited terms, the ultra-short radius technique may be defined as a system having virtually no build section, with a lateral placed by means other than rotary bit drilling.

Even though a hole could be jetted into hard rock, this system is clearly more suitable for soft, easy-to-penetrate formations, such as oil or tar sands. Ultra-short methods may also be feasible for solution mining and shallow ground water clean-up projects as well. As with any soft or unconsolidated formation, hole stability and integrity are primary concerns (see Figure 11-4).

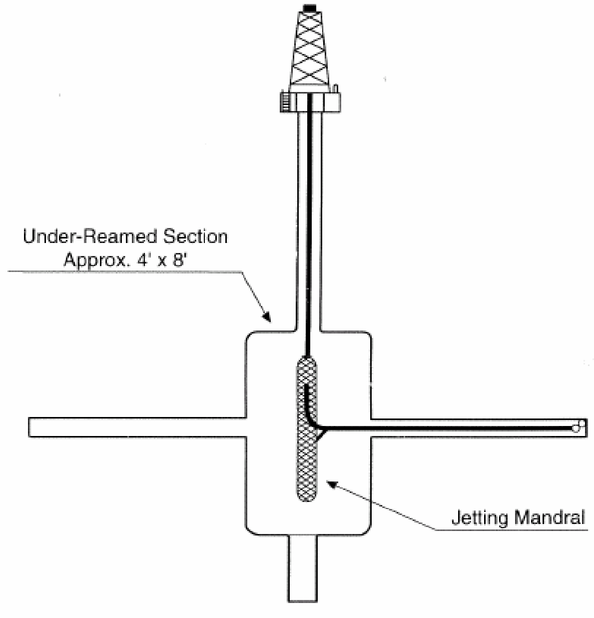


Figure 11 - 4 Schematic of Ultra-Short Radius

Horizontal Techniques Summary

The single most critical aspect of horizontal and extended-reach drilling is choosing the appropriate build rate (radius) to facilitate entrance of the reservoir at the target point. The following tables summarize the relative advantages and disadvantages of the three main horizontal drilling techniques with respect to reservoir/target entrance.

Short-Radius		
Target Height	*Build Rate*	*KOP Above TD*
5 to 20 ft	1° - 3°/ft	± 25 ft

Short-radius techniques yield high build-rate predictability and good reservoir entrance control for very thin reservoirs. Drawbacks of the short-radius system include poor directional control (azimuth), poor correction ability, and limited lateral extension.

Medium-Radius		
Target Height	*Build Rate*	*KOP Above TD*
15 to 100 ft	10° - 20°/100 ft	± 250 ft

Medium-radius techniques yield fair build-rate predictability and fair reservoir entrance control for moderately thin reservoirs. However, medium-radius drilling provides for good directional control (azimuth), good correction ability, and good lateral extension. The technique is applicable over the widest range of conditions.

Long-Radius		
Target Height	*Build Rate*	*KOP Above TD*
> 100 ft	1° - 10°/100 ft	1500 - 2000 ft

Long-radius techniques offer fair build-rate predictability and poor reservoir entrance accuracy. Advantages include good directional control (azimuth), good correction ability, and great lateral extension. The major drawback is the increased costs associated with additional target control and measured footage.

In summary, thin reservoirs requiring little extension should be drilled using short-radius techniques. Conversely, thick reservoirs requiring large lateral extensions should utilize long-radius techniques. Medium-radius drilling can be applied over a wide range of applications. For this reason, the majority of current wells employ medium-radius build rates.

DRILLING FLUID PROPERTIES AND SELECTION

It is common knowledge among drilling engineers and drillers that borehole problems can be considerably more severe in a directional hole than in a vertical well. The problems are magnified as the hole angle and horizontal displacement increases. Although most of these reactions are mechanical in nature, much can be done to alleviate them by proper selection and maintenance of the drilling fluid. For example, if a water-base fluid is being used, lubricants can be added to lower the coefficient of friction between the drill string and borehole or casing. Inhibiting salts can be added to reduce the interaction of the drilling fluid with the exposed formations, thereby improving borehole stability.

There are a number of drilling factors influenced by the drilling fluid, but the following are of primary concern in drilling a horizontal well.

- Borehole instability
- Hole cleaning
- Torque and drag
- Formation damage
- Barite sag
- Hydraulics

Borehole Instability

Borehole instability is one of the more costly, but relatively common problem associated with drilling oil and gas wells. Not only can it impede drilling, it can result in loss of the hole. The term normally conjures thoughts of borehole collapse with accompanying stuck pipe. This is one of the more critical reactions of borehole instability, but it can manifest itself in more subtle ways such as hole-fill, bridges, hole enlargement, or hole size reduction.

These reactions lead to other associated problems including increased torque and drag, logging difficulties, poor cement jobs, and increased drilling days, all of which add significantly to the drilling cost. It should be pointed out that the discussions to follow do not cover hole enlargement problems from weakly consolidated sands, or rubble zones that erode from the hydraulic action of the drilling fluid.

Cause

In simple terms, the primary cause for hole instability occurs when the rock surrounding the hole fails to support the load that was previously taken by the removed rock. This removal results in a stress concentration around the wellbore. If the rock strength is sufficient to absorb this stress, the borehole will remain stable. If not, it will fail. Aadnoy, et al, found that borehole collapse is caused mainly by shear and tensile failure, while fracturing of the wellbore is predominantly caused by tensile failure. However, even if the rock is strong enough to withstand this stress concentration, exposure to the drilling fluid may weaken it to the point that failure will occur.

Control

The first consideration to controlling borehole instability is to increase the fluid density. By having the wellbore pressure carry some of the load, the stress of the borehole wall is reduced and compressive failure may be averted. However, if the fluid density is increased too much, a tensile fracture may occur, resulting in loss of circulation.

Bradley showed through his stress cloud analyses, that the fluid weight required to prevent collapse increases significantly with increasing hole angle, while the fluid weight that can be tolerated before fracturing occurs (loss of circulation) decreases with increasing hole angle. These findings are confirmed by the work of Aadnoy and Chenevert and others. This places strict tolerances on the fluid density range that must be maintained in high-angle wells. Increases in mud weight of between 0.5 ppg and 1.0 ppg per 30 degrees inclination through shale/mudstone sections are usually necessary to prevent combat hole collapse. Experience in the local area will determine where in this range to be. The additional annular pressure losses when circulating – ECD - can lead to the selection of a suitable drilling fluid density being even more difficult. The extent and effect of Equivalent Circulating Density (ECD) needs careful consideration.

No increase in mud weight with hole inclination is necessary across permeable formations such as sands. Formations with reasonable matrix permeability can be drilled with nominal overbalance, regardless of well trajectory or formation strength. Fracture gradient may decrease with increased inclination.

In locally tectonically stressed areas, e.g. Colombia, the collapse gradient may exceed the fracture gradient, even in vertical wells. In this case one or both of lost circulation and hole collapse must be tolerated to some degree. Thus, there is a limitation that can be accomplished by fluid weight, and it is therefore imperative that the virgin strength and integrity of the rock be maintained as much as possible.

Shale Interaction

Interaction of the fluid with the formation which produces instability is primarily related to shale bodies. Shales, which include other classifications such as mudstones, siltstones, and claystones, all contain a relatively high percentage of hydratable and expandable clays. Typical mineral compositions of a young marine shale and an older indurated shale are shown in Table 11-1.

It is the interaction of these clays with the water phase of the fluid that weakens the shale structure. The absorption of water by the shales through capillarity or diffusion causes instability by creating internal stress, weakening of cementing components of the shale, and lubricating micro-fractures that may exist.

Classifications

Shales can be classified into three broad categories:

1. Soft, sticky shales
2. Dispersive shales
3. Hard, brittle shale

Component	Typical Gumbo Shale, Gulf of Mexico, % Composition	Vicksburg Formation, Starr County, Texas, % Composition
Quartz	5 - 10	10 - 15
Feldspar	Trace	2 - 3
Calcite	2 - 3	10 - 15
Dolomite	2 - 3	—
Illite	20 - 25	25 - 30
Mixed Layer	50 - 55*	35 - 40**
Kaolinite	5 - 10	3 - 5
Chlorite	5 – 10	5 - 10
* Mixed layer has 50% expandable layers ** Mixed layer has 25% - 35% expandable layers		

Table 11 - 1 Shale Composition

These classifications obviously overlap, with the soft, sticky shales exhibiting some dispersion and the dispersive shales showing a tendency to ball on the bit and bottom-hole assembly. In general, however, these descriptions can be used to differentiate the behavioral characteristics of shale.

- The *sticky* composition, often referred to as *gumbo* shale, is characteristic of many young marine shales and offers a challenge to the directional driller to gain and maintain angle if the balling cannot be controlled.
- The *dispersive* shales manifest their behavior by being easily subdivided into their integral parts, resulting in excessive fluid solids, high fluid viscosities, and borehole enlargement.
- The *hard, brittle* shales exhibit the classic behavior of spalling and sloughing with the associated problems – hole cleaning, hole fill, hole wash-out, bridges, and pack off.

Extreme differences in behavior exist between the hard shale and the softer rock upon exposure to a freshwater clay-base fluid. The soft shale balls into a plastic mass while the hard shale disintegrates into slivers.

An interesting point to consider is that once the hole has become essentially horizontal in the production zone, whether it be sandstone or carbonate rock, less borehole stability problems might be expected. Since the horizontal section of the borehole is being contained in one particular body of rock, there should be fewer discontinuities than going from one formation to another, and there would be fewer zones of weakness, unless of course, the production zone is highly fractured or faulted.

Drilling Fluid Selection

The proper selection and composition of the drilling fluid will depend upon the type or types of shale to be drilled. Invert emulsion fluids (oil or synthetic external-phase emulsions) can be prepared with the internal water phase containing sufficient electrolyte to show zero or even negative water absorption. Preventing water absorption by the formation effectively controls swelling and maintains the virgin cohesive strength between formation particles. Thus, oil fluids with the proper salinity of the internal water phase are extremely effective in stabilizing troublesome shale formations.

Unfortunately, oil-base fluids have the disadvantage of being prone to loss of circulation and more difficult to regain circulation with than water-base systems. Nance reported that the density of the oil fluid needs to be maintained 2 lb_m/gal below the lowest calculated fracture pressure for the exposed hole to minimize the probability of loss of circulation. Since the fluid density range narrows with increasing hole angle, this requirement could become a limiting factor for oil fluids in horizontal wells. The environmental aspect of oil fluids is also a deterrent to their use in some areas.

Therefore, if the horizontal well is to be drilled in a troublesome shale area, there could be a need to select a water-base fluid that provides the most stable environment possible. Unlike the controlled activity oil-base fluids, water-base fluids expose the formation to water wetting regardless of the electrolyte content of the fluid. To counteract this effect requires a fluid that not only controls the swelling of the expandable clays in the shale, but also is capable of retarding dispersion as discussed in shale classification above. Although these two phenomena are related, they must be controlled by different mechanisms.

Stabilization

The swelling activity is controlled by adjusting the electrolyte content of the fluid to minimize expansion of the clays. Lime and gypsum-treated fluids have long been used for this purpose, but basically do not satisfy the inhibition needs of the more troublesome shales. The potassium ion is an effective swelling inhibitor and is used extensively for this purpose through the addition of potassium salts. The concentration of potassium utilized ranges from several hundred mg/L to over 60,000 mg/L. The most cost-effective potassium concentration, however, appears to be in the 3000 to 7000 mg/L range. In marine environments, seawater or seawater with additional sodium chloride, are good alternates to potassium. The tendency for the shale to disperse or subdivide into discrete particles appears to be best controlled by the addition of an adsorptive, high molecular weight water-soluble polymer.

One of the more effective polymers for this purpose is the partially hydrolyzed polyacrylamide with molecular weight in excess of 15 million. These anionic polymers adsorb on to the surface of the cuttings and borehole wall to act as a binder or elastic coating to retard dispersion.

Another approach to stabilizing the hard brittle shales that contain natural or induced micro-fractures is the use of water-dispersible asphalt or asphaltines. The addition of these type materials appear to plug the micro-fractures, or perhaps even surface pore throats to retard further fluid invasion. This action has proven very effective in certain shales and can be applied in most water-base fluids.

Hole Cleaning

Cleaning cuttings from a vertical hole has been covered extensively by numerous investigators. Hole cleaning in a vertical hole is essentially a matter of overcoming the slip velocity of the cuttings with sufficient annular velocity and carrying capacity of the drilling fluid. Although any velocity greater than the settling velocity of the largest cutting will theoretically lift all the cuttings to surface eventually, too low an annular velocity will lead to an undesirable high concentration of cuttings in the annulus. Experience has shown that cuttings concentrations more than 5% by volume cause tight hole or stuck pipe when circulation is stopped.

Flow Characteristics

Theoretically, turbulent flow is more effective than laminar flow, not only because of the higher annular velocities required to reach this flow regime, but it also provides a flatter velocity profile that reduces edge-wise slip of the cuttings. On the other hand, turbulent flow may cause erosion and hole enlargement. Although a competent formation may not erode even if the flow is turbulent, others will erode because of weakening upon exposure to the drilling fluid, or by having been fractured by tectonic movements. It may become impractical or impossible with the existing rig equipment to maintain turbulent flow in any particular well, especially in washed-out or enlarged sections. Also, certain fluid motors have limits which will not allow the fluid to be pumped fast enough to reach turbulence. For this reason, it may be more desirable or necessary to increase the viscosity of the fluid to improve carrying capacity.

Fluid Viscosity

The structural viscosity of the fluid can be increased to improve lift without greatly affecting rate of penetration. This type of fluid is referred to as a *shear thinning fluid* and its behavior is illustrated in Figure 11–5, which describes shear rate to the various flow regimes in the wellbore.

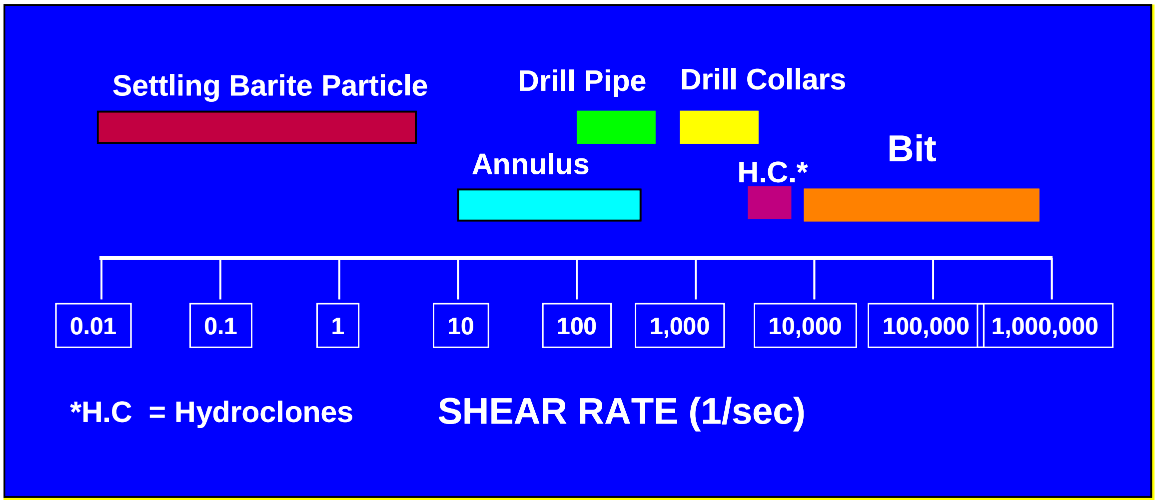


Figure 11 - 5 Range of Shear Rates in the Fluid Circulation System

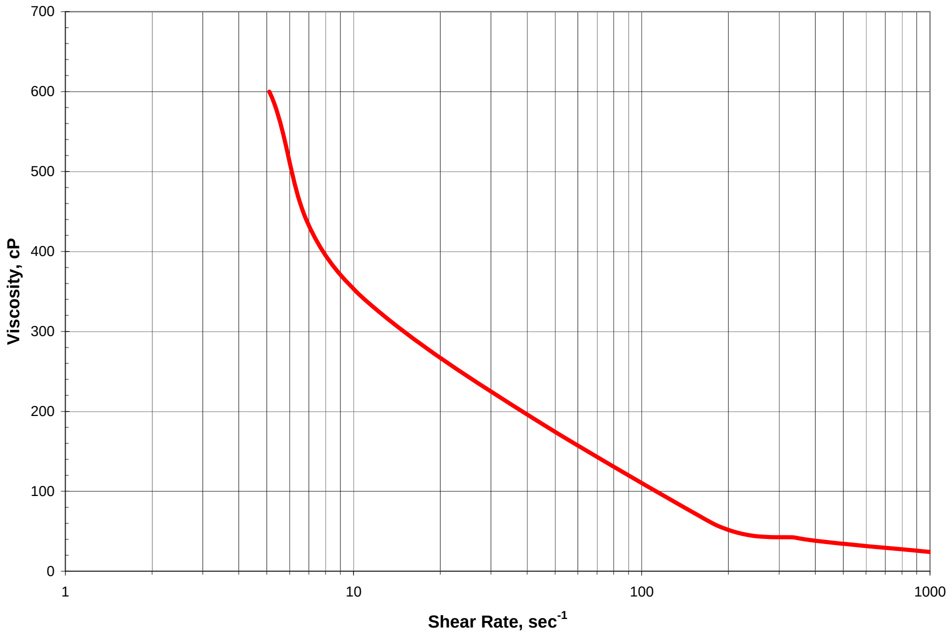


Figure 11 - 6 Effective Viscosity vs Shear Rate

Note that the effective viscosity of the fluid is quite low at bit shear rates, but relatively high in the annular region for maximum lift. *Effective viscosity* is the viscosity of the fluid at a specific shear rate and should be determined for the section of the hole being examined. Calculation and application of the effective viscosity concept is given in Chapter 1, **Fundamentals of Drilling Fluids,** or API Bulletin 13D.

The hole-cleaning concepts of annular velocity and effective viscosity for vertical holes also apply to high-angle and horizontal wells, but the inclined annulus poses several problems not encountered in vertical holes.

Cuttings Bed Formation

Radial slip velocity increases with increasing angle of inclination, forcing more cuttings to the low side of the annulus, which eventually results in the formation of a cuttings bed. Tomren, et al, reported from their work that bed formation was dramatic in the 40° to 50° angle with the bed sliding downward against the flow, resulting in a very high cuttings concentration.

The fact that a cutting bed forms is a serious problem, but the instability of the bed in this critical angle of the well makes the problem even more severe. High torque and drag resulting from the high cutting concentration at the lower part of the angle can obviously result in stuck pipe or loss of circulation. Tomren, et al, also reported that a cutting-bed formation was almost instantaneous at angles of inclination greater than 60°, but that the bed did not slide downward. Thus at angles greater than 60°, the bed depth continues to build until the fluid velocity in the restricted annulus reaches a level that causes cuttings movement, and equilibrium rate is established. Cuttings removal is complicated by the eccentric annuli as well as pipe movement, with increasing eccentricity decreasing cleaning ability while pipe movement provides some assistance.

Although there is a general agreement on the role of drilling fluid rheological properties related to hole cleaning in a vertical hole, there appears to be far less agreement on its effect in high-angle wells. Okrajni and Azar concluded from their work that in the turbulent flow regime, the cuttings transport is generally not affected by the fluid rheological properties (yield value and yield point/plastic viscosity ratio) in hole angles from 0° to 90°.

In the laminar flow range, however, they observed that the annular cuttings concentration was lower for higher yield point/plastic viscosity (YP/PV) ratios throughout the entire range of hole inclinations. Thus, maintaining a greater structural viscosity in the fluid did improve cuttings removal in laminar flow, which became more evident at lower annular fluid velocities. Brown, et al, reported that water gave remarkably better cleaning than a polymer drilling fluid below angles of 50°, probably due to the turbulence of water versus the polymer.

Unfortunately, the polymer used in their study was hydroxyl ethyl cellulose (HEC), which is not a structure-building polymer. HEC will exhibit visco-elastic behavior, however, which retards water from breaking into turbulent flow and thus may have decreased the effectiveness of the HEC fluid as compared to water. Thus, it is important to realize that if the drilling fluid is being circulated in laminar flow, it should possess true thixotropic properties, or as described above, possess shear thinning properties.

The cuttings bed in the greater than 60° angle portion of the hole is of concern, but the instability of the bed in the 40° to 60° angles appears to cause the most problems and be the most difficult to clean. According to Jefferson and Zamora, at about 30°, beds (although unstable) first start to form. Beds become thicker and more stable with increasing angle, but retain the strong tendency to slump or slide downward. This tendency diminishes as the inclination approaches 60°, after which sliding caused by gravity stops. The maximum angle for oil and synthetic based drilling fluids usually exceeds that for water based drilling fluids when cuttings do slide downward and cause pack-offs.

It has been reasoned that if the bed is disturbed periodically, its size can be altered to minimize the size of the avalanche of cuttings when the hole pump is shut-off. One way of attempting to accomplish this is through the use of sweeps.

Hole Cleaning Sweeps

Hemphill and Rojas conducted an in depth study of hole cleaning sweeps for coiled tubing operations, i.e. static drill string.. They concluded that high-density sweeps were more effective than high-density high-viscosity sweeps based on field measurements. The higher viscosity of the latter caused flow diversion to the high side of the wellbore. Not surprisingly, high-viscosity sweeps also performed poorly.

Sewell and Billingsley concluded that the best hole cleaning sweeps were high-density low-viscosity sweeps, with a density 3 – 4 ppg higher than that of the drilling fluid. They made the following recommendations:

- Calculate sweep height in the vertical part of the annulus, and added hydrostatic head in the annulus.
- Rotate at 80+ rpm while pumping the sweep, 180+ rpm is preferred. It is not recommended to pump a weighted sweep while sliding.
- Keep pumping until the sweep is out of the hole. If pumping stops while the sweep is in the deviated hole, it falls out of the “jet stream” and re-deposits captured fines.
- Avoid increasing the viscosity of the weighted sweep.
- Plan to run 3 – 4 sweeps to achieve desired results when hole cleaning problems are indicated. One sweep will probably not be sufficient to remedy an existing situation.
- Avoid checking for flow or closing the annulus with the weighted sweep in the drill pipe.
- If desired for preventative maintenance: 1) schedule sweeps every 6 – 8 hours or 500 – 1000 feet (whichever comes first, unless the hole dictates greater frequency); barite/silt build-ups are dependent on time and footage: and 2) pump a sweep while circulating bottoms up before tripping, and another once back on bottom.

Power et. al. concluded that high-density sweeps were more effective than high-viscosity sweeps. They strongly advocated the use of sweep reports, which should be standard practice in any drilling fluids operation.

Short Tripping

Another technique that has proven helpful in controlling problems created by the cuttings bed in the high-angle portion of the well is to make periodic short trips. Tripping the bit through the bed not only assures that the bottom hole assembly and bit can be pulled through it, but the action should agitate the bed to the point that a portion will slide down the hole and subsequently be picked up when circulation is commenced. The time intervals for these short trips will be determined by the torque and drag conditions that exist in any particular well. Lacking specific well history, a general rule of thumb is to short trip at least once for every 500 feet of new hole.

Drill String Rotation

The industry is in total agreement that drill string rotation improves hole cleaning, especially in hole sizes less than 17 ½”. The general opinion in the industry is that the optimum drill string rotation rate is approximately 120 rpm. It is believed that the drill string rotation improves hole cleaning by mechanically disturbing the cuttings bed on the low side of the hole. There could also be effects due to skewing the velocity profile in the wellbore and the creation of Taylor Vortices.

The recognition of the impact of drill string rotation on hole cleaning was one of the factors that encouraged the use of rotary steerable systems.

Turbulence

Bottom hole assembly design becomes important because the flow restrictions of some of the components, such as the measurement-while-drilling tools or positive displacement motors, may not allow sufficient flow to reach turbulence in the annulus. Turbulence can, of course, be induced at some constant flow rate by decreasing the annular area. This may be more difficult to accomplish in a horizontal well because of limitations on the design of drill strings and tool assemblies. An increase in the effective viscosity of the drilling fluid will decrease the Reynolds Number, and thus increase the flow rate required to obtain turbulent flow. Thus, a lower effective viscosity fluid may be desirable in the horizontal well, but attention must also be given to cleaning the larger diameter portion of the upper hole or possible washed-out sections where it is impractical to maintain turbulent flow.

It is interesting to point out a basic fact between static fluid pressure and dynamic fluid pressure. Static fluid pressure is a function of *true vertical depth*, while dynamic fluid pressure, or ECD, is a function of *measured depth*. Thus, the ECD will continue to increase, albeit slowly, even after the hole becomes essentially horizontal. The fracture pressure could be reached if the hole was extended to sufficient depth and the fluid density is close to the fracture gradient.

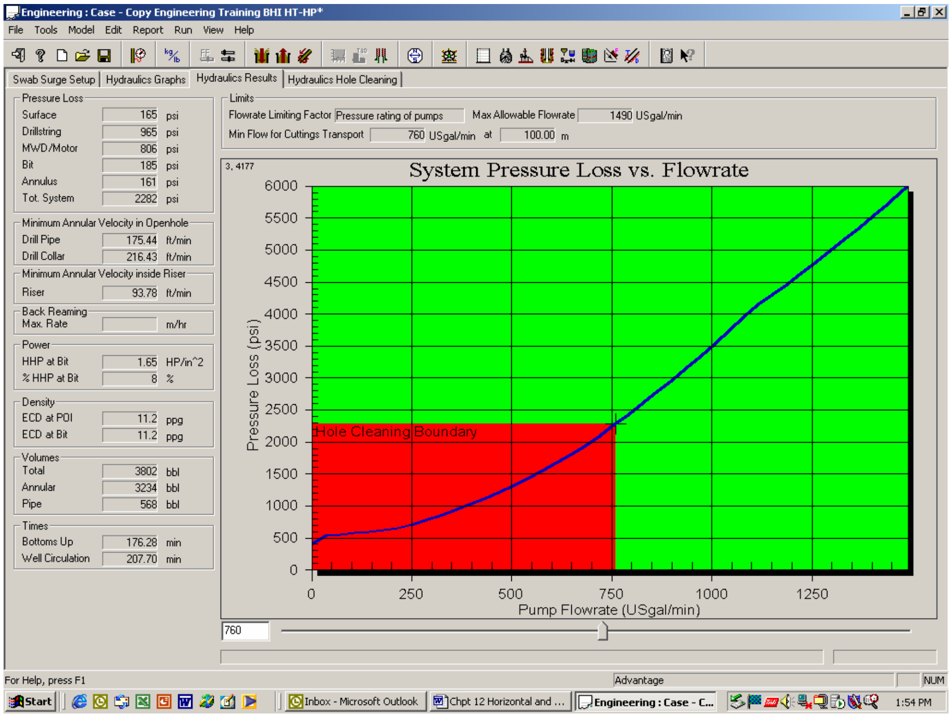
ADVANTAGE Hole Cleaning Modeling

Baker Hughes Drilling Fluids' ADVANTAGE^{SM} hole cleaning simulator is an invaluable engineering tool. Hole cleaning analysis is a critical technology for annular pressure management. The hole cleaning of highly deviated wells is so complex that it can only be adequately analyzed with the use of a simulator. The hole cleaning models within the Advantage System Engineering software can be used to predict minimum flow rate for hole cleaning (optimization mode) or to analyze cuttings transport and cuttings bed formation based on a user-defined flow rate (analytical mode). The hole cleaning model is based on the balance of forces acting on cuttings in the annulus.

Advantage System hole cleaning models provide the drilling engineer with a useful tool for identifying areas in the wellbore where problems related to hole cleaning may occur. Input parameters include cutting size and density, mud weight and rheology, ROP, survey, drill string, wellbore geometry and flow rate. The models uses a force balance analysis within each grid and identifies the most difficult grid for hole cleaning.

Advantage System hole cleaning modeling is routinely used in well planning and drilling phases to predict hole cleaning efficiency and analyze cuttings beds. This information is useful in identifying the location and size of cuttings beds, and their impact on annular pressure (ECD). In many instances, the root cause of annular pressure spikes and increases is poor hole cleaning (annular cuttings loading) rather than flow rate or drilling fluid properties

Further information on ADVANTAGE hole cleaning modeling is available in the ADVANTAGE manual and is provided during ADVANTAGE training. There follows two examples from ADVANTAGE simulations.



Pressure Loss
Surface 165 psi
Drillstring 965 psi
MWD/Motor 806 psi
Bit 185 psi
Annulus 161 psi
Tot. System 2282 psi

Minimum Annular Velocity in Openhole
Drill Pipe 175.44 ft/min
Drill Collar 216.43 ft/min

Minimum Annular Velocity inside Riser
Riser 93.78 ft/min

Back Reaming
Max. Rate m/hr

Power
HHP at Bit 1.65 HP/in^2
% HHP at Bit 8 %

Density
ECD at POI 11.2 ppg
ECD at Bit 11.2 ppg

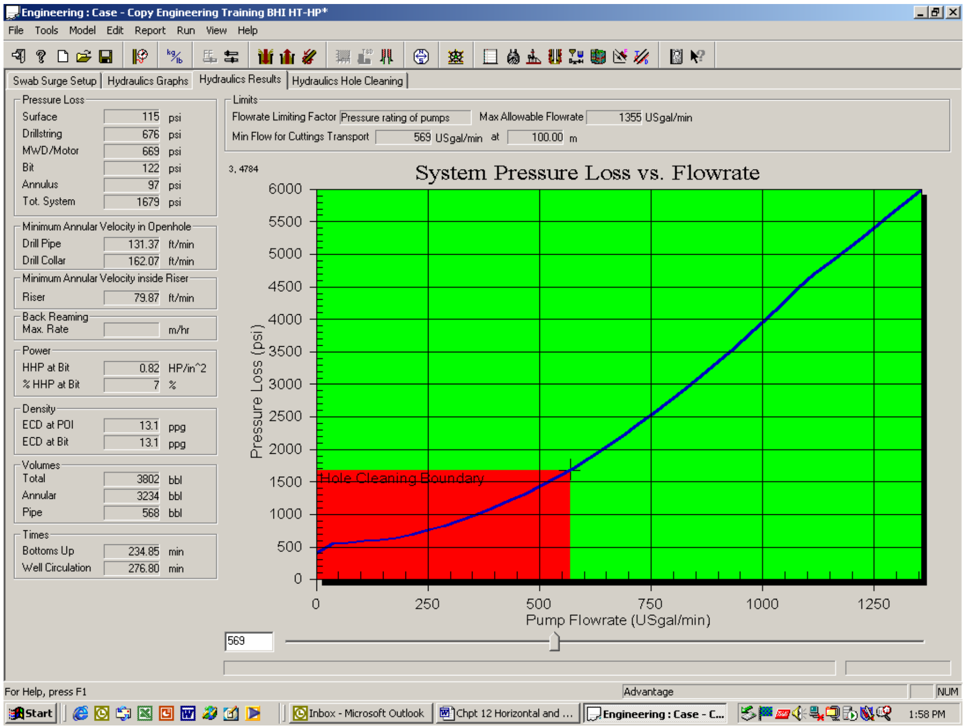
Volumes
Total 3802 bbl
Annular 3234 bbl
Pipe 568 bbl

Times
Bottoms Up 176.28 min
Well Circulation 207.70 min

Limits
Flowrate Limiting Factor Pressure rating of pumps
Max Allowable Flowrate 1490 USgal/min
Min Flow for Cuttings Transport 760 USgal/min at 100.00 m

760

Figure 11 - 7 ADVANTAGE Hole Cleaning Example 1



Pressure Loss
Surface 115 psi
Drillstring 676 psi
MWD/Motor 669 psi
Bit 122 psi
Annulus 97 psi
Tot. System 1679 psi

Minimum Annular Velocity in Openhole
Drill Pipe 131.37 ft/min
Drill Collar 162.07 ft/min

Minimum Annular Velocity inside Riser
Riser 79.87 ft/min

Back Reaming
Max. Rate m/hr

Power
HHP at Bit 0.82 HP/in^2
% HHP at Bit 7 %

Density
ECD at POI 13.1 ppg
ECD at Bit 13.1 ppg

Volumes
Total 3802 bbl
Annular 3234 bbl
Pipe 568 bbl

Times
Bottoms Up 234.85 min
Well Circulation 276.80 min

Limits
Flowrate Limiting Factor Pressure rating of pumps
Max Allowable Flowrate 1355 USgal/min
Min Flow for Cuttings Transport 569 USgal/min at 100.00 m

569

Figure 11 - 8 ADVANTAGE Hole Cleaning Example 2

Figures 11-7 and 11-8 above illustrate very well the usefulness of the ADVANTAGE hole cleaning modeling. The only difference between the two examples is that the drilling fluid density in Figure 11-7 is 11.0 ppg and in Figure 11-8 is 13.0 ppg. This change in density reduces the flow rate necessary to clean the hole from 760 to 569 gpm.

Because of the many variables involved in hole cleaning it is absolutely essential to use a simulator to study the combined effects and be able to examine “what if?” situations.

Hole Cleaning Guidelines

The single most important factor related to hole cleaning in deviated wells is flow rate. During directional drilling operations drilled cuttings will settle on the low side of the hole and form a stationary bed if insufficient annular fluid velocity is used. The critical flow rate required to prevent cuttings bed formation can be determined from ADVANTAGE.

Typically few hole cleaning problems exist in vertical or horizontal sections. Most problems associated with hole cleaning are seen on deviated wells and occur in the 40 – 60 degree section where gravity effects can cause cuttings beds to slump down the hole.

Typical flow rates to aim for in ERD wells:

Hole Size	Typical Flow Rates
17 ½”	1100 gpm minimum. Some rigs achieve 1250 – 1400 gpm.
12 ¼”	Aim for 1100 gpm (although 800 – 1000 gpm is typically achieved). If 1000 gpm is not achievable, ensure tripping procedures are in place for poorly cleaned hole.
8 ½”	Aim for 500 gpm.

When correctly designed, both laminar and turbulent flow regimes will effectively clean a deviated well. In general increasing the viscosity of a fluid in laminar flow will improve hole cleaning as will a reduction of the viscosity of a fluid in turbulent flow. It is important that one or other regime is selected and that the transition zone between the two is avoided.

Generally viscous fluids in laminar flow are preferred because:

- It is possible to achieve higher cleaning capacity.
- Viscous fluids give better transport in the near-vertical sections.
- Viscous fluids have better suspension characteristics when circulation is stopped.
- It is difficult to achieve “turbulent flow” except in small hole sizes.

Experience has shown that good drilling fluid rheological properties are extremely important to hole cleaning when drilling a high angle well. Studies show that the effects of drilling fluid rheological properties and annular flow regime are mutually dependent. In the laminar flow regime, increasing fluid viscosity will improve hole cleaning and this is particularly effective if the Yield Stress is high. In the turbulent regime, however, reducing fluid viscosity will help removing cuttings. Therefore the drilling fluid rheological properties should be designed to avoid the transitional flow regime. For hole sizes above 8 ½”, the annular flow is laminar under most circumstances. Therefore it is necessary to specify a minimum Yield Stress. The optimum level required is best established based on field data and experience.

A higher ROP requires a higher flow rate to clean the hole. It is good practice to drill the hole with a steady ROP and select the required flow rate for hole cleaning accordingly. Before making a connection, the hole should be circulated at the normal flow rate to clear the cuttings from around the BHA. Depending upon the hole angle and length of BHA, a circulation time of 5 to 10 minutes is often required.

Before tripping out, the hole should be circulated at the normal flow rate until the shakers are clean, and the drill pipe be rotated at maximum speed/reciprocated in the mean time. This may require up to 3 bottoms-ups, depending on the hole angle and hole size. Below are listed the recommended number of bottoms-up prior to tripping.

Hole Angle, deg	**8 ½”**	**12 ¼”**	**17 ½”**
0 – 10	1.3	1.3	1.5
10 – 30	1.4	1.4	1.7
30 – 60	1.6	1.8	2.5
60+	1.7	2.0	3.0

Torque and Drag

Overall friction can become so great in an extended-reach well or horizontal section that the drill string can only be rotated with great difficulty. Needless to say, this condition is conducive to stuck pipe. Obviously, this coefficient of friction will be significantly affected by the lubricating properties of the drilling fluid.

Many of the causes of torque and drag are mechanical, while others are related to hole geometry. Several, however, can be directly attributed to the drilling fluid. Since wall contact with the drill string will be extremely high in a horizontal hole, it is imperative that the lubricating characteristics of the fluid be considered.

Fluid Lubricity

Lubricating qualities of a drilling fluid are normally measured in the laboratory by use of a lubricity tester. Coefficient of friction between steel wear pieces, or between steel and ceramic surfaces, is normally determined. Although the coefficient of friction, as measured in these tests, cannot be applied directly to any particular borehole, it can be used for relative comparisons between different drilling fluids and/or lubricating additives. A comparison of the coefficients of friction of several fluid types, as determined by the Baroid lubricity tester, is described in Figure 11-9.

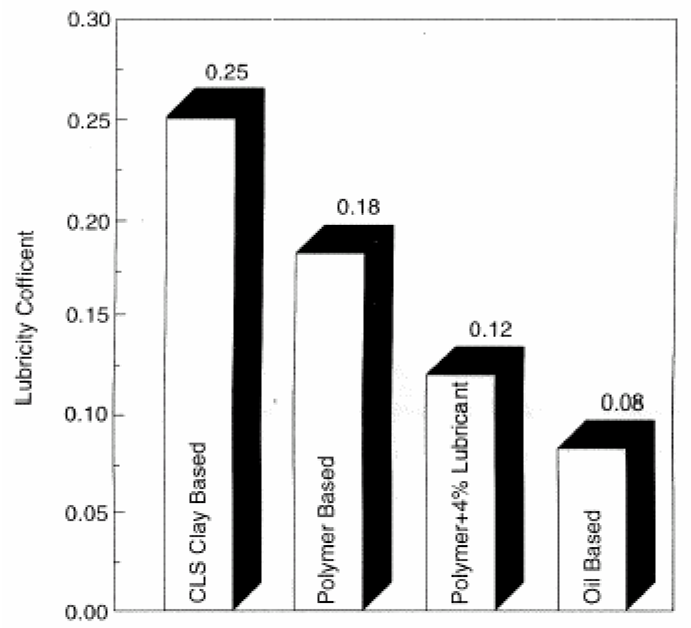


Figure 11 - 9 Comparison of Lubricity Coefficients – Baroid Lubricity Tester

Note that the lubricity coefficient of the oil-base fluid is relatively low. This fact correlates well with field operations where oil fluids generally show good lubricating properties.

However, as noted in the section on borehole stabilization, oil-base fluids may not prove a viable option where formations are prone to loss of circulation, or environmental regulations prohibit their use. It is interesting to note that oil tightly emulsified in a water-base fluid (oil in water emulsion) generally imparts very little lubricity to the system. Water is obviously the external wetting phase and the emulsified oil droplets are not available for lubricating purposes. Diesel or mineral oils contain no chemically-reactive components for boundary lubrication.

It is generally believed that Wyoming bentonite forms the basis of a good lubricating fluid because of its slippery nature. At light loads this appears to be the case, but at loads comparable to field conditions, the film strength of the clay is inadequate and very high coefficient of frictions can be observed. As noted in Figure 11-9, the clay-based lignosulphonate fluid shows a relatively high coefficient of friction. Although this type of fluid has been the most prevalent water-base fluid used for the past 25 years, from a lubricity standpoint, it is not the best choice for an extended-reach or horizontal well.

As noted in Figure 11-9, the polymer-based fluid, which contains 3 lb_m/bbl of a high molecular-weight partially-hydrolyzed polyacrylamide, shows a significantly lower coefficient of friction than that of the clay-based lignosulphonate fluid. This improved lubricity of the polymer-based fluid is inherent in the polymer's behavior. The long chain polymers slide by one another creating a boundary layer between the two sliding surfaces. Modifications of the vinyl co-polymer have also been used to gain additional lubricity. In fact, combinations of these type of polymers with special lubricants are beginning to show friction coefficients approaching those of oil fluids (see Figure 11-9). Fortunately these fluids can be formulated to meet strict environmental regulations. Since the polymers are also being added for shale stabilization and/or filtration control, the added advantage of improved lubricity is even more significant.

There are numerous additives on the market today being sold as drilling fluid lubricants. Many of these are of little value, and, in fact, can be harmful by adversely affecting other fluid properties such as viscosity, filtration control, and indirectly, fluid cost. Thus, careful evaluation and pilot testing should be carried out in selecting the best lubricant. Drilling fluid lubricants can be broadly characterized as anti-wear (extreme pressure lubricants) and modified film lubricants.

Extreme pressure (EP) lubricants were developed to decrease bit bearing wear prior to the development of sealed bearing bits. EP additives are primarily used today to decrease casing wear at high-load points. They commonly contain modified fatty acids, which, according to Browning, react with the metal oxide surfaces of the pipe through a chemi-sorption reaction to maintain their lubricating action at high friction temperatures.

Bol reported that the commercial lubricants he tested partially prevented adhesive wear, but effects were not reproducible in his full scale casing-wear tester. He correctly points out, however, that wear and friction have to be evaluated separately.

Modified film lubricants, on the other hand, are considered general borehole lubricants, and perform more effectively at lower loads. These form continuous films by absorbing layer upon layer, with the thickness of the film making and breaking with the amount of load applied. They may be completely displaced at a very high load point, such as might occur between drillpipe and casing in an high-angle portion of the well, but in general, they show sufficient tenacity to serve as a lubricant between the drillstring and the open hole. Concentration effects are very important for most of these compounds, and normally at least 2% by volume are required before any significant improvement is observed. Most of these additives are hydrocarbon-based, though recent developments have made available formulations to meet non-hydrocarbon environmental regulations.

Filter Cake

Although much of the exposed wellbore will usually consist of shales with very low permeability, a large portion will be shale-sands and sandstones with fluid filter cake deposited on their surfaces. Thus, the lubricity coefficient between the pipe and filter cake becomes important.

Most drilling personnel characterize a desirable cake as one that is thin and tough with a leathery texture. This describes a cake that is highly deflocculated, with relatively low water content. In effect, this leathery surface results in a high-lubricity coefficient with the surface of the cake resisting shear.

Certainly a thin cake is desirable, but it is even more important to have a cake where its outer surface will shear or glide along with the rotating pipe surface. To obtain this property, the filter cake must have relatively high water content, be highly compressible, and possess a very slick surface.

In permeable formations it is essential that the drilling fluid contain the correct concentration of bridging materials and that the bridging material (often calcium carbonate) has a particle size distribution suitable for the formation being drilled. This will help to minimize the thickness of the filter cake deposited and in so doing will aid in minimizing friction.

Wyoming bentonite tends to give this characteristic in fresh water under light loads, but in the presence of drilling contaminants such as gypsum and salt, or in a highly deflocculated environment, tends to lose much of this property. The water-soluble organic polymers provide a lubricating and shearable surface. As described above, the natural lubricity of the partially-hydrolyzed polyacrylamide is a factor in imparting lubricity to the fluid, but this property also carries over into the filter cake surface. The polymer maintains considerable water in the cake surface, even in the presence of contaminating electrolytes, and produces a much slicker and more lubricating surface than the clay-based systems.

One facet of torque in a horizontal hole that cannot be easily answered is the relationship of the drillstring against the inevitable cuttings bed that is formed. Questions can be asked as to what extent does the drillstring extend into this bed, and to what degree is the bed compacted? The answers become even more elusive in the steeper angles of the hole, where the cuttings bed is more dynamic and transitional. Regardless of the final effect of all the parameters of the cutting bed issue, it would appear that the lubricating properties of the drilling fluid remain important.

Formation Damage

The obvious reason for drilling a horizontal well is to expose more of the producing zone to the wellbore for increased production. Thus, the importance of preventing formation damage during drilling and completion of the horizontal well is just as important as it is in its vertical counterpart. In fact, it may be more important since the increased cost of drilling the horizontal well must show additional production for its justification. A 50% damage or permeability loss in a potential 500 bbl/day horizontal well represents a considerably greater loss in production than a 50% damage in a 100 bbl/day vertical hole through the same reservoir.

Sandstone production is by far the most susceptible reservoir rock to damage or permeability loss during drilling and completion operations. Though formation damage may be caused by poor drilling and completion practices, one of the primary causes is due to exposure to the drilling and completion fluid.

This loss, attributable to the fluid, can be caused by one or more of the following occurrences:

- Particle transport from the drilling fluid into the production zone, subsequently plugging pore throats.
- Fluid filtrate reacting with expandable clays in the rock to decrease pore throat diameters.
- Particle movement within the permeable rock due to dispersion of clays and other minerals from quartz surfaces.
- Wettability changes of the formation from exposure to the drilling fluid filtrate.
- Interaction of fluid filtrate with formation fluids to form water - insoluble precipitants.

The effect of these actions on the permeability of sandstones has been the subject of a considerable investigation. In almost all cases, some damage is caused by the drilling and completion fluid. The primary objective is to limit this damage as much as possible. Consequently, selection of the drilling and completion fluid becomes an extremely important function in drilling the horizontal well.

Examining the Formation

Where possible, a thorough examination of the formation should be made to determine its susceptibility to damage and to identify the mechanisms of damage. This analysis is of considerable value in selecting the drilling or completion fluid for a particular formation.

The examination of a core from the formation should include a petrographic analysis and mineral composition by X-ray diffraction and scanning electron microscope. This information can be coupled with data from return permeability tests of core plugs to choose the least damaging fluid. Droddy, et al, utilized these analytical procedures for fluid selection on an argillaceous sandstone from the Wilcox Formation, for example. By combining the findings of the petrological and mineralogical analyses with return oil-permeability tests, it was possible to make a comprehensive selection of the drilling fluid for this formation.

Core Permeability Testing

The formation damage test involves a sequence of flow tests in a liquid permeameter as shown schematically in Figure 11-10.

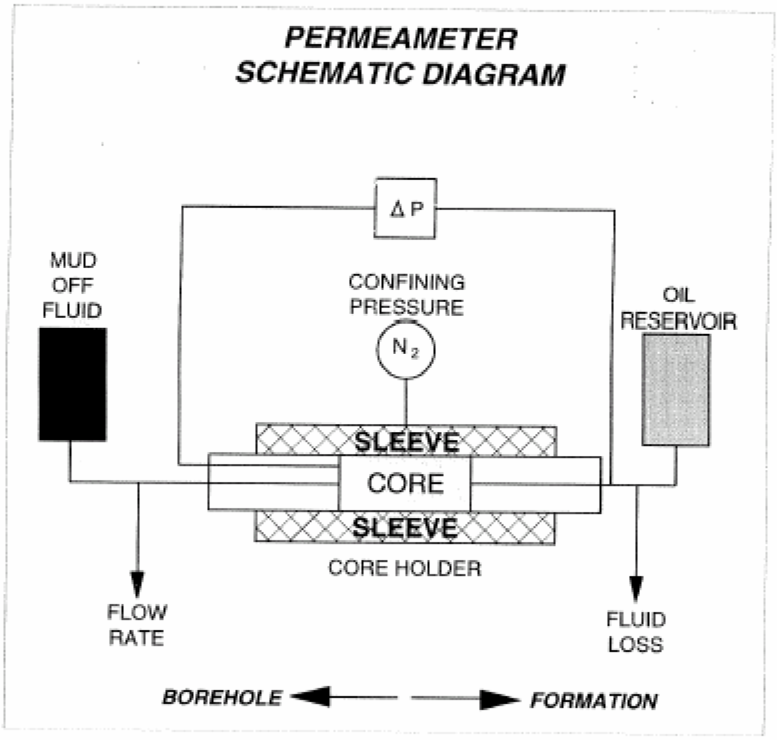


Figure 11 - 10 Permeameter Schematic Diagram

The core is mounted in a Hassler-type cell, evacuated, and then saturated with simulated formation water. The initial oil permeability, *K* (*i*, oil), is determined by flowing a filtered mineral oil through the core under constant pressure until irreducible water content is obtained. This state is indicated by a constant flow rate and stabilized differential pressure. The downstream or borehole face of the core is then exposed to the test fluid under pressure for a period of time. Oil flow is then initiated in the original direction of flow (formation to borehole) under the same initial pressure until the flow rate and differential pressure stabilize. The permeability to oil at this point is the return oil permeability, *K* (*r*, oil).

The ratio of *K* (*r*, oil) to *K* (*i*, oil) is expressed as the percent return permeability, *% K* (*r*, oil). A return permeability of 90% is considered good, since a permeability loss after fluid off of 10% or more is commonly experienced, even with the least damaging fluids.

The effects of several drilling fluid types on the return permeability of a Cook Inlet Alaska core from the Middle Ground Shoal Field are given in Figure 11 - 11. Note that the oil fluid gave a very good return permeability as did the polymer-base fluid with 3% KCl. Since the formation contained a significant amount of expandable clays, the performance of these two fluids can most likely be attributed to their swelling inhibiting properties.

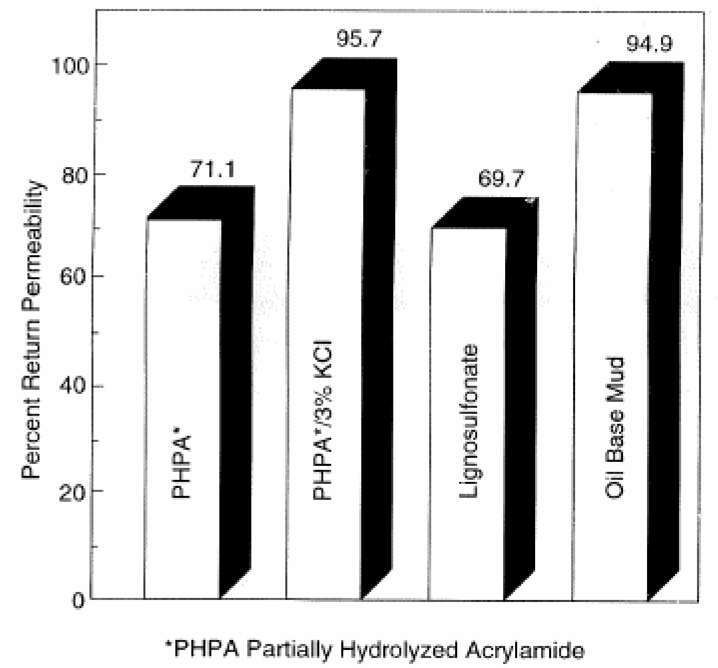


Figure 11 - 11 Return Permeability Data on Cook Inlet Cores

In other formations, particle dispersion and movement may be the primary source of damage. Lignosulphonates are excellent deflocculating agents, and thus produce extremely fine particle-size dispersion, particularly in high pH fluids. This can result in considerable particle transport into the core or particle movement within the core. In formations where this condition exists, lignosulphonates fluids can produce considerable damage with return permeabilities below 50%.

Sandstones containing kaolinite packets are particularly susceptible to particle plugging. The packets can become dispersed from the quartz surface and migrate to plug a pore throat. Fluids that enhance dispersion thus increase the plugging effect.

In general, with all other factors equal, the lower the permeability of the formation, the more subject it is to damage. This, no doubt, is due to the smaller pore openings of the lower permeable rock. Rock factors such as grain mineralogy, grain size, grain shape, and grain packing all exert an influence on the size of the pore throats. There is no specific permeability that the problem of pore plugging becomes acute, but certainly rocks with permeabilities below 100 md can be highly susceptible.

In summary, both the horizontal and vertical permeabilities of the formation are important in a well. Since the vertical permeability of the rock is normally lower than its horizontal permeability, significant differences may occur in their susceptibility to damage. Thus, when analyzing cores from a horizontal well, one should examine a core plug from both the horizontal and vertical planes.

Recommended Fluid Parameters

- *Velocity* – One of the major obstacles to overcome in horizontal and ERD drilling is hole cleaning. In vertical holes, cuttings have room to settle without causing problems. In horizontal wells, cuttings only have to settle 4+ inches to form a cuttings bed. Research and practical experience has shown that cuttings bed formation is analogous to sand dunes on an ocean beach. The bed moves in a wave fashion up the hole. If sufficient annular velocity is not present, the bed thickens until it reaches equilibrium, which usually occurs when turbulent flow conditions exist. With water, turbulent flow is easily obtained since viscosity is in the denominator of the turbulent flow equation, and water has a viscosity of 1. Fluids other than water require more pump output to approach turbulent flow conditions. Practical experience in other industries has proven that materials can be transported in water slurries if the fluid velocity is between 3 and 7 ft/sec.
- *Rheological Properties* – Ideally one would want a true thixotropic fluid to drill horizontally. In effect, two different conditions exist simultaneously. One occurs in the vertical portion of the hole where larger diameter casing may be set, or wash-outs in the open hole occur. In that case, a fluid having a high Yield Stress, or if the fluid is visco-elastic, the initial gel strength needs to be elevated. The opposite is needed in the horizontal section from a hole-cleaning point of view. Here one wants water for the reasons pointed out earlier. Compromises are the result. If casing is set into the zone of interest, or if formations up-hole are not a problem, then water may be possibly combined with occasional sweeps.
- *Surface Apparatus* – Special attention must be placed on the solids removal equipment at the surface. Solids removal efficiency must be continually monitored so that unwanted particulate material is not retained in the fluid system that may negatively affect fluid weight or filter cake quality, resulting in lost circulation or increased torque and drag. The cost of problems that may occur due to not doing this correctly may far outweigh the cost of equipment needed.
- *Common Fluid Utilized* – Table 11 - 2 is a comparison of drilling fluids utilized in horizontal wells which can vary depending upon the area in question, historical preference, environmental constraints, fluid company experience, and operator. Types have included gel and water, oil based fluids, polymers, and in some cases, sized-salt systems. Combinations of the above, as well as other fluids have been tried.

Fluid Type	Advantages	Disadvantages
Oil Fluids	Inhibitive Lubricity Formation damage	Environmental Loss circulation Expensive (Not thixotropic, Solids removal difficult)
Co-Polymer	Somewhat inhibitive Some lubricity Some formation protection Less expensive than Oil Fluid	Moderately expensive Must consider solids
Gel / Water	Inexpensive Environmentally safe Simple	Non-inhibitive Can damage formation Poor lubrication
Clear Water/ Polymer Sweeps	Inexpensive Excellent under balanced Minimum damage some formations Ultra simple	(Limited by pore pressures)
Sized Salt	Lubricity Minimal damage	Disposal Solids removal Cost

Table 11 - 2 Comparison of Drilling Fluids

Originally, fears over anticipated torque and drag saw the use of oil fluids. In medium-radius wells, this problem is not severe and oil fluids are not used as frequently as before for that purpose. Oil fluids are frequently run where the source rock is shale, or where casing is not set through troublesome formations.

Other fluids utilized are water-supplemented with occasional polymer sweeps such as partially hydrolyzed polyacrylamides (PHPAs).These fluids are ideal in certain formations which don't react to the water.

Water, as mentioned earlier, is kept in turbulence easily, provides optimum hole cleaning, is relatively cheap, and requires only minimal sweeps to keep the hole clean.

Sized-salt fluids are super-saturated (where bottom hole temperature is not too high) and contain salt crystals free to plug off the formation, thus reducing filtrate invasion. The salt is easily cleaned up by pumping fresher water, thus dissolving the crystals.

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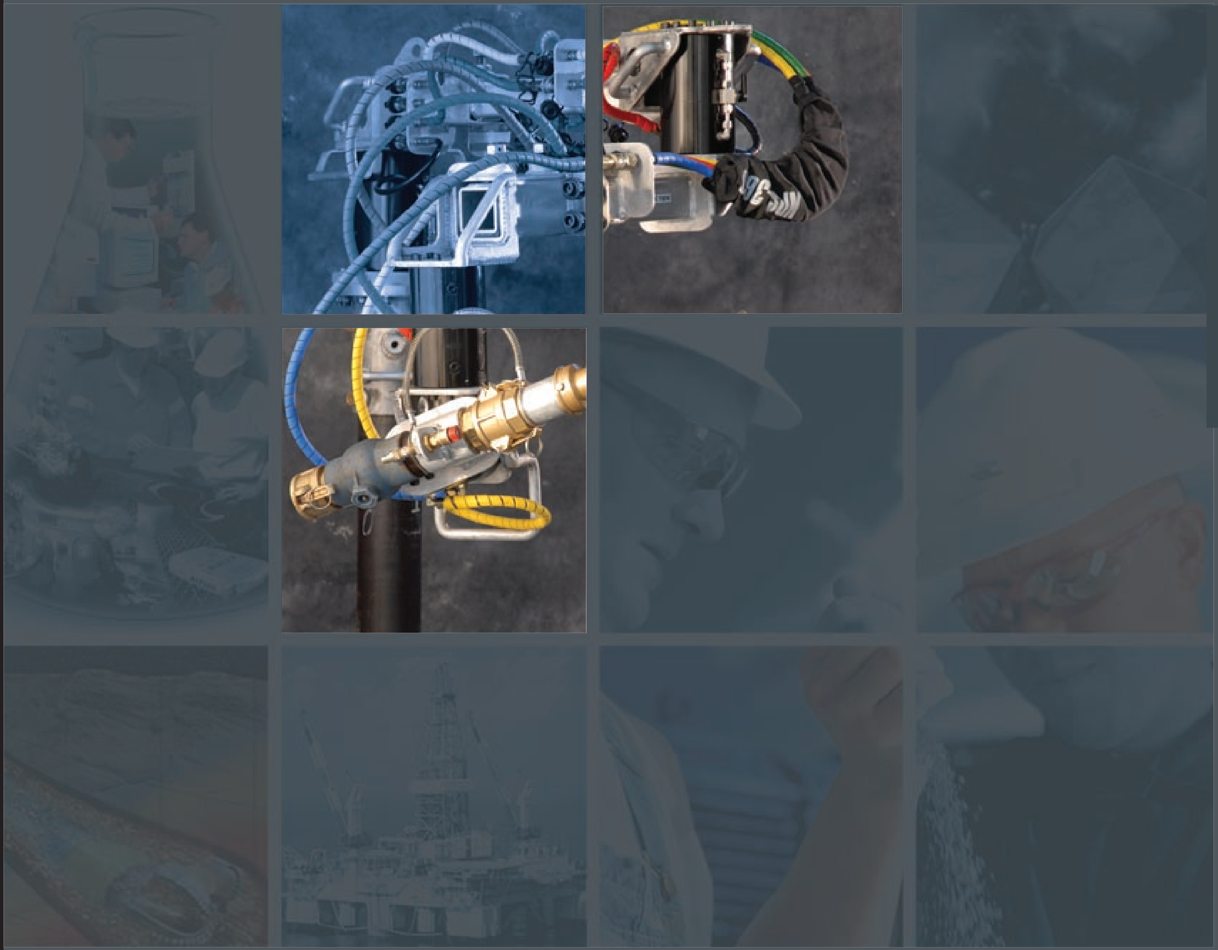

Chapter Twelve

Pressure Prediction and Control

Chapter 12

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Chapter 12

PRESSURE PREDICTION AND CONTROL

All sedimentary rocks are porous to some degree. The pore spaces are filled with fluids – liquids, gases or a combination – which are under pressure. A fundamental function of drilling fluids is to control these downhole pressures as the failure to do so can result in catastrophic consequences, both in terms of HSE and financial.

FORMATION PRESSURE

Overburden is the combined weight of the rock grains and the fluids contained within the pore spaces. For example, a rock grain density of 2.65 g/cm^3 combined with a pore fluid density of 1.07 g/cm^3 and 34% porosity would result in an average density of 2.12 g/cm^3 [(2.65 × 0.66) + (1.07 × 0.34) = 2.12 g/cm^3] would exert an overburden pressure of approximately 0.92 psi/ft. (2.12 × 8.34 × 0.052 = 0.92 psi/ft). Overburden with normal pore pressure varies from approximately 0.84 psi/ft near the surface to 1.0 psi/ft at 20,000 ft in the Gulf Coast area.

The relationship between overburden pressure gradient, pore pressure gradient, and rock grain pressure gradient can be expressed as follows,

$$P_o = P_f + P_c$$

where,

P_o = overburden pressure gradient, psi/ft

P_f = fluid pressure (pore pressure) gradient, psi/ft

P_c = rock grain pressure gradient, psi/ft.

Normally Pressured Formations

Pore pressures in normally pressured zones are equivalent to the average hydrostatic pressure exerted by the fluid contained in the pore spaces above the depth of interest. In the Louisiana and Texas Gulf Coast area, empirical data indicates a normal pressure gradient of approximately 0.465 psi/ft. This gradient corresponds to a fluid weighing approximately 9.0 lb$_m$/gal or one having a salinity of approximately 80,000 mg/L Cl$^-$. It should be noted that this is an average pressure gradient. Obviously, near surface freshwater formations could have a pressure gradient near that of freshwater (0.433 psi/ft or 8.34 lb$_m$/gal).

In the Mid-Continent areas most sediments were deposited in the presence of freshwater. Consequently, normal pore pressure is approximately equal to the gradient of freshwater (0.433 psi/ft or 8.34 lb$_m$/gal in equivalent fluid weight).

ABNORMAL FORMATION PRESSURES

Formation pressures in excess of normal formation pressures for an area are referred to as *abnormal* pressures. The fundamental difference between normally and abnormally pressured rocks is that in abnormally pressured zones the pore fluids no longer communicate 100% efficiently with the water table (surface communication). Some mechanism is providing a seal or cap to interfere with the fluid column and preventing it from achieving normal hydrostatic equilibrium. Abnormal pressure gradients in excess of 1.0 psi/ft have been recorded, but they generally do not exceed 0.91 psi/ft. Some of the causes given for abnormal formation pressures are:

- Compaction disequilibrium is a common cause of abnormal pressure. This is especially true in rapid filling (Tertiary) sedimentary basins. Rapid sedimentation rates accompanied by thick, low-permeability shale sections and growth faults entrap pore fluids. This process restricts the ability of the fluids in the sediments to escape as in a normal compaction situation. When entrapped pore fluids are coupled with overburden pressures, then abnormal pressures are generated. Examples are seen in the Gulf of Mexico, the North Sea and the Niger Delta.

- Tectonic activities such as salt and shale intrusions, faulting, folding, etc., may contribute to abnormal pressures (see Figure 12-1). In the figure below the sand has been elevated while retaining its pore pressure and is thus abnormally pressured at its uplifted depth.

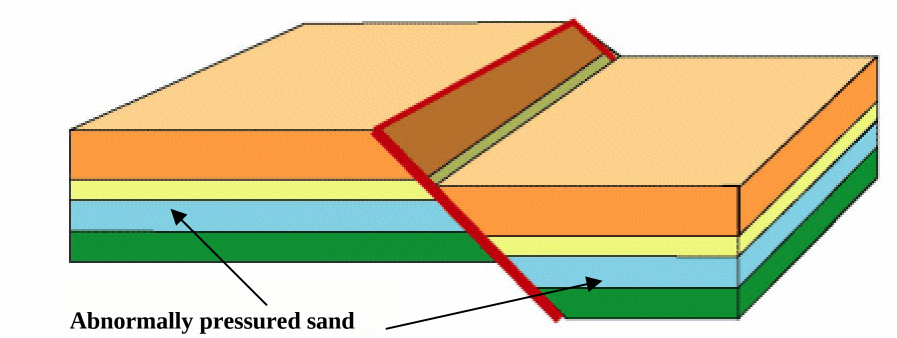


Figure 12 - 1 Tectonic Activities

- Structural features such as dipping lenses and anticlines having normal pressures in the deeper part of the zone can transmit pressure to the higher section of the zone, resulting in abnormal pressure (see Figure 12-2). Also uplifting of “rafts” in salt domes can cause severe overpressures due to the effectiveness of the seal of the surrounding salt.

- Hydrocarbon generation and migration are amongst the most significant factors in the generation of over-pressures. The hydrocarbon that produces the greatest over-pressures is gas. Gas expands much more than oil or water, and whenever it is trapped, it reduces the hydrostatic control. Adequate drainage is required to prevent pressure increases. The movement of hydrocarbons into permeable zones capped by impermeable zones often generates overpressures.

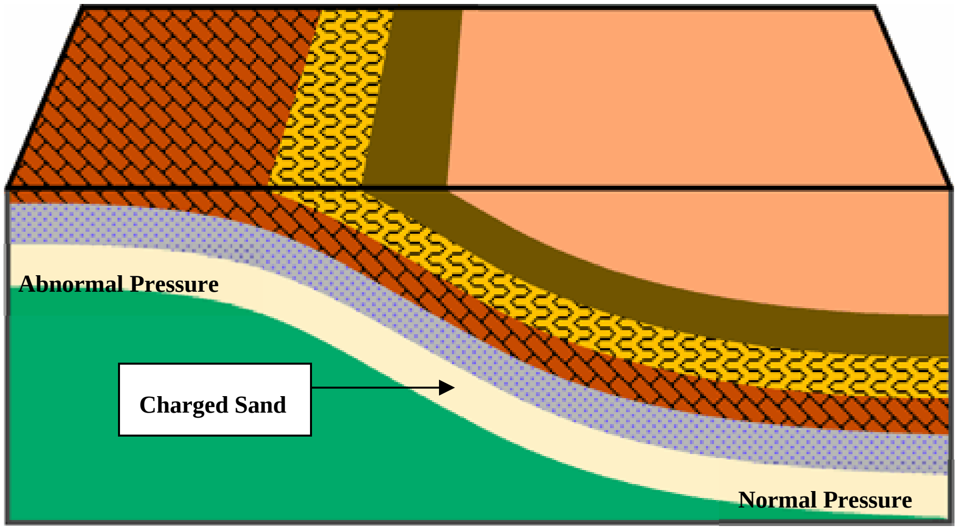


Figure 12 - 2 **Structural Feature**

- Diagenesis is the physical/chemical transformation of one rock or mineral into another. Many minerals will undergo a chemical metamorphosis at relatively low temperatures. A classic example is the conversion of gypsum to anhydrite ($CaSO_4 \cdot 2H_2O$ to $CaSO_4$) in which there is a total volume change of about 50% with the expulsion of water. If this water is not allowed to migrate this could generate substantial pressure increases within a sealed zone.

  Diagenesis of clay minerals is often associated with over-pressured and troublesome shales/mudstones/claystones. Younger argillaceous sediments are often rich in smectite clay – montmorillonite. These clays have a high surface area to which up to ten layers of water can bond. The result is a low density "swelling clay". Smectite clays go through a number of changes with burial. Initially, increasing pressure will drive out the loosely bound water, but as the number of layers is reduced, the pressure required to drive out the remaining layers increases. Ultimately, only high temperature and chemical processes will release the last layer, which can be bound with metallic cations. When smectites within a shale are subjected to lithostatic pressure and a temperature of 67 – 81°C (153 - 178ºF) the penultimate (next to last) layer will be displaced. A further rise in temperature to 172 – 192°C (342 - 378ºF) is required to drive off the last layer, which is very closely bound between the clay plates. Interfering with the migration of freed water may lead to the generation of over-pressures. At the threshold temperature for the loss of the penultimate water layer is also the point at which smectites can turn into illites. Depending on the type of smectite, the availability of available cations like K^+ will satisfy the surface charges in place of water and collapse the clay into more compact illite. The remaining water is released into the porosity created by the reduction in clay volume. It appears that the denser illite can reduce vertical permeability and thus hinder the natural migration of fluids. This may explain why over-pressures are often associated with zones containing 40 to 50% illite.

- Formations that have been charged from water floods, casing leaks, or underground blowouts.

HOW TO RECOGNIZE ABNORMAL PRESSURE ZONES

Abnormal pressure zones are often associated with under-compacted shales. This change in shale characteristic generally results in,

- Change in normal porosity, usually an increase
- Change in formation fluid content and density
- Change in shale conductivity, usually an increase.

METHODS OF FORMATION PRESSURE PREDICTION

Because many formations have abnormally high fluid pressures, it is extremely important to know about these pressures in planning and executing drilling operations. Prior to drilling, there are two means of predicting the location of abnormal pressure zones – (1) seismic data from the area to be drilled and, (2) electric log data from offset wells drilled near the proposed location.

Seismic

Since the abnormally pressured zones have not compacted normally with depth, the velocity of sound waves traveling through these formations is reduced. These reductions are measured, plotted, and converted to an amount of abnormal pressure. Seismic interpretation can be applied to the detection of two different types of abnormal pressured gas zones, shallow and deep.

Shallow Gas

Formations containing gas tend to absorb sound waves. Formations above gas sands will be highly reflective, whereas the gas sands will be absorptive. On a seismic profile, the gas sand will show up as a "bright" spot. Shallow gas sands have been responsible for numerous offshore blowouts, so their detection before drilling is important.

Deeper Gas

Abnormally pressured formations at deeper depths are more difficult to detect; the more geological information available in an area, the greater accuracy in detecting these zones; the more velocity profiles taken in an area, the better the definition of the normal compaction trend. The seismic data yields curves representing sonic velocities of the formation to be drilled.

Different lithologies have different velocity profiles. Therefore, a thorough knowledge of the geology of an area aids in the interpretation of seismic information. The unit used to measure the velocity is a value referred to as *interval velocity*. Interval velocity is the speed of sound through an interval of formation and the reciprocal of interval transit time.

The interval transit times are usually plotted on logarithmic scale versus a linear depth scale (see Figure 12-3). A normal line (±70 µ sec/ft @ 10,000 ft.) is drawn and extended into the abnormal pressure interval and compared to the extrapolated shale line (±90 µ sec/ft @ 10,000 ft). Comparison between the observed value and the extrapolated value is a measure of the amount of abnormal pressure. Common sources of error in velocity analysis include dipping beds, faults, multiple reflections, curved ray paths, processing, and interpretation. An interval transit time for limestone (±50 µ sec/ft @ 10,000 ft.) is shown for comparison purposes. The seismic wave travels faster through the harder rocks and is slowed down by the presence of increased pore pressures present in shale which is an indicator of underlying higher pressure formations.

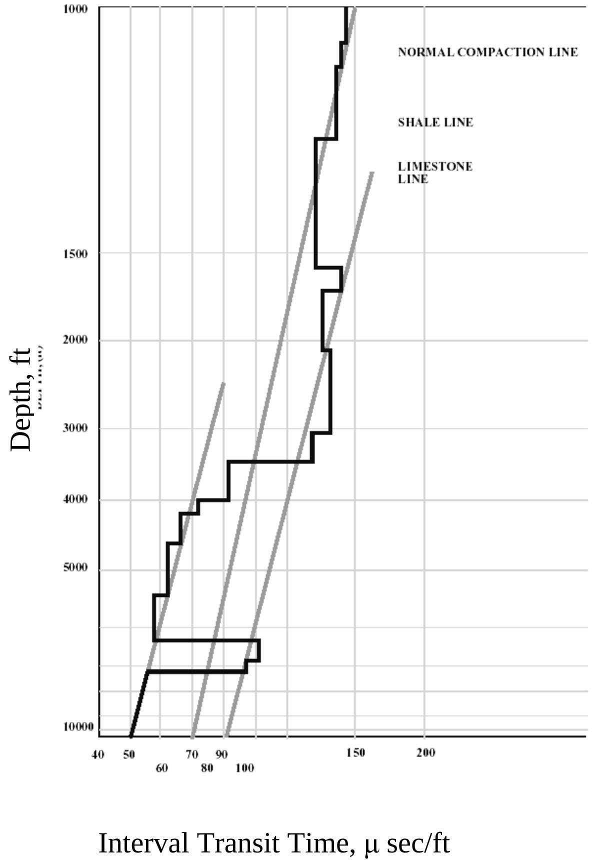


Figure 12 - 3 Interval Transit Time

ELECTRIC LOG ANALYSIS

Abnormally pressured zones can be predicted by analyzing changes in shale conductivity recorded on induction logs. Steps in the procedure are:

1. Obtain shale conductivity (C_s) readings from an induction log.
2. Make a plot of C_s vs. depth on semi-log paper.
3. Draw the best straight line through the shale conductivity plot.
4. A sharp change in direction by some of the plotted points generally indicates the presence of an abnormal pressure zone.
5. Record the ratio of shale conductivity observed to normal conductivity of that shale (see Figure 12-4).

6. Depending on the formation from which the readings are taken, calculate the ratio of observed conductivity to normal conductivity. Refer to Table 12-1 to obtain predicted pressure gradient in the form of equivalent fluid weight.

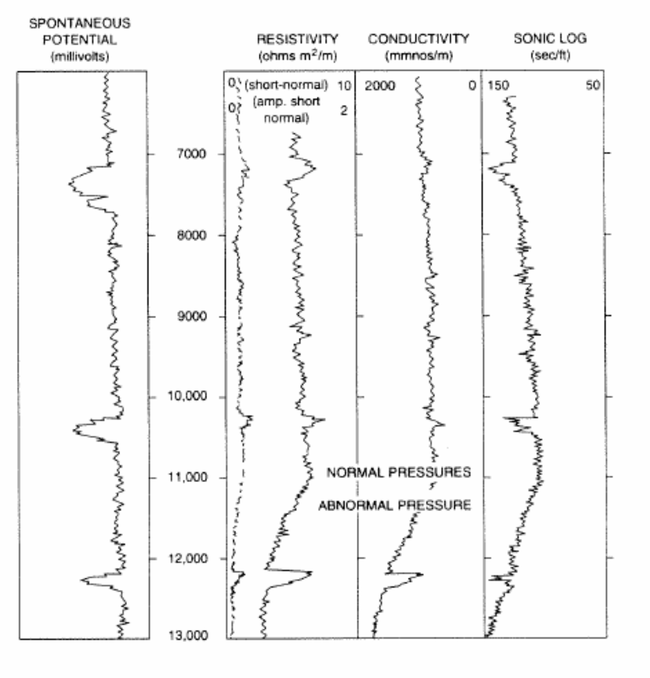


Figure 12 - 4 Log Depicting Abnormal Pressure Zones

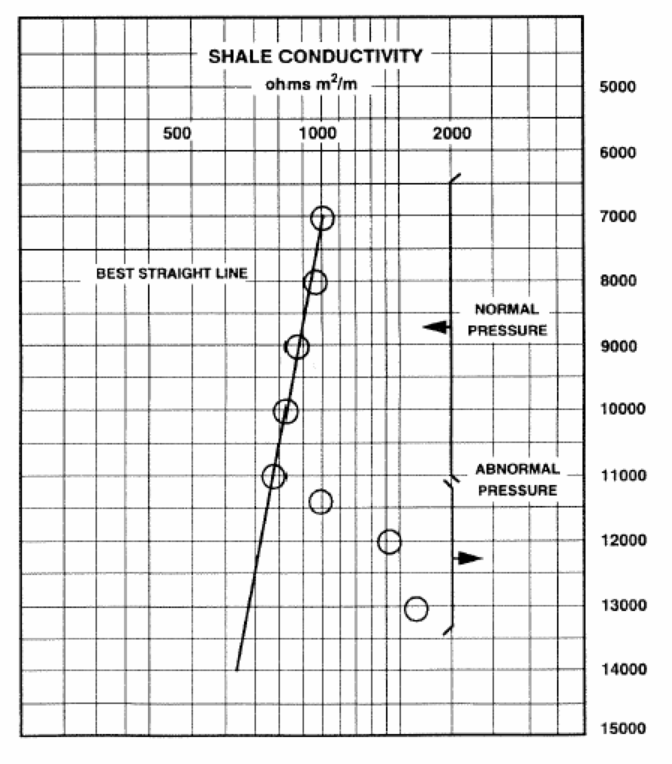


Figure 12 - 5 Conductivity Plot vs. Depth for Log in Figure 12- 4

Pressure Gradient in Equivalent Fluid Weight (lb_m/gal)	**Ratio: Observed Conductivity / Normal Conductivity Or: Normal Resistivity / Observed Resistivity**				
	MIOCENE-OLIGOCENE South Louisiana	FRIO FORMATION S. Texas Gulf Coast	WIL COX FORMATION S. Texas Gulf Coast	NORTH SEA	SOUTH CHINA SEA
10.0	1.09	1.34	.08	1.50	1.32
10.5	1.15	1.55	.13	1.76	1.50
11.0	1.20	1.78	1.22	1.95	1.65
11.5	1.28	1.97	1.28	2.30	1.80
12.0	1.34	2.18	1.39	2.60	2.00
12.5	1.43	2.43	1.50	2.90	2.20
13.0	1.53	2.68	1.64	3.25	2.45
13.5	1.65	2.96	1.80	3.60	2.65
14.0	1.78	3.33	2.00	3.85	2.85
14.5	1.93	3.60	2.21	4.2	3.1
15.0	2.10	3.95	2.44	4.5	3.30
15.5	2.33	4.31	2.71		3.54
16.0	2.60	4.67	3.03		3.70
17.0	3.58	5.72	4.0		
17.5	5.00				
NOTE: Plot conductivity values for shale on 3-cycle semi-log paper.					

Table 12 - 1 Predicted Pressure Gradients vs. Conductivity or Resistivity Ratios

Example

Figure 12-4 shows an example of an IES log. From the plot in Figure 12-5, it can be easily seen that a marked trend of normal pressure zone is obtained until a depth of approximately 11,000 feet. At this point, the sharp change indicates that an abnormal pressure zone has been encountered. Figure 12-5 shows the conductivity plot versus depth for the log in Figure 12-4.

Sample calculations from Figure 12-5:

- For abnormal pressure zone at 13,000 feet,
- Shale conductivity observed = 1670
- Shale conductivity normal = 630

Calculate the ratio of observed conductivity to normal conductivity:

If the formation were of Miocene-Oligocene geologic age, Table 12-1 indicates a formation pressure equivalent to approximately 16.1 lb_m/gal drilling fluid density.

Sonic Logs

Sonic log data is used in a manner similar to the conductivity method of pressure prediction. Sonic logs measure transit time of sound for fixed distance through formations (the same as the seismic information). Interval transit time (microseconds per foot) decreases as formation porosity decreases because a denser material transmits sound waves at a higher velocity than a less dense material. Porosity generally decreases at a near linear rate as a function of depth in normally near a straight line with gradual reduction in travel time as a function of depth.

Increased shale porosity (which usually indicates a change in compaction and abnormal pressures) would produce an increase in shale travel time. Figure 12-6 is a plot of shale transit time versus depth. Note the normal compaction trend indicating normal formation pressures down to approximately 11,000 feet. Below this depth, shale travel time values begin to increase in relation to extrapolated normal compaction line, indicating abnormal formation pressures.

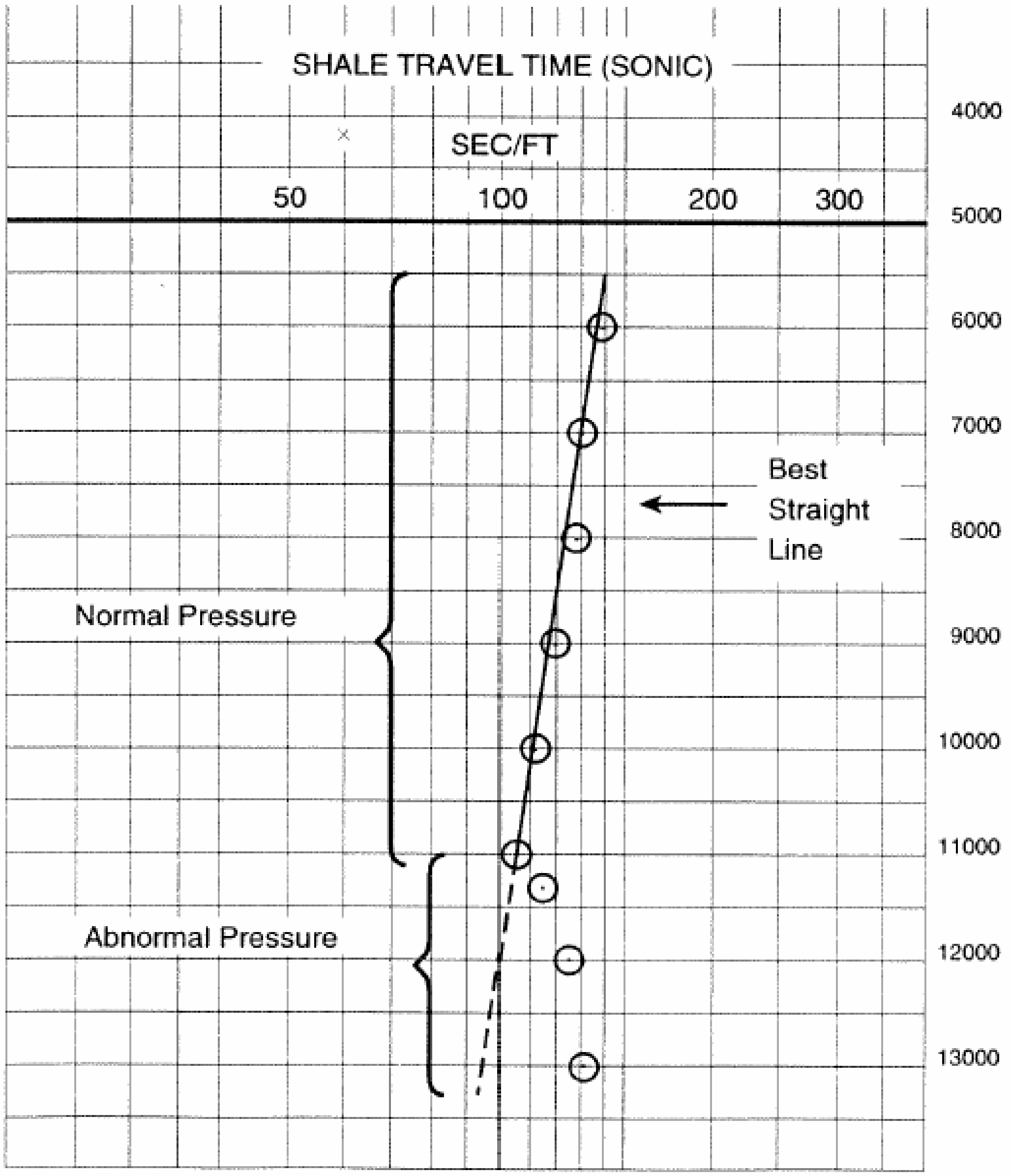


Figure 12 - 6 Shale Transit Time vs. Depth

Pressure Gradient in Equivalent Fluid Weight (lb_m/gal	U.S. GULF COAST Miocene-Oligocene to - tn	FRIO FORMATION S. Texas Gulf Coast to - tn	WILCOX FORMATION S. Texas Gulf Coast to - tn	WEST-TEXAS to - tn	NORTH SEA to - tn	SOUTH CHINA SEA to - tn
9.0				4.0	2.0	3.0
9.5	2.5	10.7	9.2	6.0	7.0	7.0
10.0	5.0	13.0	11.6	8.0	9.5	11.0
10.5	6.5	15.4	14.0	10.0	13.3	15.0
11.0	8.0			12.0	17.0	19.0
11.5	10.5	17.7	16.4	15.5	21.0	22.5
12.0	13.0	20.0	8.8	19.0	25.0	26.0
12.5	15.0	22.5	21.3	22.0	29.5	29.0
13.0	17.0	25.0	23.8	25.0	34.0	32.0
13.5	19.0	27.8	26.4	28.0	41.0	34.5
14.0	21.0	30.3	29.0	32.0	48.0	37.0
14.5	24.5	33.0	31.8	36.0	51.0	39.5
15.0	28.0	36.0	34.5	40.0	54.0	42.0
15.5	33.0	39.25	37.5	45.0	57.0	
16.0	38.0	42.50	40.5	50.0		
16.5	43.0	46.25	44.5	54.5		
17.0	48.0	52.0	48.5	59.0		
17.5				63.0		
18.0				67.0		
NOTE: Plot observed shale travel time on 3-cycle semi-log paper.						

Table 12 - 2 Predicted Pressure Gradient vs. Sonic Log Departure (At Observed-At Normal)

Example

Figure 12-6 indicates a departure from extrapolated normal travel time of approximately 35 sec/ft at 13,000 feet. Utilizing the Miocene-Oligocene column of Table 12-2, a pore pressure equivalent to 15.8 lb_m/gal drilling fluid density is predicted.

As mentioned, abrupt changes in salinity of pore water in shales can lead to erroneous pressure prediction when using resistivity or conductivity logs. Other variables which may affect logs are noted in Table 12-3.

Some suggestions for selecting the shale data points to be used in formation pressure prediction are:

- Select clean shales in intervals of low spontaneous potential (SP) deflection and uniform conductivity or sonic readings.
- Shales selected for data points should be at least 20 feet thick with points obtained from the center of section, if possible.
- The most reliable shale readings are usually the higher conductivity values midway between sand intervals.

- Shale stringers within massive sand sections tend to exhibit high, unreliable readings.
- Avoid shale readings immediately above a known gas sand. These readings will characteristically display high, unreliable values.
- If available, the caliper survey should be scanned for excessive hole enlargement. Excessive enlargement can create a skip in signal on sonic logs and lead to erroneous data.
- Avoid plotting silty or limey shales by inspecting the SP curve. Minimum SP values will result in more reliable data.
- Scan log prior to plotting for scale changes or error in tie-back on subsequent log runs.
- Utilize available well data to verify predicted pressures (formation tests, “d” exponent plots, well kick data, etc.).

Factor	Short Normal	Conductivity	Transit Time	Bulk Density
Salinity changes	x	x		
Swelling clays	x		x	x
Hole enlargement	x	s	x	x
Limey shales	x	x	x	x
Resistivity markers	x	x		
Age change	x	x	x	x
Bentonite clays	s			
Improper calibration	s	s	s	s
Tool malfunction		s	s	s

x = Affected
s = Sometimes Affected

Table 12 - 3 How Variables Affect Logs

DRILLING PARAMETERS USED TO INDICATE AN ABNORMAL PRESSURE ZONE

Although attempts at predicting actual formation pressures are important it should be realized that they are just predictions. While drilling, several indicators of abnormal zones must be watched so that early detection is possible. The most common methods used to detect abnormal pressure zones in their assumed order of occurrence are:

- Increased rate of penetration
- change in rotary torque
- change in drag on connections
- change in pit volume
- variation from normal "d" exponent and its modified d_{xc} exponent
- gas content of drilling fluid
- variances in shape and size of shale cuttings
- shale density
- flowline temperatures
- chloride ion content of drilling fluid
- paleo information.

All the above indicators will not be present at any one time. Rig personnel, however, must be able to recognize these indicators and interpret correctly those which are present on a particular job. Experience has shown that when more than one indicator exists, a cross-checking system which uses one indicator to verify others helps eliminate many potential drilling problems related to abnormal pressures.

Increased Rate of Penetration

Rate of penetration is one of the most widely accepted methods of determining changes in pore pressure. There are, however, variables other than pore pressure which affect rate of penetration. They are,

- lithology changes
- hydraulics (bottom-hole cleaning)
- bit weight
- bit type
- bit condition
- rotary speed
- drilling fluid properties.

There is no way to control lithology. It is, therefore, paramount when using penetration rate as a detection method to control the other governing variables as closely as possible.

A uniform decrease in rate of penetration of shales normally occurs with depth. This decrease, which results from increased compaction and density of the shales, can be related to the differential between hydrostatic pressure and pore pressure. The magnitude of change in differential pressure is the key to changes in penetration rates.

While drilling a transition zone, drilling fluid density should be maintained as low as possible so that any change in pore pressure will be reflected in penetration rate. As pore pressure increases, rate of penetration will increase. Any excessive overbalance in drilling fluid density will decrease the differential pressure and partially mask the formation pressure increases.

As mentioned, the inability to control lithology presents a serious problem. Generally, a sudden large increase in penetration rate may indicate a lithology change. To prove or disprove such a conclusion, the other parameters of abnormal pressure detection must be carefully evaluated.

Rotary Torque

During a normal drilling operation, rotary torque gradually increases with depth due to the effect of wall contact of the drillstring on the wellbore. Any abrupt changes from this gradual trend indicates a twist-off of the drillstring, a locked cone on the bit, a washout in the drillstring, or a change in formation pore pressure. The actual condition is usually determined by an experienced driller.

Increased pore pressure causes larger amounts of shale cuttings to come into the wellbore and the bit teeth will take larger bites into the formation. The increased amount of shale tends to stick or impede bit rotation. Rotary torque will not be easy to interpret as an indicator where hydrostatic pressure is greater than formation pressure in deviated holes or when drilling from a floating vessel.

Changes in Drag on Connections

When drilling in a balanced or near-balanced situation, an increase in drag can occur while making a connection in an abnormally pressured zone. This increase is caused by the extra shale cuttings which enter the wellbore when abnormal pressure is encountered.

Because of the plastic nature of some pressured shales, as shown by Darley, the hole may close in around drill collars and bit, and drag increases. Drag, much like rotary torque, can be masked as an indicator while drilling deviated holes or drilling from a floating vessel.

Change in Pit Volume

An increase in pit volume (rigs now employ pit totalizers to monitor this variable) is an indication of formation fluids entering the wellbore while drilling. Drilling ahead should be interrupted. Mud returns should be monitored for the increasing presence of background gas.

Circulation may also be interrupted for a short period to observe for any flow from the annulus. Caution should be exercised in this case, as the chance of becoming differentially stuck increases if all pipe movement and circulation is interrupted.

The “d” Exponent

The “d” exponent method of detecting and predicting the magnitude of pressure abnormalities while drilling is a useful tool in some areas. Improvement in plotting techniques has refined the method to the extent that pressure gradients in many areas can routinely be predicted with an accuracy of approximately 0.010 to 0.025 psi/ft, the equivalent of 0.2 to 0.5 lb_m/gal of fluid weight. The value of formation pressure information during drilling operations is readily apparent. Properly utilized, this information can reduce the incidence of blowouts and significantly reduce the use of unnecessarily heavy fluids, thereby increasing penetration rate and reducing drilling costs. Preparation of the “d” exponent plots is uncomplicated and requires no special equipment. The required information – penetration rate, rotary rpm, weight on bit, and hole diameter – is routinely available at the wellsite.

In 1965, Bingham suggested that the relationship between penetration rate, weight on bit, rotary speed, and bit diameter can be expressed by the following general equation,

$$\frac{R}{N} = \mathrm{K}\left[\frac{W}{D}\right]^{\mathrm{d}}$$

where,

R = penetration rate

N = rotary speed

K = a constant

W = weight on bit

D = hole diameter

d = exponent.

In 1966, Jorden and Shirley of Shell Oil Company introduced the “d” exponent concept. Earlier investigators had established the inverse relationship between penetration rate and the pressure differential between the fluid column and the formation. Jorden and Shirley advanced the idea that while drilling normally pressured formations with constant fluid weight, the pressure differential increases with depth and decreases as abnormally pressured formations are encountered. Under constant drilling conditions and uniform rock properties, these changes in differential pressure result in gradually decreasing penetration rate through normally pressured formations and an increase in penetration rate through abnormally pressured formations. Thus, if it were possible to hold the entire drilling variables constant, a simple plot of penetration rate versus depth could be used as a pressure detection tool.

Similarly, if all variables other than rotary speed, weight on bit, and hole size are held constant, the relationship between the “d” exponent in the Bingham equation and pressure differential would show recognizable trends when the “d” exponent is plotted versus depth. Solving Bingham's equation for “d” and adding constants to permit use of common oilfield units, Jorden and Shirley introduced the “d” exponent equation,

$$\mathrm{d} = \frac{\log \dfrac{R}{60N}}{\log \dfrac{12W}{10^6 D}}$$

where,

R = ft/hr

N = rpm

W = lb

D = diameter in inches.

As predicted, plotting “d” as calculated from this equation versus depth does establish recognizable trends in normally pressured formations and recognizable deviation from these trends as abnormal pressures are encountered.

In 1971, Rehm and McClendon proposed that if it were possible to correct for fluid weight, the “d” value could be related directly to formation pressure rather than to differential pressure. They suggest making a correction by multiplying the basic “d” value by the ratio of the normal fluid weight pressure gradient for the area to the actual fluid weight being used.

$$\mathrm{d_{xc}} = \mathrm{d}\left(\frac{\textit{Normal Fluid Weight}}{\textit{Fluid Weight in Use}}\right)$$

Use of this correction factor gives excellent results and permits graphic determination of pressure gradients in abnormally pressured zones.

Gas Content of Drilling Fluid

Increases in the gas content of a drilling fluid was recommended as an indicator for detecting abnormal pressure zones as early as 1945 (Pixler). Since experience has shown that gas cutting is not always a result of an under-balance condition, correct interpretation of gas cutting trends is imperative.

Gas may be entrained in the fluid column as a result of the following conditions.

- When a formation containing gas is drilled, cuttings and cavings containing gas are circulated up the hole. Hydrostatic pressure on these particles is reduced. Gas in the particles expands and is released to the drilling fluid system, cutting the weight. In such cases, increasing fluid weight will not stop the gas cutting. This condition can be verified by reducing drilling rate or by stopping drilling and circulating bottoms up.

- While drilling a pressured formation, the differential between the hydrostatic fluid column pressure and formation pressure is reduced. During a connection or trip, the piston effect of upward pipe movement can swab formation gases and fluids into the wellbore. As the fluid or gas is circulated up the annulus, gas (if present) will expand. When detected, the gas is generally concentrated and reaches the surface at the same time, thereby showing a significant gas cut.

When using gas in the drilling fluid as an indicator of abnormal pressure, a gas detector unit of some type is required. A trend of background gas and connection gas can be noted as drilling progresses. Both background gas and connection gas normally increase slowly with depth. Any sudden increase in background or connection gas should be watched carefully and taken as a possible warning of increasing pore pressure.

Changes in Cuttings

Shale cuttings from an abnormally pressured zone are larger than those from a normally pressured zone. They are characterized by sharp and angular edges, while normal pressure shale cuttings are generally small and flat with rounded edges.

The variables which determine the size and shape of shale cuttings are:

- mineralogical, chemical, and physical properties
- type of drilling fluid system
- circulation rate
- hole geometry
- downhole agitation.

Gas or saltwater or a combination of the two in the over-pressured shale helps support some of the overburden. Hottman and Johnson proposed one method to explain this. Over-pressure in the shale, if not offset by equal or greater hydrostatic pressure from the drilling fluid, will create a condition which aids the spalling (sloughing) action of the shale.

H.C.H. Darley and Chenevert found that shales develop pressure if certain fluids are allowed into the pores. The abnormally pressured shales then act much like popcorn – exploding into the wellbore – if forces across the face of the wellbore are not equalized.

Shale Density

Shales which are normally pressured have undergone normal compaction and their densities increase uniformly with depth. This uniform increase allows shale density to be predicted. Any reduction from the extrapolation can be interpreted as a zone of higher pore pressure. The primary problem of relying on shale density is that the shale cuttings must be circulated to the surface before measurements can be made.

Flowline Temperature

Due to abnormal pressures exerted on fluids in a transition zone, above normal temperatures occur. A normal trend of flowline temperatures can be plotted. A change of 2° to 6°F above this trend can be an indication of a transition zone. In addition to indicating a pore pressure change, changes in flowline temperature can also be attributed to:

- an increase in circulation rate
- a change in solids content of the drilling fluid
- a change in drilling practices
- an increase in bit torque.

The temperature curve, although not definitive, is still an additional indicator to help make a decision to stop drilling or increase existing fluid weights.

Chloride Trends

Changes in the chloride ion content of the drilling fluid are a valid pressure indicator, but changes are difficult to establish unless there is close control and analysis of fluid properties. Most methods currently available to make routine chloride ion tests are inadequate to show subtle changes. An alternative to actually measuring the chloride content of the filtrate is continuous monitoring of the resistivity of the fluid both into and out of the hole.

Paleo Information

Abnormally high pore pressures are frequently related to certain environmental conditions within a given geologic time period. This depositional environment is marked by the presence of certain fossils. Should examination of cuttings reveal these fossils, then the operator should be alerted to the potential problem of encountering abnormally high pore pressures.

CONTROLLING FORMATION PRESSURE

Control of formation pressure is one of the primary functions of drilling fluids. The hydrostatic pressure exerted by the fluid column is the most important method of controlling formation pressure. Whenever formation pressure exceeds the total amount of pressure exerted on the formation, formation fluids may enter the wellbore causing a kick. A kick is defined as any unscheduled entry of formation fluids into the wellbore. Early recognition of a kick and prompt initiation of control procedures are the keys to successful well control. If kicks are not detected early enough or controlled properly when detected, a blowout can occur.

Preplanning to Prevent or to Handle Kicks Safely

The cornerstone of a safe, efficient drilling program is prediction of pressure gradient, fracture gradient, and fluid densities based on drilling, geological, and physical experience in the area. This has been discussed in the first part of this chapter.

On exploratory wells, or in areas where little information is available, it is necessary to focus on drilling parameters such as penetration rate, modified “d” exponent, gas readings and trends, fluid temperature, fluid conductivity, etc., and to run confirmation logs when drilling parameters indicate changes in pressure gradient. In fact, these drilling parameters should be monitored even in areas where information is available. The preliminary drilling plan is merely a guideline and does not eliminate the possibility of unexpected changes in pressure gradient. Blowout frequency for exploratory drilling is about double that of the average for all drilling operations.

Preplanning on the rig should give consideration to the following aspects of the operation.

- *Assignment of responsibilities*. Each crew member should know who will perform various surveillance tasks, coordinate well kill procedures, and operate the choke.
- *Periodic inspection and testing* of well control and detection equipment to insure kicks can be detected and contained.
- *Pit drills* should be conducted on a regular basis by all crew members to condition the crew to execute proper kick control procedures.

- *Preventive training.* It is absolutely essential that personnel be thoroughly trained in prevention and containment of kicks. After a well kicks, it is too late to learn how to execute an engineered approach to kick control.

Kick Recognition

Early detection is necessary for successful control of a well kick. The severity of the kick depends not only on the differential between drilling fluid hydrostatic and formation pressures, but on the kick volume as well. Early detection and prompt well closure is usually the responsibility of the rig crew.

To help the rig crew recognize kicks and execute proper control procedures, pit drills should be conducted on a routine basis. Pit drills can be initiated by a company man or rig tool pusher manually activating pit level or flow indicators, and observing the reaction time of the driller and crew. Drills conducted while drilling should include raising the kelly and stopping the pump to check for flow. The Blowout Preventers are normally not closed unless an actual flow exists. Drills while tripping may include installing a safety valve in the drillstring if the pipe is inside casing. If drills are conducted on a routine basis as part of company policy, the rig crew becomes conditioned to execute proper control measures in a minimum amount of time.

Kicks While Drilling

A kick occurs while drilling when the pressures of the formation drilled exceed the total pressures of the circulating fluid column (hydrostatic pressure plus annular pressure loss, i.e., $P_{ECD} < P_f$). Some occurrences that may be associated with a kick are,

- drilling break
- increase in flow rate
- increase in pit volume
- circulating pressure drop
- well flowing with pumps off
- increase in chloride content of fluid at the flow line
- gas cut fluid or increasing gas concentration in the fluid.

Drilling break – This is one of the first indications of a kick. For hydrocarbons or water to enter the wellbore, there must be a permeable section containing a pressure greater than that exerted by the fluid column. In soft sandstones, this condition usually causes a sudden increase in drilling rate. The magnitude of the increase varies, but an increase of 200% to 300% is not unusual in soft sediments. Any significant drilling break should be checked for flow. This is done by stopping the pump and checking the flowline to see that flow stops. If the well continues to flow, it should be shut-in and checked for pressures.

In hard formations, a reverse break to a slower drilling rate may indicate a sand or limestone section. In this case, the increase in drilling rate with flow into the wellbore is masked by harder formations. However, a reverse break can also be the first indication of an over-pressured formation.

Flow rate increase – The entrance of any fluid into the wellbore will cause the flow rate to increase. This occurs shortly after, or concurrently with, the drilling rate increase. Since the intruding fluid is almost always lighter than the drilling fluid, a continued flow from the reservoir tends to lighten the fluid column causing further increase in flow. The most common flow sensor, a paddle in the flow line, allows measurement of flow increases if the flowline is not full. A full or almost full flowline restricts paddle movement making it difficult to show an increase in flow.

Pit volume increase – An increase in pit volume occurs as the result of two separate processes. First, the increased flow rate increases fluid volume in the pits. In addition, if the kick contains gas, gas expansion causes a further increase in flow rate and pit volume. Pit volume totalizers used on the rig can be adjusted to read increases accurately, but pit levels should be monitored visually as a back-up. The surface area of a standard fluid tank on a land rig is approximately 8 ft by 30 ft, or 240 ft^2. This is close to 3½ barrels of fluid per inch of depth. With a normal set of three fluid pits, a one inch change would represent a 10.7 barrel volume change.

Circulating pressure decrease – Because of the imbalance between the hydrostatic column in the drillpipe and annulus after penetrating an abnormal zone, it may take less pump pressure to circulate the fluid. Flow rate increase and pit volume increase would normally be observed before a circulating pressure decrease.

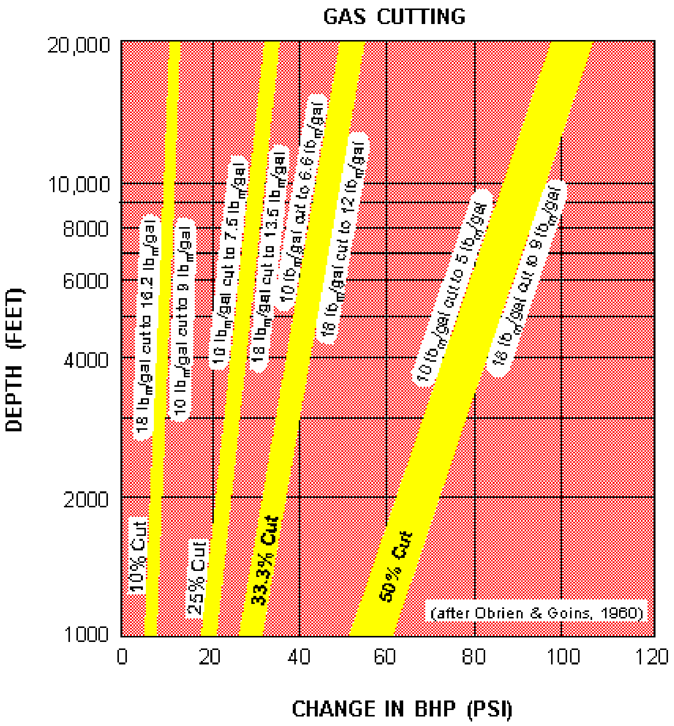
Well flows with the pump off – This indicates that reservoir fluid is flowing into the wellbore.

Chlorides increase – Formation fluids may have higher chloride contents than the make-up water being used in the fluid system. Fluid systems with chlorides above 100,000 mg/L may not show any change when formation fluids enter the fluid system.

Gas cutting – Changes in trends of trip gas, connection gas, and background gas can be a valid tool for detecting formation pressure changes. If gas cutting occurs, the source of the gas must be determined. Drilling should be halted and the hole circulated for a sufficient time to remove the cuttings from the hole. If the gas originates from cuttings, the value will decrease to a normal level after the hole is circulated clean. If gas cutting persists, it may indicate an underbalance. The slip velocity of cuttings can be quite high in low-density, low-viscosity fluids, and the time required to clean the hole may be considerably greater than calculated circulating time. It should also be borne in mind that when formations containing gas are drilled, some gas will always show up at the surface. There is no way to prevent this from happening, regardless of fluid weight. Normal levels of background gas will vary from one area to another.

The degree to which gas cutting affects hydrostatic pressure is an often misunderstood factor. Gas cutting causes only very slight reductions in hydrostatic pressure. Normally, gas cutting of 50% on the surface does not significantly reduce bottom-hole pressures (BHP), since it is less than the normal increases due to annular pressure loss.

Referring to Figure 12-7, if an 18 lb_m/gal drilling fluid is cut to 9.1 lb_m/gal at the shaker, and if the gas is evenly distributed from top to bottom of the hole, the reduction in BHP at 10,000 ft is only 95 psi, equivalent to reducing the fluid weight by 0.2 lb_m/gal.



(after Obrien & Goins, 1960)

Figure 12 - 7 Reduction in BHP Corresponding to a Surface-Observed Reduction in Fluid Weight Due to Gas Cut Fluid

If no flow occurs when the pump is shut down, hydrostatic pressure and fluid weight are sufficient. There could be a slug of gas in the annulus that could later cause trouble and caution is indicated, but gas cutting by itself is not serious. A very small amount of gas at bottom hole conditions can gas cut a large amount of fluid at surface conditions. Drilling a porous sand, a bridged hole with trapped gas or circulation of bottoms-up after a trip will often produce these results.

Kicks While Tripping Out of the Hole

It has been estimated that 50% or more of all kicks occur while tripping. The main reasons for these kicks are generally poor practices and neglect on the part of rig crews. Two major incidents cause kicks while tripping out of the hole.

1. Failure to fill the hole often enough or failure to add fluid to the hole equivalent to the displacement of pipe removed. Depending on the displacement of the pipe withdrawn, there will be a corresponding drop in fluid level (assuming no swabbing has occurred) which may lower the hydrostatic pressure enough to allow the well to kick.

   For example, five stands of 4½ in. drillpipe (16.6 lb_m/ft 93 ft stands) withdrawn from an 8½ in. hole would result in a fluid level drop of 45½ ft. Whereas, five stands of 6¾ in. × 2¾ in. drill collars (93 ft stands) would result in a fluid level drop of 263½ ft.

   Frequency for filling the hole is a function of fluid gradient, hole diameter, pipe displacement, and formation pressure.

2. Another problem associated with tripping is swabbing. Swabbing is compounded by bit or collar balling, the viscous drag of fluid on the pipe, and the speed at which the pipe is pulled from the hole. Swabbed pressure reductions due to viscous drag can be calculated using ADVANTAGE engineering software. Swab pressures should be controlled by observing safe drilling practices. If swabbing problems are anticipated, a maximum “safe” tripping speed should be calculated and adhered to by the rig crew.

To detect kicks while tripping, an accurate measurement of the volume of fluid required to keep the hole full must be made. This is best accomplished using a calibrated tank called a *trip tank*. If the volume of fluid required to fill the hole is less than the displacement of the pipe withdrawn from the hole, a kick is indicated and remedial steps should be taken.

Kicks While Tripping Into the Hole

When drilling with fluid gradients near the fracture gradient of exposed formations, surge pressures caused by viscous drag of the fluid on the drillstring may result in lost circulation. If lost circulation occurs, the decrease in pressure depends on how far the fluid level falls. If the fluid level falls enough, the corresponding decrease in hydrostatic pressure may be sufficient to allow formation fluids to enter the wellbore and cause a kick. A practical approach to recognizing this problem is to observe pit level increase versus amount of drillpipe run into the hole, and to observe the flowline on each stand run to insure that fluid returns are maintained.

Behavior of Gas in the Wellbore

To properly understand the problems of killing a kick, it is necessary to understand some of the things that can and cannot be done successfully. Gas expansion and the gas laws are basic concepts that should be understood to help prevent problems in controlling kicks.

The simple form of the general gas law states that gas expands as pressure on the gas is reduced or that if gas is not allowed to expand, the pressure in the gas remains the same. This statement is modified by the effect of the temperature and the type of gas, so that mathematically the general gas law is,

$$\frac{P_1 V_1}{T_1 Z_1} = \frac{P_2 V_2}{T_2 Z_2}$$

where,

P = gas pressure

V = gas volume

T = temperature

Z = compressibility factor

1 = the first set of conditions (bottom-hole conditions)

2 = the second set of conditions (up-hole conditions).

Rise of Gas without Expansion

A practical application of the gas laws can be illustrated by considering a 10,000 ft well with 10 lb_m/gal fluid and 1 bbl of gas that has been swabbed in on a connection. The well was shut-in and the gas bubble circulated to the surface by holding the pit volume constant (preventing the gas from expanding). For this example, the effect of temperature and compressibility is ignored.

The bottom-hole pressure in the well is 5200 psi, and the gas volume is one bbl. If the gas is circulated half way up the hole, there will be 2600 psi of fluid pressure above the gas bubble, but the pressure in the gas bubble will still be 5200 psi according to the general gas law.

The surface annular pressure will be 2600 psi, which is the difference between the pressure in the gas bubble and the fluid pressure above it. The bottom-hole pressure will be the pressure of the fluid column, 5200 psi, plus the surface annular pressure, 2600 psi, for a total of 7800 psi. The surface pressure and the wellbore pressure will continue to increase as the bubble is moved up the hole without being allowed to expand. When it reaches the surface, the surface pressure will be 5200 psi and the bottom-hole pressure 10,400 psi, or the equivalent of 20 lb_m/gal fluid. Long before the bubble gets to the surface, fracture pressures will be exceeded and an underground blowout will occur.

In earlier years, this technique of Constant Pit Volume, or Barrel-In/Barrel-Out, was used to kill wells. Although this method works for water flows, it almost always results in lost circulation and an underground blowout when the formation fluid contains gas.

Rise of Gas with Uncontrolled Expansion

The opposite extreme of circulating the gas out of a well without holding any pressure on it is equally bad. In the same circumstances, one bbl of gas is swabbed into the well, but the well is not closed in and the pump is turned ON to circulate the bubble out of the hole.

When the gas is half-way up the hole, it has expanded to 2 bbl. When the gas was at the bottom of the hole, the 1 bbl “column” of gas was only about 12½ ft long. Halfway up the hole, it is 25 ft long and three quarters the way up the hole, the gas has expanded to 32 bbl and occupies about 400 ft of annulus. The 400 ft of gas has reduced the bottom-hole pressure by about 200 psi and more gas is probably entering the wellbore.

Circulating a gas bubble up without holding some surface pressure will unload the hole and cause a blowout. The technique of trying to “out run” a well kick is risky because the bet is that the formation has such low permeability that the well could hardly blow out. Trying to outrun a well kick works occasionally because the kick may be water and, because the pumping rate is increased, the bottom-hole pressure is increased by the amount of the annulus friction loss. It still remains a risky endeavor and leads to more failures than successes.

Rise of Gas with Controlled Expansion

The proper way to handle a gas bubble in a well is to put enough pressure on the gas to keep the bottom-hole pressure constant. This is the basic idea behind proper well control techniques.

Using the previous illustration, one bbl of gas has been swabbed into the hole but allowed to expand in a controlled manor by using an adjustable choke at the surface. When the gas bubble is half-way up the hole, the casing pressure would have to be 14 psi to keep the bottom-hole pressure constant. When the gas is at 2500 ft, the casing pressure would have to be about 28 psi (Figure 12-8). At 1200 ft, the casing pressure would have to be about 57 psi.

This type of calculation can be difficult, time consuming, and will never be very accurate because the type of gas, its solubility, and the actual configuration of the gas “bubble” is unknown. The drillpipe pressure techniques described later do away with having to make this type of calculation.

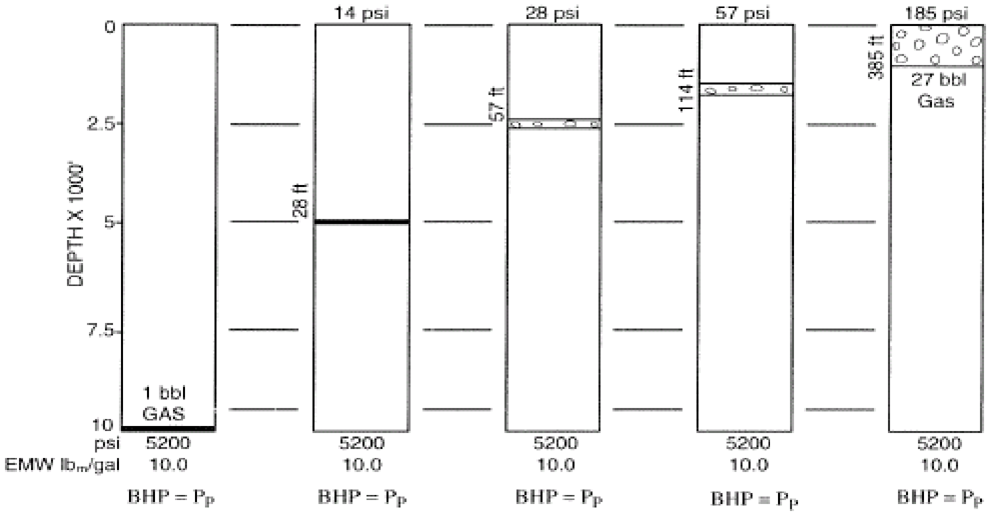


Figure 12 - 8 Rise of One Barrel of Gas With Controlled Expansion

Shut-In Drillpipe and Casing Pressures

Drillpipe and casing pressures are used in well control to determine working pressures. The drillpipe pressure gauge or pump pressure gauge is in reality a bottom-hole pressure gauge. After a well kick, when the pump is off and the well is shut-in, the drillpipe is a long gauge stem that reaches to the bottom of the hole. The drillpipe pressure gauge reads the bottom-hole pressure as seen from the gauge stem. If the drillpipe were empty, the surface gauge would read bottom-hole pressure. But the drillpipe is not empty, so the gauge reading shows the difference between bottom-hole pressure and the fluid column pressure in the drillpipe. So, shut-in drillpipe pressure is the difference between the pressure exerted by the fluid column in the drillpipe and the bottom-hole pressure. It is the kick pressure.

Casing pressure will normally always be higher than drillpipe pressure because the kick gas or water will normally be lighter than the fluid. This makes the fluid column pressure in the annulus less than the full column of fluid in the drillpipe. So, the annulus surface pressure will be higher than the drillpipe pressure.

To determine the fluid weight needed to control a kick, the formation pressure must be known. This may be obtained from the pressure on the drillpipe. Since fluid inside the drillpipe will not be contaminated, the pressure on the drillpipe plus the hydrostatic pressure of the fluid column equals formation pressure. Shut-in drillpipe pressure can be determined by:

- Reading directly from a gauge at the surface. If there is a back pressure valve in string then,
- Start pump slowly, continue until fluid moves or pump pressure increases suddenly.

- Watch annulus pressure, stop pump when annulus pressure starts to increase.
- Read drillpipe pressure at this point.
- If annulus pressure increased above original pressure, this would indicate trapped pump pressure and the amount of increase must be subtracted from the shut-in drillpipe pressure.

  This procedure should be repeated until the same value is read two consecutive times.

  or

- If a predetermined circulating pressure has been measured at a circulation rate which will be used to kill the well then,
- Open choke and start pump slowly, holding annulus pressure at same level as shut-in annulus pressure.
- Bring pump speed up to predetermined kill rate, keeping annulus pressure constant.
- Read pump pressure; subtract predetermined circulating pressure from pumping pressure. The remainder will be shut-in drillpipe pressure.

Fluid Weights and Pressures

Drillpipe pressure (or casing pressure) can be converted to Equivalent Fluid (Mud) Weight (EMW) and vice versa. In the following discussion on fluid weight increase, the equation used to convert pressure to fluid weight (lb_m/gal) is,

$$Fluid\,Weight\;Increase, lb_m\;/\;gal = \frac{SIDP}{0.052 \times (TVD)}$$

Where:

$SIDP$ = 260 psi,

TVD = 10,000 ft,

Fluid weight = 12.0 lb_m/gal.

$$Fluid\;weight\;increases, lb_m\;/\;gal = \frac{260\;psi}{0.052 \times 10{,}000\;ft} = 0.5\,lb_m\;/\;gal$$

This is the fluid weight increase needed to balance formation pressure.

Therefore,

Initial fluid weight	12.0 lb_m/gal
Required weight increase	+ 0.5 lb_m/gal
Total	12.5 lb_m/gal

When pressure is held on the circulating system with an adjustable choke, the additional pressure is felt throughout the system, including at the bottom of the hole and at the drillpipe pressure gauge. As fluid weight is increased to kill a kick, the pressure held by the choke is replaced by hydrostatic pressure from the heavier fluid. Thus, the choke is adjusted as heavier fluid is pumped into the well. See Figure 12-9. This is further explained in the Wait and Weight Method of well control.

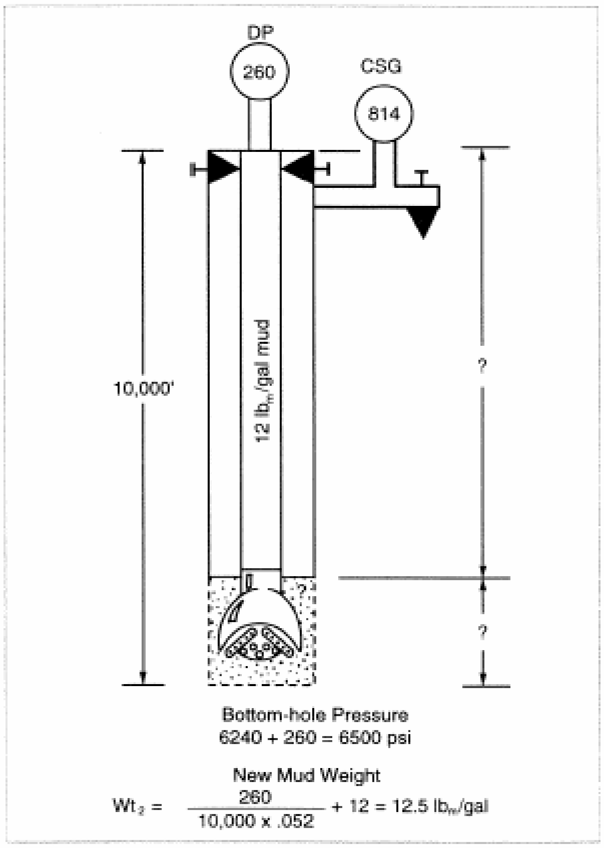


Figure 12 - 9 Kill Fluid Weight

Equivalent Circulating Density

It has been mentioned previously, that when the mud pump is running, the bottom-hole pressure is increased by the annulus friction loss. When the fluid is moving up the hole, the friction of the fluid against the drillpipe, the wellbore sides, and the fluid viscosity all combine to create a friction pressure that resists flow. The annular pressure loss is that part of the pump pressure that it takes to pump the fluid in the annulus. This pressure value reacts against the bottom of the hole and increases bottom-hole pressure. The actual fluid weight, plus the increase in bottom-hole pressure due to the annulus friction loss, can be expressed as an equivalent fluid weight and is referred to as *Equivalent Circulating Density* (ECD).

$$ECD, lb_m / gal = Fluid\,Weight + \frac{Annular\ friction\,loss\,(psi)}{TVD \times 0.052}$$

ADVANTAGE engineering software contains a field proven ECD simulator. This simulator can be run in the HPHT mode where it uses Fann 70 / 75 data for downhole rheological properties and retort and PVT data to calculate downhole densities. This results in an extremely capable tool if the correct input data is used. For water based drilling fluids, as they are not so strongly influenced by temperature and pressure the normal Fann 35 data should be sufficient. The practice of using PV / YP for hydraulics calculations should be avoided.

The total pump pressure when circulating is the friction required to move the fluid through the drilling system. The bit nozzles can take 50% to 60% of the pressure drop with most of the rest being lost in the drillpipe. These pressures do not affect bottom-hole pressure because the pressure losses occur before the fluid enters the annulus.

The pressures in the circulating system, shown in Figure 12-10, can be divided as follows.

Surface system	(2)
Drillpipe	(3)
Drill collars	(4)
Bit jets	(5)
Annulus flow	(6)
Pump pressure (standpipe gauge)	(1) = The sum of the above

The annulus flow (6) puts pressure on the open hole. This is the annular pressure element in the ECD.

BHP = Hydrostatic pressure + Annular friction loss

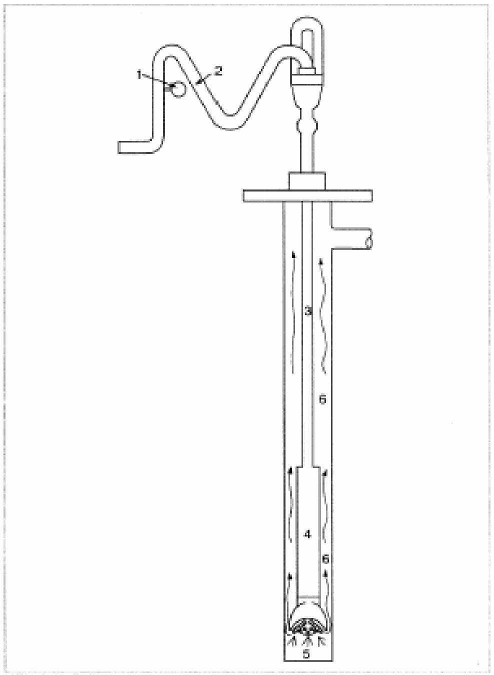


Figure 12 - 10 System Pressure Losses

U-Tube Concept

The interrelation of formation pressure and hydrostatic pressure is more easily understood if the well is thought of as being a large U-tube as shown in Figure12-11. The sum of the pressures on the drillpipe side of the U-tube must be equal to the sum of the pressures on the annulus side.

Sum of Pressure - Drillpipe Side

- Hydrostatic pressure = 5200 psi
- Shut-in drillpipe pressure (SIDP) = 0 psi
- Bottomhole pressure = 5200 psi + 0 psi = 5200 psi

Sum of Pressure - Casing Side

- Hydrostatic pressure = 5200 psi
- Shut-in casing pressure (SICP) = 0 psi
- Bottomhole pressure = 5200 psi + 0 psi = 5200 psi.

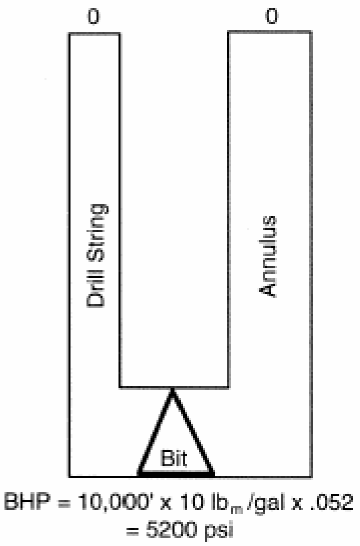


Figure 12 - 11 "U" Tube Static

With the pump off and hydrostatic pressure overbalancing formation pressure (0.052 x 10,000 ft x 10 lb_m/gal = 5200 psi) both gauges equal zero. When fluid column pressures on both sides of the U are equal to each other and equal to or greater than formation pressure, no formation fluid can enter the wellbore. Both sides of the U stand full of fluid with zero surface pressure.

The purpose of the well control system is to circulate heavy fluid into the hole. The method of circulation, then, is basic to the system of well control. It is not usually desirable to run the fluid pump at full speed while circulating out a kick because the pressures required would probably exceed the pressure limit of the pump. For this reason, a kick is usually circulated out at about half normal pump speed. The pressure required to circulate the fluid through the U-tube at some reduced pump rate is called the *Reduced Circulating Pressure* (RCP) (see Figure 12-12).

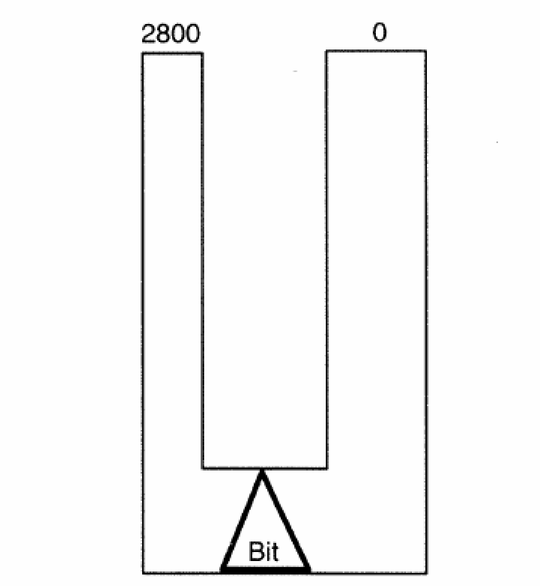


Figure 12 - 12 "U" Tube Circulating

Other names for RCP are,

- Slow Circulating Pressure
- Kill Rate Pressure
- Pre-Recorded Circulating Pressure.

This pump pressure should be obtained by circulating at a predetermined circulation rate. The corresponding pressure on the standpipe gauge is the RCP. This pressure should be recorded each hour or when significant fluid property changes are made. Higher fluid weights require higher pressures for any given circulation rate. The increase can be determined by a simple ratio,

$$P_2 = P_1\left(\frac{MW_2}{MW_1}\right)$$

where,

P_1 = old circulating pressure

P_2 = new circulating pressure

MW_1 = old fluid weight,

MW_2 = new fluid weight.

Note: *If pressure is held on the annulus, this pressure adds to the standpipe, and is also felt at the bottom of the hole.*

When bottomhole pressure becomes less than formation pressure, formation fluids can intrude into the wellbore as shown in Figure 12-13.

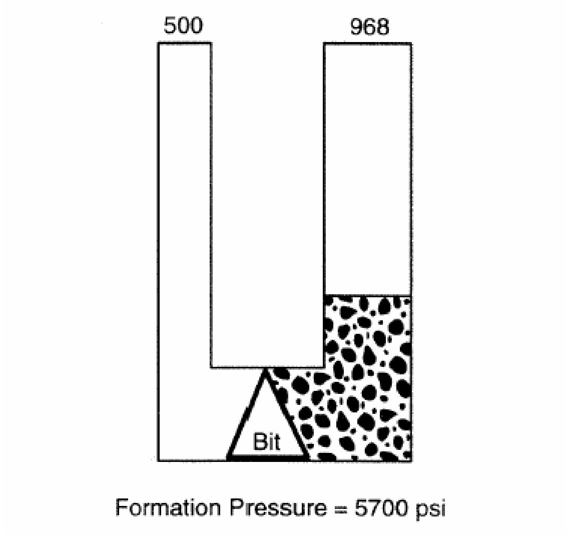


Figure 12 - 13 "U" Tube Shut In

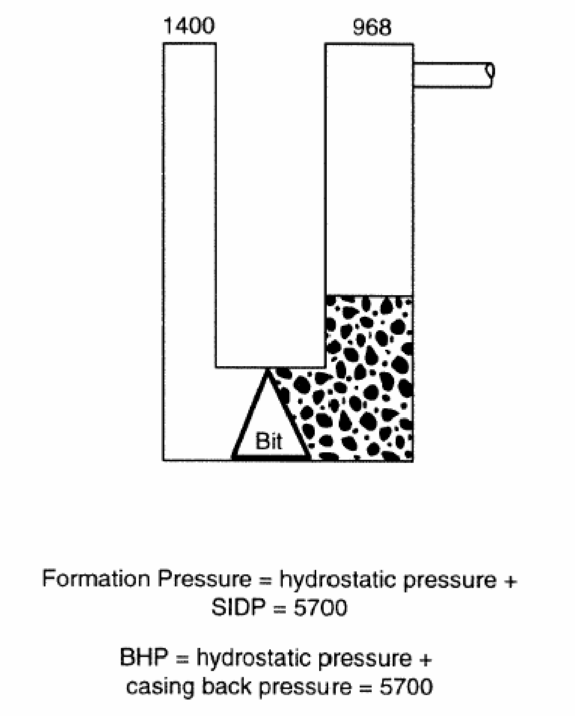
A gain in pit volume equal to the volume of intruding fluid will then occur. When the well is shut in, pressure on the drill pipe will be equal to the difference between formation pressure and hydrostatic fluid pressure. Since hydrostatic pressure can be calculated from the known height and weight of the fluid column inside the effect represents a pressure gauge by which formation pressure can be determined.

Formation pressure = Hydrostatic pressure + SIDP

The following is a summary of the pressures in Figure 12-13.

Drillpipe Pressures
Formation pressure @ 10,000 ft - Hydrostatic Pressure @ 10 lb_m/gal fluid = Drillpipe psi 5700 psi - 5200 psi = 500 psi
Annulus Pressures = Hydrostatic Pressure
1000 ft × 0.052 × 1.0 lb_m/gal = 52 psi (1000 ft gas)
9000 ft × 0.052 × 10.0 lb_m/gal = 4680 psi (9000 ft fluid)
Total Hydrostatic Pressure
52 psi + 4680 psi = 4732 psi (column)
Casing Pressure
5700 psi (Formation pressure) - 4732 psi (Hydrostatic pressure) = 968 psi (Casing pressure)

When circulating out a kick at a reduced pump rate, it is necessary to hold pressure on the drillpipe gauge in addition to the reduced circulating pressure. This is accomplished by circulating through an adjustable *choke*. When beginning a kill operation, this additional pressure equals the SIDP (see Figure 12-14).



Formation Pressure = hydrostatic pressure + SIDP = 5700

BHP = hydrostatic pressure + casing back pressure = 5700

Figure 12 - 14 "U" Tube Circulating With Choke

Thus,

$ICP = RCP + SIDP$

where,

ICP = initial circulating pressure

RCP = reduced circulating pressure

SIDP = shut-in drillpipe pressure.

For our example,

RCP = 900 psi

SIDP = 500 psi

ICP = 900 + 500 = 1400 psi.

Closing Procedure

If any of the previously discussed warning signs are observed and a flow (with pump off) is detected, the following generalized procedures should be initiated.

Procedure for Closing Well In While on Bottom

1. Position kelly so that tool joints are clear of sealing elements.
2. Stop pumps, check for flow.

3. If flow is noted, open the HCR-valve and close the BOP with the annular preventer.
4. Record shut-in drillpipe and casing pressures.
5. Record volume gain and mark pits.
6. Weigh fluid in suction pits.
7. Check blowout preventer and manifold for leaks.
8. Check flowline and choke exhaust lines for flow.
9. Check accumulator pressure.
10. Initiate well kill procedures.

Procedure for Closing Well In While Tripping

1. If a flow is detected, install and close a safety valve.
2. Position tool joints and close annular preventer.
3. Install an inside preventer and open safety valve.
4. Record casing pressure.
5. Check blowout preventer stack and manifold for leaks. Check valves for correct position.
6. Check accumulator pressure.
7. Begin stripping to bottom.

It is always easier and requires less fluid density to kill a well with the bit at or near the bottom of the hole. If a well kicks while drilling, the pipe should not be pulled into the casing. If the kick is caught quickly enough, there is less danger of pipe sticking. If the pipe is off bottom (making a trip, etc.) at the time of the flow, the pipe should be returned to bottom, if at all possible. If necessary, it should be stripped in.

PRESSURE CONTROL METHODS

Pressure control is normally a field level activity. The methods of killing well kicks which are presented here have been developed for rig site personnel. The procedures for killing a threatened blowout must be kept simple, but not oversimplified to the extent of losing their effectiveness.

The three basic, most common well-control methods employ procedures to maintain a constant bottomhole pressure on the wellbore while formation fluids are circulated to the surface. This is accomplished by using an adjustable choke which can be opened or closed to control wellbore pressures. Three variations of the balanced bottom hole pressure are as follows:

- Building fluid density in the pits before circulating (Wait and Weight).
- Begin circulating out the bubble and weighting up simultaneously (Concurrent Method).
- Circulate well clean of formation fluids, shut pumps down and close well in. Then build fluid density in pits before circulating heavy fluid (Driller's Method).

Note: *When a kick cannot be circulated out, or there is no way to communicate with the bottomhole pressure, the only way to control bottomhole pressure is by use of the volumetric method.*

Of these three methods, the Wait and Weight Method is the most commonly used. It is discussed below and a sample problem with a completed kill sheet is included to illustrate the use of this technique.

The Wait and Weight Method of Well Control

The Wait and Weight Method of Well Control is the most satisfactory method of well control since it causes the lowest annular pressures and is the quickest way of reducing the pressures on the wellbore. It does require a period of shut-in time while the fluid weight is being increased, so there is some danger of the pipe becoming stuck.

If the rig does not have adequate fluid mixing equipment, one of the other constant bottomhole pressure methods may be more satisfactory. On most large rigs, marine rigs, and rigs with sub-sea stacks, the Wait and Weight Method is the preferred method.

In the Wait and Weight Method, the well is shut in until the fluid weight is increased in the pits and the well is killed according to a completed worksheet.

As an example, the well is shut in after a kick and the following information is recorded.

Shut-In Drillpipe Pressure (SIDP)	500 psi
Shut-In Casing Pressure (SICP)	650 psi
Pit Volume Increase	15 bbl
Depth	12,000 ft
Hole Size	8½ in.
Drillpipe	5 in., 19½ lb_m/ft IEU
Collars	210 ft, 7" × 3"
Casing	$9^5/_8$" @ 10,000 ft, 47 lb_m/ft N80
Pump	6 × 16 Duplex
Kill Rate	30 spm
Kill Rate Pressure	750 psi

The fluid weight increase is calculated and the fluid weight in the pits is increased. While the fluid weight in the pits is being increased a *Well Control Kill Sheet* is filled out. The information on the Kill Sheet is completed as follows:

- *Basic Data* – Record the basic data necessary to make the well kill calculations. Circulating pressures and pump outputs should be pre-recorded.

- *Record* – Pressures and pit level gains.

Calculate

Initial Circulating Pressure = Slow Circulating Pressure + SIDP

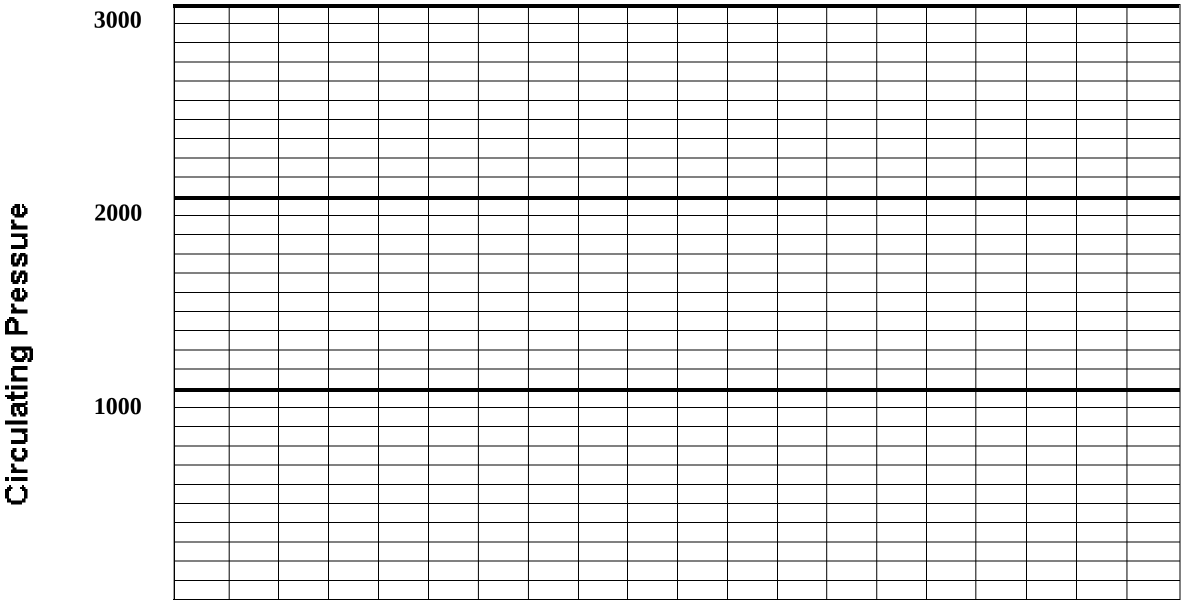
New Fluid Density = (SIDP) / (0.052) / (TVD) + Old Fluid Density

$$Final\,Circulating\ pressure = \frac{New\,Fluid\,Density}{Old\ Fluid\ Density \times Slow\,Circulating\ pressure}$$

Baker Hughes DRILLING FLUIDS Well Control Kill Sheet

BASIC DATA		RECORD	
a. True Vertical Depth (TVD)	ft	k. Shut-in Drillpipe Pressure (SIDP)	psi
b. Measured Depth (MD)	ft	l. Shut-in Casing Pressure (SICP)	psi
c. Fluid (Mud) Weight (M.W.)	ppg	m. Kick Volume	bbl
d. Drillpipe Volume	bbl	CALCULATE	
e. Riser Volume	bbl	n. Initial Circulating Pressure (ICP): SCP + SIDP = ICP: _________ + _________ = ________	
f. Pump Output	bbl/stk		
g. Drillpipe Strokes	stks	o. New Fluid (Mud) Weight: SIDP / .052 / Depth + Old M.W. = New M.W. _________ / .052 / _________ + _________ = _________ ppg	
h. Strokes to Displace Riser	stks		
i. Slow Circulating Pressures (SCP): Riser or Casing Pump #1: _________ psi @ _________ SPM Pump #2: _________ psi @ _________ SPM Choke Line (SUBSEA) Pump #1: _________ psi @ _________ SPM Pump #2: _________ psi @ _________ SPM		p. Final Circulating Pressure (FCP): New M.W. / Old M.W. × SCP = FCP _________ / _________ × _________ = _________ psi q. Maximum Allowable Casing Pressure: (Fracture M.W. Present M.W.) × Casing Depth × .052 (_________ _________) × _________ × .052 = _________psi	
j. Choke Line Friction (CLF): SCP Choke Line SCP Riser = CLF _________ _________ = _________			

GRAPHICAL ANALYSIS OF PUMPING SCHEDULE



Pump Strokes																			
Pressure																			
Fluid (Mud) Wt																			
Minutes																			

Graphical Analysis of Pumping Schedule – Divide the time (strokes) to displace the drillstring into even increments on the bottom of graph. Use 50, 100, or 200 stroke increments to utilize the maximum amount of graph. Plot initial circulating pressure at time or strokes 0. Plot final circulating pressure at time or strokes required to displace the drillpipe. Draw a straight line between the two points.

When ready to circulate, open the choke slightly until there is some flow through the choke and then start up the pump. Break circulation and bring the pump up to the predetermined kill rate. While the pump is being brought up to speed, hold the casing pressure at the shut-in value with the adjustable choke.

Note: *On rigs with subsea Blow-Out Preventer (BOP) stacks, the casing pressure is allowed to drop by the amount of the pressure loss in the choke line.*

When the pump is up to the kill rate, the drillpipe pressure should be adjusted to the initial circulating pressure by using the adjustable choke.

As the new fluid is being pumped down the drillpipe, reduce the drillpipe pressure according to the graph on the worksheet. The pump pressure will drop from the initial circulating pressure to the final circulating pressure over the time that the new fluid takes to fill the drillpipe (the surface to bit travel time). If there is gas in the kick, the annular pressure can be expected to rise and pit volume will increase as the gas comes to the surface.

When kill fluid is at the bit, the final circulating pressure should be maintained constant by keeping the pump strokes constant and adjusting the choke as required. Continue to circulate holding the final circulating pressure until the new fluid is circulated around. If calculations and procedures have been followed correctly, the well should be dead.

After the new fluid reaches the surface, the pumps should be shut down, and the well checked for flow. If no flow occurs, the well is dead. Depending upon the operating company, the well may be circulated for a time, a short trip may be made, drilling may commence, etc. If the well continues to flow, it should be shut in and kill procedures initiated again.

SPECIAL PROBLEMS

There are numerous well kill situations which develop that may require the use of special techniques to bring under control. These are typical problems that may develop.

- Nearing fracture gradient limitations
- Plugged bit
- Plugged choke
- Lost circulation
- Well flows while tripping or out of the hole, etc.

It is not the scope of this chapter to cover these problems. The operator's representative is normally responsible for handling these situations.

Barite Plugs

One special situation that will require the supervision of the drilling fluids engineer is the mixing of a barite plug. If during a well kick situation, the fracture gradient of the formation is exceeded, an underground flow will occur. This condition is signaled by a loss of gauge response and loss of returns. If the drill string is above both the loss zone and flowing zone, it should be stripped to bottom, if possible. If this is not practical, a lost circulation squeeze may plug the loss zone and allow circulation of fluid of required density.

If pipe is below fractured zones, it is sometimes possible to spot heavy fluid on bottom through drillpipe and pump light fluid down the annulus. In some instances, a balance point can be reached by this method and flow can be stopped. One method for killing underground blowouts is to bridge off the flowing zone with a barite plug.

Barite plugs seal the wellbore in four ways.

1. Due to low viscosities and yield points, barite may settle to form a solid plug in the hole.
2. Their high density increases the hydrostatic head on the active zone and helps prevent additional influx of formation fluid.
3. Due to their high fluid loss, they may dehydrate to form a solid plug of barite in the hole.
4. Their high fluid loss may also cause the hole to slough and bridge itself.

Procedure to Set Barite Plugs

The barite-water-phosphate slurry is usually mixed with the cementing equipment, pumped through the drillpipe and spotted on bottom. The bit jets do not have to be removed. Fresh water should be used, because barite does not settle as desired in sea water. Add SAPP to the mixing water before adding barite. This keeps the slurry thin to promote settling. The optimum amount of phosphate ranges from 0.2 to 0.7 lb_m/bbl in the mixing water. A one-quart fluid cup of powdered SAPP weighs 2.5 lb. Use CAUSTIC SODA with SAPP to adjust pH to 8 to 10 range (approximately 0.25 lb_m/bbl). If TSPP is used, CAUSTIC SODA is not required. In high temperatures, phosphates will not be effective and lignosulfonates can be used. Up to 6 lb_m/bbl may be required.

Slurry Density (lb_m/gal)	**Water (gal/bbl**	**Barite (sacks/bbl)**	**Slurry Volume/ Sack of Barite**	
			(bbl/sack)	**(ft^3/sack)**
18.0	26.9	5.30	0.189	1.060
19.0	25.3	5.94	0.168	0.945
20.0	23.7	6.43	0.156	0.873
21.0	22.2	6.95	0.144	0.807
22.0	20.6	7.50	0.133	0.748

Table 12 - 4 Barite Slurry Weight / Volume Relationship (Barite Specific Gravity = 4.2)

Follow these steps in mixing and placing a barite plug (see Table 12-4).

1. Choose a slurry weight between 18 and 22 lb_m/gal.

2. Determine how many feet of barite plug in the open hole are desired.
3. Calculate the bbl of slurry and sacks of barite required, and add an extra 10 bbl.
4. Mix the slurry and pump it into the drillpipe.
5. Displace the slurry so that the height of the barite plug in the drillpipe is 2 bbl higher than the top of the barite plug in the annulus.
6. Break connections and pull up immediately above the plug. If possible, circulate on top of the plug.
7. If possible, circulate for several hours.

Barite settling is inherently slow and often the results are unpredictable. Failure rates for barite plugs increase when hydrostatic kill conditions are not maintained.

Table 12-5 gives the materials and procedures necessary for mixing a barite plug for an *oil-base fluid*.

Materials	Quantities
Diesel Oil	24.6 gal
CARBO-MUL®	0.5 gal
OMNI-COTE®	0.5 gal
MIL-BAR®	576 lb

Table 12 - 5 Barite Plugs for Oil-Base Fluids (1 bbl of 18.0 lb_m/gal Slurry)

Procedure for Preparing Barite Plug for Oil-Base Fluid

1. Clear all lines that will be used to pump the plug of water or water wet materials. This may require flushing the lines with diesel oil.

2. To the appropriate amount of diesel oil, add the required CARBO-MUL® HT and OMNI-COTE® simultaneously and mix for 10 minutes.

3. Mix the required MIL-BAR® with the diesel/CARBO-MUL HT/ OMNI-COTE mixture and displace continuously into the hole with the pumping unit

Note: *Any base fluid may be substituted for the diesel oil, but the formulation must be adjusted to account for the base fluid density.*
Spot the diesel oil/barite plug in the same manner as a water-base plug.

Barite Plug Example

- Open hole = 8.5 in.
- Height of barite plug desired = 500 ft
- Weight of slurry desired = 18.0 lb_m/gal

$$\text{Volume of Barite Slurry} = \left(\frac{8.5^2}{1029.4}\right) x\ 500\ ft = 35\ bbl$$

Total Volume = (35 bbl + 10 bbl) = 45 bbl

- Materials to mix 45 bbl slurry

Water = 26.9 × 45 = 1121 gal = 29 bbl

SAPP = 0.5 × 29 = 14.5 lb

Caustic Soda = as needed

Barite = 5.3 × 45 = 239 sacks

Total Slurry Volume = 239 × 0.189 = 45 bbl

A non-settling barite plug using lignosulfonate as a thinner has been recommended by some. The materials required are listed below. One advantage of lignosulfonate is that it can be used in either fresh or sea water. It is recommended that the plug be non-settling and designed to provide a hydrostatic kill. The reasoning is that it is more reliable than a barite plug designed to settle. A settling plug can also be formulated if desired.

Field Mixing Procedure for Barite Plugs (Nonsettling)

(1 bbl of 21 lb_m/gal Density)

1. Prepare mix water equal to 54% of final volume.
2. Mix,

- Water (fresh or sea), 0.54 bbl
- Lignosulfonate, 15 lb
- Caustic Soda, 2 lb
- XANPLEX D, 1 lb
- Defoamer, if needed

For settling pill, omit XANPLEX D Polymer

3. Add barite to mix water to prepare the final slurry.

A 21 lb_m/gal slurry will require 700 lb of barite per finished bbl.

Gas Kicks in Invert Emulsion Fluids

Detection of gas kicks while drilling with an invert emulsion fluid is made more difficult because of the solubility of gas in oil. The amount of solubility is dependent on (1) composition of the formation gas, (2) composition of the oil used in the fluid, (3) pressure, and (4) temperature. Even a low volume influx that goes undetected will rapidly expand when it reaches the surface and cause unloading of fluid from the hole. This reduces bottomhole pressure, allows additional gas influx, and an uncontrolled situation (blowout) can develop. The key to well control in oil fluids is quick detection and proper shut-in procedures.

The problem lies in that the normal surface responses to gas kicks in oil fluids are dampened because of the solubility of the gas in the oil. The rig crews must be aware of the differences in responses to gas kicks in oil fluids and be prepared to detect small changes in pit levels, flow rates, and flow checks. The behavior of each kick detection parameter and how it is affected by gas kicks in oil fluids are discussed separately.

Pit Volumes

When a fluid enters the wellbore, the addition of this volume is observed at the surface. Because instruments and techniques used to detect these increases have a limited amount of sensitivity, it may take 10 or more bbl of formation fluid to be noticed at the surface. With gas in water-base fluids, this happens fairly quickly after influx because the gas begins to migrate since it is insoluble. In oil-base fluids, the gas is soluble and, therefore, will mix in and migrate very little until almost to the surface. In oil-base fluids, it is important to be able to detect very small pit gains quickly. This may require some modifications of pit level measurement techniques.

Flow Rate Increases

Flow rate increases in oil-base fluids are much smaller than in water-base fluids for the same reasons as cited earlier. In some cases, they have been about one-half as much. These smaller changes may go undetected by the rig crew or “flow shows”. Special care needs to be taken when fluid additions are made to the active system to insure all volume changes are accounted for.

Flow Checks

Stopping the pumps and checking for flow shortly after taking a kick may not give a definite indication that a kick has occurred. Even in water-base fluids, gas migration and expansion will not be occurring immediately. A shutdown period as long as 10 minutes may be necessary before flow can be detected.

Shut-In Pressures

Due to the compressibility of the gas and oil in the fluid, it may take longer for pressures to stabilize. Normally, a 30- to 60-minute period is recommended after shutting the well in to allow pressures to stabilize in water-base fluids. In an oil fluid, this may take 1.5 to 2 times longer.

In conclusion, the ability of the rig crew to adjust to the differences of gas kicks in oil fluids will determine how successfully the kick is controlled. The entire crew needs to be trained concerning these differences and how they are to be handled.

Subsea Well Control

Drilling from floaters and semi-submersible rigs has always provided challenges in well control situations, but drilling in water depths of 7000 ft and deeper has accentuated those problems. A brief discussion of the main well control problems that may occur in deep water drilling follows.

Low Formation Fracture Gradients

Fracture gradients decrease as the water depth increases. This is a function of the reduction in overburden pressure because the sediments are replaced by water. As a comparison, the calculated fracture gradient at 3000 ft on land in the Gulf Coast is 13.6 lb_m/gal in normally pressured formations. At the same depth in 1000 ft of water the fracture gradient is 11.3 lb_m/gal. This lower fracture gradient requires more casing strings to be run offshore and closer attention to maximum allowable casing pressures.

Shallow Gas

The presence of shallow gas pockets in offshore sediments poses special problems to the drilling operations. As discussed earlier, seismic methods are being used to detect these zones. If shallow gas zones are detected in the area to be drilled, one method of dealing with the problem is to drill small diameter pilot holes into the sands. The sands are penetrated and the gas depleted from the zone through use of diverters at the surface.

If the shallow gas is not detected, it is essential that proper methods of diverting the gas at the surface be available. Quick action is necessary to prevent the hole from being completely unloaded of fluid. Another method used to handle shallow gas is to divert the flow to the sea floor. Before this is done, careful analysis of the prevailing currents and winds in the area must be conducted.

Kick Detection

The movement of the rig and large volumes of fluid in the riser causes kick detection to be more difficult on floaters. It is important that the rig crew pay close attention to all abnormal pressure and kick indicators, regardless of how small the change.

New developments in measurement-while-drilling (MWD) technology are aimed at detection of gas influxes on a real-time basis. Currently, the information obtained from MWD tools (resistivity and gamma ray data) lags behind the bit depth by the distance the tool is above the bit, usually about 30 ft.

A technique has been developed which involves measuring the annular acoustic responses of the MWD tool. A pressure transducer is installed on the bell nipple and continually monitors the amplitude and character of the MWD pulses as they travel through the fluid. If gas from the formation enters the wellbore, the physical properties of the fluid are altered, thereby changing the way the acoustic signals travel through the fluid. If these changes can be measured and detected at the surface, this would mean earlier detection of gas influxes.

Choke Line Friction

The riser choke lines, manifolding, stack port, and expansion lines all exert a pressure loss on the well that varies according to choke line size and increases with water depth. The riser choke line pressure loss is found by comparing the pressure loss while circulating through the riser with the pressure loss while circulating through the kill line. The total back pressure on the annulus when circulating through the choke line equals the casing pressure gauge reading plus the choke line pressure loss. At the end of the kill procedure, additional pressure equal to the total choke line friction will be imposed against the annulus. In situations where fracture gradients are low, it may be necessary to take special precautions to avoid breaking down a formation.

Riser Collapse / Displacement / Trapped Gas

After formation gas has been circulated from the wellbore through the choke lines and the well is dead, a small volume of gas can be trapped in the sub-sea BOP between the choke line and uppermost closed BOP. If this trapped gas is not removed before opening the stack, its expansion can deplete the riser of fluid and cause another kick, collapse of the riser, or both. It is critical that before the BOPs are opened, (1) the riser has been displaced with kill fluid and (2) trapped gas has been removed from the BOP stack. A technique that has been proven successful is discussed by Shaunessy, et al.

Gas Hydrates

Gas hydrates are an ice-like mixture of natural gas and water. Their formation is a function of pressure and temperature. At low temperatures (30°F to 40°F), hydrate formation can occur at low pressures (40 to 400 psi). In the deepwater depths being drilled in the Gulf Coast, temperatures at the sea floor can be as low as 40°F. There have been several instances while killing kicks where the formation of gas hydrates has plugged choke lines and BOP stacks, making well control difficult or impossible.

The suppression of hydrate formation can be accomplished by increasing the chloride concentration of the drilling fluid. Fluid systems with chlorides in the 150,000 mg/L ($\approx$ 21% by wt.) range will suppress hydrate formation by 26°F. These fluid systems have been used to prevent the formation of gas hydrates. A discussion of the components of these systems can be found in Chapter 1, **Fundamentals of Drilling Fluids**.

Other potential hydrate suppressors are methanol, glycol, and oil. Problems with the use of these additives relate to their toxicity levels and their use may be prohibitive because of handling and disposal requirements. Another option is to insulate and heat the subsea well control equipment but, at present, the technology to do this has not been developed.

Commonly Used Equations in Pressure Control

Hydrostatic Pressure (psi)

$$\text{Hydrostatic Pressure} = 0.052 \times MW_1 \times TVD$$

Pressure Gradient (psi/ft)

$$\text{Pressure Gradient} = MW_1 \times 0.052$$

Pressure Expressed as Equivalent Fluid (Mud) Weight (EMW)

$$EMW = \frac{P_s}{0.052 \times TVD} + MW_1$$

Fluid (Mud) Weight to Balance a Kick

$$MW_2 = MW_1 + \frac{SIDP}{0.052 \times TVD}$$

Determination of the Nature of Invading Fluids

$$W_1 = MW_1 - \frac{SICP - SIDP}{0.052 \times L}$$

Maximum Casing Pressure Resulting from a Gas Kick *

$$P_{csg}max = 200\sqrt{\frac{(P)(V)(MW_2)}{C}}$$

Maximum Volume Increase while Circulating Out a Kick *

$$V_{gain}max = 4\sqrt{\frac{(P)(V)(C)}{MW_2}}$$

* Even with the solubility of gas in oil, these formulas will hold true in oil-base fluids.

Formation Pressure or Bottomhole Pressure

$$BHP = (MW_1 \text{ x } 0.052 \text{ x } TVD) + SIDP$$

Maximum Initial Shut-In Casing Pressure which will Exceed Fracture Gradient

$$SICP_{max} = (F_{mw} - MW_1) \text{ x } 0.052 \text{ x } TVD_s$$

MIL-BAR® Required to Weight up 1 bbl of Fluid **

$$\text{Sacks of MIL-BAR to weight up 1 bbl of fluid} = \frac{14.7\,(MW_2 - MW_1)}{35.0 - MW_2}$$

** Specific Gravity of Barite = 4.2

NOMENCLATURE

psi/ft	Pressure gradient of a column of fluid	units
MW_1	Initial fluid (mud) weight or fluid (mud) weight in hole	lb_m/gal
MW_2	Required or maximum anticipated fluid (mud) weight	lb_m/gal
EMW	Equivalent fluid (mud) weight	lb_m/gal
P_s	Surface pressure imposed on a fluid column	psi
F_{mw}	Fracture point (pressure integrity) of a formation	lb_m/gal
TVD	True vertical depth	feet
TVD_s	True vertical depth of casing shoe	feet
ICP	Initial circulating pressure	psi
FCP	Final circulating pressure	psi
SIDP	Shut-in drillpipe pressure	psi
SICP	Shut-in casing pressure	psi
W_1	Density of fluids invading wellbore	lb_m/gal
L	Length of the column of invading fluids in the annulus	feet
P	Formation pressure in thousands of psi (Example: 8000 would be expressed as 8.0 in the equation)	psi
V	Pit gain	bbl

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Chapter Thirteen

Deepwater Drilling Fluids

Chapter 13

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Chapter 13

DEEPWATER DRILLING FLUIDS

Deepwater drilling operations have grown to encompass large areas of the globe as oil companies search for and develop large hydrocarbon reserves. These are extremely high cost operations and offer considerable opportunities for drilling fluids to play a problem solving role.

INTRODUCTION

Deepwater drilling operations started as early as the 1960's. Activity steadily grew throughout the 70's and by the late 80's the activity, primarily in the Gulf of Mexico and Brazil, had stimulated the market to the point that both retro-fitting rigs and even some new-builds were commercially viable. Interest in deepwater continued to grow spurring worldwide activity in such areas as Trinidad, Australia, Indonesia, Malaysia, Brunei, the entire west coast of Africa, West of Shetlands, the far North Sea, Norway, Atlantic coast of Canada and Egypt. The area of greatest activity has traditionally been the Gulf of Mexico, though other areas have shown much promise for future growth.

Deepwater drilling operations face many challenges, many of them fluids related. Identification of the challenges and integrating the applicable deepwater fluid system must be thought out carefully. Deepwater wells present unique technical and operational challenges for drilling fluid systems, including:

- High daily operational costs
- Lost circulation
- Fluid selection and design
- Solids transport
- Wellbore stability, including low fracture gradients
- Shallow hazards
- Gas hydrates
- Salt
- Reservoir productivity
- Environmental compliance
- Large fluid volumes
- Low seabed temperatures
- Elevated bottom hole temperatures
- Annular pressure build-up
- Logistics

Shallow water flows, or pressurized gas zones, can present difficult technical challenges deserving special focus in the planning and execution phases of deepwater projects. These shallow hazards can cause such events as lost circulation, hole erosion, poor cement jobs, foundation instability, gas hydrates, casing buckling and in the worst cases, hole abandonment.

Shallow water flows can occur in zones 500 to 3,500 feet below the sea bed. Shallow gas sands are to be found at similar depths and require a sealing mechanism. Typically, wells are drilled riserless through these zones, using seawater and bentonite sweeps. Once a shallow hazard is detected there are two realistic alternatives: 1) spot a kill fluid and run casing or 2) drill ahead with a weighted fluid. Baker Hughes Drilling Fluids developed its Dynamic Kill Drilling (DKD™) methodology to facilitate drilling ahead with a weighted fluid to facilitate a "push" of the casing setting depth.

DKD DRILLING

The development of DKD began in 1999 as a tool to address shallow hazards. Since its inception, continuous and concurrent improvements have been made to all facets of the process. There are essentially four areas, within the DKD process on which to focus: 1) pre-planning software, 2) equipment, 3) training and 4) field service.

The DKD process employs a dual gradient concept, consisting of the seawater hydrostatic above the mud line and the ability to vary the hydrostatic below the mud line through drilling fluid density variations.

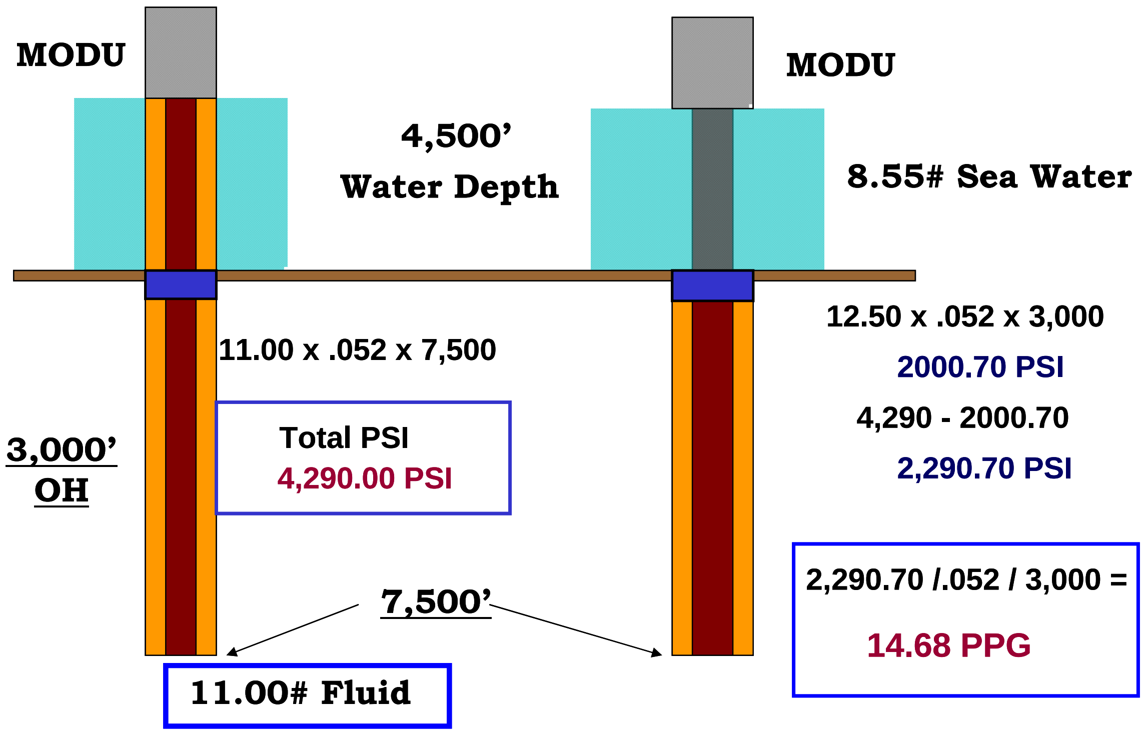


Figure 13 - 1 DKD Example

The above figure illustrates the dual gradient principle. As can be seen, the hydrostatic pressure on bottom is a combination of the seawater and drilling fluid columns.

The DKD process blends specially formulated 16.0 ppg drilling fluid with seawater or calcium chloride, or both components, to generate a fluid with a predetermined density and rheological properties. This procedure is executed using specialized proprietary equipment and techniques. Extensive pre-planning is required in order to determine the mud weight that will be used and the volume of fluid that is required. A rig survey is carried out to ensure that all the necessary components for a successful DKD process are present or identified for modification. Prior to execution of the job, the DKD unit, which consists of a shearing device and flow control equipment, is set up on-site. Once on the job, the unit has to be rigged up, and a diverse group of logistic issues must be immediately addressed in order for the procedure to be effective.

A detailed description of the entire DKD Process can be found in the DKD Best Practices Manual.

SELECTING DRILLING FLUIDS FOR DEEPWATER

Drilling fluid selection for deepwater drilling operations can be an extremely complex matter due to the many different considerations, including fluid compressibility/expansion as a function of wellbore temperatures, hydrate suppression, possible evaporate sequences, well path, environmental restrictions and perhaps most importantly, well costs. Deepwater technical challenges also include shale reactivity, formation damage and drilling and completing in unconsolidated sands. Environmental and safety issues are, as always, of paramount importance. Often, the most practical result of the fluid selection process is compromise.

In deepwater drilling, the use of a fluid that delivers all the well-specific performance issues is essential. Inhibitive fluids with low dilution and consumption rates are of considerable benefit in minimizing rig logistics, cost and maximizing fluid performance. Typical riser volumes may range from 1,000 to 3,000 bbl (160 to 500m^3) and circulating volumes from 2,500 to 5,000 bbl (400 to 800 m^3), depending on water depth, hole size and total depth of the well. As demonstrated by this example, large fluid volumes are normally associated with deepwater wells. This is the result of multiple casing string requirements and/or production requirements. Fluid volume needed to fill the riser and pits should not be confused with dilution volume. Fluid dilution requirements are the direct result of hole size (cuttings generated), Solids Removal Efficiency (SRE - cuttings removed) and the desired drilled solids content of the fluid. The fluid type can enhance SRE and certain fluid types can incorporate higher solids content without significantly degrading the fluid’s performance. Nevertheless solids removal equipment deserves a great deal of focus in the planning and execution of deepwater projects.

Solids removal efficiency is the vital factor in the control of low gravity solids (LGS) and minimizing dilution volume and associated costs. Optimum solids control equipment would include four linear motion shale shakers, ideally preceded by four scalping shakers. The deployment and use of centrifuges should be considered in association with the mud weight, type of fluid system and discharge requirements. A water base system may require one or more barite recovery centrifuges. A synthetic invert emulsion may have an external phase that has more economical value than other fluid components and therefore be most important to recover. Discharge of cuttings may require a host of equipment, including a dryer and centrifuge for LGS and oil separation. Each project should be evaluated on its economic merits. Whenever possible it is desirable to utilize a drilling fluid which is environmentally acceptable for cuttings discharge and exhibits the required fluid characteristics.

AQUEOUS VS NON-AQUEOUS DRILLING FLUIDS

The first fluids decision to make for a deepwater operation is whether the fluid is to be aqueous or non-aqueous. Both types of fluids have been used with a great deal of success in deepwater operations.

Table 13 - 1 Strengths and Weakness of Aqueous and Non-Aqueous Fluids

Non-Aqueous Strength / Aqueous Weakness	**Aqueous Strength / Non-Aqueous Weakness**
ROP	Lost circulation
Wellbore stability	Environmental characteristics
Gas hydrate suppression	Ballooning
Cuttings integrity => hole cleaning	Reservoir characterization
BHA – bit balling	Gas solubility / kick detection
Trip frequency	Cost/bbl
Temperature stability	Infrastructure requirements

The above table compares some of the weaknesses and strengths of aqueous and non-aqueous fluids. Each well must be looked at individually and the above components weighed to decide whether or not to use an aqueous fluid, e.g. if kick detection is of vital importance then an aqueous fluid is best as gas is not soluble in water and so gas kicks are more easily detected. During the decision phase one should also look at the weaknesses and their possible solutions.

Table 13 - 2 Investigative Solutions to the Weakness of Aqueous and Non-Aqueous Systems

Aqueous		Non-Aqueous	
Weakness	**Solution**	**Weakness**	**Solution**
ROP BHA / bit balling	Bit hydraulics Bit selection Additives Proven deepwater systems	Lost circulation	Permanent seal High Fluid Loss LCM's Cross link polymer
Wellbore stability	Inhibitive systems Proven deepwater systems	Environmental	Synthetic products Cuttings drying Skip & ship
Cuttings integrity => hole cleaning	Maximized hydraulics Riser booster	Ballooning	Hydraulics software Pressure tool
Gas hydrate suppression	Ethylene glycol Spotting procedures Salt	Reservoir characterization	"Tag" fluid
Trip frequency	Additives to enhance PDC bit performance Proven deepwater systems	Gas solubility	Kick detection procedures Knowledge of area
Temperature stability	Geothermal technology	Cost/bbl	Economic modeling Overall well cost
		Infrastructure requirements	Economic modeling Risk Analysis

As the industry has moved from drilling in 1,000' of water depth to greater than 10,000' of water depth, Baker Hughes Drilling Fluids has developed new systems and processes to meet the increasing challenges. Solutions developed include advanced systems and specialized fluid additives, new laboratory and field instrumentation, and a complete rigsite management program.

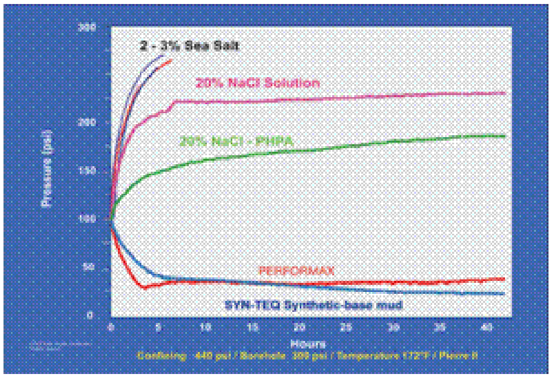
Changes in environmental regulations, coupled with more demanding well profiles, led to the widespread development of "Pseudo-Oil" muds. An understanding of kinematic viscosities and temperature effects on rheological properties led Baker Hughes Drilling Fluids to introduce a Synthetic Fluid, with an Isomerized Olefin (20) base, in 1994. This was the first deployment of an IO, which subsequently became the industry standard in the Gulf of Mexico.

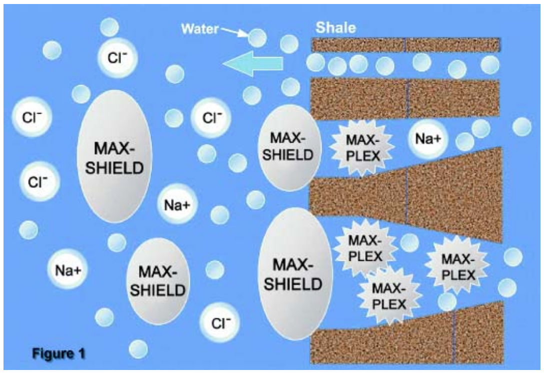
AQUEOUS SYSTEMS AND ADDITIVES

Baker Hughes Drilling Fluids is constantly striving to develop water based fluids capable of replacing invert emulsion fluids for application on deep water drilling operations. Recent developments include a calcium chloride based system, ***CLAY-TROL®****, a clay inhibitor additive and* ***PERFORMAX™****, a new high performance water based drilling fluid. Additionally, Baker Hughes Drilling Fluids is the leader in glycol technology, being the first to introduce a deepwater system in 1991 -* ***AQUA-DRILL*** *- based on cloud-point glycol technology. A short discussion on various aqueous systems and products which have proven suitable for deepwater operations follows. Further information on these products and systems is available elsewhere in this manual.*

AQUA-DRILL™ is a cloud-point glycol system which slows or prevents pore pressure transmission in its clouded state and enhances cuttings integrity while in solution. These characteristics are known to benefit wellbore stability and enhance SRE, major assets of a non-aqueous fluid. The ability to run salt **-** NaCl or KCl **-** in this system addresses both added inhibition and gas hydrate suppression needs.

PERFORMAX™ is Baker Hughes Drilling Fluids new 3rd generation high-performance water-base drilling fluid that is designed to emulate performance characteristics previously achieved only with emulsion based drilling fluids. These attributes include shale inhibition (reduced pore pressure transmission), cuttings integrity, high rates-of-penetration, and reduced torque and drag. Two features of **PERFORMAX™** that contribute to wellbore stability are: ultra-fine, deformable sealing polymer particles in **MAX-SHIELD™** (diameter: ~ 0.2 µm) mechanically seal shale micro-fractures, which physically block further intrusion of drilling fluid filtrate into the shale matrix; the resin and aluminum complexes in **MAX-PLEX™**, in combination with **MAX-SHIELD™**, can produce a semi-permeable membrane at the shale surface and chemically improve the osmotic efficiency, and reduce pressure transmission into shales. Pore pressure transmission tests clearly show that **MAX-SHIELD™** effectively works in combination with **MAX-PLEX™** to achieve pore pressure transmission characteristics previously achieved only with emulsion-based drilling fluids (oil-based or synthetic-based).





PERFORMAX™ System Limits	
Density	Tested to a maximum density of 16 lbm/gal (1.92 sg)
Temperature	Tested to a maximum temperature of 300°F (149° C)
Salinity	PERFORMAX™ fluids are compatible with sodium chloride concentrations up to saturation or potassium chloride up to 10% by weight. Sodium and Potassium Formate salts are also compatible.

Table 13 - 3 PERFORMAX System Limitations

PERFORMAX System Products and Function	
PRODUCT	FUNCTION
MAX-SHIELD™	Sealing polymer utilized to generate semi-permeable membrane for shale stabilization. Secondary function is as bridging material in pore throats of depleted sands to eliminate differential sticking and lost circulation.
Salinity	Enhance clay inhibition and general osmotic pressure.
MAX-PLEX™	Aluminum and resin complex that works in combination with MAX-SHIELD to generate semi-permeable membrane and improve well stability.

NEW-DRILL®	Cuttings encapsulation and improved cuttings integrity

Table 13 - 4 PERFORMAX™ System Products and Functions

Salt/polymer fluids have been used since the outset for deepwater applications. Baker Hughes Drilling Fluids dominated the Gulf of Mexico (GoM) deepwater market for many years with a 20% NaCl/PHPA system. These systems were traditionally utilized in the North Sea and Gulf of Mexico. The North Sea utilized a KCL component for added inhibition while the GoM, was restrained from using KCL due to environmental discharge regulations. Inherent to both systems was a level of gas hydrate suppression due to an elevated salt content. Glycols may be added to these systems to further improve hydrate suppression.

Silicate drilling fluid systems have a long history in the oilfield, first being introduced in the 1930's and known as "protective silicate muds". After some success at drilling heaving shales, they were abandoned due to problems of achieving stable rheological properties in conjunction with the introduction of natural organic dispersants. They were reintroduced in the 90's and again were mostly discontinued due to their tendency of polymerizing to form a silica gel, unacceptable lubricity and accretion. Silicates may have specialty applications in certain deepwater applications, for example to strengthen weak top hole formations such as oozes.

PENETREX® is a Rate-of-Penetration (ROP) enhancer and bit-balling prevention additive. It was introduced in 1997 to address ROP issues associated with water base mud and PDC bit applications. Outstanding results were obtained in a DEA-90 study performed on a full scale drilling simulator. The same results have been realized as **PENETREX ®** has been applied in field operations.

CLAY-TROL® was introduced in 1999 as a shale stabilizer to address hydration tendencies of young shale in the Gulf of Mexico. **CLAY-TROL®** has proven to be an excellent stabilizer and its amphoteric chemistry makes it a versatile product. It has been used successfully in several deepwater projects.

MAX-GUARD™ is the primary class hydration and swelling suppressant of the PERFORMAX™ system. Clay and gumbo inhibition is achieved by limiting water adsorption and providing improved cuttings integrity. MAX-GUARD effectively inhibits reactive clays and gumbo from hydrating and becoming plastic, which provides a secondary benefit of reducing the tendency for bit balling. MAX-GUARD can be readily added to the mud system without effecting viscosity or filtration properties.

NON-AQUEOUS SYSTEMS

Non-aqueous fluids are the fluids of choice for many operators for deepwater wells. As discussed previously, this brings with it a great deal of challenge. In order to meet these challenges Baker Hughes Drilling Fluids has developed a variety of non-aqueous fluids for deepwater operations.

*The **SYN-TEQ®** system was developed in response to environmental restrictions on the discharges associated with mineral oil based systems. **SYN-TEQ®** was developed using a low-viscosity, non-toxic, biodegradable, isomerized olefin- **ISO-TEQ®**- as the base fluid. Since then a variety of base fluids have been used in **SYN-TEQ®** formulations, including:*

- *Linear alpha olefin, **ALPHA-TEQ™***
- *Linear paraffin, **PARA-TEQ ™***

- ***CF-2002**, a base fluid designed to conform to the Gulf of Mexico discharge regulations that came into effect in 2002*
- ***PT-3500**, an iso-alkane paraffin*

***SYN-TEQ®** is an alternative to oil-based mud drilling fluids and is environmentally acceptable in many parts of the world. High lubricity, high resistance to contaminants such as carbon dioxide, and an ability to maintain a stable wellbore with no sloughing shales are key system attributes. The system is stable over a wide temperature range; 30°F–500°F (-1°C–260°C) and can be formulated with low synthetic-to-water ratios. Where oil-based mud performance is desired but environmental restrictions prevent its use, **SYN-TEQ®** is a viable alternative. Long-reach and highly deviated wells benefit from the system's high lubricity, effective in reducing torque and drag. A low leak-off, removable filter cake makes **SYN-TEQ®** an ideal fluid for coring operations and in poorly producing formations that cannot tolerate significant invasion damage.*

***NEXES™** is a "new generation" ester-based emulsion system. It is formulated to meet client expectations by providing superior drilling performance, and benchmark environmental compliance. The continuous phase, **NX-3500**, is a unique ester molecule specifically designed to address technical concerns that have long plagued other ester base fluids, namely (1) kinematic viscosity, (2) hydrolysis stability, and (3) elastomer compatibility. In addition to the base fluid, **NEXES™** employs other components chosen for their optimized performance. **NX-3500** is not a GoM compliant base fluid.*

***CARBO-DRILL®** is Baker Hughes Drilling Fluids' invert emulsion system in which the external phase is either diesel, mineral or enhanced mineral oil. This fluid has been used on several deepwater wells using low aromatic mineral oils as the base fluid. The system delivers optimized drilling performance, including excellent penetration rates, enhanced lubricity and superior wellbore stability. Discharge of cuttings generated using **CARBO-DRILL®** may be regulated by local environmental agencies.*

LOST CIRCULATION

INTRODUCTION

Lost circulation problems in deepwater are aggravated by low fracture gradients, tight casing/hole clearances, and drilling fluids made more dense and more viscous by low fluid temperatures. Lost circulation can be more dangerous in deepwater than in shallower water due to the potential for hydrate formation in the BOP from migrating gas. The risk of lost circulation can be reduced by the use of hydraulic simulators such as those in ADVANTAGE and PRESMOD. These tools can be used to establish guidelines for drilling and tripping.

Experience has shown that lost circulation is a greater problem with invert emulsion fluids than with water based fluids. The reasons are numerous and are stated below:

- Though water base and invert emulsion drilling fluids have similar fracture initiation pressures, invert emulsion systems have lower fracture propagation pressures. This means that once losses are initiated they are more difficult to cure with an invert emulsion system.
- Invert emulsion systems' densities and viscosities are increased to a greater degree by the colder temperatures at the seabed. These increases intensify surge pressures and can cause lost circulation.
- Invert emulsion systems are normally considerably more expensive in cost per barrel than water based fluids. Thus lost circulation is considerably more expensive and more noticeable.

- Logistics are normally more complex for invert emulsion fluids than for water based fluids. For invert emulsion the base fluid has to be transported by boat to the rig, often over considerable distances, whereas seawater can often be used as the base fluid in water based systems.

Successful management of lost circulation in deepwater operations should include identification of possible loss zones, optimization of drilling hydraulics, and a well thought out contingency plan for the handling of possible lost circulation.

Loss of circulation in a production zone offers additional challenges. Normally, only acid soluble materials should be added while the production zone is exposed. An engineering program is available to take much of the guess work out of this process. **Bridgewise**™ is the new bridging technology designed by Baker Hughes Drilling Fluids to maximize hydrocarbon recovery from reservoirs. **Bridgewise™** calculates the optimum blend of available calcium carbonate additives required to effectively bridge reservoir pore openings of known size. The **Bridgewise™** calculator is available on BakerHughesDirect/DRILLING FLUIDS/Toolbox/OnLine Tools and Resources.

WELLBORE BREATHING

Wellbore breathing refers to the situation where losses are experienced while drilling ahead and then fluid volume recovered when the pumps are turned off. This is often a problem in deepwater operations where the difference in fracture gradient and pore pressure in any given hole section may be relatively small. The magnitude of the losses and gains can vary from 25 to 250 barrels.

These loss and gain situations are caused by near-wellbore radial tensile and circumferential tensile failures. Fractures are initiated when the ECD exceeds the fracture initiation pressure. These fractures open and accept fluid. When the pumps are shut down, the fluid in the fractures returns to the wellbore. Typically, fluid is steadily lost during circulation/drilling and is regained when flow is static/during connections. Thermal stresses can also induce losses and gains in some cases.

Since loss and gain problems result from the initiation of fractures that do not continue to propagate, mitigation steps will be the same as for lost circulation in general. It is recommended to pre-treat the system with LCM if this sort of problem is expected. **LC-LUBE™** is an ideal material for this application as it is an effective LCM while neither detrimentally effecting viscosity nor filtration control. It exhibits excellent sealing and bridging properties due to the deformable nature of the material when particles are packed together under compression. It is able to effectively strengthen fractured and porous formations by plugging fracture/pore throats and prevention of fracture propagation and pore pressure penetration.DEA studies showed calcium carbonate to be an effective lost circulation material. **LC-LUBE** and calcium carbonate, together with **CHEK-LOSS FINE**, or **CHEK-LOSS PLUS** are the recommended materials for pre-treatment of the drilling fluid. The recommended concentrations are 5 – 10 ppb **LC-LUBE**, 10 – 15 ppb calcium carbonate and 5 ppb **CHEK-LOSS FINE**, giving a total LCM concentration of 20 – 25 ppb.

HYDRATES

INTRODUCTION

Gas hydrates are crystalline solids formed by low molecular weight hydrocarbon gas molecules combined with water. The interaction between the water and the gas is physical in nature and is not a chemical bond. They are formed and remain stable over a limited range of temperatures and pressures and exist in a number of structure types depending upon the gas composition.

Gas hydrate concerns cover two distinctly different situations, i.e. naturally occurring gas hydrates and the formation of gas hydrates in drilling fluids. The formation of hydrates in drilling fluids during a shut-in is the most likely hydrate-associated hazard in deepwater drilling.

GAS HYDRATES

A number of unusual problems encountered during drilling for hydrocarbons in deep, cold marine environments have been attributed to gas hydrates. Gas hydrates are small molecules formed when water and the components of natural gas combine thermodynamically to form crystalline, clathrate compounds. A total of seven different structures have been postulated. However, to date only three different structures have been seen (Structure I, Structure II, Structure H) when hydrocarbons combine. The basic unit of each structure is the pentagonal dodecahedron.

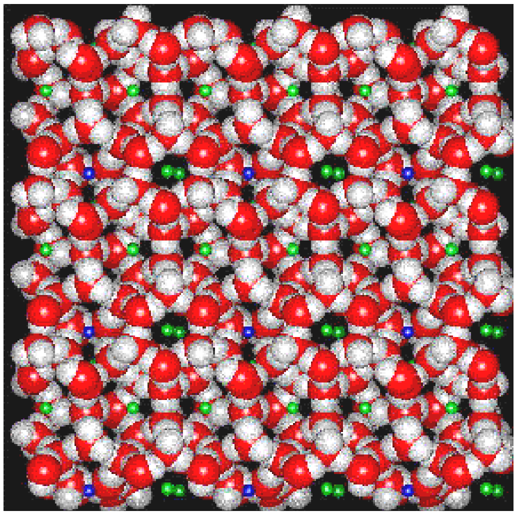


Figure 13 - 2 Gas Hydrate Structure I

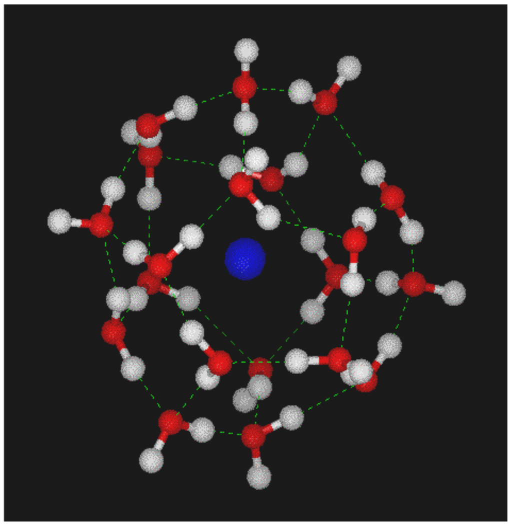
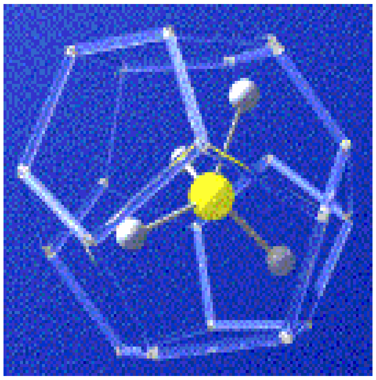


Figure 13 - 3 Basic Unit of Gas Hydrate

Clathrates are complexes formed between two chemicals in which one type of molecule completely encloses the other molecule in a crystal lattice. In the case of gas hydrates, hydrogen bonded water molecules form a cage-like structure that surrounds gas molecules, forming a solid substance with a high gas density. Agglomeration of these structures can form naturally occurring accumulations or blockages in lines and valves in drilling equipment.

Dodecahedron



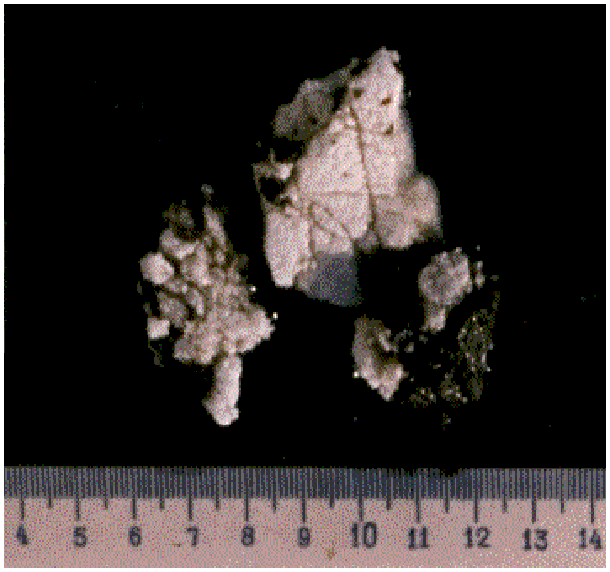
Gas hydrates are crystalline structures consisting of hydrogen bonded water lattices providing a cage like structure that host molecules of natural gas. These gas molecules are trapped in the middle of the cage with their repulsive energy stabilizing the strong hydrogen bonds of the water lattice. Common hydrate structures may contain eight to twenty-four cavities, with each cavity having a single molecule of gas. The final composition of the gas hydrates being approximately 15 % gas and 85 % water. Gas Hydrates are described as gas concentrators with the breakdown of a unit volume of methane hydrate at a pressure of one atmosphere producing about 160 unit volumes of gas.

HYDRATE FORMATION & OCCURRENCE

Hydrates are found naturally in the sediments in deep cold marine environments. They may also be incorporated into the formation.

Gas hydrates are formed by anaerobic bacteria digesting organic matter (detritus) under the ocean floor. During the digestion process mainly methane is produced along with small amounts of carbon dioxide, hydrogen sulfide, propane, and ethane. The produced gases rise, dissolving in the water between the ocean sediments.

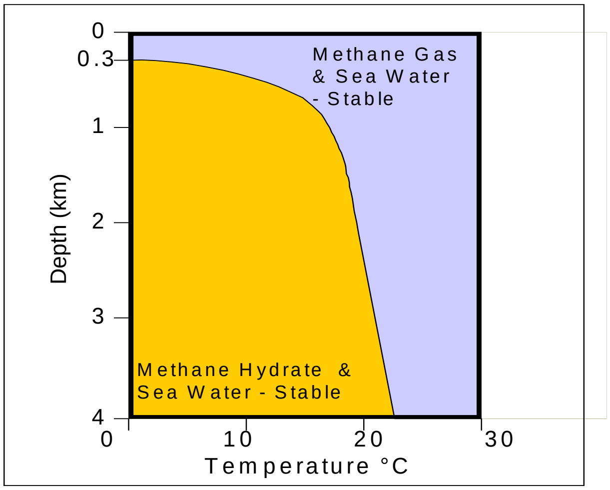
Gas Hydrates Offshore Sakhalin Island



When the temperature, and pressure conditions at the ocean bottom are appropriate (high pressure and low temperature) hydrates are formed. In addition to the formation of hydrates, vast reservoirs of methane gas often form beneath hydrate layers. Methane hydrate is stable in ocean floor sediments at water depths greater than 1000 ft (300 m), and where it occurs, it is known to cement loose sediments in a surface layer several hundred meters thick.

When hydrates are incorporated into the formation they have to be maintained during the drilling operation to avoid the collapse of the surrounding seabed.

Figure 13 - 4 **Gas Hydrates in Seawater (Phase Diagram)**



Gas Hydrate Stability Curve

To the left is a curve representing the stability of gas hydrates in sea water. Pressure and temperature are two of the major factors controlling where the hydrate (solid) or methane gas will be stable. Whether or not gas hydrate actually forms depends on the amount of gas available.

IN-SITU HYDRATES

In-situ hydrates can exist at various depths below the seabed and may be encountered while drilling in deepwater virtually anywhere in the world where there are sufficiently high pressures to favor hydrate formation. Gas may exist below the in-situ hydrates.

Associated Problems

1. Maintaining competency of in-situ hydrates while drilling and cementing
2. Maintaining static well conditions while drilling and cementing in gas/water
3. Obtaining a competent cement job in a gas environment

Problem Resolution: It may be possible to drill the in-situ hydrate section without incurring hydrate dissociation. Dissociation of the hydrates will lead to an enlarged hole section which will negatively impact both the cement bond/hydraulic seal and lateral casing support. To maintain the in-situ hydrates in a competent state, special attention needs to be paid to the annular temperature during drilling, cementing and cement transitional period.

Drilling

- Simulations can be performed to predict fluid circulating temperatures inside the drill pipe and in the annulus.
- If annular temperature does not exceed the hydrate equilibrium temperature, nothing more is necessary.
- If annular temperature exceeds the hydrate equilibrium temperature, several options should be explored:
  - Increasing the mud weight, thus pressure in the annulus, if fracture pressure will allow
  - Utilize lecithin to retard the rate of dissociation
  - Reduce the target depth of the surface casing, so as to reduce the annular temperature

Cementing

- Cementing across in-situ hydrates offers a challenge not yet solved by the industry (i.e., API):
  - Cement has an exothermic reaction during transition.
  - Hydrates are endothermic during dissociation
  - Dissociation of in-situ hydrates by cement can lead to a gas filled void behind casing and negatively impact the cement bond.
  - Foam cement should be used due to:
  - The accelerated right-angle set and reduced transition time.
  - Lower exothermic temperature when setting over conventional cement
  - Past success in shallow gas environments
  - The foam cement should be specifically designed to meet these well criteria. All foam cements are not created equally (stability, quality control, insulating maximization, and stiffness).
  - Cement should be designed to expand.
  - Weight of cement should be maximized for hydrate stability.

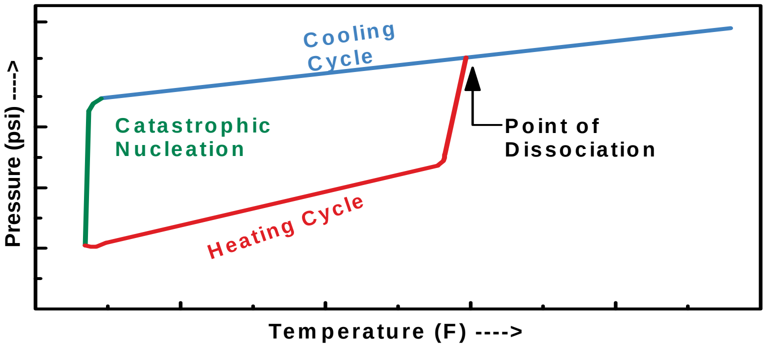
Weighted mud should be employed to drill the hole section below structure pipe.

- The increase in annular pressure will be advantageous to the stability of the in-situ hydrates
- Free gas, below the in-situ hydrates, will need to be controlled.
- A Dynamic Kill Drilling device should be utilized to supply weighted fluid

HYDRATE FORMATION IN DRILLING FLUID

Hydrate formation in drilling fluids is a relative new experience off shore. Temperature, pressure and gas composition determines the conditions for hydrate formation. Solidification occurs as the temperature decreases and/or the pressure increases.

Figure 13 - 5 Idealized Gas Hydrate Pressure/Temperature Plot



As the temperature of the fluid decreases and/or pressure is increased, seed crystals or hydrate nuclei are formed. At a critical pressure / temperature / gas combination, catastrophic nucleation and encapsulation of gas into the hydrate structure occurs. At elevated pressures and low temperatures in deep water drilling (> 500m and below 10°C) hydrate formation is promoted. This process is represented diagrammatically in the figure above. Presuming there are no other "helper" gases to promote hydrate formation, then the lower molecular weight of the hydrocarbon, the greater the resistance to hydrate formation. Thus the hydrate formation is decreased in the following order:

Methane < Ethane < Propane < Isobutane

The cold sections of the well that are exposed to the sea such as the riser, choke & kill lines and the BOP are the most probable location for the hydrates formation. When the drilling fluid is being circulated, the combination of heat generated from the actual circulating and the geothermal heat will maintain the temperature of the fluid in the riser above the critical temperature at which hydrates are formed. However when there are circulation breaks for tripping or logging, the drilling fluid must have the hydrate inhibitive capacity to keep the fluid in the cold areas of the well hydrate free.

Invert emulsion drilling fluids, which are very commonly used on deepwater drilling operations, are extremely effective hydrate inhibitors. They are not hydrate preventers, as hydrates may be formed given the right pressure-temperature-water content-calcium chloride concentration combination.

HYDRATES PREDICTION

The WHyP (Westport Hydrate Prediction) program used by Baker Hughes Drilling Fluids is a thermodynamic hydrate equilibrium prediction program that is based upon the statistical thermodynamic theory of van der Waals and Platteeuw. It also incorporates the hydrate temperature suppression methods developed using the Young-Yousif model.

The WHyP program has a wide array of input choices and modes that can be used. The design mode is a unique feature that calculates the appropriate amount of inhibitor to suppress hydrates at a given temperature and pressure. The prediction mode allows the user to enter a fluid composition and the program will generate the hydrate equilibrium line for that particular fluid. Characterizing this fluid composition can be completed in a number of ways; by weight percentage, by filtrate density and resistivity, and measured water activity. The program will predict hydrate equilibrium curves up to 10,000 psi.

The WHyP program was designed by, and for, drilling fluids personnel and caters towards deepwater applications. Fluids with up to three different types of inhibitors may be entered as inputs. The program also has a wide array of inhibitor selections, such as NaCl, KCl, $CaCl_2$, Sodium and Potassium Formates, Methanol, and several types of glycols. The program defaults to using Green Canyon Gas, but also allows the user to enter a known gas composition.

Although based upon statistical models, the WHyP program is supported by over 150 temperature suppression points that were measured experimentally on various mixed salts and glycols solutions. This large supporting database allows WHyP to be accurate as well as flexible to the needs of the drilling fluids personnel. The WHyP program is accurate to within 2K psi when using the weight percentage method, or 4K psi by using the filtrate or water activity methods.

Baker Hughes Baker Hughes Drilling Fluids has been using WHyP to assist with the design of hydrate inhibiting fluids since 1997 . The program's mixed salt/glycol capability differentiate it from other hydrate prediction programs.

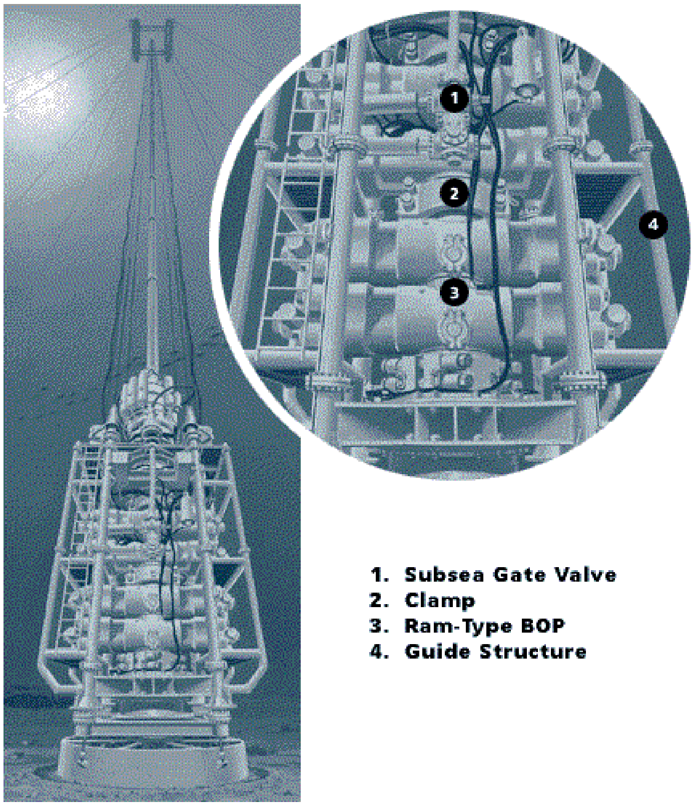
HYDRATE FORMATION DURING WELL CONTROL INCIDENTS

Hydrate formation may be accelerated during the drilling operations as a result of gas influx (kick). A critical situation, in respect to gas hydrate formation, may arise during well control incidents when the well is shut in.

A typical kick is detected at 10 bbl of pit gain. By the time the well is shut-in, the kick volume could reach 50-60 bbl. Depending on the hole and drill pipe size, the kick could reach a height of 1500 – 2000 ft. (457 - 610m.) Although the kick fluid leaves the formation at a high temperature, with an extended shut-in period it can cool to sea bed temperature. With high enough mud hydrostatic pressure at the mudline, hydrates could form in the BOP stack, choke and kill lines.

Two procedures are used by the industry to shut-in wells during a gas kick: the soft shut-in and the hard shut-in procedures. In the soft shut-in, the hydraulically operated choke line valve is opened, the annular BOP is closed, and finally the adjustable choke is slowly closed. This procedure is applied with the intention of reducing shock loads on the casing shoe.

Figure 13 - 6 Typical BOP Riser Arrangement



The hard shut-in procedure requires opening the hydraulically operated choke line valve and then closing the ram, with the adjustable choke remaining closed at all time. This procedure takes considerably less time and thus allows less influx into the well, reducing wellbore pressures during killing operations. However, because of the concern over possible shock loads, the soft shut-in method has historically been preferred by the operators.

To achieve successful kick containment, the Blowout Preventor (BOP) must operate properly and the choke and kill lines must remain clear for circulation. Consequently, and as a safety precaution, the drilling fluid must have good hydrate inhibition properties.

The risers on deep water drilling rigs are partially insulated with the floatation material attached to them. The BOP and choke and kill lines are normally exposed to sea water. Insulation will help reduce the rate of heat transfer during lengthy shut-in periods. In very deep water situations insulation may not provide adequate protection even after long circulation periods.

HYDRATE INHIBITION

Historically, most of the work on gas hydrate inhibition has been aimed at the prevention of hydrate formation during the production and transportation phase of hydrocarbons.

Listed below are the three inhibitive mechanisms utilized:

- Thermodynamic inhibition
- Kinetic inhibition
- Prevention of hydrate agglomeration

Traditionally, hydrate suppression has been accomplished by a thermodynamic approach. High concentrations of hydrate inhibitors such as salts, glycols or alcohols were added to the flow line. A more modern approach is the use of low concentration inhibitors that time-delay or minimize the amount of hydrate crystals formed (kinetic approach). The third approach, anti-aggregation, does not stop the formation of hydrates but prevents the hydrates from agglomerating into large crystalline masses or plugs. This effectively prevents a dramatic increase in the transported fluid's viscosity.

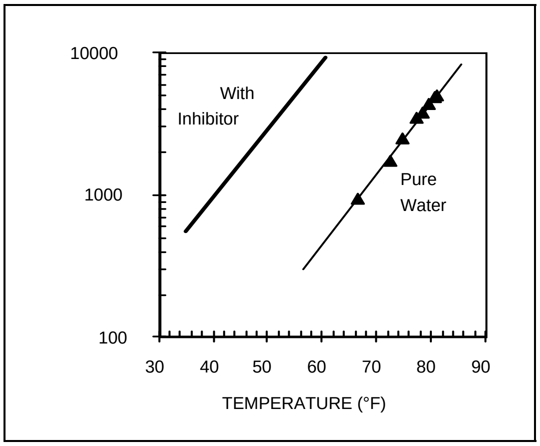
It should be noted that many of the solutions employed in mitigating gas hydrate issues in downstream operations are not applicable to drilling applications due to environmental constraints.

Thermodynamic Inhibition

In drilling fluids the principal method for hydrate inhibition is thermodynamic. As stated in the previous section thermodynamic hydrate inhibition is extensively used in petroleum production. These inhibitors which are added to the drilling fluid lower the chemical potential of the aqueous phase. The hydrate equilibrium pressures and temperatures are measured for distilled water. When the water is treated with the thermodynamic inhibitor, the phase boundaries are shifted to the left and upward. Thus the inhibitor effectively reduces the temperature and increases the pressure at which the hydrates are formed. The most common thermodynamic hydrate inhibitors are glycols, salts and glycerol.

A typical phase equilibrium plot is given in the following figure.

Figure 13 - 7 Hydrate Phase Equilibrium Conditions



- On a weight to weight basis, the hydrate suppression effectiveness (ΔT) of differing salts can be expressed in the following order:

  NaCl > KCl> $CaCl_2$> NaBr>Na Formate> Calcium Nitrate

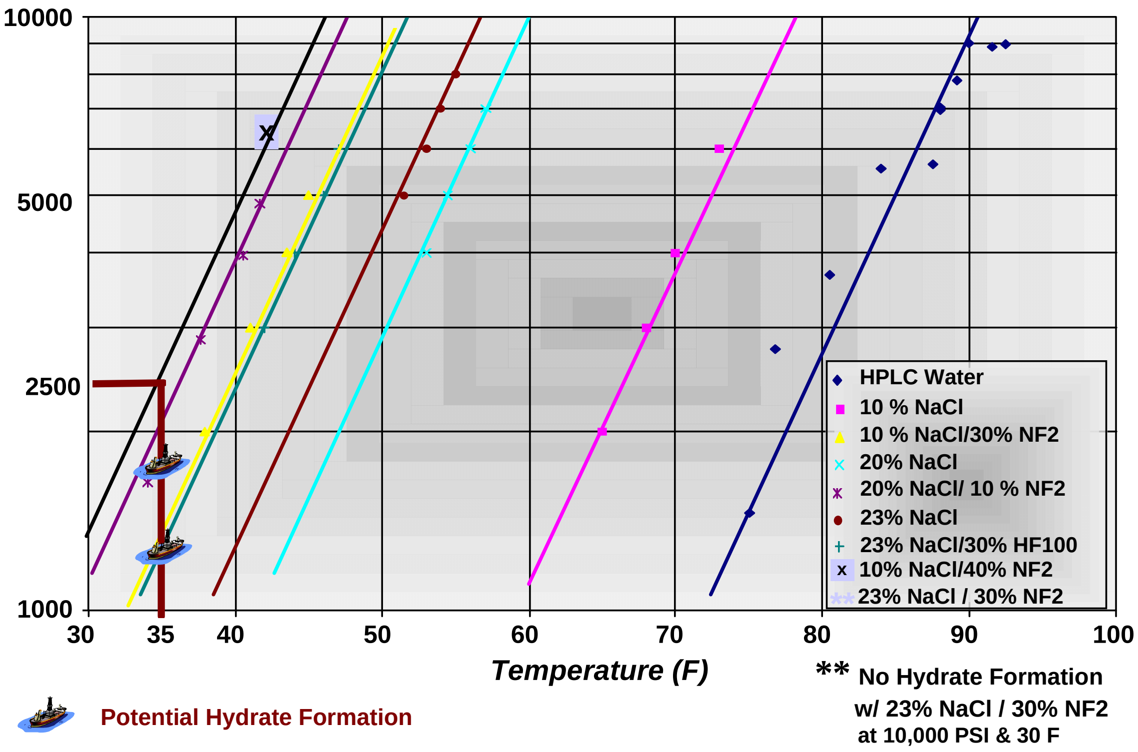
- The ability to form hydrates in SBM is related to the gas type, with higher salinities required for heavier gases.

Fluids that provide additional gas hydrate suppression and fluids that can be formulated at lower densities than traditional deep water fluids is the focus of ongoing work at Baker Hughes Drilling Fluids. These fluids utilize low molecular weight organic compounds for enhanced gas hydrate inhibition. ***NF3****™ (No Freeze, No Frac, No Formation Instability) is the sequel to Baker Hughes Drilling Fluids' first product of this type, referred to as* ***NF2****® (No Freeze, No Frac).* ***NF3™*** *has a lower specific gravity than* ***NF2®*** *and has the additional function of benefiting borehole stability as well as providing gas hydrate inhibition.* ***NF3™*** *can be added to standard deep water, water based drilling fluids at concentrations from 5% to 40% by volume depending on the degree of gas hydrate and shale inhibition desired. The ability to use* ***NF3™*** *at these various concentrations will allow flexibility between the required density, amount of shale inhibition, and the amount of gas hydrate inhibition desired.*

NF2®*, a low molecular weight, environmentally friendly glycol, is ideal for deepwater applications where high gas hydrate suppression and low fluid density (due to low fracture gradients) is required.* ***NF2®*** *is compatible in both fresh and salt water (up to and including saturated brines) drilling fluids.* ***NF2®*** *is particularly useful in formulating pills for choke and kill lines whenever favorable conditions exist for the formation of gas hydrates.*

These products have been successfully incorporated into inhibitive water based fluid systems in the Gulf of Mexico and elsewhere. A major operator in the GoM utilized the unique characteristics of these products in their world record setting water depth well of 7,800 ft. (2377 m.) with great success. A 9.3 ppg (1.12 sg) fluid was built using salt and 10% ***NF3™*** *yielding a fluid capable of suppressing hydrates in 7799 ft. (2377 m.) of water, or in the presence of 7799 ft. (2377 m) of hydrostatic pressure and a sea floor temperature 36°F (2^0C).*

Figure 13 - 8 Gas Hydrate Equilibrium Chart



GAS HYDRATES IN THE BOP

Hydrates are most likely to form in the choke & kill lines and the BOP, as these are exposed to the lowest temperature and the highest pressures. The plugging of the well control equipment presents the greatest hazard potential. In order to prevent hydrate formation during a kick situation a suitable fluid may be spotted across the BOP and in the choke and kill lines. It is recommended to spot a suitable fluid across the BOP in the event of a gas kick

Spotting Procedure

1. Close lower-most pipe rams. In this manner, the kill line, BOP stack (above lower pipe rams), and choke line can be displaced
2. Displace kill line and BOP stack with predetermined strokes. Once the fluid has cleared upper annular preventers, close preventers, open choke line, and displace same.
3. Close pipe rams above and closest to choke line and begin well killing procedure,
4. After the well is dead, there is potential for trapped gas above the closed pipe rams and below the annular preventers. A rapid expansion could cause riser collapse.

Procedure For Evacuating Gas From The BOP

1. Close bottom-most pipe rams and annular preventers.
2. Pump mud through the kill line. When this pill returns at the choke line, stop pumping.
3. Allow any gas to evacuate from the stack taking returns to the gas buster.
4. Displace the kill line, BOP stack and choke line with kill weight mud.
5. Open annular preventer, close diverter bag (i.e. diverter lines are open), and displace riser with kill weight mud.
6. After riser has been circulated with kill mud, open lower pipe rams and check for flow.

HYDRAULIC MODELING SOFTWARE

INTRODUCTION

In deepwater drilling operations it is extremely important to have control over the Equivalent Static Density (ESD) and the Equivalent Circulating Density (ECD) at all times. This is due, in part, to the young formations associated with deepwater drilling and the types of fluid normally employed to drill these wells. Overwhelmingly, invert emulsions are used in deepwater, with the external phase being decided by environmental regulations or operator policy. Invert emulsions are very inhibitive and offer excellent rates-of-penetration. There are a host of other advantages to invert emulsions covered early in this section (see section titled: ***AQUEOUS VS NON-AQUEOUS DRILLING FLUIDS***).

Non-aqueous fluids are compressible and expandable under the wide range of temperatures and pressures they are subjected to in a deepwater environment. Therefore, it is imperative that corrections are made to the fluid properties to compensate for the temperature and pressure effects on the whole mud density and rheological characteristics under downhole conditions.

Baker Hughes Drilling Fluids has two state-of-the-art modeling programs to assist in analytical solutions for our customers; **Presmod**, which is primarily used to determine dynamic temperature profiles and **ADVANTAGE**^{SM}, which is Baker Hughes Drilling Fluids proprietary hole cleaning and hydraulics model.

TEMPERATURE MODELING

Presmod

Presmod is a dynamic hydraulics/temperature simulator. **Presmod** is capable of predicting ECD, ESD and temperature profiles of the annulus and drill string as a function of time. However, **Presmod** should not be used to predict ECD since the program assumes 100% hole cleaning, regardless of flow rate or other hole cleaning variables.

For deepwater applications, **Presmod** is primarily used to predict dynamic temperature profiles when there is potential for the occurrence of gas hydrates. In practice, **Presmod** is used for the following scenario:

An upper section of a deepwater well is drilled with an aqueous fluid which is limited by the amount of salt that can be added due to density restrictions. Also, the volume of liquid additives (glycols, alcohols, etc.) necessary to ensure against hydrate formation is cost prohibitive and would be detrimental to the performance of the fluid system. The section is drilled to total depth (TD) and the fluid reaches a circulating temperature profile. The two issues to address are:

1. What will be the final annular circulating temperature? And in particular, what is the temperature at the mud line when drilling ceases, prior to tripping out to run pipe?

2. Under non-circulating conditions, how long will it take for the annular temperature to cool down to a temperature favorable for hydrate formation in the event of a kick?

The primary strength of **Presmod** can be demonstrated in the solutions to these questions and is illustrated by Figures 1 thru 3 below.

Figure 13 - 9 Temperature at Start of Drilling

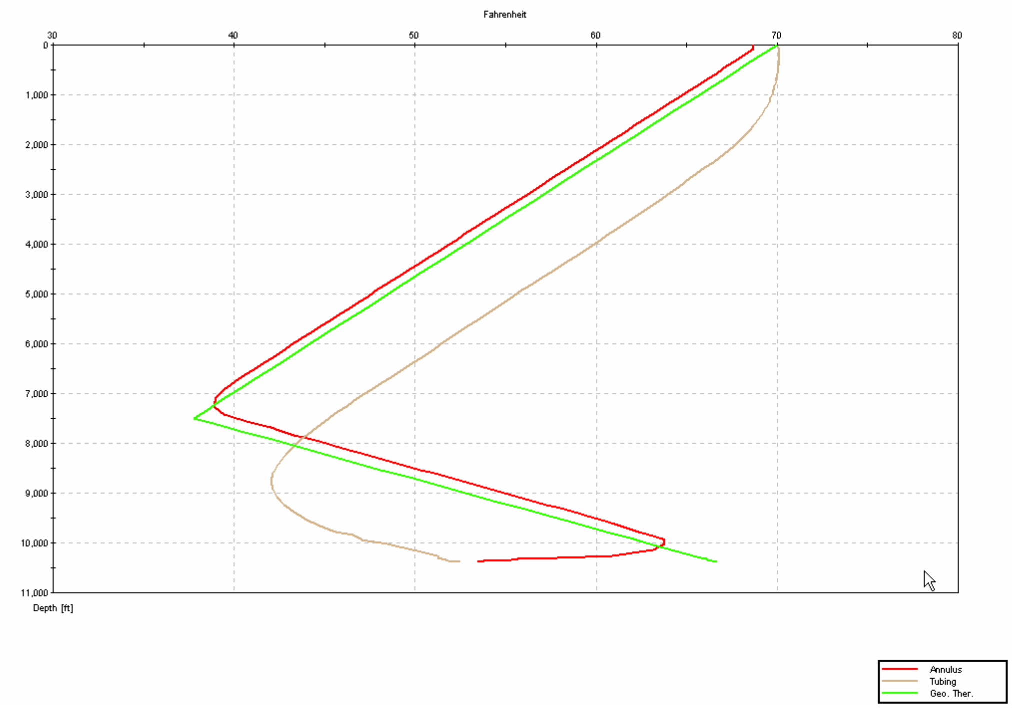

Fahrenheit
30
40
50
60
70
80
0
1,000
2,000
3,000
4,000
5,000
6,000
7,000
8,000
9,000
10,000
11,000
Depth [ft]
Annulus
Tubing
Geo. Ther.

Figure 13 - 10 Temperature at End of Drilling

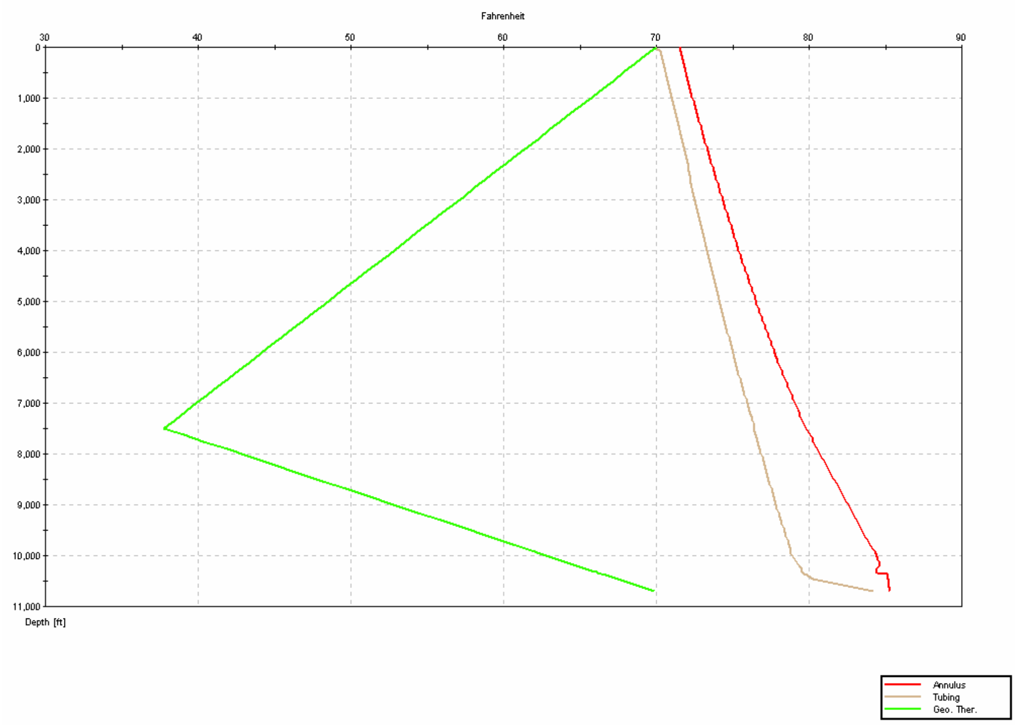
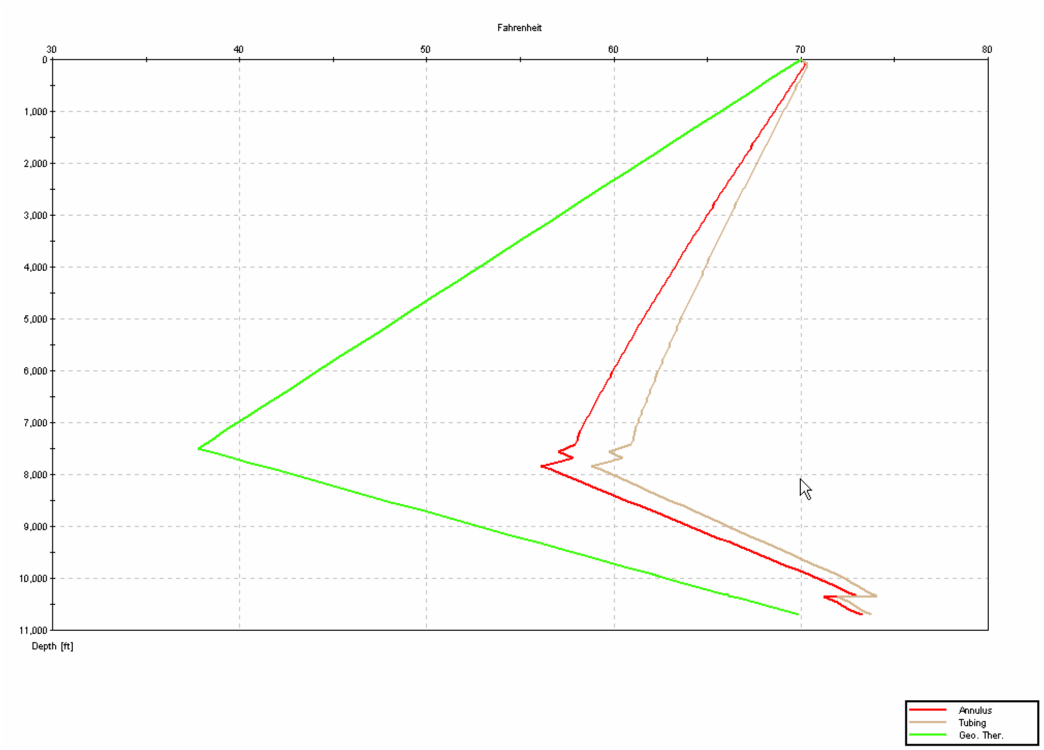


Figure 13 - 11 Temperature After 78 Hours Non-Circulating



ADVANTAGE^{SM}

ADVANTAGE^{SM} is Baker Hughes Drilling Fluids' integrated platform for all well planning, reporting and analysis services. This is a modular platform which allows for customized features depending on services being provided. Drilling Fluids Services include the comprehensive Daily Fluids Reporting system as well as the Engineering Software System. Engineering Software consists of Hydraulics and Swab and Surge Analysis

All services above share data within a common integrated multi-well relational database. Data entered in Reporting Applications can be readily loaded into the Engineering Applications for rapid analysis. The Engineering Applications themselves are integrated. Analyses can be run for Hydraulics, Hole Cleaning, HTHP, and Swab & Surge predictive results at one time with the common dataset either for pre-well planning purposes, or daily operational data.

Standard output reports from all Engineering Applications include Input Data and Calculated Results. In addition, ancillary reports (such as drill string and survey listings) are available. Also, all Engineering modules have interactive on screen graphic presentations of results. These results can be cut and pasted into standard MS Office applications (as graphics or data) for supplemental output.

More specific information on ***ADVANTAGE^{SM}*** *Modules is provided below.*

ADVANTAGE^{SM} Engineering Hydraulics

Advantage Hydraulics provides sophisticated mathematical hydraulics and hole cleaning models. It is designed to give the best available estimate of the flow rate required to maintain effective hole cleaning. The program has been developed by a combination of theoretical modeling and field verification.

Hydraulics *calculates the following:*

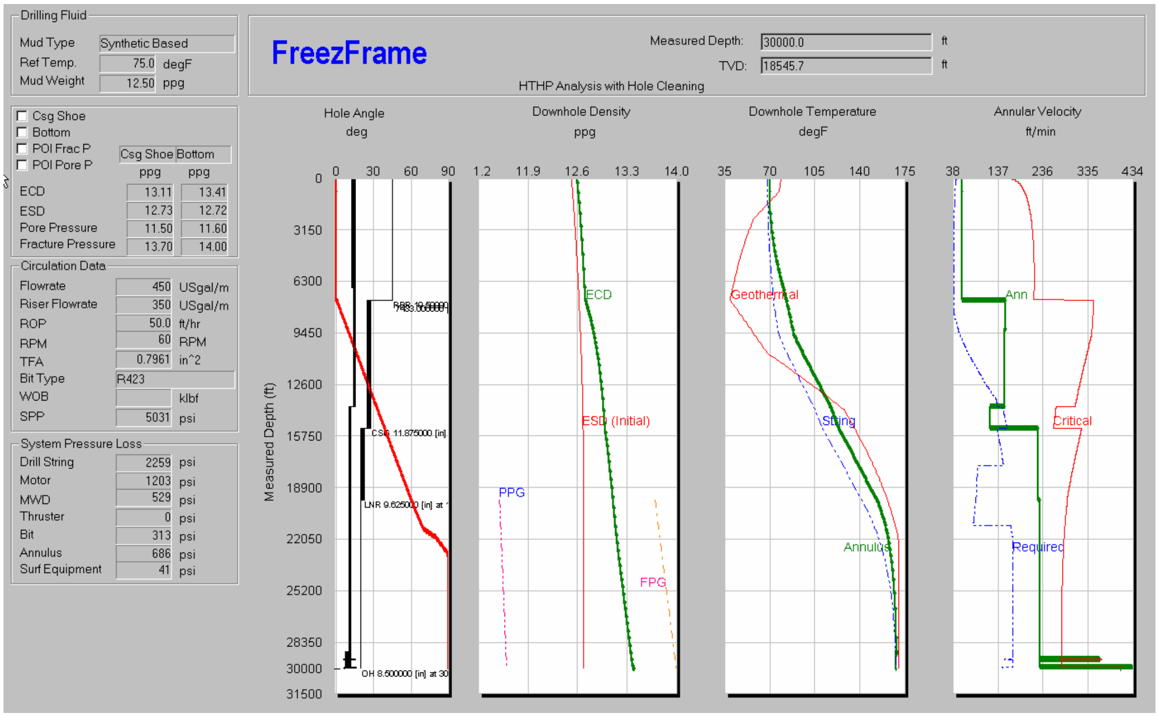
- Total system pressure loss
- Maximum and minimum allowable flow rates for the given hole and drillstring configurations
- Annular velocities
- Hydraulic horsepower at the bit
- Equivalent circulating density (ECD)
- Can be set to run several standard rheology models including: Bingham Plastic, Power Law, Newtonian, Hershel-Bulkley and Robertson-Stiff.

ADVANTAGE^{SM} HTHP Analysis

When ***ADVANTAGE^{SM}*** *is run in the HTHP analysis mode, it considers the influence of pressure and temperature on the mud density and viscosity. The temperature profile can either be calculated or defined. The calculation of downhole density based on pressure and temperature requires the knowledge of the mud density profile. This can be provided by mud density measurements or by calculating the density based on the mud components. The results are displayed graphically in the Hydraulics Results Window. The calculation of mud rheological properties requires Fann70 readings. These data must cover the range of pressures and temperatures expected in the well. The calculation performed is similar to a System Mud Hydraulics calculation. Additional results are created. There is an effective mud weight and a temperature profile report. Both are available* *graphically too. The downhole mud density and the rheological parameters are available as diagrams.*

The figure below is a typical **ADVANTAGE**^{SM} output for a deepwater well. Note the tabular data on the left side of the **Figure 13 - 12** or the graph in **Figure 13 - 12** labeled "Downhole Density" indicates the ESD at the bottom of the wellbore is 12.73 ppg and the surface mud weight is only 12.5 ppg. This is due to the pressure and temperature effects on compressibility and expandability on SBM's and OBM's.

Figure 13 - 12 Deepwater Well Example



Drilling Fluid

Mud Type: Synthetic Based
Ref Temp.: 75.0 degF
Mud Weight: 12.50 ppg

☐ Csg Shoe
☐ Bottom
☐ POI Frac P
☐ POI Pore P

	Csg Shoe ppg	Bottom ppg
ECD	13.11	13.41
ESD	12.73	12.72
Pore Pressure	11.50	11.60
Fracture Pressure	13.70	14.00

Circulation Data

Flowrate: 450 USgal/m
Riser Flowrate: 350 USgal/m
ROP: 50.0 ft/hr
RPM: 60 RPM
TFA: 0.7961 in^2
Bit Type: R423
WOB: klbf
SPP: 5031 psi

System Pressure Loss

Drill String: 2259 psi
Motor: 1203 psi
MWD: 529 psi
Thruster: 0 psi
Bit: 313 psi
Annulus: 686 psi
Surf Equipment: 41 psi

Measured Depth: 30000.0 ft
TVD: 18545.7 ft

HOLE CLEANING AND BARITE SAG

INTRODUCTION

Removing cuttings from the wellbore is the most important function of the drilling fluid. Whether the wellbore is being drilled on land, the offshore continental shelf, or in deepwater, the drill bit cannot advance if the cuttings are not removed. In deepwater wells the implications of not cleaning the wellbore are: spikes in ECD, numerous short trips, back reaming, poor cement jobs, stuck drill pipe, stuck casing/liner, etc. The bottom line results usually mean increased well costs to the operator and an unhappy client of the mud company.

Barite sag is defined as the variation in mud weight seen at the flow line. This is usually observed after extended periods without circulation. At times barite sag will result in similar problems to those seen with inadequate hole cleaning.

HOLE CLEANING TOOLS & TECHNIQUES

Riser booster pumps, i.e., pumps assigned solely to circulate the marine riser, are used to increase the flow rate in the marine riser and so enable efficient cuttings transport in the riser. Riser booster pumps commonly increase the flow rate in the annulus by 500 gallons per minute. This increase in the flow rate in the riser has a negligible effect on ECD due to the low pressure drop in the riser. Riser booster pumps are necessary due to the often dramatic diameter changes at the riser. This is most marked in 12 ¼" and smaller hole diameters. The **ADVANTAGE$^{\mathbf{SM}}$** engineering software allows the user to evaluate the effectiveness of various riser boost rates

The same basic principles for hole cleaning are as valid in deepwater as in all drilling operations. The recommended method to evaluate hole cleaning is by use of the hole cleaning model within **ADVANTAGE$^{\mathbf{SM}}$**. If the HPHT mode is selected in **ADVANTAGE$^{\mathbf{SM}}$** and the requisite temperature gradients, PVT of the base oil and Fann® 70/75 data are provided, **ADVANTAGE$^{\mathbf{SM}}$** will perform the hole cleaning analysis using downhole rheological properties.

BARITE SAG

Barite sag is as much an issue in deepwater wells as all other wells. Barite sag is a genuine risk as efforts are made to minimize rheological properties in order to minimize ECD and minimize cold water rheological properties. Care must be taken to avoid barite sag when reducing and recommending rheological properties.

ECD MANAGEMENT

On many deepwater wells effective ECD management is one of the main factors in the successful drilling of a well. This often involves running the rheological properties as low as possible without causing hole cleaning or barite sag problems. The correct way to do this is by continual use of the engineering software in **ADVANTAGE**^{SM}, taking regular samples for Fann® 70/75 testing and confirming that the low shear viscosity is sufficient to minimize the risk of barite sag.

ECD optimization should always be one of the steps during well planning, using planned well geometries and fluid properties. **ADVANTAGE$^{\mathbf{SM}}$** Engineering is the correct tool for this type of work.

Recommending, and implementing, good drilling practices is an integral part of ECD management. These include controlling rates of penetration, short trips, tripping rates, casing running speeds, methods for initiating circulation and drilling fluid properties.

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Chapter Fourteen

Fluids Environmental Services

Chapter 14

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Chapter 14

FLUIDS ENVIRONMENTAL SERVICES

The strengthening of environmental regulations around the world has changed the way service companies and their customers view the provision of drilling fluids. Ignoring the effects on the environment from mixing, transporting, cleaning, re-using and disposing of mud and cuttings is no longer an option. Baker Hughes Drilling Fluids FES (Fluids Environmental Services) includes a broad range of services and equipment to complement its drilling fluids services. The application of the services described here is subject to the environmental conditions of a project that, in many instances, determine the selection and design of the drilling fluid.

INTRODUCTION

The objective of Baker Hughes Drilling Fluids Environmental Services (FES) is to provide an integrated solution to the management of drilling fluids and the associated drilling waste generated, addressing the operation from waste generation to final disposal.

FES follows the waste management hierarchy as the guideline to manage all the issues affecting the operation. The waste management hierarchy aims at reducing the overall impact of the drilling activities to the environment:

Reduce	Minimize the volume of waste and reduce environmental risks
Reuse	Maximize the use of materials and resources for the same process
Recycle	Recover part or all of the waste to be used in a new process or to begin the process over again
Responsible	Use methods and technologies that minimize the effect on the environment and use the least amount of resources

The waste management hierarchy requires a range of services that can be applied during each stage of the process according to the characteristics of a particular project and the customer.

I – Waste Minimization Approaches	II - Recycle or Reuse Approaches	III - Disposal Approaches
Synthetic-based and oil-based mud generate less cuttings than water-based mud	Road spreading when roads benefit from application of waste	Land spreading or land farming
Coiled tubing drilling	Reuse synthetic-based and oil-based mud	Road spreading
Directional/horizontal drilling	Use cleaned cuttings for fill or cover material	Burial in onsite pit or offsite landfill
Use of less toxic components and additives for mud	Restoration of wetlands with clean cuttings	Discharge to ocean
Air drilling	Use cuttings as aggregate for concrete or bricks	Salt cavern disposal
	Thermal treatment with fluid recovery	Underground injection
		Thermal treatment
		Biotreatment (e.g., composting, vermiculture)

There are three main types of services within Baker Hughes Drilling Fluids FES product line:

- Management Systems: The FES Process is based on the Total Quality Management concept. It aligns the goals and activities of each project with the expectations of the customers, assuring that lessons are learned and best practices are retained within the organization and can be applied to future jobs.

- Best Operating Practices: These consist of several recommended procedures to minimize the volume of waste. BOP’s encompass planning and execution of drilling fluids, solids control, waste management and supporting activities that affect the quantity and quality of waste generated.

- Waste Management Services: Technologies specifically designed to collect, treat and discharge drilling waste.

This approach means Baker Hughes Drilling Fluids can provide closer co-ordination, quicker response time and better control of the project.

The benefits to the operator include:

- Rapid project deployment: The initial project set up time is greatly reduced as Baker Hughes Drilling Fluids FES will take on many of the responsibilities to ensure full environmental compliance

- Baker Hughes Drilling Fluids HSE will provide assistance with obtaining the drilling approval

- Potential risks are identified to minimize the impact of drilling operations on the environment.

- The operator's personnel are freed to concentrate on the operational big picture rather than the smaller details.

- Paths of communication, roles and responsibilities are clearly defined

- Operating efficiency is maximized through the use of Key Performance Indicators

- The logistics involved in the transportation of all fluids and the associated waste are managed

- An accurate audit trail to keep track of all drilling waste is provided

- A system of continual learning detects problems and highlights areas for improvement

FES MANAGEMENT SYSTEM

The **FES Management System** is a Total Quality Management process for the planning, execution, logistics and reporting of the total drilling fluids cycle present in every drilling operation. It is designed to reduce overall drilling project costs by providing single chain of command focus and aligning all associated fluids service lines towards common pre-determined goals to minimize waste generation and maximize fluids recovery/re-use. The ultimate objective is to focus the efforts of everyone involved, to make the process more efficient for the benefit of the customer, the environment and the service companies themselves.

The FES methodology should be expected to achieve the following:

- ***Improvement of the coordination of drilling fluids, solids control equipment and waste management services***. Rational use of resources, planning ahead and better communication are some of the tools to better coordinate these services.

- ***Optimization of Solids Control Equipment performance***. The efficiency of the solids control equipment (SCE) can have a major impact both on the condition of the mud as well as the volume of waste. Poorly operated SCE can result in unnecessary losses of drilling fluid in the form of overly wet discharge from the centrifuges and residual fluid attached to cuttings.

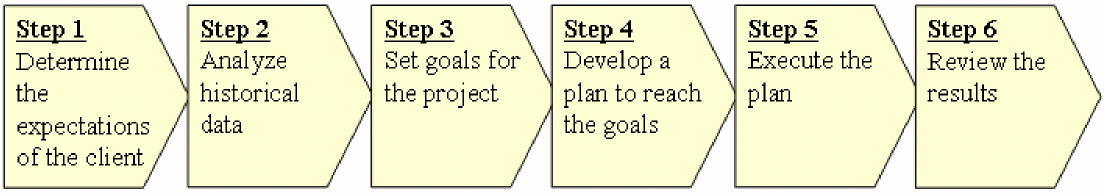
- ***Optimization of waste management*** through waste segregation to reduce costs and volumes to maintain.

- ***Improvement in the quality of the information collected in the project about drilling waste***. Accurate measurement of volumes, characteristics and sources of each type of waste will have a significant effect on the ability to optimize processes in the future. Better information will give a clearer picture of the project status and will make it possible to build a continuous improvement system.

THE SIX STEPS

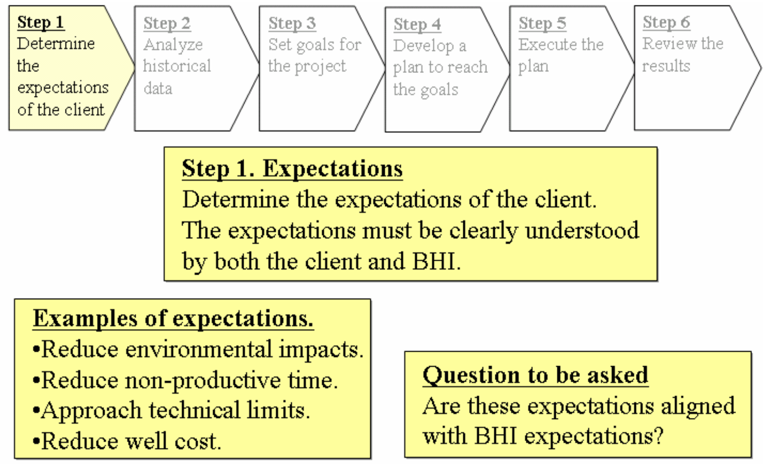
The process consists of six clearly defined steps. Each one is described below including the forms that need to be filled out.

This FES Process map has been developed to aid the optimization and planning of the drilling fluid life cycle. It is a systematic approach designed to ensure that all of the issues mentioned are addressed and that the deployment will be carried out with a high level of competence and service.



Step One – Determining Expectations

The first step in the process is determining the expectations, or needs, of the project, or well, in order to plan for a successful job. When every member of a team is aware of firm, clear expectations from the customer, it facilitates an effective delivery of results. Examples of project expectations include: finishing date for production requirements, environmental issues, logging requirements or casing requirements, projects costs, etc.



Step 1. Expectations
Determine the expectations of the client.
The expectations must be clearly understood by both the client and BHI.

Examples of expectations.
- Reduce environmental impacts.
- Reduce non-productive time.
- Approach technical limits.
- Reduce well cost.

Question to be asked
Are these expectations aligned with BHI expectations?

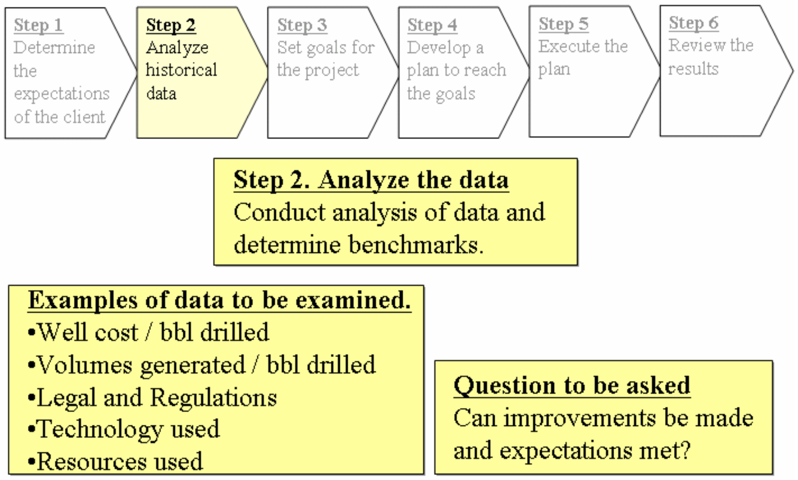
PROJECT OVERVIEW						
Operator:	A.N. OPERATOR					
Project or Well Name:	Xxxx					
Location:	Xxxx					
Well Type:	Land		Offshore		Deepwater	
Brief project description:	First batch of 6 well, then second batch of 11 wells. 16 Producing, 1 Water Injection					
Services to be provided:	Fluids		Cuttings handling		Disposal	
	Solids control		Transportation		Cleaning	
	Screens		Completions			
3rd Party Contractors:	Company		Service		Contact	
	Oil Tools		SCE & CRI			
			Cement			
Team Members:						
Date:						
Expectations	**Details**				**Source**	
H.S.&E.:	Zero LTI for DF					
Environmental:	OOC<13%, Zero spills>80L					
Drilling Economics:	Within AFE					

Early production:	Zero Skin Damage in production Zones	
Enhanced production:		
Other:		

Figure 1 - Example of a Set of Expectations for a Project

Step Two – Data Analysis

The second step is data collection, analysis and benchmarking. Historical data pertaining to the project or well is collected from offset wells, if applicable, or similar type wells if offset data is not available. This data may include, but is not limited to, days per 10,000 feet, cost, non-productive time analysis, drilling fluid volumes consumed, drilling fluid volume lost to the formation, pore pressure versus depth, non-productive time, cuttings volume per foot, cost of waste management, etc. The data is analyzed to determine percentile rankings, benchmarks and possible bottlenecks and/or risks.



Step 2. Analyze the data
Conduct analysis of data and determine benchmarks.

Examples of data to be examined.
- Well cost / bbl drilled
- Volumes generated / bbl drilled
- Legal and Regulations
- Technology used
- Resources used

Question to be asked
Can improvements be made and expectations met?

The type of data to collect and analyze will depend upon the expectations and conditions of the operation. A list of commonly used parameters is included in Table 14 - 1.

Well Information • Drilling fluid type • AFE days • AFE depths • AFE well cost • Actual days • Actual well cost • Well Non Productive Time (NPT)	**HSE** • Lost Time Incidents • Safety meetings • Number of environmental incidents • Spill incidents • Disposed waste in non authorized areas • Internal audits
Technical • Mud properties as per program (%) • Field procedures followed (%) • Corrosion procedures • Waste management procedures • Mud losses control by LCM procedures • Daily hydraulic report • Daily hole cleaning report • Recap updated • Stuck pipe incidents • Hole cleaning incidents	**Hole Size** • Total volume used • Mud recycled • Mud sent back to liquid mud plant • Surface losses • Liquid waste volume • Solid waste volume • Mud lost downhole • Cement waste
Cost • Drilling fluids engineering cost • Drilling fluids chemical cost • Solids control engineering cost • Solids control equipment (SCE) cost • Waste management cost	**KPI’s** • % Well NPT • % Total mud cost to well cost • % Total SCE cost to well cost • % Waste management cost to well cost • % FES cost to well cost • Mud cost / ft drilled • SCE cost / ft drilled • Waste management cost / ft drilled • Section dilution rate • Liquid waste / ft drilled • Solid waste / ft drilled

Table 14 - 1 Examples of Performance Criteria for Data Analysis

Information from offset wells is entered into a database. The database will be used in step three as a benchmark to establish achievable goals for the project based on historic performance.

	Performance Criteria	**8½" Salt Sat.**	**8½" Perflow**	**5⅞" Perflow**
Well Information	Well Name	209	209	209
	Mud Type	Salt Sat	Perflow	Perflow
	FES Program Available	y	y	Y
	AFE Days	107	107	107
	AFE Depth (Meters)	301	0	831
	AFE Well Cost (US$)	$11,296,510	$11,296,510	$11,296,510
	Actual Days	18	20	50
	Actual Depth (Meters)	95	444	1,178
	Actual Well Cost (US$)	$2,416,246	$3,778,611	$9,894,104
	Well Non Productive time (Days)	0.00	0.30	0.44
HSE	Lost Time Incidents (LTI)	0	0	0
	Safety Meetings			
	Internal Audits			
	Internal Inspections			
Technical	Mud Properties as per Program (%)	100%	90%	90%
	Mud Losses control by LCM	n/a	y	y

	Procedure			
	Stuck pipe incidents	0	0	0
	Hole Cleaning incidents	0	0	0
Cost	Drilling Fluids Engineering cost	17,350	12,800	40,000
	Drilling Fluid Chemical cost	68,664	148,592	234,332
	Solids Control Engineering Cost	9250	6033	21,316
	Solids Control Equipment Cost:	13,634	8892	31,417
	Mesh Screens	1875	341	2045
KPI's	% Total Mud Cost to Well Cost	2.8%	10.9%	3.8%
	% Total SCE to Well Cost	0.6%	0.7%	0.5%
	Mud Cost US$ / M drilled	$722.78	$334.67	$198.92
	SCE US$ / M drilled	$143.52	$20.03	$26.67
	Liquid Waste/M drilled (M3/M)	0.087	0.093	0.054
	Solid Waste/M drilled (M3/M)	0.051	0.050	0.023
	Number of environmental incidents	0	0	0

Figure 14 - 1 Example of FES Performance Criteria Database

Step Three – Setting Goals

Goals for the project or well are then set using the benchmarks and risks determined in the previous step. Goal management includes:

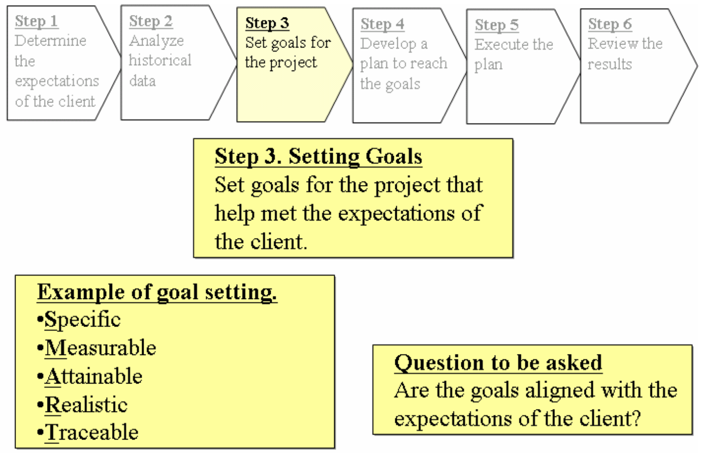
a) Defining what is needed to attain the goal.

b) What is the end result of the goal?

c) How will the goal be tracked?

d) Who is responsible for the goal?

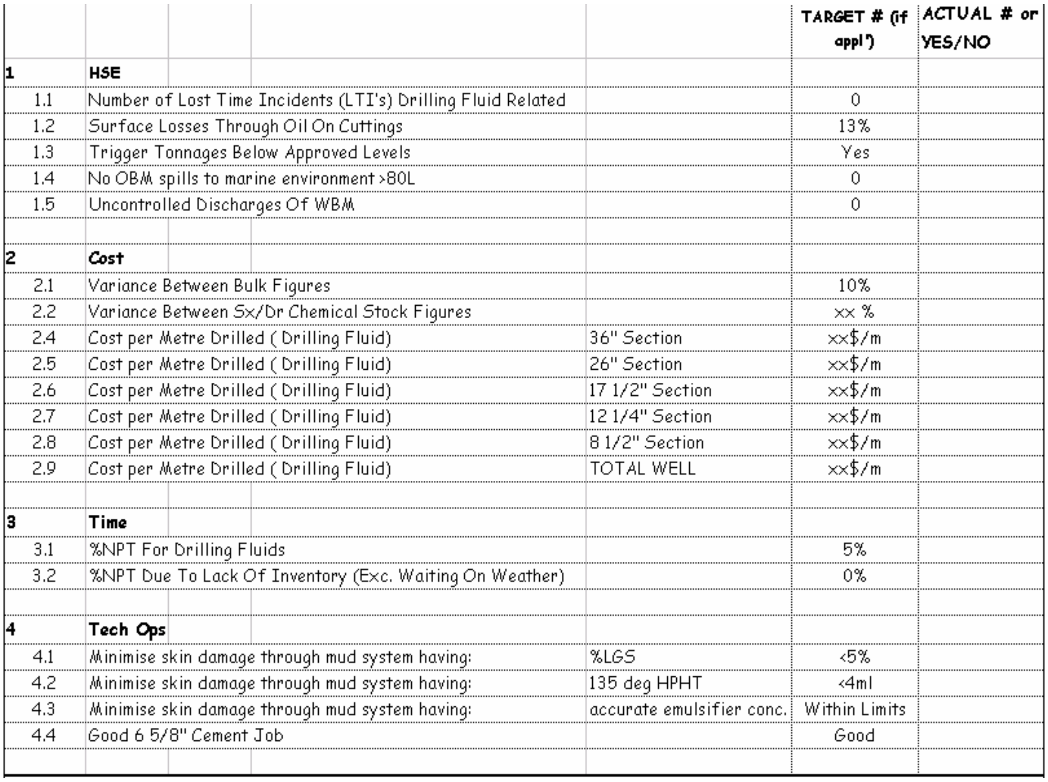
When goals are agreed upon between team members, they are discussed with all personnel involved in the project. This enables all members to be aware and focus on the tasks before them. Furthermore, those goals have to be in alignment with the expectations for the project in order for them to have an impact on the overall performance of the operation.



Step 3. Setting Goals
Set goals for the project that help met the expectations of the client.

Example of goal setting.
- Specific
- Measurable
- Attainable
- Realistic
- Traceable

Question to be asked
Are the goals aligned with the expectations of the client?



			TARGET # (if appl')	ACTUAL # or YES/NO
1	**HSE**			
1.1	Number of Lost Time Incidents (LTI's) Drilling Fluid Related		0	
1.2	Surface Losses Through Oil On Cuttings		13%	
1.3	Trigger Tonnages Below Approved Levels		Yes	
1.4	No OBM spills to marine environment >80L		0	
1.5	Uncontrolled Discharges Of WBM		0	
2	**Cost**			
2.1	Variance Between Bulk Figures		10%	
2.2	Variance Between Sx/Dr Chemical Stock Figures		xx %	
2.4	Cost per Metre Drilled (Drilling Fluid)	36" Section	xx$/m	
2.5	Cost per Metre Drilled (Drilling Fluid)	26" Section	xx$/m	
2.6	Cost per Metre Drilled (Drilling Fluid)	17 1/2" Section	xx$/m	
2.7	Cost per Metre Drilled (Drilling Fluid)	12 1/4" Section	xx$/m	
2.8	Cost per Metre Drilled (Drilling Fluid)	8 1/2" Section	xx$/m	
2.9	Cost per Metre Drilled (Drilling Fluid)	TOTAL WELL	xx$/m	
3	**Time**			
3.1	%NPT For Drilling Fluids		5%	
3.2	%NPT Due To Lack Of Inventory (Exc. Waiting On Weather)		0%	
4	**Tech Ops**			
4.1	Minimise skin damage through mud system having:	%LGS	<5%	
4.2	Minimise skin damage through mud system having:	135 deg HPHT	<4ml	
4.3	Minimise skin damage through mud system having:	accurate emulsifier conc.	Within Limits	
4.4	Good 6 5/8" Cement Job		Good	

Figure 14 - 2 Examples of Goals That Can Be Defined For a Project

The FES system requires a continuous tracking of progress throughout the operation. For each parameter, a reporting frequency needs to be agreed upon. More importantly, using the results as feedback in the design of better practices or during the planning phases of future wells will ensure that the process does produce improvements in the quality of the services provided.

Step Four – Detailed Planning

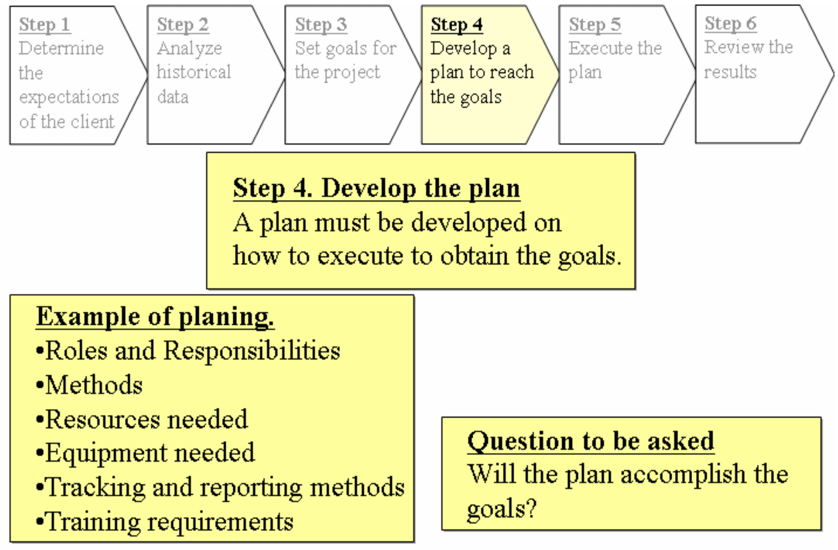
The fourth step is to generate a detailed plan for the operation that addresses all technical hurdles. This includes details collected during the examination of historical data and the goals for the project.

A meeting with key project personnel such as drilling engineers, rig supervisors, drilling fluids engineers, and FES coordinators is held to discuss the critical issues that may include:

- HSE issues
- Hydraulics
- Sweep programs
- Minimum flow rates for hole cleaning
- Fluid properties
- Pipe rotation and rates of penetration
- Tripping guidelines
- Lost circulation prevention and cure

- Swab and surge calculation for running and pulling speeds
- QA procedures for ISO 14001
- Solids control equipment performance
- Waste segregation and disposal
- Training requirements

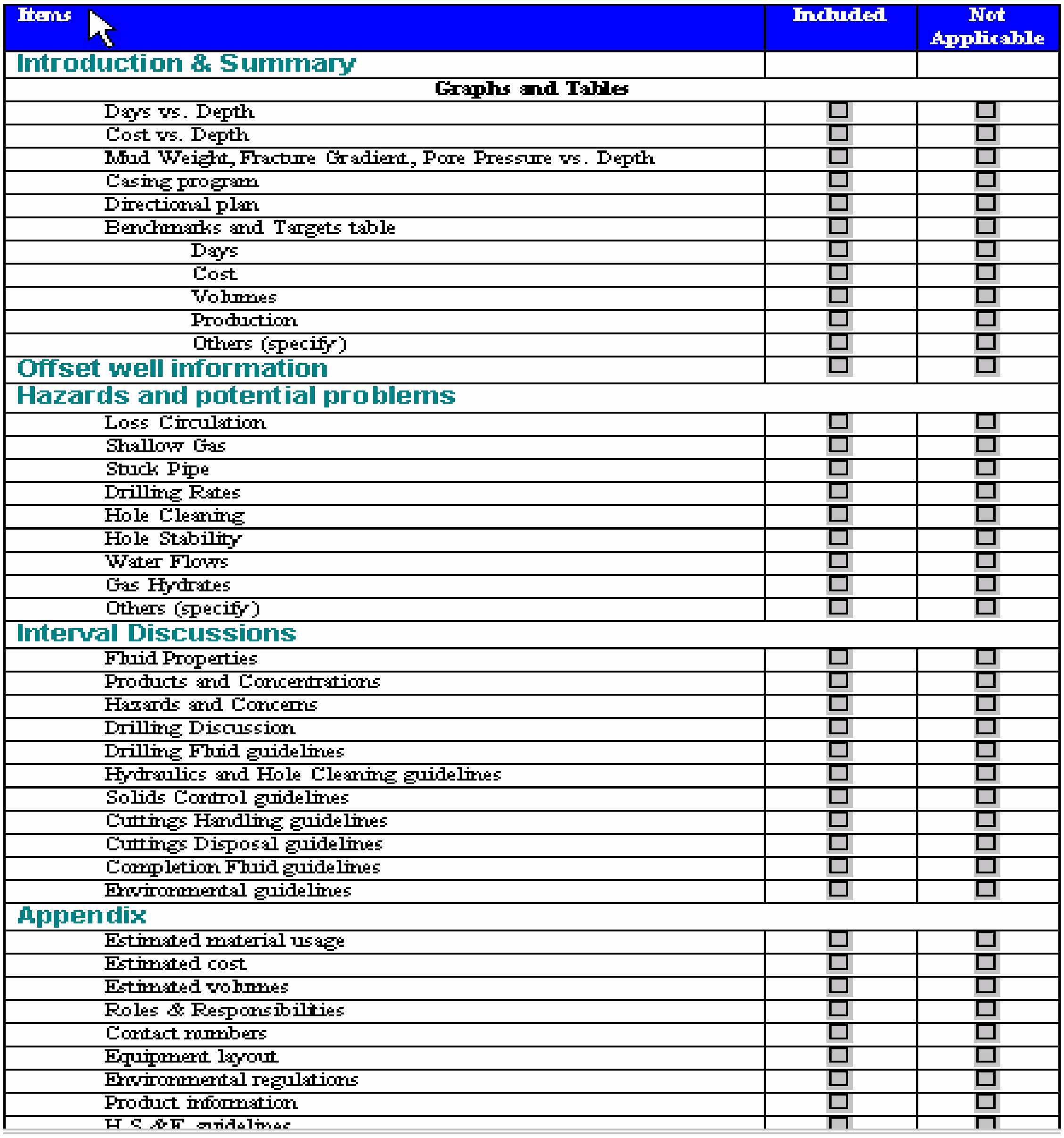
Based on the results of the meeting, a FES plan is prepared that will identify the main technical and logistical obstacles for drilling fluids, completion fluids, solids control and waste management activities. The plan should define the procedures and processes to overcome those potential problems and establish tracking and reporting protocols for the relevant data needed to measure performance.



Step 4. Develop the plan
A plan must be developed on how to execute to obtain the goals.

Example of planing.
- Roles and Responsibilities
- Methods
- Resources needed
- Equipment needed
- Tracking and reporting methods
- Training requirements

Question to be asked
Will the plan accomplish the goals?

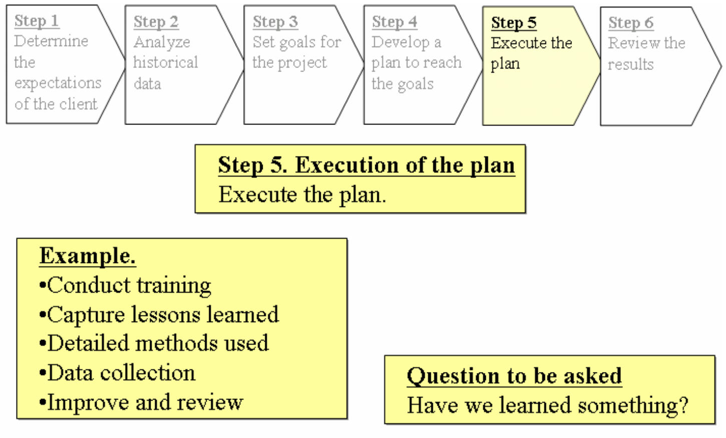


Items	Included	Not Applicable
Introduction & Summary		
Graphs and Tables		
Days vs. Depth	☐	☐
Cost vs. Depth	☐	☐
Mud Weight, Fracture Gradient, Pore Pressure vs. Depth	☐	☐
Casing program	☐	☐
Directional plan	☐	☐
Benchmarks and Targets table	☐	☐
Days	☐	☐
Cost	☐	☐
Volumes	☐	☐
Production	☐	☐
Others (specify)	☐	☐
Offset well information	☐	☐
Hazards and potential problems		
Loss Circulation	☐	☐
Shallow Gas	☐	☐
Stuck Pipe	☐	☐
Drilling Rates	☐	☐
Hole Cleaning	☐	☐
Hole Stability	☐	☐
Water Flows	☐	☐
Gas Hydrates	☐	☐
Others (specify)	☐	☐
Interval Discussions		
Fluid Properties	☐	☐
Products and Concentrations	☐	☐
Hazards and Concerns	☐	☐
Drilling Discussion	☐	☐
Drilling Fluid guidelines	☐	☐
Hydraulics and Hole Cleaning guidelines	☐	☐
Solids Control guidelines	☐	☐
Cuttings Handling guidelines	☐	☐
Cuttings Disposal guidelines	☐	☐
Completion Fluid guidelines	☐	☐
Environmental guidelines	☐	☐
Appendix		
Estimated material usage	☐	☐
Estimated cost	☐	☐
Estimated volumes	☐	☐
Roles & Responsibilities	☐	☐
Contact numbers	☐	☐
Equipment layout	☐	☐
Environmental regulations	☐	☐
Product information	☐	☐
H S &E guidelines	☐	☐

Figure 14 - 3 Thorough Planning Ensures Process Optimisation

Step Five - Execution

The fifth step is the execution of the plans and capturing lessons learned. All of the previous steps should lead to a more effective operation and the FES system is designed to ensure that all relevant information is captured. It is important in this phase to capture ideas and changes to the original plans in order to improve performance. The system should provide the tools for reporting and distributing lessons learned and best practices.



Step 5. Execution of the plan
Execute the plan.

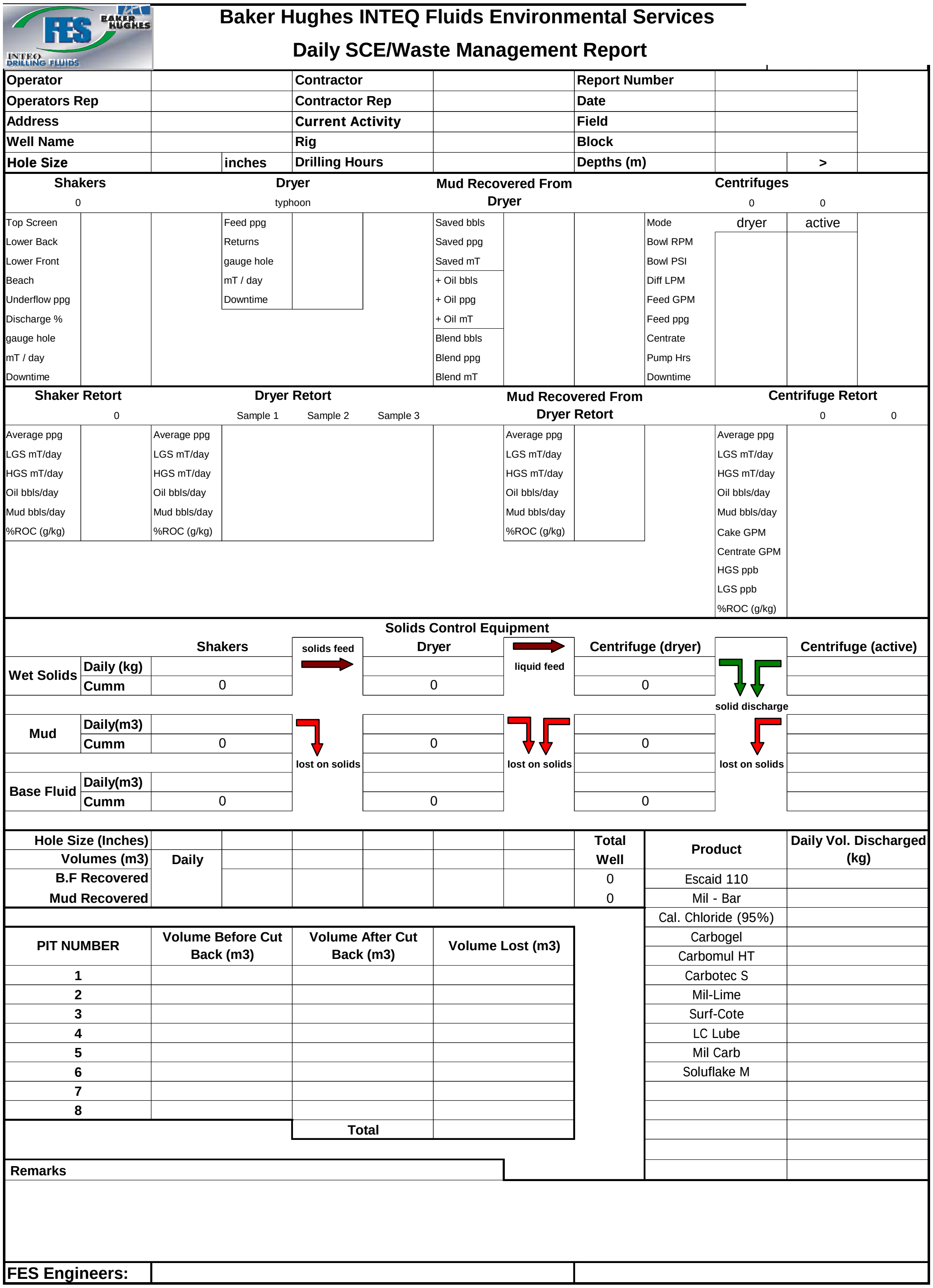
Example.
•Conduct training
•Capture lessons learned
•Detailed methods used
•Data collection
•Improve and review

Question to be asked
Have we learned something?

Every person involved in the project should be familiarized with the key documents that constitute the FES system:

- Roles and responsibilities description: Detailed description of duties and items specific to operations.
- Daily reports: Templates used to record properties, activities and values.
- Weekly reports: Template used to examine performance and take appropriate action if it is falling short of achieving the objectives.
- Lessons Learned: Template used to track and report lessons learned and suggestions for improvement.
- Drilling Practices: Specific practices that affect the FES performance. The key element is effective communication between team members to implement the plan and provide feedback about results and possible improvements.
- Personnel skill assessments and training matrix: A template summarizing the existing pool of skills among personnel in the project, the minimum proficiency requirements based on the project scope and the plan to develop each competency.

Data is recorded on a daily and weekly basis, with the reporting format being tailored to the operator’s needs. Where Baker Hughes Drilling Fluids is also contracted to handle the waste management, a reporting structure is put in place to track the waste from the rig to its final disposal or recycling point, regardless of the manner of process being used. The aims are to ensure a complete audit trail, give accurate volumes, and conform to ISO 14001 requirements and to provide a methodology for waste reduction.



Baker Hughes INTEQ Fluids Environmental Services

Daily SCE/Waste Management Report

Operator		**Contractor**		**Report Number**		
Operators Rep		**Contractor Rep**		**Date**		
Address		**Current Activity**		**Field**		
Well Name		**Rig**		**Block**		
Hole Size	inches	**Drilling Hours**		**Depths (m)**		>

Shakers		**Dryer**		**Mud Recovered From Dryer**		**Centrifuges**		
	0		typhoon				0	0
Top Screen		Feed ppg		Saved bbls		Mode	dryer	active
Lower Back		Returns		Saved ppg		Bowl RPM		
Lower Front		gauge hole		Saved mT		Bowl PSI		
Beach		mT / day		+ Oil bbls		Diff LPM		
Underflow ppg		Downtime		+ Oil ppg		Feed GPM		
Discharge %				+ Oil mT		Feed ppg		
gauge hole				Blend bbls		Centrate		
mT / day				Blend ppg		Pump Hrs		
Downtime				Blend mT		Downtime		

Shaker Retort		**Dryer Retort**				**Mud Recovered From Dryer Retort**		**Centrifuge Retort**		
	0		Sample 1	Sample 2	Sample 3				0	0
Average ppg		Average ppg				Average ppg		Average ppg		
LGS mT/day		LGS mT/day				LGS mT/day		LGS mT/day		
HGS mT/day		HGS mT/day				HGS mT/day		HGS mT/day		
Oil bbls/day		Oil bbls/day				Oil bbls/day		Oil bbls/day		
Mud bbls/day		Mud bbls/day				Mud bbls/day		Mud bbls/day		
%ROC (g/kg)		%ROC (g/kg)				%ROC (g/kg)		Cake GPM		
								Centrate GPM		
								HGS ppb		
								LGS ppb		
								%ROC (g/kg)		

Solids Control Equipment

		Shakers		**Dryer**		**Centrifuge (dryer)**		**Centrifuge (active)**
Wet Solids	**Daily (kg)**		solids feed		liquid feed			
	Cumm	0		0		0	solid discharge	
Mud	**Daily(m3)**							
	Cumm	0	lost on solids	0	lost on solids	0	lost on solids	
Base Fluid	**Daily(m3)**							
	Cumm	0		0		0		

Hole Size (Inches)							**Total**	
Volumes (m3)	**Daily**						**Well**	
B.F Recovered							0	
Mud Recovered							0	

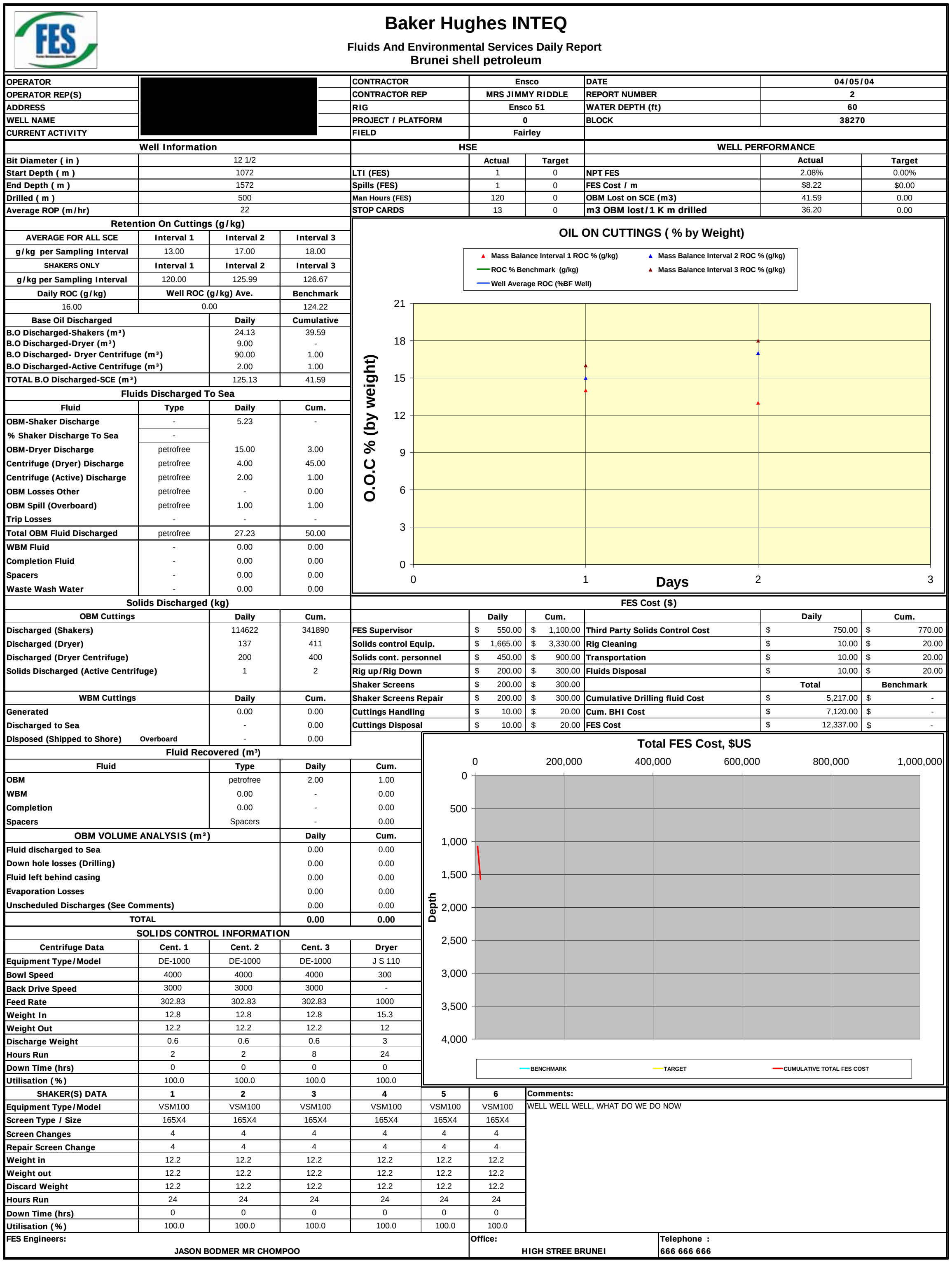
PIT NUMBER	**Volume Before Cut Back (m3)**	**Volume After Cut Back (m3)**	**Volume Lost (m3)**
1			
2			
3			
4			
5			
6			
7			
8			
		Total	

Product	**Daily Vol. Discharged (kg)**
Escaid 110	
Mil - Bar	
Cal. Chloride (95%)	
Carbogel	
Carbomul HT	
Carbotec S	
Mil-Lime	
Surf-Cote	
LC Lube	
Mil Carb	
Soluflake M	

Remarks

FES Engineers:

Figure 14 - 4 Example of Daily Solids Control / Waste Management Report



Baker Hughes INTEQ

Fluids And Environmental Services Daily Report
Brunei shell petroleum

OPERATOR	[redacted]	CONTRACTOR	Ensco	DATE	04/05/04
OPERATOR REP(S)	[redacted]	CONTRACTOR REP	MRS JIMMY RIDDLE	REPORT NUMBER	2
ADDRESS	[redacted]	RIG	Ensco 51	WATER DEPTH (ft)	60
WELL NAME	[redacted]	PROJECT / PLATFORM	0	BLOCK	38270
CURRENT ACTIVITY	[redacted]	FIELD	Fairley		

Well Information		HSE			WELL PERFORMANCE		
			Actual	Target		Actual	Target
Bit Diameter (in)	12 1/2						
Start Depth (m)	1072	LTI (FES)	1	0	NPT FES	2.08%	0.00%
End Depth (m)	1572	Spills (FES)	1	0	FES Cost / m	$8.22	$0.00
Drilled (m)	500	Man Hours (FES)	120	0	OBM Lost on SCE (m3)	41.59	0.00
Average ROP (m/hr)	22	STOP CARDS	13	0	m3 OBM lost/1 K m drilled	36.20	0.00

Retention On Cuttings (g/kg)			
AVERAGE FOR ALL SCE	Interval 1	Interval 2	Interval 3
g/kg per Sampling Interval	13.00	17.00	18.00
SHAKERS ONLY	Interval 1	Interval 2	Interval 3
g/kg per Sampling Interval	120.00	125.99	126.67
Daily ROC (g/kg)	Well ROC (g/kg) Ave.		Benchmark
16.00	0.00		124.22

Base Oil Discharged	Daily	Cumulative
B.O Discharged-Shakers (m^3)	24.13	39.59
B.O Discharged-Dryer (m^3)	9.00	-
B.O Discharged- Dryer Centrifuge (m^3)	90.00	1.00
B.O Discharged-Active Centrifuge (m^3)	2.00	1.00
TOTAL B.O Discharged-SCE (m^3)	125.13	41.59

Fluids Discharged To Sea			
Fluid	Type	Daily	Cum.
OBM-Shaker Discharge	-	5.23	-
% Shaker Discharge To Sea	-		
OBM-Dryer Discharge	petrofree	15.00	3.00
Centrifuge (Dryer) Discharge	petrofree	4.00	45.00
Centrifuge (Active) Discharge	petrofree	2.00	1.00
OBM Losses Other	petrofree	-	0.00
OBM Spill (Overboard)	petrofree	1.00	1.00
Trip Losses	-	-	-
Total OBM Fluid Discharged	petrofree	27.23	50.00
WBM Fluid	-	0.00	0.00
Completion Fluid	-	0.00	0.00
Spacers	-	0.00	0.00
Waste Wash Water	-	0.00	0.00

Solids Discharged (kg)		
OBM Cuttings	Daily	Cum.
Discharged (Shakers)	114622	341890
Discharged (Dryer)	137	411
Discharged (Dryer Centrifuge)	200	400
Solids Discharged (Active Centrifuge)	1	2
WBM Cuttings	Daily	Cum.
Generated	0.00	0.00
Discharged to Sea	-	0.00
Disposed (Shipped to Shore) Overboard	-	0.00

FES Cost ($)					
	Daily	Cum.		Daily	Cum.
FES Supervisor	$ 550.00	$ 1,100.00	Third Party Solids Control Cost	$ 750.00	$ 770.00
Solids control Equip.	$ 1,665.00	$ 3,330.00	Rig Cleaning	$ 10.00	$ 20.00
Solids cont. personnel	$ 450.00	$ 900.00	Transportation	$ 10.00	$ 20.00
Rig up/Rig Down	$ 200.00	$ 300.00	Fluids Disposal	$ 10.00	$ 20.00
Shaker Screens	$ 200.00	$ 300.00		Total	Benchmark
Shaker Screens Repair	$ 200.00	$ 300.00	Cumulative Drilling fluid Cost	$ 5,217.00	$ -
Cuttings Handling	$ 10.00	$ 20.00	Cum. BHI Cost	$ 7,120.00	$ -
Cuttings Disposal	$ 10.00	$ 20.00	FES Cost	$ 12,337.00	$ -

Fluid Recovered (m^3)			
Fluid	Type	Daily	Cum.
OBM	petrofree	2.00	1.00
WBM	0.00	-	0.00
Completion	0.00	-	0.00
Spacers	Spacers	-	0.00

OBM VOLUME ANALYSIS (m^3)	Daily	Cum.
Fluid discharged to Sea	0.00	0.00
Down hole losses (Drilling)	0.00	0.00
Fluid left behind casing	0.00	0.00
Evaporation Losses	0.00	0.00
Unscheduled Discharges (See Comments)	0.00	0.00
TOTAL	0.00	0.00

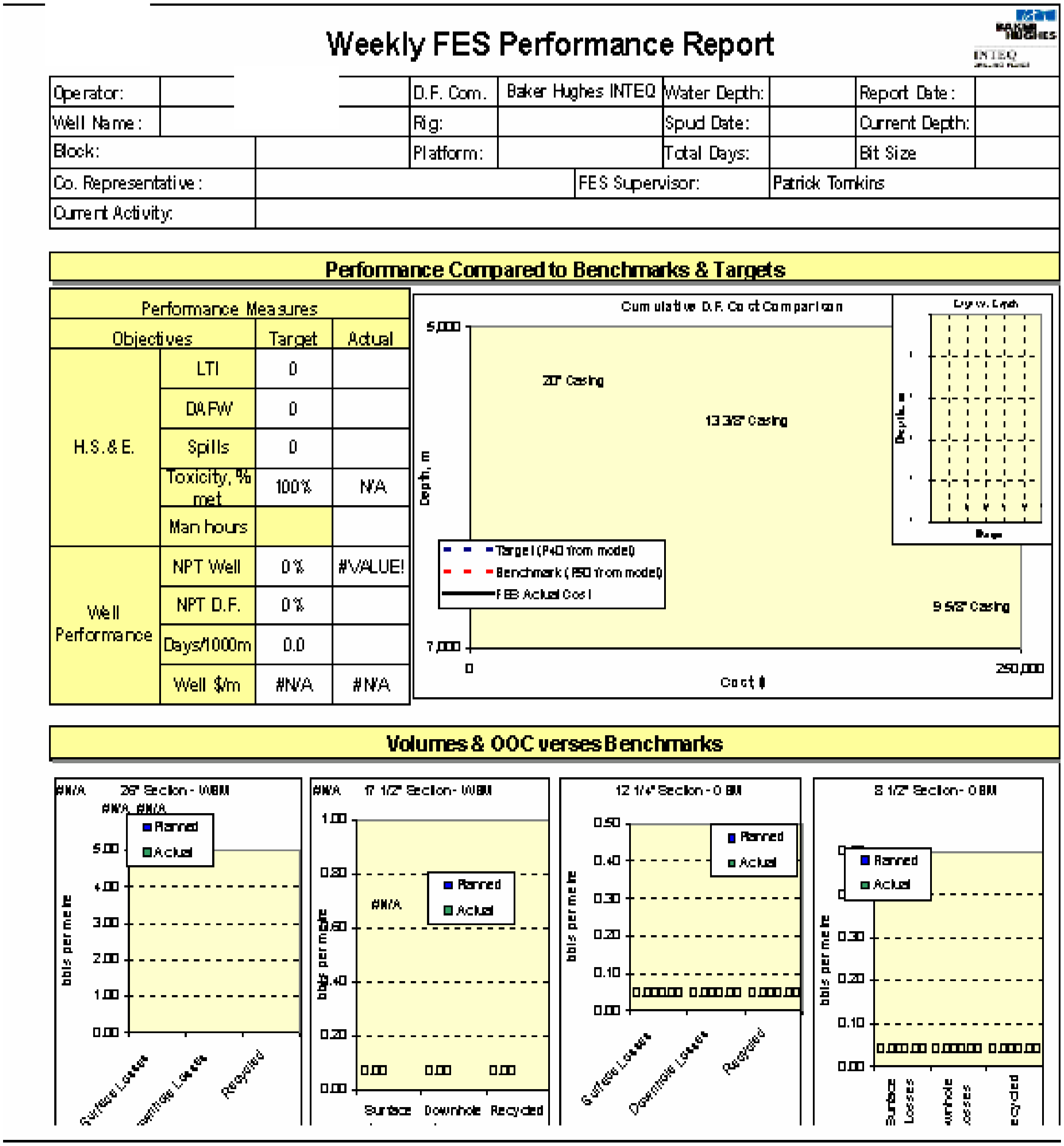
SOLIDS CONTROL INFORMATION				
Centrifuge Data	Cent. 1	Cent. 2	Cent. 3	Dryer
Equipment Type/Model	DE-1000	DE-1000	DE-1000	J S 110
Bowl Speed	4000	4000	4000	300
Back Drive Speed	3000	3000	3000	-
Feed Rate	302.83	302.83	302.83	1000
Weight In	12.8	12.8	12.8	15.3
Weight Out	12.2	12.2	12.2	12
Discharge Weight	0.6	0.6	0.6	3
Hours Run	2	2	8	24
Down Time (hrs)	0	0	0	0
Utilisation (%)	100.0	100.0	100.0	100.0

SHAKER(S) DATA	1	2	3	4	5	6
Equipment Type/Model	VSM100	VSM100	VSM100	VSM100	VSM100	VSM100
Screen Type / Size	165X4	165X4	165X4	165X4	165X4	165X4
Screen Changes	4	4	4	4	4	4
Repair Screen Change	4	4	4	4	4	4
Weight in	12.2	12.2	12.2	12.2	12.2	12.2
Weight out	12.2	12.2	12.2	12.2	12.2	12.2
Discard Weight	12.2	12.2	12.2	12.2	12.2	12.2
Hours Run	24	24	24	24	24	24
Down Time (hrs)	0	0	0	0	0	0
Utilisation (%)	100.0	100.0	100.0	100.0	100.0	100.0

Comments:
WELL WELL WELL, WHAT DO WE DO NOW

FES Engineers: JASON BODMER MR CHOMPOO	Office: HIGH STREE BRUNEI	Telephone : 666 666 666

Figure 14 - 5 Example of a Daily FES Report



Weekly FES Performance Report

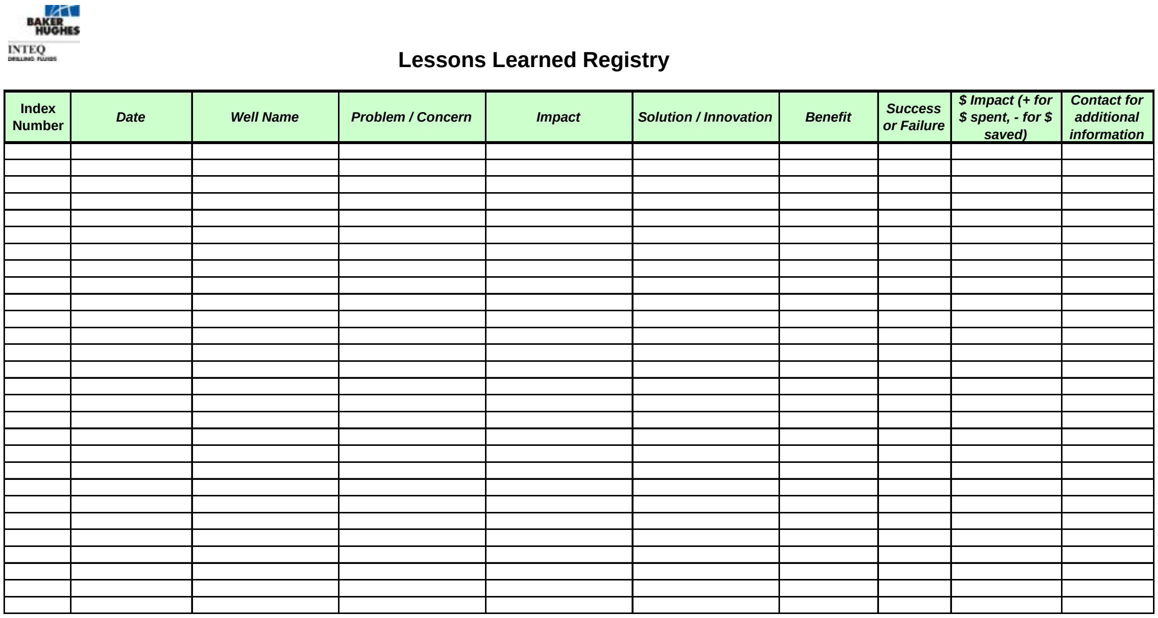
Operator:		D.F. Com.	Baker Hughes INTEQ	Water Depth:		Report Date:	
Well Name:		Rig:		Spud Date:		Current Depth:	
Block:		Platform:		Total Days:		Bit Size	
Co. Representative:			FES Supervisor:	Patrick Tomkins			
Current Activity:							

Performance Compared to Benchmarks & Targets

Performance Measures			
Objectives		Target	Actual
H.S.& E.	LTI	0	
	DAFW	0	
	Spills	0	
	Toxicity, % met	100%	N/A
	Man hours		
Well Performance	NPT Well	0%	#VALUE!
	NPT D.F.	0%	
	Days/1000m	0.0	
	Well $/m	#N/A	#N/A

Volumes & OOC verses Benchmarks

Figure 14 - 6 Example of a Weekly FES Report



BAKER HUGHES
INTEQ
DRILLING FLUIDS

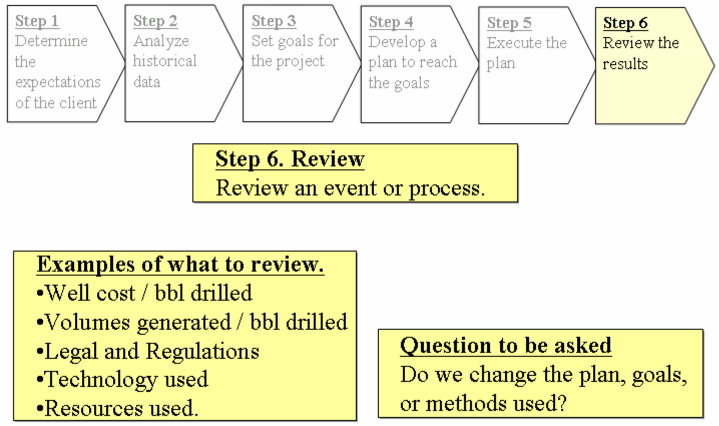
Lessons Learned Registry

Index Number	*Date*	*Well Name*	*Problem / Concern*	*Impact*	*Solution / Innovation*	*Benefit*	*Success or Failure*	*$ Impact (+ for $ spent, - for $ saved)*	*Contact for additional information*

Figure 14 - 7 Example of a Lessons Learned Registry

Step Six - Continuous Improvement and Learning

The final step in the FES process is a formal review and validation of the lessons learned during the well or project. The idea is to compare the actual results with the goals and expectations defined at the beginning of the project. The objective is to improve the process for future operations.



Step 6. Review
Review an event or process.

Examples of what to review.
•Well cost / bbl drilled
•Volumes generated / bbl drilled
•Legal and Regulations
•Technology used
•Resources used.

Question to be asked
Do we change the plan, goals, or methods used?

There are six questions asked during the After Action Review (AAR):

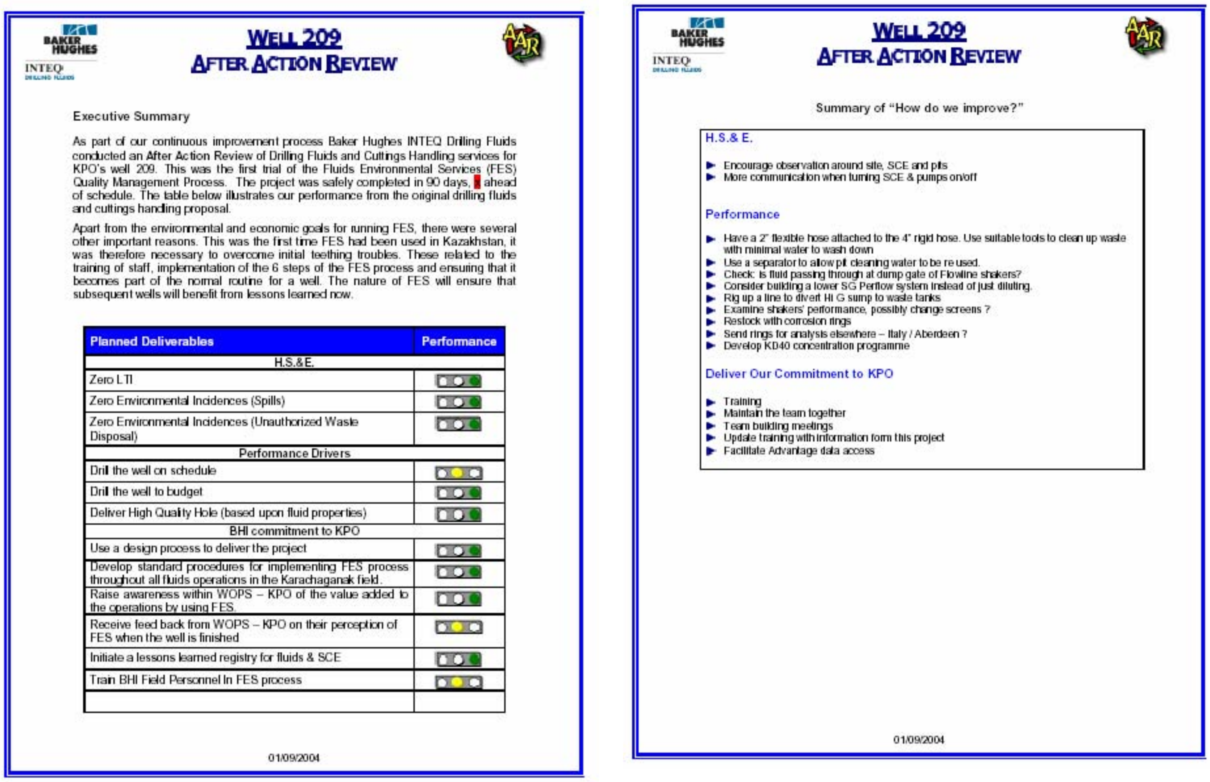
- What were the plan and the goals for the well or project?
- What was done and/or accomplished?
- What were the differences between the plan and what was accomplished?
- Why did these differences occur?
- How do we sustain and promote what was done right?

- How do we improve or eliminate what was done incorrectly?

There are several key aspects that need to be considered when performing a review:

- Identify weaknesses and strengths during the process.
- Distribute lessons learned throughout the organization.
- Assign responsibilities for implementing new actions.
- Perform a self-assessment review of those involved in the project.

Examples from an After Action Review are shown below.



WELL 209
AFTER ACTION REVIEW

Executive Summary

As part of our continuous improvement process Baker Hughes INTEQ Drilling Fluids conducted an After Action Review of Drilling Fluids and Cuttings Handling services for KPO's well 209. This was the first trial of the Fluids Environmental Services (FES) Quality Management Process. The project was safely completed in 90 days, x ahead of schedule. The table below illustrates our performance from the original drilling fluids and cuttings handling proposal.

Apart from the environmental and economic goals for running FES, there were several other important reasons. This was the first time FES had been used in Kazakhstan, it was therefore necessary to overcome initial teething troubles. These related to the training of staff, implementation of the 6 steps of the FES process and ensuring that it becomes part of the normal routine for a well. The nature of FES will ensure that subsequent wells will benefit from lessons learned now.

Planned Deliverables	Performance
H.S.&E.	
Zero LTI	○ ○ 🟢
Zero Environmental Incidences (Spills)	○ ○ 🟢
Zero Environmental Incidences (Unauthorized Waste Disposal)	○ ○ 🟢
Performance Drivers	
Drill the well on schedule	○ 🟡 ○
Drill the well to budget	○ ○ 🟢
Deliver High Quality Hole (based upon fluid properties)	○ ○ 🟢
BHI commitment to KPO	
Use a design process to deliver the project	○ ○ 🟢
Develop standard procedures for implementing FES process throughout all fluids operations in the Karachaganak field.	○ ○ 🟢
Raise awareness within WOPS – KPO of the value added to the operations by using FES.	○ ○ 🟢
Receive feed back from WOPS – KPO on their perception of FES when the well is finished	○ 🟡 ○
Initiate a lessons learned registry for fluids & SCE	○ ○ 🟢
Train BHI Field Personnel In FES process	○ 🟡 ○

01/09/2004

WELL 209
AFTER ACTION REVIEW

Summary of "How do we improve?"

H.S.& E.

- Encourage observation around site, SCE and pits
- More communication when turning SCE & pumps on/off

Performance

- Have a 2" flexible hose attached to the 4" rigid hose. Use suitable tools to clean up waste with minimal water to wash down
- Use a separator to allow pit cleaning water to be re used.
- Check: is fluid passing through at dump gate of Flowline shakers?
- Consider building a lower SG Perflow system instead of just diluting.
- Rig up a line to divert Hi G sump to waste tanks
- Examine shakers' performance, possibly change screens ?
- Restock with corrosion rings
- Send rings for analysis elsewhere – Italy / Aberdeen ?
- Develop KD40 concentration programme

Deliver Our Commitment to KPO

- Training
- Maintain the team together
- Team building meetings
- Update training with information form this project
- Facilitate Advantage data access

01/09/2004

Figure 14 - 8 Examples from an After Action Review Report

BEST OPERATING PRACTICES

Reducing the volume of waste and containing those substances with higher potential for pollution is critical to improve the environmental performance under a FES system. A key area for improvement is in the segregation and accounting of wastes. As a rule, treatment costs are higher as the concentration of hydrocarbon increases. If wastes free from hydrocarbons are commingled with oily residues then a larger than necessary volume of waste containing hydrocarbons is being treated. Likewise, poor accounting at both the rig site and at the waste treatment center could lead to differences between volume of waste sent and received. It is important that it is realized that all waste is not the same and even though it is waste, it needs to be tracked as carefully as any other asset. This is of particular importance to the operator as it is related to liability, duty of care and ownership of any waste.

Volume Reduction

An important part of the FES strategy is to reduce the overall volumes of fluids produced from the drilling and completion of each well. By reducing excess volume there will be a corresponding reduction in waste, bringing further cost benefits.

The main sources of excess fluids volume are:

a) Discharges of WBM

- Limited fluids recycling and reuse.

Water based drilling fluids by their nature are more readily biodegradable and have a shorter “shelf life” than oil based drilling fluids. As they are generally less inhibitive than OBM they tend to become solids laden more readily and require expensive separation processes to remove the incorporated drilled solids.

In the past very little effort was spent on evaluating the economical and environmental potential of reusing WBM fluids in offshore operations. This was primarily due to the perception that the incremental cost of shipping, reconditioning and storing these fluids would be prohibitive. This is particularly evident when the water-based system is being replaced by an oil based system. Many drilling installations do not have the capacity or the facilities to handle two types of drilling fluids simultaneously and marine vessels do not have sufficient tanks to transport both systems independently.

For onshore operations, ***dewatering*** techniques are used in the closed loop mud systems (CLMS) as an alternative to direct discharge of WBM drilling fluids. This process eliminates the use of reserve pits and recirculation pits or sumps, in the treatment and removal of drill solids from drilling fluids. The dewatering techniques used in this process combines conventional solids control equipment with chemically enhanced dewatering methods to remove the ultra-fine solids from the drilling fluid and dispose of it as a dry waste. The application of these techniques has grown in usage to become an integral part of routine drilling operations.

Dewatering methods were initially used to treat the liquid drilling waste in a reserve pit, removing the solids and discharging the cleaned fluid. As the economic and environmental pressures grew to go to a CLMS operation, the use of coagulation and flocculation chemical technology in conjunction with decanting centrifuges and specialized dewatering equipment became the preferred method for drilling operations. The active water-based drilling fluid is dewatered with chemically enhanced centrifugation, removing the fine drilled solids and returning the clear water to the system.

The solids are discarded to a collection bin and the clear water is returned to the active system. Depending on chemical content, the solids can be land-farmed on the location, restoring it to original form, or hauled off to a disposal area.

In areas where solids water content is closely monitored, the use of drying mechanisms has been implemented to complement the typical centrifugation equipment to further reduce the volume of waste. The drying systems used include:

- High impact drying shakers.
- Centrifugal cuttings dryers (i.e. Baker Hughes Drilling Fluids' Typhoon).
- Filter presses.

b) Excess Dilution and Mud Retention on Cuttings (OBM & WBM).

The volume of dilution is a direct function of the efficiency of the solids control equipment. Waste is generated because of (1) build up of solids in the drilling fluid that result in higher dilution rates and (2) excess of liquid bonded to the solids particles removed by the solids control equipment. A balance has to be achieved between these two options to find the preferred specifications that will maximize the reduction in the volume of waste.

The efficiency of the solids control equipment can have a major impact both on the condition of the drilling fluid as well as the volume of waste. Wet cuttings obviously weigh more and take up more space than drier cuttings, which ultimately increases the transport and treatment costs. Additionally, this is drilling fluid that is effectively being thrown away when it could easily be retained within the system for further use.

Shakers that aren't being operated at their optimum can force the driller to cut the pump strokes in order to prevent mud being discharged over the end of the screens. This can result in poor hole cleaning and slower ROPs.

By monitoring the SCE and waste management this will ensure the SCE is being run at optimal efficiency, treatment costs should be reduced and unnecessary fluid losses avoided, which will ultimately save money.

An efficient solids control system requires continuous actions and monitoring to ensure a proper operation. At a minimum the following actions should be carried out:

- *Adherence to the API R13B rules for solids control systems efficiency determination.*
- *Definition of the recommended operational parameters for each piece of equipment for each section. This is an expected set of values (i.e. feed rates, dryness, output weights) for each piece of solids control equipment and for each section that is at least required to guarantee a minimum level of efficiency commensurate with the drilling requirements. These values will be decided in conjunction with the parties in charge of their operation.*
- *Continuous monitoring of compliance with the recommended parameters.*

- *Periodic testing of individual solids control equipment to establish their solids removal efficiency, following the API R13C rule.*

Waste Minimization

In addition to the reduction of the volume of fluids and cuttings, it is also critical to minimize the amount of other wastes produced as part of the operation in order to mitigate the environmental impact of drilling activities.

a) Tank cleaning (Rigs, supply boats, onshore tanks).

  - Frequent changes in fluid type carried.
  - Excess residues in tanks as a result of inefficient design.
  - Logistics limitations and poor planning.
  - Limited storage space on rigs, vessels and onshore.
  - Poor practices.

Tank cleaning of marine vessels, trucks and installation tanks is a major source of waste. Vessel tanks are frequently cleaned after each shipment. On many occasions the tank is then refilled with a similar product to the previous shipment, making the cleaning operation unnecessary.

Sharing vessels between operators, who use different base oils, normally necessitates cleaning tanks between shipments. Most vessels are not able to dedicate tank space to specific product types, which also leads to tank cleaning between shipments.

Many boat tanks were not designed specifically to carry drilling fluids. In some cases this leads to excessive volumes being left in the tanks which become non-recoverable volume that ultimately gets included in the waste stream instead of being recovered for use. Most often this can be avoided by proper planning.

b) Slop water

  - Poor drainage design - no segregation of type of fluid rainwater, waste oil etc. all gathered into one tank.
  - Large oil / water interfaces when displacing to or from the well.

When using OBM, all the drains run into a common collection system. This collects all run-off including rainwater that may have been contaminated with OBM. The contaminated “slop water” is then shipped to shore for processing. Additional contaminated water is generated from vessel tank cleaning, cleaning skips and cleaning big bags once the contaminated cuttings have been removed.

c) Cuttings Transportation Systems

  - Use of skips and big bags leads to extensive cleaning with high associated wastes.

Many operators currently use big bags and skips to transport OBM cuttings to waste sites for disposal. This generates additional waste. Skips can sometimes collect water en route and this water is contaminated with oil from the cuttings even if they are in big bags. This water then has to be collected and treated. The skip also has oil contamination within it that requires cleaning before shipment, generating more oily slop waste.

The big bags when emptied need cleaning before final disposal, again this leads to additional oily slop waste. Plus the big bags themselves are an unnecessary waste item.

d) Packaging

- Mixing on rigs results in large amount of waste packaging - sacks, drums, plastic wrapping, pallets, etc.

Current drilling fluid practice is to ship many individual components to the installations for fluid building and maintenance. Considerable packaging waste is generated in this process. While recent advances in offshore plant have made some improvement in this area, there is still excessive packaging waste to be disposed of.

Recommendations to Reduce Surplus Volumes and Wastes at the Rig Site

The following procedures and actions can be applied to reduce surplus volumes and waste at the rig site:

a) Reviewing the primary solids control equipment and plumbing to identify the best-in-class equipment and /or layout for each installation to reduce dilution by removing low gravity solids before they become included into the system. This approach will dramatically reduce both the volumes of fluids and waste to be handled and subsequently processed. A reduction of more than 10% in dilution and discharges from this action can be expected.

b) Ensuring the correct screens are used for each formation encountered considerably reduces the number of shaker screens utilised on each well.

c) The installation and correct use of efficient centrifuges for density reductions will greatly reduce the volume of dilution fluid normally used for density decreases. This reduces the need to dump or handle excessive volumes.

d) The use of these recommendations will reduce the cost of building unnecessary fluid for dilution and the volume of surplus fluid that would subsequently need to be handled and shipped to shore for processing.

Recommendations to Reduce Surplus Slop Waste at the Rig Site

a) The preferred approach for handling oil contaminated water is, where ever possible, to reduce the unnecessarily excessive volume of clean water that is incorporated into the waste that will be shipped for treatment. This may be achieved as follows:

- Segregate drains that are likely to contain heavy hydrocarbons with minimal water (i.e. crane containment, pump, engine and compressor skids) directly to a waste oil containment tank and handle separately.
- Re-route drains from areas that are likely to contain limited hydrocarbons and filter this through oil specific filter medium or collect it into a skimmer tank to remove any gravity-separated oil prior to discharging or disposal.
- All drilling package drains (i.e. drill floor, mud treatment areas) should be routed to an OBM slop waste storage tank. This slop can then either be shipped to shore for processing or processed on site, space and deck load permitting. If an on site process is feasible then the concentrated OBM waste could be reused in the system, providing it was contained close to or less than the water percentage of the mud system.
- Use a mud vacuum system to recover all drilling fluid spills back into the active system before they enter the drains. This will reduce the cost of processing slop waste.

- Reduce water used for rig washing etc. by limiting the use of water hoses and replacing them with a high pressure washer system. This greatly reduces the water that would subsequently require processing.

The main benefits from this approach include:

- Reducing the required storage for collecting slop for shipping to shore.
- Reducing the cost to ship, clean tanks and process a product, which is generally ±80% water, will offset the cost of implementing these changes.

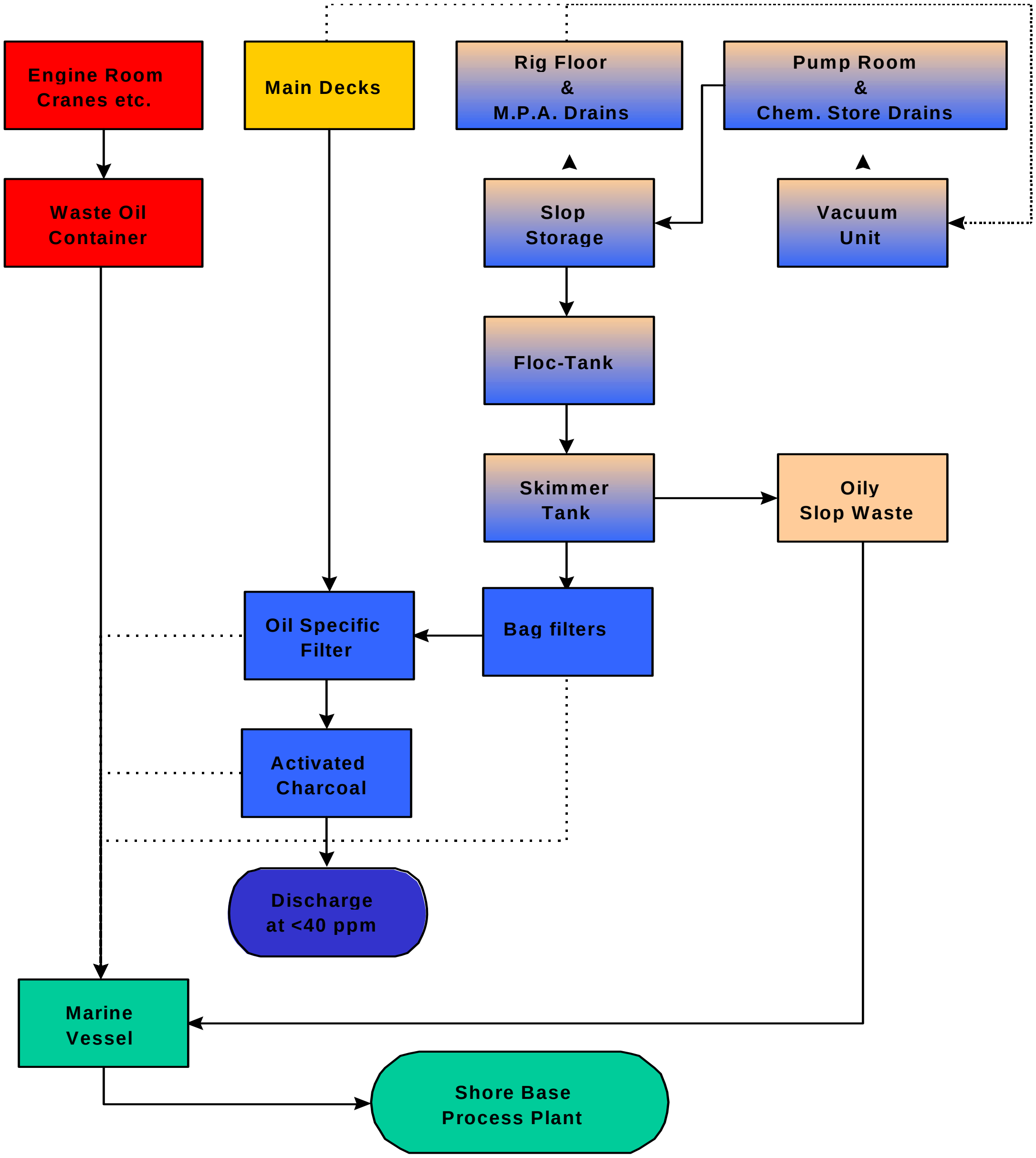


Figure 14 - 9 Typical Rig Site Water and Oily Waste Handling System (Offshore)

WASTE TRANSPORT AND DISPOSAL

When an operator decides to go to zero discharge, there are two main options for handling the waste, either cuttings re-injection or skip and ship. Cuttings re-injection is a very effective disposal option that fully complies with zero discharge to the surface environment. It is discussed later in this section.

When waste is transported from an offshore rig to the shore, there are several equipment options that depend upon the infrastructure in the drilling area, the type of final disposal treatment and the logistical limitations of the operator.

Skip & Ship

Skip & ship: use of cutting boxes that can be easily lifted between the rig and transport vessel and from the vessel to shore on to trucks. These containers are built according to marine safety specifications and provide an efficient means to transfer waste for long distances. Using sealed containers has the following advantages:

a) The sealed containers are designed to enable them to be stacked on top of each other, thus reducing deck space to store them.

b) The containers are easily handled by offshore cranes making them safer to handle than big bags. The containers are designed to DNV standards and can be easily stacked.

c) Prevents both rain and sea water being incorporated into the waste stream.

d) Reducing water in the solids waste improves the efficiency of both thermal desorption and incineration processes.

The skips or cutting boxes are usually manufactured to hold 12 bbls (1.90 m^3) or 25 bbls (3.81 m^3).

Determining the number of cutting boxes required to satisfy the waste transportation demands of the operation is very important. Rigs have very limited footprint available for storing idle equipment and weight limitations per unit of area. In addition, transport vessels are expensive so an optimum use of their capacity and time is important to reduce the waste management cost of the project.

When estimating the number of boxes needed for each section, the following factors have to be taken into account:

- Footage to be drilled in the section
- Hole size
- Average footage per day
- Skip capacity
- Filling up level of cutting boxes (percentage)
- Estimated liquid content in the waste
- Turnaround time for cutting boxes
- Dry waste density
- Drilling fluid density
- Oil-water-ratio of the drilling fluid
- Base oil density

A simplified version of a cutting box requirements calculator can be found in the toolbox section of the **BakerHughesDirect** website.

Bulk Transport Systems: These are systems that use larger containers to store and transport the waste between the rig and the final disposal site. A loading/unloading system is installed on both ends to transfer the waste to the sealed containers. Usually, pneumatic equipment such as blowers (pushing action) and vacuum units (pulling action) is employed for this operation.

Cuttings Fixation

Cuttings fixation, also known as cuttings stabilization, blends dry material with the moist cuttings to achieve bonding and drying. Three materials are commonly used in the blending process; activated lime, fly ash, and kiln dust. The availability and cost of the blending material will determine which one is the most economical to use, with lime the material of choice. The EPA recognizes that activated lime does an excellent job in solidifying non-hazardous waste and recommends it for use in oilfield and industrial applications.

The bonding material is blended with the "cuttings" in ratios that promote stabilization of the wet cuttings. The blending process is performed using a pug mill auger and feed hopper, allowing proper mixing of the bonding material with the cuttings. This "stabilized" material can then be used as road fill, made into bricks for building purposes, or is buried in pits and covered.

Bioremediation

Bioremediation uses naturally occurring micro-organisms, such as bacteria, fungi, or yeast to degrade harmful chemicals into less toxic or non-toxic compounds. These micro-organisms break down a wide variety of organic compounds (hydrocarbons) found in nature and are considered nature's recyclers. Certain species of soil bacteria process hydrocarbons as a food source converting the contaminants into carbon dioxide, water and fatty acids.

The micro-organisms are applied to the contaminated soils through tilling or spraying. Nutrients can then be added for enhanced activity of the micro-organisms and to promote the biodegradation of the hydrocarbons. Third party companies provide the equipment and services for the successful bioremediation of hydrocarbon contaminated soil and water.

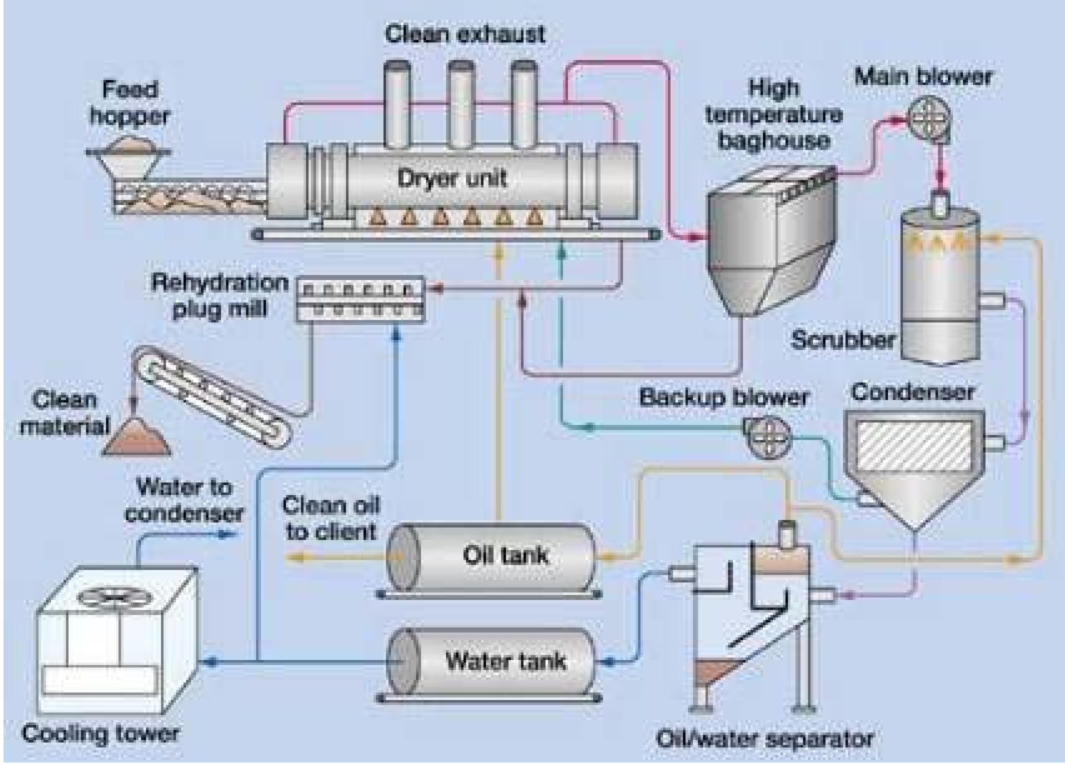
Landfarming

Land farming or land treatment is an economical technique for the mixing of the appropriate type of drilling solids and liquids with the soil found at that location. This eliminates the transfer of the waste material to another site and typically enhances the soil's productivity.

Soil samples should be analyzed to determine the condition of the location prior to the drilling operation and establish background parameters. During the operation, appropriate drilling wastes can be stacked on location or stored in pits, while material containing contaminants such as salt or oil should be contained separately. Once drilling operations are complete, the waste material can be applied to soil and ploughed until dryness and adequate mixing has occurred. Samples are tested to meet the state regulatory requirements, i.e. 29-B Louisiana. In some cases, fill material is added to meet the state specifications.

Thermal Treatment

There are several methods of thermal treatment (desorption) of drilling waste, the most common being indirect thermal desorption:



The externally heated rotary dryer is sealed on either end to limit oxygen entering the system, and vapor exiting. The dryer shell heats cuttings to between 600 and 900°F by conductive heat transfer. Retention time within the drum varies between 20 and 30 min. to thoroughly heat and vaporize all of the liquids. Cleaned cuttings exit as dry, inert dust, and are re-hydrated with water to a manageable consistency prior to non-hazardous disposal or use in construction materials, e.g., bricks, road base or cover for a sanitary landfill.

The hot oil and water vapors are filtered through a high-temperature, fabric-filter bag-house for fine particulate removal, and subsequently condensed into liquid by means of a shell and tube condenser system cooled by a closed-loop cooling tower. The fluid then passes through an oil / water separator system, with recovered water used as makeup water for the cooling tower and cuttings re-hydration, and recovered oil returned to the client for reuse in the mud system (or other use), with a small portion used to fuel the self-contained, thermal-desorption process.

Air emissions from the system are well below EPA's 1990 Clean Air Act for Particulate Matter, SOx, NOx and VOCs, and EPA has designated this type of system as "BDAT" (Best Demonstrated Available Technology) for cleanup of hydrocarbon-contaminated soils.

Other Thermal Treatments

Distillation

Distillation enables solids and liquids and the different constituents of liquid mixtures to be separated, relying on the fact that the constituents of liquid mixtures evaporate at different temperatures.

Two types of processes are available:

- Thermo-mechanical conversion and cracking (TCC) where the drill cuttings are subjected to distillation/cracking with water and oil being boiled off. In some cases the vapors are condensed to allow recovery;

- Thermal stripping which is carried out a lower temperature. This means the oil is not cracked and can be re-used.

The resulting treated cuttings can potentially be re-used although they may contain elevated concentrations of heavy metals and chloride salts. The latter can be removed through chloride stripping.

Solvent Extraction

Solvent extraction relies on mixing cuttings with a suitable solvent to form a fluid emulsion, which can then be distilled to allow separation. There is no thermal damage to the oil, which can therefore be re-used.

Combustion

Incineration has been used for the disposal of organic waste which is highly toxic, highly flammable and/or resistant to biological breakdown. The process normally leaves a solid residue or ash, which can be disposed of to landfill. Energy requirements are directly related to water content and therefore costs for the incineration of materials such as drill cuttings could be high if the cuttings have a high water content.

Stabilization

Chemical and physical stabilization can be used to modify the cuttings into a more usable form or into less hazardous waste. This can be carried out by solidification, effectively encapsulating the waste into a solid mass to minimize the possibility of leaching. Organic polymers or inorganic additives can be used to improve the stability of the mass. The main problem with such treatments is that may result in the total volume of waste increasing. However, they require minimal energy input and result in minimal emissions to air.

Possible Uses of Waste

Concrete Products

Use in the construction industry as a concrete/cement mix aggregate has frequently been touted as a suitable reuse option for treated drill cuttings. During this study a number of construction companies expressed an interest in using the cuttings in this manner. To identify more precisely which concrete products might be suitable, treated drill cuttings were analyzed by the Concrete Technology Unit of the University of Dundee. Preliminary findings found the treated cuttings to be high in chlorides, barite and sulfates. High chloride levels make the cuttings unsuitable for steel reinforced concrete. Barite is insoluble but also contains toxic elements and this toxicity will necessitate leachate testing of concrete products. From these analyses the Concrete Technology Unit suggest that, subject to further testing, treated drill cuttings would be appropriate for use as a binder filler with Portland cement, in pre-cast units, as an activator or as an aggregate. A cuttings processing facility, in partnership with a brick manufacturer, have previously attempted to manufacture bricks from treated cuttings. The first batch was successful but the quality of the bricks in the second batch was poor. The problem was thought to be in the variability of the cuttings geology found in the second batch of drill cuttings. The conclusion to the trial was therefore that given the unpredictable nature of the cuttings feedstock, their use in brick manufacture would be impractical.

Coastal Defense

The maintenance of coastal integrity is often achieved through the construction of sea walls. The high salinity of treated drill cuttings has been identified as a restriction on some possible reuse options. Reuse in a saline environment would reduce or remove this restriction. Therefore, use as a concrete mix aggregate for sea wall structures is a reuse possibility. However, further research may be required to confirm the suitability of treated drill cuttings as a concrete mix aggregate for sea wall structures.

Land Reclamation

Land is commonly reclaimed from the sea during the development of coastal regions. This process involves the filling of cells previously isolated from the sea with a general fill material. Treated drill cuttings have been identified as a possible fill material for such developments.

Roads and Cycle Paths

The creation of roads and cycle paths can require a considerable volume of construction material. For example, a $5m^2$ area of surface construction would require approximately 1.8 tons of cuttings. Road and path construction have therefore been identified as possible reuse options for treated cuttings.

SLOP SEPARATION

Introduction

Slops represent a challenging type of waste. They are usually composed of emulsified non-aqueous fluids, commercial solids, drill cuttings and fresh or sea water. They are too contaminated to be returned to the drilling fluid active system without compromising its performance. Normally they are sent to a disposal site where they have to be treated to comply with most environmental regulations around the word. Because of their complex composition, slop treatment creates unusually heavy stress on the waste processing systems which are designed to deal with one or two contaminants and a relatively stable waste flow. The use of simple technologies to separate valuable components before they reach the disposal stage can create important product recycling opportunities while reducing negative effects on the environment.

Benefits of Using Slop Treatment Technology

- Operator cost for slop treatment greatly reduced
- Slop treatment is carried out close to where it is generated

- Improved working environment
- Reduced CO_2 pollution due to reduced transportation of slops
- Increased reuse of brine
- Chemical consumption for treating slop reduced because fluids are separated using mechanical methods
- Regeneration of drilling fluids is made nearer to the user; i.e. on rig
- Decreased transportation costs

Equipment Set-Up and Operation

The fluid being processed consists of oil contaminated brines, seawater, soap, freshwater and water generated at the surface from drilling and completion operations. After the shaker screens, the decanter unit removes the solids by a mechanical process, exposing the fluid to 3000 G. The fluid is then transferred to the separator unit for oil removal. The disc-stack separator unit also uses a mechanical process, exposing the fluid to 10,000 G, thereby reducing the oil content to less than 40 ppm (mg/l). In order to further reduce the oil content of the water to be discharged, a guard filter consisting of oil absorbing cartridge filters is installed to polish the fluid after separation. The hydrocarbon content is measured before the fluid is reused or discharged to the sea.

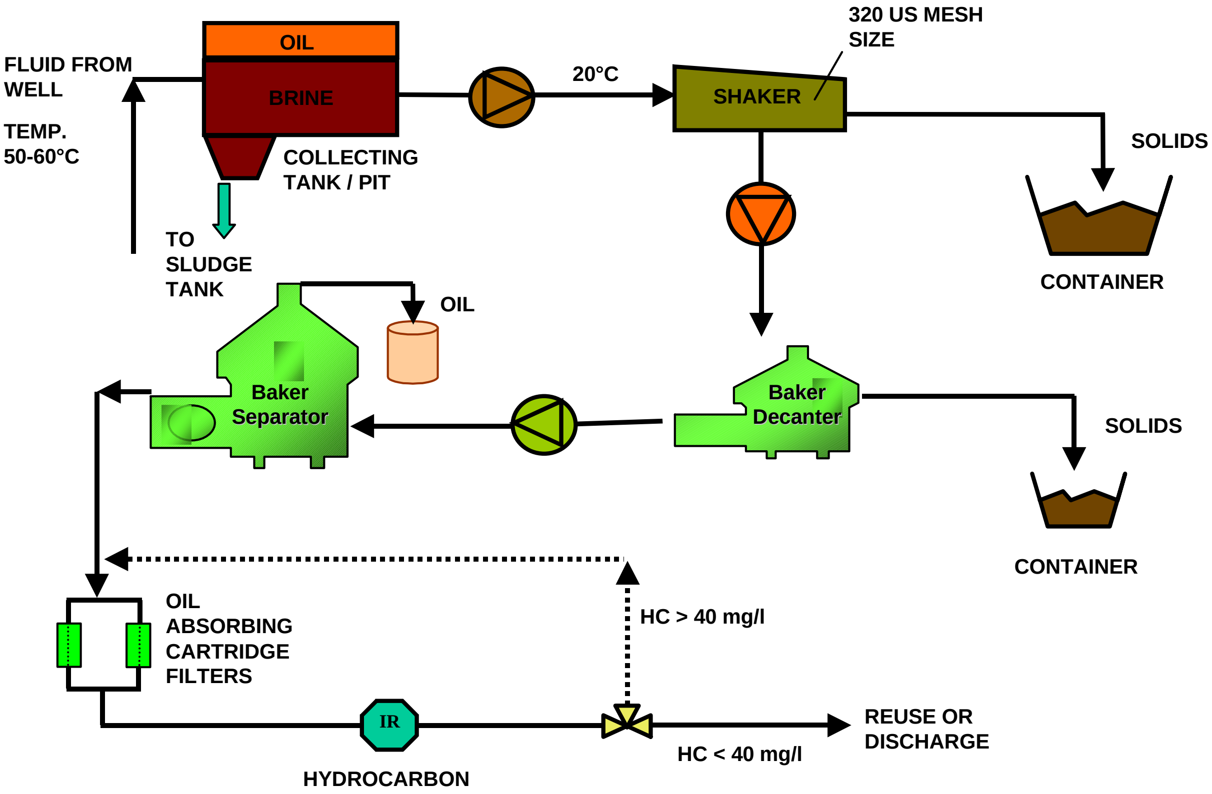
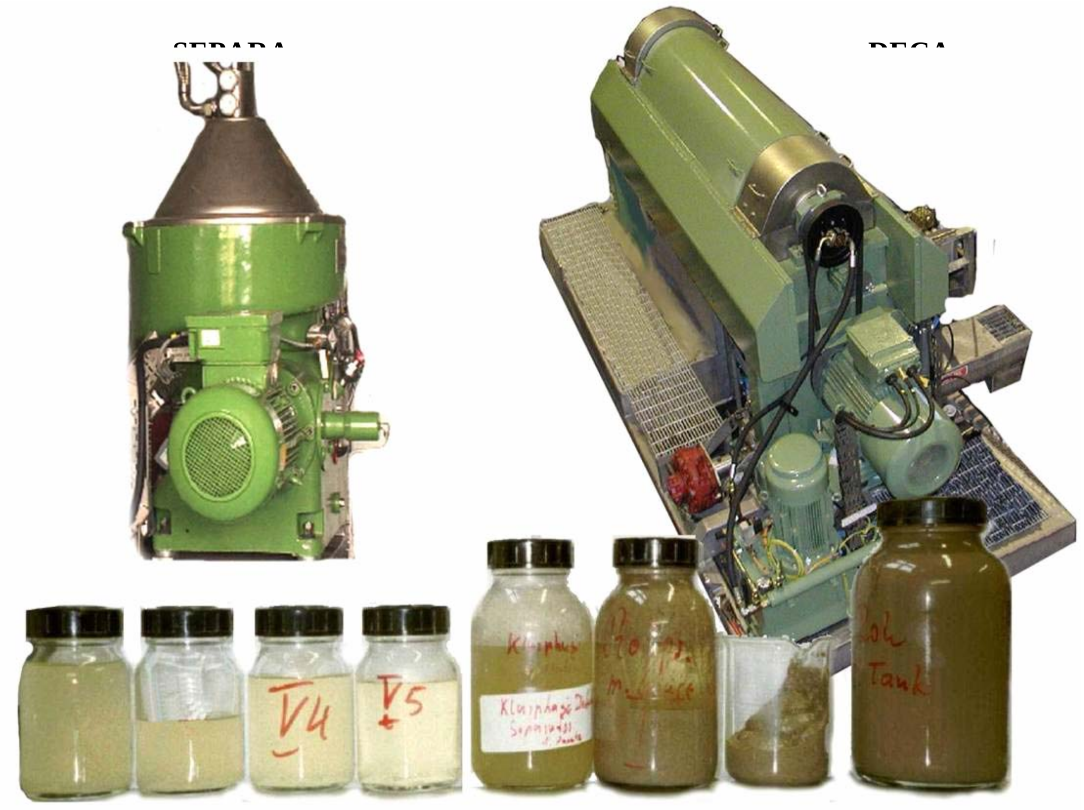


Figure 14 - 10 Schematic of Set-up of a Typical Slop Treatment Scenario on an Offshore Rig



The sample bottles in the figure above illustrate the process from slop water to discharged water. Experienced offshore operators adjust the decanter unit to discharge solids at the most effective cut between solids and fluid phase. Once the decanter unit has been correctly set up, the liquid phase can go directly into the separator unit for oil separation. Once again an effective cut between the phases is essential: At this stage the cut point between the oil and water phases is made as close to the oil phase as possible, minimizing the volume of oil waste for disposal. The relatively large fluid volume from the clean fluid outlet is discharged to the sea with an oil content less than 40 ppm. The separator is capable of processing fluid to an oil-in-water content less than 15 ppm, if necessary.

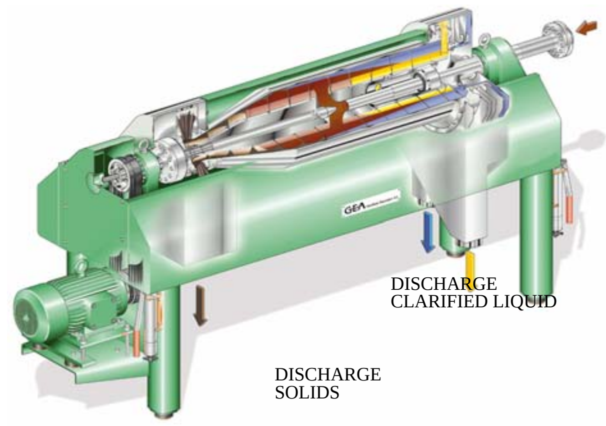
Equipment Details

Brine separator Unit, electric driven, zone II.

The Baker Hughes Drilling Fluids separator is a non-waste generating brine treating unit, which uses internal forces of 10000 G to separate brine / water / oil / sludge / particulates. Conventional methods would require large amount of chemicals, manpower and filters to process the same fluid.

The separator includes a modified disc bowl centrifuge designed to handle brines with a density of up to 1.80 SG at a process flow rate of 10 – 15 m^3 / h. The bowl is self-ejecting for automatic removal of solids, i.e. the centrifuge is self-cleaning to avoid unnecessary shutdowns. This concept allows simultaneous separation of brine, oil and particulates up to 0.5 mm.

Decanter Unit , CA 458



- Handles up to 60% solids in fluid
- Uses 3000 G internal forces
- Field tested weight reduction of drilling fluid from 1.65 SG down to 1.24 SG
- Capacity: 10 - 15 m^3 / hr
- Dimensions: 4.0 m x 1.2 m x 1.8 m
- Weight: 4,000 kg

Filtration and Separation

Filtration skid with pump

Separator

The filtration skid was developed to handle small volumes of slop water more cost effectively. This unit has three filtration pods with the possibility of combining three different types of filters. For example: load the first pod with a 50 micron size filter for coarse media, 25 micron filters for medium size particles in the second pod and 10 micron filters in the last pod. The last pod can also be used as an oil absorbing pod. The first two pods only contain six cartridge filters, so if a small volume of drilling fluid is fed accidentally into the unit, only 6 - 12 filters become blocked and need to be replaced. The same scenario using a conventional dual filter unit would block 50 - 100 filters. There is an integral pump on the skid, which provides the capability of feeding the filters directly from the slop holding tanks.

For small volume applications:

- Filtration skid for solids and oil removal

For large volume applications:

- Filtration skid for solids removal
- Separator unit for oil removal

Handling OBM Slops Onshore

All contaminated water returned to shore for treatment can be transferred to a holding tank for analysis. Once the extent of the contamination has been established then appropriate treatment can be undertaken.

The standard cleaning process is to pump the fluid through a mixing tank while injecting a coalescing agent. The fluid then flows into a separation flotation tank where the oil is skimmed off and collected in a waste oil storage tank. The aqueous phase and settled "oil wet" solids will be passed through a D.E. filter press to remove the solids.

The water collected will be pumped through an oil specific filtration medium and activated charcoal filters. The water will then be analyzed to confirm that the oil concentration is <5 ppm prior to reuse or discharge.

In many cases it will be possible to reclaim the "skimmed" oil directly to the OBM without the need for further processing. However, the skimmed oil would need to be analyzed to ensure that there are no contaminants, such as surfactants, that would not be suitable for inclusion into the OBM.

The centrifuged solids will be collected and stored and subsequently transferred to the OBM cuttings storage area for further processing to remove or reduce the oil content prior to discharging the cleaner solids.

CUTTINGS SLURRIFICATION AND RE-INJECTION

Introduction to Cuttings Slurrification/Re-Injection

Down-hole cuttings re-injection (CRI) has come of age over the past 10 years and is considered a viable option for many drilling operations. Environmental regulations are based upon the cradle-to-grave concept, and thus the operator never relinquishes responsibility for the drill cuttings and the chemicals left on them.

Tightening of the allowable discharge limits and the increasing cost of land fills/land farm, has forced many operators into switching from short term planning to long range planning for drilling waste.

CRI represents the following:

- The only permanent onsite disposal method that can fully comply with zero discharge to the surface environment.
- A method that returns cuttings to their native environment.

- Does not discharge hydrocarbon waste to the air.
- Is an inexpensive process, relative to many environmental solutions which are not permanent.

Downhole cuttings injection technology is used by many operators to dispose of drilled cuttings at the rig site. Developing sound slurrification and injection methods has played an important role in expanding the utilization of cuttings re-injection. A clear, concise understanding of what happens downhole during the cuttings re-injection operation is critical to successfully implementing this technology and completing a project successfully.

Cuttings Slurrification

Cuttings generated by the drilling operation are removed from the drilling fluid using conventional solids control equipment, and then transported to the cuttings slurrification system using blowers, vacuums, screw conveyors, and/or slides. When the cuttings reach the CRI system, they are transformed (slurrified) into pumpable slurry by mixing sea water and/or chemicals with the drilled cuttings at approximately a two to one ratio.

The finer the grinding of the cuttings, the less chemical is needed and the smaller quantities of slurries generated per length of hole drilled. While the cuttings/water/chemicals are blended, the cuttings are reduced to a predetermined particle size distribution/viscosity by grinding and shearing them with specially modified centrifugal pumps, and possibly mills, into a homogeneous mixture.

The resulting slurry is usually pumped to an additional onboard storage tank prior to either re-injection back into the formation (as explained below) or for pumping to a stand-by vessel for onward shipment to a dedicated intra-field injection platform/rig. There it is usually reduced in viscosity and then re-injected back into the dedicated well and formation.

Injection Theory

Complex modeling techniques have been created to establish fracturing parameters for increased hydrocarbon production in tight and porous, brittle and ductile formations. These models have proven to work well as a guide for CRI services.

To utilize the fracture models, an experienced CRI subsurface engineer must temper the fracture design with cuttings injection experience to adequately judge how the formations are impacted by injection operations. This is due to CRI consisting of a different set of parameters than those that the fracture models were designed for. The fracture models for hydrocarbon simulation are designed for:

- High rates of injection to prevent sand-out.
- Injection with specific brittle particles that are large when compared to cuttings slurry particles
- No distribution of particle size.
- High fluid horsepower at the formation face.
- Short duration pumping.
- Slurry rheological properties that have low fluid loss and are ultimately designed to create the maximum fracture that can be obtained.

Disposal of cutting slurries is exactly the opposite:

- Particles are small in size, soft/ductile in nature.
- Pumped at low rates for long periods of time.
- Purposely designed to keep the fluid horsepower low.
- Generally high in fluid loss.
- Designed to impact the formation minimally - large fractures are not desired.

Injection Process

After a homogeneous slurry is prepared and conditioned to site specific properties, the cuttings slurry is then injected through a dedicated conduit, such as the annular space between two strings of casing (annular injection) into the exposed formation. The cutting slurries are pumped at planned rates into the formation.

When the pressure increase resulting from the pumping operation exceeds the strength of the exposed formation rock and the natural pore pressure, the formation allows the cutting slurries to flow into the formation. If the rheology/physical properties and pumping methods are correct, the formation will safely hold large amounts of cuttings.

Operating Considerations

A variety of operational details must be dealt with to properly plan the project. Successful operations dictate that the majority of the work is done in the planning stage. Some of the details include:

- Identifying suitable cuttings disposal/sealing formations.
- Selecting surface equipment.
- Designing the casing programs.
- Designing the injection programs and contingency planning.
- Plug prevention in the annulus and the formation.
- Preventing cutting slurries from breaching to the surface or contaminating potable water zones.
- The impact on existing producing wells or future wells to be drilled.
- Quality control/monitoring of injection procedures
- Abandonment of waste disposed to permanently entomb the waste.
- Obtaining regulatory approval.

Characteristics of the subsurface environment, sealing formations, injection zone, slurry properties, drilling plans, subsurface slurry disposal dimensions and other elements directly impact each of these operational considerations. Of the various technical details that must be evaluated, the least understood but of equal importance, are those questions associated with downhole considerations:

- Into what formation can the cuttings slurry be injected?
- How will the cuttings slurry be contained?
- In what direction will the cuttings slurry propagate? And how far?

- How significant an impact will the cuttings slurry have on nearby wellbores/formations?
- How will the cuttings slurry affect existing wells and future drilling plans?
- What volume of cuttings slurry can be safely disposed of?
- What forces will be put on the well casing?
- How can the cuttings slurries be injected in order to minimize formation impact?
- How can the annulus and the formation be protected?
- When the formation changes, what does the CRI operator do next?

Lithology Concerns

An accurate description of the various lithologies and the transition depths from one lithology to another is integral in determining where injection of the cuttings slurry should take place.

The disposal formation must be able to readily accept the cuttings slurry, and must also be massive enough to accommodate the volume of cuttings produced.

The target formation should not contain natural fractures or faults that might communicate the slurry to the surface or to formations containing potable water. Additionally, the disposal formation must be associated with some type of seal mechanism that will adequately restrict the slurry to the specified formation interval.

A review of mechanical property logs, cores, leak off tests, pore pressures, mud logs and other data from offset wells is a very useful tool when addressing these issues. Fracture modeling, although currently designed for hydrocarbon stimulation operations, has proven useful for estimating the size and shape of the disposal plumes.

Seismic data can be utilized for identification of natural vertical fracturing that could make the project fail and can be utilized to define the formation properties, such as fracture pressures, pore pressures, and other elements crucial to CRI.

Surface Equipment Requirements

The type of surface equipment required to process the drilled cuttings is based on a number of parameters established after addressing downhole considerations. The properties of the drill cuttings dictate the type of grinding equipment required. Modified centrifugal pumps designed to reduce the size of the cuttings using high shear rates are most effective when processing cuttings from soft, hydratable shale formations. All modified centrifugal pumps are not the same. In those instances where a sizable quantity of hard cuttings will be processed, the use of a mechanical grinder should be considered.

Proven equipment durability, manpower, requirements, utilities, ease of installation/time requirements and contingency plans must all be considered when designing the surface equipment system. Proper system design is important since any downtime for repairs or maintenance directly impacts the drilling process. In zero discharge operations, the rig cannot drill if the CRI surface equipment is not adequately designed and installed to stay ahead of the drill rate/surge conditions. The costs associated with CRI increases rapidly when the drilling progress is negatively impacted.

Casing Program

The casing program is developed once the injection zone and sealing formations have been identified. The cement integrity of the surface casing defines the upper sealing boundary of the injection zone and the top of cement for the intermediate casing string provides the lower boundary.

It should be borne in mind that the injection plume takes the path of the least resistance, and accordingly, will likely be initiated at the casing shoe and could grow vertically upward and outward from that point, depending on a variety of conditions. For this reason, the casing shoe needs to be set at an adequate depth below the top of the specified injection zone.

In theory, the height of the top of the cement for the intermediate casing string is planned such as to make certain that the length of exposed formation will allow for desired downward fracture growth. Experience in designing the subsurface injection profile and related casing/cement programs is paramount to successfully implement the technology. To ignore the required engineering experience and judgment in this phase of the operation and in later evaluation of formation changes will result in failure.

Monitoring Procedures

No matter how well the project is planned there is always the possibility of a breakdown which may result in disposal failure. Negative impacts on the existing drilling program, on future wells and to the environment are risked if proper quality control of the slurry and the surface operation is not maintained. The quality control procedures should monitor, at minimum, the following:

- Pressure impact on nearby wells.
- Disposal plumes, direction and location.
- Injection rate, total volume and pressure.
- Disposal slurry properties, density, funnel viscosity, rheological properties and particle size.
- Equipment condition.
- Experience level of operators/management.

In many cases, a meeting with the appropriate regulatory agencies will not be necessary, but adequate communication is always crucial to gaining the agency’s understanding and approval. Obtaining early regulatory input has two primary advantages:

- Allows the operator to comply with pertinent regulations.
- Provides the operator with an opportunity to hear concerns of regulatory personnel so that special needs can be addressed and appropriate changes made to the work plan.

Early dialogue makes it possible to resolve concerns and issues while developing the cuttings injection plan.

Main Components of CRI System

COMPONENT	FUNCTION	OPERATED / MONITORED BY
Cuttings Screw Conveyor	Transport cuttings from shakers to CRI Slurry Tank	FES Engineer / Drilling Crew
Optional Vacuum System Continuous Discharge Vacuum Hopper	Transport cuttings from shakers to CRI Slurry Tank	FES Engineer / Drilling Crew
CRI Slurry Tank	Mix cuttings with seawater and reduce to a controlled slurry	FES Engineer
CRI Seawater Supply	Seawater used to produce slurry	FES Engineer
CRI Classification Shaker	Control slurry particle size to D90, 300 microns	FES Engineer
CRI Roller Mill	Aid breakdown of hard rock and cemented sands	FES Engineer
CRI Holding Tank	Temporary storage of classified slurry to allow control of viscosity prior to re-injection	FES Engineer
CRI HP Injection Pump	Injection of slurry from holding tank into annulus of injection well	FES Engineer
CRI Slurry Injection Line	Dedicated line to selected re-injection well	FES Engineer / Drilling Crew
Injection Well Annulus & Formation	Act as conduit for slurry from surface to formations below the shoe	FES Engineer / Drilling Crew
Charge Pump	Provides sufficient suction pressure to the high pressure pump	FES Engineer

Cuttings Slurrification Package

FEATURES

- Designed to DNV 2-7-1 and DNV Certified
- Zone 1 rated
- Two lift system for quick mechanical and electrical installation
- Agitated tanks
- Adjustable jet / impingement nozzles and wear plates fitted to the slurry tank
- 30% increase in holding tank capacity
- Overflow from holding tank to slurry tank

- Manual handling assessments on all equipment
- Positive valve isolations on tanks
- 100% contingency
- Provision for additional grinding pumps
- Flexibility to suit all cuttings transfer systems i.e. slurry flush, auger, vacuum
- Meets offshore noise test requirements

PROCESSING TIME

2 x Grinder Pumps			Hole Section	4 x Grinder Pumps		
Slurry	BBLs Out	Drill Rate		Drill Rate	BBLs	Slurry

Generation Per Hour (3:1)	**Per Hour**	**Ft/hr**		**Ft/hr**	**Out Per Hour**	**Generation Per Hour (3:1)**
120	30	100	17 ½”	150	45	180
		120	16”	180		
		210	12 ¼”	310		
		350 +	8 ½”	350 +		
= 2 Bbl/min						= 3 Bbl/min

DIMENSIONS AND WEIGHTS

Item	Description	Dimensions (m) L x W X H	Dry Weight (kg)	Operating Weight (kg)
1	Slurry Package 'Lift' Slurry Tank 8.0m^3 Holding Tank 11.0m^3	5.8 x 2.9 x 3.5	13,800	24,700 kg When full of 1.3 sg fluid
2	Shaker and Roller Mill Package 'Lift'	2.7 x 1.7 x 2.1	3,500	NA
3	Handrails and Davit	To suit	2,500	NA
Total	Combined Package Assembly on Rig Including Access Platforms and Handrails	5.8 x 4.7 x 5.6	19,800	44,500

ELECTRICAL POWER REQUIREMENTS

(440 Volts ± 10%, 3 phase, 60 Hz, EExde IIC T4, IP56)

1	Grinder Pump Motor No:1	CD250M-4	64-kW
1	Grinder Pump Motor No:2	CD250M-4	64-kW
1	Grinder Pump Motor No:3	CD250M-4	64-kW
1	Grinder Pump Motor No:4	CD250M-4	64-kW
1	Charge Pump	CD180L-4	26-kW
1	Slurry Tank Agitator Motor	CD132M-4	8.5-kW
1	Holding Tank Agitator Motor	CD132M-4	8.5-kW
1	Roller Mill Hydraulic Power Pack Motor	CD132M-4	8.5-kW
1	Classification Shaker Motor	CD112M-4	4.8-kW
Total Installed Power			**313-kW**

DIESEL INJECTION PUMP

Description

Zone Two High Pressure Pumping Unit.

Environmental

Fully soundproofed to 80dB(A) and built to the highest standards and current legislation. Engine meets the required emission controls and legislation including. IMO Marpol 73/78 Annex VI – Regulations for the Prevention of Air Pollution from Ships (NOx Technical Code**)**

Engine

Detroit 60 Series, 600BHP, 530 – 580 HHP MAX

Fuel Consumption

31.1 gallons per hour under full load

Fuel Capacity: 600 liters

Centrifugal Pump

4” x 3” x 13” c/w mechanical seal

Maximum head 120 psi.

Suction – 4”

Triplex Pump

4” Fluid End

Maximum Pump Rate – 9 BPM

Maximum Pump Pressure – 8000 PSI

Discharge – 2”

Alternative Fluid Ends available

Control Panel

Engraved stainless steel control panel giving central control and visual display of rates, pressures etc.

Safety

Built to the new ATEX directive (equipment and protection systems intended for use in potentially explosive atmospheres). Emergency stop, fuel stop, fail safe system. Platform control shut downs available pneumatic or electric. Designed and manufactured in accordance with the current DCR regulations.

Certification

Certified to allow the duty holder to demonstrate compliance with the requirements of SI 913.

Dimensions

Engine Skid	4571mm (L) X 2438mm (D) X 2820mm (H)
Pump Skid	2438mm (L) X 2438mm (D) X 2820mm (H)
Combined	7009mm (L) X 2438mm (D) X 2820mm (H)

Weight Data

Engine Skid Gross Weight:	14,000 kg
Pump Skid Gross Weight:	8,000 kg

ELECTRICALLY DRIVEN INJECTION PUMP

Description

Zone 1, High pressure pumping unit with variable speed inverter drive.

Environmental

Acoustically clad to reduce noise levels to 78dbA. Zero atmospheric emissions.

Triplex pump

Maximum pumping rate 3.15 bbl/min at 2500psi.

Maximum pressure 5000psi at 26 gpm

Controls

Remote control from operator station with local maintenance control panel.

Safety

Built to the new ATEX directive, can be tied in with platform shut down controls.

Dimensions

Length	3600mm
Width	2062mm
Height	2220mm

Weight

Total Gross Weight: 8,000 kg

Includes

- Safe area variable speed inverter drive. (Zone 1 enclosure available as option).
- Zone 1 operator’s panel.
- Noise hood.

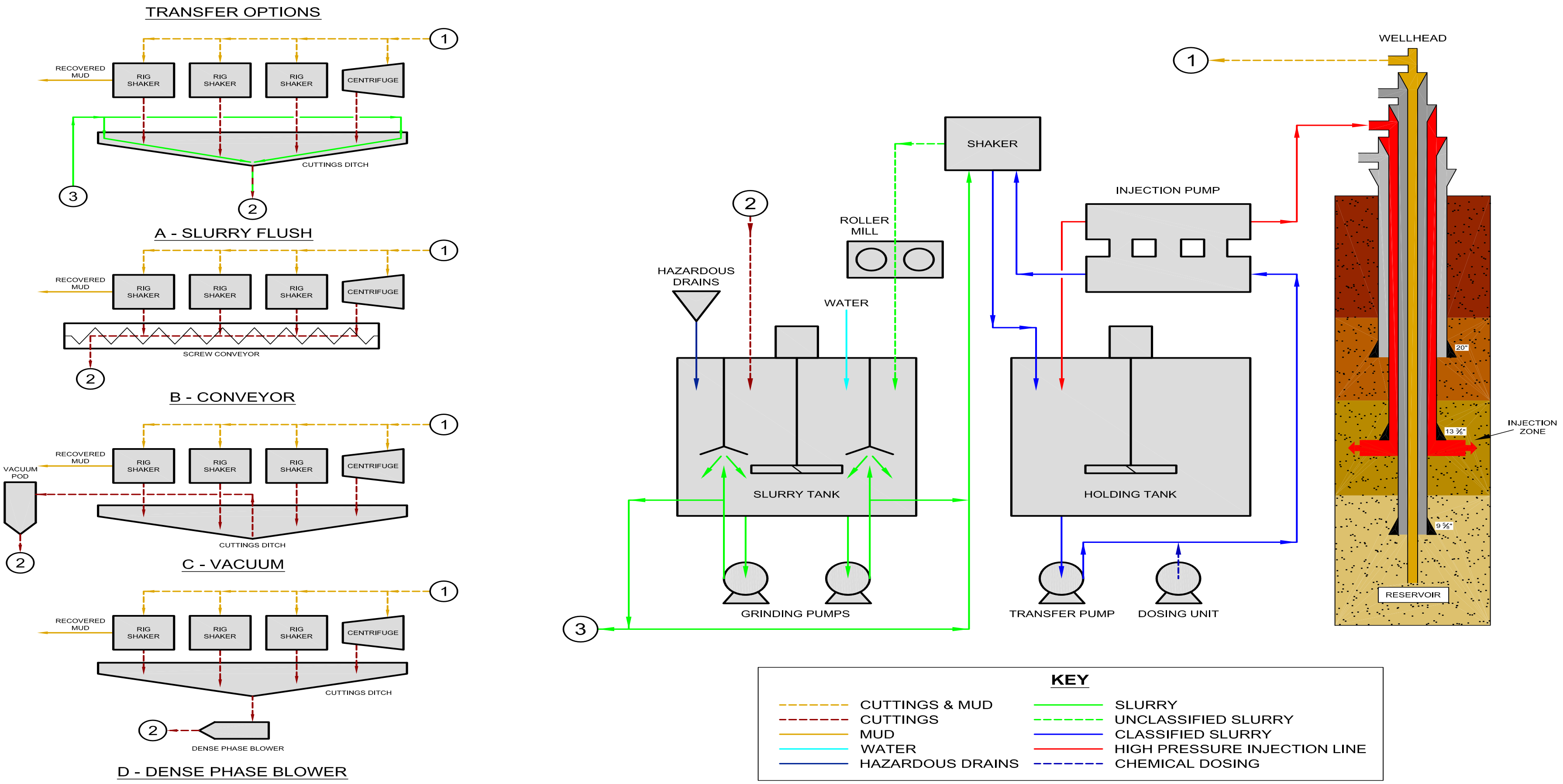
- High and low pressure dampers.
- Anti vibration mounts
- Relief valve PED compliant.
- Lifting beam and sling set.
- Suction and discharge pressure transducers.

DATA ACQUISITION LOGGER

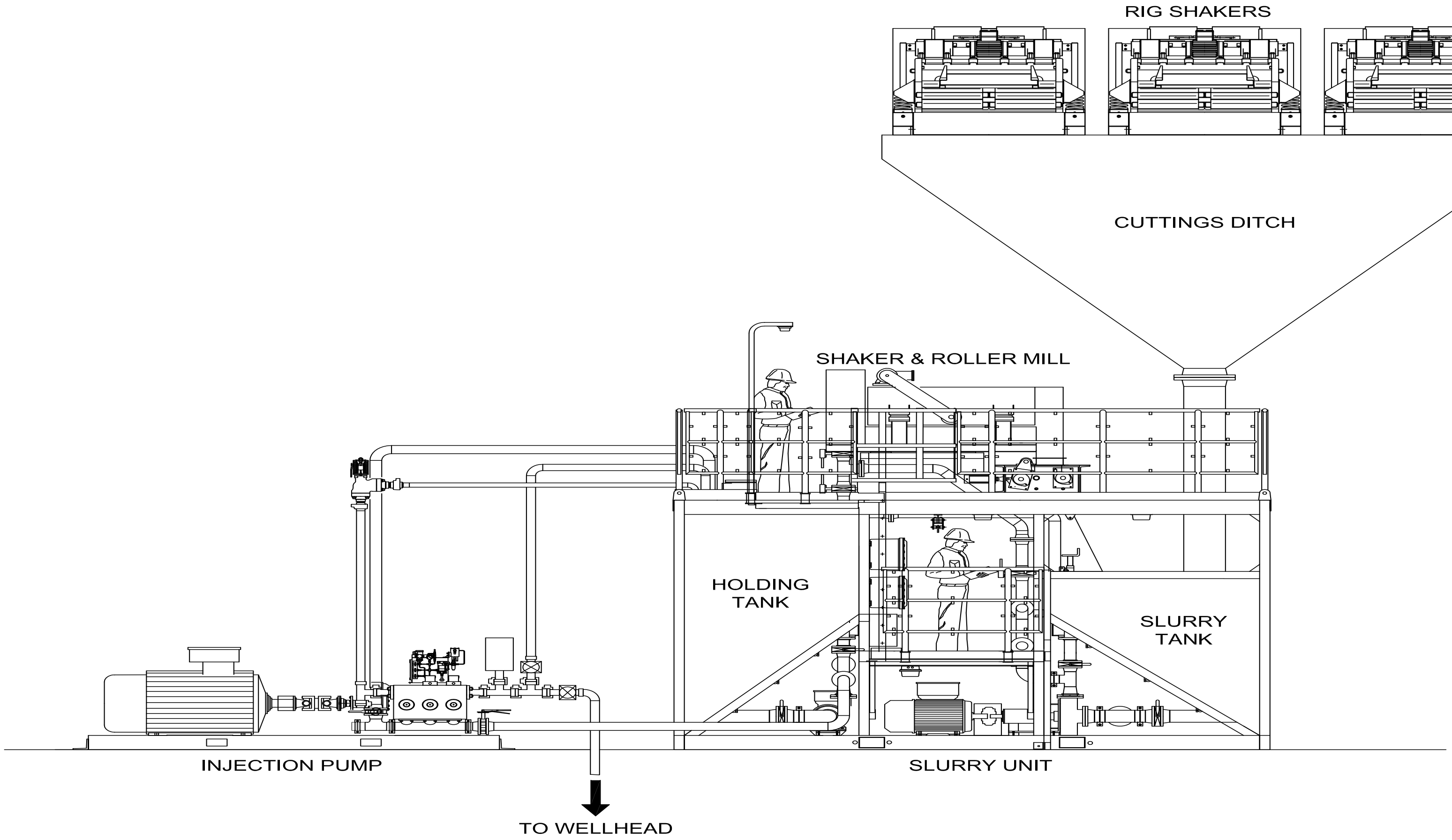
Features

- Zone 1 Rated
- Explosion Proof
- Safety Shutdown
- Reads:
  - Pressures
  - Tank Levels
  - Amps
  - Adjacent well pressures
  - Pump strokes
  - Pump rate (bbls)
  - Total Volumes (bbls)

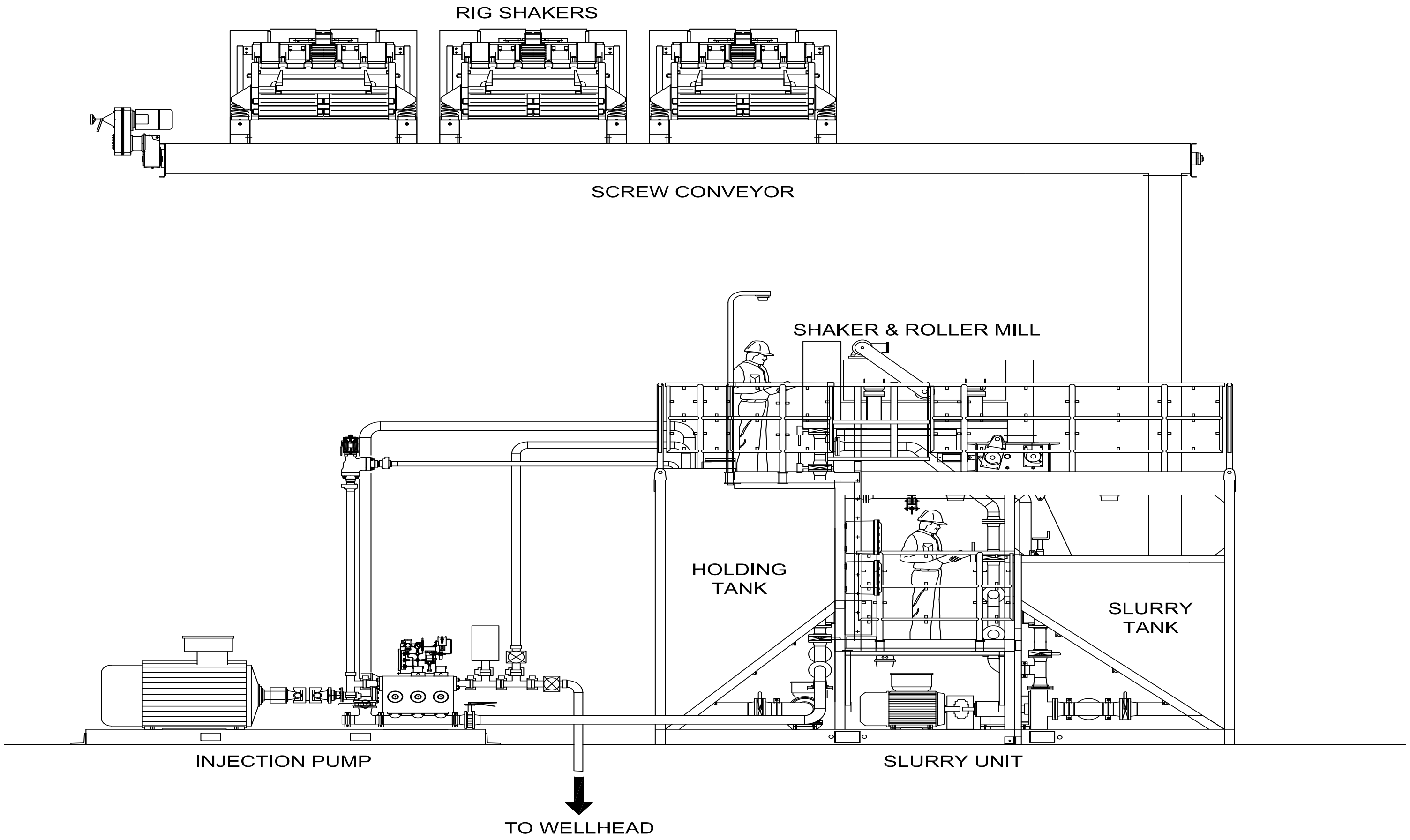
CUTTINGS INJECTION OVERVIEW



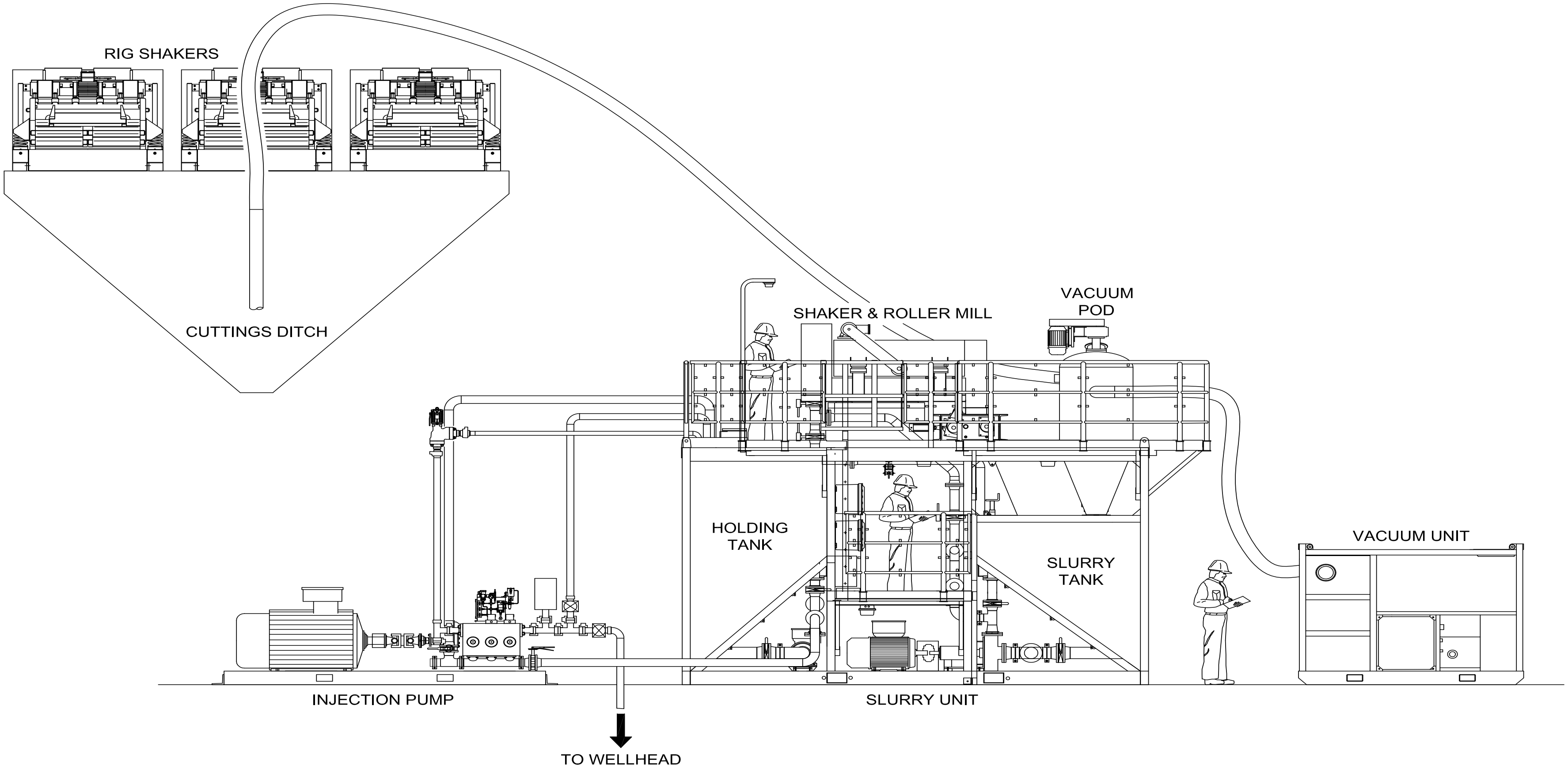
TRANSFER OPTION 1 –SLURRY FLUSH



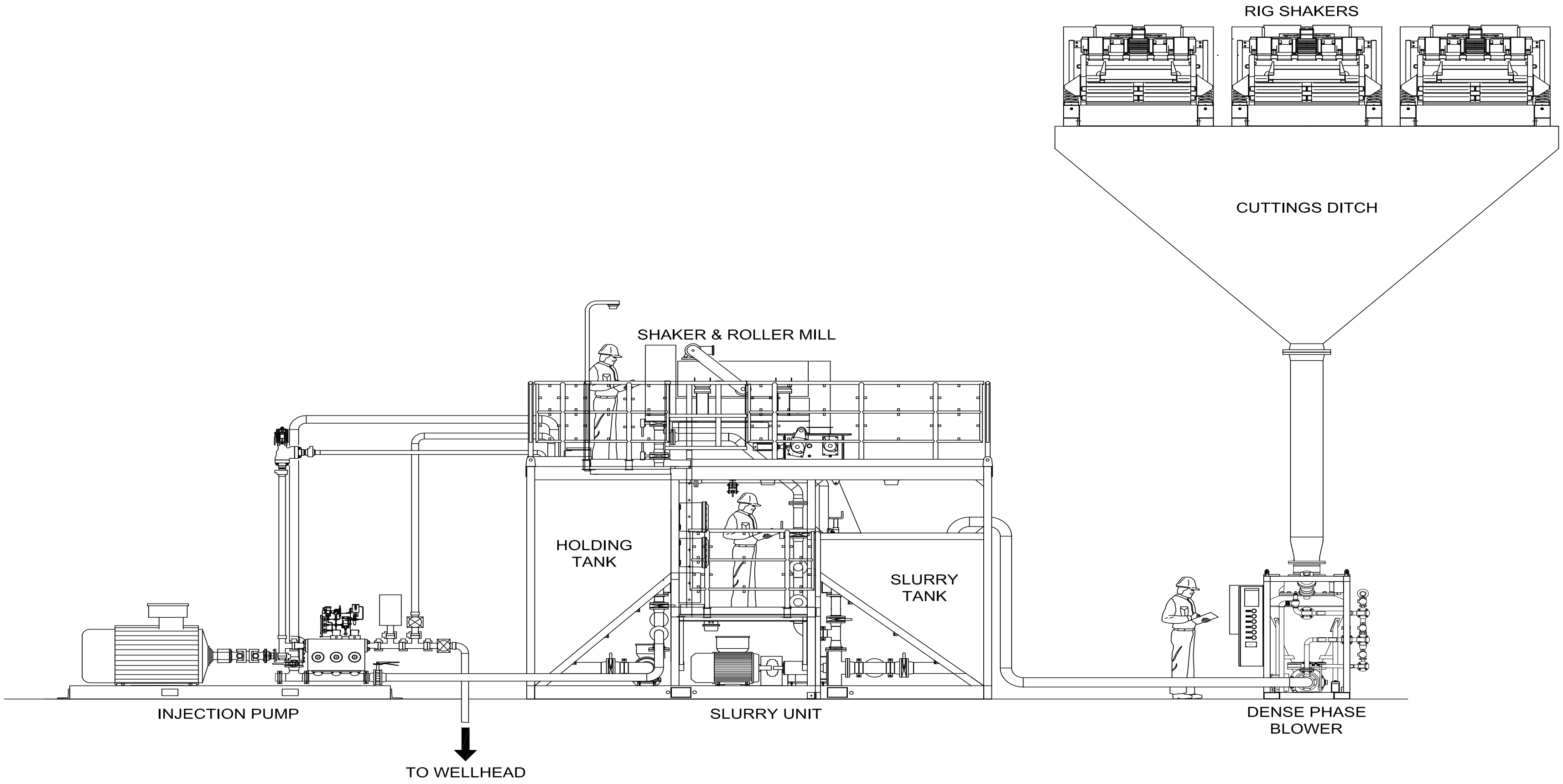
TRANSFER OPTION 2 –CONVEYOR



TRANSFER OPTION 3 –VACUUM



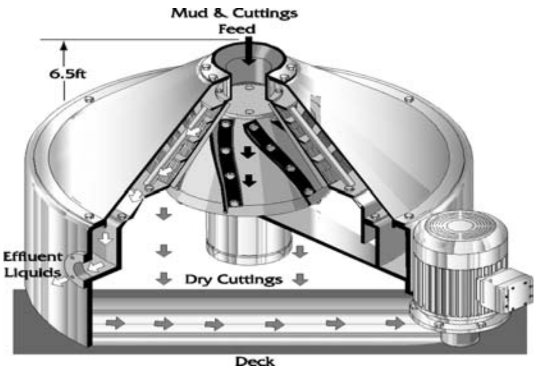
TRANSFER OPTION 4 –DENSE PHASE BLOWER



CUTTINGS DRYER

With waste reduction at source a major part of any drilling operation Baker Hughes Drilling Fluids FES provides cuttings dryers to reduce the volume of the drill cuttings waste being generated at the rig site. The cuttings dryer should be positioned down stream of the rig's solids control equipment prior to discharge into onboard containment equipment. The Typhoon Dryer is a high capacity vertical centrifuge with a rotating cone - complete with spiral flights. On entering the cone laundering area the cuttings are forced against a fixed screen/basket by the centrifugal action, this separates the bulk of the fluids from the solids into two phases. The solids phase continues through the dryer and self discharges into a skip/box/conveyance below with the liquid phase draining to the feed tank. The fluid phase is normally returned to the drilling fluid tanks after being centrifuged.

Features



- Low Profile-Space Saver
- OOC<3% Average
- Recover/Recycle Mud from Cuttings
- Produces 230 Gs Centrifugal Force
- Auger or Vacuum Feed System
- Process rate:-up to 40 tons/hour
- Reduces costs by returning mud back into the active mud system -typically saves 78 bbl of mud per 1000 ft. of 12-¼" hole section drilled
- Reduces haul-off volumes and disposal/thermal treatment costs

Applications

- Can be used onshore or offshore
- FES bulk tank transfer system –reduced volume of drill cuttings transferred in 'bulk'
- Ship to shore of drill cuttings in skips –reduced volume of drill cuttings transferred in skips

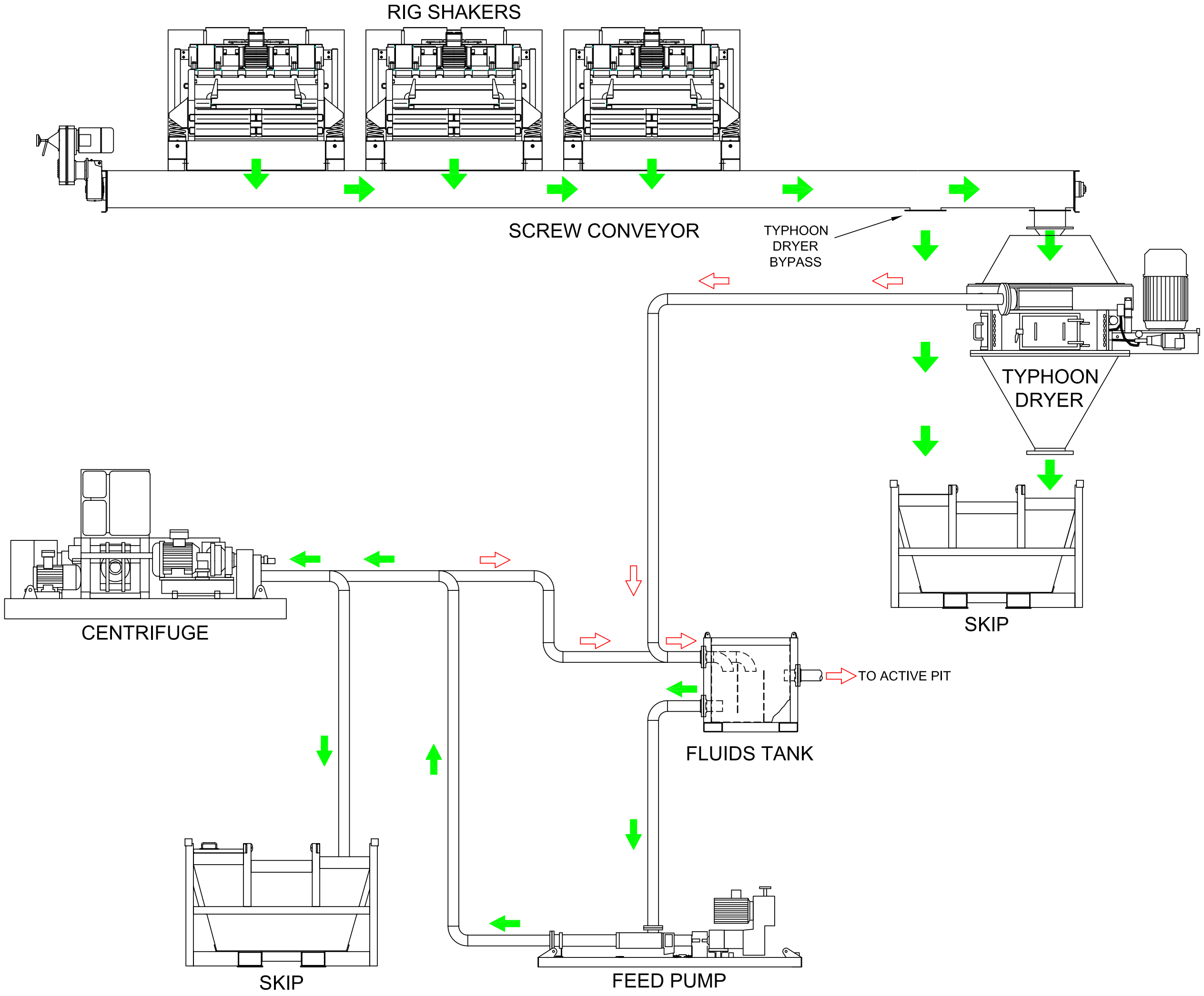
Dimensions and Weight

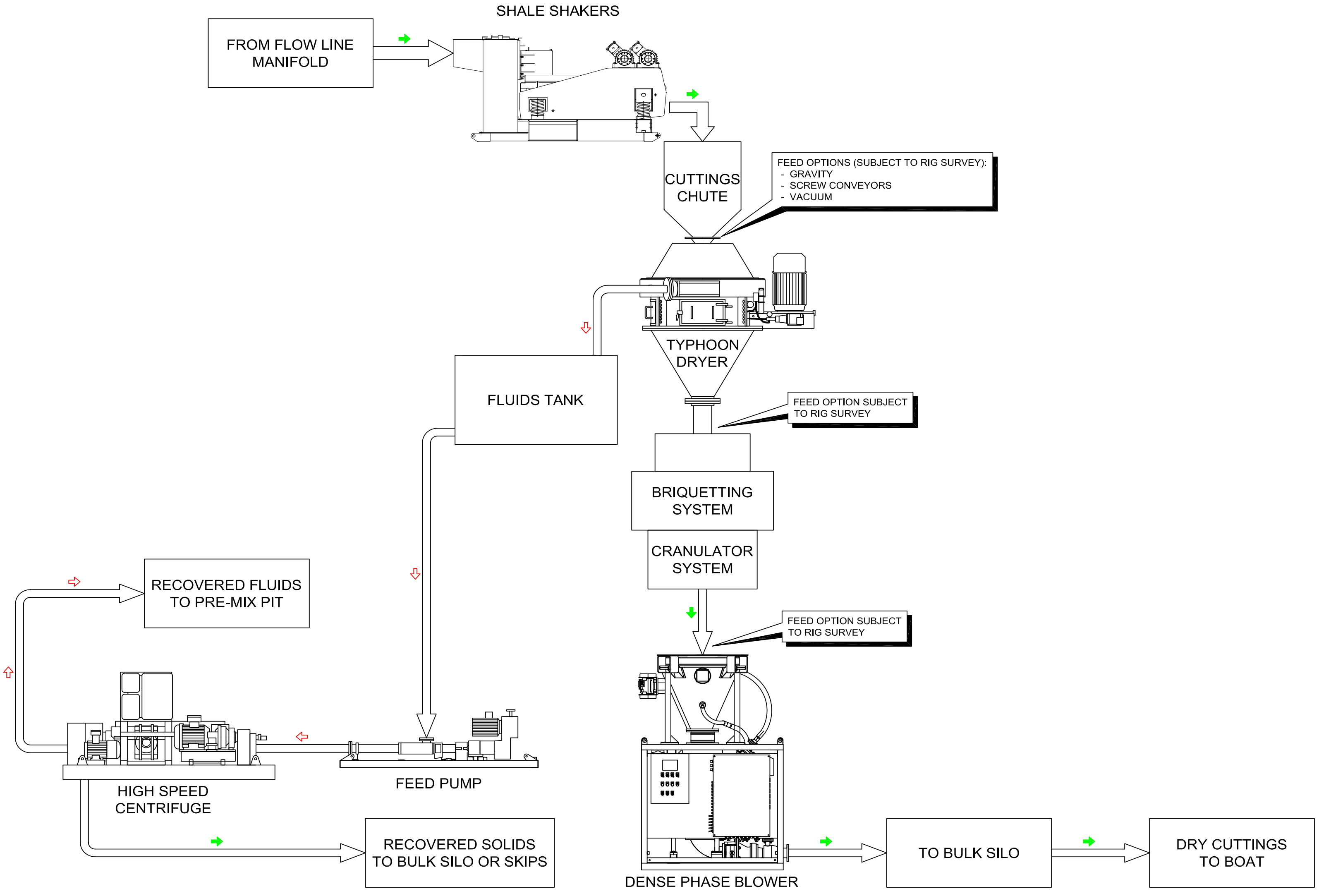
Diameter:	2.1 m
Height:	2.0 m
Length:	2.5 m (over motor drive end)
Dry transit weight:	5,000 kg

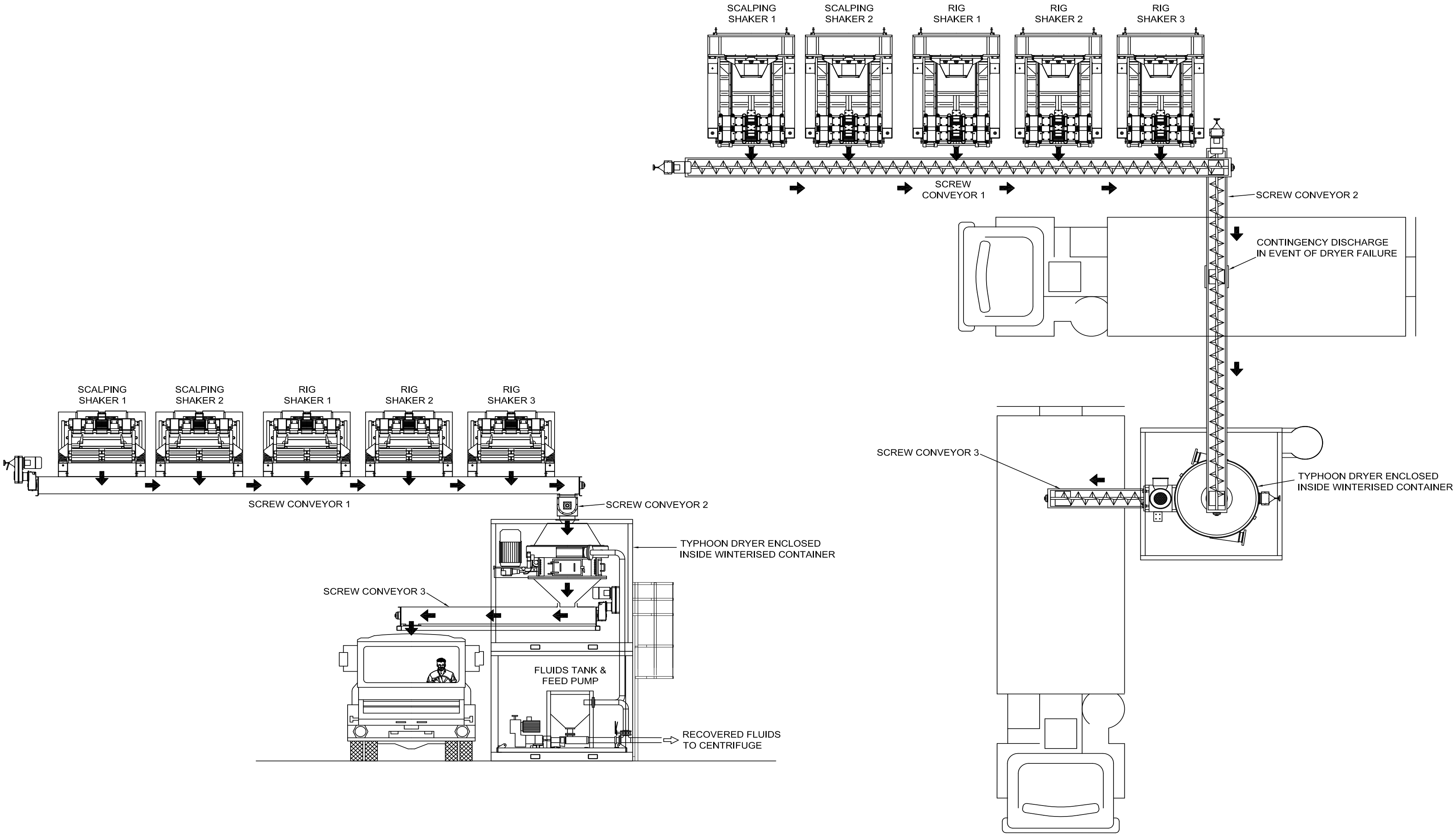
Specifications

- 440 Volt/60Hz
- EExd1 drive motor: 55 Kw (75 hp)
- EExdoil pump motor: 0.55 Kw (0.75hp)
- Electrical EExd starter enclosure

Typical Cuttings Dryer Arrangements




SHALE SHAKERS
FROM FLOW LINE MANIFOLD
CUTTINGS CHUTE
FEED OPTIONS (SUBJECT TO RIG SURVEY):
- GRAVITY
- SCREW CONVEYORS
- VACUUM
TYPHOON DRYER
FLUIDS TANK
FEED OPTION SUBJECT TO RIG SURVEY
BRIQUETTING SYSTEM
CRANULATOR SYSTEM
FEED OPTION SUBJECT TO RIG SURVEY
RECOVERED FLUIDS TO PRE-MIX PIT
HIGH SPEED CENTRIFUGE
FEED PUMP
RECOVERED SOLIDS TO BULK SILO OR SKIPS
DENSE PHASE BLOWER
TO BULK SILO
DRY CUTTINGS TO BOAT


SCALPING SHAKER 1
SCALPING SHAKER 2
RIG SHAKER 1
RIG SHAKER 2
RIG SHAKER 3
SCREW CONVEYOR 1
SCREW CONVEYOR 2
CONTINGENCY DISCHARGE IN EVENT OF DRYER FAILURE
SCREW CONVEYOR 3
TYPHOON DRYER ENCLOSED INSIDE WINTERISED CONTAINER
SCALPING SHAKER 1
SCALPING SHAKER 2
RIG SHAKER 1
RIG SHAKER 2
RIG SHAKER 3
SCREW CONVEYOR 1
SCREW CONVEYOR 2
TYPHOON DRYER ENCLOSED INSIDE WINTERISED CONTAINER
SCREW CONVEYOR 3
FLUIDS TANK & FEED PUMP
RECOVERED FLUIDS TO CENTRIFUGE

FILTRATION SERVICES

Baker Hughes Drilling Fluids FES is capable of providing filtration equipment, personnel and consumables to perform the following operations.

- Filtration of wellbore clean-up returns
- Filtration of sand control gravel-pack carrier fluids
- Well test produced water treatment
- Filtration of injection water
- Mud pit cleaning
- Fluid analysis (solids and oil-in-water)

Filtration of Wellbore Clean-up Returns

Filtration equipment and procedures planning for a wellbore clean-up depends on many variables including the type of drilling fluid, level of cleanliness required, space limitations and the completion fluid type. BHDF FES provides different package options to suit the customer ranging from a single cartridge filter unit using filter elements to a twin filter press package using diatomaceous earth filter media. Expected flow rates, flow duration and solids loadings all have different impacts on the type of equipment chosen.

During the completions planning stages, BHDF FES will obtain the maximum amount of information so as to recommend the most suitable filtration system for the job, e.g. generally BHDF FES would recommend cartridge units for filtration (polishing) of relatively clean fluids whereas a filter press system would be recommended for dealing with fluids with higher solids contamination.

Filtration of Gravel Pack Carrier Fluids

Gravel pack carrier fluids need to be filtered to a high specification due to the potential of causing solids entrapment within the gravel and the near wellbore formation area. Almost all gravel pack filtration equipment consists of a twin filter press package in order to ensure a constant supply of filtered fluid with 90% by volume of all solids remaining being below 10micron.

Produced Water Treatment

BHDF FES experience includes filtering oily water during well testing, platform decommissioning, and tanker water discharge. Filtration of produced and oily water typically consists of a three stage process consisting of gravity separation in a surge tank and then solids removal and oil absorption, using special non-leaching absorption filter media in cartridge filter units. The overboard discharge is tested for hydrocarbons using the extraction method and an infra-red spectrophotometer.

Seawater Injection

During a seawater injectivity test, the requirement for high volumes of polished seawater necessitates the use of cartridge filter units due to their ability to polish fluids at high flow rates. Depending on the flow rates, one or more cartridge units may be used in parallel.

Fluid Analysis

Analysis of oilfield completion fluids is performed using a variety of equipment including turbidity meters, laboratory centrifuges, laser particle counters and infra-red spectrophotometers. BHDF FES offshore filtration engineers are all trained in the operation of the above equipment and prepare reports required by the operation.

Waste Water Treatment

BHDF FES is developing a method for removing solids, hydrocarbons and chemicals from waste water contaminated with oil based drilling fluid water so that the water quality will satisfy regulatory discharge levels for disposal. The process involves the use of a decanter centrifuge, a high speed disk stack centrifuge, settling tanks and fine filtration, whilst testing will include solids, hydrocarbons, chemical oxygen demand and pH.

Filtration Equipment Technical Information

Diatomaceous Earth Filtration Filter Press Systems

A diatomaceous earth filter press works on the principle of starting with a significantly large surface area onto which a permeable filter cake is built until the internal plate recesses are completely filled with the filter cake, at which point the plates are then opened for cleaning of fluids.

A diatomaceous earth unit usually requires two filtration engineers on any shift to operate but has the advantage of being able to filter large volumes of fluids with a high solids loading. The surface areas of typical diatomaceous earth units range from 600 sq. ft. to 1200 sq. ft. and in many cases two units are used in order to maintain a constant supply of filtered completion fluid.

The process starts with the filter plate screens being pre-coated in order to build the initial filtration surface. The function of the screens is not to act as a filter, but rather to provide a surface onto which a pre-coat cake of diatomaceous earth may be built. The pre-coat, consisting of a diatomaceous earth slurry is circulated through the filter press via a separate tank (slurry tank) until the diatomaceous earth is retained on the screens and the base fluid begins to return to the slurry tank in a clear state. Once complete (usually around 5-10 minutes), the filter press is ready to receive the feed of dirty fluid for filtration.

The solids typically found in completion fluids are barite and clay which can build up a non-permeable cake and blind the filter press screens very quickly. In order to counter this effect, a volume of body feed or diatomaceous earth slurry is also injected into the dirty fluid upstream of the filter press so that the filter cake maintains a level of permeability. The quantity of body feed is adjusted according to the level of solids in the feed fluid.

The higher the solids in the feed, the more body feed required to maintain the permeability. The importance of a good pre-coat and body feed cannot be over emphasized, and becomes very apparent when a badly prepared filter press is prematurely blocked at a critical time during a gravel pack or wellbore clean-up job. A good pre-coat prevents the barite and clays from coming into contact with the screens, and enables the cake to be removed easily when cleaning. When used correctly, diatomaceous earth filtration systems are the best choice for wellbore clean-up and gravel packing jobs.

- Used for brine filtration with heavy barite or clay solids loadings.

- Can convert highly contaminated fluids to clear fluids efficiently.
- Economic first pass filtration for high volumes.
- Used in conjunction with downstream cartridge type ‘polishing’ unit.

Filter Press Unit

Technical Specifications

DNV 2.7-1 Certified Lifting Frame

Size of plates	1200mm x 1200mm
Surface area	up to 1200 sq ft
Number of plates	36 - 48
Inlet	4 inch
Outlet	4 inch
Dimensions and Weight	4.8m x 1.6m x 2.2m
Weight	8,000kg
Flow Capacity	2 to 12 bbl/min (depending on feed pressure and feed quality)
Maximum Working Pressure	7 bar
Utility requirements	Rig air (for opening and closing ram) Rig feed Pump.

Integrated Pre-Coat Slurry Mixing Tank

Pre-coating a Filter Press

A typical 1000 sq ft filter press uses approximately 85 kg of D.E. to produce a 3mm pre-coat on the internal screens. To ensure that the pre-coat solids form a uniform cake on the plate screens, the filter press is circulated with diluted pre-coat slurry before introducing the balance of the diatomaceous earth pre-coat solids. The slurry mix tank will circulate to “clear” at the end of the pre-coat cycle indicating that all of the diatomaceous earth pre-coat solids have been captured on the filter plate screens.

Body Feed

The filtration of slurries which contain gelatinous, slimy, and/or compressible solids typically results in poor filter performance; e.g. low flow rates, short cycle times, high operating pressures and low filter efficiency. The addition of non-compressible solids (Diatomaceous Earth) to the inlet slurry being filtered can cancel or significantly reduce these undesirable effects and improve the performance level of the filtration operation. A body-feed therefore can be defined as the solids which are added to process slurry for the purpose of enhancing the filterability of the slurry. The addition of body-feed will change the physical characteristics of the cake solids by increasing its permeability (reducing the resistance). The amount of body-feed required cannot be accurately predicted due to the many variables involved. A good starting point is to use a 1:1 ratio of body feed solids to suspended solids in the feed and then adjust the injection rate of the body feed so as to obtain the optimum performance which:

- Minimizes the initial filter differential pressure.
- Prevents a rapid increase in the rate of differential pressure.
- Prevents terminal differential pressure until the filter press plate recesses are fully utilized.
- Slimy, gelatinous and highly compressible solids (barite and clay) typically require higher body-feed addition rates to effect cake permeability.

Technical Specifications

DNV 2.7-1 Certified Lifting Frame

Vessels & pipework: ASME Div VIII

Integrated Pre-coat and divert manifolds

Integrated Hose Basket

Dimensions	3.8m Long x 1.8m Wide x 1.86m High
Weight	5000kg empty (7 500 kg with water)
Flow Capacity	Up to 18bbl/min
Max Working Pressure	7bar
Utility requirements	Rig air
Pre-coat Pump	3” Diaphragm
Body-Feed Pump	1.5” Diaphragm
Powder Hydration Pump	2” Diaphragm
Inlet	4 inch
Outlet	4 inch

Reduced hose requirement due to integrated components resulting in a safer working environment.

Powder Handling System

Features

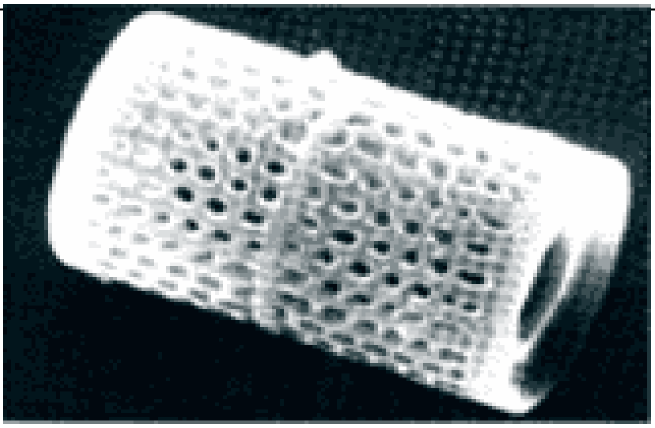
- Internal fluidizing system.
- Large capacity means no re-filling offshore
- Filtered vent for added personnel protection.
- Pressure relief valve.

Technical Specifications

DNV 2.7-1 Certified Lifting Frame

Dimensions	2.2m x 2.2m x 3.3m High
Weight Empty	3100kg
Load Capacity	4000kg Diatomaceous Earth
Gross Weight	7100kg
Utility requirements	Rig air

Diatomaceous Earth Filter Medium



Diatomite is the fossilized remains of microscopic unicellular plants which lived in ancient water bodies. It is known for its unique cylindrical geometry; which has high strength, high pore volume and low resistance to flow, thereby making it an excellent selection for filtration.

The filtration of slurries containing gelatinous, slimy, and/or compressible solids (barite and clay) typically results in poor filter performance; e.g. low flow rates, short cycle times, high operating pressures and low filtration efficiency. The addition of non-compressible and highly permeable solids (diatomaceous earth) to the slurry being filtered can cancel or significantly reduce these undesirable effects and improve the performance level of the filtration operation.

The addition of diatomaceous earth to the slurry being filtered will alter the physical characteristics of the formed cake solids by increasing its permeability and reducing the resistance to the flow of the fluid.

Typical dose rates (guideline):

Pre-coating: 1 kg per square meter of filter plate screen.

e.g. 1200 sq meter = 120kg diatomaceous earth.

Body-feed: 1:1 (or more) volume ratio of diatomaceous earth to solids in slurry being filtered.

Highly compressible solids (barites and clay) typically require higher body-feed addition rates to affect cake permeability.

Cartridge Filtration Unit

Mainly used for polishing new brines and filtering seawater and fresh water. By using absolute rated filter elements a guaranteed cut in the ‘size’ of the contaminating particle is achieved. The maximum flow rate through each of these units is 18 barrels/minute and for this reason, they are usually considered as the first option when planning completion fluid filtration. The cartridge unit is easy to operate and only requires one operator per shift. Fluids that are heavily contaminated with soft compressible solids like barite and clay (which have a low permeability when compacted) tend to block the elements very quickly resulting in numerous and costly change-outs. They are also installed downstream of a diatomaceous earth filtration system and fitted with 2 micron absolute filter elements in order to provide a final polish. These robust units are widely used in the oilfield industry and require little maintenance.

- Variety of cartridge types and ratings available.
- Can filter brine, acid, diesel, gels.
- Best suited to relatively clean fluids like seawater or pre-filtered brine.

Technical Specifications

DNV 2.7-1 Certified Lifting Frame

CE Pressure Equipment Directive

Number of cartridges	50
Cartridge type	63mm x 1000mm
Tank diameter	600mm
Material	stainless steel
Maximum working pressure	7 bar
Design temperature	100^{o}C
Design code	ASME VIII div. 1
Interconnecting pipework	4” serial / parallel / bypass
Drain	1” pipework flange terminated
Standard gauges	in/outlet 0-160psi
Weight (empty)	1700 kg
Dimensions	2100mm x 1150mm x 2200mm

Absolute Rated Pleated Filter Elements

A beta 5000 absolute rated range of highly efficient, cost effective pleated process filters. Elements are manufactured in accordance with ISO 9002 using the highest quality materials where applicable.

Absolute cartridges are available in a wide range of micron ratings extending from 2 microns to 100 microns as measured by the industry standard OSU F2 particle challenge test, using fine/coarse A.C. test dust.

Higher temperatures and differential pressures can be accommodated using stainless steel cores and end caps.

Technical Specifications

Filter media	Glass fiber/Polyester
Core material	Polypropylene
Dimensions (approx)	Diameter 63mm, length 1000mm
Seal material	Buna O-Ring
End details	Single closed end, single open end type 222 fitting.
Micron ratings	2, 5, 10, 20, 50 & 100 (absolute)

Recommended Operating Conditions

Maximum temperature	65ºC @ 20psid.
Maximum flow rate	4m^3/hour per 1000mm element.
Maximum change out differential pressure	4 bar

Absolute Rated Pleated Filter Elements

The diameter of the largest, hard, non-deformed particle which will pass through a filter medium under specific test conditions, verified using automatic particle counters upstream and downstream of the filter under test. Absolute filters are utilized in critical applications where guarantee of filtrate quality is required at all times throughout the life of the filter. They have a higher unit cost than their nominal counterparts. Absolute rated filters are often used in combination with nominal rated filters to optimize economics and filtration efficiency e.g. absolute rated cartridge filters downstream of a diatomaceous earth filter press.

Nominal Rated Wound Filter Elements

A less defined rating, which is usually expressed as a percentage removal efficiency at a given particle size (90%) removal of particles of 5 microns and above, nominal rated filters are generally used as “bulk” solids removal filters or as cost effective pre-filtration to absolute filters. Nominal rated filters are normally not given a true removal rate as their efficiency will vary through the life of the filter cycle, e.g. the efficiency will increase if a uniform cake of debris is built up on the upstream surface, or conversely the efficiency will decrease if the filter media flexes under the build up of differential pressure and the release of captured debris takes place.

Hydrocarbon Absorption Filter Elements

Hydrocarbon absorption filters are made of treated polypropylenes or polymers and are modified so that they chemically bond to hydrocarbons. Some of these filters will begin to release the hydrocarbons once they are saturated, while others will absorb the hydrocarbons into the polymeric structure until they solidify and prevent any further flow through the filters.

Analysis Equipment

Turbidity (NTU) Turbidity Meters

The Portable Turbidity Meter operates on the nephelometric principle of turbidity measurement. The optical system includes a tungsten-filament lamp, a 90^0 detector to monitor scattered light and a transmitted light detector. The instrument's microprocessor calculates the ratio of the signals from the 90^0 and transmitted light detectors. The ratio technique corrects for interferences from color and compensates for fluctuations in lamp intensity, providing long term calibration stability.

A turbidity Meter is used to measure the level of turbidity or cloudiness of a fluid. The readings will not give any indication of what is causing the fluid to be turbid, however it can be concluded that a high reading warrants further testing using more sophisticated equipment. The turbidity meter is a useful tool for quick analysis and should only be used to provide an indication of changing cleanliness rather than a conclusion that the fluid is within the cleanliness specification required.

Percent Solids Laboratory Centrifuge

The electric bench top centrifuge is used to provide a visual assessment of the amount of particulate in the fluid. They are best suited to measuring solids or oil in heavily contaminated fluids as the final readings are taken visually and are useful when determining the solids content trend during a wellbore clean-up. The laboratory centrifuge is also relatively easy to operate and requires no more than a 5 minute spin cycle to determine a reasonably accurate reading. A 100ml sample is poured into a glass vial that is placed in a counter balanced receptacle where it is spun at speed creating high gravitational forces that separate the different constituents by their densities e.g. oils to the top, water or brine in the middle and solids at the bottom of the glass vial. The glass vial is calibrated so that the user can determine the level of contamination as a percentage of the total volume tested.

Particle Counting and Size Distribution Laser Analyzers

A laser particle analyzer is used to count the number of particles in filtered fluids within pre-set size bands ranging from 2 microns to 200 microns. These units are best suited for measuring particles in filtered fluids if accurate readings are to be achieved. Unfiltered fluids can cause blockages in the internal components of these instruments.

During well stimulation work and gravel packing the requirement is normally for a pre-filtered fluid that is filtered to 2 micron absolute with 99.9% removal efficiency.

A laser analyzer is sensitive enough to measure the remaining particles at various micron sizes and will print the readings for future safekeeping.

Chapter Fifteen

Glossary of Terms

Chapter 15

GLOSSARY OF TERMS

The following is a glossary of terms associated with the drilling and development of wellbores.

Absorption - The penetration or apparent disappearance of molecules or ions of one or more substances into the interior of a solid or liquid. For example, in hydrated bentonite, the planar water that is held between the mica-like layers is the result *of* absorption.

Abnormal Pressure - A subsurface condition in which the **pore pressure** of a **geologic formation** exceeds or is less than the expected, or **normal**, **formation pressure**. When **impermeable** rocks such as shales are compacted rapidly, their **pore** fluids cannot always escape and must then support the total overlying **rock** column, leading to abnormally high **formation** pressures. Excess **pressure**, called **overpressure** or **geopressure**, can cause a well to blow out or become uncontrollable during drilling. Severe **under-pressure** can cause the **drillpipe** to stick to the **under-pressured formation**.

Acid - Any chemical compound containing hydrogen capable of being replaced by positive elements or radicals to form salts. In terms of the dissociation theory, it is a compound which, on dissociation in solution, yields excess hydrogen ions. Acids lower the pH. Examples of acids or acidic substances are hydrochloric acid, tannic acid, and sodium acid pyrophosphate.

Acidity - The relative acid strength of liquids as measured by pH. A pH value below 7. See pH.

Accretion - The mechanism by which partially hydrated **cuttings** stick to parts of the bottomhole assembly and accumulate as a compacted, layered **deposit**.

Acid Gas - A gas that can form acidic solutions when mixed with water. The most common **acid** gases are hydrogen **sulfide** [H_2S] and carbon dioxide [CO_2] gases. Both gases cause **corrosion**; hydrogen **sulfide** is extremely poisonous. Hydrogen **sulfide** and carbon dioxide gases are obtained after a **sweetening** process applied to a **sour** gas.

Adhesion - The force which holds together unlike molecules.

Adsorption - A surface phenomenon exhibited by a solid (adsorbent) to hold or concentrate gases, liquids, or dissolved substances (adsorptive) upon its surface, a property due to adhesion. For example, water held to the outside surface of hydrated bentonite is Silicate or water.

Aeration - The technique of injecting air or gas at controlled rates into a drilling fluid for the purpose of reducing hydrostatic head. Compare Air Cutting.

Aerobic - Referring to a condition or a situation in which free oxygen exists in an environment.

Agglomerate - The larger groups of individual particles usually originating in sieving or drying operations.

Agglomeration - The grouping of individual particles. The **formation** of groups or clusters of particles (aggregates) in a fluid. In water or in water-base **mud**, **clay** particles form aggregates in a dehydrated, face-to-face configuration. This occurs after a massive influx of hardness ions into **freshwater mud** or during changeover to a lime **mud** or gyp **mud**. Aggregation results in drastic reductions in **plastic viscosity**, **yield** point and **gel** strength. It is part of wastewater **cleanup** and water clarification. **Alum** or polymers cause **colloidal** particles to **aggregate**, allowing easier separation.

Aggregate - A group of two or more individual particles held together by strong forces. Aggregates are stable to normal stirring, shaking, or handling as powder or a suspension. They may be broken by drastic treatment such as ball milling a powder or by shearing a suspension.

Aggregation - Formation of aggregates. In drilling fluids, aggregation results in the stacking of the clay platelets face to face. The viscosity and gel strength decrease in consequence.

Air Cutting - The inadvertent mechanical incorporation and dispersion of air into a drilling-fluid system. Compare Aeration.

Air Drilling - A drilling technique whereby gases (typically compressed air or nitrogen) are used to cool the drill **bit** and lift **cuttings** out of the **wellbore**, instead of the more conventional use of liquids. The advantages of air drilling are that it is usually much faster than drilling with liquids and it may eliminate lost **circulation** problems. The disadvantages are the inability to control the influx of **formation** fluids into the **wellbore** and the destabilization of the **borehole** wall in the absence of the **wellbore pressure** typically provided by liquids.

Alkali - Any compound having marked basic properties. See **Base**.

Alkalinity - The combining power of a base measured by the maximum number of equivalents of an acid with which it can react to form a salt. In water analysis, it represents the carbonates, bicarbonates hydroxides, and occasionally the borates, silicates, and phosphates in the water. It is determined by titration with standard acid to certain datum points. See *API RP 13B** for specific directions for determination of phenolphthalein *(Pf)* and methyl orange *(Mf)* alkalinities of the filtrate in drilling fluids and the alkalinity of the fluid itself (Pm)' Also see Pf, Mf, and Pm.

Aluminum Stearate - An aluminum salt of stearic acid used as a defoamer. See **Stearate**.

Amorphous - The property of a solid substance which does not crystallize and is without any definite characteristic shape.

Analysis, Fluid - Examination and testing of the drilling fluid to determine its physical and chemical properties and condition.

Anhydrite - See Calcium Sulfate. Anhydrite is often encountered while drilling. It may occur as thin stringers or massive formations.

Anhydrous - Without water.

Anaerobic - Pertaining to systems, reactions or life processes of species, such as bacteria, in which atmospheric oxygen is not present or not required for survival.

Aniline Point - The lowest temperature at which equal volumes of freshly distilled aniline and oil which is being tested are completely miscible. This test reveals the cyclic compound characteristics of an oil (naphthenic, asphaltic, aromatic, mid-continent, etc.) of the oil. The aniline point of diesels or crude oils used in drilling fluid is also an indication of the deteriorating effect these materials may have on natural or synthetic rubber. The lower the aniline point of an oil the more severe it usually is in damaging rubber parts.

Anion - A negatively charged atom or radical, such as CI^-, OH^-, $S0_4^=$ etc., in solution of an electrolyte. Anions move toward the cathode (positive electrode) under the influence of an electrical potential.

Annular Velocity - The velocity of a fluid moving in an annulus of specific dimensions.

Annulus or Annular Space - The space between the drillstring and the wall of the hole or casing.

Annular Flow – The flow of fluids in the annulus or annular space. The rate of flow in the annulus or annular space is commonly expressed in ft/min, or meters/min.

Antifoam - A substance used to prevent foam by greatly increasing the surface tension. Compare **Defoamer**.

Anomaly - An entity or property that differs from what is typical or expected, or the measurement of the difference between observed and expected values of a physical property. Anomalies can be of great interest in **hydrocarbon** and **mineral exploration** because they often indicate **hydrocarbon** and **mineral** prospects and accumulations, such as **geologic** structures like folds and faults.

Geochemical anomalies at the surface of the Earth can also indicate an **accumulation** of hydrocarbons at depth. Geophysical anomalies, such as **amplitude** anomalies in **seismic** data and magnetic anomalies in the Earth's **crust**, can also be associated with **hydrocarbon** accumulations.

API - Abbreviation for American **Petroleum** Institute, a trade association founded in 1919 with offices in Washington, DC, USA. The API is sponsored by the oil and gas industry and is recognized worldwide. Among its long-term endeavors is the **development** of standardized testing procedures for drilling equipment, drilling fluids and cements, called API Recommended Practices ("RPs"). The API licenses the use of its monogram (logo), monitors supplier quality assurance methods and sets minimum standards for materials used in drilling and **completion** operations, called API Specifications ("Specs"). The API works in conjunction with the International Standards Organization (ISO).

API Gravity - The gravity (weight per unit volume) of crude oil or other related fluids as measured by a system recommended by the American Petroleum Institute. It is related to specific gravity by the following formula:

$$Deg\ API = \frac{141.5}{Specific\ Gravity} - 131.5$$

Apparent Viscosity - The viscosity (shear stress) a fluid appears to have on a given instrument at a stated rate of shear (shear stress/shear rate relationship) . It is a function of the Bingham properties of plastic viscosity and yield point. The apparent viscosity in centipoises, as determined by the direct-indicating viscometer, which is equal to *1/2 of the 600*-rpm Fann Viscometer reading. See also Viscosity, Plastic Viscosity, and Yield Point. In a Newtonian fluid, the apparent viscosity is numerically equal to the plastic viscosity.

Asphalt - A natural or mechanical mixture of solid or viscous bitumens found in natural beds or obtained as a residue from petroleum. Asphalt, blends containing asphalt, and altered asphaltic materials (e.g., air-blown, chemically modified, etc.) have been added to certain drilling fluids for such varied purposes as a component in oil-base fluids, lost-circulation material, emulsifier, fluid-loss-control agent, wall-plastering agent, etc.

Asphaltenes - Organic materials consisting of aromatic and naphthenic ring compounds containing nitrogen, sulfur and oxygen molecules. The asphaltene fraction of crude is defined as the organic part of the oil that is not soluble in straight-chain solvents such as pentane or heptane. Asphaltenes exist as a **colloidal** suspension **stabilized** by **resin** molecules (aromatic ring systems) in the oil. The stability of asphaltic dispersions depends on the ratio of **resin** to asphaltene molecules. The determination of the quantity of **resin** is important in estimating the potential **damage** created by asphaltenes. Asphaltene precipitates as a result of **pressure** drop, **shear** (turbulent flow), acids, solution carbon dioxide [CO_2], injected **condensate**, mixing of incompatible crude oils or other conditions or materials that **break** the stability of the asphaltic **dispersion**. For example, in **matrix acidizing**, iron ions in solution favor the **precipitation** of asphaltene deposits.

Attapulgite - A needle-like **clay mineral** composed of magnesium-aluminum **silicate**. Major deposits occur naturally in Georgia, USA. Attapulgite and **sepiolite** have similar structures and both can be used in salt-water **mud** to provide low-shear rate **viscosity** for lifting **cuttings** out of the **annulus** and for **barite** suspension. Attapulgite and **sepiolite** are sometimes called "**salt gel**," or Salt Water Clay. Attapulgite has no capability to control the **filtration** properties of the **mud**. For use as an oil-mud additive, the **clay** is coated with quaternary amine, which makes it oil-dispersible and provides **gel structure** but does not improve the **filter cake**, unlike **organophilic bentonite clay**.

Atom - According to the atomic theory, the smallest quantity of an element which is capable of existing alone or in combination with electrons.

Atomic Weight - The relative weight of an atom of an element as compared with the weight of 1 atom of oxygen, using 16 as the weight of 1 atom of oxygen.

Bactericide - An additive that kills bacteria. Bactericides are commonly used in water muds containing natural starches and gums that are especially vulnerable to bacterial attack. Bactericide choices are limited and care must be taken to find those that are effective yet approved by governments and by company environmental policy. Bactericides are also called Biocides and can be used to control sulfate-reducing bacteria, slime-forming bacteria, iron-oxidizing bacteria and bacteria that attacks polymers.

Balanced-Activity Oil Mud – An oil-base mud in which the activity , or vapor pressure, of the brine phase is balanced with that of the formations drilled. Although long shale sections may not have a constant value for vapor pressure, a_w, the oil mud will adjust osmotically to achieve an “average” a_w value. Dynamic (autopilot) balance of mud salinity and drilled shales is maintained because as water moves into or out of the mud, it also moves out of or into the shale. As water transfer continues during drilling, the mud’s water phase will be either diluted or concentrated in $CaCl_2$ as needed to match the average a_w value of the shale section and cuttings exposed to the mud.

Balance, Fluid - A beam-type balance used in determining fluid density. It consists primarily of a base, graduated beam, with constant-volume cup, lid, rider, knife edge, and counterweight.

Barite, Barytes, Heavy Spar Ore - Natural barium sulfate used for increasing the density of drilling fluids. If required, it is usually upgraded to a specific gravity of 4.20; an API Standard specification. The barite mineral occurs in white, greenish, and reddish ores or crystalline masses.

Barite Plug - A plug made from barite weighting materials that is placed at the bottom of a wellbore. Unlike a cement plug, the settled solids do not set solid, yet a barite plug can provide effective and low-cost pressure isolation. A barite plug is relatively easy to remove and is often used as a temporary facility for pressure isolation or as a platform enabling the accurate placement of treatments above the plug.

Barite Sag - Terminology used to describe the settling of barite under minimal dynamic conditions so as to increase the density of the fluid column on the bottom while the density of fluid at the top of the column decreases. The term does not refer to nor does it reflect the hard settling of barite in the form of a solid plug.

Barium Sulfate - $BaSO_4$. See **Barite**.

Barrel - A volumetric unit of measure used in the petroleum industry consisting of 42 gal (U.S.).

Barrel Equivalent - A laboratory unit used for evaluating or testing drilling fluids. One gram of material, when added to 350 ml of fluid is equivalent to 1 lb of material when added to one 42-gal barrel of fluid.

Base - A compound of a metal, or a metal-like group, with hydrogen and oxygen in the proportion to form an OH radical, which ionizes in aqueous solution to yield excess hydroxyl ions. Bases are formed when metallic oxides react with water. Bases increase the pH. Examples are caustic soda and lime.

Base Exchange - The replacement of cations associated with the clay surface by those of another species, e.g. the conversion of sodium clay to calcium clay.

Basicity - base pH value above 7.

Beneficiation - Chemical treatment or mechanical processes that improve a mineral or ore for its designed use. For example, barite and bentonite are beneficiated in order to help them meet certain specifications for use in drilling fluids.

Bentonite - A plastic, colloidal clay, largely made up of the mineral sodium montmorillonite, a hydrated aluminum silicate. For use in drilling fluids, bentonite has a yield in excess of 85 bbl/ton of 20 cps viscosity. The generic term "bentonite" is neither an exact mineralogical name, nor is the clay of definite mineralogical composition.

Bioassay - A laboratory test or other assessment utilizing a living organism, such as mysid shrimp, to determine the effect of a condition to which the organism is exposed. Such tests are performed under controlled environmental conditions and duration. Bioassay tests of drilling fluids are required by governmental agencies throughout the world prior to discharge of mud or cuttings. The organisms used in bioassays are those found in the area that would be most affected by contact with the proposed drilling fluid. The dosage of interest is typically the lethal concentration, known as LC_{50} that will kill 50% of the population of organisms in a given period of time.

Bicarb - See **Sodium Bicarbonate.**

Blooie Line - Flow line for air or gas drilling.

Blowout - An uncontrolled escape of drilling fluid, gas, oil, or water from the well caused by the formation pressure being greater than the hydrostatic head of the fluid in the annulus. A blowout may consist of salt water, oil, gas, or a mixture of these. If reservoir fluids flow into another formation and do not flow to the surface, the result is called an underground blowout.

Boiler house - To falsify a report with fictitious data.

Brackish Water - Water containing low concentrations of chloride regardless of the type soluble salt.

Break Circulation - To initiate movement of the drilling fluid after it has been quiescent in the hole.

Breakout - A separation of the drilling fluid with a visible layer of liquid on the surface. This is applicable in both invert and water based fluids.

Bridge - An obstruction in a well formed by intrusion of subsurface formations.

Brine - Water saturated with or containing a high concentration of common salt (sodium chloride); hence, any strong saline solution containing such other salts as calcium chloride, zinc chloride, calcium nitrate, etc.

Bromine Value - The number of centigrams of bromine which are absorbed by 1 gram of oil under certain conditions. This is a test for the degree of saturation of a given oil.

Brownian Movement - Continuous, irregular motion exhibited by particles suspended in a liquid or gaseous medium, usually as a colloidal dispersion.

BS or BS & W - Basic sediment, or basic sediment and water. A reference to undesirable sediments or water incorporated in produced fluids.

Buffer - Any substance or combination of substances which, when dissolved in water, produces a solution which resists a change in its hydrogen ion concentration upon the addition of acid or base.

Cable-Tool Drilling - A method of drilling a well by allowing a weighted bit at the bottom of a cable to fall against the formation being penetrated. See **Rotary Drilling.**

Cake Consistency - According to *APIRP 13B.* such notations as "hard." "soft." "tough." "rubbery ... "firm." etc.. may be used to convey some idea of cake consistency.

Cake Thickness – The thickness measurement of filter cake deposition by a drilling fluid against a porous medium, most often following the standard API filtration test. Cake thickness is usually measured in 1/32 of an inch. See-Filter Cake and Wall Cake.

Calcium - An alkaline earth element with a positive valence of 2 and an atomic weight of about 40. Calcium compounds are indigenous to the hardness of water. It is also a component of lime, gypsum, limestone, etc.

Calcium Carbonate - $CaCO_3$. A water insoluble, yet acid soluble calcium salt sometimes used as a weighting material (limestone, oyster shell, etc.), in specialized drilling fluids. It is also used as a unit and/or standard to report hardness.

Calcium Chloride - $CaCI_2$. A hydroscopic salt used in both oil and water based drilling fluids for inhibition control. Used in completion fluids for inhibition and to increase the density of clear brines.

Calcium Contamination - Dissolved calcium ions in sufficient concentration to impact undesirable properties in a drilling fluid, such as flocculation, reduction in yield of bentonite, increase in fluid loss, etc. See also Calcium Carbonate.

Calcium Hydroxide - $Ca(OH)_2$. The active ingredient of slaked lime. It is also the main constituent in cement (when wet). This material is referred to as "lime" in field terminology.

Calcium-Treated Fluid - Calcium-treated fluids are drilling fluids to which quantities of soluble calcium compounds have been added or allowed to remain from the formation drilled in order to impart special rheological and inhibition properties.

Calcium Sulfate - (Anhydrite: $CaSO_4$; plaster of paris: $CaSO_4 \times \frac{1}{2}H_2O$ and gypsum: $CaSO_4 \times 2H_20$). Calcium sulfate occurs in fluids as a contaminant from the formation drilled or may be added to certain fluids to impart special properties of inhibition and/or rheology.

Carrying Capacity - The ability of a circulating drilling fluid to transport cuttings out of the wellbore. Carrying capacity is an essential function of a drilling fluid, synonymous with hole-cleaning capacity and cuttings lifting. Carrying capacity is determined principally by the annular velocity, hole angle and flow profile of the drilling, but is also affected by mud density, cuttings size and pipe position and movement.

Cation - The positively charged particle in the solution of an electrolyte. Which under the influence of an electrical potential, moves toward the anode (negative electrode). Examples are: Na^+, H^+, NH_4^+, Ca^{++}, Mg^{++}, Al^{+++}.

Cation-Exchange Capacity (CEC) - The quantity of positively charged ions (cations) that a clay mineral or similar material can accommodate on its negatively charged surface, expressed as million equivalent per 100 g, or more commonly as milliequivalent (meq) per 100 g. Clays are aluminosilicates in which some of the aluminum and silicon ions have been replaced by elements with different valence, or charge. For example, aluminum (Al^{+++}) may be replaced by iron (Fe^{++}) or magnesium (Mg^{++}), leading to a net negative charge. This charge attracts cations when the clay is immersed in an electrolyte such as salty water and causes an electrical double layer. The cation-exchange capacity (CEC) is often expressed in terms of its contribution per unit pore volume, Q_v See **Methylene Blue Capacity.**

Caustic or Caustic Soda - See Sodium Hydroxide**.**

Cave-In - See **Sloughing.** Cave-in is a severe form of wellbore instability where as the formation falls into the annulus from the wellbore wall.

Cavernous Formation - A formation having voluminous voids, usually the result of dissolution by formation waters which or may not be still present.

cc or Cubic Centimeter - A metric-system unit for the measure of volume. It is essentially equal to the milliliter and commonly used interchangeably. One cubic centimeter of water at room temperature weighs approximately 1 g.

Cement - A mixture of calcium aluminates and silicates made by combining lime and clay while heating. Slaked cement contains about 62.5 percent calcium hydroxide, which is the major source of trouble when cement contaminates fluid.

Centipoise (Cp) - A unit of viscosity equal to 0.01 Poise. Poise equals 1 g per meter-second. and a centipoises is 1 g per centimeter-second. The viscosity of water at 20°C is 1.005 cp (1 cp = 0.000672 lb/ft-sec).

Centrifuge - A device for the mechanical separation of high-specific gravity solids from a drilling fluid. Normal application is on weighted fluids to recover weight material and discard drill solids. The centrifuge uses high-speed mechanical rotation to achieve this separation as distinguished from the cyclone type separator in which the fluid energy alone provides the separating force. See **Cyclone and Desander.**

Chemicals - In drilling-fluid terminology, a commercial additive used to alter drilling fluid physical or chemical properties.

Chemical Barrel - A container used to make additives soluble prior to being discharged into the mud system.

Chromate - A compound in which chromium has a valence of 6, e.g., sodium bichromate. Chromate may be added to drilling fluids either directly or as a constituent of chrome lignites or chrome lignosulfonates. In certain areas, chromate is widely used as an anodic corrosion inhibitor, often in conjunction with lime. The plus 6 valence chrome compounds carry environmental restraints.

Chrome Lignite - Mined lignite, usually leonardite, to which chromate has been added and/or reacted. The lignite can also be causticized with either sodium or potassium hydroxide.

Circulation - The transport of drilling fluid through the circulating system back to the original starting point which is usually the suction pit. The time of travel from point A back to point A is referred to as the circulating time.

Circulation, Loss of (or Lost) - The result of whole drilling fluid escaping into the formation by way of crevices or porous media. It is the loss of whole mud to the formation.

Circulation Rate - The volume flow rate of the circulating drilling fluid usually expressed in gallons or barrels per minute, i.e. a unit of time to discharge a given volume.

Clabbered - A slang term commonly used to describe moderate to severe flocculation of fluid due to various contaminants; also called "gelled up".

Clay - A plastic, soft, variously colored earth, commonly a hydrous silicate of alumina, formed by the decomposition of feldspar and other aluminum silicates. See also Attapulgite, Bentonite, High Yield, Low Yield, and Natural Clays. Clay minerals are essentially insoluble in water but disperse under hydration, shearing forces such as grinding, velocity effects, etc., into the extremely small particles varying from submicron to 100-micron sizes.

Clay Extender - Any of several substances, usually high molecular weight organic compounds that, when added in low concentrations to a bentonite or to certain other clay slurries, will increase the viscosity of the system, e.g., polyvinyl acetatemaleic anhydride copolymer. See **Low Solids Fluids.**

Cloud Point - The temperature at which a solution of a surfactant or glycol starts to form micelles (molecular agglomerates), thus becoming cloudy. This behavior is characteristic of nonionic surfactants, which are often soluble at low temperatures but "cloud out" at some point as the temperature is raised. Glycols demonstrating this behavior are know as "cloud-point glycols" and are used as shale inhibitors. The cloud point is affected by salinity, being generally lower in saline fluids.

CMC - See **Sodium Carboxymethylcellulose**.

Coagulation - In drilling-fluid terminology, a synonym for flocculation: Coalescence-The change from a liquid to a thickened curd-like state by chemical reaction. Also the combination of globules in an emulsion caused by molecular attraction of the surfaces.

Cohesion - The attractive force between the same kind of molecules, i.e. the force which holds the molecules of a substance together.

Colloid - A state of subdivision of matter which consists either of single large molecules or of aggregations of smaller molecules dispersed to such a degree that the surface forces become an important factor in determining its properties. The size and electrical charge of the particles determine the different phenomena observed with colloids, e.g., Brownian movement. The sizes of colloids, range from l x $l0^{-7}$ cm to 5 x $l0^{-5}$ cm (0.001 to 0.5 microns) in diameter, although the particle size of certain emulsoids can be in the micron range.

Colloidal Composition - A colloidal suspension containing one or more. colloidal constituents.

Colloidal Suspension - A aqueous solution which contains particles of matter 1 micron or less in size.

Conductivity - A measure of the quantity of electricity transferred across unit area per unit potential gradient per unit time. It is the reciprocal of resistivity. Electrolytes may be added to the drilling fluid to alter its conductivity for logging purposes.

Connate Water - Water that was trapped in sedimentary deposits with deposition of sediment, as distinguished from migratory waters (have flowed into deposits after they were laid down).

Consistency - The viscosity of a nonreversible fluid, in poises, for a certain time interval at a given pressure and temperature.

Consistometer - A thickening-time tester having a stirring apparatus to measure the relative thickening time for fluid or cement slurries under predetermined temperatures and pressures. See *API RP 10, "Recommended Practice for Testing Oil Well Cements and Cement Additives, American Petroleum Institute, Dallas, Texas, March, 1965, 14th Edition"*.

Contamination - The presence in a drilling fluid of any foreign material that may tend to produce detrimental properties.

Continuous Phase - The fluid phase which completely surrounds the dispersed phase that may be colloids, oil, etc.

Controlled Aggregation – Condition in which the clay platelets are maintained stacked by a polyvalent cation, such as calcium, and are deflocculated by use of a thinner.

Conventional Fluid - A drilling fluid based on commercial bentonite and fresh water to achieve viscosity and filtration characteristics.

Copolymer - A substance formed when two or more substances polymerize at the same time to yield a product which is not a mixture of separate polymers but a complex having properties different from either polymer alone. See **Polymer.** Example are polyvinyl acetate - maleic anhydride copolymer (clay extender and selective flocculant), acrylamidecarboxylic acid copolymer (total flocculant), etc.

Corrosion - The adverse chemical alteration of a metal or the eating away of the metal by air, moisture, or chemicals; usually an oxide is formed. This is caused by the corrosive environment promoting an electrical cell and the transfer of ions.

Crater – A funnel-shaped deformation of the formation at the surface of a wellbore due to blowout, underground water flow, or loss of formation structural integrity.

Creaming of Emulsions - A separation between the internal and external phases of an emulsion with the lighter phase on top and the denser phase on bottom. When oil muds are stagnant, the less dense oil phase rises and the denser aqueous phase settles. The settling or rising of the particles of the dispersed phase of an emulsion as observed by a difference in color shading of the layers formed. This can be either upward or downward creaming, depending upon the relative densities of the continuous and dispersed phases. This behavior is not necessarily related to emulsion weakness, nor does it portend breaking of the emulsion, as does coalescence.

Created Fractures - Induced fractures by means of hydraulic or mechanical pressure exerted on the formation by the drilling fluid or a frac – fluid. Hydrocarbon based fluids are more prone to create induced fractures due to their low “leak off” values which causes further propagation of the fluid into the formation.

Cuttings - Small pieces of formation that are the result of the shearing, chipping, and/or crushing action of the bit. See **Samples**.

Cycle (Circulation) Time, Fluid – The time of a cycle, or down the hole and back to the surface is the time required in minutes for the pump to move the drilling fluid in the hole back to the pump. The time cycle equals the barrels of fluid in the total circulating system divided by barrels per minute pump output.

Cyclone - A device for the separation of various particles from a drilling fluid, most commonly used as a desander. The fluid is pumped tangentially into a cone, and the fluid rotation provides enough centrifugal force to separate particles by mass weight. See **Centrifuge.**

Cuttings Bed - The collection of drill cuttings in a particular location due to a lack of carrying capacity of the drilling fluid as a result of diminished fluid velocity. This particular phenomenon is a characteristic of horizontal hole drilling where the cuttings tend to settle and collect in beds on the bottom side of the hole where the fluid velocity is at a minimum.

Darcy - A unit of permeability. A porous medium has a permeability of 1 Darcy when a pressure of 1 atm on a sample 1 cm long and 1 sq cm in cross section will force a liquid of l-cp viscosity through the sample at the rate of 1 cc/sec.

Deflocculant - A thinning agent used to reduce viscosity or prevent flocculation; sometimes incorrectly called a “dispersant.” Most deflocculants are low-molecular weight anionic polymers that neutralize positive charges on clay edges.

Deflocculation - Breakup of flocs of gel structures by use of a thinner.

Defoamer or Defoaming Agent - Any substance used to reduce or eliminate foam by reducing the surface tension. Compare Antifoam.

Dehydration - Removal of free or combined water from a compound.

Diesel-Oil Plug - See **Gunk** Plug.

Deliquescence - The liquefaction of a solid substance due to the solution of the solid by adsorption of moisture from the air, e.g., calcium chloride. The term deliquescence is often used interchangeably with the term hydroscopic.

Density - Matter measured as mass per unit volume expressed in pounds per gallon (lb_m/gal), grams per cubic centimeter, and pounds per cubic ft (lb_m/cu. ft). Density is commonly referred to as "weight."

Desander - See **Cyclone.**

Diatomite - A soft, silica-rich sedimentary rock comprising diatom remains that forms most commonly in lakes and deep marine areas.

Diatomaceous Earth - An infusion earth composed of siliceous skeletons of diatoms and being very porous. Sometimes used for combating lost circulation and as an additive to cement; also has been added to special drilling fluids for a specific purpose of application. Also used as a filtering medium to remove undesirable solids from clear fluids (usually brines).

Differential Pressure - The difference in pressure between the hydrostatic head of the drilling-fluid column and the formation pressure at any given depth in the borehole. It can be positive, zero, or negative with respect to the hydrostatic head.

Differential-Pressure (Wall) Sticking – When part of the drillstring (usually the drill collars) becomes embedded in the filter cake resulting in a non-uniform distribution of pressure around the circumference of the pipe. The conditions essential for sticking require a permeable formation and a pressure differential across a nearly impermeable filter cake and drillstring.

Diffusion - The spreading, scattering, or mixing of a material (gas, liquid, or solid**).**

Dilatant Fluid - A dilatant or inverted plastic fluid usually made up of a high concentration of well dispersed solids which exhibits a non- linear consistency curve passing through the origin. The apparent viscosity increases instantaneously with increasing rate of shear. The yield point, as determined by conventional calculations from the direct-indicating viscometer readings, is negative; however, the true yield point is zero.

Diluent - Liquid added to dilute or thin a solution.

Direct-Indicating Viscometer - See Viscometer, Direct-Indicating.

Dispersant - Any chemical which promotes the subdivision of the dispersed phase by neutralization of counter charges.

Dispersed Phase - The scattered phase (solid, liquid, or gas) of dispersions. The particles are finely divided and completely surrounded by the continuous phase.

Dispersion (of Aggregates) - Subdivision of aggregates. Dispersion increases the specific surface of the particle; hence results in an increase in viscosity and gel strength.

Dispersoid - A colloid or finely divided substance.

Dissociation - The splitting up of a compound or element into two or more simple molecules, atoms, or ions. Applied usually to the effect of the action of heat or solvents upon dissolved substances. The reaction is reversible and not as permanent as decomposition; i.e., when the solvent is removed, the ions recombine.

Distillation - Process of first vaporizing a liquid and then condensing the vapor into a liquid (the distillate), leaving behind non-volatile substances, the total solids of a drilling fluid. The distillate is the water and/or oil content of a fluid.

Dog-Leg - The "elbow" caused by a sharp change of direction in the wellbore.

Drilling In - The operation during the drilling procedure at the point of drilling into the pay formation.

Drilling Fluid, Fluid, or Drilling Mud - A fluid formulated with chemicals to obtain specific chemical and physical characteristics for circulating during the rotary drilling process.

Drilling Out - The drilling procedure used when the cement is drilled out of the casing before further hole is made or completion attempted.

Drill-Stem Test (DST) - A test to determine whether oil and/or gas in commercial quantities have been located in the reservoir.

Dynamic - The state of being active or in motion; opposed to static.

Electric Logging - Electric logs are run on a wire line to obtain information concerning the porosity, permeability, fluid content of the formations drilled, and other information. The drilling fluid characteristics may need to be altered to obtain good logs with interpretable data.

Electrical Stability Test - A test for oil-base and synthetic-base muds that indicates the emulsion and oil-wetting qualities of the sample. The test is performed by inserting the ES probe into a cup of 120ºF (48.8ºC) mud and pushing a test button. The ES meter automatically applies an increasing voltage (from 0 to 2000 volts) across an electrode gap in the probe. Maximum voltage that the mud will sustain across the gap before conducting current is displayed as the ES voltage. The ES readings have been studied and were found to relate to an oil mud’s oil-wetting of solids and to stability of the emulsion droplets in a complex fashion not yet completely understood.

Electrolyte - A substance which dissociates into charged positive and negative ions when in solution or a fused state and which will then conduct an electric current. Acids, bases, and salts are common electrolytes.

Emulsifier or Emulsifying Agent - A chemical additive used to lower the surface tension between two immiscible liquids which do not mix. Emulsifiers may be divided, according to their behavior, into ionic and non-ionic agents. The ionic types may be further divided into anionic, cationic, and amphoteric, depending upon the ionic nature of the active groups.

Emulsion - An intimate mixture of two immiscible liquids one dispersed in the other in small droplets or particles. Emulsions may be mechanical, chemical, or a combination of the two. They may be oil-in-water or water-in-oil types.

Emulsoid - Colloidal particles which take up water.

End Point - Indicates the end of some operation or when a definite change is observed. In titration, this change is frequently a change in color of an indicator which has been added to the solution or the disappearance of a colored reactant.

Engineer, Fluid - One versed in drilling fluids whose duties are to manage and maintain the various types of oil-well fluid programs.

EP Additive - See **Extreme-Pressure Lubricant.**

Epm or Equivalents Per Million - Unit chemical weight of solute per million unit weights of solution.

Equivalent Circulating Density - For a circulating fluid, the equivalent circulating density in lbs/gal equals the hydrostatic head (psi) plus the total annular pressure drop (psi) divided by the depth (ft) multiplied by 0.052.

Equivalent Weight or Combining Weight – The atomic or formula weight of an element, compound, or ion divided by its valence. Elements entering into combination always do so in quantities proportional to their equivalent weights.

Extreme-Pressure Lubricant - Additives which, when added to the drilling fluid, impart lubrication to the bearing surfaces when subjected to extreme pressure conditions, noted as a reduction in friction, torque, and drag.

Fault - Geological term denoting a formation break, upward or downward, in the subsurface strata. Faults can significantly affect the selection of fluids and casing program design.

Fermentation - The decomposition process of natural occurring organic molecular structures, e.g., starch in which a chemical change is brought about by enzymes, bacteria, or other micro-organisms. Often referred to as "souring".

Fiber or Fibrous Materials - Any tough stringy material used to prevent loss of circulation or to restore circulation. In field use, fiber generally refers to the larger fibers of plant origin.

Filling The Hole - Pumping drilling fluid continuously, or intermittently into the well bore to maintain a constant fluid level near the surface, as the drillpipe is withdrawn, i.e. to fill the remaining void with drilling mud as the drillpipe is removed from the annulus. The purpose is to maintain a constant level of hydrostatic pressure to avoid the danger of blowout, water intrusion, and/or caving of the well bore.

Fill-Up Line - The line through which fluid is added to the hole via the riser.

Filter Press - A pressurized cell, fitted with a filter medium, used for evaluating filtration characteristics of a drilling fluid while it is either static or stirred (to simulate circulation) in the test cell. Generally, either low-pressure, low-temperature or high-pressure, high-temperature devices are used.

Filter Cake - The suspended solids of a drilling fluid that are deposited on a porous medium during the process of filtration. See also **Cake Thickness**.

Filter-Cake Texture (or Quality) - A subjective description of a filter cake. The physical properties of a cake as measured by toughness, slickness, and brittleness. See also **Cake Consistency.**

Filter-Cake Thickness - A measurement of the solids deposited on filter paper in 32nds of an inch during the standard 30-minute API filter test. See **Cake Thickness**. In certain areas, the filter-cake thickness is a measurement of the solids deposited on filter paper for a 7 minute duration.

Filter Loss - See **Fluid Loss.**

Filter Paper – Sized, porous paper for filtering liquids. API filtration test specifies one thickness of 9-cm filter paper Whatman No. 50, S&S, No.576, or equivalent.

Filter Press - A device for determining fluid loss of a drilling fluid having specifications in accordance with *API RP 13B.*

Filtrate- The liquid fraction of a drilling fluid that is forced through a porous medium during the filtration process. For test, see **Fluid Loss**.

Filtration - The process of separating suspended solids from their liquid by forcing the latter through a porous medium. Two types of fluid filtration occur in a well - dynamic filtration while circulating, and static filtration when the fluid is at rest.

Filtration Rate - See **Fluid Loss.**

Fishing - Operations on the rig for the purpose of retrieving from the well bore sections of pipe, collars, junk, or other obstructive items which are in the hole.

Fish Eye - A slang term for a globule of partly hydrated polymer caused by poor dispersion during the mixing process (commonly a result of adding the product too fast for the shearing ability of the hopper). Fish eyes consist of a granule of unhydrated polymer surrounded by a gelatinous covering of hydrated polymer which inhibits water from completing the hydration process. Thus, once formed, fish eyes do not disperse and the byproduct is removed by the shaker screens and discarded. Fish eyes are notorious for plugging off (blinding) the shaker screens thereby resulting in loss of drilling fluid with the discharged cuttings.

Flat Gel - A condition wherein the ten-minute gel strength is essentially equal to the initial gel strength.

Flipped - The reversal of an emulsion; a separation between two immiscible fluids into two separate phases, i.e. no longer dispersed.

Flocculate - A process whereby the electromagnetic attraction between suspended particles dominate the particle alignment under quiescent conditions thereby resulting in increased gel strengths of the fluid.

Flocculating Agent - Substances, such as most electrolytes, some polysaccharides, certain natural or synthetic polymers, that bring about the thickening of the consistency of a drilling fluid. In Bingham Plastic fluids, the yield point and gel strength increase.

Flocculation - Loose association of particles in lightly bonded group’s, i.e., non-parallel association of clay platelets. In concentrated suspensions, such as drilling fluids, flocculation results in gelation. In some drilling fluids, flocculation may be followed by irreversible precipitation of colloids and certain other substances from the fluid, e.g., red beds.

Flocs - See **Flocculates.**

Fluid - A fluid is a substance readily assuming the shape of the container in which it is placed. The term includes both liquids and gases. It is a substance in which the application of every system of stresses (other than hydrostatic pressure) will produce a continuously increasing deformation without any relation between time rate of deformation at any instant and the magnitude of stresses at that instant.

Fluid Flow - The state of fluid dynamics of a fluid in motion is determined by the type of fluid (e.g., Newtonian plastic, pseudoplastic, dilatant), the properties of the fluid such as viscosity and density, under a given set of conditions and fluid properties, the fluid flow can be described as plug flow, laminar (called also Newtonian, streamline, parallel, or viscous) flow, or turbulent flow. See above terms and Reynolds Number.

Fluidity - The reciprocal of viscosity. The measure of rate with which a fluid is continuously deformed by a shearing stress. Ease of flowing.

Fluid Loss - Measure of the relative amount of fluid lost (filtrate) through permeable formations or membranes when the drilling fluid is subjected to a pressure differential. For standard API filtration test procedure, see *API RP 13B.*

Fluorescence - Instantaneous re-emission of light, of a greater wave length, than that light originally absorbed.

Foam - Foam is a two-phase system, similar to an emulsion, where the dispersed phase is a gas or air.

Foaming Agent - A substance that produces fairly stable bubbles at the air-liquid interface due to agitation, In air or gas drilling, foaming agents are added to turn water influx into aerated foam. This is commonly called "mist drilling."

Formation Damage - Damage to the productivity of a well resulting from invasion into the formation by fluid particles or fluid filtrate. Asphalt from crude oil will also damage some formations. See **Mudding Off.**

Formation Sensitivity - The tendency of certain producing formations to adversely react with invading fluid filtrates.

Functions of Drilling Fluids - The most important function of drilling fluids in rotary drilling is to bring cuttings from the bottom of the hole to the surface. Some other important functions are - control subsurface pressures, cool and lubricate the bit and drill string, deposition of an impermeable wall cake, etc.

Funnel Viscosity - See **Marsh Funnel** Viscosity,

Galena - Lead sulfide (PbS). Technical grades (specific gravity about 7) are used for increasing the density of drilling fluids to points impractical or impossible with barite.

Garrett Gas Train - An instrument used for quantitative analysis of sulfides and carbonates. Specific test methods have been published by API. The oil-mud procedure analyzes active sulfides and uses whole mud samples, whereas the water-base mud procedure tests filtrate. The GGT unit is a clear, plastic block that contains three interconnected chambers. A carrier gas is used to flow an inert gas through the chambers. The sample is placed in chamber #1 and is acidified to release sulfides as H_2S and carbonates as CO_2. The appropriate Dräger tube is used to measure the effluent gas that is evolved from the sample.

Gas Cut - Gas entrained by a drilling fluid. See **Air Cutting**.

Gas Hydrate - A crystalline solid consisting of water with gas molecules in an ice-like cage structure. Water molecules form a lattice structure into which many types of gas molecules can fit. Most gases, except hydrogen and helium, can form hydrates. C_1 to $_nC_5$ hydrocarbons, H_2S and CO_2 readily form hydrates at low temperature and high pressure. Gas-cut muds can form hydrates in deepwater drilling operations, plugging BOP lines, risers and subsea wellheads, causing a well-control risk.. Gas hydrates are thermodynamically suppressed by adding antifreeze materials such as salts or glycols. Gas hydrates are found in nature, on the bottom cold seas and in arctic permafrost regions.

Gel - A term used to identify highly colloidal, high yielding, viscosity- building commercial clays, such as bentonite and attapulgite clays.

Gelation - Association of particles to form a continuous structure of charged clays, the state of which can be face to face, face to edge, and edge to edge forming a continuous network structure held together by electronic charges.

Gel Cement - Cement having a small to moderate percentage of bentonite added as filler and/or to reduce the slurry weight. See Gunk Plug.

Gelled - A state of a colloidal suspension in which shearing stresses below a certain finite value fail to produce permanent deformation. The minimum shearing stress that will produce permanent deformation is known as-the shear or-gel-strength of the gel. Gels commonly occur when the dispersed colloidal particles have a great affinity for the dispersing medium, i.e., are lypophilic. Thus, gels commonly occur with bentonite in water. For their measurement, see **Gel Strength, Initial** and **Gel Strength**, **10-Minute**.

Gelled Up - Oil-field jargon usually referring to any fluid with high gel strength and/or highly viscous properties, often a state of severe flocculation.

Gel Strength - The ability or the measure of the ability of a colloid to form gels. Gel strength is a pressure unit usually reported in lbs/100 sq ft. It is a measure of the same inter-particle forces of a fluid as determined by the yield point except that gel strength is measured under static conditions, yield point under dynamic conditions. The common gel-strength measurements are initial and ten-minute gels. See also **Shear** and **Thixotropy.**

Gel Strength, Initial - The measured initial gel strength of a fluid is the maximum reading (deflection) taken from a direct-reading viscometer after the fluid has been quiescent for 10 sec. It is reported in lbs/100 sq ft. See *API RP 13B* for details of test procedure.

Gel Strength, 10 Minute – The measured to-minute gel strength of a fluid is the maximum reading (deflection) taken from a direct-reading viscometer after the fluid has been quiescent for l0 min, The reading is reported in lbs/l00 sq ft. See *API RP 13B* for details of test procedure.

Geothermal Gradient - The rate of increase in temperature per unit depth in the earth. Although the geothermal gradient varies from place to place, it averages 25 to 30ºC/km (15ºF/1000 ft). It is particularly important to know the geothermal gradient in an area when designing the drilling mud program for a deep well. The downhole temperature can be estimated by adding the surface temperature to the product of the depth and the geothermal gradient.

Gpg or Grains per Gallon - ppm equals gpg x 17.1.

Gravity, Specific – The ratio of the mass of a body to the mass of an equal volume of water at 4ºC. For example, 1 mL of water weighs 1 gm at 4ºC (i.e. the density is 1 gm/mL). One mL of barite weighs 4.2 g (it's density is 4.2 gm/mL). The ratio of the two equal volumes of material is 4.2g/1g and the specific gravity is 4.2.

Grains per Gallon - Equal to the number of grains of a given substance in one U.S. gallon of water. One grain = 1/7,000 pound and one U.S. gallon of water weighs 8.33 pounds. Hardness can be expressed in terms of **ppm** (parts per million). Conversion of parts per million or milligrams per liter into grains per gallon is accomplished by dividing the parts per million (or milligrams per liter) by 17.1 to convert to grains per gallon.

Greasing Out - Certain organic substances, usually fatty-acid derivatives, which are added to drilling fluids as emulsifiers, extreme pressure (EP) lubricants, etc., may react with such ions as calcium and magnesium that are in, or will subsequently come into the system. An essentially water-insoluble greasy material separates out.

Gum - Any hydrophilic plant polysaccharides or other derivatives which when dispersed in water, swell to produce a viscous dispersion or solution. Unlike resins, they are soluble in water and insoluble in alcohol.

Gumbo - A generic term for soft, sticky, swelling clay formations that are frequently encountered in surface holes offshore or in sedimentary basins onshore near seas. This clay fouls drilling tools and plugs piping, both sever problems for drilling operations. It is a nonspecific type of shale that becomes sticky when wet and adheres aggressively to surfaces. It forms mud rings and balls that can plug the annulus, the flowline and shale-shaker screens. Gumbo is likely to contain appreciable amounts of Ca^{++} smectite clays. It is dispersed in a water mud, causing rapid accumulations of colloidal solids.

Guar Gum - A naturally occurring hydrophilic polysaccharide derived from the seed of the guar plant. The gum is chemically classified as a galactomannan. Guar gum slurries made up in clear, fresh, or brine water possesses pseudo-plastic flow properties.

Gunk Plug or Squeeze - A slurry in crude or diesel oil containing any of the following materials or combinations - bentonite, cement, attapulgite, and guar gum (never with cement), used primarily in combating lost circulation. The plug may or may not be squeezed.

Gunning the Pit - The mechanical agitation of the drilling fluid in a pit by means of, a high pressure fluid gun, electric mixer, or agitator.

Gyp or Gypsum - See **Calcium Sulfate**. Gypsum is often encountered while drilling. It may occur as thin stringers or massive formations.

Hardness (of Water) - The hardness of water is due principally to the calcium and magnesium ions present in the water and is independent of the accompanying acid ions. The total hardness is measured in terms of parts per million of calcium carbonate or calcium and sometimes equivalents per million of calcium. For hardness tests, see *API RP 13B.*

Heaving - The partial, intermittent, or complete collapse *of* the walls *of* a hole resulting from internal pressures due primarily to swelling from hydration or formation gas pressures. See Sloughing.

Heterogeneous - A substance that consists *of* more than one phase and is not uniform, such as colloids, emulsions, etc. It has different properties in different parts.

High-pH fluid - A drilling fluid with a pH range above 10.5, a high-alkalinity fluid.

High-Yield Drilling Clay - A classification given to a group of commercial drilling-clay preparations having a yield of 35 to 50 bbl/ton and intermediate between bentonite and low-yield clays. High- yield drilling clays are usually prepared by peptizing low-yield calcium montmorillonite clays or, in a few cases, by blending some bentonite with the peptized low-yield clay.

Homogeneous - Of uniform or similar nature throughout; or a substance or fluid that has at all points the same property or composition.

Hopper, Jet - A device to facilitate the addition of drilling fluid additives to the system.

Horizontal Drilling - A subset of the more general term "directional drilling," is used where the departure of the wellbore from vertical exceeds about 80 degrees. Note that some horizontal wells are designed such that after reaching true 90-degree horizontal, the wellbore may actually start drilling upward. In such cases, the angle past 90 degrees is continued, as in 95 degrees, rather than reporting it as deviation from vertical. Because a horizontal well typically penetrates a greater length of the reservoir, it can offer significant production improvement over a vertical well.

Humic Acid - Organic acids of indefinite composition in naturally occurring leonardite lignite. The humic acids are the most valuable constituent. See **Lignin.**

Hydrate - A substance containing water combined in the molecular form (such as $CaSO_4$ x $2H_20$), a crystalline substance containing water of crystallization.

Hydration - The act of a substance to take up water by means of absorption and/or adsorption.

Hydrogen Ion Concentration - A measure of the acidity or alkalinity of a solution, normally expressed as pH. See **pH**.

Hydrogen Embrittlement - The process whereby steel components become less resistant to breakage and generally much weaker in tensile strength. While embrittlement has many causes, in the oil field it is usually the result of exposure to gaseous or liquid hydrogen sulfide (H_2S). On a molecular level, hydrogen ions work their way between the grain boundaries of the steel, where hydrogen ions recombine into molecular hydrogen (H_2), taking up more space and weakening the bonds between the grains. The formation of molecular hydrogen can cause sudden metal failure due to cracking when the metal is subject to tensile stress.

Hydrolysis - Hydrolysis is the reaction of a salt with water to form an acid and base. For example, soda ash (Na_2CO_3) hydrolyzes basically, and hydrolysis is responsible for the increase in the pH of water when soda ash is added.

Hydrometer - A floating instrument for determining the specific gravity or density of liquids, solutions, and slurries. A common example is the fluid weight hydrometer used to determine the density of fluid.

Hydrophile - A substance usually in the colloidal state or an emulsion, which is wetted .by water, i.e. it attracts water or water adheres to it.

Hydrophilic - A property of a substance having an affinity for water or one that is wetted by water.

Hydrophilic-Lypophilic Balance (HLB) - Surfactants are characterized according to the "balance" between the hydrophilic ("water –loving") and lypophilic ("oil loving") portions of their molecules. The hydrophilic-lypophilic balance (HLB) number indicates the polarity of the molecules in an arbitrary range of 1-40, the the most commonly used emulsifiers having a value between 1 and 20. The HLB number increases with increasing hydrophilicity. According to the HLB number, surfactants may be utilized for different purposes.

Function	**HLB Range**
Antifoaming Agent	1 to 3
Emulsifier, water-in-oil	3 to 6
Wetting Agent	7 to 9
Emulsifier, oil-in-water	8 to 19
Detergent	13 to 15
Solubilizer	15 to 20

Oils also have HLB values assigned; however, this "HLB" is relative as to whether an oil-in-water emulsion is to be stabilized. Emulsifiers should have similar HLB values to that of the respective oils in order to achieve maximum stabilization. Mineral oil has an assigned HLB number of 4 when a water-in-oil emulsion is desired, and a value of 10.5 when an oil-in-water emulsion is to be prepared. Accordingly, the HLB number of the emulsifier should also be around 4 and 10.5, respectively. The desired HLB numbers can also be achieved by mixing lypophilic and hydrophilic surfactants. The overall HLB value of the mixture is calculated as the sum of the fraction times the individual HLB.

Hydrophobe - A substance, usually in the colloidal state, not wetted by water.

Hydrophobic - Descriptive of a substance which repels water.

Hydrostatic Head - The pressure exerted by a column of fluid, usually expressed as pounds per square inch. To determine the hydrostatic head in psi at a given depth, multiply the depth in feet by the density in pounds per gallon by 0.052.

Hydroxide - A designation that is given for basic compounds containing the $OH^{=}$ radical. When these substances are dissolved in water, they increase the pH of the solution. See **Base**.

Hygroscopic - The property of a substance enabling it to absorb water from the air.

Indicator - Substances in acid-base titrations which, in solution, change color or become colorless as the hydrogen ion concentration reaches a definite value, these values varying with the indicator. In other titration such as chloride, hardness, and other determinations, these substances change color at the end of the reaction. Common indicators are phenolphthalein, potassium chromate, etc.

Inhibited Fluid - A drilling fluid having an aqueous phase with a chemical composition that tends to retard and even prevent (inhibit) appreciable hydration (swelling) or dispersion of formation clays and shale through chemical and/or physical means. See **Inhibitor** (Fluid).

Inhibitor (Corrosion) - Any agent which, when added to a system, slows down or prevents a chemical reaction or corrosion. Corrosion inhibitors are used widely in drilling and producing operations to prevent corrosion of metal equipment exposed to hydrogen sulfide, carbon dioxide, oxygen, saltwater, etc. Common inhibitors added to drilling fluids are filming amines, chromates, and lime.

Inhibitor (Fluid) - Substances generally regarded as drilling fluid contaminants, such as salt and calcium sulfate, are called inhibitors when purposely added to fluid so that the filtrate from the drilling fluid will prevent or retard the hydration of formation clays and shales.

Initial Gel - See **Gel Strength, Initial.**

Interfacial Tension - The force required to break the surface between two immiscible liquids. The lower the interfacial tension between the two phases of an emulsion, the greater the ease of emulsification. When the values approach zero, emulsion formation is spontaneous. See **Surface Tension.**

Interstitial Water - Water contained in the interstices or voids of formations.

Invert Oil-Emulsion Fluid - An invert emulsion is a water-in-oil emulsion where fresh or saltwater is the dispersed phase and diesel, crude, or some other oil is the continuous phase. Water increases the viscosity and oil reduces the viscosity.

Iodine Number - The number indicating the amount of iodine absorbed by oils, fats, and waxes, giving a measure of the unsaturated linkages present. Generally, the higher the iodine number the more severe the action of the oil on rubber.

Ions - Acids, bases, and salts (electrolytes) when dissolved in certain solvents, especially water, are more or less dissociated into electrically charged ions or parts of the molecules, due to loss or gain of one or more electrons. Loss of electrons results in positive charges producing a cation. A gain of electrons results in the formation of an anion with negative charges. The valence of an ion is equal to the number of charges borne by it.

Jetting - The process of periodically removing a portion of, or all of, the water, fluid and/or solids, from the pits, usually by means of pumping through a jet nozzle arrangement.

Kelly - A heavy square or hexagonal pipe that works through a like hole in the rotary table and rotates the drill string. The kelly contains a fluid path through which the drilling mud can be pumped down through the drill string. The kelly is connected on its upper end to the swivel which allows it to be rotated, thereby rotating the drillstring.

Kelly Bushing - An adapter that serves to connect the rotary table to the Kelly. The Kelly bushing has an inside diameter profile that matches that of the Kelly, usually square or hexagonal. It is connected to the rotary table by large steel pins that fit into mating holes in the rotary table. The rotary motion from the rotary table is transmitted to the bushing through the pins, and then to the Kelly itself through the square or hexagonal flat surfaces between the Kelly and the Kelly bushing. The Kelly then turns the entire drillstring.

Kelly Cock - A valve in the Kelly that allows pressure to be shut off and prevent reverse flow of fluids from the drill string.

Kelly Hose - A large diameter (3 to 5 inch inside diameter, high-pressure flexible line used to connect the standpipe to the swivel. This flexible piping arrangement permits the kelly (and, in turn the drill string and bit) to be raised or lowered while drilling fluid is pumped through the drill string. The simultaneous lowering of the drillstring while pumping fluid is critical to the drilling operation.

Key Seat - That section of a hole, usually of abnormal deviation and; relatively soft formation, which has been eroded or worn by drill-pipe to a: size smaller than the tool joints or collars. This keyhole type configuration will not allow these members to pass when pulling out of the hole causing the drill string to become stuck.

Killing A Well - Bringing a well that is blowing out under control. Also; the procedure of circulating water and fluid into a completed well before starting well-service operations.

Kill Line - A line connected to the annulus below the blowout preventers (BOP) for the purpose of pumping into the annulus while the preventers are closed.

Kinematic Viscosity - The kinematic viscosity of a fluid is the ratio of the viscosity (e.g., cp in g/cm-sec) to the density (e.g., g/cc) using consistent units. In several common commercial viscometers, the kinematic viscosity is measured in terms of the time of efflux (in seconds) of a fixed volume of liquid through a standard capillary tube or orifice. See **Marsh Funnel Viscosity**.

LC_{50} - The lethal concentration of a substance reported in ppm that kills 50% of a population of test organisms, such as mysid shrimp, in a standard, controlled laboratory bioassay test. In offshore drilling operations, the LC_{50} number is used to determine whether waste mud or cuttings can be discharged into the water. The larger the LC_{50} ppm number from the test, the less toxic the sample is to the organism. If the LC_{50} number is 1,000,000 ppm the sample is presumably nontoxic according to the test protocol.

Laminar Flow - Fluid elements flowing along fixed streamlines which are parallel to the walls of the channel of flow. In laminar flow, the fluid moves in plates or sections with a differential velocity across the front which varies from zero at the wall to a maximum toward the center of flow. Laminar flow is the first stage of flow in a Newtonian fluid. It is the second stage in a Bingham plastic fluid. This type of motion is also called parallel, streamline, or viscous flow. See **Plug** and **Turbulent Flow.**

Leonardite - A naturally occurring oxidized lignite. **See Lignins**.

Lignins, Mined or Humic Acids - Mined lignins are naturally occurring special lignite, e.g., leonardite, that are produced by strip mining from special lignite deposits. The active ingredient is the humic acid. Mined lignins are used primarily as thinners, which may or may not be chemically modified. However, they are also widely used as mechanical emulsifiers.

Lignosulfonates - Organic drilling-fluid additives derived from by-products of sulfite paper manufacturing process from coniferous woods. Some of the common salts, such as the ferrochrome, chrome, calcium, and sodium, are used as universal dispersants while others are used selectively for calcium-treated systems. In large quantities, the ferrochrome and chrome salts are used for fluid loss control and shale inhibition.

Lime - Commercial form of calcium hydroxide.

Lime-Treated Fluids - Commonly referred to as "lime-base" fluids. These high-pH systems contain most of the conventional freshwater additives to which slaked lime has been added to impart special properties. The addition of lime creates a state in which the majority of clay particles are in an aggregated state producing near zero flat gel strengths. The alkalinities and lime contents vary from low to high.

Limestone - See **Calcium Carbonate**.

Live Oil - Crude oil that contains gas and has not been stabilized or weathered. This oil can cause gas cutting when added to fluid and is a potential fire hazard.

Logging - See **Fluid Logging** and **Electric Logging**.

Loss of Circulation - See **Circulation, Loss** of.

Loss of Head or Friction Loss - See **Pressure Drop Loss**.

Lost Circulation Additives - Materials added to a drilling fluid to control or prevent lost circulation. These non-soluble materials are added in varying amounts and are classified as fiber, flake, or granular.

Lost Returns - See **Circulation, Loss of**.

Low-Colloid Oil Mud - An oil mud designed and maintained with a minimum of colloid-sized solids, typically by omitting fatty-acid soaps and lime, and minimizing organophilic clays and fluid-loss additives. Low-colloid oil mud, also called a relaxed filtrate oil mud, increases drilling rate. A disadvantage is that filter cake formed on sands is not tight, can quickly become very thick, and can cause pipe to stick by differential pressure.

Low-Gravity Solids - A type of drilling-fluid solid having a lower density than the barite (4.20 g/cm^3) or hematite (5.505 g/cm^3) that is used to weight up a drilling mud, including drill solids plus the added bentonite clay. Low gravity solids are normally assumed to have a gravity of 2.6 g/cm^3

Low-Solids Fluids - A designation given to any type of fluid where high performing additives, e.g., CMC, have been partially or wholly substituted for commercial or natural clays, for comparable viscosity and densities (weighted with barite), a low-solids fluid will have a lower volume-percent of low gravity solids content.

Low-Yield Clays - Commercial clays chiefly of the calcium montmorillonite type having a yield of approximately 15 to 30 bbl/ton.

Lypophile - A substance usually colloidal and easily wetted by oil.

Lypophilic - Having an affinity for the suspending medium, such as bentonite in water.

Lypophilic Colloid - A colloid that is not easily precipitated from a solution, and is readily dispersible after precipitation by the addition of a solvent.

Lypophobic - A colloid that is readily precipitated from a solution and cannot be re-dispersed by addition of the solution.

Marsh Funnel - An instrument used in determining the Marsh funnel viscosity. The Marsh funnel is a container with a fixed orifice at the bottom so that when filled with 1500 cc freshwater, 1 qt (946 rnL) will flow out in 26 seconds. For 1000 cc out, the efflux time for water is 27.5 seconds. See *API RP 13B* for specifications.

Marsh Funnel Viscosity - Commonly called the funnel viscosity, the Marsh Funnel viscosity is reported as the number of seconds required for a given fluid to flow 1 qt through the Marsh funnel. In some areas, the efflux quantity is 1000 cc. See *API RP I3B* for instructions. See also **Kinematic Viscosity**

Meniscus - The curved interface between two immiscible phases in a tube, such as in a pipette or graduated cylinder. Liquid volumes should be read at the bottom of a curved meniscus by alignment of the bottom of the meniscus. For water and liquids that wet the glass, the meniscus is concave. For nonwetting liquids, such as mercury, the meniscus is convex.

Mesh - A measure of fineness of a woven material, screen, or sieve; e.g.; a 200-mesh sieve has 200 openings per linear inch. A 200-mesh screen with a wire diameter of 0.0021 in. (0.0533 mm) has an opening of 0.074 mm, or will pass a particle of 74 microns. See **Micron**.

Methylene Blue Test - A test to determine the amount of clay-like materials in a water-base drilling mud based on the amount of methylene blue dye absorbed by the sample. Results are reported as "MBT" and also as "lb_m/bbl, bentonite equivalent" when performed to API specifications. See **Cation-Exchange Capacity (CEC).**

M_f - The methyl orange alkalinity of the filtrate, reported as the number of milliliters of 0.02 Normal (N/50) acid required per milliliter of filtrate to reach the methyl orange end point (pH 4.3).

Mica - A naturally occurring flake material of varying size used in combating lost circulation. Chemically, an alkali aluminum silicate.

Micelles - Organic and inorganic molecular aggregates occurring in colloidal solutions. Long chains of individual structural units chemically joined to one another and lay side by side to form bundles. When bentonite hydrates, certain sodium, or other metallic ions go into solution, the clay particle plus its atmosphere of ions is technically known as a micelle. See **Oil-Emulsion Water.**

Micron (μ) = MU **-** A unit of length equal to one millionth part of a meter, or one thousandth part of a millimeter.

Millidarcy - 1/l000 Darcy. See **Darcy.**

mL or Milliliter - A metric system unit for the measure of volume. Literally 1/1000th of a liter. In drilling fluid analysis work, this term is used interchangeably with cubic centimeter (cc). One quart is about equal to 946 mL.

Mist Drilling - A method of Rotary drilling whereby water and/or oil is dispersed in air and/or gas as the drilling fluid.

Mixed-Metal Hydroxide (MMH) - A compound containing hydroxide anions in association with two or more metal cations. MMH particles are extremely small and carry multiple positive charges. They can associate with bentonite to form a strong complex that exhibits highly shear-thinning properties, with high and fragile gel strengths, high yield point (YP), and low plastic viscosity (PV). MMH muds are used as nondamaging drilling fluids, metal-reaming fluids (to carry out metal cuttings) and for wellbore shale control. Being anionic, MMH mud is sensitive to anionic deflocculants and small anionic polymers, such as polyphosphates, lignosulfonate or lignite.

Molecular Weight - The sum of the atomic weights of all the constituent atoms in the molecule of an element or compound.

Molecule - When atoms combine, they form a molecule. In the case of an element or a compound, a molecule is the smallest unit which chemically still retains the properties of the substance in mass.

Monkeyboard - The small platform that the derrickman stands on when tripping pipe.

Montmorillonite - A clay mineral commonly used as an additive to drilling fluids. Sodium montmorillonite is the main constituent in bentonite. The structure of montmorillonite is characterized by a form which consists of a thin platey-type sheet with the width and breadth indefinite, and thickness that of the molecule. The unit thickness of the molecule consists of three layers. Attached to the surface are ions that are replaceable. Calcium montmorillonite is the main constituent in low-yield clays.

Mud - A water- or oil-base drilling fluid whose properties have been altered by solids, commercial and/or native, dissolved and/or suspended. Used for circulating out cuttings and many other functions while drilling a well. Mud is the term most commonly given to drilling fluids. See **Drilling Fluids**.

Mud Additive - Any material added to a drilling fluid to achieve a particular physical or chemical attribute to the fluids properties.

Mudding Off - Commonly thought of as reduced formation productivity caused by the penetrating, sealing, or plastering effect of a drilling fluid.

Mudding Up - Process of mixing fluid additives to achieve some desired purpose not possible with the former fluid, which has usually been water, air, or gas.

Mud House - A structure at the rig to store and shelter sacked materials used in drilling fluids.

Mud Logging - A method of determining the presence or absence of oil or gas in the various formations penetrated by the drill bit. The drilling fluid and the cuttings are continuously tested on their return to the surface, and the results of these tests are correlated with the depth or origin.

Mud-Mixing Devices - The most common device for adding solids to the fluid is by means of the jet hopper. Some other devices for mixing are eductors, paddle mixers, electric stirrers, fluid guns, chemical barrels, etc.

Mud Pit - Earthen or steel storage facilities for the surface fluid system. Mud pits which vary in volume and number are of two types, circulating and reserve. Mud testing and conditioning is normally done in the circulating pit system.

Mud Program - A step by step procedural plan based on prior knowledge of all known drilling parameters before actual drilling is initiated. When the unexpected arises in the actual drilling then deviation from the mud program in may be required. These departures can be planned for in advance and included in the program as contingency procedures should the mud program require altering. Deviation from the mud program is normally encountered when drilling wildcat type wells.

Mud Pumps - Pumps at the rig used to circulate drilling fluids.

Mud Scales - See **Balance, Fluid**.

Mud Still- An instrument used to distill oil, water, and other volatile material in a fluid to determine oil, water, and total solids contents in volume-percent. Should the fluid contain dissolved components such as salts the volume of liquid fraction distilled will require adjustment.

Natural Clays - Natural clays, as opposed to commercial clays, are clays that are encountered when drilling various formations. The yield of these clays varies greatly, and they may or may not be purposely incorporated into the fluid system.

Neat Cement – A slurry composed of Portland cement and water.

Neutralization - A reaction in which the hydrogen ion of an acid and the hydroxyl ion of a base unite to form water, the other ionic product being a salt.

Newtonian Flow - See **Newtonian Fluid.**

Newtonian Fluid - The basic and simplest fluids from the standpoint of viscosity consideration in which the shear force is directly proportional to the shear rate.. These fluids will immediately begin-to- move when a pressure or force in excess of zero is applied. Examples of Newtonian fluids are water, diesel oil, and glycerin. The yield point as determined by direct-indicating viscometer is zero.

Non-Conductive Fluid - Any drilling fluid, usually oil-base or invert- emulsion fluids, whose continuous phase does not conduct electricity, e.g., oil. The spontaneous potential (SP) and normal resistivity cannot be logged, although such other logs as the induction, acoustic velocity, etc., can be run.

Normal Pressure - The pore pressure of rocks that is considered normal in areas in which the change in pressure per unit of depth is equivalent to hydrostatic pressure. The normal hydrostatic pressure gradient for freshwater is 0.433 pounds per square inch per foot (psi/ft), and 0.465 psi/ft for seawater with 100,000 ppm total dissolved solids (a typical Gulf Coast water).

Normal Solution - A solution of such a concentration that it contains 1 gram-equivalent of a substance per liter of solution.

Oil Base Mud (OBM) - The term "oil-base mud" is applied to a special type drilling fluid where oil (usually diesel oil) is the continuous phase and water the dispersed phase. Oil-base muds contain emulsifiers, wetting agents, viscosifiers, filtration control agents, and water (usually brine) emulsified into the system. These muds are also referred to as “non-aqueous” fluids as the major, or continuous phase is not water. These systems may also be formulated from more environmentally acceptable synthetic oils and are then referred to as “synthetic oil-base muds” (SOBM)

Oil/Brine Ratio - Ratio of the volume percent oil to the volume percent water in an oil mud, where each is a percent of the total liquid in the mud. OWR is calculated directly from the retort analysis of an oil mud, but the brine content is calculated from the water content by using the chloride and calcium titration data. For example, if a mud contains 60 vol.% oil and 20 vol.% brine, the oil percentage is [60/(60 + 20)]100 = 77% and the water percent is [18/(60 + 18)] = 23%. That OWR is written as 77/23.

Oil Content - The oil content of any drilling fluid is the amount of oil in volume-percent.

Oil-In-Water Emulsion Fluid - Commonly called "emulsion fluid." Any conventional or special water-base fluid to which oil has been added. The oil becomes the dispersed phase and may be emulsified into the fluid either mechanically or chemically.

Oil-Wet - Pertaining to the preference of a solid to be in contact with an oil phase rather than a water or gas phase. Oil-wet rocks preferentially imbibe oil. Generally, polar compounds or asphaltenes deposited from the crude oil onto mineral surfaces cause the oil-wet condition. Similar compounds in oil-base mud also can cause a previously water-wet rock to become partially or totally oil-wet. Solids in an oil mud must be oil-wet for the mud to remain stable. Water-wet solids in an oil mud will create an unstable system with the solids agglomerating and either being removed by the shale shaker, or sticking to and building up on tubulars such as the drill pipe. This situation is aggravated by high shear, i.e. inside the drill pipe or drill collars where the solids will build up and cause undesirable increases in pump pressure.

Packer Fluid - Any fluid placed in the annulus between the tubing and casing above a packer. Along with other functions, the hydrostatic pressure of the packer fluid is utilized to reduce the pressure differentials between the formation and the inside of the casing and across the packer itself.

Particle - A minute unit of matter, usually a single crystal, of regular shape with a specific gravity approximating that of a single crystal.

Parts-Per Million - See-**ppm.**

Parallel Flow - See **Laminar Flow.**

Pay Zone or “Pay” - The formation drilled that contains oil and/or gas in commercial quantities.

Penetration, Rate of - The rate in feet per hour at which the drill proceeds to deepen the well bore and is commonly referred to as Rate of Penetration (ROP).

Peptization - An increased dispersion due to the addition of electrolytes or other chemical substances. See **Deflocculation** and **Dispersion**.

eptizing Agent - A product that enhances dispersion of a substance (such as clay) into colloidal form. Peptizing agents for drilling-mud clays are sodium carbonate, sodium metaphosphates, sodium polyacrylates, sodium hydroxide and other water-soluble compounds, even common table salt, NaCl, if added at low concentration.

Peptized Clay - A clay to which a chemical agent has been added to increase its initial yield. For example, soda ash is frequently added to calcium montmorillonite clay.

Percent - For weight -percent, see **ppm**. Volume-percent is the number of volumetric parts of any liquid or solid constituent per 100 like volumetric parts of the whole. Volume-percent is the most common method of reporting solids, oil, and water contents of drilling fluids.

Permeability - Normal permeability is a measure of the ability of rock to transmit a one-phase fluid under conditions of laminar flow. Unit of permeability is the Darcy.

P_f - The phenolphthalein alkalinity of the filtrate, reported as the number of milliliters of 0.02 Normal (N/50) acid required per milliliter of filtrate to reach the phenolphthalein end point.

pH - An abbreviation for potential hydrogen ion. The pH numbers range from 0 to 14, 7 being neutral, and are indices of the acidity (below 7) , or alkalinity (above 7) of the fluid. The numbers are a function of the hydrogen ion concentration in gram ionic weights per liter which, in turn, is a function of the dissociation of water as given by the following expression:

$$\frac{(H)(OH)}{H_2O} = K_{H_2O}$$

$$= 1 \times 10^{-\upsilon}$$

The pH may be expressed as the logarithm (base 10) of the reciprocal (or the negative logarithm) of the hydrogen ion concentration. The pH of a solution offers valuable information as to the immediate acidity or alkalinity, as contrasted to the total acidity or alkalinity (which may be titrated).

Phosphate - Certain complex phosphates, usually sodium tetraphosphate ($Na_6P_4O_{13}$) and sodium acid pyrophosphate (SAPP, $Na_2H_2P_2O_7$), are used either as fluid thinners or for treatment of various forms of calcium-and magnesium contamination

Pilot Testing - A method of predicting behavior of fluid systems by mixing quantities of fluid or fluid additives, then testing the results.

Plastic Flow - See **Plastic Fluid.**

Plastic Fluid - A complex, non-Newtonian fluid in which the shear force is not proportional to the shear rate. A definite pressure is required to start and maintain movement of the fluid. Plug flow is the initial type of flow and only occurs in plastic fluids. Most drilling fluids are plastic fluids. The yield point as determined by direct-indicating viscometer is in excess of zero.

Plasticity - The property possessed by some solids, particularly clays and clay slurries, of changing shape or flowing under applied stress without developing shear planes or fractures. Such bodies have yield points, and stress must be applied before movement begins. Beyond the yield point, the rate of movement is proportional to the stress applied, but ceases when the stress is removed. See **Fluid**.

Plastic Viscosity - The plastic viscosity is a measure of the internal resistance to fluid flow attributable to the amount, type, and size of solids present in a given fluid. It is expressed as the number of dynes per sq cm of tangential shearing force in excess of the Bingham yield value that will induce a unit rate of shear. This value, expressed in centipoises is proportional to the slope of the consistency curve determined in the region of laminar flow for materials obeying Bingham's Law of Plastic Flow. When using the direct-indicating viscometer, the plastic viscosity is found by subtracting the 300-rpm reading from the 600-rpm reading.

Plug Flow - The movement of a material as a unit without shearing within the mass. Plug flow is the first type of flow exhibited by a plastic fluid after overcoming the initial force required to produce flow.

P_m - The phenolphthalein alkalinity of the fluid (mud) reported as the number of milliliters of 0.02 Normal (N/50) acid required per milliliter of fluid to reach the phenolphthalein end point.

Polyalkalene Glycol - A polymer or copolymer of an alkaline oxide, such as polyethylene glycol (PEG), a polymer of ethylene oxide with general formula $HO(CH_2CH_2O)nH$, or polypropylene glycol (PPG) which is a polymer of propylene oxide. PAGs are effective shale inhibitors and have effectively replaced the earlier polyglycerols.

Polymer - A substance formed by the union of two or more molecules of the same kind linked end to end into another compound having the same elements in the same proportion but a higher molecular weight and different physical properties, e.g., paraformaldehyde. See **Copolymer.**

Pore Plugging Apparatus (PPA) – A device for the study of filter cake deposition. Drilling fluid filter cake is deposited on a filter media and evaluated for potential differential pressure sticking characteristics.

Pore Pressure Transmission (PPT) - The ability of a sedimentary rock of minimum porosity and permeability, i.e. shale, to transmit fluid pressure across a given cross section, longitudinally as well as horizontally.

Porosity - The amount of void space in a formation rock usually expressed as percent voids per bulk volume. Absolute porosity refers to the total amount of pore space in a rock regardless of whether or not that space is accessible to fluid penetration. Effective porosity refers to the amount of connected pore spaces, i.e., the space available to fluid penetration. See **Permeability.**

Potassium - One of the alkali metal elements with a valence of 1 and an atomic weight of about 39. Potassium compounds, most commonly potassium hydroxide (KOH) or potassium chloride (KCl) are sometimes added to drilling fluids to impart special properties, usually inhibition.

Pound Equivalent - A laboratory unit used in pilot testing. One gram or pound equivalent, when added to 350 mL of fluid, is equivalent to 1 lbm/bbl.

Parts Per Million (ppm) - Unit weight of solute per million unit weights of solution (solute plus solvent), corresponding to weight- percent except that the basis is a million instead of a hundred. The results of standard API titrations of chloride, hardness, etc. are correctly expressed in milligrams (mg) per liter but not in ppm. At low concentrations mg/L is about numerically equal to ppm. A correction for the solution specific gravity or density in g/mL must be made as follows:

$$ppm = \frac{mg / L}{solution\ Density, gm / L}$$

$$\%\ by\ wt = \frac{mg / L}{(10{,}000)(solution\ Density, gm / L)}$$

$$= \frac{ppm}{10{,}000}$$

Thus, 316,000 mg/L salt is commonly and erroneously called 316,000 ppm or 31.6 percent, which correctly should be 264,000 ppm and 26.4 percent, respectively.

Precipitate - Material that separates out of solution or slurry as a solid. Precipitation of solids in a drilling fluid may follow flocculation or coagulation such as the dispersed red-bed clays upon addition of a flocculation agent to the fluid.

Prehydration - The addition of a mud product to fresh water prior to adding it into the mud system. Bentonite clay and XC polymers are two additives whose performance improves by hydration in fresh water before adding them to a highly-treated or salty mud system.

Preservative - Usually paraformaldehyde. Any material used to prevent starch or any other substance from fermenting through bacterial action.

Pressure-Drop (Loss) - The pressure lost in a pipeline or annulus due to the resistance to flow. Factors such as velocity of the liquid in the pipeline, the properties of the fluid, the state of the pipe wall, and the-alignment of the pipe are all additive in the resistance to flow or pressure drop: In certain fluid-mixing systems, the loss of head can be substantial.

Pressure Surge - A sudden, usually short-duration, increase in pressure. When pipe or casing is run into a hole too rapidly, an increase in the hydrostatic pressure results, which may fracture exposed formations enough to create lost circulation.

Pseudoplastic Fluid - A complex non-Newtonian fluid that does not possess thixotropy. A pressure or force in excess of zero will start fluid flow. The apparent viscosity or consistency decreases instantaneously with increasing rate *of* shear until at a given point the viscosity becomes constant. The yield point as determined by direct- indicating viscometer is positive, the same as in Bingham plastic fluids; however, the true yield point is zero. An example of a pseudoplastic fluid is guar gum in fresh or saltwater.

Quaternary Amine - A cationic amine salt in which the nitrogen atom has four groups bonded to it and carries a positive charge. Quaternary amines are used as oil-wetting agents, corrosion and shale inhibitors and bactericides.

Quebracho - A drilling-fluid additive used extensively for thinning or dispersing to control viscosity and thixotropy. It is a crystalline extract of the quebracho tree consisting essentially of tannic acid.

Quicklime - Calcium oxide, CaO. Used in certain oil-base fluids to neutralize the organic acid.

Quiescence - The state of being quiet or at rest (being still). **Static**.

Radical - Two or more atoms behaving as a single chemical unit, i.e., as an atom, e.g., sulfate, phosphate, nitrate.

Rate of Shear - The rate at which an action, resulting from applied forces, causes or tends to cause two adjacent parts of a body to slide relatively to each other in a direction parallel to their plane of contact. Generally referred to in reciprocal seconds (sec$^{-:l}$).

Resin - Semi-solid or solid complex, amorphous mixture of organic compounds having no definite melting point nor tendency to crystallize. Resin may be a component of compounded materials that can be added to drilling fluids to impart special properties to the system, wall cake, etc.

Resistivity - The electrical resistance offered to the passage of a current; expressed in ohm-meters; the reciprocal of conductivity. Freshwater_fluids are usually characterized by high resistivity, saltwater fluids by a low resistivity.

Resistivity Meter - An instrument for measuring the resistivity of drilling fluids and their filter cakes.

Reverse Circulate - The method by which the normal flow of a drilling fluid is reversed by circulating down the annulus and up and out the drillstring.

Reynolds Number - A dimensionless number (Re) that occurs in the theory of fluid dynamics. The diameter, velocity, density and viscosity (consistent units) for a fluid flowing through a cylindrical conductor are related as follows:

$$\mathrm{Re} = (Diameter)(Velocity)(Density)/(Viscosity)$$

or

$$\mathrm{Re} = (\mathrm{D})\,(V)p/u$$

The number is important in fluid hydraulics calculations for determining the type of fluid flow, i.e., whether laminar or turbulent. The transitional range occurs approximately from 2000 to 3000; below 2000 the flow is laminar, above 3000 the flow is turbulent.

Rheology - The science that deals with deformation and flow of water.

Rotary Drilling - The method of drilling wells that depends on the rotation of a column of drillpipe to the bottom of which is attached a bit. A fluid is circulated to remove the cuttings.

Salt - In fluid terminology, the term salt is applied to sodium chloride, NaCI. Chemically, the term salt is also applied to anyone of a class of similar compounds formed when the acid hydrogen of an acid is partly or wholly replaced by a metal or a metallic radical. Salts are formed by the action of acids on metals, or oxides and hydroxides, directly with ammonia, and in other ways.

Saltwater Clay - See **Attapulgite Clay**.

Saltwater Fluids - A drilling fluid containing dissolved salt (brackish to saturated). These fluids may also include native solids, oil, and/or such commercial additives as clays, starch, etc.

Sample Fluid - A drilling fluid possessing properties to bring up suitable drilled rock cutting samples.

Samples - Cuttings obtained for geological information from the drilling fluid as it emerges from the hole. They are washed, dried, and labeled as to the depth

Sand - A loose granular material resulting from the disintegration of rocks most often silica.

Sand Content - The sand content of a drilling fluid is the insoluble abrasive solids content rejected by a 200-mesh screen. It is usually expressed as the percentage bulk volume of sand in a drilling fluid. This test is an elementary type in that the retained solids are not necessarily silica nor may not be altogether abrasive. For additional information concerning the kinds of solids retained on the 200-mesh screen (> 74 micron), more specific tests would be required. See **Mesh**.

Sand Trap - A small pit, typically located immediately after the shaker screens, which is used as a settling pit to separate coarser solids that accidentally bypass the shakers. Mud enters the pit at one side and exits via an overflow at the other. Sand traps are dumped periodically to remove the settle solids, or alternatively the contents can be processed over a fine screen or with a centrifuge.

Saturated Solution - A solution is saturated if it contains at a given temperature as much of a solute as it can retain. At 68°F, it takes 126.5 lb_m/bbl salt to saturate 1 bbl of freshwater, which will result in 1.13 bbls of saturated salt solution. See **Supersaturation.**

Screen Analysis - Determination of the relative percentages of substances, e.g., the suspended solids of a drilling fluid, passing through or retained on a sequence of screens of decreasing mesh size. Analysis may be by wet or dry methods. Referred to also as "sieve analysis." See Mesh.

Sealing Agents - Any of many materials added to drilling fluids to restore circulation by mechanically sealing off the thief zone or zones into which whole fluid has flowed.

Seawater Fluids - A special class of saltwater fluids where seawater is used as the fluid phase.

Seconds API - A unit of viscosity as measured with a Marsh funnel according to API procedure. See *APIRP 13B* and Marsh Funnel Viscosity.

Sequestration - The formation of stable calcium, magnesium, iron complex by treating water or fluid with certain complex phosphates that do not precipitate but stay suspended in a non-reactive neutralized state.

Sequestering Agent - A chemical whose molecular structure can envelop and hold a certain type of ion in a stable and soluble complex. Divalent cations, such as hardness ions, form stable and soluble complex structures with several types of sequestering chemicals. When held inside the complex, the ions have a limited ability to react with other ions, clays or polymers.

Set Casing - The installation of pipe or casing in a well bore. Usually requires “mudding up”, reconditioning or at least checking the drilling fluid properties.

Shale - Fine-grained clay rock with slate-like cleavage, sometimes containing an organic oil-yielding substance.

Shale Shaker - Any of several mechanical devices for removing cuttings and other large solids from the fluid. Typically a vibrating screen.

Shear (Shearing Stress) **-** An action, resulting from applied forces, which causes or tends to cause two contiguous parts of a body to slide relatively to each other in a direction parallel to their plane of contact.

Shearometer - A device used as an alternative method for measuring gel strengths. See *API RP 13B* for specifications and procedure.

Shear Strength - A measure of the shear value of the fluid. The minimum shearing stress that will produce permanent deformation. See Gel Strength.

Side Tracking - See **Whipstock**.

Sieve Analysis - See **Screen Analysis**.

Silica Gel - A porous substance consisting of SiO_2. Used on occasion as a dehydrating agent in air or gas drilling where small amount of water is encountered.

Silicate Mud - A type of shale-inhibitive water mud that contains sodium or potassium silicate as the inhibitive component. High pH is a necessary characteristic of silicate muds to control the amount and type of polysilicates that are formed. Mud pH is controlled by addition of NaOH (or KOH) and the appropriate silicate solution. Silicate anions and colloidal silica gel combine to stabilize the wellbore by sealing microfractures, forming a silica layer on shales and possibly acting as an osmotic membrane, which can produce in-gauge holes through troublesome shale sections that otherwise might require an oil mud. Good solids control practices are very important in the control of silicate mud properties. Silicate muds are not recommended to be used while drilling the pay zone.

Silt - Materials that exhibit little or no swelling whose particle size generally falls between 2 microns and API sand size, or 74 microns (200-mesh). A certain portion of dispersed clays and barite for the most part also fall into this same particle-size range.

Skid - Moving a rig from one location to another, usually on tracks where little dismantling is required.

Slide - To drill with a mud motor rotating the bit downhole without rotating the drillstring from the surface. This operation is conducted when the bottomhole assembly has been fitted with a bent sub or bent housing mud motor, or both, for directional drilling. Sliding is the predominant method to build and control or correct hole angle in modern directional drilling operations. By controlling the amount of hole drilled in the sliding versus the rotating mode, the wellbore trajectory can be controlled precisely.

Slip Velocity - The difference between the annular velocity of the fluid and the rate at which a cutting is removed from the hole.

Sloughing - The partial or complete collapse of the walls of a hole resulting from incompetent, unconsolidated formations, high angle or repose, and wetting along internal bedding planes. See **Heaving** and **Cave-In**.

Slug the Pipe - A procedure before pulling the drillpipe whereby a small quantity of heavy fluid is pumped into the top section of the drillstring to cause an unbalanced column. As the pipe is pulled, the heavier column in the drillpipe will fall, thus keeping the inside of the drillpipe dry at the surface when the connection is unscrewed.

Smectite Clay - A category of clay minerals that have a three-layer crystalline structure (one alumina and two silica layers) and that exhibit a common characteristic of hydrational swelling when exposed to water. Montmorillonite is a well-known smectite clay mineral. Its sodium form, bentonite, is a widely-used water mud additive. It is also used as an oil-mud additive when made oil-dispersible by surface treatment.

Soap - The sodium or potassium salt of a high molecular-weight fatty acid. When containing some metal other than sodium or potassium, they are called "metallic" soaps. Soaps are commonly used in drilling fluids to improve lubrication, emulsification, sample size, defoaming, etc.

Soda Ash - See **Sodium Carbonate**.

Sodium - One of the alkali metal elements with a valence of -1 and an atomic weight of about 23. Numerous sodium compounds are used as additives to drilling fluids.

Sodium Bicarbonate - $NaHCO_3$. A material used extensively for treating cement contamination and occasionally other calcium contamination in drilling-fluids. It is the half -neutralized sodium salt of carbonic acid.

Sodium Bichromate - $Na_2Cr_2O_7$. Also correctly called "sodium dichromate." See **Chromate.**

Sodium Carbonate - Na_2CO_3- A material used extensively for treating out various types of calcium contamination- It is commonly called "soda ash." When sodium carbonate is added to a fluid, it increases the pH of the fluid by hydrolysis. Sodium carbonate can be added to salt (NaCl) water to increase the density of the fluid phase.

Sodium Carboxymethylcellulose - Commonly called CMC. Available in various viscosity grades and purity. An organic material used to control filtration, suspend weighting material, and build viscosity in drilling fluids. Used in conjunction with bentonite where low-solid fluids are desired.

Sodium Chloride - NaCl. Commonly known as salt. Salt may be present in the fluid as a contaminant or may be added for any of several reasons. See Salt.

Sodium Chromate - Na_2CrO_4. See **Chromate**.

Sodium Hydroxide - NaOH. Commonly referred to as "caustic" or "caustic soda." A chemical used primarily to impart a higher pH.

Sodium Polyacrylate - A synthetic high molecular weight polymer of acrylonitrile used primarily as a fluid loss control agent.

Sodium Silicate Fluids - Special class of inhibited chemical fluids using as their bases sodium silicate, salt, water, and clay.

Solids Concentration or **Content -** The total amount of solids in a drilling fluid as determined by distillation includes both the dissolved and the suspended or undissolved solids. The suspended solids content may be a combination of high and low-specific gravity solids and native or commercial solids. Examples of dissolved solids are the soluble salts of sodium, calcium, and magnesium. Suspended solids make up the wall cake; dissolved solids remain in the filtrate. The total suspended and dissolved solids contents are commonly expressed as percent by volume, and less commonly as percent by weight.

Solubility - The degree to which a substance will dissolve in a particular solvent.

Solute - A substance which is dissolved in another (the solvent).

Solution - A mixture of two or more components that form a homogeneous single phase. Example solutions are solids dissolved in liquid, liquid in liquid, gas in liquid.

Solvent - Liquid used to dissolve a substance (the solute).

Sour Gas - A general term for those gases that are acidic either alone or when associated with water. Two sour gases associated with oil and gas drilling and production are hydrogen sulfide (H_2S) and carbon dioxide (CO_2). Sulfur oxides and nitrogen oxides, generated by oxidation of certain sulfur or nitrogen bearing materials, are also in this category but not found in the anaerobic conditions of the subsurface.

Souring - A term commonly used to mean fermentation.

Specific Gravity - See **Gravity, Specific.**

Specific Heat - The number of calories required to raise 1 gram of substance 1 degree Centigrade. The specific heat of a drilling fluid gives an indication of the fluid's ability to keep the bit cool for a given circulation rate.

Spudding In - The starting of drilling operations for a new hole.

Spud Mud - The fluid used when drilling starts at the surface, often a thick bentonite-lime slurry.

Spurt Loss - See **Surge Loss**.

Squeeze - A procedure whereby slurries of cement, fluid, gunk plug, etc. are forced into the formation by pumping into the hole while maintaining a back pressure, usually by closing the rams.

Stability Meter - An instrument to measure the breakdown voltage of invert emulsions.

Stacking a Rig - Storing a drilling rig upon completion of a job when the rig is to be withdrawn from operation for a period of time.

Starch - A group of carbohydrates occurring in many plant cells. Starch is specially processed (pre gelatinized) for use in fluids to reduce filtration rate and occasionally to increase the viscosity. Without proper protection, starch ~~is~~ subject to bacterial degradation resulting in the fermentation and the alteration of fluid properties.

Static - Opposite of dynamic. See **Quiescence**.

Streaming Potential - The electrokinetic portion of the spontaneous potential (SP) electric-log curve which can be significantly influenced by the characteristics of the filtrate and fluid cake of the drilling fluid that was used to drill the well.

Streamline Flow - See **Laminar Flow.**

Stearate - Salt of stearic acid, which is saturated, 18 carbon fatty acid. Certain compounds, such as aluminum stearate, calcium stearate, zinc stearate, have been used in drilling fluids for one or more of the following purposes: defoamer, lubrication, air drilling in which a small amount of water is encountered, etc.

Stuck - A condition whereby the drillpipe, casing, or other devices inadvertently become lodged in the hole. Can be the result of numerous conditions including but not limited to; sloughing (caving) of the well bore, formation swelling, salt flow (migration), differential pressure sticking, key seating, junk in the hole, dogleg, etc.

Sulfide Scavenger - A chemical that removes all three soluble sulfide species, H_2S, S^{-2} and HS^-, and forms a reaction product that is irreversible by chemical reaction, nonhazardous and noncorrosive. Zinc compounds are commonly used to precipitate ZnS and decrease the concentration of all three sulfides that are in equilibrium in a solution to a very low concentration. For water mud, zinc basic carbonate, and for oil mud, zinc oxide, are recognized to be effective sulfide scavengers. Oxidation of sulfides to form other types of sulfur compounds will remove sulfides from a mud, but slowly and with less certainty.

Supersaturation - If a solution contains a higher concentration *of* a solute in a solvent that would normally correspond to its solubility at a given temperature, this constitutes supersaturation. This is an unstable condition, as the excess solute separates when the solution is needed by introducing a crystal *of* the solute. The term "supersaturation" is frequently used erroneously for hot salt fluids.

Surface-Active Materials - See **Surfactant.**

Surfactant - A material which tends to concentrate at an interface. Used in drilling fluids to control the degree of emulsification, aggregation, dispersion, interfacial tension, foaming, defoaming, wetting, etc.

Surfactant Fluid - A drilling fluid which contains a surfactant. Usually refers to a drilling fluid containing surfactant material to effect control over degree of aggregation and dispersion or emulsification.

Surface Tension - Generally the force acting within the interface between a liquid and its own vapor which tends to maintain the area of the surface at a minimum and is expressed in dynes per centimeter. Since the surface tension of a liquid is approximately equal to the interfacial tension between the liquid and air, it is common practice to refer to values measured against air as surface tension, and to use the term "interfacial tension" for measurements at an interface between two liquids, or a liquid and a solid.

Surge Loss - The flux of fluids and solids which occurs in the initial stages of any filtration before pore openings are bridged and a filter cake is formed. Also called "spurt loss."

Suspensoid - A mixture consisting of finely divided colloidal particles floating in a liquid. The particles are so small that they do not settle but are kept in motion by the moving molecules of the liquid (Brownian movement).

Swabbing - When pipe is withdrawn from the hole in a viscous fluid or if the bit is balled, a suction is created. This process can cause a reduction in hydrostatic head resulting in the intrusion of formation fluids, or in some cases, collapse of the formation into the well bore.

Swelling - See **Hydration.**

Synergism, Synergistic Properties - Term describing an effect obtained when two or more products are used simultaneously to obtain a certain result. Rather than the results of each product being additive to the other, the result is a multiple of the effects.

Tannic Acid - Tannic. acid is the active ingredient of quebracho and other quebracho substitutes such as mangrove bark, chestnut extract, etc.

Temperature Survey - An operation to determine temperatures at various depths in the hole. This survey is used to find the location of inflows of water into the hole, where doubt exists as to proper cementing of the casing and for other reasons.

Ten-Minute Gel - See **Gel Strength, Ten-Minute**.

Thermal Decomposition - The chemical breakdown of a compound or substance by temperature into simple substances or into its constituent elements. Starch thermally decomposes in drilling fluids as the temperature approaches 300°F.

Thinner - Any of various organic agents (tannins, lignins, lignosulfonates, etc.) and inorganic agents (pyrophosphates, tetraphosphates, etc.) that are added to a drilling fluid to reduce the viscosity and/or thixotropic properties.

Thixotropy - The ability of fluid to develop gel strength with time. That property of a fluid which causes it to build up a rigid or semi-rigid gel structure if allowed to stand at rest, yet can be returned to a fluid state by mechanical agitation. This change is reversible.

Tighten Up Emulsion - Drilling fluid jargon to describe condition in some systems to which oil has been added and the oil breaks out and rises to the surface. Any chemical or mechanical means which will emulsify the free oil is known as "tightening up."

Titration - A method or process of using a standard solution for the determination of the amount of some substance in another solution. The known solution is usually added in a definite quantity to the unknown until a reaction is complete.

Tool Joint - A drillpipe coupler consisting of a pin and box of various designs and sizes. The internal design of tool joints has an important effect on fluid hydraulics.

Torque - A measure of the force or effort applied to a shaft causing it to rotate. On a rotary rig this applies especially to the rotation of the drill stem in its action against the bore of the hole. Torque reduction can usually be accomplished by the addition of various drilling-fluid additives.

Total Depth (TD) - The greatest depth reached by the drill bit.

Total Hardness - See **Hardness of Water**

Tour - A person's turn in an orderly schedule. The word, which designates the shift of a drilling crew, is pronounced as if it were spelled t-o-w-e-r.

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Turbulent Flow - Fluid flow in which the velocity at a given point changes constantly in magnitude and the direction of flow; pursues erratic and continually varying courses. Turbulent flow is the second and final stage of flow in a Newtonian fluid; it is the third and final stage in a Bingham plastic fluid. See **Velocity Critical and Reynolds Number.**

Twist-Off – Separation of the drill string caused by the severing of a joint of drillpipe. Can be caused by the bit becoming stuck inadvertently while the rotary table continues to rotate the drill string to the point of pipe failure.

Ultraviolet Light - Light waves shorter than the visible blue-violet waves of the spectrum. Crude oil colored distillates, residium, a few drilling-fluid additives, and certain minerals and chemicals fluoresce in the presence of ultraviolet light. These substances, when present in fluid, may cause the fluid to fluoresce.

Univalent – Monovalent - See **Valence**.

Valence or Valency - The valence is a number representing the combining power *of* an atom, i.e., the number *of* electrons lost, gained, or shared by an atom in a compound. It is also a measure *of* the number *of* hydrogen atoms with which an atom will combine or replace, e.g., an oxygen atom combines with two hydrogens, hence has a valence of 2. Thus, there are mono-, di-, tri-, etc. valent ions.

Valence Effect - In general, the higher the valence of an ion, the greater the loss of stability to emulsions, colloidal suspensions, cross-linking etc. these polyvalent ions will impart.

Velocity - Time rate of motion in a given direction and sense. It is a measure of the fluid flow and may be expressed in terms of linear velocity, mass velocity, volumetric velocity, etc. Velocity is one of the factors which contribute to the carrying capacity of a drilling fluid.

Velocity, Critical - That velocity at the transitional point between laminar and turbulent types of fluid flow. This point occurs in the transitional range of Reynolds numbers of approximately 2000 to 3000.

V-G Meter or Viscosity-Gravity Viscometer - The name commonly used for the direct-indicating viscometer. See **Viscometer**.

Vibrating Screen - See **Shale Shaker**.

Viscometer - An apparatus to determine the viscosity of a fluid or suspension. Viscometers vary considerably in design and methods of testing.

Viscometer, Direct- Indicating - Commonly called a.”V-G meter” The-instrument is a rotational-type device powered by means of an electric motor or hand crank, and is used to determine the apparent viscosity, plastic viscosity, yield point, and gel strengths of drilling fluids. The usual speeds are 600 and 300 rpm. See *API RP I3B* for operational procedures.

Viscometer, Stormer - A rotational shear viscometer used for measuring the viscosity and gel strength of drilling fluids. This instrument has been superseded by the direct-indicating viscometer.

Viscosimeter - See **Viscometer**.

Viscosity - The internal resistance offered by a fluid to flow. This phenomenon is attributable to the attractions between molecules of a liquid, and is a measure of the combined effects of adhesion and cohesion to the effects of suspended particles, and to the liquid environment. The greater this resistance, the greater the viscosity. See **Apparent Viscosity** and **Plastic Viscosity.**

Viscosity, Funnel - See **Funnel Viscosity.**

Viscous Flow - See **Laminar Flow**.

Volatile Matter - Normally gaseous products, except moisture, given off by a substance, such as gas breaking out of live crude oil that has been added to a fluid. In distillation of drilling fluids, the volatile matter is the water, oil, gas, etc. that is vaporized, leaving behind the total solids which can consist of both dissolved and suspended solids

Wall Cake – Mud solids deposited on the wall of the wellbore opposite permeable formations in the form of filter cake resulting from filtration of the liquid fraction of the fluid.

Wall Sticking - See **Differential-Pressure Sticking**.

Water-Base Fluid - Common conventional drilling fluids. Water is the suspending medium for solids and is the continuous phase, whether or not oil is present.

Water Block - Reduction of the permeability of a formation caused by the invasion of water into the pores (capillaries). The decrease in permeability can be caused by swelling of clays, thereby shutting off the pores, or in some cases by a capillary block of the pores due to surface tension phenomena.

Water-In-Oil Emulsion - See **Invert Oil-Emulsion** Fluid.

Water Loss - See **Fluid Loss.**

Weight - In fluid terminology, this refers to the density of a drilling fluid. This is normally expressed in lb_m/gal, lb_m/ft^3, or kg/m^3.

Weight Material - Any of the high specific gravity materials used to increase the density of drilling fluids. This material is most commonly barite but can be galena, etc. In special applications, limestone ($CaCO_3$) also called a weight material.

Well Logging - See **Electric Logging** and **Fluid Logging**.

Wetting - The adhesion of a liquid to the surface of a solid.

Wetting Agent - A substance or composition which, when added to a liquid, increases the spreading of the liquid on a surface or the penetration of the liquid into a material.

Whipstock - A device inserted in a well bore used for deflecting or for directional drilling.

Whole Mud Dilution - A dilution process which involves selective dumping of the active system (such as sand traps and “bottoms up” mud) and replacement of the lost volume with fresh mud. This process has proved economical with inhibitive water-base systems and is the only method that actually removes colloidal size particles. Water dilution of the mud recovered from the aforementioned circumstances to reduce low gravity solids concentration, does not remove the undesirable solids which remain in the mud and require additional chemical treatment.

Wildcat - A well in unproved territory,

Workover Fluid - Any type of fluid used in the workover operation of a well.

Yield - A term used to define the quality of a clay by describing the number of barrels of a given centipoise slurry that can be made from a ton of the clay. Based on the yield, clays are classified as high-, medium-, low-yield bentonite, etc. types of clays.

Yield Point - In drilling-fluid technology, yield point means yield value. Of the two terms, yield point is by far the most commonly used expression. See **Yield Value**.

Yield Value - The yield value (commonly called "yield point") is the resistance to initial flow, or represents the stress required to start fluid movement. This resistance is due to electrical charges located on or near the surfaces of the particles. The values of the yield point and thixotropy, respectively, are measurements of the same fluid properties under dynamic and static states. The Bingham yield value, reported in Ib/l00 sq ft, is determined by the direct-indicating viscometer by subtracting the plastic viscosity from the 300-rpm reading.

Zero-Zero Gel - A condition wherein the drilling fluid fails to form measurable gels during a quiescent time interval (usually 10 minutes).

Zeta Potential - Electrokinetic potential of a particle as determined by its electrophoretic mobility. This electrical potential causes colloidal particles to repel each other and stay in suspension.

Zinc Chloride - $ZnCI_2$. A very soluble salt used to increase the density of water to points more than double that of water. Normally added to a system first saturated with calcium chloride.

Barker, S. E., 1981
Determining the Area of Review for Industrial Effluent Disposal Wells

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DETERMINING THE AREA OF REVIEW FOR INDUSTRIAL EFFLUENT DISPOSAL WELLS

Determining the Area of Review for Industrial Waste Disposal Wells (Barker, 1981)

DETERMINING THE AREA OF REVIEW FOR INDUSTRIAL WASTE DISPOSAL WELLS

APPROVED BY SUPERVISORY COMMITTEE:

DETERMINING THE AREA OF REVIEW FOR INDUSTRIAL WASTE DISPOSAL WELLS

BY

STEPHEN EUGENE BARKER, B. S.

REPORT

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University of Texas
Austin, Texas

October, 1981

A

Abstract

The area of review is defined by the radial distance from waste disposal wells in which the injection formation fluid pressure increases sufficiently to force formation fluids and/or injected wastes up abandoned well bores to contaminate underground sources of drinking water. The cost of corrective action required to prevent such contamination within the area of review can be considerable. To minimize the costs associated with subsurface disposal operations an appropriate area of reveiw must be adequately defined. This report provides a simplified procedure which can be utilized to determine a minimum area of review which can be safely applied to given subsurface injection operation.

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INTRODUCTION

Introduction

The increased fluid pressure in a disposal zone which results from a waste injection operation may force injected and/or formation fluid to migrate up an abandoned well bore which penetrates the injection formation. Should migration occur, commingling with underground sources of drinking water may result. When a waste injection well reaches its design life (typically twenty years) the radial distance form the injector at which the potential for fresh water contamination exists is defined as the ar of review. Environmental regulations require the well operator to take corrective action, as required, at each abandoned well within the area of review to insure that contamination does not occur. The cost of corrective action can be significant. Therefore, it is essential that the area of review be adequately defined before corrective measures are undertaken. This paper presents simplified procedure which can be utilized to calculate the area of review.

If an abandoned well was not produced, drilling mud remains in the well bore since it has no means of escape. To evaluate the potential for fluid migration such a well bore the forces which act on this static mud column within the well bore must be determined. In most cases the wells were drilled with water base drilling mud which develop a gel structure when allowed to remain quiescent. To initiate flow up the abandoned well bore the fluid pressure in the formation must exceed the sum o the static mud column pressure (Ps) and the gel strength pressure (Pg). The area of review is defined as that are within which the well life formation pressure (P_f) is greater than (P_s) + (P_g).

Theoretical Development

Figure (1) represents a vertical force diagram o the static mud column in an abandoned well bore. The equation for the force balance takes the following form,

$$w + 2\pi\, r_w hGS = P_f \;\; \pi r_w^2 - P_t\, \pi r_w^2 \qquad (1-$$

simplify and let $r_w = \frac{D}{2}$, equation 1-1 becomes

$$P_f - P_t = 0.052\rho h + \frac{4hGS}{D} \qquad (1-$$

neglecting surface pressure (P_t) and converting consistent field units,

$$P_f = 0.052\, \rho_{min}\, h + 3.33 \times 10^{-3}\ \frac{Gsh}{D_{max}} \qquad (1-$$

Where: $P_s = 0.052\ \rho_{min} h$ -- represents the static mud column pressure

$P_g = 3.33 \times 10^{-3}\ \frac{Gsh}{D_{max}}$ -- represents the gel strength pressure

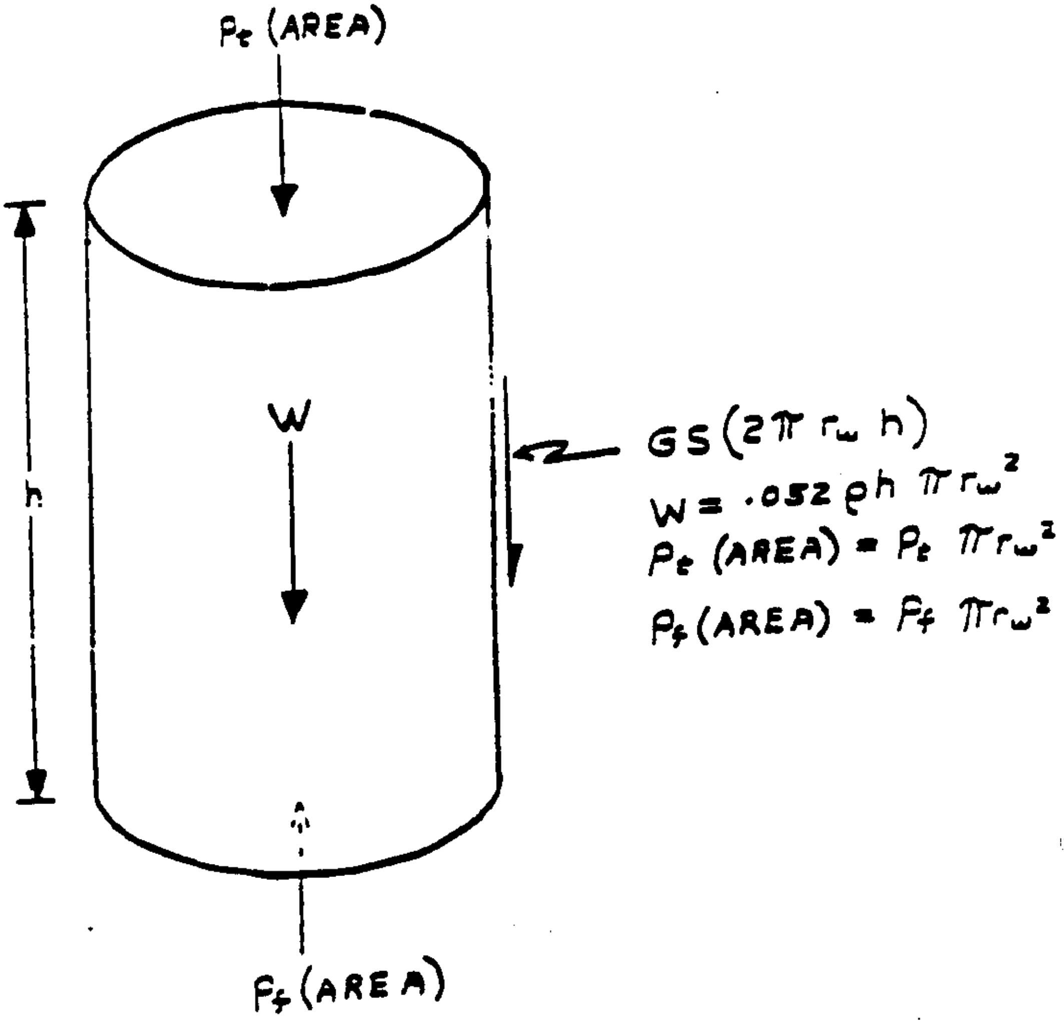


FIGURE 1
STATIC MUD COLUMN
FORCE BALANCE DIAGRAM

P_f represents the well life formation pressure. The pressure which results at a radial distance r from the injection well at time t after the start of injection of a waste of small and constant compressibility at a constant rate Q throughout the life of the well into an infinite, isotropic, homogeneous, horizontal reservoir of uniform thickness and porosity is well approximated by,

$$P_f = Pi - \frac{QuB}{4\pi kh} E_i\left(\frac{-\phi ucr^2}{4kt}\right) \qquad (1-$$

Procedure for Determining The Area of Review

The proposed procedure for determining the area of review for waste injection wells is predicated on the following basic assumptions:

1.) The static mud column extends to the surface and is uniform in density.

2.) Abandoned well bore diameters used in calculations are equal to the bit diameter plus two inches where bit refers to that used to drill th hole at the depth of the injection formation.

3.) The gel strength applied to all wells is 20 lbs/100 ft.^{2}

4.) Injection pressures will not exceed the fractur pressure of the injection formation.

5.) Known abandoned wells for which no data are available will be assigned the minimun mud density and the largest bit diameter noted for all wells within a 2½ mile radius of the injector.

6.) None of the abandoned wells were completed and produced.

7.) All pressures are calculated at the top of the injection formation.

8.) All abandoned wells were drilled with water base muds.

9.) None of the abandoned wells are plugged.

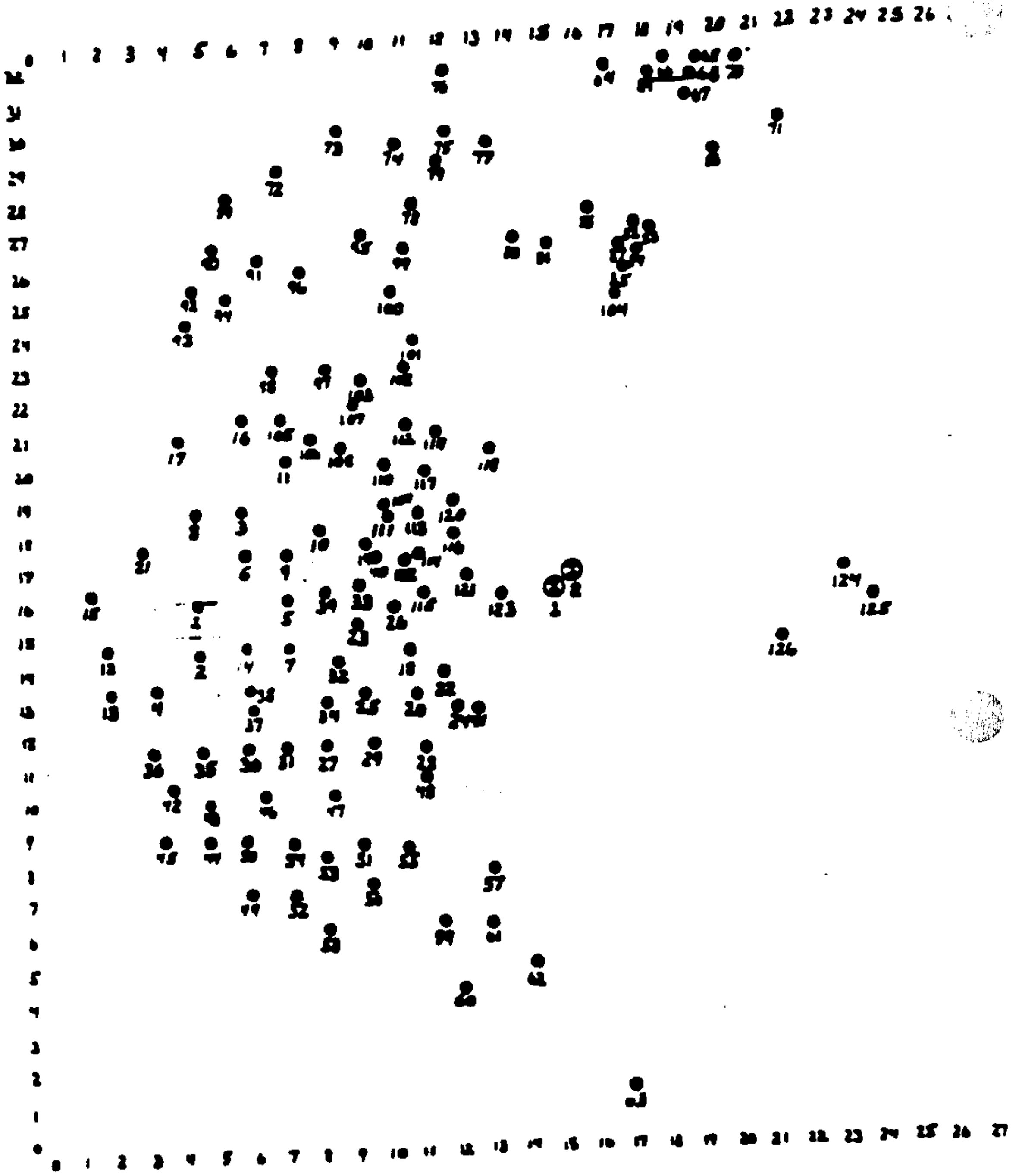
Utilizing the developed theory and applying the basic assumptions, it is possible to compare P_f with $P_s + P_g$. The area of review will be defined by the radial distance from the injection well at which $P_f > P_s + P_g$.

The procedure employs an iterative process to determine the appropriate area of review for a given injection operation. The first iteration considers all abandon wells within a 2½ mile radius of the injection wells. Once an area of review is determined, the process is repeated considering only those wells within the determined area of review. The iterative process is repeated until both the minimum mud density (ρmin) and maximum bi diameter at the depth of the injection formation (Dmax) for the abandoned wells within the previously defined ar of review no longer vary with the iterations. When ρmin and Dmax stabilize the resulting area of review is the true area of review for the specified injection operatio The procedure is demonstrated by the following example.

Example

An industrial waste injection operation is proposed to dispose of 500 gal/min of waste for a period of 20 years. The waste will be injected into a sand formation at a depth of 5000 ft. employing two injection wells each operating at a rate of 250 gal/min. Figure (2 displays the abandoned well locations with respect to the injection wells. The mud densities and bit diameters for all abandoned wells are as noted in Table 1. The pertinent formation and fluid characteristics for the proposed operation are presented in Figure (3).

By means of a digital computer it is possible to use the developed theory to plot P_g, P_s, and $P_s + P_g$ as function of the radial distance from the injection well shown in Figure (3). The area of review is indicated by the radial distance from the injector at which the well life formation pressure intersects the constant pressure line $P_s + P_g$. For injection operations which utilize multiple injectors at a single site, the total flow of t wells can be input as one well and the area of review ad quately approximated as that of a single well. Likewis for wells of variable flow rate, an average, constant f rate can be utilized to obtain satisfactory approximate results. P_g is calculated by using the largest bit diameter noted on well logs for all abandoned wells wit a radial distance of 2½ miles of the injectors.



● ABANDONED WELLS

⊙ PROPOSED INJECTION WELLS

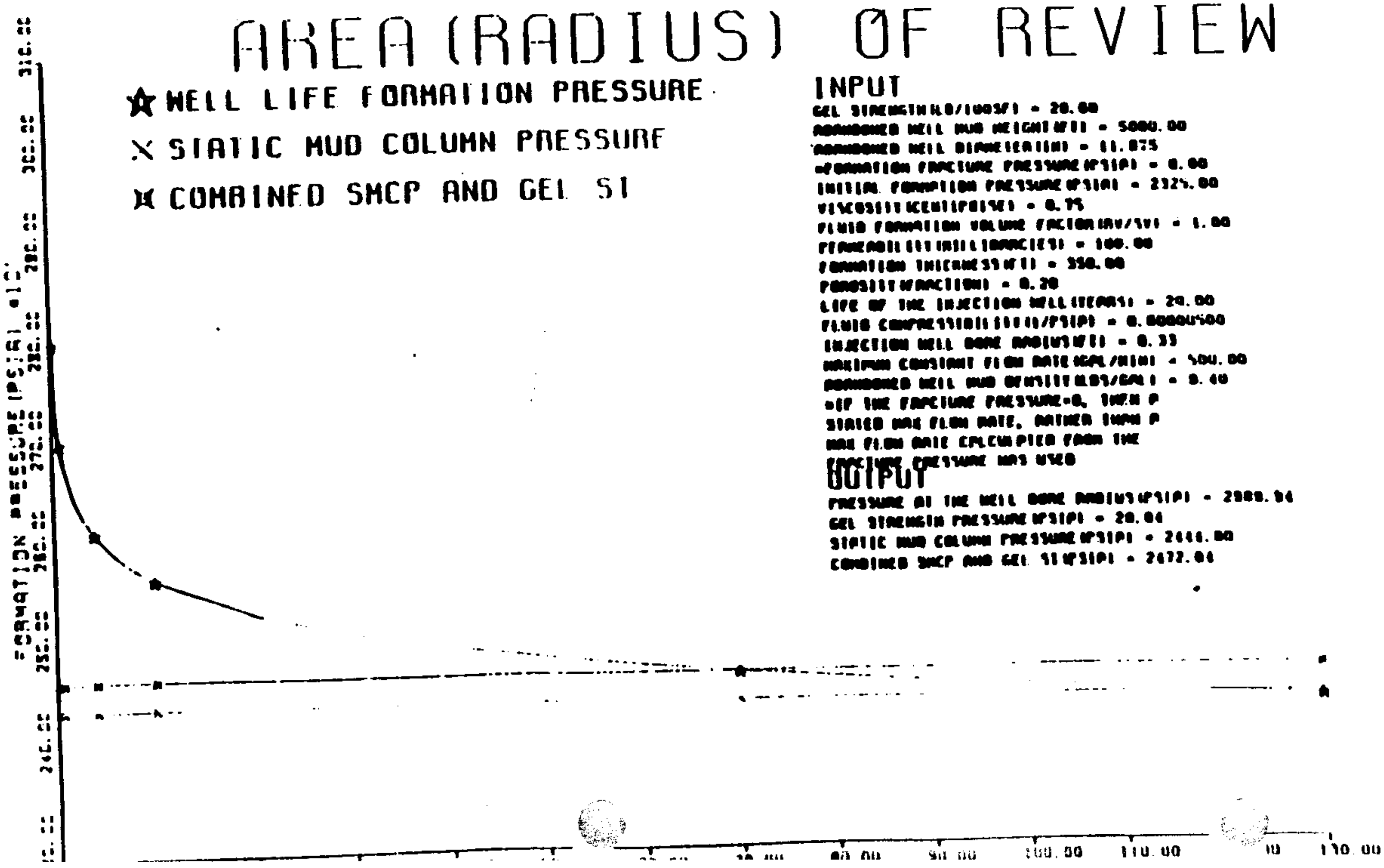
FIGURE 2. Abandoned and injection well locations

TABLE 1

INFORMATION PERTINENT TO EACH ABANDONED WELL

WELL #	X-CORD	Y-CORD	DENSITY lb/gal	BIT DIA in	WELL #	X-CORD	Y-CORD	DENSITY lb/gal	BIT DIA in
1	4650	19900	9.4	7.875	64	16850	31900	11.0	8.75
2	4700	14550	10.5	7.875	65	19900	31650	10.9	7.625
3	9925	18600	10.5	7.875	66	18700	31050	10.5	9.875
4	3375	13275	10.3	71875	67	19800	30900	10.5	9.879
5	7350	13900	10.7	7.875	68	19800	31100	10.2	9.875
6	6625	17350	11.8	7.875	69	18100	31200	10.2	7.875
7	7375	14900	10.7	8.75	70	20400	31550	12.1	9.875
8	4975	18600	10.7	7.875	71	21750	29700	10.7	8.75
9	7350	17350	10.7	7.875	72	7350	28800	17.0	8.50
10	8300	17950	10.6	7.875	73	8000	29900	10.7	8.625
11	7325	20075	10.6	7.875	74	10750	29400	10.4	9.875
12	1950	14600	10.6	7.875	75	12200	29750	10.0	7.875
13	2000	13250	10.0	8.75	76	12250	31500	10.1	7.875
14	6050	14550	10.8	7.875	77	13600	29400	11.0	8.75
15	1525	16375	10.7	7.875	78	11250	27050	10.0	7.875
16	6650	21275	10.6	7.875	79	11900	28850	10.4	7.875
17	6175	20850	10.1	6.5	80	14100	28400	10.4	7.875
18	10000	14900	12.9	6.75	81	15100	28600	9.9	9.875
19	9600	17350	10.6	7.875	82	17050	26850	10.6	8.75
20	10950	12950	12.5	7.875	83	18825	26700	10.3	9.875
21	7050	17075	10.3	7.875	84	17700	28075	10.3	9.875
22	11825	13650	12.6	7.875	85	17225	25875	10.3	8.75
23	9350	15100	10.7	7.875	86	16300	27275	10.5	7.625
24	12150	12600	12.7	7.875	87	17800	26200	10.1	7.875
25	9525	13875	11.3	7.875	88	19925	28975	10.3	9.625
26	10050	13600	10.1	7.875	89	3700	28875	11.2	7.875
27	8800	11375	10.7	7.875	90	5325	26600	10.1	7.875
28	11225	11600	10.6	8.75	91	6650	26200	10.2	8.75
29	9700	11600	9.5	8.75	92	4725	25325	9.9	7.875
30	6000	11900	9.5	7.875	93	6425	26375	10.2	8.75
31	7250	11900	9.8	7.875	94	5600	25000	10.8	8.625
32	8750	14000	9.6	7.875	95	9625	26825	10.5	7.875
33	9800	14275	9.7	7.875	96	7775	25800	10.5	8.75
34	8600	12800	9.5	7.875	97	8650	22775	10.4	7.875
35	4675	11075	10.0	7.875	98	6975	22800	10.5	7.875
36	3300	11900	9.7	7.875	99	10075	24400	10.2	7.875
37	6150	12725	9.7	9.75	100	10050	23825	10.3	7.875
38	6100	13225	9.8	7.875	101	11075	23975	10.8	7.875
39	8600	16100	9.6	7.875	102	10775	22700	10.5	7.875
40	9825	17100	9.5	7.875	103	9550	22375	10.5	7.875
41	12700	12050	13.4	7.875	104	17000	20750	10.7	9.875
42	3800	10750	10.1	7.875	105	7175	21350	10.6	7.875
43	6650	9875	10.5	7.875	106	8000	20875	10.7	7.875
44	4650	8800	10.5	7.875	107	9800	21675	10.8	7.875
45	3550	8775	10.6	7.875	108	8875	20425	10.6	7.875
46	6650	10075	9.8	7.875	109	10100	18850	10.9	7.875
47	8525	10050	10.3	7.875	110	10175	19850	11.1	7.875
48	11200	10900	12.5	7.875	111	10150	18800	11.0	7.875
49	9950	7200	10.1	7.875	112	10825	21000	10.5	7.875
50	9800	8800	9.6	7.875	113	11100	18350	10.5	7.875
51	9300	8650	11.8	8.75	114	11200	17150	11.6	7.875
52	7725	7075	11.0	8.75	115	11325	19975	11.5	7.875
53	8250	8150	10.1	8.75	116	12225	17750	11.0	7.875
54	7150	8650	9.5	8.75	117	11425	19600	11.1	7.875
55	10650	8375	9.7	7.875	118	13325	20125	11.2	7.875
56	9550	7050	9.6	7.875	119	11700	20750	9.7	7.875
57	13000	7600	10.1	7.875	120	12250	18700	9.7	7.875
58	8275	6075	10.2	7.875	121	12050	16500	9.5	7.875
59	11650	6175	9.8	7.875	122	10700	17000	9.7	7.875
60	12100	6175	10.5	7.875	123	13075	13800	11.6	7.875
61	12975	6150	10.3	7.875	124	23300	14250	10.5	7.875
62	14250	4675	10.1	7.875	125	20050	13075	10.6	8.75
63	16050	1325	10.5	7.875	126	21550	14325	10.2	7.875

AREA (RADIUS) ØF REVIEW



INPUT
GEL STRENGTH(LB/100SF) = 20.00
ABANDONED WELL MUD HEIGHT(FT) = 5000.00
ABANDONED WELL DIAMETER(IN) = 11.875
*FORMATION FRACTURE PRESSURE(PSIP) = 0.00
INITIAL FORMATION PRESSURE(PSIA) = 2325.00
VISCOSITY(CENTIPOISE) = 0.75
FLUID FORMATION VOLUME FACTOR(RV/SV) = 1.00
PERMEABILITY(MILLIDARCIES) = 100.00
FORMATION THICKNESS(FT) = 350.00
POROSITY(FRACTION) = 0.20
LIFE OF THE INJECTION WELL(YEARS) = 20.00
FLUID COMPRESSIBILITY(1/PSIP) = 0.00000500
INJECTION WELL BORE RADIUS(FT) = 0.33
MAXIMUM CONSTANT FLOW RATE(GAL/MIN) = 500.00
ABANDONED WELL MUD DENSITY(LBS/GAL) = 9.40
*IF THE FRACTURE PRESSURE=0, THEN A
STATED MAX FLOW RATE, RATHER THAN A
MAX FLOW RATE CALCULATED FROM THE
FRACTURE PRESSURE WAS USED

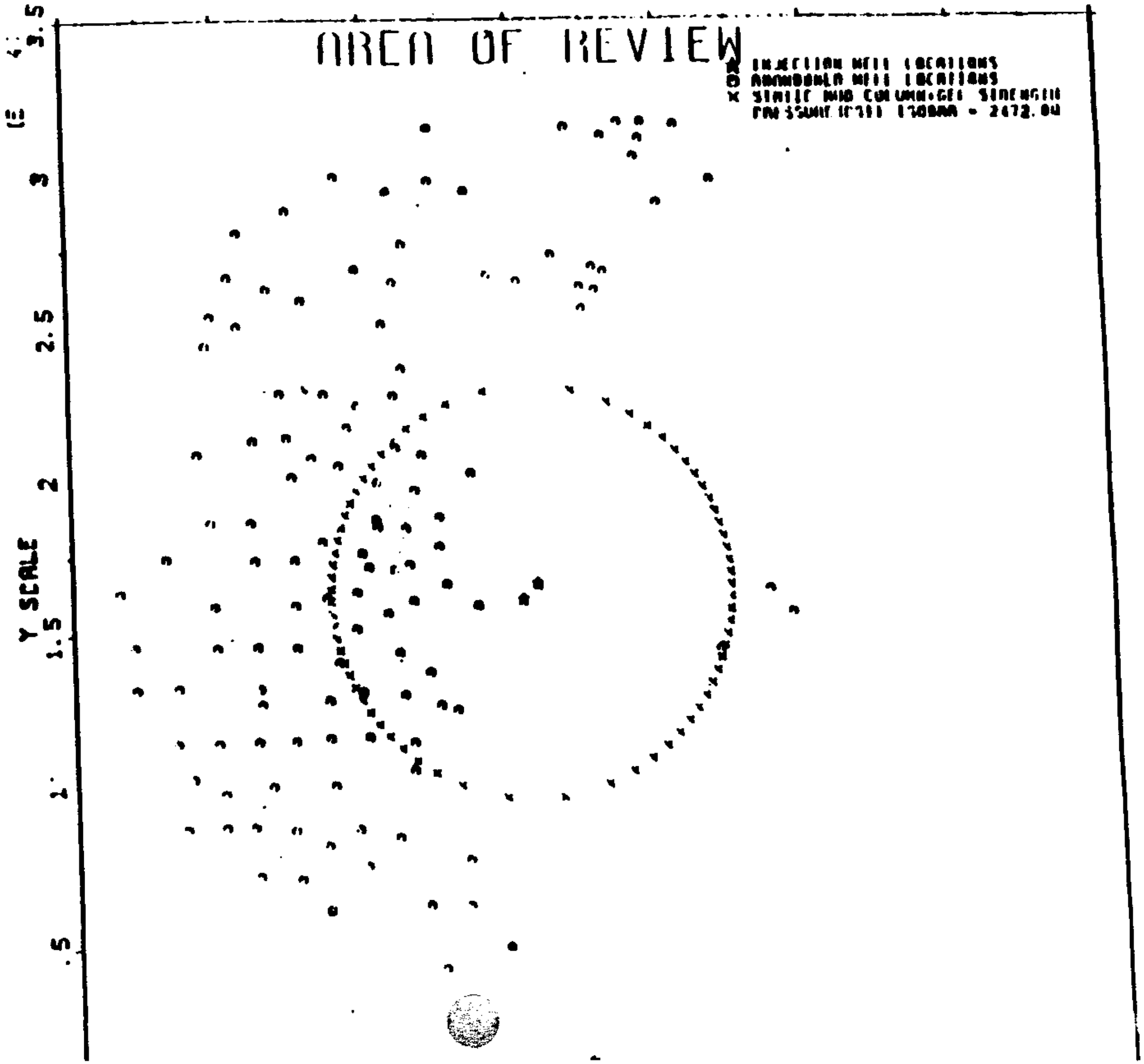
OUTPUT
PRESSURE AT THE WELL BORE RADIUS(PSIP) = 2888.94
GEL STRENGTH PRESSURE(PSIP) = 28.04
STATIC MUD COLUMN PRESSURE(PSIP) = 2444.00
COMBINED SMCP AND GEL ST(PSIP) = 2472.04

This provides a worst case design. Similarly, P_s is calculated utilizing the minimum mud density obtained fr logs for the same radial distance from the injector. Figure (3) indicates the area of review for the example using these criteria as approximately 7000 ft.

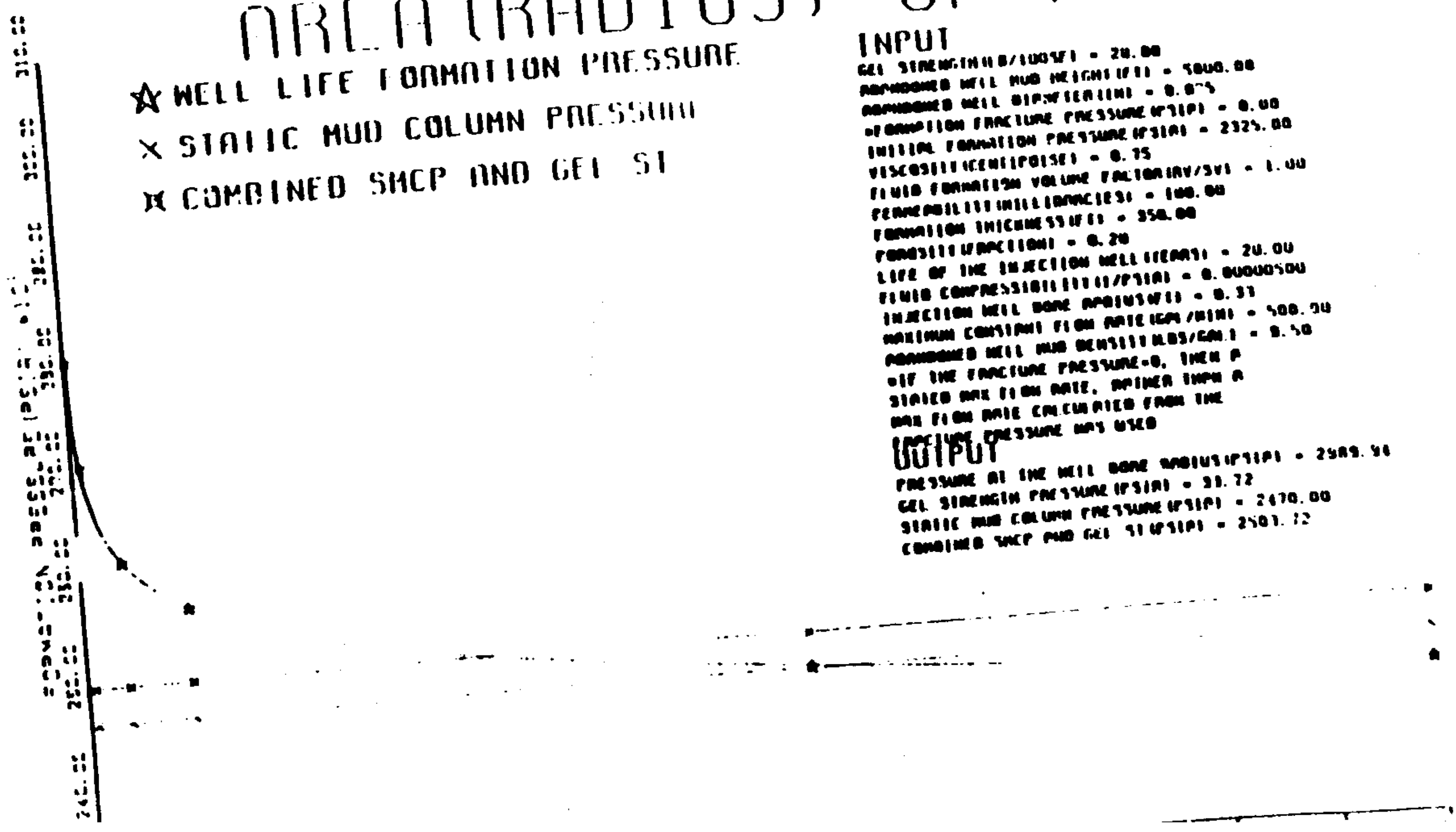
Figure (4) is a computer generated plot which displays the location of the isobar on which $P_f = P_s + P_g$ and indicates those abandoned wells which lie within the area of review defined by the isobar.

Considering only the abandoned wells contained within the isobar defined in Figure (4), the area of rev is recalculated. The new area of review, as noted in Figures (5) and (6), is an area encompassed by a radial distance of approximately 3800 ft from the injection wel which contains only 3 abandoned wells. It is noted that in the second iteration the minimum mud density (ρ_{min}) has increased from 9.4 to 9.5 lbs/gal and the maximum corrected bit diameter (D_{max}) has decreased from 11.875 to 9.875 in. Another iteration of the procedure yields the same values for ρ_{min} and D_{max}. Therefore, the area review defined is the true area of review for the specified injection operation.

Corrective action must be considered for all we within the area of review. Therefore, each of the thre wells should be analyzed on an individual basis using t


AREA OF REVIEW
INJECTION WELL LOCATIONS
ABANDONED WELL LOCATIONS
STATIC AND COLUMN+GEL STRENGTH
PRESSURE(PSI) ISOBAR = 2472.04
Y SCALE
3.5
3
2.5
2
1.5
1
.5
(E

AREA (RADIUS) OF REVIEW

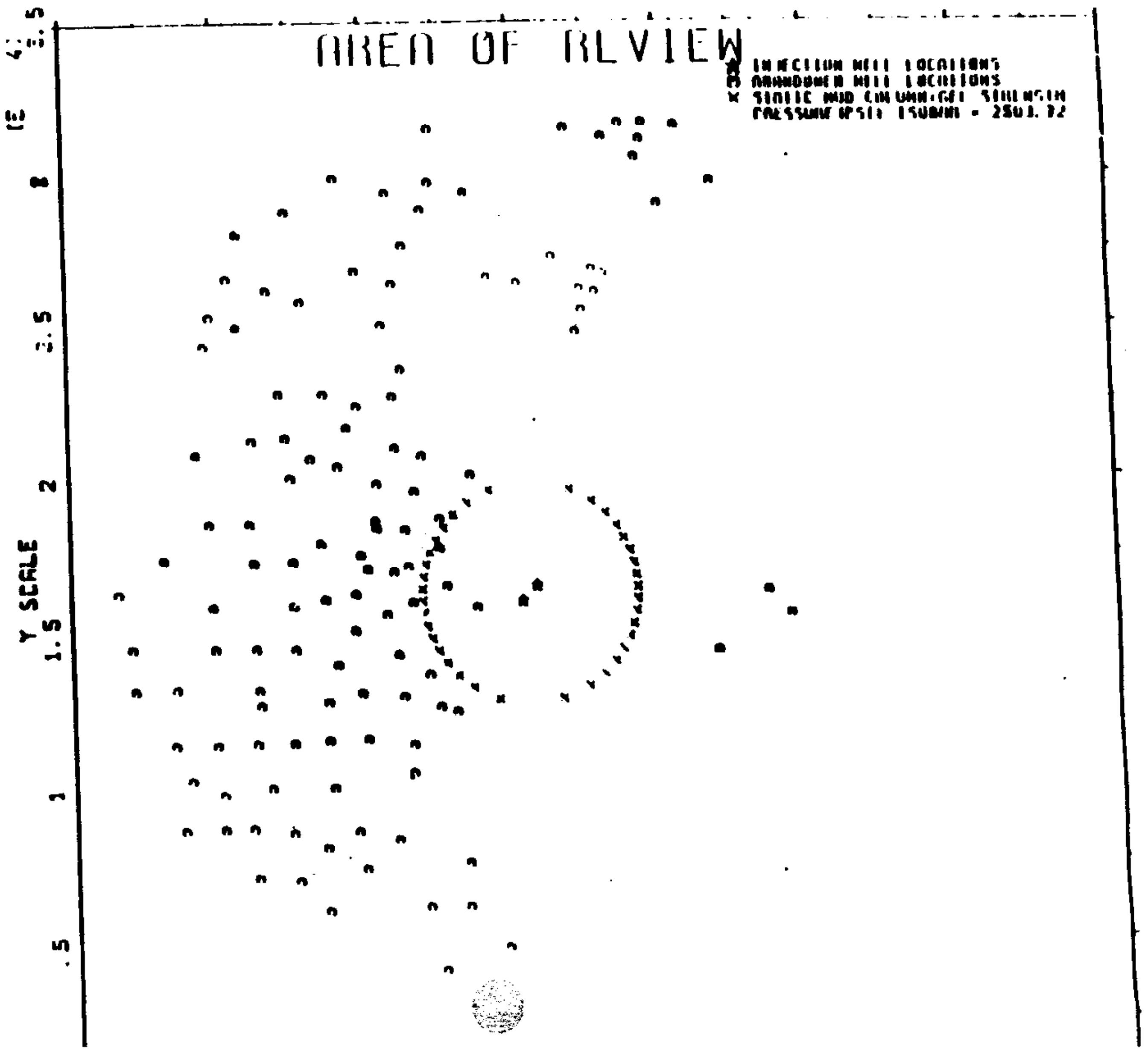


INPUT

GEL STRENGTH(LB/100SF) = 20.00
ABANDONED WELL MUD HEIGHT(FT) = 5000.00
ABANDONED WELL DIAMETER(IN) = 8.875
*FORMATION FRACTURE PRESSURE(PSIA) = 0.00
INITIAL FORMATION PRESSURE(PSIA) = 2325.00
VISCOSITY(CENTIPOISE) = 0.75
FLUID FORMATION VOLUME FACTOR(RV/SV) = 1.00
PERMEABILITY(MILLIDARCIES) = 100.00
FORMATION THICKNESS(FT) = 350.00
POROSITY(FRACTION) = 0.20
LIFE OF THE INJECTION WELL(YEARS) = 20.00
FLUID COMPRESSIBILITY(1/PSIA) = 0.00000500
INJECTION WELL BORE RADIUS(FT) = 0.33
MAXIMUM CONSTANT FLOW RATE(GAL/MIN) = 500.00
ABANDONED WELL MUD DENSITY(LBS/GAL) = 9.50
*IF THE FRACTURE PRESSURE=0, THEN A
STATED MAX FLOW RATE, RATHER THAN A
MAX FLOW RATE CALCULATED FROM THE
FRACTURE PRESSURE WAS USED

OUTPUT

PRESSURE AT THE WELL BORE RADIUS(PSIA) = 2589.98
GEL STRENGTH PRESSURE(PSIA) = 31.72
STATIC MUD COLUMN PRESSURE(PSIA) = 2470.00
COMBINED SMCP AND GEL ST(PSIA) = 2501.72


AREA OF REVIEW
INJECTION WELL LOCATIONS
ABANDONED WELL LOCATIONS
x STATIC MUD COLUMN-GEL STRENGTH
PRESSURE (PSI) ISOBAR = 2801.72
Y SCALE
(E3)
3.5
3
2.5
2
1.5
1
.5

developed theory. After individual analysis it is apparent that well number 121 is capable of allowing flu to migrate up its well bore. If records indicate that well number 121 was properly plugged no corrective actio would be required prior to conducting the proposed waste injection operation.

Conclusions

1. The costs associated with record searches and field surveys undertaken to determine the plugging history of abandoned wells can be avoided if the wells lie outside the area of review determined by the described procedur

2. The costs associated with plugging abandoned wells located outside the calculated area of review can also avoided.

3. Since the pressure cone resulting from the injection operation falls off quickly the size of the area of rev is extremely sensitive to small pressure differences at large radial distances from the injector.

43. The number of abandoned wells which fall inside the area of review can be reduced by varying injection wel locations, injection rates and the injection formation

NOMENCLATURE

D - Diameter of the well bore (in)

Dmax - Maximum bit diameter (in)

GS - Gel strength (lbs/100 Ft^2)

h - height of mud column (Ft)

r_w - well bore radius (in)

P_f - formation pressure (Psi)

P_g - gel strength pressure (Psi)

P_s - Static mud column pressure (Psi)

P_t - air pressure (Psi)

W - weight of the mud column (16s)

ρ - mud density (lbs/gal)

ρ_m - minimun mud density (lbs/gal)

CHAPTER II

BACKGROUND

The Environmental Atmosphere

The rapid rate of industrial developement that exists in a highly industrialized country like the Unite States has given birth to a myriad of environmental problems which resist time and linger to haunt man for decades. For example, the extensive use of polychlorinated biphenols (PCB's) as a cooling medium in electric transformers and capacitors presents a current problem which remains to be solved. The widespread use PCB's has resulted in the distribution of millions of gallons of nonbiodegradeable, carcinogenic waste in tran formers located in our factories, schools, office buildings, and neighborhoods. Many of the transformers are leaking and the public is unknowingly being exposed the carcinogenic waste. Extensive use of the insectici DDT and the insulating material asbestos has presented similar environmetnal hazards. An environmental dilemm exists in the case of PCB's and other hazardous wastes. Environmental groups have strongly opposed the establis ment of hazardous waste disposal sites within their geographic area of interest. The proposed disposal si would utilize advanced technology to provide the best means of disposal presently available. Without the establishment of the needed waste disposal facilities wastes will remain interdispersed throughout the populac where they pose a greater risk to man and the environmen It becomes apparent that the government, industry and th general public must cooperate and pool their resources i a logical and acceptable course of disposal action is to be pursued. The total dominance and influence of one interest group over another may destroy the balance required to allow growth and developement to continue while minimizing any adverse impact on the environment.

The well managed and organized efforts of envir mentally conscious organizations have increased the pub awareness of the dangers which result from the impro disposal of hazardous waste. These efforts and extensi media coverage of the environmental catastrophies resul form the improper disposal of hazardous wastes (i. e. L Canal in Niagara Falls, New York) have fueled the proli feration of federal, state and local regulations desig to protect man and the environment. These regulations which govern all aspects of hazardous waste disposal, necessitate considerable capital investments by indust in their efforts to attain compliance. Although few c dispute the need to regulate hazardous waste disposal, some of the regulations promulgated towards this end be questioned. Some requirements appear to be predicated on political, social or historical preferences or practices, rather than evolving from sound engineering and scientific principals which provide a means of verification and/or justification. This approach has resulted in the unnecesssary expendature by industry of funds to gain compliance with the regulations.

The Goal of Industrial Waste Disposal Regulations

The primary goal of the hazardous waste regulations which govern the disposal of liquid hazardous wast is to protect underground sources of drinking water. Th originators and enforcers of the regulations must not loose sight of this goal. The regulations should be enforced in a manner which allows the waste generator to utilize the most advanced waste disposal technology available if it can be demonstrated that the technology provides the best environmental alternative for disposal When more than one disposal option can be pursued, the regulatory agencies should encourage the generator to p sue the best environmental option. The regulations sho not be so restrictive that they eliminate the waste dis sal option which presents the least potential for contamination of ground water sources of drinking water.

Liquid Waste Disposal Options

Biological Treatment, Incineration, Off-site Disposal, On-site Landfill, Surface Impoundment, and Subsurface Injection are liquid waste disposal options available to the waste generator. Surface impoundment (evaporation) is the most common and frequently utilized means of disposal for liquid hazardous waste. Annually, Texas generates and disposes of 13.3 billion gallons of industrial waste in surface impoundments.[1] Since few of the impoundments are lined, the potential for contamination of ground water sources of drinking water is high. Even those evaporation impoundments located on low permeability clays present a contamination risk since no natural material is impermeable. The cost of modifying existing impoundment facilities to eliminate the contamination risk and/or to comply with regulatory requirements is prohibitive. To eliminate the risk other sources of disposal must be pursued. A preliminary study of surface impoundments examined 85 case histories of ground water contamination resulting from surface impoundment.[2] The study emphasizes the risks that result from utilizing surface impoundment disposal methods.

To eliminate the contamination which is inherent with many of the existing surface impoundments it has become necessary to pursue alternate means of hazardous waste disposal. A disposal means which has gained in popularity during the past four decades is the subsurface disposal of wastes by injection into subsurface formation containing salt water. Subsurface injection removes the waste from the biosphere and confines it in deep geologic formations. Since 1961 over 42 billion gallons of waste has been disposed of by subsurface injection in Texas alone.[1]

Summary

As of 1973, 20% of the total United States water needs have been fulfilled utilizing ground water. Groun water fulfills more than 85% of the public water needs i several states (Mississippi, Florida, New Mexico, Idaho and Hawaii).[3] This heavy dependance on ground water as source of drinking water demands every effort to protect the remaining ground water aquifers from sources of contamination. Once the aquifer is contaminated, methods available to return it to an acceptable level of water quality are not presently economically feasible.[4]

Where geologic and engineering studies indicate that a prospective site is suitable for subsurface inje tion, this method of hazardous waste disposal should be pursued. Few cases of ground water contamination resulting from subsurface injection operations have bee documented. Technological advances and more restrictiv waste injection regulations have virtually eliminated the potential sources of contamination which presented problems in the past. Subsurface injection has demonstrated itself to be an effective means of hazardous waste disposal. Regulatory actions that eliminate subsurface injection as a economical means of hazardous waste disposal will adversely effect the quality of ground water either directly or indirectly.

CHAPTER III

DETERMINING THE AREA OF REVIEW FOR INDUSTRIAL WASTE DISPOSAL WELLS

Introduction

During the course of the past four decades disposal of hazardous wastes by means of subsurface injection has emerged as an acceptable alternative to surface disp sal methods. At present, subsurface injection is conducted at more than 300 industrial waste disposal wells located at several geologically favorable sites througho the country. The largest concentration of industrial waste disposal wells is along the Gulf Coast of Texas. Figure (7). The majority of the wells inject waste int zones located below ground water sources of drinking wat at depths between 3000 and 7500 feet. The disposal well are designed to inject into sedimentary formations, approximately 62% of which are sand formations and 34% which are limestone dolomite.[5] The sedimentary basins which provide deep reception formations containing brin may also contain shallower formations saturated with ground water suitable for drinking. Since most industr sites are located within or near densely populated area which may rely heavily upon undergroundd sources of drinking water, precautions must be taken to ensure th

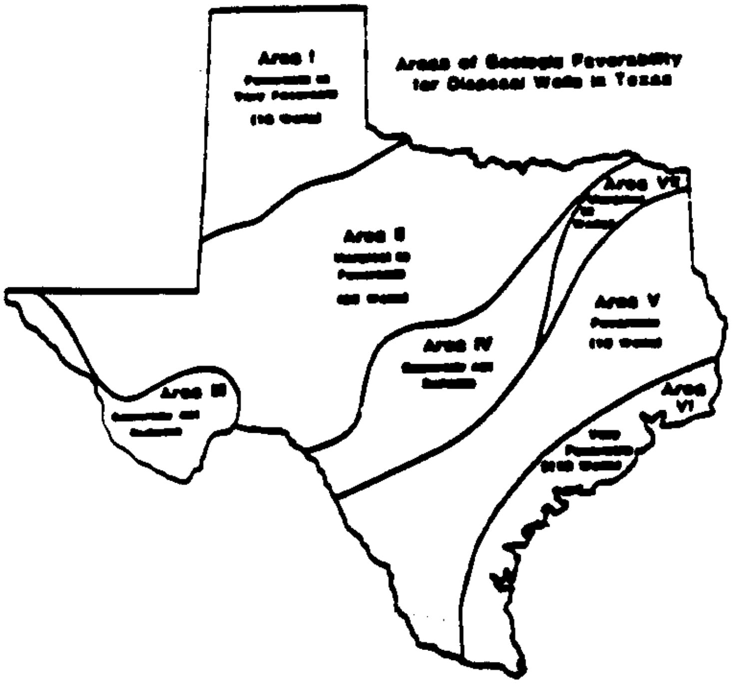


FIGURE 7. Location of waste disposal wells in Texas (From Kent[1])

the waste injection operations do not contaminate the overlying formations containing drinking water.

In compliance with the Safe Drinking Water Act,[6] The Environmental Protection Agency (EPA) has developed minimun requirements for state operated programs designed to regulate the subsurface disposal of industri waste by injection. This effort is designed to protect underground sources of drinking water from endangerment resulting from underground injection operations. The technical criteria and standards for use by the states i the developement and implementation of their state Underground Injection Control (UIC) Programs were promulgated by the Federal Register on 24 June 1980.[7] Texa was the first state to have an injection well regulator program and to a large extent the Federal UIC Program wa patterned after the Texas guidelines. The Texas Department of Water Resources (TDWR) recently promulga the Texas UIC program.[8] The program establishes the st dards and technical criteria which will govern subsurfa disposal of industrial waste in Texas. Appendix A discusses the standards and criteria establishes by the EPA and TDWR.

Several potential sources of groundwater contamination may develop during the life of an injection operation. Potential sources include: 1) failure of injection well, 2) faults or fractured confining zone,

3) upward migration of wastes via the abandoned well bores which penetrate the prospective injection zone. An adequate hydrogeologic survey should eliminate the possibility of injecting into excessively faulted zones and/or zones with fractured confining rock. Proper design, installation, maintainance and monitoring of the injection well will virtually eliminate the injector as a source of contamination. The potential for upward migration of waste via the abandoned well bores however, requires further investigation.

This report reviews the criteria which apply to contamination which may result from the migration of native formation fluid and/or injected waste up the abandoned well bore. A procedure is presented to determine which abandoned wells should be reviewed to determine if corrective action is necessary to prevent the contamination of ground water sources of drinking water which may result from upward migration in the abandoned well bore. The procedure is readily applicable in the Gulf Coast Area and can be adapted to other areas as required.

Criteria Which Apply to Abandoned Wells

Defining the Area of Review

The EPA and TDWR have promulgated regulations defining the area of review for an injection well or a group of wells.[7,8] The EPA defines the area of review to be the zone of endangered influence or a radius of ¼ m which ever is less. Where the zone of endangered influence is the area outlined by a radial sweep around injection well, field or project where in the pressures the injection zone may cause the migration of the injec and/or formation fluid into an underground source of drinking water. The computation of the zone of endange influence may be based on appropriate equations for pressure calculations and/or models and shall be determined for the life of the injection well system. The T defines the area of review for industrial waste disposa wells as a radius of 2½ miles or an area of lesser rad if so determined by the TDWR. The minimun area of revi allowed by the TDWR shall not be less than a ¼ mile ra distance from the injection well.

References (9) and (10) indicate that the TDWR ut lized a formation pressure increase tolerance of .01 o .015 psi/ft at well depth to calculate the pressure re tance in an unplugged abandoned wells. If the formati pressure does not exceed the pressure increase toleran at a given abandoned well then the area of review may reduced to exclude that well. The tolerance does not sider the characteristics of the fluid which occupies abandoned well bore.

Significance of the Area of Review

The significance of the area of review is that the regulations require wells within the area of review, which are not adequately plugged and which as a result of injection operations may cause contamination of subsurface sources of drinking water, to receive corrective action adequate to prevent such contaminaton as a condition of the underground injection operating permit.

The required corrective action is usually the plugging of the abandoned well with cement. Since plugging wells can represent an extensive capital investment, an adequate definition of the area of review becomes an important economic factor which must be considered whe the waste injection feasibility study is conducted. I area was fully developed as a result of oil and gas exploration the area defined by a 2½ mile radius would contain more than 300 wells. The cost of locating and plugging that number of wells would be prohibitive.

The Texas UIC regulations[8] require the subsurface disposal well permit applicant to submit a technical report with the application for permit. The information required in the technical report that relates to the area of review includes:

1) A map indicating the location of the proposed injection well and the applicable area of review Within the area of review, the map must show

number, or name and location of all producing wells, dry holes, surface bodies of water, springs, mines, quarries, water wells and other pertinent surface features including residences and roads;

2) A tabulation of reasonably available data on all wells within ½ mile of the injection well and al wells within the area of review which penetrate t within 300 feet of the injection zone. The data shall include a description of the type, construction date drilled, location depth, record of plugging and/or completion, and other information of each well as required;

3) Maps and cross-sections indicating the general vertical and lateral limits of those aquifers within the area of review that contain water with less than 3,000 mg/l Total Dissolved Solids (TDS) and those that contain water with less than 10,00 mg/l TDS, their positions relative to the injection formation and the direction of water movement, where known, in each fresh water aquifer which may be affected by the proposed injection.

The cost of obtaining and preparing the above required information could represent a significant perce tage of the initial costs associated with the proposed subsurface waste disposal well. Thus the magnitude of t effort required to prepare the permit application and technical report is controlled to a large degree by the determined area of review.

Theoretical Description of the Pressures Acting at the Abandoned Well Bore

Discussion

The vast majority of the artificial penetrations which intersect potential injection aquifers are the result of oil and gas exploration and developement. Therefore, it is logical to conclude that a means of adequately defining the area of review may lie in an understanding of the principals and practices which govern drilling and well completion operations.

The rotary drilling method is predominately utilized in the drilling of oil and gas exploration and development wells. This drilling method is dependant upon the use of a drilling fluid (mud) which performs several functions which are vital to the method. Appendix B provides a brief discussion of the importance of drilling fluid to the rotary drilling method. Upon completion of the drilling operation if the well is not completed for production, the drill string and bit are removed from the well bore. Drilling mud will remain in the well bore. Since no means of escape exists, provided lost circulation zones were not encountered, the drilling mud used to dril the well will remain in the well bore indefinately.

Important Drilling Mud Characteristics

One of the primary functions of the drilling mud is the removal of bit cuttings during the drilling operation. The mud must remove the cuttings from beneath the bit, transport them up the well bore-drill pipe annulus and release them at the surface. During periods of suspended circulation, the primary mud property which act to suspend the cuttings in the static mud column is the mud gel strength. The gel strength develops with time a the mud column remains quiescent. Since the bouyant for of a static fluid increases with density, drilling fluid of higher density are also capable of suspending cutting during periods of non-circulation. The density of the m also accomplishes another important function, that of controlling encountered formation pressures by providing static mud column which is capable of exerting sufficien pressure to prevent the inflow of formation fluids into the well bore.

Pressures at the Well Bore

An abandoned well bore can be considered to exi in a static state. For a static state to exist the for which act on the mud column must balance. Figure 1 rep sents a vertical force diagram of the static mud colum an abandoned well bore. The equation for the force balance takes the following form,

(1-

$$w + 2\pi r_w h\, GS = P_f\, \pi r_w^2 - P_t\, \pi r_w^2$$

where $w = \pi r_w^2 \gamma h$

Simplifying the force balance results in the following pressure equation,

(3-

$$P_f = \gamma h + \frac{4hGS}{D}$$

Pressure Generated by the Static Mud Column

The hydrostatic law of variance of pressure can be written in the form,

(3-

$$P = \gamma h$$

Where: h denotes the height of the liquid column, ft P denotes th pressure at the base of th tical liquid column of height lbs/ft^2

γ denotes the specific weight lbs/ft^3

Equation 3-2 can be transformed into following usable field equation:

(3

$$P_s = 0.052\, \rho h$$

Where: the contant 0.052 has the units gal/ft-in^2

ρ denotes the density of drilling mud, lbs/gal

h denotes the height

static mud column, ft

Ps denotes the static mud

column pressure, psi

Pressure Required to Break the Gel Strength of the Stat Mud Column and Initiate Flow

Most oil and gas wells are drilled utilizing wa base drilling fluids. When these fluids remain in a quiescent state a gel structure developes. The strengt of this structure is important since the formation pressure would have to increase sufficiently to shear t structure before the mud in the abandoned well will flo freely. Melrose, et al[11] defined the pressure gradient required to rupture the gel strength and initiate flow a horizontal pipe as:

(3

$$\frac{\Delta P}{h} = \frac{4GS}{D}$$

Equation 3-4 can be converted to the following usable field equation:

(

$$Pg = 3.33 \times 10^{-3} \quad \frac{Gsh}{D}$$

Where: The constant $3.33X10^{-3}$ has the units f

h denotes the height of the static mud column, ft

GS denotes the gel strength of the drilling mud, lbs/100 ft^2 (Gel streng pressure, Psi)

D denotes the diameter of the abandon

well bore, in P_g denotes the pressur
required to break the gel structure and
initiate flow in a horizontal pipe syste
where gravity effects are negligible

Formation Pressure Rise During Injection

The well life formation pressure (P_f) which results at a radial distance r from the injection well a time t after the start of injection of a small and constant compressible fluid at a constant rate Q throughout the life of the well into an infinite, isotropic, homogeneous, horizontal reservoir of uniform thickness and porosity is well approximated by,[12].

$$P_f(r, t) = P_i - \frac{Q\mu B}{4\pi Kh}\, Ei\left(\frac{-\phi\mu c r^2}{4kt}\right) \qquad 3-$$

Appendix C provides a definition of the terms of equatic 3-6 and demonstrates the derivation of the equation fror the diffusivity equation.

Pressure Theory Summary

The area of review may theoretically be defined the radial distance from an injection well where in:

The formation pressure is greater than the stat mud column pressure + the gel strength pressure of the static mud column which occupies the abandoned well bor

$$P_f > P_s + P_g \qquad (3$$

Field Procedure for Determining the Area of Review

Introduction

This section of the report promulgates a general procedure which can be utilized to determine the area of review for a proposed subsurface injection disposal operation. The procedure employs the developed theory to deterdetermine which abandoned wells must be reviewed to determine if corrective action is required. The corrective action is required to prevent the contamination of underground sources of drinking water which could result from the migration of waste and/or formation fluid up the abandoned well bore. Application of the procedure during the initial planning stages of a proposed injection operation could play an important role in the decision making process. The variations and options provided by the procedure will allow planners the flexibility of varing the injection rates, well locations and other pertinent factors to insure that the required injection operation can be accomplished without the expenditure of funds to physically locate and/or correct abandoned wells unnecessarily

Assumptions

1.) The static mud column extends to the surface and is uniform in density.

2.) Abandoned well bore diameters used in calculations are equal to the bit diameter plus two inches where bit refers to that used to drill hole at the depth of the injection formati

3.) The gel strength applied to all wells is 20 lbs/100 Ft^2

4.) Injection pressures will not exceed the fractu pressure of the injection formation.

5.) Known abandoned wells for which no data are available will be assigned the minimum mud density and the largest bit diameter noted for al wells within a 2½ mile radius of the injector

6.) None of the abandoned wells were completed and produced.

7.) All pressures are calculated at the top of the injection formation.

8.) All abandoned wells were drilled with water muds. (fresh water, salt water, oil-in-water emulsions and surfactant muds).

9.) None of the abandoned wells were plugged.

Justification of Assumptions

1.) Upon entering some abandoned wells it has bee noted that segregation of the mud components occur with time. A sedimentary process apparently occurs to some degree within the s tic mud column. Data describing the degree t which sedimentation occurs is not readily available since the phenomenon has received little attention. If segregation of the mud column occurs the mud density will increase wit depth. The actual characteristics of the densi gradient is not known since it would vary with the mud type, composition and the characteristi of the formation drilled. Since the mud has no means of escape from the well bore the assumpti that the mud column has a constant density with depths should result in the calculation of a st tic mud colum pressure at the depths of concern which varies little, if at all, from the actual pressure. Here again the gel structure would b expected to increase with depth because of the deposition of the gel producing particles at th lower portion of the well bore. The assumptio of uniform mud consistency provides the only means of calculating the gel strength pressure since the variations of gel strength with mud segregation in abandoned wells are not known.

2.) The gel strength pressure (Pg) is inversely pr portioned to the well bore diameter, therefore compensate for the larger surface casing the effective diameter of the abandoned well bore will be the bit diameter used to drill the hol at the depth of the injection formation plus t inches.

3.) The justification for selecting 20 lbs/100 Ft^2 as the expected minimun gel strength for all water base muds is discussed in Appendix D.

6.) If an abandoned well was completed and produce the fluid occupying the well bore will be a li fluid without gel strength and the procedure described here would not apply.

8.) Because of the lack of gel strength associated with oil-base, air and gas drilling fluids wel drilled or completed with these fluids should evaluated by alternate procedures.

9.) Considering all wells to be unplugged allo pressure calculations to be conducted on the tic mud column in each abandoned well bore in equitable manner for all wells.

Example

Appendix E is an example which correlates with procedural steps presented below. The example represe a two well injection system which is injecting into a with characteristics selected to emphasize the procedu The abandoned wells represent an actual field orientat and the mud densities and bit sizes utilized were obt from the well logs for the various wells.

Step 1

The first step in the procedure is obtaining the information required to calculate the pressures. Table 2 lists the subsurface information required and the means b which it can be evaluated. An effort to attain well logs for all abandoned wells within a 2½ mile radius of the proposed injection well or wells should ensue. The appropriate state regulatory agency for oil and gas exploration should be contacted for assistance in obtaining well logs or a commercial log library can be contacted.

Step 2

Upon completion of a thorough investigation to locate all abandoned wells within the 2½ mile radius of the injectors, the abandoned well locations should be accurately indicated on a suitable map. An appropriate grid system which indicates the distance, in feet betwee the abandoned wells should then be superimposed over the map. The grid system provides a means by which the relative distance between the abandoned wells and the injection wells can be determined so that the pressures resulting from the injection operation can be evaluated each abandoned well.

TABLE 2.

SUBSURFACE INFORMATION REQUIRED FOR PRESSURE CALCULATI

PRESSURE CALCULATED	INFORMATION DESIRED	METHODS AVAILABLE FOR EVALUATION
Formation	Porosity	Core analysis, electric, so and radioactive logs
	Permeability	core analysis, buildup, drawd or injectivity tests or electric logs
	Formation fluid pressure	Drill stem test, hydrostatic pressure gradient, pressure bomb
	Formation thickness	electric logs, sonic logs, radioactive logs
	Formation depth	electric, sonic and radioactive logs
Static mud column	Mud density	well log headers
	Formation depth	(same as above)
Gel strength	Bit size	well log headers
	Formation depth	(same as above)

Step 3

Utilizing the information gathered in step one, the formation, static mud column, and gel strength pressures are calculated. The formation pressure calculated must represent the injection formation pressure at the end of the stated life of the injection well system. A computer program INJWEL (Appendix F) was developed to calculate the required pressures. Use of the program is demonstrated in the example contained in Appendix E. The program calculates the formation pressure, static mud column, and gel strength pressures up to a radial distanc of 13,000 feet (approx. 2½ miles) from the injector. Th program also generates an X-Y Plot of the formation, static mud column, and static mud column + gel strength pressures as a function of the radial distance from the injection well. The x-y Plot graphically approximates the area of review by indicating the radial distance fro the injector where the static mud column + gel strength pressure exceed the formation pressure. Since most wast injection operations utilize more than one injection wel the program can be used in these instances by assuming that the combined flow rates of all injectors is input into one well. Since the wells are usually located rela tively close together this assumption should provide a realistic approximation of the area of review. The program is designed to calculate the formation pressure utilizing an input flow rate or by determining a maximum allowable flow rate utilizing an input formation frac pressure.

The static mud column pressure calculated by INJWEL depends on the mud density.

(3-

$$P_s = 0.052\rho h$$

Since the mud density varies with each abandoned well, the static mud column pressure will also vary. To define properly the area of review it is necessary to ta the extreme case where P_s is a minimun. Therefore the density to be utilized in the static mud column pressure calculation must be the lowest density recorded in the abandoned wells within a 2½ mile radius of the injector Equation 3-3 can be modified to yield the appropriat equation:

(3-

$$P_s = 0.052\ \rho_{min}\ h$$

The gel strength presure calculated by INJWEL is inversely proportional to the diameter of the abandoned well. Since the diameters of the abandoned wells vary, proper definition of the area of review requires the us of the minimun gel strength pressure calculated in the abandoned wells located in the 2½ mile radius of the injectors. This minimun theoretically will occur in th abandoned well drilled with the largest bit size at the injection formation depth. Equation 3-5 can be modifie yield the appropriate equation:

$$P_g = 3.33 \times 10^{-3} \frac{Gsh}{D_{max}} \qquad (3-9)$$

Where: D may denote the largest bit diameter at the injection formation depth plus two inches.

Step 4

The information obtained in step two is utilized in this step to determine the formation pressure at each of the abandoned wells for the specified time period. The formation pressure is calculated by utilizing a computer program PRES (Appendix (G)) which has undergone some FORTRAN modification from the original program developed by Carter.[13] The program determines the formation pressure at each abandoned well at specified time periods. For use in calculating the area of review the time must equal the life of the injection well or wells. Although an average injection rate would suffice, the program is capable of determining the formation pressure at a specified time for wells injecting at varing rates. The use of PRES is demonstrated in the example contained in Appendix E. In addition to calculating the pressures at the abandoned wells PRES also generates an X-Y Plot which locates the injectors and the abandoned wells on an appropriate grid system. The x-y Plot also contains an isobar which represents the static mud column + gel strength pre pressure calculated by INJWEL in step three. This isobar fines the area of review. Inside the area encompassed b isobar the formation pressure exceeds the static mud column + gel strength presure and the potential for co tamination of underground sources of drinking water by migration of injection and/or formation fluid up the abandoned well bore exists. The X-Y Plot graphically defines the area of review and clearly delineates the wells which fall within the area of review and will require further examination.

INJWEL and PRES both provide means of calculating the required pressures and utilize the pressures to graphically display the area of review. INJWEL relates the pressure cone which results from the injection operation and it clearly displays the rapidity with which the pressure falls off with increased distance from the w The cone demonstrates the sensitivity of the area of review to small pressure changes at large radial distance from the injector. In other words a small variation in the static mud column plus gel strength pressure at large radial distances can result in a big variance in the area of review defined. PRES provides a graphical representation which requires little explanation. The area of review is clearly defined with respect to the injection wells and the abandoned wells.

Step 5

If after completing steps one through four it is found that all wells contained within the static mud column plus gel strength pressure isobar, the area of review, have a mud density greater than the density used to calculate the static mud column pressure in step three then the static mud column pressure should be recalculate using the minimun mud density obtained for all abandoned wells within the area of review defined by steps three a four. Should all abandoned wells within the defined are of review have a bit size at the injection formation les than that used to calculate D_{max} in equation (3-9) then gel strength should be recalculated utilizing the larges bit diameter encountered in the abandoned wells containe within the isobar defining the area of review in step four. This iterative process can be repeated until the wells contained within the area of review have the same gel strength and static column pressure as determined in the previous iteration. Once the iterative process is completed the area of review defined is the true area of review for the particular injeciton well system in question.

Step 6

Step 5 defines the area of review for the propo injection operation. Reference 8 requires that corrective action be taken on all wells within the area of review which are inadequately constructed, completed, abandoned and which as a result of the injection activity may cause the pollution of fresh water. Utilizing the developed theory it is possible to evaluate each abandoned well within the area of review on an individual basis to determine if the injection activity will cause interformational fluid transfer at that particular well. Utilizing equations (3-8) and (3-9) to evaluate each well it is possible to determine those wells which present a pollution problem. Those abandoned wells where $P_f > P_s + P_g$ should be reviewed to determine if corrective action is necessary.

Step 7

Once the wells requiring corrective action are identified the action should be inetiated. The EPA and TDWR standards [7,8] for action required to prevent pollution of ground water sources of drinking water indicate that corrective action shall consider the following factors:

(1) Toxicity and volume of the injected waste;
(2) Toxicity of native fluids and by-products of injection;
(3) Population potential affected;
(4) Geology and hydrology;

(5) Completion and plugging records:

(6) Abandonment procedures in effect at the time a well is abandoned; and

(7) Hydraulic connections with fresh water.

Normally corrective action should involve the location and re-entry of the well and proper plugging in accordance with the Texas Railroad Commission rules and regulations. In some cases this may not be possible due to inability to locate the well site or because construction has covered the site. In these cases two options are: (1) lower the injection volume so that lower pressures will occur or (2) drill a nearby monitor well i the drinking water source.

Summary

The heavy dependance on ground water for daily needs demands that every precaution be taken to protect the remaining supplies. Subsurface disposal of hazardous wastes by injection is an alternative which provides for the protection of subsurface sources of drinking water. Subsurface disposal presents less water pollution potential than the commonly utilized surface disposal methods. Economic conditions must be favorable to subsurface inje tion before waste generators will consider it as a viabl waste disposal option in geologically favorable areas. The cost of compliance with the UIC program regulations may be the deciding factor when the costs of disposal options are evaluated. The extent of corrective action required within the area of review could represent a significant portion of the costs required to comply with UIC regulations. The disposal option selected and the resulting impact potential on underground sources of fresh water may be controlled by the size of the area of review. Therefore, it is necessary to have a procedure which will ensure the protection of ground water while eliminating unnecessary expendatures for corrective action.

Conclusions

The following conclusions were drawn from the results of this investigation.

1.) The costs associated with record searches and field surveys undertaken to determine the plugging history of abandoned wells can be avoided if the wells lie outside the area of review determined by the proposed procedure.

2.) The costs associated with plugging abandoned wells located outside the calculated area of review can also be avoided.

3.) The procedure minimizes the cost of locating and plugging abandoned wells since it allows the user to reduce the number of abandoned wells located within the area of review by varing the well locations, the selection of injection formation and flow rates.

4.) Utilization of the procedure to determine the area of review should present no risk to subsurface sources of drinking water since the procedure considers all abandone wells within the 2½ mile radius of the injection wells a utilizes the data obtained to design for the worst possible conditions.

5.) The area of review determined will decrease as the depth to the injection formation increases. Thus where equivalent injection formations exist injection into the deeper formation will result in the smaller area of revie determination.

6.) The 20 lb/100SF gel strength utilized for the determination of the gel strength pressure represents the minimu ultimate gel strength expected to be encountered when evaluating abandoned wells drilled with water-base drilling fluids.

7.) The procedure described can not be applied to zones lost circulation or to abandoned wells drilled with muds that do not exhibit the thixotrophic property of gel strength.

8.) Since the pressure cone resulting from the injection operation falls off quickly the size of the area of revi varies greatly with small pressure changes at large radi distances from the injectors.

Recommendations

The following recommendations are offered in a effort to better define the area of review for hazardous waste disposal wells:

1.) That the procedure outlined in the previous sections be utilized to determine the area of review for hazardous waste disposal wells.

2.) That research be undertaken to determinme the long term effects of bore hole conditions on the gel strength of water-base drilling fluids.

3.) That research be undertaken to determine the degree o component segregation which water-base muds undergo while remaining quiescent in the bore hole for long periods of time.

4.) That other procedures utilized to determine the area of review consider the characteristics of the drilling fluid which occupies the abandoned well bore.

APPENDIX A

STANDARDS AND TECHNICAL CRITERIA APPLICABLE TO INDUSTRIAL WASTE INJECTION

STANDARDS AND TECHNICAL CRITERIA APPLICABLE TO INDUSTRIAL WASTE INJECTION

The regulations promulgatged by the 24 June 1981 Federal Register were proposed under the authority of the Safe Drinking Water Act and are designed to protect the quality of underground sources of drinking water from contamination which could result from the injection of waste fluids into subsurface formations. The regulations established the technical criteria and standards for use by states and the EPA in the developement and implementation of state UIC programs. The regulations promulgate by the 24 June 1980 Federal Register do not etablish requirements for owners or operators of injection wel They establish requirements for state and EPA officials be used in developing the state UIC programs which, when they become effective, will in turn establish enforceabl requiremnts for owners or operators of injection wells.

The Texas injection well act incorperates the standards and technical criteria promulgated by the 24 J 1981 Federal Register into the Texas UIC program. Since large percentage of the waste injection wells in operati in the United States are located in the State of Texas, provisions of Injection Well Act will be reviewed to pr an overview of the standards and technical criteria which apply to the owners and operators of industrial waste disposal wells within Texas. UIC programs will vary from state to state but compliance with the Federal Register ensures that all programs must incorporate the same basic standards and technical criteria.

The Injection Well Act requires owners and operators of industrial waste disposal wells to comply with the following:

A Permit Application - It is the responsibility of the owner of a waste injection facility to submit an application for permit; except if the facility is owned by one individual and operated by another, then it is the responsibility of the operator to submit the application for permit. Each application for permit shall include the following:

1.) Name, mailing address, and location of the injection operation for which the application is submitted;

2.) Ownership status as federal, state, local, private, public or other;

3.) Operator's name, mailing address, and telephone number;

4.) A brief description of the type of business operated;

5.) Activities conducted at the site which require a permit;

6.) Statement of up to four SIC codes which describe the principal products or services provided by the facility;

7.) An appropriate map which shows the facility and each of its intake and discharge structures. The map shall depict the approximat boundaries of the tract of land to be used the applicant and shall extend at least one mile beyond the tract boundaries sufficient to show the following:

   a.) Each well, spring, and surface water body within the map area;

   b.) The presence of public roads, town the nature of developement such as residential, commercial, agricultural, recreational, undeveloped or otherwise within the map area;

   c.) The location of other waste disposal activities conducted at the tract but not included in the permit applicati

   d.) The ownership of tracts of land withi reasonable distance from the proposed injection point; and e.) Such other information as reasonably requested.

8.) A list of all permits or construction approvals received or applied for under the provisions of other environmental protection regulations or programs.

9.) Whether the facility is located on Indian lands;

10.) A supplementary technical report. The report shall be prepared by a registered professional engineer or other qualified person and shall be submitted when requested. The report shall include the following:

a.) A general discription of the facility and systems used in connection with the waste injection activity.

b.) For each injection well:

i.) The injection rate of the disposal waste stream, including appropriate averages, the maximun rate of injection over representative periods of time, and detailed information regarding patterns of injection; and

ii.) The physical and chemical properties of the defined waste injection stream; chemical, physical, thermal, organic, bacteriological, or radioactive, as applicable.

c.) Such other information as may be reasonably required for an adequate understanding of the project or operatio

11.) Additional information as follows:

a.) A plugging and abandonment plan;

b.) A letter from the Railroad Commission of Texas stating that the drilling of a disposal well and the injection of the waste in the selected subsurface disposal formation will not endanger or injure any oil or gas formations.

H. <u>Terms and Conditions of the Permit</u> - Acceptance of the permit by the person to whom it is issue constitutes an acknowledgement and agreement th he will comply with all the terms and condition contained within the permit, the rules of the TDWR and any other orders issued by the TDWR. Conditions applicable to all permits issued un the UIC program are as follows:

1.) All reasonable steps required to minimize or correct any adverse impact on the environment resulting from noncompliance with the permit must be promptly undertaken;

2.) All facilities shall be properly operated and maintained at all times;

3.) The permittee shall provide to the TDWR, upon request, copies of records required to be kept by the permit;

4.) The permittee shall notify the TDWR prior to any physical modifications which would require a permit modification;

5.) The permittee shall not begin any mofications which would result in noncompliance with other permit requirements without written approval from the TDWR;

6.) Within 24 hours after occurance, the permittee shall orally notify the TDWR of any noncompliance which may endanger health or the environment.

7.) The permitted shall allow entry to and inspection by TDWR personnel as prescribed by Texas law;

8.) The permittee shall monitor and obtain samples and measurements required to provide sufficient evidence that the disposal operation is conducted in compliance with the permit provisions

9.) Monitoring results shall be provided to the TDW at the intervals specified in the permit; and

10.) The permittee shall promptly submit facts or information to the TDWR if it is noted that s facts were omitted from the permit application, or were submitted incorrectly.

C. Conditions Applicable to Individual Permits - The following conditions will be determined on a case-by-case basis.

1.) The duration of the permit varies with the type of waste disposal operation. Industrial waste disposal (Class 1) wells shall be permitted for a fixed term not to exceed 10 years;

2.) The type, intervals and frequency of monitoring, recording and reporting shall be determined to yield representative data of the disposal operation;

3.) A schedule of compliance prescribing a timetable for achieving compliance with the permit conditions an appropriate regulations may be incorperated into the permit.

D. Corrective Action - For wells within the area of review which are inadequately constructed, completed, or abandoned, and which as a result of the injection operation may cause the pollution of fresh water, the TDWR will incorperate into the permit conditions requiring corrective action adequate to prevent such pollution. Permits issued for existing injection wells requiring correcti action may include a compliance schedule prescribing the time within which the corre tive action must be completed.

D. Financial Responsibility - The permittee shall obtain a performance bond or other equivalent form of financial assurance or guarantee approv by the TDWR to ensure that closing, plugging an abandoning of the injection operation is accomplished in the manner prescribed by TDWR.

E. Surface Facilities - The surface facilities ass ciated with a hazardous waste disposal well mus comply with the rules and regulations which ar applicable to hazardous waste management facilities.

F. Record Retention- The permittee shall maintain all records concerning the nature and composit of the injected waste until five years after completion of the plugging and abandonment of well.

G. Site Identification and Access - Industrial wa disposal wells shall have the following:

1.) A posted sign at the well site which shall show the name of the company, company well number and permit number.

2.) An all-weather road maintained to allow access to the injection well and related facilities.

3.) Painting and maintainance of the wellhead and associated equipment to ensure proper working order without significant leaks.

H. Standards and Conditions Which Apply to Class I or Industrial Waste Disposal Wells

1.) An injection well must demonstrate mechanical integrity. An injectin well is said to have mechanical integrity if there . no significant leak in the casing, tubing, or packer, and if there is no significant fluid movement through vertical fluid channels adjacent to the injection wellbore. The following tests shall be conducted to evaluate the mechanical integrity of an injection well:

a.) Monitoring of annulus pressure, or a pressure test with liquid or gas to detect any leaks in casing, tubing, or packer; and,

  - b.) A temperature or noise log to detect any fluid movement through vertical channels behind the casing.

2.) Corrective action required to prevent or correct pollution of underground sources of drinking water shall consider the following factors:
   - a.) toxicity and volume of the injected waste;
   - b.) toxicity of native fluids and by-products of injection;
   - c.) population potential affected;
   - d.) geology and hydrology;
   - e.) history of the injection operation;
   - f.) completion and plugging records;
   - g.) abandoment procedures in effect at the time a well was abandoned; and,
   - h.) hydraulic connections with fresh water.

3.) The TDWR will certify construction and completion of an injection well or project which is constructed and completed in compliance with the requirements of a permit. To determine if such certification will be made, TDWR shall consider the following:
   - a.) logging and testing program data on the well;
   - b.) a demonstration of mechanical integrity;
   - c.) anticipated operating data;

d.) the results of the formation testing program;

e.) the injection procedure;

f.) the compatibility of injected waste with formation fluid in the injection zone and with the minerals in both the injection and confining zones; and,

g.) the status of corrective action required fo abandoned wells in the area of review.

4.) Prior to abandoning hazardous waste disposal wells the well shall be plugged with cement in manner which will not allow the upward migratic of fluids out of the injection zone either intc or between freshwater aquifers. At least 9 days notice will be given the TDWR before the plugging and abandonment commences in complianc with an approved plan. Placement of the cemen plug shall be accomplished utilizing one of th following aproved methods:

a.) the Balance Method;

b.) the Dump Bailer Method; or

c.) the Two-Plug Method.

The adequacy of a plugging and abandonment pla shall be determined by considering the following:

a.) the type and number of plugs to be use b.) the placement of the plugs;

c.) the type, grade and quantity of the plugging material used;

d.) the method of placement of the plugs;

e.) the procedure used to plug and abandon the well;

f.) any new information obtained on wells within the area of review;

g.) geologic or economic conditions; and,

h.) such other factors that may affect the adequacy of the plan.

Within 30 days after completion of plugging, the permittee shall file a plugging report with the TDWR.

5.) All hazardous waste disposal wells shall be cased and cemented to prevent the movement of fluids into or between fresh water aquifers. Sufficient cement shall be used to fill the annulus between the casing and the wellbore to ground level. The casing and cement used shall be selected to ensure that the final design is adequate for the life of the well. The minimun depth of the surface casing will be determined by the TDWR and will be selected to protect fresh water formations. The following factors shall be considered when specifying casing and cementing requirements:

a.) depth to the injection zone;

b.) injection pressure, formation pressure, wellbore pressure, and axial loading;

c.) hole size;

d.) size and grade of all casing;

e.) corrosive effects of injected waste, formation fluids, and temperatures;

f.) lithology of injection and confining intervals;

g.) types and grades of cement.

6.) All hazardous waste disposal wells shall inject through tubing with either a packer set abo the injection zone or a fluid seal system approved by the TDWR. Tubing, packers or fluid seals shall be selected utilizing the following considerations;

a.) setting depth; characteristics of the injected waste;

c.) injection pressure;

d.) annular pressure;

e.) rate, temperature, and volume of injected waste; and,

f.) size of casing.

7.) Appropriate logs and other tests shall be completed during the drilling and construction stages of the hazardous waste injection well. A minimun of the following logs and tests shall be conducted:

a.) deviation checks;

b.) Spontaneous Potential (SP), resistivity or Gamma-Resistivity, and caliper logs before the surface casing is installed;

c.) SP, resistivity or gamma-resistivity, and caliper logs before intermediate and long string casings are set and a cement bond log, a gamma-ray log and an inclination survey after casing is set;

d.) pressure testing of all casings;

e.) full-hole cores of the injection zone and lowermost overlying confining zone;

8.) After completion of the well, injectivity tests shall be performed to determine the well capacity and reservoir characteristics.

9.) The following operating requirements are imposed:

a.) Injection pressure at the wellhead shall be limited so as to assure that the pressure in the injection formation during injection will not initiate new fractures or propagate existing fractures in the injection formation;

b.) Injection outside the outermost casing is prohibited.

c.) The annulus between the tubing and the casing shall be filled with a fluid approved by the TDWR.

d.) Monthly average and instantaneous rates of injection, and annual and monthly volumes of injected waste shall not exceed limits specified by the TDWR.

e.) The chemical and physical characteristics of the injected waste shall maintained within specified permit limts.

f.) The TDWR shall be notified if any workover operation or corrective maintenance which involves taking the inje tino well out of service is contemplated.

10.) Monitoring requirements include the following:

a.) Sampling and analysis of injected wast with sufficient frequency to yield representative data of the characte b.) Gauges so that the tubing and casing annulus pressures can be monitored at all times;

c.) The installation of continuous recording devices to record injection tubing pressures, injection flow rates, injection volumes, tubing-long string casing annulus pressure, and any other specified data.

d.) The demonstration of mechanical integrity at least every five years during the life of the well.

e.) The monitoring of wells within the area of review to observe water quality and determine if waste migration has resulted.

11.) Reporting requirements are as follows:

- a.) Prior to operating the injection wel the permittee shall within 90 days after completion of the well submit to the TDWR the following:
  - i.) A completion report providing th drilling and completion history, casing and cementing records, well logs, injectivity tests performed on the well and a sur-

veyors plat showing the exact location and giving the latit and longitude of the well.

ii.) A well data report on forms supplied by the TDWR.

b.) The permittee shall provide the health and pollution control authorities of the county, city and town where the well is located with a copy of the permit prior to start-up.

c.) The permittee shall notify the TDWR ir writing of the anticipated well start-up date.

d.) Within 20 days after the last day each quarter the permittee shall file a quarterly Report of Injection Operation.

e.) An Injection Zone Annual Report shall be filled with the December quarterly Report of Injection operation. The report shall provide an updated repor of the pressure effects of the injection well on the injection formation.

f.) The permittee shall within 45 days after completion of a test for mech nical integrity provide the data an an interpretation of the results to the TDWR.

g.) The permittee shall notify the Aust office of the TDWR within 24 hours any change in monitoring parameters which could reasonably be attribute to a leak or other failure of the well equipment or injection formati integrity.

h.) Within 60 days after the completion of a workover, a report shall be filed with the TDWR. During major workovers the bottom pressure shall be determined.

12.) Record keeping requirements are as follows:

a.) All monitoring required by the permit, including continuous records of:

i.) surface injection pressure,

ii.) tubing-long string annulus pressure,

iii.) injection flow rate.

b.) Monthly total volume of injected wastes.

c.) Periodic well tests of the following:

  i.) Injection fluid analyses,

  ii.) Bottom hole pressure determinations, and

  iii.) Mechanical integrity

d.) All records shall be made available upon request of a representative of the TDWR.

e.) The permittee shall retain for a period of three years from the date of record records of all informaiton resulting from any monitoring activities or othe records required by the permit.

APPENDIX B

THE IMPORTANCE OF DRILLING FLUID TO THE ROTARY DRILLING METHOD

THE IMPORTANCE OF DRILLING FLUID TO THE ROTARY DRILLING METHOD

The Rotary Drilling Method

The rotary drilling method employs a rotating drill string, a series of casings ans collars, to apply a force to a connected drill bit which interacts with the rock being drilled. The force applied to and the rotating action of the bit causes the rock to fail. A drilling fluid is continuously circulated down the inside of the drill string, out the nozzels of the bit, and up the annular space between the well-bore and the drill pipe to facilitate the removal of the cuttings generated by the bit. As the drilling continues additional joints of drill p are added. When the bit becomes dull the drilling mud circulation is discontinued, the drill string is removed from the hole, the bit is replaced, the drill string is run back into the hole and mud circulation is restarted. Once the mud is circulated to the surface it is diverted through a series of tanks and pits designed to allow the mud to release the cuttings it has removed from beneath the bit. The pits also provide the operator an opportunity to condition the mud so that it is capable of per-

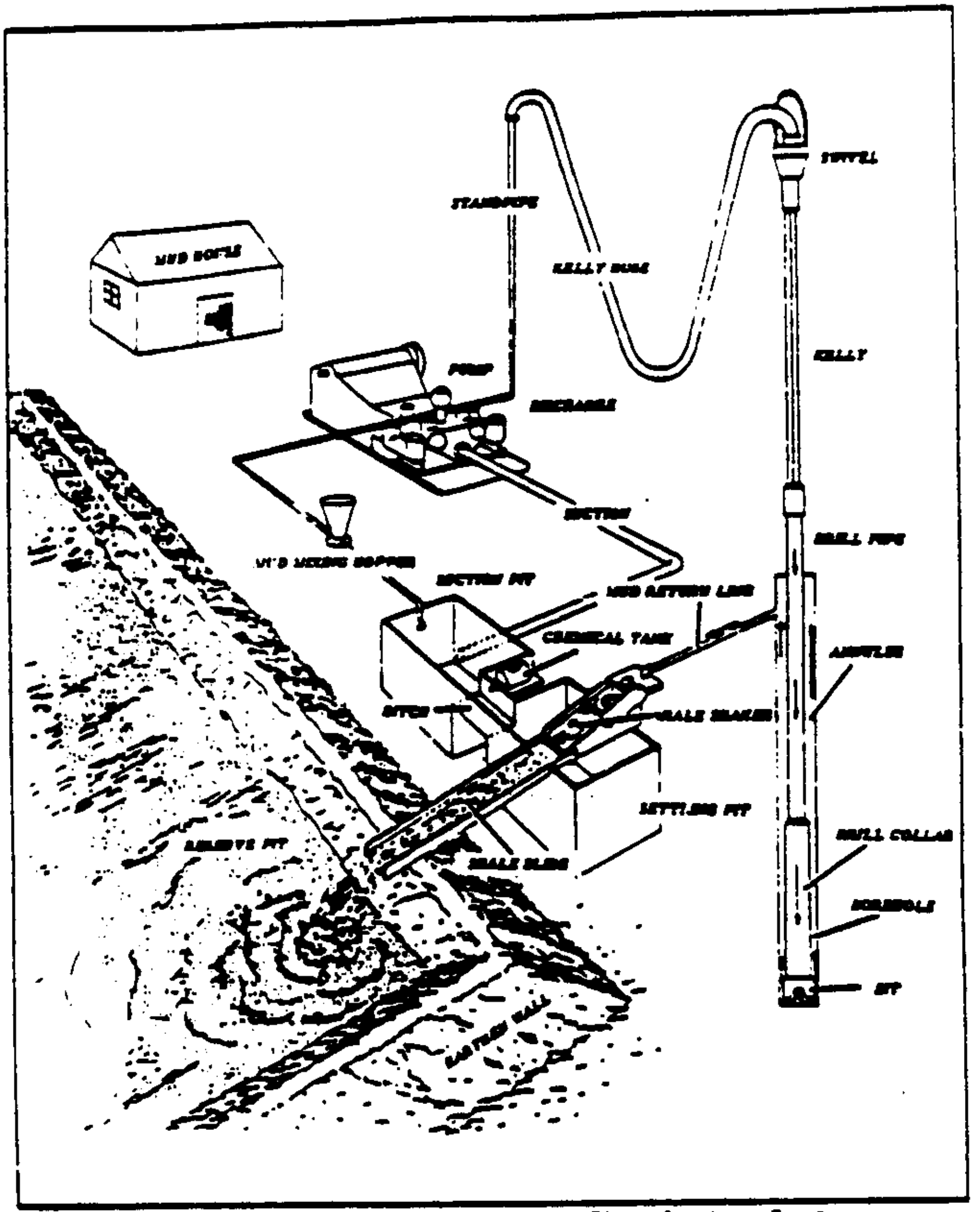


FIGURE 8. Typical Drilling Mud Circulating System
(From[23])

forming the desired functions. Figure (8) shows a typical mud circulating system.

The Functions of Rotary Drilling Fluids

Rotary drilling fluids perform the following functions:

1.) Remove cuttings from beneath the bit, transport them up the annulus, and deposit them at the surface.
2.) Cool and clean the drill string and bit.
3.) Control encountered formation pressures by preventing the inflow of formation fluids into the wellbore.
4.) Form an impermeable filter cake to seal the pores and voids in formations penetrated b the bit.
5.) Suspend cuttings during periods when circulation is suspended.
6.) Aid in the collection of information from cuttings, cores, and wireline logs.
7.) Improve the drilling rate.
8.) Release entrained gas at the surface.
9.) Trasnmit hydraulic horsepower to the drilling bit.
10.) Minimize wellbore erosion.

11.) Lower swab and surge pressures and pressures required to inetiate circulation.

Composition and Types of Drilling Fluids

A wide and varied range of fluids are utilized in the rotary drilling method. The fluids range from air and natural gas to fluids two to three times as dense as water. Table 3 lists the classifications of drilling fluids and briefly outlines their principal components and characteristics. The commonly used drilling muds consist of:[14]

1.) A continuous liguid phase (usually water).

2.) A dispersed gel-forming phase such as colloidal solids (usually bentonite clay) and/or emulsified liquids (usually oil) which furnish the desired viscosity, thixotrophy, and filter cake.

3.) Other dispersed solids such as weighting material (usually barite), sand and cuttings.

4.) Various chemicals to control mud properties within desired limits.

The choice of drilling mud for a particular well is dependant upon the geologic conditions which exist at the formation being drilled and is guided by the mud functions which are most critical to the well in question. Other

TABLE 3

CLASSIFICATION OF DRILLING FLUIDS

Classification	Principal Ingredients	Characteristics
GAS:		
Dry Air	Dry Air	Fast frilling in dry. rock No water Influs D
Mist	Air, water or mud	Wet formations but lit water influx High Annular velocity
Foam	Air, water, foaming agent	Stable rock Moderate water flow tolerated
Stable foam	Air, water containing polymers and/or bentonite;foaming agent	All "reduced-pressure" conditions: Large volu of water, big cuttings removed at low annular velocity Select polymer and fo ing agent to afford hc stability and tole[illegible] salts Foam can be formed at surface
WATER:		
Fresh	Fresh Water	Fast drilling in stab formations. Need larg settling area, floc- culants, or ample wat supply and easy dispo
Salt	Sea Water	Brines for density increase and lower freezing point Limited to low perm r
Low Solids Muds*	Fresh water, poly- mer, bentonite	Fast drilling in comp ent rocks Mechanical solids rem equipment needed Contaminated by cemen soluble salts

---

NOTES:

Detergents, lubricants, and/or corrosion inhibit[illegible] be added to any water composition

* When barite is added to raise the density of thes muds, they are called "nondispersed" muds.

TABLE 3 CONT

CLASSIFICATION OF DRILLING FLUIDS

Classification	Principal Ingredients	Characteristics
Spud Mud	Bentonite and water	Inexpensive
Salt Water Muds*	Sea water, brine saturated salt water, salt-water clays, starch, cellulosic polymers	Drill rock salt Work overs Drilling salts other than halite may require speci treatment
Lime Muds*	Fresh or brackish water, bentonite(or native clays), lime, chrome-lignosulfonate Lignite, sodium chromate and surfactant for high temperatures	Shale drilling Simple maintenance at medium densities Max. temp. 300°F with lign added
Gyp Muds**	Same as lime muds, except substitute gypsum for lime in above composition	Shale drilling Simple maintenance Max. temp. 325°F Unaffected by anhydrite, cement, moderate amount of salt pH 9-10
CL-CLS Muds**	Fresh or Brackish water, bentonite caustic soda, chrome lignite, chrome-lignosulfonate Surfactant added for high temperature	Shale drilling Simple maintenance Max Temp. 350°F Same tolerance for conta inants as gyp muds pH 9-10

NOTES:

*Diesel oil is often added to these muds, frequently along with an emulsifying agent.

**Temperature stability of these muds is increased b removing calcium and adding lignite and surfactant (DMS)

TABLE 3 CONT

CLASSIFICATION OF DRILLING FLUIDS

Classification	Principal Ingredients	Characteristics
Potassium Muds	Potassium chloride acrylic, bio or cellulosic polymer, some bentonite	Hole stability Mechanical solids-remov equipment necessary Fast drilling at minimu solids content pH 7-8
OIL:		
Oil	Weathered crude oil Asphaltic crude + soap + water	Low-pressure well compl ion and workover Drill shallow, low-pres sure productive zones Water can be used to increase density and cutting-carring abili
Asphaltic Muds	Diesel oil, asphalt, emulsifiers, water 2-10%	The composition of oil muds can be designed satisify any density hole stabilization requirements and erature requiremen 600°F
Non-Asphaltic Muds ("Invert")	Diesel oil, emulsifiers, oleophilic clay, modified resins and soaps, 5-40% water	High initial cost and environmental restric ions, but low maintenance cost

NOTES:

(1) Density of oil muds can be raised by addition calcium carbonate or barite.

(2) Calcium chloride is added to the emulsion wate phase to increase shale stability.

(From Gray, Darley & Hog

significant factors include economics and the availabilit of make-up water.

Important Static Drilling Fluid Properties

Two of the properties of drilling fluid which enable it to perform its required functions are also important when determining the pressures which act on a static mud column in an abandoned well. These properties must be understood in order to evaluate the pressures which could cause formation fluids to migrate up an abandoned wellbore. The pertinent properties are the gel strength and the mud density. A review of the functions these mud properties perform provides background information which may be helpful when attempting to evaluate the pressures which act at the static wellbore.

The Importance of Controlling the Gel Strength in Drilling Fluids

Proper control of the gel strength of a drilling fluid is essential to the adequate functioning of the mu The gel strength must be high enough to suspend cuttings during periods of non-circulation, but low enough to:[15]

1.) Allow sand and shale cuttings to settle out and entrained gas to escape in the mud pits.
2.) Permit ready breaking of circulation as the pum is started.

3.) Minimize swabbing effects when pulling the drill string from the hole.

The most common causes of high gel strength during drilling are:

1.) Insufficient deflocculation of the clay colloids which may require the addition of chemical thinners.

2.) To high a concentration of solids; the accumulated solids must be reduced by dillution or mechanical seperation.

3. Contamination from drilling anhydrite, gypsum, cement rock salt or from a salt-water flow: The effects of the contaminants can be nullified by using thinners and filtration control agents.

Blow outs may result if the gel strength is too high. High gel strengths require excessive pump pressure to initiate mud circulation thus the increased pressure m be sufficient to fracture a weak formation and cause lost circulation. High gel strength may cause a suction when pulling the drill pipe out of the hole, this situation ma swab formation fluid into the hole producing a kick whicl could lead to a blowout.

The Removal of the Bit Cuttings

The removal of cuttings from beneath the bit and the transport of the cuttings to the surface is the mary function which all rotary drilling fluids must perform effectively if the bit penetration is to progress optimally. The bit nozzel and annulus velocities of the drilling mud circulated during drilling operations are the chief factors which control cutting removal and transport, respectively. Annulus velocities between 100 and 200 ft/min are frequently used. The annular mud velocity is dependant on pump capacity, pump speed, bore hole size and drill pipe size. The viscisity of the mud determines the efficiency of the cuttings removal for a specific velocity. While changing bits and during other periods of inactivity, the drilling fluid must be capable of suspending the cuttings being circulated to the surface. If the cuttings are not suspended during non-circulation they will fall back towards the bottom of the hole where they could cause the bit or drill collars to stick and produce an expensive fishing job.

Mud Properties Which Enable the Static Mud Column to Suspend Cuttings

The primary mud property which acts to suspend cuttings in the static mud column is the gel strength. Gel strength is the result of a gelled structure which developes in common drilling fluids when they remain in a quiescent state. The gel structure acts to support the weight of the suspended cuttings. Since the bouyance force exerted by a static fluid increases with its density, an increas in mud density will result in a greate ability of the mud to support cutting during periods of non-circulation.

Controlling Formation Pressures

The mud density also accomplishes another important function, that of controlling encountered formation pressures by preventing the inflow of fluids into the wellbore. It is imperative that the mud density be fully controlled since serious drilling hazards may result if it isn't. A fluid kick may result if the formation pressure exceeds the static mud column pressure. The kick occurs when the formatin fluid (gas, oil or water) enters th bore hole. As the fluid rises up the annulus, it expands and displaces the drilling mud contained in the annulus. The loss of mud in the annulus further reduces the static mud column pressure, allowing more fluid to enter the wellbore. If the situation is not brought under control blowout could result. When the density of the mud is excessive, the pressure of the static mud column may be sufficient to fracture weak formations which could resul in lost circulation. Lost circulation is defined as a significant loss of drilling mud to a formation. When this occurs the mud column will drop and a reduction in the static mud column pressure results.

If the static mud column pressure drops below the formation pressure the risk of a blowout will again be encountered. The normal pressure gradient, the gradient utilized to determine the formation pressure in normally pressured zones, is considered to be the pressure exerted by a column of typical formation water and is equal to 0.465 psi/ft of depth in the Texas Gulf Coast Area.

APPENDIX C

THEORY OF PRESSURE BUILDUP IN INJECTION ZONES

THEORY OF PRESSURE BUILDUP IN INJECTION ZONES

The Diffusivity Equation

Mathews and Russell[12] developed the basic differential equation for the unsteady state radial flow of a slightly compressible fluid from an injection well. The diffusivity equation provides the fundamental means of investigating the fluid flow which occurs in porous media. The equation is derived by applying the idea of continuity to a general mass balance:

$$\frac{\partial}{\partial X}\left(\rho\frac{K_x}{u}\frac{\partial\phi}{\partial x}\right)+\frac{\partial}{\partial y}\left(\rho\frac{K_y}{u}\frac{\partial\phi}{\partial y}\right)+\frac{\partial}{\partial z}\left(\rho\frac{K_z}{u}\frac{\partial\phi}{\partial z}\right)=\frac{\partial}{\partial t}(\phi\rho)$$

The following assumptions are applied to reduce the diffusivity equation to a usable form:

1.) single fluid of samll and constant compressibility
2.) homogeneous, isotropic, and constant thickness porous media
3.) negligible gravity effects
4.) constant fluid viscosity and media porosity
5.) horizontal flow
6.) radial flow

Utilizing the assumptions, equation (C-1) is simplified the following differential form:

$$\frac{1}{r}\frac{\partial}{\partial r}\left(r\frac{\partial P}{\partial r}\right) = \frac{\phi u c}{k}\frac{\partial P}{\partial t}$$

Constant Injection Into a Reservoir of Infinite Areal Extent

The following boundary conditions are applied to solve the differential equation:

Initial conditions: $\lim\limits_{r \to \infty} P(r,t) = P_i$

$$\lim_{r \to 0}\left(r\frac{\partial P}{\partial r}\right) = \frac{-qu}{2\pi kh}$$

The initial conditions establish the initial pressure throughout the reservoir, and ensures that the system maintains an unsteady state flow. The second condition requires that the flow must approach steady state radial flow when the fluid is at the infinitely small wellbore.

Define a variable,   as:

$$\eta = \frac{\phi u c r^2}{4kt}$$

$$\frac{\partial \eta}{\partial r} = \frac{\phi u c r}{2kt}$$

$$\frac{\partial \eta}{\partial t} = \frac{\phi u c r^2}{4kt^2}$$

By the chain rule:

$$\frac{1}{r}\frac{\partial}{\partial \eta}\frac{\partial \eta}{\partial r} \quad r\frac{\partial P}{\partial \eta}\frac{\partial \eta}{\partial r} = \frac{\phi u c}{k}\frac{\partial P}{\partial \eta}\frac{\partial \eta}{\partial t} \qquad \text{(C-3)}$$

By substitution:

$$\frac{1}{r}\frac{\partial \eta}{\partial \eta}\frac{\phi u c r}{2kt} \quad r\frac{\partial P}{\partial \eta}\frac{\phi u c r}{2kt} = \frac{\phi u c}{k}\frac{\partial P}{\partial \eta}\frac{-\phi u c r^2}{4kt^2} \qquad \text{(C-4)}$$

Simplifying:

$$\phi\frac{uc}{kt}\frac{\partial}{\partial\eta}\left(\frac{\partial P}{\partial\eta}\frac{\phi ucr^2}{4kt}\right) = \frac{\phi uc}{kt}\frac{\partial P}{\partial\eta}\left(-\frac{\phi ucr^2}{4kt}\right) \tag{C-5}$$

Setting things in terms of η :

$$\frac{\partial}{\partial\eta}\left(\eta\frac{\partial P}{\partial\eta}\right) = -\eta\frac{\partial P}{\partial\eta} \quad \text{or} \tag{C-6}$$

$$\frac{d^2P}{d\eta^2} + \frac{dP}{d\eta} = -\eta\frac{dP}{d\eta}$$

let $P' = \frac{dP}{d\eta}$

$$P-P_i = \frac{-qu}{4\pi kh}\,E_i(-\eta) \tag{C-12}$$

Converting back to polar coordinates:

$$P(r,t) = P_i \quad \frac{qu}{4\pi kh}\,E_i\left(\frac{-\phi ucr^2}{4kt}\right) \qquad \text{(C-13}$$

The formation volume factor can be incorporated to exp the bottom hole flow rate q or BQ where Q is surface volume flow rate and the equation for constant rate injection by a single well can be presented for use in this report as:

$$P(r,t) = P_i - \frac{QuB}{4\pi kt}\,E_i\left(\frac{-\phi ucr^2}{4kt}\right) \qquad \text{(C-14}$$

Superposition

The method of superposition allows the modification of equation (C-14) to allow the incorporation of variable flow rates and multiple wells. The modification for variable rate provides the following equation:

$$P(x,\ y,\ t) = P_i - \frac{B\ u}{4\ kt} \sum_{j=i}^{m} \sum_{i=1}^{nj} \Delta\ Q_{ij}\ E_1 \left(\frac{-ucr^2_j}{4k(t-t_{ij})} \right) \text{(C-}$$

where: Q_{ij} = is rate in well j at time t_{ij}

$rj = \sqrt{(x-xj)^2 + (y - yj)^2}$

$xj,\ yj$ = coordinates of well j

$x,\ y$ = coordinates where P is evaluated P(x, y,

For $t > t_{nj}$

NOMENCLATURE

B = Reservoir fluid formation volume factor, reservoir volume/surface volume

c = Fluid compressibility, 1/atmospheres

h = Formation thickness, ft

k = Permeability, darcys

P = Formation pressure, atmospheres

P_i = Initial formation pressure, atmospheres

q = Flow rate, cm^3/sec

Q = Flow rate, cm^3/sec

rij = Radial distance from the injection well, cm

t = Time, sec

t_i = Starting time of 1th well, sec

u = Viscosity, cp

ϕ = Porosity, fraction

APPENDIX D

DETERMINATION OF GEL STRENGTH

DETERMINATION OF GEL STRENGTH

Introduction

When common use, water base drilling fluids remain in a quiescent state a gel structure develops. The strength of this structure is important since the difference between the formation pressure and the static mud column pressure would have to be sufficiently large to break the gel structure before the drilling mud can flow freely in an abandoned well bore. To calculate the formation pressure increase which is required to break the gel strength structure a means of determining the value of the gel strength of the drilling mud is required.

Since the gel strength varies with the mud type and the conditions that act on the mud it is difficult to determine the exact gel strength of the mud in a particular abandoned well bore. To overcome this difficulty it is necessary to review the gel strength characteristics of various mud types and evaluate the factors which act to alter the gel strength structure. The aim of this review is to provide sufficient information to determine the minimum gel strength structure that could be anticipated for any combination of formation, well bore and mud type. The determined minimum gel strength value will be utilized to determine the gel strength pressure for adandoned wells in a given waste injection scheme. The calc lated gel strength will allow the determination of the formation pressure increase which can result from the waste injection without rupturing the gel strength structure. The following discussion is devoted to the determination of a minimum gel strength value.

Thixotropy

Thixotropy is defined as the property exhibited by certain gels of liquifying when stirred or shaken and returning to the hardened state upon standing.[16] To understand the thixotrophic properties of drilling muds some knowledge of clay minerology is necessary. Nearly all aqueous drilling fluids and some oil-based drillinc fluids utilize clay as their colloidal base. Due to their size definition all clay particles fall into the colloidal particle range. Colloidal systems utilized in drilling fluids include solids dispersed in liquids and liquid droplets dispersed in other liquids. These colloidal systems define clay suspension and emulsion muds, respectively. The highly active colloidal paticles comprise a small percentage of the total solids in drilling muds but act to form the dispersed gel forming phase of the mud which furnishes the desired viscosity, thixotropy, and wall cake. Clay particles and organic colloids comprise the two classes of colloids used in mixing of drilli fluids. The common organic colloids include starch, carboxycelluloses (CMC) and polyacrylomine derivatives.

The clay colloids utilized in common drilling fluids are characterized by a crystaline structure which influences the ability of the clay to retain water. Clays used in fresh water muds consist of hydrated alumnosilicates comprised of alternate plates of silica and aluminum to form layers of each mineral. The plate-like crystals have two distinct surfaces: a flat face surface and an edge surface. Slight surface polarities induce weak electrostatic forces along the faces and edges of the mineral plates. Garison[17] noted that these electrostatic forces attract planer water to the colloidal particles forcing the clays to swell when wet and shrink when dry. The attraction of planer water to the faces of the plates is greater than the attraction of the sheets for each other therefore the structure tends to swell due to the absorbsion of the planer water from the drilling fluid. The bentonite clays demonstrate a strong ability to attrac planer water as a result they experience extreme swelling. When in contact with fresh water, the face to face attraction of water by the mineral layers will continue until the swelling reduces the attraction of the plates to the point where they seperate. This seperation results in a higher number of particles and is referred to as dispersion. The dispersion causes the colloidal suspension thicken. The degree of thickening depends on the electrolytic content, salt concentration of the water, time, temperature, pressure, Ph, the exchangeable cations on the clay, and the clay concentration.

Gel Strength, The Measure of Thixotropy

Thixotropy is essentially a surface phenomenon which is characterized by gel strength measurements. The gel strength indicates the attractive forces between particles under static conditions. The strength of the gel structure which forms under static conditions is a function of the amount and type of clays in suspension, time, temperature, pressure, Ph, and the chemical treating agents used in the mud. The factors which promote, the edge-to-edge and face-to-edge assocation of the clay particles, flocculation increase the gelling tendancy of the mud and those factors which prevent the association decrease the gelling tendancy.

Due to their size, colloidal particles remain indefinately in suspension. When suspended in pure wate the clay particles will not flocculate. When flocculati occurs the particles form clumps or flocs. These loosel associated flocs contain large volumes of water. If the clay concentration in the mud is sufficiently high, floc culation will cause formation of a continuous gel structure instead of individual flocs.

The gel structure commonly observed in aqueous drilling fluids results from salt contamination. Soluable salts are usually present in sufficient quantities to cause at least a mild flocculation. The time required for the gel to attain an ultimate strength depends on the critical concentration of electrolyte required to initiate flocculation, the thinners present, and the concentration of the clay and of the salt present. During drilling the presence of salts and clay particles varies with each formation being drilled, therefore the drilling fluid is monitored and adjustments are made in order to maintain the desired gel strength.

Gel Strength of the Static Mud Column

Gel strength is measured by a multispeed direct indicating viscometer by slowly turning the driving shaft by hand and observing the maximum deflections before the gel structure breaks. The gel strength is normally measured after a quiescent period of 10 seconds (initial gel strength) and 10 minutes. The measurements are taken at surface conditions of standard temperature and pressure. To determine the gel strength of the static mud column in an abandoned well it is necessary to determine the gel strength of the mud under the influence of bore hole conditions. The initial and 10 minute gel strengths bare no direct relation to the ultimate gel strength of the mud at bore hole conditions. To determine the ultimate gel strength of a mud it is necessary to discuss the factors which act to influence the initial gel strength at bore hole conditions.

Once the drilling operation is completed and the well is abandoned the mud is subjected to conditions vastly different from those encountered at the surface. In the range of formation depths utilized for disposal of industrial wastes the temperature would be expected to range from 80 to 300°F, the pressure from 1500 to 5000 psi and time from days to several years. Several studies have been conducted to determine the impact of time, temperature and pressure on the gel strength of muds at bore hole conditions. The information obtained from this research should provide a means of determining a reasonable minimum gel strength value for the abandoned wells which exist in the range of formations described above.

It is observed that common use water base muds develope high gel strengths after prolonged periods of quiescence. The relationship between gel strength and time varies widely from mud to mud, depending on the composition, degree of flocculation, temperature, Ph, solids and pressure. Figure (9)[18] indicates the increase in ge strength with time for various mud types and reveals that there is no well established means of predicting long term gel strengths with time. It is noted in all cases that the gel strength is observed to increase.

Garrison[17] studied the gel strength in relation to time and rate of reaction for california bentonites. He observed that both the speed and the final strength increased with the bentonite percentages. The gelling was found to follow the equation:

$$S = \frac{S'kt}{1+kt} \qquad (D-1)$$

where S is the gel strength at any time t, S' is the ultimate gel strength, and k is the gel rate constant. Figure (10) indicates that the gel strength forms more rapidly at first then gradually approaches an ultimate value as time elapsed. Equation (D-1) may be rewritten as:

$$\frac{t}{S} = \frac{t}{S'} + \frac{1}{S'k} \qquad (D-2)$$

which indicates that a plot of t/S verses t should be a straight line. Figure (11) represents the graph of t/S verses t, and indicates the slope of the line is k and th y-intercept is 1/S'k. This approach provides a means to evaluate the ultimate gel strength for each bentonite con centration. Table 4 represents the ultimate gel strength and rate constants for the five samples shown in figures (10) and (11). Garrison also made measurements on simila

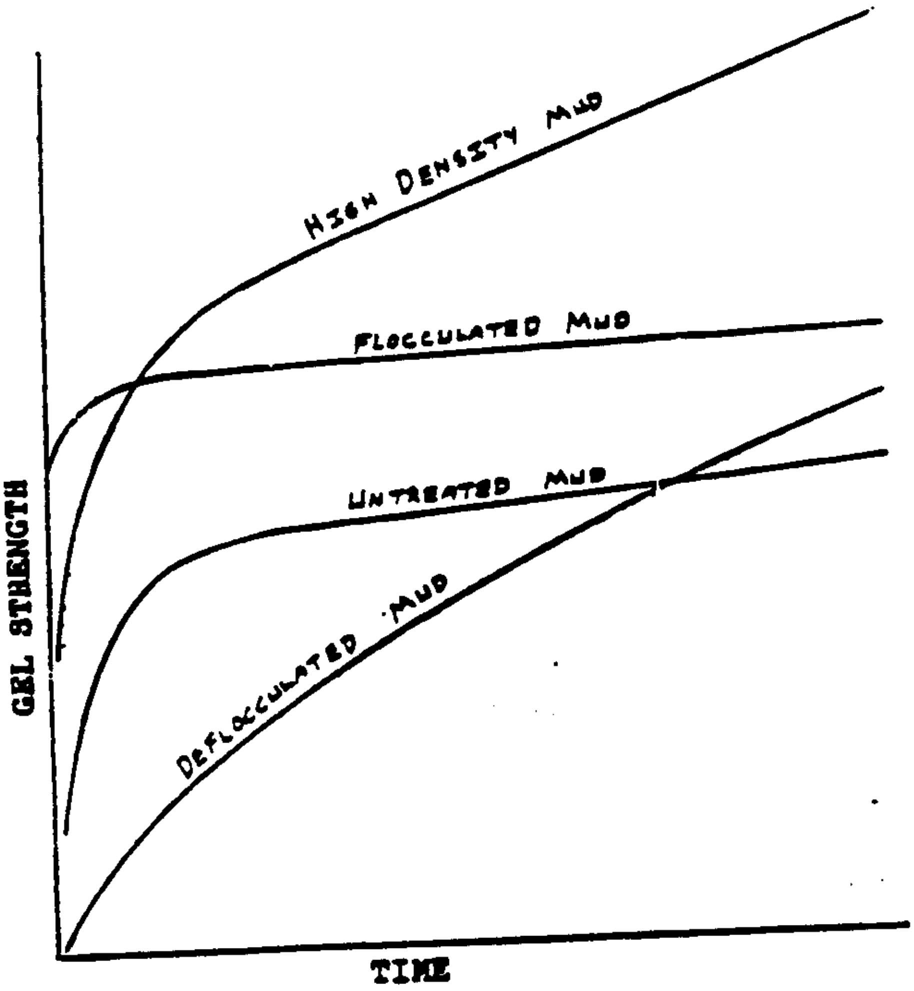


FIGURE 9. Increase in gel strength of various mud types with time (From Gray, Darley, and Rogers[18])

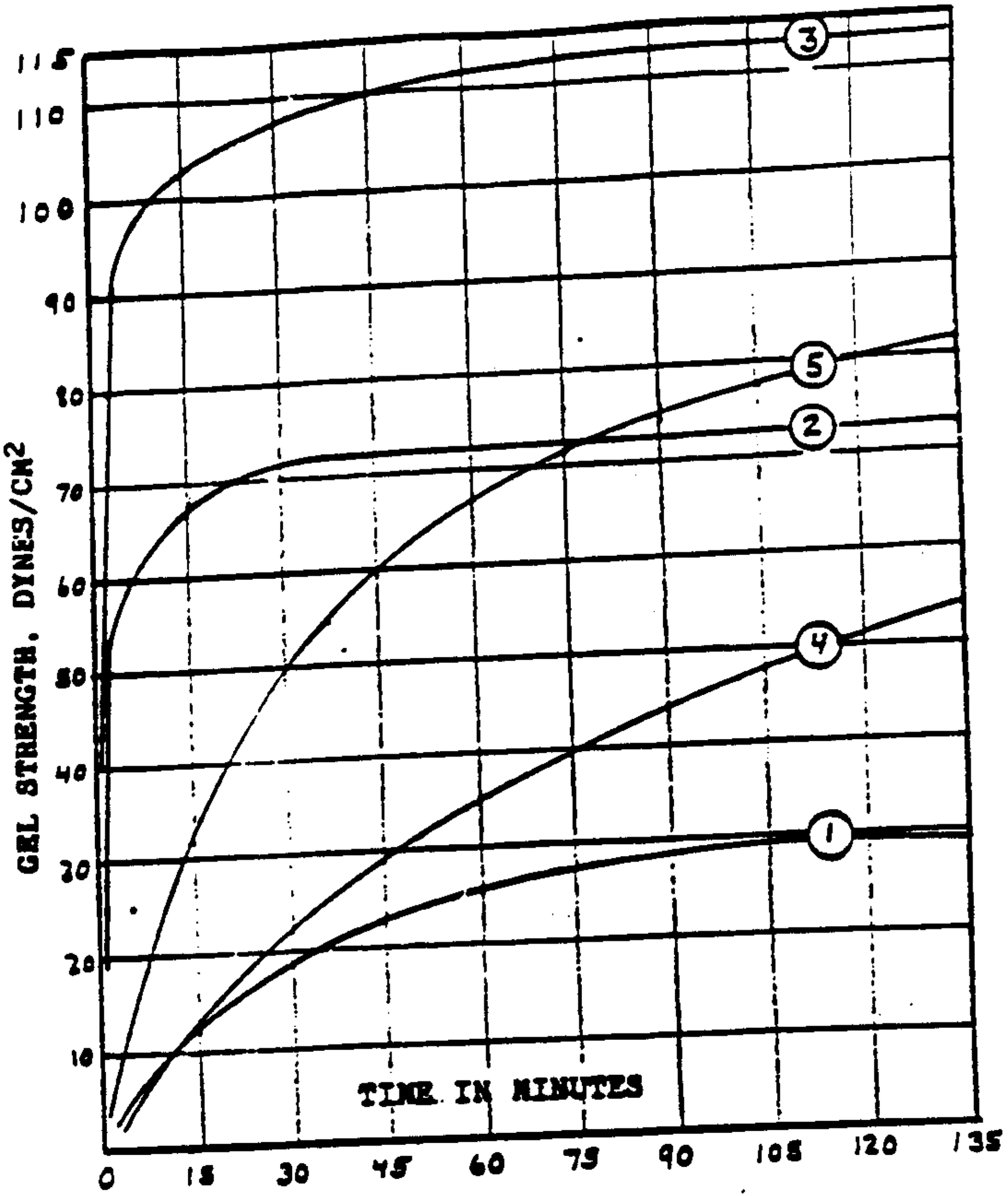


FIGURE 10. Gel Strength in relation to time and rate of reaction (From Garrison[17])

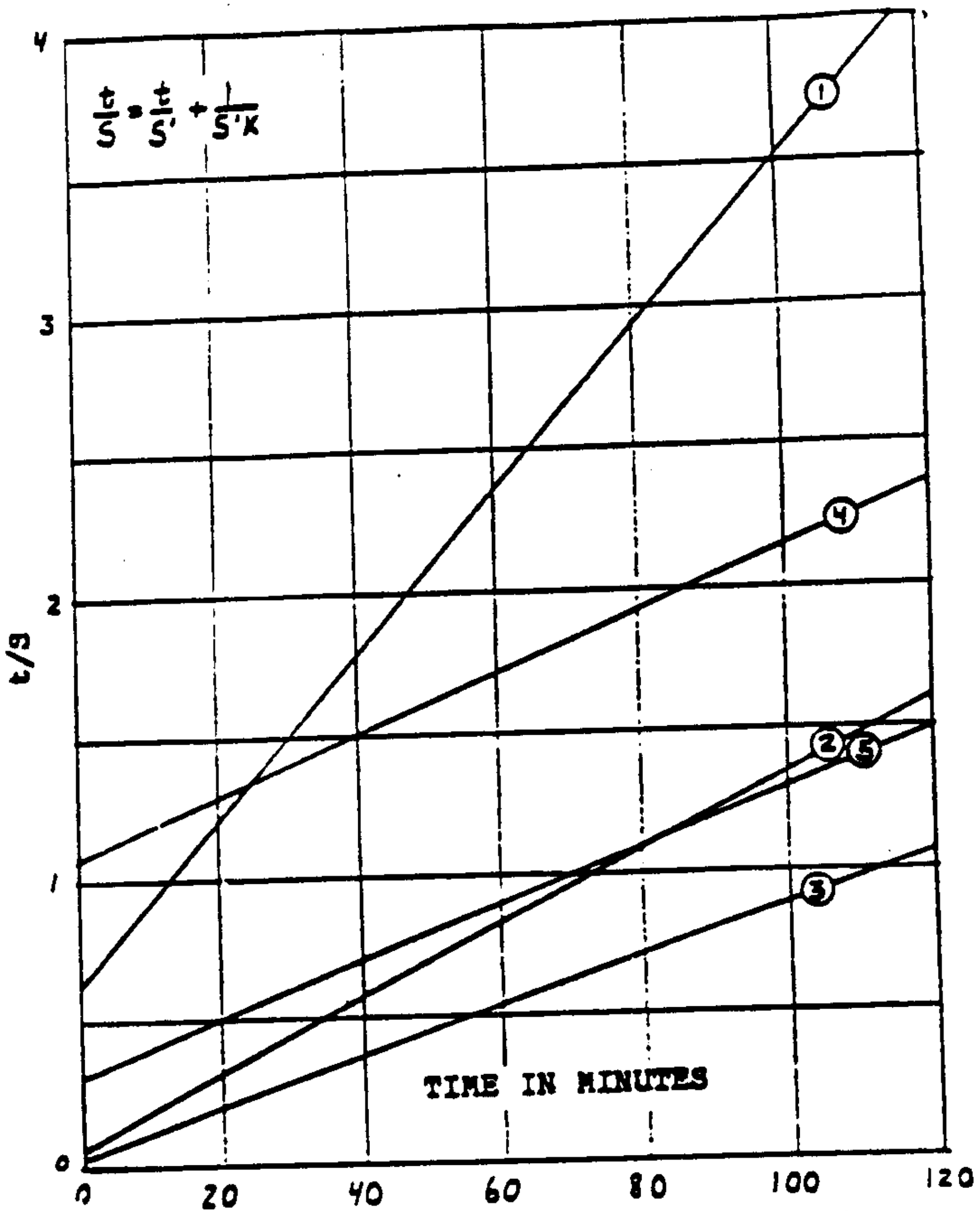


FIGURE 11. Gel Strength and Rate Constants

(From Garrison[17])

suspensions at higher Ph and determined that the ultimate strengths of the bentonite gels increased with each suspension as the Ph increases. Table 5 refects the Ph - ultimate gel strength relationship observed.

Garrison also noted that the treating of muds with thinners had the effect of decreasing the rate of gelling but not the ultimate gel strength. Thus it can be concluded that the reduced initial and 10 minute gel strengths recorded for treated muds reflect the reduced rate of gelling and do not indicate that the ultimate gel strength will be any less than that recorded for an untreated sample of the same mud. In fact, the ultimate gel strength may even increase as indicated in table 4.

Garrison's work does not indicate that all muds comply with equation (D-2), but it does point out that the initial and 10 minute gel strengths do not provide a reliable means of predicting the ultimate gel strength. Weintritt and Hughes[19] conducted progressive gel strength tests on ferrochrome lignosulfonate muds for periods up to 16 hours and obtained the results presented in table 6. They noted that although mud E and mud F had similar properties, Mud F developed only a moderate gel strength while that of Mud E was much greater. Once again it is observed that the initial gel strength and 10 minute gel strength measurements are not always indicative of gel

TABLE 4

GEL RATE CONSTANTS CALCULATED FROM FIGURE 5

Bentonite Per Cent	Sample #	Additives	Gel Strength (Ultimate)	Rate Constan
4.5	1	---------	34.4	0.047
5.5	2	---------	74.4	0.75
6.5	3	---------	114.	0.79
5.5	4	0.1% Na Tannate	104.	0.0089
5.5	5	Sodium Hydroxide	99.7	0.033

(From Gray, Darley and Rogers[18])

TABLE 5

CONSTANTS IN GELLING EQUATIONS OF BENTONITE SUSPENSIONS

Bentonite Per Cent	Gel Strength and Rate Constant	pH+ 9.2	pH+ 9.3-9.5	pH+ 9.9-10	pH+ 10.8-11
4.5	S'	34.4	40.1	48.5	69.6
4.5	k	0.047	0.071	0.076	0.063
5.5	S'	74.4	82.2	129.9	152.7
5.5	k	0.75	0.22	0.13	0.18
6.5	S'	114.	141.	250.	268.
6.5	k	0.79	0.30	0.10	0.25

(From Garrison[17])

TABLE 6

COMPARISON OF MUD PROPERTIES WITH PROGRESSIVE GEL-STRENGTH TESTS, GYP-FERROCHROME LIGNOSULFONATE EMULSION MUDS

		SAMPLE			
		Mud E	Mud F	Mud G No Treatment	Mud G 1 lb/bbl FCL
Weight, unstirred, lb/gal		11.0	10.7	10.6	
Weight, stirred, lb/gal		11.0	10.3	10.7	
Plastic Viscosity, cp		14	23	16	15
Yield Point, lb/100 sq ft		3	6	2	1
10-sec gel, lb/100 sq ft		1	2	1	0
10-min gel, lb/100 sq ft		8	8	7	3
API filtrate, ml		6.2	3.3	5.2	2.9
pH		10.9	10.6	10.5	10.4
Composition:	Water % by vol	76	63	75	
	Oil, % by vol	5	11	9	
	Solids, % by vol	19	16	16	
	Solids, % by wt	39	36	37	
	Solids, SG	2.7	2.9	3.0	
Filtrate Ion Analysis:	Chlorides ppm	3500	400	3000	
	Sulfate, epm	250	300	130	
	Carbonate, epm	24	28	12	
	Bicarbonate, epm	12	160	12	
	Calcium, epm	44	52	44	

Progressive Gel Strengths (lb/100 sq ft)	Temperature (°F)							
Time	75°	180°	75°	180°	75°	180°	75°	180°
0 minutes	1	1	2	2	1	1	0	0
3 minutes	2	3	2	5	3	8	1	1
10 minutes	8	18	8	12	7	26	3	3
30 minutes	15	40	11	18	17	58	5	5
60 minutes	27	90	18	16	29	91	6	6
2 hours	31	145	22	22	29	104	7	7
4 hours	37	190	29	42	46	172	10	10
8 hours	46	190	33	42	95	320	25	25
16 hours	80	320	40	57				

(From Weintritt and Hughes[19])

strength development which is observed at elevated temperatures and extended time. The trhee muds designated in table 6 were obtained from wells within the same field just prior to cementing operations.

Annis[20] noted that when a bentonite mud is quiescent, the gelling process depends on both temperature and time. Annis compared the effect of temperature on the initial and 30 minute gel strength of an 18 ppb bentonite suspension. Figure (12) indicates that the 30 minute gel strength of the 18 ppb suspension is at any temperature the approximately six times the initial gel strength. the dependance of gel strength on time at different temperatures, as noted by Annis, is shown in figure (13). Based on these and other tests of up to 18 hours Annis concluded that there is a strong indication that gel strength increases indefinately with time.

In review, the above works indicate that the ultimate gel strength of water base muds is considerably higher than the values recorded for the initial and 10 minute gel strength. Although there is no direct relationship between gel strength and time it is possible, based on available information, to conclude that the ultimate gel strength of a mud will be several times larger than the initial or 10 minute gel strength of the mud. reference to the work by Garrison,[17] it is possible to

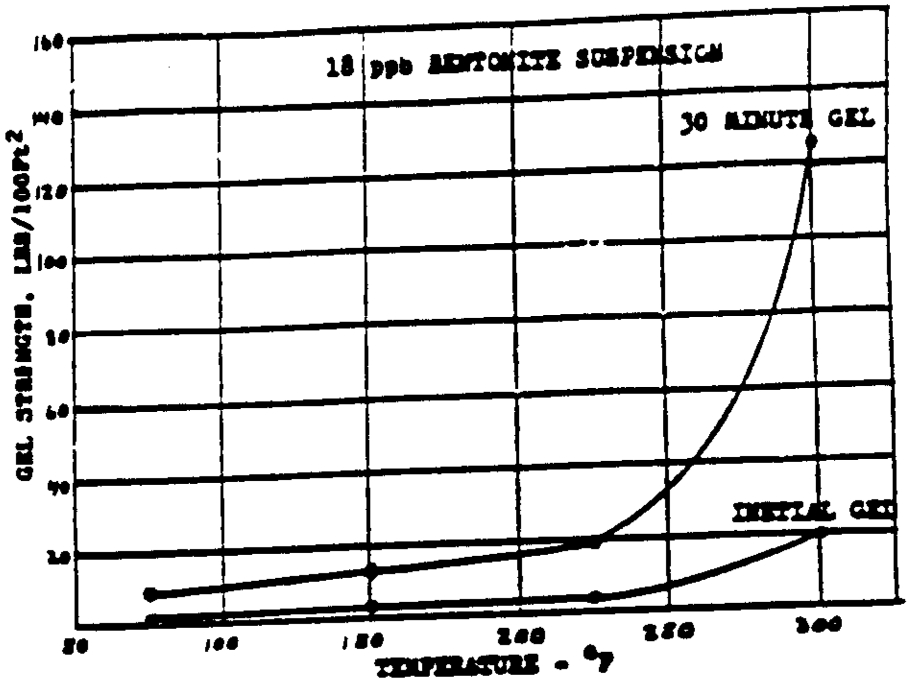


FIGURE 12. Effect of temperature on Initial and 30-Minute Gel Strengths (From Annis[20])

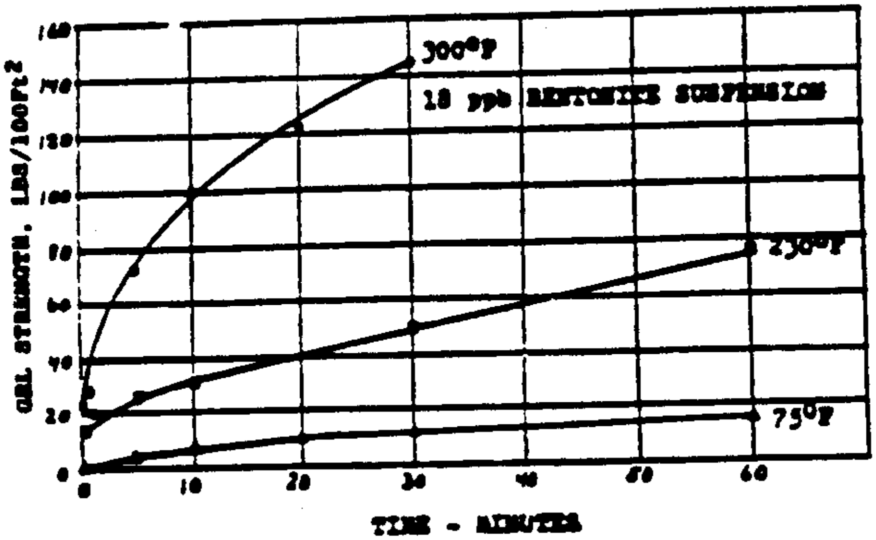


FIGURE 13. Effects of Time and Temperature on Gel Strength (From Annis[20])

consider the ultimate gel strength of a treated mud to b equivalent to that of a similar mud that was not treat since the effect of the thinner is to decrease the rate o gelling and not the ultimate gel strength obtained.

In addition to time, temperature can have a major effect on the gel strength of water based drilling fluids Srini-Vasan[21] studied the effects of temperature on the gel strength of several water based drilling muds. Table 7 lists the muds which were tested and figures (14), and (15) indicate the temperature verses gel strength relationships obtained. In most of the cases investigated by Srini-Vasan it was noted that the gel strength leveled of after 160°F. The emulsion and lime treated muds showed change in gel strength with increase of temperature. was found that each mud had its own characteristic curve and no quantitative interpretation was possible. The wo of Weintritt and Hughes[16] as noted in table 6, indicates that emulsion mud G experienced no change in gel strengt in going from 75 to 180°F over a wide range of times. I is noted that although the gel strength did not vary wit temperature, it went from an initial gel strength of 0 t a gel strength of 25 after 16 hours.

The equipment utilized by Srini-Vasan restricte his investigation to temperatures up to 220°F. Annis[20] was capable of investigating the gel strenght u

TABLE 7

COMPOSITION OF THE MUD SAMPLES TESTED FOR GEL STRENGTH

SAMPLE NUMBER	COMPOSITION OF THE MUD**
33	2 per cent bentonite mud
34	3 per cent bentonite mud
35	4 per cent bentonite mud
39	10 lb/gal. 4 per cent bentonite. barite mud
43	10 lb/gal. 10 per cent (by volume) Diesel oil. 4 per cent bentonite. barite, emulsion mud
47	10 lb/gal. 4 per cent bentonite. barite, surfactant (DAS) mud
49	10 lb/gal. low lime (1 lb/bbl) treated 4 per cent bentonite, barite mud

** All muds referred to are water base muds.
All per cent quantities mentioned denote weight per cents, unless other wise designated.

(From Srini-Vasan[21])

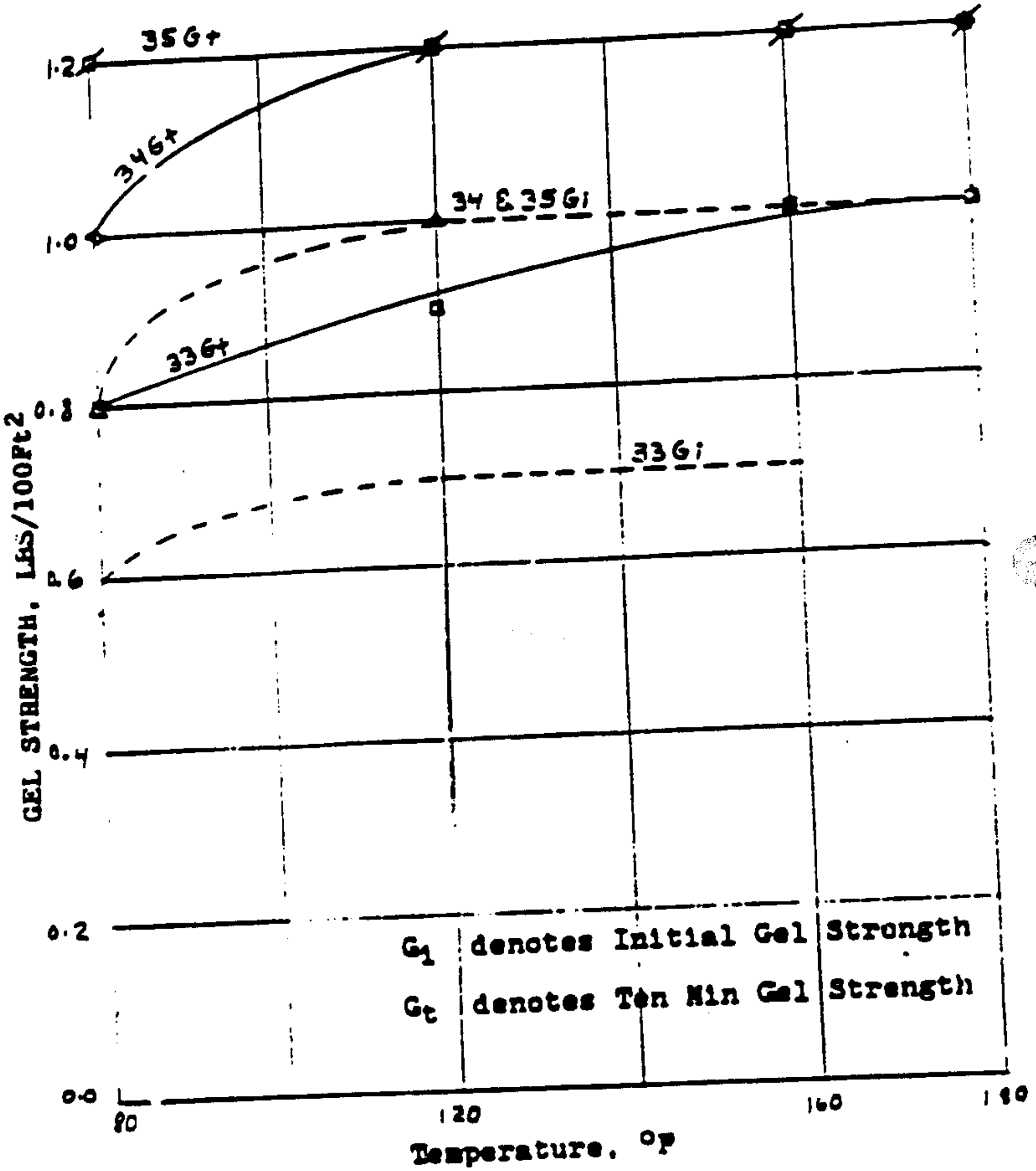


FIGURE 14. Gel Strength versus Temperature for Bentonite-water muds (From Srini-Vasan[21])

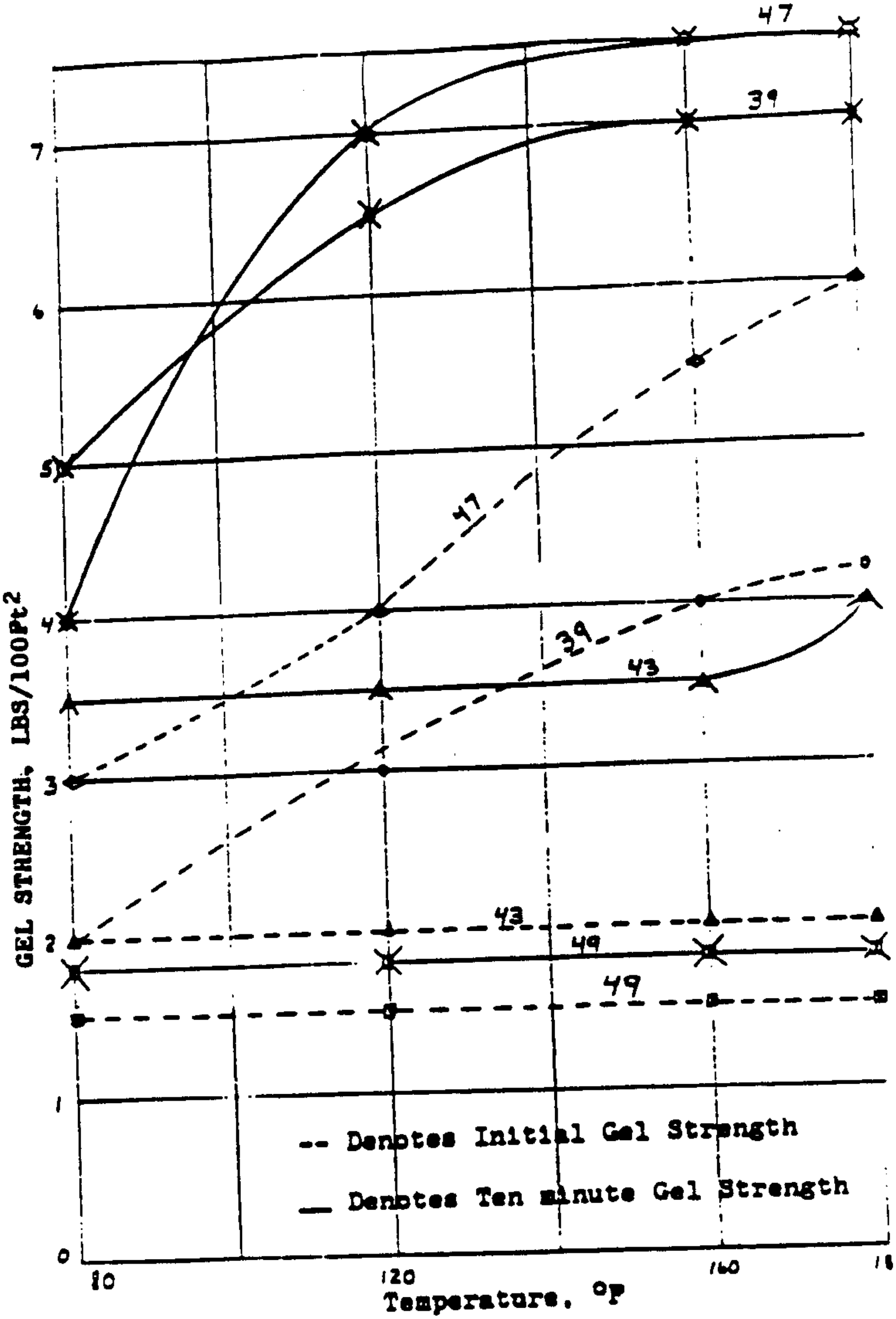


FIGURE 15. Gel Strength versus Temperature for different muds (From Srini-Vasan[21])

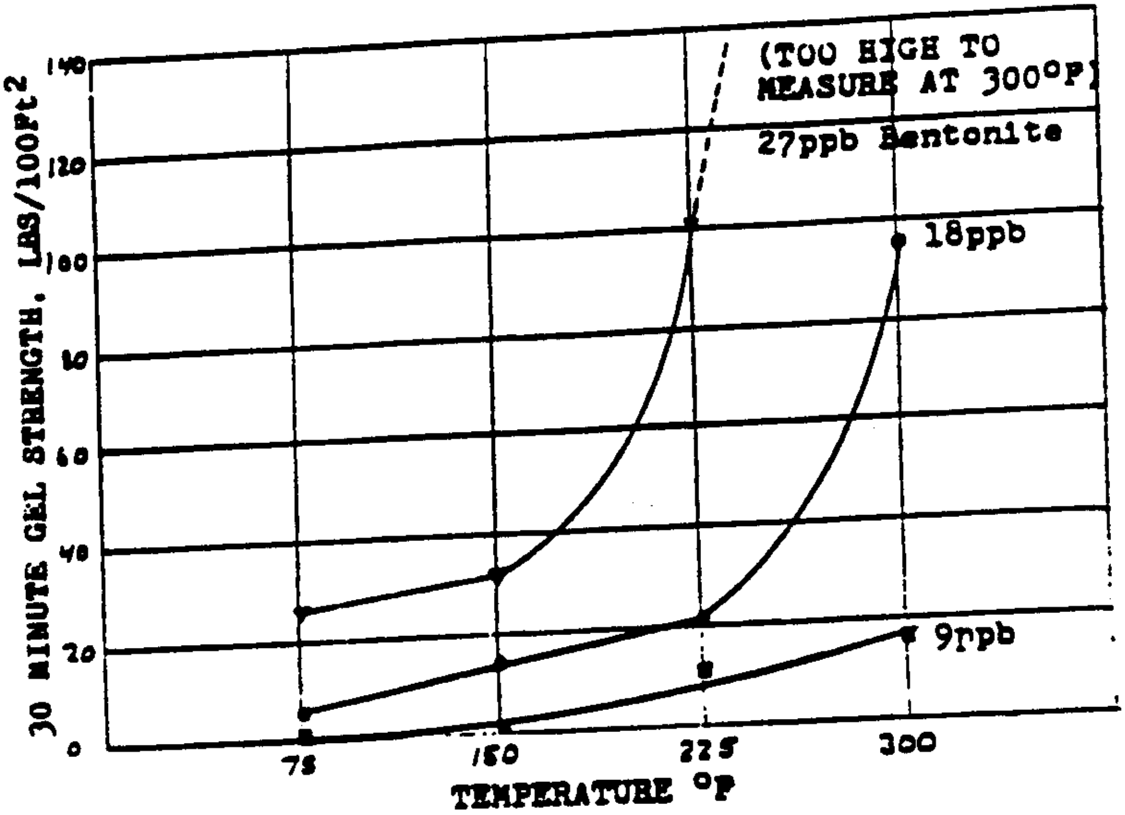


FIGURE 16. Effects of Temperature and Bentonite concentration on 30-Minute Gel Strength (From Annis[20])

to temperatures of 350°F. Srini-Vasan observed that the gel strengths leveled off after 160°F but Annis noted that at higher temperatures a rapid increase in the gel strength was noted. Figure (16) reflects this observation. Thus increased temperature, like increased bentonite concentration promotes flocculation. The temperature at which a rapid increase in gel strength occurs. represents the onset of flocculation. Therefore it is possible to expect the gel strength to increase significantly at some elevated temperature.

Annis studied the gel strength properties of about 40 water base field muds at temperatures ranging to 300°F. The muds covered a wide range of densities and mud types, although the majority were lignosulfonate muds. To draw conclusions on the effects of high temperature on gel strength the gel strength properties were averaged and are presented in figure (17).

Hiller[22] noted that some clay suspensions display a decrease in gel strength with increased pressure, especially at high temperatures. It was noted that the gel strength was reduced to 1/4 of its original value for a pressure increase from 300 to 8000 psi at a temperature o 302°F. This reduction in the gel strength resulting from increased pressure is presented in table 8.

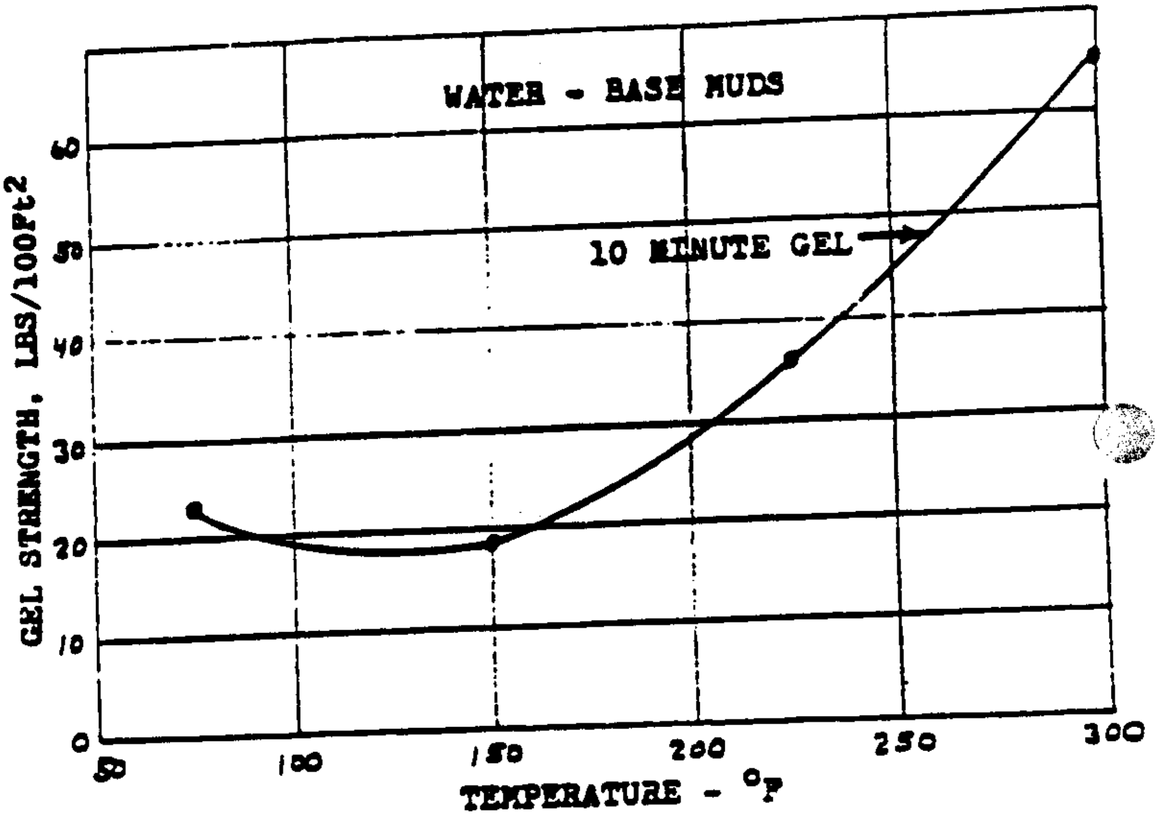


FIGURE 17. Effect of Temperature on 10-Minute Gel Strength (From Annis[20])

TABLE 8

GEL STRENGTH OF A 4 PER CENT SUSPENSION OF PURE SODIUM MONTMORILLONITE TO WHICH AN EXCESS OF 50 MEQ/LITER OF NaOH HAS BEEN ADDED, MEASURED AT VARIOUS TEMPERATURES AND PRESSURES.

t(°F)	P(psi)	Gel Strength (lb/100sq ft) 1 min	10 min	30 min
78	300	2.2	--	35.0
	8000	2.2	--	7.0
212	300	18.0	26.0	40.0
	8000	9.0	9.0	15.0
302	300	240.0	290.0	265.0
	8000	88.0	100.0	100.0

(From Hiller[22])

Although no direct means exists to determine the ultimate gel strength of a drilling mud at bore hole conditions, it is possible to safely say that the gel strength developed in the bore hole is considerable greater than that indicated by the initial and 10 minute gel strengths recorded for a given mud. The effects of time, temperature and pressure on the gel strength of the static mud column have been discussed above. In the range of pressures and temperatures normally encountered in disposal formations, pressure should exert a negligible effect on the gel strength. Flocculation at high temperature should not occur except in the deepest of disposal formations. Certain muds do not display a temperat dependance, but the effects of time is ever present.

The research discussed above investigated muds with 0 initial gel strength to ultimate gel strengths of 100'slbs/100SF. In an attempt to select a minimum ultimate gel strength that could be expected for the worst of mud and bore hole conditions, a value of 20 lbs/100 Ft^2 will be utilized for the ultimate gel strength in all gel strength pressure calculations in this report. This value will provide a considerable safety factor in most cases. The user of the procedure outlined in chapter III may utilize another value of the ultimate gel strength if available data allows such a determination.

The 20 lb/100Ft^2 ultimate gel strength was arbitrarily selected to insure that a sufficient safety factor is built into the proposed procedure. The selection is the result of individual judgment prejudiced by the above discussion.

APPENDIX E

EXAMPLE OF THE AREA OF REVIEW DETERMINATION PROCEDURE

Example of the Area of Review Determination Procedure

A chemical plant desires to initiate a new process at it's plant site located along the gulf coast of Texas. The new process will generate a continuous waste stream of 500 GPM for an estimated 20 years. The surface disposal capabilities of the plant are limited therefore the company desires to dispose of the new waste stream by subsurface injection. The proposed process will generate a chemical which is in high demand. To meet the demand the plant must operate without interruption, therefore the disposal system must be designed to provide continuous waste disposal for 20 years. The chemical company has employed a consultant to determine if it is feasible to dispose of the anticipated waste stream by subsurface injection. If the proposed injection is feasible, the company desires to know what the area of review will be so that its staff may begin to prepare the permit application and technical report.

Step 1

The consultant obtained all available well logs, formation water samples, core samples and other appropirate information from wells in the immediate area of the plant site. Utilizing the information obtained, the consultant preformed a hydrogeologic survey, conducted waste and formation fluid compatibility tests, and assembled other information which indicated that a suitable injection formation existed at a depth of 5000 feet below the plant site. Table 9 presents the waste stream and injection formation properties determined by the consultant. The consultant selected a two well injection system to ensure continuous disposal capability.

The consultant determined that in addition to active wells there exists 126 abandoned wells within an approximate 2½ mile radius of the plant site.

Step 2

Figure (2) is a map of the relative positions of the abandoned wells with respect to the proposed injectio wells at the plant site. The map has a grid system superimposed over it so that the relative distance, in feet between the abandoned wells and the injection wells can be determined.

Step 3

A two well injection system is selected to ensure that the disposal of the waste is not interrupted. Each well will inject at a rate of 250 GPM. Should a workover be required on a well, the other well will operate at 500 GPM until both wells are back on line. The well bore radius (r_w) of each well equals four inches. The wells will be operted for a period of 20 years.

TABLE 9

WASTE STREAM AND INJECTION FORMATION PROPERTIES

FORMATION PROPERTIES	DETERMINED VALUE
Porosity	.20
Depth to top of injection formation	5000 feet
Thickness	350 feet
Initial Pressure	2325 psi
Fracture Gradient	.68 psi/ft
Permeability	100 md

WASTE PROPERTIES	DETERMINED VALUE
Viscosity	.75 cp

COMBINED PROPERTIES	DETERMINED VALUE
Total Compressibility	.000005 1/psi

Information obtained in steps one and two is utilized to determine the gel strength and static mud column pressures. The pertinent information is presented in Table 1. A review of table 1 indicates that the minimun mud density recorded in the 126 abandoned wells is 9.4 lbs/gal. and the maximun bit diameter at the injection formation depth is 9.875 inches. These values are input into computer program INJWEL to calculate the static mud column and gel strength pressures, respectively. (See Appendix F). Table 10 represents the input required to calculate the formation, static mud column, and gel strength pressures and draw the X-Y Plot utilizing INJWEL. The injection rates are combined and it is assumed all the waste is being injected into well number one. Table 1 and Figure (3) represent the output and X-Y Plot, respectively that were generated by INJWEL. It is noted that the calculated area of review is approximately a radial distance of 7000 feet from the injection well.

Step 4

Utilizing information contained in tables 9 and 11 it is possible to calculate the formation pressure at a specified time at each of the abandoned wells. Table 12 represents the appropriate input to the computer program PRES to allow it to calculate the formation pressure at the abandoned wells and to draw an X-Y Plot of the ar review. The pressure isobar drawn on the X-Y plot represents the static mud column plus gel strength pressure calculated by INJWEL. Table 13 and Figure (4) represent the output and X-Y Plot from PRES, respectively. Table 14 represents a listing of the abandoned wells determined to be located within the area of review.

Step 5

Since the minimum mud density (9.5 lbs/gal) found in the abandoned wells within the calculated area of review is greater than the 9.4 lbs/gal mud density utilized in the new calculations made in step three and the maximum bit diameter found in the abandoned wells within the area of review if 7.875 inches which is less than the 9.875 inches used in step three, INJWEEL will be rerun utilizing the above noted values. The gel strength plus a static mud colum pressure calculated with the new values for mud density and bit size is 2503.72 psi. This value replaces the old value and PRES is rerun to obtain the X-Y Plot of only the newly calculated area of review. Since the formation pressures do not change there is no need to recalculate them in PRES. Figures 5 and 6 represent the X-Y Plots of the area of review calculated by INJWEL and PRES, respectively. Table 5 lists the abandoned wells contained in the newly calculated area of review. A review of the table indicates that the mud density and bit diameter have both stabilized therefore the iterative pro-

TABLE 10

INPUT FOR COMPUTER PROGRAM INJWEL

```
20.00      5000.0     11.875
0.0        .75        1.0        100.      350.
2325.      20.0       .000005    .33
500.       9.4
```

TABLE 11

OUTPUT FROM FIRST RUN OF COMPUTER PROGRAM INJWEL

```
   20.000  5000.000    11.875
FRAC PRES FOR INJECTION FORMATIONS        0.00

  2325.00       .75      1.00     100.00    350.00
      .20     20.00  .00000500       .33
PRES TO BREAK GEL STRENGTH       28.84PSI

THE PRESSURE RESULTING FROM THE       9.40LBS/GAL MUD     COLUMN=    2444.00PSIA

THE COMBINED MUD COLUMN AND GEL STRENGTH PRESSURE=   2472.84

CONSTANT FLOW RATE=    500.00GAL/MIN

RADIUS     PRESSURE
      .33    2989.94
    10.00    2812.56
    20.00    2776.44
    30.00    2755.35
    40.00    2740.38
    50.00    2728.78
    60.00    2719.30
    70.00    2711.27
    80.00    2704.33
    90.00    2698.20
   100.00    2692.72
   200.00    2656.67
   300.00    2635.57
   400.00    2620.61
   500.00    2609.00
   600.00    2599.32
   700.00    2591.50
   800.00    2584.56
   900.00    2578.43
  1000.00    2572.95
  2000.00    2536.90
  3000.00    2515.81
  4000.00    2500.85
  5000.00    2489.25
  6000.00    2479.78
  7000.00    2471.70
  8000.00    2464.85
  9000.00    2458.70
 10000.00    2453.20
 11000.00    2448.24
 12000.00    2443.84
 13000.00    2439.70
```

TABLE 12

INPUT FOR COMPUTER PROGRAM PRES

```
                                 5          3          5
        124         2
          1
0.25          352.4      6.0        100.0         100.0        20.00
0.75        .100000      2325.0     39000.
0.0          39000.      0.0
  4450.      15900.
  4700.      14950.
  5975.      18610.
  3375.      13275.
  7350.      15030.
  6125.      17350.
  7375.      18900.
  8575.      14400.
  7350.      17950.
  8300.      17050.
  7325.      20075.
  1950.      14600.
  2000.      13250.
  6090.      14550.
  1525.      16375.
  4400.      21275.
  4175.      24850.
 10800.      16900.
  8400.      17950.
 10000.      12950.
  3950.      17475.
 11475.      13450.
  9350.      15120.
 12150.      12600.
  9525.      13075.
 10990.      15600.
  8400.      11975.
 11275.      11430.
  9700.      11400.
  6100.      11590.
  7290.      11930.
  8750.      10800.
  9900.      16275.
  8800.      12030.
  4475.      11675.
  3500.      11900.
  6150.      12725.
  6100.      13225.
  8800.      16100.
  9025.      17100.
 12700.      12450.
  3000.      10350.
  6880.       9875.
  6090.       9430.
  3500.       9775.
  6650.      10075.
  9525.      10950.
 11200.      10500.
  9950.       7200.
  9800.       8800.
  9300.       8450.
  7325.       7075.
  8250.       8150.
  7150.       4650.
 10650.       4375.
  9550.       7450.

            13000.      7600.
             8275.      6875.
            11600.      6175.
            12100.      4175.
            12975.      6150.
            14250.      4875.
            16490.      1325.
            16950.     31500.
            19500.     31650.
            18700.     31450.
            10200.     30900.
            10000.     31100.
            19100.     31200.
            20000.     31550.
            21750.     29700.
             7350.     29400.
             9000.     29000.
            10750.     29000.
            12200.     29750.
            12250.     31500.
            13400.     29000.
            11250.     27650.
            11900.     29850.
            10100.     26600.
            15100.     26400.
            17650.     24850.
            18025.     24700.
            17700.     24075.
            17225.     29475.
            16300.     27275.
            17200.     26200.
            10925.     20975.
             5700.     24075.
             5325.     26600.
             6650.     24200.
             4725.     25325.
             4525.     24375.
             5600.     25000.
             9025.     26025.
             7775.     25800.
             8490.     22775.
             6975.     22000.
            10875.     20400.
            10050.     25025.
            11875.     23575.
            10775.     22700.
             9550.     22375.
            17000.     24750.
             7175.     21350.
             8000.     20075.
             9200.     21075.
             9875.     20025.

                       10100.     18450.
                       10175.     19450.
                       10150.     19400.
                       10925.     21000.
                       11100.     18350.
                       11200.     17150.
                       11375.     15975.
                       12225.     17750.
                       11425.     19600.
                       13375.     23125.
                       11700.     20750.
                       12200.     19700.
                       12050.     16500.
                       10700.     17900.
                       13675.     15800.
                       23300.     16250.
                       20450.     19475.
                       21950.     14325.
                     250.           15000.      16000.
                     250.           15500.      16900.
                     (1982)
                       1.0
                     (1986)
                       5.0
                     (1991)
                      10.0
                     (1996)
                      15.0
                     (2001)
                      20.0
                      2072.
```

TABLE 13

OUTPUT FROM COMPUTER PROGRAM [illegible]

```
WELL       WELL COORDINATES              FLOW RATES     INITIAL
 ID        X(FT)       Y(FT)             (GAL/MIN)     TIME(YRS)

  1      15000.00    10000.00             250.00          0.00
  2      15500.00    10900.00             250.00          0.00




                                                          FORMATION FLUID
FIELD DATA:           RESERVOIR                  VISCOSITY    COMPRESSIBILITY
                POROSITY     THICKNESS              (CP)         1/(PSIA)
                (FRAC.)        (FEET)
                                                    .790        .000009000
                 .200          350.0


                 INITIAL        FORMATION PERMEABILITY        WELL
                RESERVOIR          (MILLIDARCIES)            RADIUS
               PRES.(PSIA)     X-DIRECT      Y-DIRECT        (IN.)

                2725.00         100.0         100.0          6.00
```

TABLE 13 CONT

OBSERVATION POINT	PT. COORDINATES X(FT)	Y(FT)	BOTTOM HOLE PRESSURE(PSI) BY YEARS (1982)	(1986)	(1991)	(1996)	(2001)
1	8053.0	15000.0	2374.1	2413.9	2431.1	2441.4	2446.7
2	4700.0	14550.0	2373.8	2413.2	2430.7	2441.0	2448.1
3	5925.0	18600.0	2379.7	2414.4	2436.0	2446.3	2453.7
4	3375.0	13275.0	2367.5	2406.3	2423.8	2434.1	2441.4
5	7350.0	19000.0	2384.2	2424.4	2446.0	2456.3	2463.7
6	6825.0	17350.0	2380.6	2420.2	2437.8	2448.1	2455.4
7	7375.0	14500.0	2387.2	2427.4	2445.0	2455.3	2462.7
8	4575.0	18600.0	2372.7	2412.0	2429.5	2439.8	2447.1
9	7350.0	17350.0	2387.7	2427.0	2445.5	2455.0	2463.2
10	8300.0	17050.0	2393.0	2433.4	2451.1	2461.4	2468.8
11	7325.0	20075.0	2382.9	2422.0	2440.5	2450.8	2458.2
12	1950.0	14600.0	2363.4	2401.8	2419.2	2429.5	2436.8
13	2400.0	13250.0	2362.8	2401.1	2418.5	2428.8	2436.1
14	6450.0	14550.0	2380.1	2419.9	2437.4	2447.8	2455.1
15	1525.0	16375.0	2362.4	2400.6	2418.0	2429.3	2435.6
16	6350.0	21275.0	2374.6	2414.1	2431.6	2441.9	2449.3
17	4175.0	20850.0	2368.4	2407.3	2424.8	2435.1	2442.4
18	10804.0	14300.0	2412.8	2453.3	2471.0	2481.3	2488.7
19	9600.0	17550.0	2403.4	2444.1	2461.8	2472.1	2479.5
20	10950.0	12950.0	2406.9	2447.7	2465.4	2475.7	2483.1
21	3450.0	17475.0	2367.4	2406.3	2423.7	2434.0	2441.3
22	11025.0	13650.0	2414.6	2450.6	2477.3	2487.6	2495.0
23	9350.0	19100.0	2401.7	2442.1	2460.0	2470.4	2477.7
24	12150.0	12600.0	2413.2	2454.0	2471.7	2482.1	2489.5
25	9525.0	13075.0	2397.5	2438.0	2455.7	2466.0	2473.4
26	10450.0	15600.0	2412.5	2453.3	2471.0	2481.4	2488.8
27	8800.0	11575.0	2385.9	2426.0	2443.6	2453.9	2461.3
28	11225.0	11400.0	2400.4	2440.0	2457.4	2468.0	2475.4
29	9700.0	11600.0	2392.5	2432.9	2450.5	2460.9	2468.2
30	6400.0	11550.0	2375.1	2414.5	2432.1	2442.4	2449.7

TABLE 13 CONT

31	7250.0	11800.0	2380.3	2420.2	2437.7	2448.1	2455.
32	8750.0	14000.0	2399.0	2435.5	2453.1	2463.5	2470.8
33	9400.0	16275.0	2403.0	2443.7	2461.4	2471.7	2479.1
34	8400.0	12800.0	2389.7	2430.2	2447.6	2457.9	2465.3
35	8675.0	11675.0	2378.0	2408.9	2426.5	2436.8	2444.1
36	3300.0	11500.0	2365.3	2403.9	2421.3	2431.6	2438.9
37	6150.0	12725.0	2378.1	2417.7	2435.3	2445.6	2453.0
38	6100.0	13225.0	2376.7	2418.4	2435.9	2446.3	2453.6
39	8400.0	10100.0	2399.2	2435.6	2453.3	2463.7	2471.8
40	9825.0	17100.0	2406.2	2446.9	2464.6	2474.9	2482.3
41	12700.0	12650.0	2415.5	2456.3	2474.1	2484.4	2491.8
42	3400.0	10350.0	2369.2	2403.8	2421.2	2431.5	2438.8
43	4450.0	9675.0	2367.7	2406.9	2424.0	2434.3	2441.6
44	4950.0	8800.0	2365.5	2404.2	2421.6	2431.8	2439.2
45	3550.0	8775.0	2361.9	2400.1	2417.4	2427.7	243[illegible]
46	6450.0	10075.0	2373.5	2412.0	2430.4	2440.7	24[illegible]
47	8525.0	10050.0	2381.2	2421.0	2438.6	2448.9	2456.3
48	11200.0	10500.0	2394.0	2434.4	2452.0	2462.4	2469.7
49	9950.0	7200.0	2364.9	2403.4	2420.9	2431.1	2438.4
50	5900.0	8800.0	2366.3	2407.2	2424.7	2435.0	2442.3
51	9300.0	9650.0	2376.6	2418.3	2435.9	2446.2	2453.5
52	7325.0	7075.0	2364.0	2406.4	2424.3	2434.6	2441.9
53	8250.0	8150.0	2373.7	2413.1	2430.6	2440.9	2448.2
54	7150.0	8650.0	2372.0	2411.2	2428.7	2439.0	2446.4
55	10450.0	8375.0	2381.3	2421.2	2438.8	2449.1	2456.4
56	9950.0	7450.0	2374.7	2414.1	2431.7	2442.0	2449.3
57	13000.0	7600.0	2382.3	2422.2	2439.8	2450.1	2457.4
58	8275.0	6075.0	2367.2	2406.0	2423.4	2433.7	2441.0
59	11650.0	6175.0	2373.7	2413.1	2430.6	2440.9	2448.3
60	12100.0	6175.0	2366.6	2405.4	2422.0	2433.1	2440.4
61	12975.0	6150.0	2375.3	2414.8	2432.3	2442.6	2449.0

TABLE 13 CONT

62	14250.0	6475.0	2374.7	2409.8	2427.3	2437.6	2444.9
63	14850.0	1325.0	2358.5	2396.2	2413.5	2423.7	2431.0
64	16450.0	31500.0	2357.6	2395.1	2412.4	2422.6	2429.9
65	19500.0	31650.0	2355.9	2393.1	2410.4	2420.6	2427.9
66	18700.0	31600.0	2356.4	2393.7	2411.0	2421.2	2428.5
67	19200.0	30500.0	2359.1	2396.9	2414.3	2424.5	2431.8
68	18800.0	31100.0	2357.3	2394.9	2412.1	2422.4	2429.7
69	18100.0	31200.0	2357.9	2395.5	2412.8	2423.0	2430.3
70	20600.0	31550.0	2355.3	2392.4	2409.6	2419.8	2427.1
71	21750.0	29700.0	2358.7	2396.4	2413.7	2424.0	2431.3
72	7350.0	28800.0	2359.0	2396.8	2414.1	2424.3	2431.6
73	9000.0	29000.0	2358.5	2396.2	2413.5	2423.7	2431.0
74	10750.0	29400.0	2361.6	2400.0	2417.4	2427.6	2434.9
75	12200.0	29750.0	2362.0	2400.2	2417.6	2427.8	2435.1
76	12250.0	31500.0	2357.0	2394.5	2411.7	2422.0	2429.2
77	13400.0	29400.0	2363.8	2402.3	2419.7	2429.9	2437.2
78	11250.0	27650.0	2368.1	2407.0	2424.4	2434.7	2442.0
79	11900.0	28850.0	2364.6	2403.2	2420.6	2430.9	2438.2
80	14100.0	26600.0	2375.0	2414.4	2432.0	2442.3	2449.6
81	15100.0	26400.0	2376.2	2415.7	2433.3	2443.6	2450.9
82	17650.0	26850.0	2373.8	2412.3	2429.8	2440.1	2447.5
83	14925.0	26700.0	2373.2	2412.8	2430.1	2440.4	2447.7
84	17700.0	26875.0	2376.3	2415.9	2433.4	2443.7	2451.1
85	17225.0	25475.0	2379.7	2419.6	2437.0	2447.3	2454.7
86	16300.0	27275.0	2372.1	2411.6	2428.9	2439.2	2446.5
87	17200.0	26200.0	2374.2	2415.8	2433.3	2443.7	2451.0
88	19925.0	28075.0	2362.9	2401.3	2418.6	2428.9	2436.2
89	9700.0	28075.0	2357.9	2395.6	2412.8	2423.1	2430.4
90	9325.0	26600.0	2360.4	2398.4	2415.8	2426.0	2433.3
91	6050.0	26200.0	2364.2	2402.7	2420.1	2430.4	2437.7
92	4725.0	29325.0	2361.8	2400.0	2417.4	2427.6	2434.9

TABLE 13 CONT

93	4525.0	24375.0	2363.2	2401.6	2419.0	2429.2	2436.6
94	5600.0	25000.0	2364.7	2403.2	2420.6	2430.9	2438.2
95	9625.0	20825.0	2364.5	2407.4	2424.9	2435.2	2442.5
96	7775.0	25800.0	2367.9	2406.8	2424.2	2434.5	2441.8
97	8450.0	22775.0	2379.7	2419.4	2437.0	2447.3	2454.7
98	6975.0	22800.0	2374.3	2413.9	2431.3	2441.6	2448.9
99	10875.0	26400.0	2372.2	2411.4	2428.9	2439.2	2446.6
100	10450.0	25025.0	2376.8	2416.9	2434.0	2444.3	2451.7
101	11475.0	23575.0	2385.0	2425.1	2442.7	2453.0	2460.4
102	10775.0	22700.0	2388.5	2428.7	2446.3	2456.7	2464.0
103	9550.0	22375.0	2385.6	2425.9	2443.1	2453.4	2460.7
104	17775.0	24750.0	2383.7	2423.7	2441.3	2451.6	2458.9
105	7175.0	21350.0	2379.0	2418.8	2436.3	2446.7	2454.0
106	8400.0	20675.0	2384.6	2424.7	2442.3	2452.6	2460.0
107	9200.0	21675.0	2386.8	2426.9	2444.6	2454.9	246[illegible]
108	8675.0	20475.0	2389.0	2430.2	2447.8	2458.2	2465.5
109	10100.0	18650.0	2404.4	2445.1	2462.8	2473.1	2480.5
110	10175.0	19050.0	2399.9	2440.9	2458.1	2468.7	2475.9
111	10150.0	18400.0	2405.7	2446.4	2464.1	2474.5	2481.8
112	10625.0	21000.0	2397.8	2438.3	2456.0	2466.3	2473.7
113	11100.0	19350.0	2414.4	2455.3	2473.0	2483.3	2490.7
114	11200.0	17150.0	2424.2	2461.1	2478.9	2489.2	2496.6
115	11325.0	19075.0	2423.0	2464.0	2481.7	2492.0	2499.4
116	12225.0	17750.0	2430.5	2471.9	2489.2	2499.6	2507.0
117	11425.0	19600.0	2409.9	2450.7	2468.4	2478.8	2486.1
118	13325.0	20125.0	2418.0	2458.9	2476.6	2487.0	2494.4
119	11700.0	20750.0	2404.0	2444.6	2462.3	2472.7	2480.0
120	12250.0	18700.0	2423.5	2464.9	2482.2	2492.6	2500.0
121	12450.0	16900.0	2440.0	2481.0	2498.8	2509.2	2516.5
122	13700.0	17000.0	2414.9	2455.8	2473.5	2483.8	2491.2
123	13475.0	18000.0	2462.3	2503.9	2521.2	2531.6	2539.0

TABLE 13 CONT

124	23300.0	16750.0	2387.5	2427.9	2445.1	2455.4	2462.0
125	24750.0	15475.0	2382.0	2422.7	2440.3	2450.7	2458.0
126	21550.0	14325.0	2397.1	2437.6	2455.3	2465.6	2473.0

TABLE 14

WELLS CONTAINED IN THE AREA OF REVIEW

WELL	X-CORD	Y-CORD	Mud Den (lb/gal)	Bit Size (in)
18	10800	14300	12.9	6.75
19	9600	17550	10.6	7.875
20	10950	12950	12.5	7.875
22	11825	13650	12.4	7.875
23	9350	15200	10.7	7.875
24	12150	12600	12.7	7.875
25	9525	13075	11.5	7.875
26	10450	15600	10.1	7.875
28	11225	11400	10.4	8.75
33	9400	16275	9.7	7.875
40	9825	17100	9.5	7.875
41	12700	12450	13.4	7.875
109	10100	18650	10.9	7.875
110	10175	19850	11.1	7.875
111	10150	18400	11.0	7.875
112	10825	21000	10.5	7.875
113	11100	18350	10.5	7.875
114	11200	17150	11.6	7.875
115	11325	15975	11.5	7.875
116	12225	17750	11.0	7.875
117	11425	19600	11.1	7.875
118	13325	20125	11.2	7.875
119	11700	20750	9.7	7.875
120	12250	18700	9.7	7.875
121	12450	16500	9.5	7.875
122	10700	17000	9.7	7.875
123	13475	15800	11.6	7.875
126	21550	14325	10.2	7.875

cedure need not be repeated. The area of review calculated by this second iteration is the true area of review for the proposed injection operation.

Step 6

Since step five defined the true area of review for the proposed injection operation it is now necessary to evaluate each well listed in table 15 on an individual basis. Utilizing the mud density and bit size for each well listed in the table the static mud column and gel strength pressure, respectively are calculated at each well. The sum of the pressures at each well is compared with the formation pressure calculated at the well by PRES, Table 13. If the combined gel strength and static mud column pressure is less than the formation fluid pressure corrective action must be considered at the well in question. Corrective action could be avoided by reducing the injecting rate or by relocating the injectors to modify the area of review so that the critical well no longer presents a problem. If the gel strength pressure plus static mud column pressure exceeds the formation pressure the well in question will not pose a pollution threat to fresh water.

Step 7

Table 16 lists the wells located within the true area of review. These wells need to be reviewed on an individual basis to determine which wells need corrective action utilizing the criteria established by the TDWR.

TABLE 15

WELLS CONTAINED IN THE TRUE AREA OF REVIEW

WELL #	X-CORD	Y-CORD	MUD DEN	BIT SIZE
116	12225	17750	11.0	7.875
121	12450	16500	9.5	7.875
123	13475	15800	11.6	7.875

TABLE 16

WELLS REQUIRING INDIVIDUAL REVIEW FOR POSSIBLE CORRECTIVE ACTION

WELL #	Static Mud Column Pres (psi)	Gel Strength Pressure (psi)	Combined Pressure (psi)	Formation Pressure (psi)
116	11.0(5000)(.052)	+ 33.72 =	2893.72	2507.0
*121	9.5(5000)(.052)	+ 33.72 =	2503.72	2516.5
123	11.6(5000)(.052)	+ 33.72 =	3049.72	2539.0

*Well 121 is the only well which requires actual investigat to determine if corrective action is required. If well 12 is properly plugged no further action is required, if not it requires corrective action.

APPENDIX F

COMPUTER PROGRAM INJWEL

```
      PROGRAM INJWEL(INPUT,OUTPUT,PLOTR)
C
C      THE PURPOSE OF THE FOLLOWING PROGRAM IS TO:
C
C      DETERMINE AN AREA OF REVIEW AROUND A SINGLE INJECTION
C      WELL BY COMPARING THE FORMATION PRESSURE CONE OF THE
C      INJECTOR WITH THE SUM OF:
C      (1) THE PRESSURE REQUIRED TO BREAK THE GEL STRENGTH OF
C      MUD FOUND IN THE ABANDONED WELLS WITHIN THE VICINITY
C      (2 1/2 MILE RADIUS) OF THE INJECTOR
C      (2) THE HYDROSTATIC PRESSURE OF THE MUD COLUMN IN THE
C      ABANDONED WELLS WITHIN THE VICINITY
C
C      THE RESERVOIR IS ASSUMED TO BE ISOTROPHIC, HOMOGENEOUS,
C      HORIZONTAL AND INFINATE IN AREAL EXTENT.  GRAVITY EFFECTS
C      ARE ASSUMED NEGLIGIBLE.  THE FLUID WITHIN THE RESERVOIR
C      IS CONSIDERED TO HAVE A SMALL AND CONSTANT COMPRESSIBILITY.
C
C      CALCULATIONS OF THE PRESSURE REQUIRED TO BREAK THE MUD
C      GEL STRENGTH ASSUME:  THE ABANDONED WELL DIAMETER USED
C      IS THE LARGEST ABANDONED WELL DIAMETER IN THE VICINITY
C      OF THE INJECTOR. THE GEL STRENGTH USED IS THE ONE HOUR
C      GEL STRENGTH OF THE MUD USED TO DRILL THE VICINITY WELLS.
C      THE HEIGHT OF THE MUD COLUMN IN THE ABANDONED WELLS CAN
C      BE MEASURED  AND THE LOWEST MEASURED VALUE IS USED. AND
C      ALL WELLS WERE ABANDONED WITHOUT LONG STRING CASING.
C
C      CALCULATIONS OF THE PRESSURE REQUIRED TO OVERCOME THE
C      HYDROSTATIC MUD COLUMN PRESSURE ASSUME THAT THE MUD
C      DENSITY IS UNIFORM THROUGHOUT THE HEIGHT OF THE
C      ABANDONED WELL BORE AND THAT THE MUD OCCUPIES THE ENTIRE
C      WELL BORE HEIGHT
C
C      INPUT DATA FOR THE PROGRAM IS DESCRIBED AS FOLLOWS:
C
C      VARIABLE      UNIT            DESCRIPTION
C
C
C      GELSTR        LBS/100SF       GEL STRENGTH OF MUD IN
C                                    ABANDONED WELLS
C      HMUD          FEET            LOWEST HEIGHT OF THE MUD COLUMNS
C                                    IN THE ABANDONED WELLS
C      DABDW         INCHES          LARGEST DIAMETER OF THE ABANDONED
C                                    WELLS IN THE VICINITY
C      PFRAC         PSIA            FRACTURE PRESSURE OF INJECTION
C                                    FORMATION
C      PINIT         PSIA            INITIAL INJECTON FORMATION PRESSURE
C      VISC          CENTIIPOISE     FLUID VISCOSITY
C      B             RES VOL/        RESERVOIR FLUID FORMATION VOLUME
C                    SURFACE VOL     FACTOR
C      PERM          MILIDARCIES     PERMEABILITY
C      H             FEET            FORMATION THICKNESS
C      PHI           FRACTION        FORMATION POROSITY
C      TLIFE         YEARS           LIFE OF THE INJECTION WELL
C      C             1/PSIA          FLUID COMPRESSIBILITY
C      RW            FEET            WELL BORE RADIUS
C      QCONST        GAL/MIN         CONST MAX FLOW RATE OF WASTE
C                                    INJECTED INTO THE INJECTION
C                                    FORMATION
C      RHO           LBS/GAL         ABANDONED WELL MUD DENSITY
C
```

```
C
C     INPUT DATA CARDS FOR THE PROGRAM ARE AS FOLLOWS:
C
C                                          FORMAT
C     CARD   VARIABLE NAMES
C
C                                          (3F10.2)
C      1     GELSTR,WMUD,DABBW             (3F10.2)
C      2     *PFRAC                        (5F10.2)
C      3     PINIT,VISC,B,PERM,H           (2F10.0,F10.0,2F10.2)
C      4     PHI,TLIFE,C,RW                (2F10.0)
C      5     *QCONST,RHO
C
C     *IF IT IS DESIRED TO RUN THE PROGRAM TO DETERMINE THE
C     MAXIMUM FLOW RATE ALLOWABLE FOR A SPECIFIED FRACTURE
C     PRESSURE,LET PFRAC=THE SPECIFIED FRACTURE PRESSURE
C     AND QCONST=0.0
C     IF IT IS DESIRED TO RUN THE PROGRAM FOR AN INPUT
C     CONSTANT MAXIMUM FLOW RATE, LET PFRAC=0.0 AND
C     QCONST=THE DESIRED FLOW RATE
C
C
C
      DIMENSION PATRAD(50),RADIUS(50),PGELRW(50),PCOMRO(50),PCOLMN(50)
      DIMENSION PLINITS(50)
      READ 10,GELSTR,WMUD,DABBW
      PRINT 10,GELSTR,WMUD,DABBW
   10 FORMAT(3F10.3)
      READ 10,PFRAC
      PRINT 11,PFRAC
   11 FORMAT(1X,*FRAC PRES FOR INJECTION FORMATION=*,F10.2//)
      READ 12,PINIT,VISC,B,PERM,H
      PRINT 12,PINIT,VISC,B,PERM,H
   12 FORMAT(5F10.2)
      READ 13,PHI,TLIFE,C,RW
      PRINT13,PHI,TLIFE,C,RW
   13 FORMAT(2F10.2,F10.6,F10.2)
      PDELTA=(3.33E-4)*(GELSTR*WMUD)/DABBW
      PGEL=PDELTA
      PRINT 21,PGEL
   21 FORMAT(1X,*PRES TO BREAK GEL STRENGTH=*,F10.2,*PSI*,//)
      READ 14,QCONST,RHO
   14 FORMAT(2F10.2)
      PCOLM=.052*RHO*WMUD
      PRINT 17,RHO,PCOLM
   17 FORMAT(1X,*THE PRESSURE RESULTING FROM THE*,F10.2,*LBS/GAL MUD
     *COLUMN=*,F10.2,*PSIA*//)
      PCOMB=PCOLM+PDELTA
      PRINT 18,PCOMB
   18 FORMAT(1X,*THE COMBINED MUD COLUMN AND GEL STRENGTH PRESSURE=*,
     *F10.2//)
      RWC=RW*30.5
      CC=C*14.7
      PERMC=PERM/1000
      PINITC=PINIT/14.7
      PFRACC=PFRAC/14.7
      HC=H*30.5
      TLIFEC=TLIFE*31536000
      PI=3.14159
      IF(PFRAC.LE.0.0) GO TO 15
      AR=(PHI*VISC*CC*(RWC**2))/(4*PERMC*TLIFEC)
      QMAXC=((PINITC-PFRACC)*4*PI*PERMC*HC)/(VISC*B*(EIX(AR)))
      QMAX=QMAXC*.0150
      PRINT 22,QMAX
```

```
22 FORMAT(1X,*TO PREVENT FRACTURING, THE MAXIMUM FLOW RATE ALLOWABL
  *E FOR THE*,F10.2,*YEAR LIFE OF THE INJECTION WELL=*,F10.2//)
   IF (PFRAC.GT.0.0) GO TO 25
15 PRINT 16,QCONST
16 FORMAT(1X,*CONSTANT FLOW RATE=*,F10.2,*GAL/MIN*//)
   QMAX=QCONST
   QMAXC=QMAX/.0150
   AR=(PHI*VISC*CC*(RW**2))/(4*PERMC*TLIFEC)
25 PATRW=PINITC+(((VISC*B)/(4*PIE*PERMC*HC))*QMAXC*(EIX(AR)))
   PATRW=PATRW*14.7
   RW=RW/30.5
   PRINT 23,RW,PATRW
23 FORMAT(1X,*RADIUS     PRESSURE*,/2F10.2)
   I=1
   RADIUS(I)=10.
   DO 30 I=1,31
   AR=(PHI*VISC*CC*((30.5*RADIUS(I))**2))/(4*PERMC*TLIFEC)
   PATRAD(I)=PINITC+(((VISC*B)/(4*PIE*PERMC*HC))*QMAXC*(EIX(AR)))
   PATRAD(I)=PATRAD(I)*14.7
   PRINT 24,RADIUS(I),PATRAD(I)
24 FORMAT(2F10.2)
   IF(RADIUS(I).GE.1000.) GO TO 32
   IF(RADIUS(I).GE.100.) GO TO 31
   RADIUS(I+1)=RADIUS(I)+10.
   IF(RADIUS(I).LT.100.) GO TO 30
31 RADIUS(I+1)=RADIUS(I)+100.
   IF(RADIUS(I).LT.1000.) GO TO 30
32 RADIUS(I+1)=RADIUS(I)+1000.
30 CONTINUE
   DO 33 I=1,31
   PCOLMN(I)=0.052*RHO*HMUD
   PCOMBO(I)=PCOLMN(I)+PDELTA
33 CONTINUE
   I=1
   PLIMITS(I)=PINIT
   I=2
   PLIMITS(I)=PATRW
   CALL PLOTS(0,0,9LPLOTR)
   CALL SCALE(RADIUS,13.,31,1)
   CALL AXIS(2.0,1.5,34HRADIAL DISTANCE FROM INJECTOR (FT),
  *-34,13.,0.,RADIUS(32),RADIUS(33))
   CALL SCALE(PLIMITS,8.,2,1)
   PATRAD(32)=PLIMITS(3)
   PATRAD(33)=PLIMITS(4)
   PCOMBO(32)=PLIMITS(3)
   PCOMBO(33)=PLIMITS(4)
   PCOLMN(32)=PLIMITS(3)
   PCOLMN(33)=PLIMITS(4)
   CALL AXIS(2.0,1.5,26HFORMATION PRESSURE(PSIA),
  *26,8.,90.,PATRAD(32),PATRAD(33))
   CALL ORIGIN(2.0,1.5,0)
   CALL LINE(RADIUS,PATRAD,31,1,0,16)
   CALL LINE(RADIUS,PCOMBO,31,1,0,10)
   CALL LINE(RADIUS,PCOLMN,31,1,0,4)
   CALL SHADE(3,0,0)
   CALL SYMBOL(2.0,7.9,0.15,22HAREA(RADIUS) OF REVIEW,0.,22)
   CALL SYMBOL(1.0,7.6,0.2,14,0.,-1)
   CALL SYMBOL(1.3,7.5,.2,28HWELL LIFE FORMATION PRESSURE,0.,28)
   CALL SYMBOL(1.0,7.1,0.2,4,0.,-1)
   CALL SYMBOL(1.3,7.0,0.2,26HSTATIC MUD COLUMN PRESSURE,0.,26)
   CALL SYMBOL(1.0,6.6,0.2,10,0.,-1)
   CALL SYMBOL(1.3,6.5,0.2,24HCOMBINED SHCP AND GEL ST,0.,24)
```

```
 CALL SYMBOL(0.0,7.5,.2,5HINPUT,0.,5)
 CALL SYMBOL(0.0,7.3,.10,25HGEL STRENGTH(LB/100SF) = ,0.,25)
 CALL NUMBER(999.,999.,.10,GELSTR,0.,2)
 CALL SYMBOL(0.0,7.1,.10,
*32HABANDONED WELL MUD HEIGHT(FT) = ,0.,32)
 CALL NUMBER(999.,999.,.10,HMUD,0.,2)
 CALL SYMBOL(0.0,6.9,.10,30HABANDONED WELL DIAMETER(IN) = ,
*0.,30)
 CALL NUMBER(999.,999.,.10,DABDN,0.,3)
 CALL SYMBOL(0.0,6.7,.10,
*37HFORMATION FRACTURE PRESSURE(PSIA) = ,0.,37)
 CALL NUMBER(999.,999.,.10,PFRAC,0.,2)
 CALL SYMBOL(0.0,6.5,.10,
*35HINITIAL FORMATION PRESSURE(PSIA) = ,0.,35)
 CALL NUMBER(999.,999.,.10,PINIT,0.,2)
 CALL SYMBOL(0.0,6.3,.10,24HVISCOSITY(CENTIPOISE) = ,0.,24)
 CALL NUMBER(999.,999.,.10,VISC,0.,2)
 CALL SYMBOL(0.0,6.1,.10,
*39HFLUID FORMATION VOLUME FACTOR(RV/SV) = ,0.,39)
 CALL NUMBER(999.,999.,.10,B,0.,2)
 CALL SYMBOL(0.0,5.9,.10,29HPERMEABILITY(MILLIDARCIES) = ,0.,29)
 CALL NUMBER(999.,999.,.10,PERM,0.,2)
 CALL SYMBOL(0.0,5.7,.10,26HFORMATION THICKNESS(FT) = ,0.,26)
 CALL NUMBER(999.,999.,.10,H,0.,2)
 CALL SYMBOL(0.0,5.5,.10,
*21HPOROSITY(FRACTION) = ,0.,21)
 CALL NUMBER(999.,999.,.10,PHI,0.,2)
 CALL SYMBOL(0.0,5.3,.10,
*36HLIFE OF THE INJECTION WELL(YEARS) = ,0.,36)
 CALL NUMBER(999.,999.,.10,TLIFE,0.,2)
 CALL SYMBOL(0.0,5.1,.10,
*32HFLUID COMPRESSIBILITY(1/PSIA) = ,0.,32)
 CALL NUMBER(999.,999.,.10,C,0.,8)
 CALL SYMBOL(0.0,4.9,.10,
*33HINJECTION WELL BORE RADIUS(FT) = ,0.,33)
 CALL NUMBER(999.,999.,.10,RW,0.,2)
 CALL SYMBOL(0.0,4.7,.10,
*38HMAXIMUM CONSTANT FLOW RATE(GAL/MIN) = ,0.,38)
 CALL NUMBER(999.,999.,.10,QMAX,0.,2)
 CALL SYMBOL(0.0,4.5,.10,
*38HABANDONED WELL MUD DENSITY(LBS/GAL) = ,0.,38)
 CALL NUMBER(999.,999.,.10,RHO,0.,2)
 CALL SYMBOL(0.0,4.3,.10,
*36HIF THE FRACTURE PRESSURE=0, THEN A ,0.,36)
 CALL SYMBOL(0.0,4.1,.10,
*36HSTATED MAX FLOW RATE, RATHER THAN A ,0.,36)
 CALL SYMBOL(0.0,3.9,.10,
*34HMAX FLOW RATE CALCULATED FROM THE ,0.,34)
 CALL SYMBOL(0.0,3.7,.10,27HFRACTURE PRESSURE WAS USED ,0.,27)
 CALL SYMBOL(0.0,3.5,.10,6HOUTPUT,0.,6)
 CALL SYMBOL(0.0,3.3,.10,
*41HPRESSURE AT THE WELL BORE RADIUS(PSIA) = ,0.,41)
 CALL NUMBER(999.,999.,.10,PATRW,0.,2)
 CALL SYMBOL(0.0,3.1,.10,
*30HGEL STRENGTH PRESSURE(PSIA) = ,0.,30)
 CALL NUMBER(999.,999.,.10,PGEL,0.,2)
 CALL SYMBOL(0.0,2.9,.10,
*35HSTATIC MUD COLUMN PRESSURE(PSIA) = ,0.,35)
 CALL NUMBER(999.,999.,.10,PCOLM,0.,2)
 CALL SYMBOL(0.0,2.7,.10,
*33HCOMBINED SHCP AND GEL ST(PSIA) = ,0.,33)
 CALL NUMBER(999.,999.,.10,PCOMB,0.,2)
```

```
      CALL PLOT(13.,0.,999)
      STOP
      END
      FUNCTION EIX(ARG)
      IF (ARG.GT.2.) GO TO 2
      IF(ARG.LE.0.01) GO TO 3
      N=12
      IF (ARG.LT.1.) N=8
      F=1.0
      XO=1.0
      EIX=ALOG(ARG)+.577215665
      N1=N-1
      DO 1 I=1,N1
      F=F*I
      XO=-ARG*XO
      EIX=EIX+XO/(F*I)
1     CONTINUE
      EIX=EIX-ARG*XO/(F*N*(N+1.34))
      RETURN
2     XO=EXP(-ARG)
      EIX=ARG+6./(1.+5./ARG)
      I=5
4     EIX=ARG+I/(1.+I/EIX)
      I=I-1
      IF (I.LE.0) GO TO 5
      GO TO 4
5     EIX=-XO/EIX
      RETURN
3     EIX=ALOG(ARG)+.577215665-ARG+ARG*ARG/4.
      RETURN
      END
```

APPENDIX G

COMPUTER PROGRAM PRES

```
      PROGRAM PRES(INPUT,OUTPUT,TAPE5=INPUT,TAPE6=OUTPUT,PLOT)
C   THE PURPOSE OF THE FOLLOWING PROGRAM IS TO:
C
C   (1)  SOLVE FOR RESEVOIR PRESSURES AT GIVEN DISTANCES AND TIMES
C
C   (2)  CALCULATE AND PLOT ISOBARS
C
C
C   THE RESERVOIR IS ASSUMED TO BE ANISOTROPIC, HOMOGENEOUS, INFINITE
C   AND IN AN UNSTEADY STATE FLOW.  THE FLUID WITHIN THE RESERVOIR
C   IS CONSIDERED TO BE SLIGHTLY COMPRESSIBLE.
C
C   FOR FORMULA DERIVATION AND BACKGROUND INFORMATION REFER TO:
C
C   CAUDLE,DR.BEN H., FUNDAMENTALS OF RESERVOIR ENGINEERING,
C        SOCIETY OF PETROLEUM ENGINEERING OF AIME (AMERICAN
C        INSTITUTE OF MINING, METALLURGICAL, AND PETROLEUM
C        ENGINEERS,INC., DALLAS,TEXAS, 1967.
C
C   SINCE DATA INPUT IS THE ONLY NECESSARY REQUIREMENT FOR THE
C   FUNCTIONING OF THE PROGRAM, IT WILL BE DESCRIBED AS FOLLOWS:
C
C
C                                                DESCRIPTION:
C   VARIABLE:                   UNITS:
C                                                NUMBER OF LOCATIONS FOR
C   N                           DIMENSIONLESS(DL)  PRESSURE CALCULATIONS
C
C                                                NUMBER OF WELLS
C   W                           DL
C                                                NUMBER OF TIME CHANGES
C   NTCHG                       DL               FOR PRESSURE CALCULATIONS
C
C                                                CODED VARIABLE THAT
C   NCALC                       DL               DETERMINES THE SUBJECT
C                                                AREA TO BE CALCULATED
C
C                                                NUMBER OF YEAR PERIODS
C   NYRP                        DL               FOR PRESSURE CALCULATIONS
C
C                                                NUMBER OF ISOBAR PLOTS
C   NIBAR                       DL
C                                                FORMATION POROSITY
C   PHI                         FRACTION
C                                                FORMATION THICKNESS
C   H                           FEET
C                                                WELL RADIUS
C   RW                          INCHES
C
C                                                FLUID VISCOSITY
C   VISC                        CENTIPOISE
C                                                FLUID COMPRESSIBILITY
C   C                           1/(PSIA)
C                                                INITIAL RESERVOIR
C   PINIT                       PSIA             PRESSURE
C
C                                                PERMEABILITY IN X&Y
C   XK,YK                       MILLIDARCIES     DIRECTIONS
C
C                                                TIME PERIOD FOR ISOBAR
C   YRPLOT                      YEARS
```

```
                                                          PLOT
C
C                                                         FIELD MIN. & MAX. LIMITS
C   FXMIN,FXMAX                   FEET                    IN X DIRECTION OF PLOT
C
C                                                         FIELD MIN. & MAX. LIMITS
C   FYMIN,FYMAX                   FEET                    IN Y DIRECTION OF PLOT
C
C                                                         X AND Y INCREMENTS ON
C   XINC,YINC                     FEET                    ISOBAR PLOT
C
C                                                         X,Y LOCATION OF
C   X(I),Y(I)                     FEET                    PRESSURE CALCULATIONS
C
C                                                         FLOW RATE OF WELL (J)
C   Q(J)                          GAL/MIN
C                                                         X,Y LOCATION OF WELLS
C   XW(J),YW(J)                   FEET
C                                                         INITIAL TIME OF
C   T(J)                          YEARS                   (PRODUCTION/INJECTION)
C
C                                                         SPECIFIED YEAR FOR
C   YR(J)                         YEARS                   PRESSURE CALCULATIONS
C
C                                                         YEAR INCREMENTS BETWEEN
C   YRINC(J)                      YEAR                    SPECIFIED YEARS
C
C                                                         NIBAR NUMBER OF
C   PRBAR(K)                      PSIA                    PRESSURES FOR ISOBAR
C                                                         PLOTS
C
C
C                                                         SYMBOL USED FOR
C   ISYM(K)                       DL                      CORRESPONDING PRESSURE
C                                                         ON ISOBAR PLOT
C                                                         +=1,*=3,X=4
C
C
C
C   THE PRECEDING VARIABLES ARE INPUTTED INTO THE COMPUTER EACH TIME THE
C   FLOW OF THE PROGRAM CROSSES A READ STATEMENT.  FOR EACH READ
C   STATEMENT A DATA CARD SHOULD BE READ.
C
C   CARD#      VARIABLE NAMES               FORMAT       #READS
C   1          N,M,NTCHG,NCALC,NYRP           (8I10)     C   1
C   2          NIBAR                          (8I10)         1
C   3          PHI,H,RW,                      (8F10.0)       1
C   4          VISC,C,PINIT,XK,YK,YRPLOT      (8F10.0)       1
C   5          FXMIN,FXMAX,FYMIN,FYMAX        (8F10.0)       1
C   6          X(I),Y(I)                      (8F10.0)       N
C   7          Q(J),XW(J),YW(J),T(J)          (8F10.0)       M
C   8          YR(J)                          (10A4)         NYRP
C   9         YRINC(J)                       (8F9.0)       NYRP
C   10         PRBAR(K)                       (8F10.0)         NIBAR
C   11         ISYM(K)                        (8I10)           NIBAR
C
C   WARNINGS:
C   (1)   ALWAYS USE INPUT DATA WITH CORRECT UNITS.  SEE ABOVE
C   (2)   INJECTION WELLS MUST BE INPUTTED BEFORE PRODUCTION
C         WELLS REGARDLESS OF WHEN THE WELLS BEGAN OPERATING
C   (3)   OSCILLATION OF PLOT AROUND WELL BORES MAY BE ELLIMINATED BY
C         INCREASING VARIABLE RW
C   (4)   EXCESSIVE RUN TIME OF PROGRAM MAY BE REDUCED BY:
C         A. INCREASING THE VARIABLE DPCT WITHIN THE DATA STATEMENT
```

```
C      B. INCREASING THE XINC AND YINC INCREMENT VALUES WITHIN THE
C         ISOBAR PLOT
C (5)  THE PLOT ROUTINE WITHIN THIS PROGRAM IS SUBJECT TO CHANGE
C      ACCORDING TO USER.  THUS, THE PROGRAM WILL BE SLIGHTLY
C      ALTERED WITH EACH USER TO CONFORM TO THE LIMITATIONS AND
C      RESTRICTIONS OF EACH PLOT ROUTINE
C (6)  IF THE ISOBAR PLOT SHOULD BE BLANK, THE PRESSURES DEFINING
C      THE ISOBARS DO NOT EXIST WITHIN THE FIELD
C
C NOTE:
C (1)  SET NCALC EQUAL TO THE FOLLOWING NUMBERS TO CALCULATE THE
C      SPECIFIED SECTIONS OF THE PROGRAM
C
C
C      NCALC=
C            1...PRESSURE CALCUATION ONLY
C            2...ISOBAR PLOT ONLY
C            3...ISOBAR PLOT AND PRESSURE CALCULATION
C (2)  WELLS WITH VARYING FLOW RATES WITH TIME MAY BE USED BY SUPER-
C      IMPOSING THE DIFFERENTIAL ON THE PREVIOUS FLOW RATE
C
C
      COMMON T(100),XW(1000),YW(1000),XK,YK,N,PHI,Q(100),VISC,C,NTOTW
      DIMENSION X(200),Y(200),XP(1000),YP(1000),XX(1000),YY(1000),
     1FYRMX(15),YR(10),YRINC(15),PRES1(20),PRBAR(10),ISYM(10)
C
C INPUT DATA SECTION
C
      DATA PI,CF1,CF2,EPS,YCON,DFCT,TCONV,XINC,YINC/3.140.13478811.76.30
     1022.01.1.0E-10.0,842228.0,0.1,31536000.0,400.0,400.0/
      READ(5,9)M,N,NTCHG,NCALC,NYRP
      READ(5,9)NIBAR
      READ(5,5) PHI,H,RW
      READ(5,5)VISC,C,PINIT,XK,YK,YRPLOT
      READ(5,5)FXMIN,FXMAX,FYMIN,FYMAX
       DO 10 I=1,M
       READ(5,5)X(I),Y(I)
 10    CONTINUE
      WRITE(6,70)
      WRITE(6,71)
      WRITE(6,72)
      WRITE(6,73)PHI,H,VISC,C
      WRITE(6,74)
      WRITE(6,76)
      WRITE(6,77)
      WRITE(6,78)PINIT,XK,YK,RW
      WRITE(6,47)
      WRITE(6,48)
      NI=0
      NP=0
       DO 15 J=1,N
       READ(5,5) Q(J),XW(J),YW(J),T(J)
       IF(Q(J).GT.0.0) NI=NI+1
       IF(Q(J).LT.0.0) NP=NP+1
       WRITE(6,49) J,XW(J),YW(J),Q(J),T(J)
       T(J)= T(J)*TCONV
 15    CONTINUE
       DO 23 J=1,NYRP
       READ(5,11)YR(J)
       READ(5,5)YRINC(J)
 23    CONTINUE
       DO 30 K=1,NIBAR
       READ(5,5)PRBAR(K)
       READ(5,9)ISYM(K)
 30    CONTINUE
```

```
      IF(NCALC.EQ.2)GO TO 38
C
C  PRESSURE CALCULATIONS
C
      WRITE(6,50)
      WRITE(6,51)
      WRITE(6,52) (YR(J),J=1,NYRP)
       DO 35 I=1,N
       WRITE(6,60)I,X(I),Y(I)
       DO 30 II=1,NYRP
       TSEC=TCONV*TRINC(II)
       SUM=0.
       DO 25 J=1,M
       IF (TSEC-T(J).LE.0.) GO TO 25
       STEI=(PHI*VISC*C*CF1)/(4.*(TSEC-T(J)))
       FINEI=(((X(I)-XW(J))**2)/XK)+(((Y(I)-YW(J))**2)/YK)
       IF(FINEI.LT.EPS) GO TO 30
       X1=STEI*FINEI
       CALL EIX(X1,FUNC)
       SUM=(FUNC*Q(J))+ SUM
 25    CONTINUE
       AP=(VISC*CF2)/(4.*PI*((XK*YK)**.5)*H)
       HALF=AP*SUM
       PRES1(II) = PINIT+HALF
 30    CONTINUE
       WRITE(6,61) (PRES1(II),II=1,NYRP)
 35    CONTINUE
      IF(NCALC.EQ.1)GO TO 555
C
C  PRESSURE CALCULATIONS FOR ISOBAR PLOT
C
 38   CONTINUE
      RW=(RW/12.)+4.5
      NTOT=NWP+NI
      CALL PLOTS(0,0,5LPLOTR)
      CALL DRWPAD(FXMIN,FXMAX,FYMIN,FYMAX)
      CALL SKETCH(XW,YW,M,14,0)
      CALL SKETCH(X,Y,N,1,0)
      CALL SYMBOL(3.0,10,1.0.3,14HAREA OF REVIEW,0.,14)
      CALL SYMBOL(7.0,10.05,.10,14,0.,-1)
      CALL SYMBOL(7.2,10.0,.10,24HINJECTION WELL LOCATIONS,0.,24)
      CALL SYMBOL(7.0,9.9,.10,1,0.,-1)
      CALL SYMBOL(7.2,9.85,.10,24HABANDONED WELL LOCATIONS,0.,24)
      CALL SYMBOL(7.0,9.75,.10,6,0.,-1)
      CALL SYMBOL(7.2,9.7,.10,30HSTATIC MUD COLUMN+GEL STRENGTH,0.,30)
      CALL SYMBOL(7.2,9.55,.10,23HPRESSURE(PSI) ISOBAR = ,0.,23)
      CALL NUMBER(999.,999.,.10,PRBAR,0.,2)
      DO 301 J=1,NTOT
      XTEST=ABS(FXMIN-XW(J))
      YTEST=ABS(FYMIN-YW(J))
      IF(((XTEST**2)+(YTEST**2)).LE.(RW**2)) FXMIN=FXMIN+RW
 301  CONTINUE
       DO 300 K=1,NIBAR
       XP=FXMIN
       YP=FYMIN
       TSEC=TCONV*YRPLOT
 323   CONTINUE
       SUM=0.0
       DO 302 J=1,M
       IF(TSEC-T(J).LE.0.) GO TO 302
       STEI=(PHI*VISC*C*CF1)/(4.*(TSEC-T(J)))
       FINEI=(((XP-XW(J))**2)/XK)+(((YP-YW(J))**2)/YK)
```

```
      IF(FINEI.LT.EPS) GO TO 303
      XI=STEI*FINEI
      CALL EIX(XI,FUNC)
      SUM=(FUNC*Q(J))+ SUM
302   CONTINUE
      AP=(VISC*CF2)/(4.*PI*((XK*YK)**.5)*H)
      HALF=AP*SUM
      PRESP=PINIT+HALF
303   CONTINUE
      XPOLD=XP
      XP= XP+XINC
      IF((XP.GT.FXMAX).AND.(YP.GT.FYMAX))GO TO 400
      IF(XP.GT.FXMAX)GO TO 304
      DO 305 J=1,N
     IF((((XP-XW(J))**2)+((YP-YW(J))**2)).LE.(RW**2)) GO TO 303
305   CONTINUE
      SUM=0.0
      DO 306 J=1,N
      IF(TSEC-T(J).LE.0.)GO TO 306
      STEI=(PHI*VISC*C*CF1)/(4.*(TSEC-T(J)))
      FINEI=(((XP-XW(J))**2)/XK)+(((YP-YW(J))**2)/YK)
      IF(FINEI.LT.EPS) GO TO 312
      XI=STEI*FINEI
      CALL EIX(XI,FUNC)
      SUM=(FUNC*Q(J))+SUM
306   CONTINUE
      AP=(VISC*CF2)/(4.*PI*((XK*YK)**.5)*H)
      HALF=AP*SUM
      PROLD=PRESP
      PRESP=PINIT+HALF
312   CONTINUE
      IF((PROLD.LT.PRBAR(K)).AND.(PRESP.GT.PRBAR(K))) GO TO 307
      IF((PROLD.GT.PRBAR(K)).AND.(PRESP.LT.PRBAR(K))) GO TO 307
      GO TO 303
307   CONTINUE
      PDIF1=ABS(PRBAR(K)-PROLD)
      PDIF2=ABS(PRESP-PROLD)
      XP=(((XP-XPOLD)*PDIF1)/(PDIF2)) + XPOLD
      CALL SYSTCH(XP,YP,.1,ISYM(K),1)
      GO TO 303
304   CONTINUE
      YP= YP+YINC
      XP=XMIN
      GO TO 323
400   CONTINUE
300   CONTINUE
     CALL PLOT(0.0,0.0,999)
555  CONTINUE
5    FORMAT(8F10.0)
6    FORMAT(8I10)
11   FORMAT(10A6)
47   FORMAT(59H1 WELL        WELL COORDINATES          FLOW RATES     INIT
    1IAL)
48   FORMAT(60H   ID           X(FT)      Y(FT)           (GAL/MIN)     TIME(
    1YRS))
49   FORMAT(/,1X,I3,6X,F9.2,3X,F9.2,7X,F6.2,9X,F9.2)
50   FORMAT(73H1 OBSERVATION   PT. COORDINATES              BOTTOM HOLE PRESS
    1URE(PSI) BY YEARS)
51   FORMAT(29H    POINT       X(FT)     Y(FT))
52   FORMAT(1H0,13X,1A6,4X,1A6,4X,1A6,4X,1A6,4X,1A6)
60   FORMAT(/,3X,I3,6X,F8.1,1X,F9.1)
61   FORMAT(1H0,33X,F6.1,4X,F6.1,4X,F6.1,4X,F6.1,4X,F6.1)
```

```
                                                                        FORM
                                                    RESERVOIR
 70   FORMAT(67H1 FIELD DATA:
     1ATION FLUID)                                POROSITY     THICKNESS      VISCOSITY
 71   FORMAT(70H
     1    COMPRESSIBILITY)                        (FRAC.)       (FEET)          (CP)
 72   FORMAT(70H
     1         1/(PSIA))
 73   FORMAT(/,18X,F5.3,9X,F5.1,8X,F6.3,10X,F10.6)           FORMATION PERMEABILI
 74   FORMAT(//,69H                                    INITIAL
     1TY       WELL)                              RESERVOIR       (MILLIDARCIES)
 76   FORMAT(60H
     1     RADIUS)                                PRES.(PSIA)      X-DIRECT      Y-DIRECT
 77   FORMAT(60H
     1        (IN.))
 78   FORMAT(/,18X,F8.2,7X,F7.1,6X,F7.1,7X,F5.2)
      STOP
      END

      SUBROUTINE EIX(X,XEI)
C
C   SUBROUTINE TO CALCULATE THE EXPONENTIAL INTEGRAL USING THE
C   INFINITE SERIES METHOD
C
      DATA EPMS,GAMMA/1.E-10,0.5772156649/
      XEI=-GAMMA-ALOG(X)
      I=0
 8    I=I+1
      FACT=1.
       DO 6 J=1,I
       XJ=J
 6     FACT= FACT*XJ
      XI=I
      FNEG=-1.0
      TERM=((FNEG)**(I+1))*((X**I)/(XI*FACT))
      XEI=XEI+TERM
      IF (TERM.LT.0.0) TERM=-TERM
      IF (TERM.LT.EPMS) GO TO 7
      GO TO 8
 7    CONTINUE
      RETURN
      END
```

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VITA

Stephen Eugene Barker was born in Norwich, New York, on November 8, 1950, the son of Jacke Marie Barker and Stuart Harold Barker. After completing his work at New Berlin Central High School, New Berlin, New York, in 1968, he entered the United States Army. Upon discharge from the Army in 1973, he entered the State University of New York College at Oneonta, New York. He received the degree of Bachelor of Science from State University College at Onenota in December, 1976. In September, 1976 he entered the State University of New York at Buffalo, New York. He received the Bachelor of Science in Engineering from the University of Buffalo in September, 1977. Commissioned an Ensign in the United States Navy i July, 1977, he presently holds the rank of Lieutenant. Married to the former Holly Edwards of New Berlin, New York, they have three childres: Brie Alexandra (May, 1978) Wesley Adam (October 1980) and Eric Christian (October, 1980). In January, 1981, he entered the Graduate School of the University of Texas.

Permanent address: 31 Genesee St.
New Berlin, New York

California Specialty Cheese
UIC Permit Application

PERMIT APPLICATION FOR CLASS I NON-HAZARDOUS INJECTION WELL

California Specialty Cheese
Section 24-T1S-R6E, SE/4
San Joaquin County, California

October 2005

Prepared for:

California Specialty Cheese
14253 South Airport Way
Manteca, CA 95336
209-858-9696

Prepared by:

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California Specialty Cheese
14253 South Airport Way
Manteca, CA 95336
209-858-9696

OMB No. 2040-0042 Approval Expires 1/31/05

EPA

United States Environmental Protection Agency

Underground Injection Control
Permit Application

(Collected under the authority of the Safe Drinking Water Act. Sections 1421, 1422, 40 CFR 144)

I. EPA ID Number

		T/A	C
U			

Read Attached Instructions Before Starting

For Official Use Only

Application approved mo day year	Date received mo day year	Permit Number	Well ID	FINDS Number

II. Owner Name and Address

Owner Name: California Specialty Cheese

Street Address: 14253 South Airport Way

Phone Number: (209) 858-9696

City: Manteca

State: CA

ZIP CODE: 95336

III. Operator Name and Address

Owner Name: California Specialty Cheese

Street Address: 14253 South Airport Way

Phone Number: (209) 858-9696

City: Manteca

State: CA

ZIP CODE: 95336

IV. Commercial Facility

☒ Yes
☐ No

V. Ownership

☒ Private
☐ Federal
☐ Other

VI. Legal Contact

☒ Owner
☐ Operator

VII. SIC Codes

2022

VIII. Well Status *(Mark "x")*

☐ A. Operating

Date Started mo day year:

☐ B. Modification/Conversion

☒ C. Proposed

IX. Type of Permit Requested *(Mark "x" and specify if required)*

☒ A. Individual
☐ B. Area

Number of Existing Wells: 0

Number of Proposed Wells: 2 (1 operating; 1 optional back-up)

Name(s) of field(s) or project(s): California Specialty Cheese

X. Class and Type of Well *(see reverse)*

A. Class(es) (enter code(s))	B. Type(s) (enter code(s))	C. If class is "other" or type is code 'x,' explain	D. Number of wells per type (if area permit)
Class 1	Type I		1

XI. Location of Well(s) or Approximate Center of Field or Project

Latitude			Longitude			Township and Range							
Deg	Min	Sec	Deg	Min	Sec	Sec	Twp	Range	1/4 Sec	Feet From	Line	Feet From	Line
121	15	22.7	37	50	0.91	24	1S	6E	SE	882	E	2,565	S

XII. Indian Lands (Mark 'x')

☐ Yes
☒ No

XIII. Attachments

(Complete the following questions on a separate sheet(s) and number accordingly; see instructions)

For Classes I, II, III, (and other classes) complete and submit on a separate sheet(s) Attachments A–U (pp 2-6) as appropriate. Attach maps where required. List attachments by letter which are applicable and are included with your application.

XIV. Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32)

A. Name and Title *(Type or Print)*: Ming Shin Kou, Vice President

B. Phone No. *(Area Code and No.)*: (323) 234-9000

C. Signature:

D. Date Signed: 10/13/2005

EPA Form 7520-6 (Rev. 8-01)

ORIGINAL

Permit Application Attachments
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    Pan Petroleum, Hayre Egg Farms No. 1, 18-1S-7E
    Christiana Oil, Schleiss No. 1, 30-1S-7E (Induction and Sonic Logs)
    U.S. Natural Resources, Towne-S.P. Unit Two No. 1, 14-1S-6E
California Division of Oil and Gas, Well Abandonment Records for:
    Quintana Petroleum, S.P. No. 1, 25-1S-6E
    Pan Petroleum, Hayre Egg Farms No. 1, 18-1S-7E
Well Record – 1888 abandoned gas exploration well, 24-1S-6E
Class II Injection Well records – Laymac Reynolds & Carver-Long
McMullin Ranch Gas Field documenting permeability of Tracy Sand
Plugging and Abandonment Cost Estimates for UIC Injection Well
Certificate of Recognition to Fisherman’s Pride Processing, 2004

Executive Summary

Introduction

The California Specialty Cheese (CSC) facility is located at 14253 South Airport Way in Manteca, California, approximately nine miles south of Stockton and 75 miles east of San Francisco (Figure 1). The site is located on approximately 60 acres with the southern 18 acres containing the main plant site and the northern 42 acres containing former wastewater ponds constructed by the site's previous owner (Figure 2).

Cheese processing operations have been halted at the site since 2003 when the current owners (CSC) purchased the site. The previous owner had processed cheese at the facility until wastewater and other issues contributed to plant closure. Wastewater that had been discharged to onsite ponds was discovered to have impacted local groundwater quality. The current owner plans to return the site to cheese processing after conducting significant plant upgrades and incorporating a newly-designed wastewater improvement process. More details on the processing operation are included in Attachment U.

CSC has examined various methods of wastewater disposal and has determined that a deep injection well that fully protects drinking water aquifers is the most environmentally viable option. Details on wastewater generation and treatment prior to injection at the site are provided in Attachment H. The wastewater flow process is shown conceptually on Table 3. Anticipated wastewater quality prior to treatment is summarized from site historical data on Table 4.

The proposed injection well requires a permit through the U.S. Environmental Protection Agency's (USEPA) Underground Injection Control (UIC) program. This application is being submitted to USEPA to obtain a permit to drill, construct, test, and operate a Class 1 Non-Hazardous injection well at depths below 2,000 feet. Depending on the subsurface conditions, up to 300,000 gallons per day of non-hazardous wastewater from cheese manufacturing will be treated and injected into the Class 1 well. Operating data and injection procedures are described in Attachments H and K. This application submittal follows the regulations of 40 CFR Parts 144-146 and various guidance documents prepared by or for the USEPA as listed in the references section of this application.

This permit application assumes that only one well will be necessary for injection operations. However, the applicant requests the option of installing a back-up well in the future as part of a contingency plan in the event of well failure (Attachment O). The installation of a back-up well would not increase total injection volumes contained in this application. In addition, the back-up well would be located close to the initial injection well such that the distances and analysis for the Area of Review and the geological evaluation would remain applicable for the additional well.

Selection of Target Injection Zones

Based on an evaluation of the subsurface geology of the area, two zones have been selected as possible injection targets. The main target for injection is a Miocene Sand, likely equivalent to the Valley Springs formation and expected to occur at a depth of 2,010 feet in the proposed well. An alternative target injection zone has also been identified in the event that the Miocene Sand does not meet stated requirements. This alternative target is a Cretaceous Sand, referred to locally as the 2nd Tracy Sand, and is expected to occur at a depth of 5,235 feet in the proposed well. Both of the targets appear to meet regulatory requirements for total dissolved solids (TDS) exceeding 10,000 milligrams per liter (mg/L). In addition, both targets are protective of underground sources of drinking water (USDWs) as documented in the Attachments to this summary.

Data collected during the drilling and testing process will be evaluated to select one of the targets for well completion. The shallower Miocene Sand will be tested first, and if the zone meets regulatory and operational requirements, the well will be completed there and will not be drilled deeper. However, if it appears that TDS regulatory requirements cannot be met in the Miocene Sand, the well will be drilled deeper to the alternative injection target.

This application describes the geological evaluation that identified the target injection zones and demonstrates that injection into these zones would not impact USDWs. The selection of target injection zones considered geology, hydrogeology, groundwater quality, and operational and regulatory requirements. Potential target injection zones interpreted to occur beneath the CSC site were assessed using the following criteria:

- Protects USDWs
- TDS exceeds 10,000 mg/L
- Meets other UIC regulatory requirements
- Thickness and permeability sufficient for injection capacity
- Shallow depth to minimize drilling, installation, and rehabilitation costs.

Because permeability generally decreases with depth, shallow targets were considered to be preferable and were investigated first. While deep Cretaceous sands (>6,000 feet), such as the Lathrop Sand, have been targets for gas exploration in this area, these deeper targets do not contain sufficient permeability to sustain injection rates required for most industrial operations (as indicated by permeability data from nearby gas fields, CDOG, 1982). A nearby UIC injection well at the San Joaquin CoGen facility attempted to inject into the Lathrop Sand, but could not sustain a rate of more than 100 gallons per minute (gpm). A rate of 100 to 200 gpm is required for CSC's wastewater program. For this reason, the Lathrop Sand is not a target and the Cretaceous 2nd Tracy Sand is considered the deepest potential target for injection in this area.

In order to select the most feasible target based on site-specific data collected during drilling and testing, this application requests a permit allowing for either the

Miocene Sand or the Cretaceous 2nd Tracy Sand to be the target injection zone without preparing an additional application.

Area of Review

The Area of Review (AOR) is the radius around the injection well in which impacts from injection could potentially occur. It is based on parameters of the target injection zones and the location of USDWs. Three methods were used to calculate and compare potential AORs including the USEPA method for calculating the Zone of Endangering Influence (Attachment A). These calculations indicate that an AOR of 0.5 miles is reasonable. In addition, the calculations consider locations of the nearest wells outside of the AOR that have penetrated either of the two target injection zones. Using reasonable site-specific data and assumptions, calculations indicate that these wells will not provide a conduit and will not result in impacts to USDWs. As such, a corrective action program to locate and seal wells is not proposed (Attachment C).

Underground Source of Drinking Water (USDW)

Data from more than 600 water supply wells, more than 300 monitoring wells, about 10 injection wells, and 20 abandoned gas exploration wells were used to evaluate groundwater occurrence and use in the area (Attachment B). Most of the water supply wells were extracting water from depths of 50 feet to 300 feet. None of the wells pump water below 400 feet and only two wells were drilled below 500 feet. Those two wells, located at the former Occidental Chemicals site, are used for injection only. Other wells in the area include monitoring wells installed by various facilities, including DDJC-Sharpe and CSC, to monitor shallow groundwater quality and abandoned gas exploration wells (Attachment B).

Of the more than 900 well records reviewed in the area, only 27 wells appear to have been drilled in the AOR. None of these wells penetrate either of the two target injection zones. According to public records compiled from eight separate sources, wells within the 0.5-mile AOR include the following:

- 12 water supply wells
- 1 abandoned gas exploration well
- 14 monitoring wells.

These wells in the AOR are shown on Figure 3, summarized in Table 1, and described in more detail in Attachment B. Well data compiled both inside and in the vicinity of the AOR are described in the attachment.

Only two wells within about 1.5 miles of the proposed CSC injection site have penetrated the target injection zone (Attachment B). These two abandoned gas exploration wells, Quintana S.P. No. 1 well and the Pan Petroleum Hayre Egg Farms No.

1 well, are located approximately 4,385 feet and 4,520 feet, respectively from the CSC site. Analyses presented in Attachments A, B, and C indicate that USDWs will not be impacted through these abandoned wells due to the distance away from the proposed injection well, plug depths, and mud weight of the fluid remaining in the wells (Figure 4). There are seven deep wells within 2 miles of the CSC injection site (Table 2). Data from these wells and 13 additional deep wells were used to correlate and map the regional geology.

Attachment D provides geologic and hydrogeologic analyses of the USDW. The geologic map on Figure 5 shows the site's location in the Central Valley of California between the Sierra Nevada to the east and the Coast Ranges to the west. Quaternary deposits transition to Tertiary and Cretaceous sediments at depth. These sediments overlie the Jurassic bedrock complex at an estimated depth of about 12,000 feet in this area (Bartow, 1983). Local hydrostratigraphic units with the corresponding ages and characteristics are summarized on Figure 6. A regional cross section of these units across the valley with the CSC site projected onto the section is shown on Figure 7.

The CSC site is located in the Eastern San Joaquin subbasin of the larger San Joaquin Valley groundwater basin (DWR, March 5, 2003).The subbasin covers more than 1,000 square miles and is bounded by the San Joaquin River on the west, the Stanislaus River on the south, and the Mokelumne River on the north. The eastern subbasin boundary is the surface intersection of the alluvium and the outcropping consolidated rocks of the Sierra Nevada foothills. Groundwater occurs in the unconsolidated alluvial deposits beneath this basin under unconfined conditions and becomes more confined with depth.

The water table beneath the CSC site is unconfined and occurs at an approximate depth of 10 feet. Water levels in the drinking water aquifers (with approximate depths ranging from 50 feet to 300 feet) have declined over the last 30 years as indicated by a water level hydrograph from a nearby DWR monitoring well (Figure 8). However, water levels appear to have stabilized at about 7 feet above msl.

Historically, groundwater within this basin flowed toward the major drainages, including the San Joaquin River, and then north and west toward the Sacramento-San Joaquin delta. Groundwater extraction over time has lowered water levels near pumping centers and has altered regional flow patterns. Groundwater in the aquifers down to about 400 feet in the vicinity of the CSC site is in the transition zone between the natural northwesterly flow and the pumping-influenced northeasterly groundwater flow. Groundwater beneath the site generally flows northeast toward the central pumping depression while groundwater just west of the site flows westward toward the river (Figure 9).

According to maps produced by DWR and USGS, the base of fresh water (generally defined as TDS of less than about 2,000 mg/L) occurs beneath the CSC site at an approximate elevation of -550 feet below msl (Figure 10). The base of the USDW, defined by a TDS of less than 10,000 mg/L, is not known. By using water quality data from nearby wells at depths of 500 feet and electric log analyses of salinity from regional gas exploration wells to depths below 2,500 feet (Figure 11), the base of the USDW may be as shallow as 900 to 1,300 feet. Given the variability in regional log response and focusing on the closest wells, the base of the USDW is conservatively estimated at 1,789 feet beneath the CSC site. This depth is the bottom of the sand immediately above the confining layer of the target Miocene Sand, a depth that represents the most conservative and worst-case scenario for purposes of this analysis. Attachment D provides more detail on this analysis.

Target Injection Zones

Attachment F provides the geological evaluation of the subsurface stratigraphy in the area and the selection of target injection zones. The geological evaluation indicates that both target injection zones can be correlated and mapped within an approximate 50-square mile study area (Figure 1). The geological relationships between the target zones and the other geologic units of the area can be seen on Figure 12. Due to their thickness and permeability, the Miocene Valley Springs Sand and the Cretaceous 2nd Tracy Sand were identified as the most promising injection targets. The Miocene target contains approximately 372 feet of permeable sand as indicated by electric log responses in wells near the CSC site (Figure 13). A structural contour map on top of the sand indicates that it slopes to the southwest at approximately one degree (Figure 14). The sand is separated from USDWs by a confining layer of thick low permeability clay and silt that is approximately 250 feet thick beneath the CSC site (Figure 15). Two geologic cross sections (Figures 16 and 17) show details of the local structure and stratigraphy within one mile of the proposed well.

Cross sections also show the stratigraphy and structure of the Upper Cretaceous section, including the alternative injection target, the Cretaceous 2nd Tracy Sand (Figures 16 and 17). The alternative target contains approximately 267 feet of sand, as correlated between existing electric logs. The zone is illustrated on the closest electric log, Quintana S.P. No. 1, shown on Figure 18. Electric log response, as well as permeability estimates from nearby gas fields, indicates that the sand is sufficiently permeable for injection. The top of the zone is predicted to occur at an elevation of 5,200 feet below msl as shown on the structural contour map on Figure 19. As shown on the map, the sand dips to the southwest an average of 3 degrees across the site with dips steepening to the southwest. The sand is confined by a shale unit that extends for several miles around the CSC site and is estimated to be approximately 135 feet thick (Figure 20). An even thicker confining layer, the Ragged Valley Shale, occurs uphole of the mapped confining layer. This thick and regionally-extensive shale can be seen on the cross sections on Figures 16 and 17 and is easily correlated throughout the study area. This layer provides further protection between the Cretaceous 2nd Tracy Sand and the base of the USDW.

Although faults have been interpreted by the California Division of Oil and Gas (CDOG) to intersect the 2nd Tracy Sand interval (Figure 19), these faults are not anticipated to be a conduit of fluid into shallower sediments. The faulting provides a seal for natural gas at the Lathrop Sand level, demonstrating its lack of conductive properties. In addition, the faulting is associated with pre-Miocene deposition and does not extend up into the USDW.

Drilling and Testing Program

Attachments L, M, and I provide details on the proposed drilling and testing of the injection zone and well at the CSC site. A flexible well design will allow for drilling to 5,550 feet, if necessary, but will test the shallower Miocene Sand (top of zone at an approximate depth of 2,010 feet) before drilling deeper (Figure 21). If the Miocene Sand can be demonstrated to meet regulatory requirements through an open-hole test sample or other testing method, the well will be completed in the Miocene Sand and will not be drilled deeper. If the Miocene Sand does not meet regulatory requirements, the well will be deepened to the alternative target zone, the Cretaceous 2nd Tracy Sand. The well will be permitted as an exploration well under CDOG guidelines to ensure adequate safety measures are followed in this area of gas production.

For either completion, 13-3/8 inch diameter, 48#, H-40 surface casing will be run below the base of fresh water to approximately 650 feet and cemented to the surface. Production casing will consist of 8-5/8 inch diameter, 32#, J-55 ST&S casing and will extend approximately 10 feet below the top of the target injection zone (2,020 feet for a Miocene Sand completion or 5,245 feet for a Cretaceous 2nd Tracy Sand completion) (Figures 21 and 22). In order to maximize the injection area at depth, the target injection zone will be under-reamed to a diameter of 15 inches. A 5-½ inch diameter Bakerweld gravel pack screen will be placed across the zone and the hole filled with gravel pack material. Blank 5 ½ inch, 15.5#, J-55 LT&C liner will extend from the screen up into the 8-5/8 inch casing and secured with a liner packer. Injection will occur through 4-½ inch, 12.75#, EUE, J-55 tubing, held in place with an 8-5/8 inch Baker Model D packer (set at approximately 1,900 feet for the Miocene Sand completion or 5,100 feet for the Cretaceous 2nd Tracy Sand completion) (Figures 21 and 22).

Monitoring Program

Attachment P outlines a proposed monitoring program for injection operations at the CSC site. The monitoring program will consist of continuous readings of injection pressure, annular pressure, flow rate, and volume, as well as quarterly sampling and analysis of wastewater to be injected. Pressure readings in the annulus of the 8-5/8 inch diameter casing and the 4-½ inch diameter tubing will be capable of detecting any leaks within the tubing or at the packer. Annual logging will include temperature, spinner, and radioactive logs to ensure no fluid migration above the shoe of the 8-5/8 inch diameter casing or around the lower packer. Measurements and data will be submitted to USEPA on a quarterly basis and maintained at the site for inspection. Injection fluid will be monitored for a suite of organic and inorganic constituents as well as physical parameters (Attachment P). A hazardous waste determination will be made on the injection fluid prior to injection and at any change in the waste stream or treatment process that could impact water quality.

Plugging and Abandonment Program

Once the injection well is no longer necessary or not performing as required, the well will be abandoned in accordance with CDOG and USEPA abandonment procedures. Attachment Q provides a general plugging and abandonment program for the injection well. The exact depths of the plugs and abandonment procedures will be determined after the well has been installed. At a minimum, the following plugs and plate are anticipated:

- Plug across the injection zone, bringing cement 100 feet into the 8-5/8 inch casing (>300 foot plug)
- Plug at the base of the USDW, estimated at 1,789 feet (200-foot plug)
- Plug at the surface of the well (100-foot plug)
- Cut casing 5 feet below ground and weld steel plate on top of the casing stub.

of impression and the radius away from the wellbore where the cone would potentially rise above the USDW hydrostatic head. The third method, and perhaps the most relevant to potential injection impacts from this project, estimates the horizontal movement of the pressure wave in the target injection zone. This calculation is used to predict pressure increases at the closest wells that penetrate the injection zones. Since the injection target zone could be either the Miocene Sand or the Cretaceous Tracy Sand, depending on drilling and testing results, all calculations are performed for both target zones.

Estimated Area of Review - Volumetric Assessment

A volumetric assessment has been provided by some UIC permit applicants as one methodology for estimating the AOR (NCPA, October 1993; Hilmar Cheese, September 17, 2004). This method compares the injection amounts with the porosity and storage volume in the injection zone. Inherent in the methodology is the assumption that the injection fluid will fill an expanding cylinder away from the injection well, assuming horizontal flow and reasonable estimates of dispersion (Engineering Enterprises, May 1985). This method estimates the fluid front radius only and does not consider the pressure buildup that defines the ZEI. As such, it has been suggested that the method should not be used for AOR delineation (Engineering Enterprises, May 1985). However, it is provided here as an additional check for estimating minimum requirements for storage volume in the injection zone and the possible movement of the injected fluid.

$$R = (V / (23.4 \text{ x } H \text{ x } P))^{1/2}$$

where: R = radius of invaded zone from the well, in feet
V = volume injected, in gallons
H = height (thickness) of the injection zone, in feet
P = percent porosity of the aquifer

using: V = 2,186,496,000 gallons (208 gpm for 20 years)
H = 372 feet (Miocene target zone - mapping and nearby logs)
267 feet (Cretaceous target zone - mapping and nearby logs)
P = 0.30 (Miocene target zone – Sonic log 1.75 miles SE)
0.17 (Cretaceous target zone – Sonic log 1.75 miles SE)

Miocene Target Zone, R = 916 feet
Cretaceous Target Zone, R = 1,437 feet

Correcting for dispersion with a dispersion coefficient for sandstone, the following equation is used:

$$r' = r + (2.3 \text{ x } (D \text{ x } r)^{½})$$

where:
r' = radius of invaded zone with dispersion, in feet

r = 100 percent invaded zone – from calculation above
D = dispersion coefficient – 3 feet (Warner and Lehr, 1981)

Miocene Target Zone, R = 1,001 feet
Cretaceous Target Zone, R = 1,543 feet

These calculations indicate that if the total volume of injected fluid moves uniformly and radially away from the well, the injectate front is predicted to be approximately 1,001 feet away from the well in the Miocene target zone after 20 years of injection. If the Cretaceous target zone is selected, the front is predicted to migrate approximately 1,543 feet away from the well after 20 years. Migration is further in the Cretaceous due to the lower porosity and thinner sand interval, resulting in less storage space.

Estimated Area of Review (AOR) – Theis Equation Method

A modified version of the Theis well pumping equation is offered in the UIC regulations for a conservative calculation of the ZEI and AOR (40 CFR Part 146, Subpart A, Section 146.6). The methodology relies on reasonable estimates for injection zone parameters such as hydraulic conductivity, thickness, storativity, and hydrostatic heads, as well as injection rates and duration (Engineering Enterprises, May 1985). The equation is applied with the assumption that when the potentiometric surface of the injection cone is higher than the hydrostatic head of the USDW, there is a higher potential for possible impacts, *assuming a vertical pathway for injectate to reach USDW.*

The modified Theis equation is as follows:

$$r = (2.25KHt / S10^{x})^{1/2}$$

where:

r = radius of endangering influence from injection well (ZEI) (length)
K = hydraulic conductivity of the injection zone (length/time)
H = thickness of the injection zone (length)
t = duration of injection, project life (time)
S = storage coefficient (dimensionless)
$x = (4 \prod KH) (h_w - h_{bo} * S_pG_b) / 2.3Q$
Q = injection rate (volume/time)
h_w = hydrostatic head of USDW (length) measured from the base of the USDW
h_{bo} = observed original hydrostatic head of injection zone (length) measured from the base of the USDW
S_pG_b = specific gravity of fluid in the injection zone (dimensionless)

A major assumption in this calculation is that there is a vertical pathway for USDWs to be impacted. For consistent units, input parameters in length, volume, and time are expressed as feet, cubic feet, and days.

The injection rate (Q) is calculated from the maximum amount of wastewater that will require disposal, currently estimated at 300,000 gallons per day (gpd) or 40,107 cubic feet per day (ft^3/day). Additional treatment may lower this amount by about one-half. In addition, this injection rate will not be reached until several years after resuming operation. Nonetheless, the maximum capacity over a 20-year project life (t=7,300 days) is conservatively assumed in the calculations. These two parameters, Q and t, are held constant for the separate calculations for the two potential target injection zones. A specific gravity of one is assumed for the injection fluid.

Input parameters that are specific to the hydrogeologic conditions are developed for each target zone using site-specific data where available or reasonable estimates. Storativity is estimated using an empirical relationship based on the target injection zone thicknesses and confined aquifers where zone thickness is multiplied by 10^{-6} (Engineering Enterprises, May 1985; Warner and Lehr, 1981). The Miocene zone is 372 feet thick and the Cretaceous zone is 267 feet thick (documentation provided in Attachment F). Based on these values, storativity (S) values are calculated at 3.7×10^{-4} and 2.7×10^{-4} for the Miocene and Cretaceous zones, respectively.

A value for hydraulic conductivity (K) for the Cretaceous Tracy Sand is converted from permeability data of 117 millidarcies (md) for this sand in the McMullin Gas field, located approximately five miles south of the CSC site (CDOG, 1982; included in Supporting Documentation attached to this application). This published permeability of 117 md (0.117 darcy) is converted to a hydraulic conductivity of 0.32 feet/day using the conversion factor of 1 darcy = 2.725 feet/day (Warner and Lehr, 1981). This permeability is consistent with the 100 md value used by SMS Briners for the equivalent Starkey Sand in their Class I UIC permit application (SMS Briners, September 1991). The SMS Briners' permeability estimate was based on core data in the injection zone.

Permeability values are unavailable for the target Miocene Sand. DWR (1967) reports a regional transmissivity value of 68,000 gallons per day per foot (gpd/ft) for the Miocene Mehrten, which converts to a K value of about 24 feet/day (based on a thickness of 372 feet). The K value for the Mehrten formation is considered to be a good surrogate for the target sand, given that the sands are the same age and were sourced from the same parent rock. However, the DWR regional K value is based on wells producing from the Mehrten outside of the study area and the permeability in this area would be expected to be lower, given its deeper depth. DWR (1967) reports Mehrten permeability values about 20 miles northeast of the CSC site, near the Farmington Control Dam. These values range from 0.01 feet/day to 50 feet/day. The electric log response of the target Miocene Sand indicates a permeable sand package as shown, in part, by the relatively large negative deflection of the SP curve (up to -40 millivolts from an average shale baseline, see type log in Supporting Documentation). Additional information relating to the Miocene permeability is the measured value in the much deeper Tracy Sand of 117 md (0.32 feet/day). The Miocene would be expected to have a much higher permeability, given the younger age, shallower depth of about 2,000 feet (compared to the Cretaceous Tracy Sand depth of 5,235 feet), and thick sand development as indicated by the electric logs in the area. Considering all of the information discussed, it seems reasonable to assume that the Miocene permeability is at least one order of magnitude lower than the highest reported Miocene permeability (50 feet/day or 20,000 md) and one order of magnitude higher than the Cretaceous Tracy Sand of 117 md. As such, a permeability of 1 darcy (1,000 md) or a K of 2.7 ft/day is used for the Miocene target injection zone in the AOR calculation.

Hydrostatic head data for the USDW (h_w) or the injection zone (h_{bo}) are not available and are difficult to estimate. The hydrostatic head, (i.e. the height to which groundwater rises in a well completed in a confined aquifer) is the sum of the pressure head and elevation head (Todd, 2004; Fetter, 1988). Some of the factors considered in the head estimation are outlined below.

From a regional perspective, the geologic formations of the USDWs and the Miocene target injection zone both outcrop in the foothills of the Sierra Nevada to the east, controlling the elevation head. As water pressure increases toward the center portion of the basin, hydrostatic heads may increase with depth. This regional condition may be altered somewhat due to the outlets of the USDW and the target zones as water moves out of the basin. Groundwater production is not occurring from either target zone so the hydrostatic head is likely unimpacted from pumping. Although the shallow USDWs are pumped in the area, the deeper USDWs are confined and the impact from pumping is assumed to be less with depth.

Given this uncertainty, various trial inputs of hydrostatic head were used in the equation to determine the sensitivity of the AOR calculation to head. Since the equation only applies the difference in the hydrostatic heads, actual head estimates are not required. Using the estimated input parameters summarized in the following table, the ZEI (and AOR) can be estimated for each of the two target zones for several estimates of $h_w - h_{bo}$.

Parameter	Miocene Target Zone	Cretaceous Target Zone
K, feet/day	2.7	0.3
H, feet	372	267
t, days	7,300	7,300
S, dimensionless	3.7×10^{-4}	2.7×10^{-4}
Q, cubic feet/day	40,106.95	40,106.95
S_pG_b, dimensionless	1	1
$h_w - h_{bo}$, feet	32	335
Solve for r:	1,310	1,266
$h_w - h_{bo}$, feet	28	274
Solve for r:	2,474	2,617
$h_w - h_{bo}$, feet	25	233
Solve for r:	3,985	4,264

As shown in the three calculations for r above, results are sensitive to estimates of $h_w - h_{bo}$. Much larger differences in head are required in the Cretaceous zone to produce the same r, but larger differences are more likely due the larger vertical distance between the Cretaceous and the USDW base (3,462 feet) compared to the Miocene target (372 feet). As shown from the calculations, an AOR of less than 0.25 mile (1,310 feet) is supported by a difference in heads of only 32 feet in the Miocene and 335 feet in the Cretaceous. For an AOR of about 0.5 miles, a head difference of about 28 feet should exist between the Miocene and the USDW and a head difference of 274 feet between the Cretaceous and the USDW. The required head differences drop further when evaluating an AOR that extends to the closest deep well (about 4,385 feet), which has been abandoned. To support an AOR less than that distance, head differences of only 25 feet and 233 feet are required for the Miocene and Cretaceous sands, respectively.

Again, this calculation assumes that there is a possible vertical pathway to the USDW, a condition that does not exist at this site at a distance less than 4,385 feet. As explained in Attachment F, there is a 250 foot thick confining layer above the Miocene target that is laterally continuous for at least several miles around the site. There are no faults or other natural conduits within 0.5 miles that have been identified that could transport injectate into USDWs. The only identified pathway within at least one mile of the site is the presence of two abandoned gas exploration wells that penetrate the target zones and are located about 4,400 feet from the CSC proposed injection well. To further analyze potential impacts at these wells, additional calculations to estimate pressure changes at the abandoned well locations are presented in the following section.

Estimated Area of Review – Pressure Wave Calculation Method

In order to estimate the increase in formation pressure resulting from the injection project at specific times and distances from the injection well, an equation provided by Warner and Lehr (1981) was used. This equation assumes that the system has reached steady state from injection, an assumption applicable to this project because impacts are analyzed for a long time (20 years) after injection is initiated. The equation used in this calculation, along with inputs for both Miocene and Cretaceous injection targets, is provided below.

$$P(r,t)= (Pi + (162.6Qu)/(kh)) (\mathrm{log}t + \mathrm{log}(k/(pucr^{2})) - 3.23 + 0.87s)$$

where:

P(r,t) = pressure as function of distance from the injection well and time since injection began, psi
Pi = initial reservoir pressure, psi
Q = flow rate, bbls/day
u = viscosity of injectate, cp
k = permeability, md
h = reservoir thickness, feet
t = time, hours
p = porosity, fraction

c = compressibility, v/v/psi
r = radial distance, feet
s = well efficiency, considered negligible for this example

using:

Pi = 870.3 psi (Miocene target 2,010 feet x 0.433 psi/ft)
2,266.7 psi (Cretaceous target 5,235 feet x 0.433 psi/ft)
Q = 7,131.4 bbls/day (both injection targets)
u = 1 cp (both injection targets)
k = 1,000 md (Miocene target)
117 md (Cretaceous target)
h = 372 feet (Miocene target)
267 feet (Cretaceous target)
t = 175,200 hours (hours in 20 years for both injection targets)
p = 0.30 (Miocene target)
0.17 (Cretaceous target)
c = 0.000003, dimensionless (Warner and Lehr, 1981 for both targets)
r = up to 5,000 feet including a calculation at 4,400 feet (distance to closest deep well)

Solving the above equation for various distances (r) from the injection well and subtracting the initial pressure from the total pressure, the increase in pressure due to 20 years of injection at 208 gpm is predicted as follows:

Distance from injection well, r	Increase in pressure in Miocene Sand	Increase in pressure in Cretaceous Sand
1,000 feet	16 psi	163 psi
2,000 feet	14 psi	140 psi
3,000 feet	13 psi	127 psi
4,000 feet	12 psi	118 psi
4,400 feet	12 psi	115 psi
5,000 feet	11 psi	111 psi

As shown above, the increase in pressure 5,000 feet from the injection well after 20 years of injection is either approximately 11 psi in the Miocene Sand or 111 psi in the Cretaceous Sand, depending on the completion zone. Assuming an AOR of 0.5 mile (2,640 feet), predicted pressure increases are about 13 psi and 131 psi for the Miocene target and the Cretaceous target, respectively.

The order of magnitude increase in the Cretaceous Sand pressure is primarily controlled by the order of magnitude decrease in permeability. Again, the permeability of the Cretaceous Sand has been measured in nearby gas fields (Supporting Documentation). The permeability of the Miocene Sand is less certain, however, it is reasonable to assume a much higher permeability given the much shallower depth, younger age, and permeable character on electric logs. Even if the Miocene Sand permeability was reduced by one half from the current estimate (1,000 md to 500 md), the pressure increase at 4,400 feet from the injection well (distance to the closest well) would only be 22 psi, still a relatively small increase.

As previously mentioned, the only two wells within about 1.5 miles of the proposed CSC injection site are the Quintana S.P. No. 1 well, which is about 4,385 feet southwest, and the Pan Petroleum Hayre Egg Farms No. 1 well, which is about 4,520 feet northeast. Using the equation and values discussed above, the predicted pressure increases at the abandoned wells are only about 12 psi from injection into the Miocene Sand and about 115 psi from injection into the Cretaceous Sand using a distance of 4,400 feet from the injection well (see table above).

As shown in more detail in Attachment C, the weight of the fluid in the abandoned wells would prevent fluid migration, given these ranges of pressures. Borehole fluids (mud) in the Quintana and Pan Petroleum wells have pressures of 87 pounds per cubic foot (ppcf) and 78 ppcf, respectively. These provide pressures of 1,078 psi and 1,050 psi for the two wells at the Miocene level, and 3,166 psi and 2,745 psi for the two wells at the Cretaceous level. Subtracting formation pressures from the mud pressures results in 303 psi and 288 psi at the Miocene level and 840 psi and 545 psi at the Cretaceous level for the Quintana and Pan Petroleum wells, respectively. Injection pressures are anticipated to be much lower than these calculated pressures in the abandoned wells. Abandonment procedures for the two wells are provided in Attachment C and in the Supporting Documentation included with this application. Given the abandonment procedures and mud weights in the two abandoned wells, these pressures are not expected to impact USDWs.

Area of Review Selection

Until the injection well is drilled and tested, there are unknowns associated with all of the methods used to determine a reasonable AOR. However, using reasonable input estimates, all of the calculations support an AOR of less than 0.5 mile. Permit applications at three UIC well sites in San Joaquin County were reviewed to determine the respective AORs chosen at these facilities after the injection wells were drilled and site-specific conditions were better known. The AORs are summarized below:

UIC Class I Permit Applicant	Distance from CSC Site	Target Injection Zone	Area of Review (AOR)
San Joaquin CoGen	2.5 miles southwest	Cretaceous sand	0.25 mile
SMS Briners	11 miles northeast	Cretaceous sand	0.25 mile
NCPA	19 miles northwest	Eocene sand	1 mile*

*AOR for NCPA was arbitrarily expanded to the closest well. All calculations supported <0.25 mile.

Because of the many uncertainties that cannot be presently addressed, a conservative (relatively large) AOR of 0.5 mile is selected with respect to providing detailed information on wells and other possible pathways for injection fluids. This will ensure a conservative AOR, even in the unlikely event that site-specific data from injection well testing supports enlarging the AOR from previous calculations. As such, an

AOR of 0.5 mile from the location of the proposed injection well is used in the remainder of this permit application.

ATTACHMENT B - Maps Of Well/Area and Area Of Review

Requirements

This attachment provides information on the physical setting in the vicinity of the proposed injection well and information on wells and water features to ensure that the project poses no risk to drinking water supplies. At a minimum, a topographic map that extends one mile beyond the property boundaries must be included. Maps must include the intake and discharge structures and all hazardous waste treatment, storage, or disposal facilities. Within the AOR, wells, surface water bodies, and other pertinent features must be shown on a map. The map must also identify drinking water wells within one quarter mile of the facility or in the AOR. However, only public information is required to be placed on the map.

Physical Setting and Surface Water Features

The CSC site is located approximately three miles northwest of the City of Manteca and one mile northeast of the City of Lathrop in south-central San Joaquin County (Figure 1). The topography is generally flat to gently sloping to the west toward the San Joaquin River, located about 3.5 miles west of the site. Natural ground surface elevations are approximately 20 to 23 feet above mean sea level (msl) at the site. Several shallow basins have been excavated on the western and northern portions of the site associated with former wastewater treatment and disposal (Figure 2).

The only natural surface water feature in the area is the San Joaquin River (Figure 1). The river drains the southern San Joaquin Valley and flows northward toward the Sacramento-San Joaquin Delta and ultimately into San Francisco Bay. The site is bounded on the west and south by irrigation drainage canals operated by the South San Joaquin Irrigation District (SSJID) (Figure 2). Additional canals associated with the SSJID canal distribution system cross the general area (Figures 1 and 2). Onsite stormwater currently drains westward to a series of onsite ponds associated with the former wastewater treatment system.

The San Joaquin Valley has a semi-arid climate and the site receives about 14 inches of precipitation each year (URS, May 2005). More than 80 percent of the precipitation falls from November to April.

Land use around the CSC site is predominantly agricultural with industrial facilities to the west and south. Adjacent to the site on the west is the Defense Distribution Depot San Joaquin, California Sharpe military facility (a.k.a. Sharpe Army Depot or DDJC-Sharpe) (Figure 1). Some of the surrounding land is being converted from agricultural to residential as the nearby cities of Manteca and Lathrop continue to grow (Figure 1).

Two water supply wells exist on the CSC site (Figure 2). One well, on the southeastern portion of the site, was drilled in 1972 to a depth of 160 feet. Records are unavailable for the second well, which is located on the south-central portion of the site and used only for backup and fire protection. Three shallow monitoring wells have been installed on the northern parcel of the property to monitor impacts to groundwater from former land application of wastewater (Figure 2).

Wells Within Area of Review

Because groundwater serves as a source of municipal, domestic, and irrigation water supply, there are more than 600 water supply wells that have been drilled within 2.5 miles of the project. In addition, nearby industrial facilities, including the former owner of the CSC site, have installed a total of more than 400 wells to monitor and/or extract shallow contaminated groundwater. The occurrence of hydrocarbons in nearby gas fields have resulted in eight gas exploratory wells drilled within about two miles of the site. None of these wells are currently producing gas. With the exception of seven of the exploratory gas wells (all abandoned), none of the wells have penetrated the target injection zones.

According to the public records compiled from eight separate sources, wells within the 0.5-mile AOR include following:

- 12 water supply wells
- 1 abandoned gas exploration well
- 14 monitoring wells.

These wells in the AOR are shown on Figure 3 and are summarized in Table 1. Well data compiled both inside and in the vicinity of the AOR are described in more detail below.

Water Supply Wells

Local permitting agencies for water supply wells in California require that drillers submit a Water Well Drillers report to the Department of Water Resources (DWR) for all water supply wells drilled in the state, including domestic, municipal, industrial, and irrigation wells (Water Code Section 13752). Although these records are not available to private parties due to confidentiality requirements, public agencies can allow access to the records for specific uses. In support of this project, the Central Valley Regional Water Quality Control Board (CVRWQCB) allowed access to well records within an approximate 2.5 mile radius around the site. According to the DWR records, more than 600 water wells have been drilled within this area, although well depths are significantly shallower than the target injection zones. None of the wells produce drinking water below

400 feet. Only six wells out of the 600 wells in the DWR records were drilled below 400 feet (several of these were abandoned test holes) and only two of the six were drilled below 500 feet. The two wells below 500 feet were drilled on the former Occidental Chemicals facility for wastewater injection to total depths of 504 feet and 510 feet. Wells from the DWR records were plotted on the map both inside the 0.5-mile AOR and an additional mile outside the AOR (Figure 3). Well locations were not field checked and are approximate since most of the DWR well records do not contain detailed location data. However, by plotting wells in a much larger area than the AOR, it is reasonable to assume that all wells on file with DWR in the AOR have been reasonably identified. Since none of the wells within an approximate 2.5 mile radius penetrate either of the injection zones, approximate locations were determined to be sufficient for the purposes of this evaluation.

Although the DWR records contained information for hundreds of wells in the site vicinity, records from CVRWQCB documents indicated that several known wells appeared to be missing in the DWR files. In order to ensure a more accurate accounting of wells in the area, additional documents and data were compiled from the following sources to supplement the DWR data.

- City of Stockton
- City of Lathrop
- City of Manteca
- San Joaquin County
- Former Occidental Chemicals (documents accessed through the CVRWQCB)
- Defense Distribution Depot San Joaquin Sharpe site (DDJC-Sharpe)

Although many of these wells were outside of the AOR, they were considered in this evaluation for completeness. A summary of the well data is provided below.

City of Stockton – The City of Stockton is located approximately six miles north of the project site and provides municipal water supply to residents through a combination of groundwater wells and surface water deliveries that are organized into three service areas. The South Stockton service area is the closest to the proposed injection well with the southern boundary located along Roth Road, approximately 1.5 miles north of the site. Well depths within the service area range from 172 feet to 625 feet (West Yost, 2004). The closest well to the project site is located approximately 3.75 miles to the northeast and is 429 feet deep (West Yost, 2004), outside of the AOR.

City of Lathrop – The CSC property is located east and north of the City of Lathrop's water service area. The City has historically relied on groundwater for its municipal water supply and currently pumps from four active wells (Nolte, 2001; City of Lathrop, personal communication, July 26, 2005). None of these wells are in the AOR. Wells are completed in the Victor and Laguna formations with casing depths from 270 feet to 282 feet. The closest well to the CSC site is approximately 6,000 feet to the southwest and is completed to a depth of 270 feet (Nolte, 2001). Three additional wells are planned, but they will be more than a mile away from the site and will not be drilled below about 300 feet (City of Lathrop, personal communication, July 26, 2005).

City of Manteca – The City of Manteca water system consists of 16 active groundwater wells completed to depths ranging from 100 feet to 400 feet (City of Manteca, personal communication, July 22, 2005 and July 25, 2005). The City wells closest to the site are Well No. 23 and Well No. 12, approximately 4,900 feet and 9,800 feet to the southwest, respectively (Kennedy/Jenks, December 30, 2002). An additional unnamed test well has been drilled approximately 6,700 feet east (near the intersection of Lathrop and Union roads) for the new Union Ranch development. A new City well may be drilled at that location in the near future (City of Manteca, personal communication, July 22, 2005). No City wells have been drilled deeper than 425 feet due to increasing salinity below that depth (City of Manteca, July 25, 2005, and personal communication, July 22, 2005).

Monitoring Wells

CSC Site – There have been five shallow groundwater monitoring wells installed to depths of 30 feet on and off of the site. Four of the five wells are within the AOR. These wells were installed in 2000 in response to regulatory requirements for monitoring percolation of treated wastewater at the site. Two of the wells were drilled on agricultural parcels east of the facility owned by the previous site operator. This parcel does not belong to the current CSC owners. Three additional wells were drilled on the northern parcel of the current site to monitor onsite percolation ponds. Water levels from these wells were used to assess local groundwater flow in the drinking water aquifers.

DDJC Sharpe – The Defense Distribution Depot San Joaquin Sharpe Site (Sharpe) is an active storage and distribution facility serving the U.S. military in the western U.S. and throughout the Pacific Region (CVRWQCB, June 9, 2004). The facility was first established in 1940 and covers 720 acres west of the project site. The Sharpe site is adjacent to the western parcel boundary of the CSC site, separated by an agricultural distribution canal. More than 300 wells have been drilled on the facility to investigate and remediate groundwater contamination. These wells consist of 212 monitoring wells, 45 extraction wells, 10 injection wells, 6 observation wells for injection, and 40 piezometers (URS, May 2005). Ten monitoring wells and piezometers are within the AOR.

Most of the monitoring, extraction, and injection wells target aquifers from the water table down to about 200 feet. Only 11 monitoring wells have been drilled to depths greater than 200 feet and none were drilled deeper than 300 feet (URS, May 2005). Piezometers are completed at the water table and are generally shallower than 30 feet. The deepest wells in the Sharpe monitoring program are offsite production wells that have total depths ranging from 100 feet to 375 feet deep (URS, May 2005). The deepest well within the AOR is 113 feet.

Former Occidental Chemicals – The former Occidental Chemical Corporation facility, located on 341 acres approximately 1.7 miles southwest of the project site, has manufactured fertilizers and pesticides since 1952 (CVRWQCB, no date 2004). Soil and groundwater has been impacted with various chemicals including 1,2-dibromo-3-chloropropane (DBCP), ethylene dibromide (EDB), solfolane, and several inorganic constituents. As a result of documented groundwater contamination, more than 60 monitoring wells, 8 extraction wells, and 2 injection wells have been installed at this facility (CVRWQCB, no date 2004). None of these wells are within the AOR and none have been drilled deeper than 510 feet.

Injection Wells

DDJC - Sharpe - As a result of groundwater contamination at the site, groundwater is being extracted, treated and re-injected back into the groundwater system. Ten injection wells have been installed in the central portion of the site. Wells are screened over various shallow aquifers from depths of 22 feet to 152 feet (URS, July 29, 2005).

Former Occidental Chemicals – At the former Occidental Chemicals facility, two injection wells receive treated effluent from the facility's groundwater extraction and treatment program for the remediation of groundwater contamination. The two injection wells, IW-1 and IW-2, are located on the western and southwestern portions of the property and are drilled to depths of 504 feet and 510 feet, respectively. Injection zones are screened in various sand intervals from depths of 300 feet to 496 feet. Neither well is in the AOR.

San Joaquin CoGen (abandoned) – This facility, located 2.5 miles southwest of the project site, installed a deep UIC injection well in January 1990 to dispose of wastewater associated with electricity generation (San Joaquin CoGen, November 1988). The well was drilled to a depth of 9,646 feet and completed as a Class I non-hazardous UIC injection well in the Lathrop sands from 9,585 feet to 8,574 feet. The injection well could not take sufficient quantities of wastewater and was essentially idle until 1993 when the well was plugged back and re-completed in shallower Cretaceous sands at approximately 4,600 feet. Due in part to the low permeability of the sands, sufficient injection capacity was never established and the well was properly abandoned in 2003 (CDOG May 19, 2005).

Oil and Gas Wells

Information on gas exploration and production wells in and surrounding the local gas fields was obtained from the California Division of Oil and Gas (CDOG) and supplemented with DWR well files. One well in the DWR files may have been drilled within the AOR although the exact location is not documented. This well was drilled by an unknown party for the exploration of gas in 1888. The section-township-range location indicates that the well was drilled within a mile of the CSC site. The well was apparently drilled to a total depth of 1,042 feet and recovered small amounts of gas and salt water before being abandoned. Although abandonment procedures of the well are unknown given its early date, the well depth is not sufficient to have penetrated the target injection zones or the upper confining layers, and as such, the abandoned well is not considered a risk for vertical migration. The well record is included in the Supporting Documentation attached to this application.

The two closest wells to penetrate the target injection zones, Quintana S.P. No. 1 and Pan Petroleum Hayre Egg Farms No. 1, are located approximately 4,385 feet southwest and 4,520 feet northeast of the proposed CSC injection well, respectively (Figure 3). Both of these wells were abandoned when petroleum reserves were not found in commercial quantities. Wells were properly plugged according to the CDOG requirements. Additional well data and plugging information are provided in Attachment C.

Additional gas exploration wells have been drilled outside the AOR and were used to interpret the regional geology and prepare the target injection zone maps. Data from 20 wells within about 4 miles of the site were used in the interpretations in Attachment F. These wells are labeled on Figure 1.

ATTACHMENT C – Corrective Action Plan and Well Data

Requirements

This attachment requires a tabulation of well data for all wells within the AOR that penetrate the target injection zones. The table must include the well type, construction data, location, depth, date drilled, and records of plugging and/or completion. A corrective action plan must be proposed under 40 CFR 144.55 if any of these wells have not been properly plugged to prevent the migration of injectate through improperly sealed wellbores into the overlying USDW. As provided in 40 CFR 146.7, the following criteria shall be considered in determining the adequacy of any corrective action plan:

- Nature and volume of injected fluid
- Nature of native fluids or by-products of injection
- Potentially affected population
- Geology
- Hydrology
- History of the injection operation
- Completion and plugging records
- Abandonment procedures in effect at the time the well was abandoned
- Hydraulic connections with USDW.

Closest Wells Penetrating the Target Injection Zones

As discussed in Attachment B, no wells have been identified within the 0.5 mile AOR that have penetrated the target injection zones. Only seven wells within a two-mile radius have penetrated the target injection zones. Information and plugging data for those wells are summarized on Table 2.

As shown on Table 2, the closest deep wells are located approximately 4,385 feet southwest (Quintana SP No. 1 well) and 4,520 feet to the north (Pan Petroleum Hayre Egg Farms No. 1 well) (Figures 1 and 3). The analysis in Attachment A indicated that no impacts to USDWs would result from these wells. To further illustrate the details of the plugged wells, a schematic cross section is shown on Figure 4. Abandonment records obtained from the CDOG are provided in the supporting documentation attached to this submittal.

Figure 4 illustrates the depth relationships between the target injection zones in the proposed injection well and the plugs located in the two closest deep wells. As shown the S.P. No. 1 well lowermost plug separates the alternative target injection zone in the Cretaceous from USDWs. The upper plugs in both wells at approximately 1,000 feet separate the base of the fresh water aquifers (TDS <2,000 mg/L) at approximately 570 feet (elevation -550 below msl) from both target injection zones (more information on the base of fresh water provided in Attachment D). Although the plugs do not separate the Miocene target from the estimated base of the USDW, the mud weight, confining layer, and distance from the injection well assure no impacts to USDWs from injection, given the anticipated pressures increases from injection as calculated in Attachment B.

Corrective Action Plan

Since no known wells within the AOR have penetrated the zones of injection, no corrective action plan is required under 40 CFR 144.55. Data collected during the drilling and testing process will be used to confirm the current assumptions.

ATTACHMENT D – Maps and Cross Sections of USDW

Requirements

All Underground Sources of Drinking Water (USDWs) are to be defined using geologic maps and cross sections that delineate the vertical and horizontal limits of USDW in the AOR. The occurrence of groundwater and the direction of flow in the USDW, where known, shall be described. Cross sections shall also depict the vertical location of USDW relative to the injection formation.

Estimation of the Base of USDW

USDWs are defined by the UIC regulations as aquifers containing groundwater with a TDS value below 10,000 mg/L. In this area, the base of the USDW has not been defined. Shallow drinking water aquifers above about 300 feet produce fresh water to wells with TDS values below 500 mg/L. Some TDS data are available in the area down to about 500 feet. Data are also available from the deeper Cretaceous-age marine sands, indicating TDS concentrations greater than 10,000 mg/L below 3,500 feet in this area. However, water quality data are unavailable between about 500 feet and 3,500 feet. To determine the base of the USDW, regional geologic and hydrogeologic information was used. An approximate depth of 1,800 feet for the base of the USDW beneath the CSC site was selected as explained in more detail in the following sections.

Geologic and Hydrogeologic Setting

The CSC site is located in south-central San Joaquin County in the northern portion of the San Joaquin Valley of California. This valley has been filled with thousands of feet of Tertiary and Quaternary sediments sourced from the consolidated rocks of the Sierra Nevada to the east and the Coast Range rocks to the west. The geologic map on Figure 5 identifies the geologic formation names of these sediments and shows the extent of the valley around the CSC site, marked predominantly by the Quaternary aged deposits (“Q” abbreviations on Figure 5). The Jurassic rocks of the Sierra Nevada on the northeast (Jgo and Jch) and the Jurassic and Cretaceous rocks of the Coast Range on the southwest (Kjf) extend beneath the valley and form the basement complex of the sedimentary basin.

Because the Sierra Nevada mountain-building processes pre-dated the rising of the Coast Ranges, deposition through at least Cretaceous time was predominantly marine (Norris and Webb, 1990). The rising of the Coast Ranges ultimately cut off the valley’s outlet to the ocean and resulted in increasing non-marine deposition throughout most of the Tertiary and Quaternary. Shallow brackish and freshwater lakes resulted in deposition of widespread clays throughout the valley during the Tertiary, including the Corcoran Clay, which appears to extend into the study area south of the CSC site. Shallow sediments down to these lacustrine clays at about 500 feet are used in the area for water supply.

The CSC site is located in the Eastern San Joaquin subbasin of the larger San Joaquin Valley groundwater basin (DWR, March 5, 2003).The subbasin covers more than 1,000 square miles and is bounded by the San Joaquin River on the west, the Stanislaus River on the south, and the Mokelumne River on the north. The eastern subbasin boundary is the intersection of the alluvium with the consolidated rocks of the Sierra Nevada foothills. Groundwater occurs in the unconsolidated alluvial deposits beneath this basin under unconfined conditions and becomes more confined with depth.

Aquifers and Hydrostratigraphy

Local nomenclature of the geologic units and hydrostratigraphy beneath the CSC site are summarized on Figure 6. The stratigraphic column presented on Figure 6 was slightly modified from DWR (1955) to better reflect project-specific conditions. The main aquifers that provide water supply in the subbasin are comprised of the Quaternary and Upper Tertiary (Pliocene) sediments that extend below the site at an approximate depth of 1,000 feet. These sediments include various recent alluvial deposits as well as the Modesto, Riverbank, and Victor formations of Quaternary age and the Laguna formation of Tertiary age. Salinity increases with depth and limits water use at about 500 feet. The underlying Mehrten formation of Miocene age is considered to provide suitable water supply in some portions of the groundwater basin, but is limited by water quality problems in the study area (Figure 6) (DWR, 1955, 1967).

The Modesto and Riverbank formations and other Quaternary alluvial deposits are exposed on the surface at the CSC site and east of the site (Qm, Qr, and Qs on Figure 5) (Wagner, et. al., 1991). These sediments are Recent to Late Pleistocene in age and consist of dune sands, alluvial fans and inter-fan deposits sourced from the east. Maximum thicknesses of about 150 feet are recorded near the central portion of the basin near the CSC site (DWR, March 5, 2003). Geologic investigations at the Occidental Chemical facility show interbeds of sand and silty clay (assumed to be mostly the Modesto formation) down to about 200 feet, where a 10- to 50-foot clay layer has been mapped. The clay is interpreted to be the northern extension of the Pleistocene Corcoran Clay or the equivalent (Figure 6) (Franks, 1981; The Source Group, July 18, 2002).

The Laguna formation is Plio-Pleistocene in age and provides water for most of the supply wells in the area. Sands and gravels from stream deposition result in high permeability and productive wells. However, the heterogeneous nature of the deposits results in local confining units. DWR mapping indicates that the Laguna extends to a depth of around 1,000 feet beneath the CSC site and is the lowermost aquifer containing fresh water. TDS concentrations are <2,000 mg/L in the upper portions of this formation.

The Miocene-age Mehrten formation lies below the fresh water aquifers. The Mehrten is typically a well-indurated andesitic sandstone, but varies in lithology. Interbeds of conglomerate, tuffaceous siltstone, and claystone have been mapped in the formation (DWR, March 5, 2003). Groundwater in the Mehrten is assumed to be confined in this area of the basin. The Mehrten formation is reported to be approximately 600 to 800 feet thick in the vicinity of the CSC site (DWR, 1967). Using nearby electric logs and other data, the Mehrten is interpreted to occur at about 1,000 feet beneath the CSC site and extends to an approximate depth of 1,800 feet (CDOG, May 19, 2005; DWR, 1967). Although the Mehrten contains fresh water north of the Stockton Arch, it is considered “saline” for drinking water purposes in this area (DWR, 1967). This observation and other data (discussed in subsequent sections) indicate that the Mehrten is likely the lowermost USDW in the area.

Below the Mehrten formation is the Valley Springs formation, also Miocene in age (Figure 6). The Valley Springs is considered to contain saline water and has not been developed for water supply in the area (DWR, 1967; DWR, March 5, 2003). Available data indicate that the Valley Springs formation has TDS above 10,000 mg/L (discussed in more detail in following sections) and, therefore, is below USDWs.

The exact thickness of the Valley Springs or the age of the sediments underlying this formation is not known. Thicker sections of Eocene and Paleocene sediments exist north of the Stockton Arch and south of the study area in the central San Joaquin Valley, but these sediments have been interpreted to be either thin or missing in this area. (Figure 6; additional information provided in Attachment F). Most investigations south of the site do not differentiate between Paleocene and upper Cretaceous ages for the sediments between about 2,300 feet and 3,500 feet. The main Cretaceous unconformity is mapped at a depth of about 3,500 feet in this area with marine-deposited sediments extending below the unconformity to thicknesses in excess of 8,500 feet (CDOG, May 19, 2005, Figure 6). Data from nearby gas fields indicate that the Cretaceous age sediments have TDS concentrations above 10,000 mg/L (CDOG, 1982).

A cross section of USDWs discussed above is included on Figure 7. The section was prepared by DWR (1967) and has been modified below -800 feet to show the Mehrten formation top below the projected location of the CSC injection well. The base of the Mehrten is assumed to be the base of the USDW in this area as discussed in the following sections.

Water Levels

Groundwater occurs at a relatively shallow depth of approximately 20 feet in the study area. Water level data have been monitored by DWR at a well within about two miles of the site since the 1970s (DWR, July 31, 2005). Data are plotted over time to illustrate the trends and fluctuations of water levels in the area (Figure 8). As shown on the hydrograph, water levels illustrate an overall decline in the last 30 years from an elevation of 22 feet above msl in 1973 to about 9 feet above msl in 2005, although levels have stabilized to some degree over the last 10 years. This overall trend in water levels has been registered throughout the County and results from over-pumping of the groundwater basin (San Joaquin County, September 2004). Water levels have declined significantly during drought cycles (e.g., 1987 to 1992) and recovered during times of increased precipitation (e.g., 1978 to 1986). In 2004, water levels beneath the adjacent Sharpe facility ranged from about 12 feet above msl in the water table aquifer to about -8 feet below msl in deeper aquifers (URS, May 2005).

Groundwater Flow Directions

Prior to groundwater development for agriculture, regional groundwater flow in the area was westerly toward the San Joaquin River and then northward toward the Sacramento-San Joaquin delta. However, pumping has occurred in the groundwater basin dating back to the mid-1800s and groundwater flow patterns have been altered significantly since that time (San Joaquin County, September 2004). Due to over-pumping in the central portion of the County, especially east of Stockton, large water level declines have changed groundwater flow directions toward the central County.

This pattern is illustrated on County-wide water level contour maps prepared through a cooperative monitoring program by the U.S. Geological Survey (USGS), DWR, and San Joaquin County. One of these maps showing water levels in the fall of 1998 is provided on Figure 9. The map indicates that the lowest water levels are recorded in the central portion of the basin east of Stockton. This persistent pumping depression causes regional flow directions to shift to the northeast near the CSC site as shown by the arrows depicting groundwater flow. While water levels below the CSC site are about five feet above msl, the water levels in the pumping depression about ten miles to the northeast are below -50 feet msl, a water level drop of 55 feet (Figure 9). However, the CSC site is located near the transition zone where the influences of regional gradients west and southwest toward the river are less affected by the regional pumping depression. As such, groundwater flow directions west of the CSC site are westerly to northwesterly. Temporal and spatial fluctuations in water levels alter groundwater flow directions from westerly to northeasterly in the vicinity of the site with local flow directions possibly influenced by nearby pumping wells.

According to groundwater investigations beneath the nearby Sharpe facility, flow directions appear to be influenced by both natural westerly flow and the regional pumping depression, resulting in a northwesterly groundwater flow direction (URS, May 2005). The northwesterly flow is evident in all of the shallow unconfined to semi-confined aquifers beneath the Sharpe facility to approximate depths of 300 feet. However, the operation of extraction wells, injection wells, disposal ponds, and, perhaps, local irrigation canals appear to impact local flow directions across the site as indicated by water level contour maps and well locations (URS, May 2005). Easterly to northeasterly flow on the east side of the facility, closest to the CSC site, occurs during some time periods (URS, May 2005).

Water level data in the five CSC monitoring wells are available for 2000 and 2001 (Nolte, February 2002). Water level contour maps presented in the former site owner's annual monitoring reports indicate a variety of groundwater flow directions beneath the site ranging from southwest to northeast. These maps may not reflect regional water table conditions due to the localized influences from the onsite percolation ponds.

Groundwater elevation data from the former Occidental Chemicals facility to the southwest of the CSC site also indicates variable directions of groundwater flow. Shallow groundwater flows mainly to the west and southwest as indicated by contaminant plume mapping (The Source Group, July 18, 2002). However, the deeper aquifer (150 to 200 feet deep), which is apparently influenced more by regional pumping, has a more northeasterly flow direction, especially on the eastern portion of the site, closest to the CSC site.

Groundwater flow in the sedimentary units below about 500 feet cannot be mapped in the area due to a lack of data. However, flow in the deeper section of the USDW, including the Mehrten formation, is expected to be unimpacted by local pumping and is likely controlled mainly by the outcrop elevations in the Sierra Nevada foothills to the east and the regional groundwater discharge area in the Sacramento-San Joaquin delta to the northwest.

Base of Fresh Water

In 1955, DWR published a map on the base of fresh water, placing it at a subsea elevation of approximately -550 feet msl beneath the CSC site (Plate 5, DWR, 1955). A portion of this map is presented unmodified on the right side of Figure 10. This elevation was further corroborated by DWR during a multi-year study about ten years later (DWR, 1967). The DWR definition of fresh water was based on chloride concentrations below about 300 mg/L (DWR, 1967).

An additional map of the base of fresh water was constructed by USGS in 1973 (Berkstresser, 1973). The USGS map was based on more than 900 electric logs and 4,000 chemical analyses in the Sacramento Valley and northern San Joaquin Valley. For the purposes of mapping, USGS defined "fresh water" as groundwater with a specific conductance less than 3,000 umhos/cm (an equivalent TDS concentration of about 2,000 mg/L). These conductance and TDS values are consistent with a chloride concentration in excess of 200 to 300 mg/L, allowing the USGS map to be compared directly to the DWR map. The portion of the USGS map covering the CSC site is shown with the DWR map on the left side of Figure 10. Both maps indicate that the base of fresh water as defined by a TDS concentration of about 2,000 mg/L occurs at an elevation of –550 feet below msl at the CSC site, a depth of about 572 feet at the location of the proposed injection well.

This depth is also consistent with water quality data generated at the former Occidental Chemicals facility, located two miles southwest of the CSC site (Figure 1). At this facility, treated effluent associated with groundwater remediation is being injected back into the lower portion of the main drinking water aquifers at depths of 300 to 500 feet. Formation water from a test hole in this interval contained TDS concentrations from 1,930 mg/L to 2,580 mg/L (Luhdorff & Scalmanini, December 1981).

TDS data were also provided by the DDJC-Sharpe facility in support of this project (URS, July 29, 2005). Although they are not required to monitor groundwater for TDS, 47 measurements in 25 monitoring and production wells were available. A few TDS values exceeded 1,000 mg/L, but well construction data were unavailable for these wells and a relationship between TDS and depth could not be established. Since the deepest well recorded in the DDJC-Sharpe well construction database was only 375 feet deep (URS, May 2005), it was assumed that wells were not sufficiently deep to provide additional information on the base of the USDW.

Base of USDW

Although the base of the fresh water appears to have been adequately defined in this area, the exact base of the USDW (defined by TDS concentrations greater than 10,000 mg/L) is unknown. Upper Cretaceous sands, occurring below about 3,400 feet, appear to have TDS concentrations in excess of 10,000 mg/L as indicated by data from nearby gas fields and a UIC Class I well drilled about 2.5 miles southwest (CDOG, 1982; San Joaquin CoGen, 1988). Although these upper sands are not expected to be well developed beneath the CSC site, the entire Cretaceous interval is likely below the base of the USDW. This places the base of the USDW below 500 feet and above about 3,400 feet, a zone with very limited data.

As previously discussed, the Miocene Mehrten formation is interpreted to occur at an elevation of about -1,000 feet below msl at the CSC site and is reported to contain “saline water” in this area (DWR, 1967; Franks, 1981; CDOG, May 19, 2005; DWR, 1955; Brown and Caldwell, 1985). Salinities of the Mehrten and underlying formations in the vicinity of the Occidental Chemical facility were estimated by Dr. Alvin Franks of the USGS using electric log data (Franks, 1981). His investigation considered data in 20-square mile study area, which included the CSC site. Franks interprets TDS concentrations from about 2,000 mg/L to above 10,000 mg/L in the upper section of the Mehrten at depths from about 800 feet to 1,000 feet, indicating that the base of the USDW may occur within this section. However, data were not consistent with depth.

To further examine these data, the TDS laboratory measurements from the wells at Occidental Chemicals and estimates from log values discussed above were plotted with depth (Figure 11). Data included 27 laboratory measurements of TDS in monitoring well samples from depths of 300 to 500 feet (Luhdorff & Scalmanini, 1981) and 8 depth-specific TDS interpretations from electric logs (Franks, 1981). Data from wells more than four miles away from the site are not included on the plot.

These TDS data are shown on Figure 11 with laboratory data represented by circles or squares, and log estimates represented by the triangles. A linear trend line through all of the data delineates a preliminary salinity profile at the site. As seen on the graph, laboratory analyses follow a better defined salinity trend with depth than do estimates from electric logs, which show significant scatter. Electric log TDS estimates range from 2,210 mg/L to more than 10,000 mg/L in the depth range between about 800 and 1,000 feet. A trend line using only laboratory data would predict TDS values of 10,000 mg/L close to a depth of 1,000 feet.

Although information is incomplete, data from a late 1800s exploratory well provides some additional information on the base of the USDW. Historical well records from DWR files indicate that this well was drilled within one mile of the CSC site (indicated by State well number) and recovered gas and water at a depth of 1,042 feet. The well was apparently drilled in 1888 by an unknown operator and was included in the DWR well files. The well was included in the AOR, even though the exact location is unknown (Table 1). Since the well apparently recovered hydrocarbons at 1,042 feet, it is unlikely that USDW extend significantly deeper than this unit. A reproduction of the well record is provided in the supporting documentation.

Additional TDS data at depths from 2,000 feet to 2,500 feet are available several miles to the north. TDS value of 7,150 mg/L at a depth of 2,000 feet was reported in one well about 6.5 miles north of the site (23B-1N-6E), presumably resulting from a laboratory measurement (DWR, 1955). About 2.5 miles south of this well (about 4.25 miles northwest of the CSC site), TDS values of more than 10,000 mg/L were estimated in a Miocene sand at a depth of 2,500 feet. This well, the Laymac Corporation No. 1 Reynolds & Carver-Long (34-1N-6E, Figure 1), was permitted and operated as a Class II water injection well for the French Camp gas field. Although TDS laboratory analyses were unavailable, a geological and engineering study documented TDS estimates from electric logs from 13,600 mg/L to 18,000 mg/L, meeting the 10,000 mg/L permit requirement for a Class II well (Laymac, 1985; CDOG, July 12, 2005). Geologic correlations to this log indicate that the CSC Miocene target injection zone is equivalent to the interval just above the injection zone of the Laymac well. Class II injection records from the CDOG files are included in the supporting documentation attached to this application.

Collectively all of these data support a USDW base between about 1,000 feet and about 2,000 feet. Salinity estimates from the closest abandoned exploratory well were used to further refine the exact depth of the base of the USDW and to document the likelihood of the target Miocene Sand meeting TDS regulatory requirements. These estimates are presented in the following section.

Salinity Estimates from Quintana SP No. 1 Well

The Quintana S.P. No. 1 well is the well closest to the CSC site that has penetrated the Miocene target injection zone (Figures 1 and 3). The well was drilled by Quintana Petroleum Corporation in 1970 and contains an induction-electrical log over the Miocene section. This log, included in the supporting documentation, was used to estimate formation water salinity, applying a water resistivity method as outlined by Schlumberger (1984). The method calculates water resistivity at formation temperature using an equation relating apparent resistivity of the formation water (Rwa) to the resistivity measurement on the electric log and properties of the formation. A Schlumberger crossplot is then used to graphically determine the salinity of the water (as NaCl) in mg/L. The equation is shown below.

$$Rwa = (Sw)^2 (Rt) / F$$

and:

F = formation factor defined by

$$F = 0.62/P^{2.15}$$

where:

Rwa = actual resistivity of the formation water
Rt = true resistivity read from the Quintana electric log = 2.5 ohm meters
Sw = water saturation of the sand – assumed to be 100% (1.0)
P = porosity = 0.3 estimated from nearby Sonic log (30-1S-7E)
Formation Temperature = corrected to 90 ^{o}F from measurement of 156^{o}F at 7,933 ft

solving:

F = 8.25
Rwa = 0.3

Using crossplot with Rwa and formation temperature (Schlumberger Gen-7):

Salinity = 15,000 mg/L

Although some uncertainties are inherent in this calculation such as the percentage of fine-grain material in the sand, porosity, and water saturation, this estimate of NaCl salinity appears sufficiently high to conclude that TDS would exceed 10,000 mg/L and, therefore, the Miocene target injection zone would be below USDWs. Using this same methodology to estimate salinity values for shallower sands in the Quintana well, electric log data indicate that the sands at a depth of 1,700 feet may contain TDS values between 9,000 and 10,000 mg/L, although the calculation is less certain because of the thinner and finer-grained sand. For a conservative estimate of the USDW base, the bottom of the 1,700-foot sand package (1,789 feet on the Quintana log) is assumed to be the base in this area. Regional correlations indicate that this base will be encountered a depth of 1,773 feet in the CSC injection well.

ATTACHMENT F - Maps and Cross Sections of Geologic Structure of Area

Requirements

Information in this attachment provides the regional geologic setting as well as the local geologic conditions to illustrate the structure, stratigraphy, and lithology of the target injection zones and adjacent confining intervals. Results of the geological evaluation are to be presented on appropriate maps and cross sections.

Regional Geological Setting

The CSC site lies in the central portion of the Great Valley, a large structural basin with a surface elevation near sea level and surrounded by mountains (Norris and Webb, 1990). Also referred to as the Central Valley, the basin represents a relatively un-deformed syncline filled with sediments eroded from the Sierra Nevada to the east and the Coast Ranges to the west. Beneath the CSC site, a thickness of more than 12,000 feet of sedimentary units has been deposited on the basement complex of the Sierra Nevada (Bartow, 1983).

The tectonic history dates to the Late Jurassic with the inception of a subduction zone and trench west of the valley, allowing for the deposition of large thicknesses of sediment from the continental margin (Cherven, May 1983). The subduction likely reactivated volcanic activity, resulting in the plutons and volcano remnants that make up the Sierra Nevada. Sediments eroded from the rising Sierra Nevada were deposited in marine depositional environments in the Central Valley area throughout the Cretaceous.

By the end of the Cretaceous, the subduction complex had been sufficiently uplifted to form a ridge at or above sea level (Cherven, May 1983). This cut off the basin from the sea and created a western source area for sedimentation. Subsidence and regression caused a large thickness of fluvial sediments to be deposited in the basin during the Paleocene, but most of this section appears to have been eroded in the project area, likely due to the uplift of the Stockton Arch (Cherven, May 1983). The Stockton Arch is a regional cross-basin fault with about 3,000 feet of displacement (Teitsworth, 1964). This structural high resulted in the erosion or non-deposition of a significant thickness of Early Tertiary (Paleocene and Eocene) sediments in the vicinity of the site. This erosional surface, called the Cretaceous unconformity, separates Miocene sediments of continental origin from Cretaceous sediments of marine origin in the CSC study area.

Faults

Regional faulting near the CSC site vicinity includes the cross-cutting Stockton Arch described above and a basin-bounding fault, the Vernalis fault, located on the western side of the valley (Figure 5). Both of these faults are regionally extensive. The Vernalis fault is a large reverse fault that parallels regional strike and has a maximum vertical displacement of 1,500 feet (Hoffman, 1963). The bounding fault of the Stockton Arch is thought to exhibit about 3,000 feet of vertical displacement (Teitsworth, 1964). However, both of these faults are located more than five miles from the CSC site and well outside of the 0.5 mile AOR.

In addition to these regional faults, local deformation occurred during the Cretaceous that formed structural and stratigraphic traps of hydrocarbons in the area. Although these faults have not been regionally mapped, they all appear to reflect reverse dip slip with displacement of about 100 feet (CDOG, 1981). These faults were formed in a compressional regime and are not likely conduits for transmitting fluids. Additional evidence for their lack of transmissivity is the fact that faulting has served to trap gas in the productive fields. In addition, these Cretaceous faults do not extend above the Cretaceous unconformity according to regional mapping (CDOG, 1981). As such, they are not considered to be conduits for injectate into USDWs.

Extensive faulting is not anticipated in the post-Cretaceous sediments in this area. Bartow (1991) characterizes the eastern limb of the valley syncline between the Stockton Arch and the San Joaquin River (CSC study area) as the least deformed region of the San Joaquin Valley. No known faults have been mapped in the Miocene section in this area.

Stratigraphy

A stratigraphic section provided by Edmondson et. al. (1964) has been slightly modified to reflect site-specific conditions and is included on Figure 12. This stratigraphic column focuses on nomenclature for a portion of the Upper Cretaceous section (Edmondson, et. al., 1964). Stratigraphic names are assigned to the east side or west side of the valley based on usage. In most cases, the divisions correspond to the source direction of the sand deposition (i.e., west side sands were sourced from the Coast Range on the west and east side sands were sourced from the Sierra Nevada on the east). Although the CSC site is just on the east side of the valley, many of the west-side units extend into the study area since the site is close to the valley center.

Below the USDW discussed in the previous attachment (base of the Mehrten formation) lies a 1,600-foot section of Miocene and Lower Tertiary sediments underlain by a thick sedimentary sequence of Upper Cretaceous age. The lower Miocene section, beginning at about 1,700 feet at the CSC site, is thought to be the Valley Springs formation. The base is less certain since the exact thickness of the unit beneath the site is unknown and older Tertiary sediments may underlie the Valley Springs. These sediments are separated from the main Cretaceous units with an erosional unconformity.

Due to its central location in the valley, the study area is sufficiently far from both eastern and western source areas, and, as a result, has fewer well-developed sands. Many of the thick and coarse-grain sand packages of the Upper Cretaceous are either not present at the site or poorly developed. For example, the Azevedo and Blewett sands are eroded or very thin beneath the CSC site even though they are more than 500 feet thick just a few miles to the southwest (San Joaquin CoGen, 1988; CDOG, May 19, 2005). Western-sourced Tracy sands also pinch out in this area. The Starkey sands, while present, thin dramatically to the west near the CSC site. The lack of sand and lower permeability makes the upper Cretaceous sands a difficult target for injection in this area.

Callaway (1964) indicated that the sands in the Tracy interval (nomenclature used in nearby Lathrop, S.E. gas field) near the CSC site were actually more correctly referred to as the Starkey sands, sourced from the east. The regressive sand pattern of the Starkey as seen on electric logs can be correlated across the area and appears to thin to the west, consistent with an eastern source. Callaway mapped the Tracy sands as deltaic sands extending from western sources and thinning to the east. Both sections appear to thin within the study area, although one thick regressive sand package appears to persist beneath the CSC site, as evidenced by electric log data. However, because the nearby gas fields of Lathrop, Lathrop S.E, and French Camp all keep the nomenclature of Tracy Sand as applied to the Starkey section, the name “Tracy Sand” is used in this document as a synonym for the Cretaceous target injection zone.

Although deeper Cretaceous sands exist beneath the Tracy Sand, they are much less permeable (CDOG, 1982). Further, the deeper sands were tested in a nearby UIC Class I injection well and could not sustain reasonable injection rates (San Joaquin CoGen, 1988). This abandoned UIC well, located 2.5 miles southwest at the San Joaquin CoGen facility, failed to function as an adequate injection well in the Lathrop Sand at a depth of about 8,575 feet. A comparison of electric logs does not indicate that the Lathrop sands are significantly thicker or more permeable beneath the CSC site. As such, they are not considered a target for injection.

Miocene Target Injection Zone

The character and thickness of the Miocene target injection zone is illustrated on the electrical log of the nearby S.P. No. 1 well, located 4,385 feet southwest of the CSC proposed well (Figure 13). The sand interval is approximately 389 feet thick. The target sand is estimated to be approximately 372 feet thick in the proposed CSC injection well based on an average thickness of the zone in nearby logs. As indicated by the significant negative deflection of the SP curve (up to -40 mv from an average shale baseline, Figure 13), the sands appear coarse-grained with only minor amounts of silt and clay. The separation of the deep induction curve and the short normal curve indicates the more permeable zones.

Low permeability layers exist both above and below the target sand. The upper confining layer is almost 300 feet thick. Mapping indicates that the zone extends for miles around the site and maintains a thickness of at least 180 feet where mapped. On a mudlog from a well 1.8 miles southeast, the Miocene confining layer is described as a blue-gray clay to dark gray shale (Schleiss No. 1, location shown on Figure 1 and electric and sonic logs in Supporting Documentation). This thick, persistent, and low permeability unit provides significant protection for the USDWs in the area.

Structural contours on the top of the Miocene Sand target injection zone are shown on Figure 14. As shown by the contours, the sand occurs at subsea elevations from about -1,800 feet below msl to -2,250 feet below msl, indicating a southwestern structural dip of about one degree. As shown on the map, the top of the target zone is expected to exist at an elevation of -1,975 feet below msl at the proposed CSC injection well (Figure 14). Assuming a ground surface elevation of 23 feet and a rig floor height of approximately 12 feet, the depth of the Miocene is anticipated at 2,010 feet in the CSC injection well.

An isopach map of the upper confining layer for the Miocene Sand target is shown on Figure 15. The confining layer persists across the study area and ranges from about 125 feet to 375 feet thick as indicated by electric logs. The thickness of the unit is expected to be approximately 250 thick in the CSC injection well (Figure 15).

Cross sections illustrating the structural and stratigraphic relationships of the target injection zones across the site are shown on Figures 16 and 17. Cross section locations are included on Figure 15. Figure 16 shows a cross section oriented southwest-northeast, approximately along the structural dip of the area. The cross section on Figure 17 is oriented northwest-southeast, approximately along the structural strike. As shown on the sections, a deep abandoned exploration well is correlated on either side of the CSC site, approximately equidistant from the proposed well. Both sections have the same vertical scale, but the section on Figure 17 has a horizontal scale of almost twice that on Figure 16, increasing the vertical exaggeration on the strike-oriented section.

Both sections show the persistence of the target Miocene sand package and the upper confining layer across the study area. Both the confining layer and the sand thicken to the southwest (Figure 16), consistent with the maps previously discussed (Figures 14 and 15).

Cretaceous Target Injection Zone

The injection target in the Cretaceous section is the equivalent of the 2nd Tracy Sand, using nomenclature from the Lathrop S.E. gas field (CDOG, 1982). This sand is generally equivalent to the Starkey Sands, consistent with nomenclature used east of the site (Figure 12). In general, the Starkey Sands are thought to be sourced from the east and the Tracy Sands sourced from the west. Log character has been used in the past to differentiate the units and based on these descriptions, the target injection sand may be more correctly called the Starkey Sands. However, to avoid confusion with previously-established nomenclature in the local area, the target sand is referred to as the 2nd Tracy Sand. The more general term, Cretaceous Sand target, also refers to this sand.

The electric log response of the Cretaceous target injection zone is shown on the type log on Figure 18. Again the log from the nearby Quintana S.P. No. 1 well is used to illustrate the sand. The thick sand interval is approximately 350 feet thick on the log. The interval thins to the northeast and is expected to be approximately 267 feet thick in the CSC injection well. As indicated by the SP curve, the sand package demonstrates a coarsening-upward sequence, whereby the fine-grained sands in the lower portion of the zone grade upward into more coarse-grained sands (Figure 18). This pattern produces a characteristic “carrot” shape on the electric log, assisting log correlation. The permeability of the sand is demonstrated by the large negative SP deflection and the separation of the short normal and deep induction curves. The separation indicates that the zone is sufficiently permeable to have been invaded by drilling fluids, a typical indication of permeability (Schlumberger, 1984). A sidewall core sample from the 2nd Tracy Sand in the Christiana Schleiss well (30-1S-7E, Figure 1) is described as gray fine to medium-grained sand that is well sorted, kaolinitic, friable, and permeable.

A structural contour map on the top of the Cretaceous target injection zone is shown on Figure 19. As shown by the contours, the zone dips to the southwest at an average dip of approximately 3.5 degrees. The top of the sand is flatter in the immediate vicinity of the CSC site and steepens to the southwest. A fault on the updip (northeast) side of the nearby abandoned Southeast Lathrop Gas Field has been projected onto this map using the fault location mapped by CDOG (1982) in their geologic summary of the gas field. The displacement across the fault appears to be decreasing up-section and is interpreted to be between 100 and 200 feet at this level. However, the lack of gas in the Tracy Sand may indicate that the fault did not provide closure to the structure. The fault is not expected to be a conduit to USDWs, given the nature and age of the fault. CDOG interprets the fault to be truncated along the Cretaceous unconformity, an interpretation consistent with other geologic interpretations in the area, and does not extend the fault into younger sediments. In addition, the nature of the field-bounding faults is to provide closure to a gas reservoir and therefore, is not a conduit to flow.

Numerous confining units separate the target Cretaceous Sand from USDWs over the 3,500-foot interval between the two zones. As shown on Figures 16, 17, and 18, a continuous local confining layer exists immediately above the sand package. The thickness of this local confining layer is contoured on Figure 20. As shown on the map, the unit thins to the west, but is persistent within a few miles of the site. The zone apparently does not separate the 2nd Tracy Sand from upper Tracy sands in the Lathrop Gas Field located four miles northwest (CDOG, 1982). However, an additional confining unit exists above the Tracy Sand interval (sands above the 2nd Tracy Sand). This unit, called the Ragged Valley Shale, is a very thick and regionally-extensive confining layer that adds additional separation from the target injection zone and the base of the USDW. This unit is correlated across the site on the cross sections on Figures 16 and 17. As shown by the electric logs on the sections, the Ragged Valley Shale confining layer

ATTACHMENT A – Area of Review (AOR)

Requirements

UIC regulations require that an *Area of Review* (AOR) be established around a new injection well for the investigation of possible pathways for vertical migration of injected fluids, including improperly abandoned wells or conductive geologic faults. Within that area, data that are *reasonably available from public records* are reviewed to identify existing, improperly completed, and abandoned wells, and faults and fractures. In order to conduct this investigation, the AOR must first be determined using site-specific conditions. Regulations require that the minimum AOR for a Class I Non-Hazardous UIC is a *fixed radius* of 0.25 mile (1,320 feet) around the injection well, but may be larger as defined by site-specific conditions.

The determination of the AOR also involves a consideration of the *radius of endangering influence also called the zone of endangering influence* (ZEI*).* As defined in the regulations, the ZEI is the radial zone around the well that extends to the point where the projected injection cone of impression, or pressure curve, intersects the potentiometric surface of the lowermost USDW. If the radius of endangering influence is calculated to be larger than the fixed radius of 0.25 mile, then the ZEI becomes the AOR.

Approach

Many of the parameters needed in the calculation of the ZEI are unknown prior to injection well drilling. USEPA guidance states that since the potentiometric surface of the lowermost USDW is only rarely known, the elevation of the base of the USDW is commonly used (Engineering Enterprises, May 1985). It is acknowledged that this assumption is used as a conservative approach, but seems unrealistic given the regional groundwater flow systems commonly associated with synclinal basins. Other parameters are also difficult to estimate such as the initial undisturbed potentiometric surface in the target zone prior to injection. The calculations are subject to large errors when this surface is unknown (McLin, 1986).

Although reasonable and conservative estimates are used in the following calculations, results contain many assumptions and uncertainties that may need refinement after the drilling and testing phases of this project. The selected AOR considers several different methods of evaluating potential impacts, both vertically and horizontally away from the injection well.

The first method presents a volumetric calculation to assess the physical storage space needed for the volumes of injectate associated with this project. The calculation also considers dispersion of the injected fluid in the reservoir. The second method uses a modified version of the Theis equation (provided in the regulations) to estimate the cone consists of more than 500 feet of low permeability units. This interpretation is consistent with sample descriptions of the zone in the area.

ATTACHMENT H – Operating Data

Requirements

As provided by 40 CFR 146.13, the operating requirements shall at a minimum specify that:

- Except during stimulation, injection pressure at the wellhead shall not exceed the calculated pressure that would allow the injection zone pressure to initiate new fractures or propagate existing fractures in the injection zone. In no case shall injection pressure initiate fractures in the confining zone or cause the movement of injection or formation fluids into a USDW.
- Injection between the outermost casing protecting USDWs and the well bore is prohibited.
- Unless an alternative to a packer has been approved under Part 146.12(c), the annulus between the tubing and the long string of casings shall be filled with a fluid approved by the Director. A certain pressure, also approved by the Director, shall also be maintained on the annulus.

Wastewater Generation and Treatment

As previously discussed, the CSC site is not currently generating wastewater and will not be in full operations until manufacturing and wastewater treatment equipment, including the proposed injection well, have been designed and installed. Therefore, the information in this section describes the treatment process as currently envisioned, but minor modifications may be necessary to the proposed system as the design and installation process proceeds.

Wastewater from the CSC plant will be generated during cheese-manufacturing activities. The process waste streams resulting from plant operations is summarized on Table 3 and described below. The quality of wastewater from the facility is related to cheese and whey production and cleaning operations. Before final discharge to the UIC well for disposal, the wastewater passes through a wastewater treatment system.

Cheese and Whey Production: The CSC facility will produce mozzarella, provolone, and ricotta cheese. When operating at capacity, approximately 210,000 gpd of raw milk will be delivered to the facility. Milk deliveries are likely to occur seven days a week throughout the year, with little seasonal variation. The facility is expected to operate twenty-four hours per day.

In the production of mozzarella and provolone, pasteurized milk and starter media are added to fermentation vats. After fermentation, the curdled solids and whey are pumped to long tables where the whey drains through screens. The curds are rinsed and salt is added. The whey is transferred to further processing. The rinse water is discharged to the wastewater system. The separated curds are then cooked, molded, chilled, conveyed through brine flumes, wrapped, and stored in a cooler until shipped. Ricotta cheese is curdled with acetic acid, blended to the desired consistency, and placed in tubs and stored in a cooler until shipped.

Screened whey passes through specialized equipment for removal of solids and whey cream, respectively, which are sold. The remaining whey is processed through ultrafiltration (UF) for protein removal, and reverse osmosis (RO) for lactose removal. The whey protein concentrate and lactose are also sold. The RO permeate is discharged to the wastewater treatment system.

Cleaning Operations: In addition to processed whey (RO permeate) and cheese table rinse water, CSC wastewater will include wash water from cleaning operations. CSC will use Clean-In-Place (CIP) processes for most equipment (milk storage silos, fermentation vats, whey-processing equipment, and interior of milk tanker trucks). In the CIP process, the units are rinsed, followed by an application of heated caustic, an acid wash, and a final rinse. CIP clean-up will be performed once every 24 hours and will require about four hours. Nearly all of the equipment (except the cheese washing tables and floors, which are washed by hoses) are suitable for the CIP process. CIP solutions will be pumped from the CIP solution tanks through the process equipment and discharged to the wastewater collection sump.

The silo room floor will be washed daily using pressurized hoses, and portions of the floor area are washed as needed throughout the day. Floors in the cheese production rooms will be washed down using spray hoses at the end of each shift. The insides of the milk tanker trucks will be washed at the CSC facility, but the outsides will not be washed at the facility.

Sanitary Wastewater: Sanitary wastewater from employee restrooms is treated separately and not combined with food-processing wastewater.

Wastewater Treatment: The wastewater treatment plant and disposal system is expected to operate seven days per week. Table 4 shows the process flow and mass balance of the proposed wastewater treatment system. The influent wastewater will flow into a main collection sump. Oily water waste will be removed from the sump, collected in an above ground tank, and disposed offsite at a permitted facility. The main collection sump pumps will lift the wastewater through a fixed (coarse) and rotary (fine) screen process and into the first stage equalization. The first stage equalization will provide surge control for the pretreatment lift pumps. The water will then be filtered and recovered settled solids will be disposed offsite at a permitted facility. The filtrate will then discharge into the UIC equalization. This basin provides surge capacity and collection and feed for the UIC injection pumps.

The wastewater quality and quantity is estimated based on historical information and sound engineering assumptions. Information from past site operations during years 2000 and 2002 provided the basis of the quantity and quality estimations. This information is summarized in the attached Wastewater Characterization on Table 4.

As discussed above, the CSC waste stream consists of processed whey (RO permeate) and rinse water generated from washing equipment. Dairy wastewater tends to be acidic due to the conversion of lactose to lactic acid and other organic acids. In addition, a relatively small amount of CIP cleaning solutions (caustic and acids, such as nitric and phosphoric acid) will be discharged to the wastewater treatment system. An appropriate base such as caustic will be dosed to neutralize the pH.

Other added chemicals include salt (used to control cheese moisture content), acetic acid (used to make ricotta cheese), starter media (fermentation culture bacteria), and a small amount of cleaning chemicals, such as bleaches and detergents. Polymer and coagulant may be added to facilitate removal of suspended material. Wastewater treatment and site operations will ensure that the injected liquid is non-hazardous.

Injection Well Operation

It is anticipated that approximately 300,000 gpd (208 gpm) of wastewater may be generated at the site for injection. Although initial production will be significantly less, the details of this permit are based on this anticipated maximum rate. Depending on the properties of the formation and the injection capacity of the well, additional treatment processes could be incorporated to concentrate the wastewater, resulting in lower volumes.

The injection well will be operated so as not to initiate or propagate fractures in the formation. Injection will occur through tubing as further described in Attachment L and shown on Figures 21 and 22. The maximum surface injection pressure will be determined based on data collected during formation testing on the new well. A fracture gradient limit of 0.8 psi/ft has been used by CDOG for a 2,500-foot sand in a Class II injection well located 4.25 miles northwest (Laymac Corporation, September 30, 1985). This information is documented in the well's Class II Injection Well records at CDOG and provided in the supporting documentation attached to this application. Based on reasonable assumptions compiled to date, and a formation fracture gradient of 0.8 psi/ft, the following maximum pumping pressure can be estimated.

Miocene Sand Completion (top of sand at 2,010 feet):

2,010' x (0.8-0.433) = 738 psig + friction pressure between the 4 ½ inch tubing and injected fluid

(The friction pressure is a function of the injection rate and can be calculated more accurately after construction of the well).

Cretaceous 2nd Tracy Sand Completion (top of sand at 5,235 feet):

5,235' x (0.8-0.433) = 1,921 psig + friction pressure between the 4 ½ inch tubing and injected fluid

(The friction pressure is a function of the injection rate and can be calculated more accurately after construction of the well).

ATTACHMENT I – Formation Testing Program

Requirements

The formation testing program for Class I wells must be designed to obtain data on fluid pressure, temperature, and fracture pressure of the injection zone. The program must also collect data to characterize the physical, chemical, and radiological characteristics of both the formation water as well as the injection fluids.

Fracture Pressure Determination

The open-hole testing planned for the Miocene Sand will determine the formation pressure and reconfirm the salinity of the formation water. The formation fracture gradient as provided by CDOG ranges from 0.8 to 1 psi/ft. CDOG used a fracture gradient of 0.8 for a Class II injection well injecting into a similar depth as the Miocene Sand (2,500 feet) (Laymac well files included in supporting documentation attached to this application). As shown previously in Attachment H, the fracture pressure can be estimated as follows (using the more conservative gradient of 0.8 psi/ft) and determined more accurately after the well is installed:

Miocene Sand Completion (top of sand at 2,010 feet):

2,010' x (0.8-0.433) = 738 psig + friction pressure between the 4 ½ inch tubing and injected fluid

(the friction pressure is a function of the injection rate and can be calculated more accurately after the construction of the well).

Cretaceous 2nd Tracy Sand Completion (top of sand at 5,235 feet):

5,235' x (0.8-0.433) = 1,921 psig + friction pressure between the 4 ½ inch tubing and injected fluid

(the friction pressure is a function of the injection rate and can be calculated more accurately after the construction of the well).

Mechanical Integrity Test

The absence of significant leaks in the casing, tubing, and/or liner hanger will be demonstrated by a pressure test on the annular space between the tubing and production casing. The test shall be conducted for a minimum of 30 minutes at a pressure equal to the maximum allowable injection pressure determined from the fracture pressure testing summarized above. Temperature, spinner, and natural radioactive logs will be run to ensure that fluid is entering the injection zone only and that no fluid migration is indicated above the top of the 8-5/8 inch casing or around the packer. A cement bond log will demonstrate the inability for fluid migration within the cemented annulus.

Formation Water Sampling

Samples of the formation water in the selected injection zone will be taken and analyzed to determine the physical, chemical, and radiological characteristics of the water. Samples from open-hole testing, if successful, will be analyzed before well completion. If testing fails to produce a credible sample in the target injection zone, the well will be completed and formation water produced for sampling.

Injection Fluid Sampling

Since the plant is not currently in operation, no injection fluid is available for sampling. Wastewater data from past operations at the site (expected to be similar to future wastewater generated) are provided in Attachment H and Table 4. Once plant facilities are in place to develop wastewater, samples will be collected and analyzed for physical, chemical, and radiological characteristics. The conveyance system will allow for sampling of the injectate just before entering the wellhead. Data will be generated for a waste determination to ensure that injection fluid is not hazardous as defined in 40 CFR Part 261. As shown on Table 3, wastewater will be pre-treated prior to injection to ensure that hazardous liquids are not injected and that solids and other constituents are reduced to levels suitable for injection.

ATTACHMENT J – Stimulation Program

No stimulation is expected to be necessary for the target injection zone.

ATTACHMENT K – Injection Procedures

Requirements

Equipment and procedures are to be documented including details on the pump, surge, tank, etc.

Proposed Injection Procedures

The conceptual design of the wastewater treatment system prior to injection is described in Attachment H and summarized on Table 3. Filtered and treated wastewater will be discharged into the UIC equalization basin with surge capacity and collection and feed for the UIC injection pumps. The wellhead will be designed with a tap allowing for the sampling of injection fluid prior to conveyance down the tubing string. As detailed in the monitoring program, devices will be installed to continuously measure and record injection pressure, annulus pressure, flow rate, and injection volumes. The maximum allowable surface pressure for injection will be determined after the well has been completed, and the well will be operated so as not to exceed the established pressure.

ATTACHMENT L – Construction Procedures

Requirements

This section describes the procedures for the construction of the injection well and includes details on the casing and cementing program, logging procedures, deviation checks, the drilling and testing program, and proposed annulus fluid. Construction procedures follow the requirements listed in 40 CFR Part 146.12 for Class I Non-hazardous wells.

Permits

The injection well will require a draft permit for a UIC Class I injection well from USEPA under the UIC program, a drilling permit from San Joaquin County, and a well permit from CDOG. Because of the depth of the target injection zones and the local occurrence of gas-bearing formations, the well will be drilled as an exploratory gas well under the requirements of a CDOG permit.

Proposed CSC Injection Well Drilling and Logging

In order to provide USEPA with the proper documentation and planning data required for both target injection zones, two drilling programs are provided below. The first program includes drilling to the Miocene Sand, testing the formation water and permeability, documenting that the zone meets regulatory and technical requirements, and completing the well in that zone. The second program involves drilling to the Miocene Sand, finding that it doesn’t meet either regulatory or technical requirements, drilling to the alternative injection target of the Cretaceous 2nd Tracy Sand, and completing the well in the deeper zone.

Each program contains specifications and information on the drilling procedures, casing lengths and materials, and liner installation (including gravel packing). General procedures to be required of the drilling contractor and site personnel are also included throughout the procedures and in the requirements provided in the ***Standing Orders*** section following the two drilling programs. For completeness, significantly more detail is provided in the text than required. The additional text is included to provide USEPA with a full vision of the drilling and completion program that we are proposing. Some of the drilling and completion details that are not relevant to the overall permit requirements may be modified in the field as necessary.

The logging program is summarized after the two drilling programs. The logging program includes both open-hole and cased-hole logs envisioned to evaluate the USDW, target injection zones, and the mechanical integrity of the well.

Target depths and elevations for both of the programs are summarized in the following table:

General Information: CSC Proposed Injection Well

Well Location	24-1S-6E MD	2143847.09N; 13742028.22 E*
Surface Elevation	22 feet, msl	USGS, Lathrop, CA 1996
Estimated KB	35 feet, msl	
Top of Miocene Injection Target	2,010 feet, MD	-1,975 feet below msl
Base of Miocene Injection Target	2,382 feet, MD	-2,347 feet below msl
Top of Cretaceous Injection Target	5,235 feet, MD	-5,200 feet below msl
Base of Cretaceous Injection Target	5,502 feet, MD	-5,467 feet below msl

*NAD_1927_UTM_Zone_10N
MD = measured depth
msl = mean sea level

All depths in the drilling and completion program are approximations and will be modified in the field based on site-specific data.

Drilling and Completion Program – Miocene Sand Completion

Drilling & Completion Program – Miocene Sand

1. Install 24-inch diameter conductor casing cemented at 40 feet. Drill 17.5 inch hole to approximately 650 feet. Run open-hole logs over freshwater zone from total depth (TD) to 40 feet. Cement 13-3/8 inch 48# H-40 ST&C casing at about 650 feet with 250 sacks Class G premixed 3% $CaCl_2$ and 6% gel, followed with 100 sacks Class G cement premixed 3% $CaCl_2$ (50% excess). Tack weld and Bakerlok bottom 4 collars and weld shoe solid. Run float shoe. Run centralizer 15 feet above shoe. Use top rubber plug only and plug holding head. Bump plug on shoe.

2. After 2 hours waiting on cement, land casing. Test weld 500 psig. Install Series 900 Shaffer dual hydraulic control gate and Hydril GK. Test according to Standing Orders. Notify CDOG & UEPA to witness.

3. Drill 12-1/4 inch hole to 1900'. Install mud loggers at 1700 feet. Circulate as necessary for evaluation. Take one set of wet and dry samples every 30 feet. Monitor pit level closely at all times.

4. At 1900 feet, reduce the size of the hole to 7-7/8 inch diameter and drill 35 feet into the Miocene Sand (the top of the Miocene sand expected at 2010 feet). Run

Baker open-hole tester with 500 feet of 8000 mg/L TDS saltwater in tools and 25 feet of perforated tail with two pressure bombs. Set bottom packer 10 feet into sand. Open test tools. Keep tools open until sufficient entry has been observed. Close tools for one hour and obtain bottom hole shut-in pressure. Unset packers and pull out of hole. Obtain several samples of the formation fluid and determine the TDS. Notify USEPA to witness open-hole test.

If the TDS for the samples are higher than 10,000 mg/L or if the test fails, go to Step No. 5. If the TDS is below 10,000 mg/L, the well will be drilled to the 2nd Tracy Sand as described in the next section, ***Drilling and Completion program – Cretaceous 2nd Tracy Sand***.

5. Run in hole with 12-1/4 inch diameter bit and drill from 1900 feet to 2020 feet (10 feet into Miocene Sand). Run open-hole logs from total depth (TD) to 650 feet.

6. Run 8-5/8 inch, 32#, J-55, LT&C, new casing, equipped with float shoe and float collar on top of shoe joint on bottom. Cement casing with to surface. Perform a top job with PVC pipe and 60 sacks of G cement premixed 3% $CaCl_2$. The cement program will be prepared after logging.

7. Wait on cement. Remove blow-out prevention equipment (BOE). Install tubinghead. Install adapter. Install and test BOE. Notify CDOG to witness. Run 7-7/8 inch diameter bit and drill out float collar and shoe. Drill as directed to expose 300 feet or more of the Miocene Sand. Run open-hole logs. Run 8-5/8-inch scraper to bottom of 8-5/8 inch casing. Run 7-7/8 inch bit and check for fill. Clean mud pits. Change hole to 9.0 pounds per gallon (ppg) HEC polymer saltwater. Run a 15 inch under-reamer and open 7-7/8 inch hole to 15 inches. Circulate clean. Check for fill. Clean mud pits. Equalize clean 9.0 ppg HEC polymer saltwater pill from bottom to 200 feet above shoe. Pull up to 100' above shoe and change hole to clean saltwater.

8. Run 5-1/2 inch Baker liner and gravel pack as described in the Liner Program for the Miocene Sand completion on the following pages.

9. Mud Program. Geo-Western. Cypan Mud System.

Depth	Weight	Viscosity	Water Loss
0'- 560'	To protect fresh water		
560'-1900'	9.0-9.3 ppg	35-45 sec	6cc/30 min
1900'- TD	9.3 ppg	35-45 sec	6cc/30 min

10. Have sufficient mud material on location to raise mud weight 0.4 pounds per cubic foot (pcf). Adjust mud weight to maintain mud log baseline below 30 units and to stabilize shale.

11. Set Baker Model D packer with a flapper valve at 1900'. Pick up seal assembly on bottom of 4-1/2 inch, 12.75#, EUE, J-55 tubing. Run in hole to top of packer. Change annulus to freshwater treated with corrosion inhibition chemical. Have

filtered saltwater in tubing. Stab into packer. Test annulus to 2,000 psig. Install single master X-mas tree.

12. Perform a 2-hour injection test with Baker pump truck using 240 bbls of filtered saltwater. Monitor annulus for any leaks. Notify USEPA to witness. Start the construction of the surface facilities.

Casing Program – Miocene Sand

Hole conditions: 13-3/8 inch 48# surface casing at 650 feet, 12 ¼ inch diameter hole, mud weight of 9.3 ppg.

1. Run 8-5/8 inch 32# J-55 LT&C 8RD, R3, new casing to 2020’. Sand blast bottom 6 joints.

2. Run float shoe. Run float collar on top of shoe joint. Weld shoe solid.

3. No X-over joints should be required.

4. Prepare tally sheets for the casing using dark ink. Last joint in the hole should be on the first sheet.

5. Use B&L casing tongs to run casing. Run fill-up and circulating tool. Clean threads. Visually inspect casing. Have welder on location while running casing. Have extra LT&C collar on location to weld on top joint if pipe stops off bottom.

6. X-mas tree should be 3000 psi.

7. Run two centralizers per joint from TD of casing to 1900’, then one centralizer per joint into surface casing. Run casing to desired depth. Rig up cementing head. Have two lines to cementing head and two pump trucks on location. Circulate casing clean. Do not work pipe.

8. Cement Mix: Pump 35 bbls of mud flush ahead and cement casing shoe at 2020’ measured depth (MD) per Halliburton cementing program. Bump top plug on float collar. Use two vacuum trucks full of mud for displacement. Perform 60 sacks top job with PVC pipe.

Liner Program

Hole conditions: TD 2382 feet, 8-5/8 inch 32# production casing set at 2020’, 15 inch diameter hole with MW of 9.0 pcf.

1. Open hole with polymer mud. Circulate clean. Pull to shoe. Wait one hour. Run in hole and check for fill. Spot a clean viscous pill across the open hole interval and 200 feet into the 8-5/8 inch casing.

2. Pull up to 100 feet above the shoe of the 8-5/8 inch casing. Rig up Baker Defiltering Unit. Change hole over to clean filtered 9.0 ppg saltwater.

3. Pull out of hole.

4. Run cement bond log and gamma ray log (CBL/GR) from bottom of hole to surface.

5. Pick up liner assembly consisting of:

   4 feet 5-½” Circulating Shoe with open hole centralizer
   ? feet 5-½” (6” OD) Excluder Screen.
   ? feet 5-½” Blank Pipe (1 joint is 38 feet)
   35 feet 8-5/8 inch Baker SC-1 Gravel Pack Tool with Sliding Sleeve, extensions setting and crossover tool
   130 feet tail pipe and polished stinger for circulating shoe (to be run inside WWS)

   Note: Centralize both circulating shoe and blank pipe. Minimize the use of pipe dope. Apply to pin end only.

6. Run in with liner assembly on 4 inch diameter drill pipe to desired depth.

7. Rig up pumping equipment and lines.

8. Conduct safety meeting.

9. Test lines to about 4,000 psi. Drop ball.

10. Set and test gravel pack tools. Blow ball seat.

11. Using clean filtered brine from rig pits, establish and record pump rate and pressure in reverse position.

12. Clean drill pipe by performing a sand scour. With the crossover tool in the reverse position, pump a 5-bbl slurry of about 2 ppg sand down the work string to the reverse port in the crossover tool. Immediately reverse the slurry out of the work string. Keep pump rate as high as conditions allow. Inspect returns to see what material the scour may have removed from the work string.

13. Establish and record pump rate and pressure in circulating position and circulate viscous pill from 15 inch open hole annulus and into the annulus of the drill pipe and the 8-5/8 inch casing. Un-sting from circulating shoe. Using Baker Gravel Infuser System, install gravel pack. Begin infusing Baker Low Fine Ottawa Gravel into clean brine at 0.5 lb/gal. Typical pump rates are 4 to 6 barrels per minute (bpm). Once sand clears crossover tool then increase sand loading to maximum of 2 ppg as conditions allow. Continue pumping at this rate and

concentration until wellhead pressure begins increasing. Pump rate should be reduced accordingly as well head pressure increases. Once pressure reaches 500 psi over initial circulating pressure is achieved stop pumps. Do not restress pack at this time.

14. Close annular blow-out preventer (BOP) and apply 500 psi to the annulus. Place the crossover tool in the reverse position. Reverse out excess gravel until returns are clean. Monitor and determine the volume of gravel reversed out. To test the gravel pack, lower crossover tool into the circulating position. Circulate at sand out rate and attempt to achieve sand out pressure established earlier. If same sand out pressure cannot be achieved, mix and pump another amount of gravel recommended by pump specialist. Repeat this step until final sand out occurs. Pull out of hole with service tools.

    Recommend a minimum of 200 bbl of brine available at surface for gravel pack operations.

    <u>Volume Estimates</u>

300 feet of 15 inch open hole	66 bbls	300 ft x .22 bbl/ft
2020 feet of 8-5/8 inch 32# casing	123 bbls	2020 ft x .0609 bbl/ft
Gravel for 300 feet of 6 inch OD Liner in 15 inch open hole plus 40%	310 cf (62,000 lbs)	300 ft x 1.03 cf/ft
Brine for GP Slurry at 1 lb/gal	62,000 gal (1,400 bbls)	62000 lb x 1 lb/gal
Brine for misc. GP steps (Set packer, establish rates, reversing, etc.)	300 bbls	
Subtotal brine needs	1,889 bbls	

Drilling and Completion Program – Cretaceous 2nd Tracy Sand Completion

<u>Drilling & Completion Program – Cretaceous Sand</u>

1. If a decision is made to complete the well in the Cretaceous 2nd Tracy Sand per Step 4 of the original Miocene Sand program, the following steps will be taken.

2. Run in hole with 12-1/4 inch bit and drill to 5100 feet. Reduce the size of the hole to 7-7/8 inch and drill 35 feet into the 2nd Tracy Sand (the top of the 2nd Tracy

Sand is expected at 5235 feet). Run Baker open-hole tester with 500 feet of 8000 mg/L TDS saltwater in tools and 25 feet of perforated tail with two pressure bombs. Set bottom packer 10 feet into sand. Open test tools. Keep tools open until sufficient entry has been observed. Close tools for 1 hour and obtain bottom hole shut in pressure. Unset packers and pull out of hole. Obtain several samples of the formation fluid and determine the TDS for the samples.

3. Run in hole with 12-1/4 inch bit and open hole to 12-1/4 inch from 5100 feet to 5245 feet (10 feet into the target Tracy Sand). Run open-hole logs per logging program from 650 feet to TD.

4. Run 8-5/8 inch, 32#, J-55, LT&C new casing equipped with float shoe and float collar on top of shoe joint on bottom. Cement the shoe with enough cement to have returns at surface. Perform a top job with PVC pipe and 60 sacks of G cement premixed 3% $CaCl_2$. The cement program will be prepared after the logging.

5. Wait on cement. Remove BOE. Install tubinghead. Install adapter. Install BOE. Test BOE. Notify CDOG to witness. Run 7-7/8 inch bit and drill out float collar and shoe. Drill as directed to expose 250 feet or more of the target Tracy Sand. Run open-hole logs over the target interval per logging program. Run 8-5/8 inch scraper to bottom of 8-5/8 inch casing. Run 7-7/8 inch bit and check for fill. Clean mud pits. Change hole to 9.0 ppg HEC polymer saltwater. Run a 15 inch under-reamer and open 7-7/8 inch hole to 15 inches. Circulate clean. Check for fill. Clean mud pits. Equalize clean 9.0 ppg HEC polymer saltwater pill from bottom to 200 feet above shoe. Pull up to 100 feet above shoe and change hole to clean saltwater.

6. Run 5-1/2 inch Baker liner and gravel pack per the attached program.

7. Mud Program: Geo-Western. Cypan Mud System.

Depth	Weight	Viscosity	Water Loss
0- 650 ft	To protect drinking water		
650-1,900 ft	9.0-9.3 ppg	35-45 sec.	6cc/30 min
1,900 ft - TD	9.3-9.9 ppg	35-45 sec.	6cc/30 min

Have sufficient mud material on location to raise mud weight 0.4 pcf. Adjust mud weight to maintain mud log base line below 30 units and to stabilize shale.

8. After the liner is gravel packed, perform an injection test with Baker pump truck using 200 bbls of filtered saltwater.

9. Set Baker Model D packer with a flapper valve at 5100 feet. Pick up seal assembly on bottom of 4-1/2 inch, 12.75#, EUE, J-55 tubing. Run in hole to top of packer. Change annulus to freshwater treated with corrosion inhibition

chemical. Have filtered saltwater in tubing. Stab into packer. Test annulus to 2000 psig. Install single master X-mas tree.

11. Perform an injection test with Baker pump truck using 200 bbls of filtered saltwater. Monitor annulus for any leaks. Notify USEPA to witness. Start the construction of the surface facilities.

Casing Program – Cretaceous Sand

Hole Conditions: TD 5,500 feet, 13-3/8 inch 48# surface casing at 650 feet, 12-¼ inch hole, MW 9.8 ppg.

1. Run 8-5/8 inch 32# J-55 LT&C 8RD, R3, new casing to 5245 feet. Sand blast bottom 6 joints.

2. Run float shoe. Run float collar on top of shoe joint. Weld shoe solid.

3. No X-over joints should be required.

4. Tally sheets for the casing will be prepared.

5. Use B&L casing tongs to run casing. Run fill-up and circulating tool. Clean threads. Visually inspect casing. Have welder on location while running casing. Have extra LT&C collar on location to weld on top joint if pipe stops off bottom.

6. X-mas tree should be 3000#.

7. Run two centralizers per joint from TD of casing to 5100 feet, then one centralizer per joint into surface casing (625 feet). Run casing to desired depth. Rig up cementing head. Have two lines to cementing head. Have two pump trucks on location. Circulate casing clean. Do not work pipe.

8. Cement Mix: Pump 35 bbls of mud flush ahead and cement casing shoe at 5245 feet per Halliburton cementing program. Bump top plug on float collar. Use three vacuum trucks full of mud for displacement. Perform 60 sacks top job with PVC pipe.

Liner Program – Cretaceous Sand

1. Open hole with polymer mud. Circulate clean. Pull to shoe. Wait one hour. Run in hole and check for fill. Spot a clean viscous pill across the open hole interval and 200 feet into the 8-5/8 inch casing.

2. Pull up to 100 feet above the shoe of the 8-5/8 inch casing. Rig up Baker Defiltering Unit. Change hole over to clean filtered 9.0 ppg saltwater.

3. Pull out of hole.

4. Run CBL/GR from bottom of hole to surface.

5. Pick up liner assembly consisting of:

4’	5-½ inch Circulating Shoe with open hole centralizer
?’	5-½ inch (6” OD) Excluder Screen.
?’	5-½ inch Blank Pipe (1 joint is 38 feet)
35’	8-5/8 inch Baker SC-1 Gravel Pack Tool with Sliding Sleeve, extensions setting and crossover tool
130’	Tail Pipe and polished stinger for circulating shoe (to be run inside WWS)

Note: Centralize both circulating shoe and blank pipe. Minimize the use of pipe dope. Apply to pin end only.

6. Run in with liner assembly on 4 inch drill pipe to desired depth.

7. Rig up pumping equipment and lines.

8. Conduct safety meeting.

9. Test lines to about 4,000 psi. Drop ball.

10. Set and test gravel pack tools. Blow ball seat.

11. Using clean filtered brine from rig pits, establish and record pump rate and pressure in reverse position.

12. Clean drill pipe by performing a sand scour. With the crossover tool in the reverse position, pump a 5-bbl slurry of about 2 ppg sand down the work string to the reverse port in the crossover tool. Immediately reverse the slurry out of the work string. Keep pump rate as high as conditions allow. Inspect returns to see what material the scour may have removed from the work string.

13. Establish and record pump rate and pressure in circulating position and circulate viscous pill from 15 inch open hole annulus into the annulus between the drill pipe and the 8-5/8 inch casing. Un-sting from circulating shoe. Using Baker Gravel Infuser System, install gravel pack. Begin infusing Baker Low Fine Ottawa Gravel into clean brine at ½ lb/gal. Typical pump rates are 4-6 bpm. Once sand clears crossover tool then increase sand loading to maximum of 2 ppg as conditions allow. Continue pumping at this rate and concentration until wellhead pressure begins increasing. Pump rate should be reduced accordingly as well head pressure increases. Once pressure reaches 500 psi over initial circulating pressure is achieved stop pumps. Do not restress pack at this time.

14. Close annular BOP and apply 500 psi to the annulus. Place the crossover tool in the reverse position. Reverse out excess gravel until returns are clean. Monitor and determine the volume of gravel reversed out. To test the gravel pack, lower crossover tool into the circulating position. Circulate at sand out rate and attempt to achieve sand out pressure established earlier. If same sand out pressure cannot be achieved, mix and pump another amount of gravel recommended by pump specialist. Repeat this step until final sand out occurs. Pull out of hole with service tools.

Recommend that driller has a minimum of 200 bbl of brine at surface available for gravel pack operations.

<u>Volumes Estimate</u>

300 feet of 15 inch open hole	66 bbls	300’ x .22 bbl/ft
5235 feet of 8-5/8 inch 32# Casing	320 bbls	5235’ x .0609 bbl/ft
Gravel for 300 feet of 6 inch OD Liner in 15 inch open hole plus 40 %	310 cf (62000 lbs)	300’ x 1.03 cf/ft
Brine for GP Slurry @ 1 lb/gal	62000 gal (1400 bbls)	62000 lb x 1 lb/gal
Brine for misc. GP steps Set packer, establish rates, reversing.	300 bbls	
Subtotal brine needs:	2,090 bbls	

Standing Orders, Drilling & Remedial Operations

The following general guidelines have been prepared as part of the well planning process. They will be carried out by the onsite drilling contractors and are provided here for general information.

*1. Prior to drilling out the surface casing, the blowout prevention and all associated equipment shall be pressure tested to 50% of the rated working pressure (Bag preventer to 40%). Equipment to be tested separately are: pipe rams, blind rams, bag preventer, kelly cock, standpipe valve, kill line (stop valve, check valve) and blow down line (each valve, choke and bean). Blow down manifold shall have at least one operating pressure gage of a range at least 1000 psig higher than blowout preventer rated working pressure. CDOG to witness.

*2. Blowout preventers on protection and production casing shall be tested as above to 70% of rated pressure (Bag to 50%).

*3. Each drilling crew is to have at least one blowout drill weekly.

*4. Before tripping, check the ditch for flow with pumps off.

*5. Daily record the one-half pump stroke standpipe pressure.

6. Measure drill pipe on first trip after installing mud loggers.

7. All casing run shall be carefully visually inspected for pipe body and thread defects as it is unloaded. Casing shall not be permitted to drop from trucks, roll it off on ramps.

8. Protection and production casing shall be run with hydraulic tongs set to the proper torque for the casing being run. Pick up thread protectors shall be used.

9. All casing shall have threads "bright" cleaned and a teflon pipe dope (Bakerseal, TF-17) liberally applied.

10. Keep hole full at all times.

*11. Check operation of BOE each round trip.

12. Take all measurements from Kelly bushing (KB).

13. Drilling rig mud pits shall have a calibrated tank to gage mud used to fill the hole on trips.

Each 60 feet stand of 4 inch drill pipe takes 0.29 barrels.
*Shall be entered on tour sheet and signed by person in responsible charge.

<u>Additional Orders</u>

1. Run a stabilizer to drill the surface hole.

2. Use the following bottom hole assembly for drilling out shoe: 12-1/4 inch bit, stab, 8 inch drill collars, stab, 8 inch drill collars, BS, 10 Hw's. Use straight edged stabilizers and bumper sub from Brewster.

3. Drill out shoe with a new bit with 16/16/16 jets.

4. Mud weight must be 9.3 ppg by 1,900'. The first two wiper runs should be to the shoe, after that 10 stands would do. Wipe hole every 4 to 6 hours. Wipe to shoe every 50 to 60 hours.

5. Survey as directed.

6. Install a mud cleaner.

7. Keep pipe moving at all times.

Logging Program Summary

The logging program will consist of at least three open-hole logging runs in the well. The first logging run will be conducted after the drilling of the upper 650 feet of the hole and prior to setting the 13-3/8 inch surface casing. Logging will assist in the determination of fresh water and the further evaluation of USDWs. Logs will include Spontaneous Potential (SP), Induction Resistivity, and Sonic.

The second open-hole logging run will be conducted after the well has just penetrated the top 10 feet of the Miocene Sand target injection zone at an approximate depth of 2,020 feet. This logging run will allow for delineation of the base of the USDW as well as providing lithologic information on the confining zone above the Miocene Sand target. The logging suite will include an Array Induction Electrical Resistivity and SP log that will provide formation resistivity at five radial depths of investigation to determine formation water salinity (in combination with formation porosity). Porosity tools will consist of a compensated neutron porosity, a triple detector litho-density and a gross gamma ray. These logs will provide the lithology and porosity of the lower USDW and the confining zone to allow for salinity calculations to be made. They will also provide porosity and relative permeability information for the top of the target Miocene Sand.

Following the open-hole test, a decision whether to complete the well in the Miocene Sand or drill deeper will be made. If the well is completed in the Miocene Sand, the entire target injection zone will be drilled and open-hole logs will be run to cover the injection interval. This third open-hole logging run will include, at a minimum, the same tools run in the second open-hole run. Depending on data obtained in the second logging run, the third logging run may include a Combinable Magnetic Resonance logging run to more accurately define effective porosity and permeability of the target zone.

If the well is to be drilled deeper, the third open-hole logging run will be deferred until the upper 10 feet of the Cretaceous 2nd Tracy Sand is penetrated. After the 8-5/8 inch production casing has been set and the full target injection sand has been drilled, a final open-hole logging run will be conducted to evaluate the target zone. Proposed logging tools for the Cretaceous 2nd Tracy Sand will be the same as those proposed for the logging runs in the Miocene Sand. USEPA will be given 24 hour advance notice of all tests and logging to be conducted.

The cased hole logging program will consist of cement bond logs run to ensure no fluid migration in the annulus of the casing strings. After well completion, temperature, spinner, and/or natural radioactive logs will be run to ensure that injection fluid is contained within the tubing, liner, and injection zone.

ATTACHMENT M – Construction Details

Requirements

The injection well must demonstrate mechanical integrity to comply with a UIC permit. The two main tests for mechanical integrity include a demonstration that the casing does not contain leaks and that there is no significant fluid movement into a USDW adjacent to the well casing. The well must be constructed in a way to comply with these two requirements. A well construction diagram is required to be submitted with this attachment.

Construction Diagram

The well construction diagram for a well completed in the Miocene Sand target injection zone is provided on Figure 21. The well construction diagram for a completion in the alternative injection zone, the Cretaceous 2nd Tracy Sand, is provided on Figure 22. The two diagrams conform to USEPA guidance and are consistent with the procedures described in Attachment L.

ATTACHMENT O – Plans for Well Failures

Requirements

Contingency plans should be developed for failure of the injection well to perform as permitted. These plans will outline steps to ensure that injection fluids will not migrate into USDWs.

Contingency Options

Numerous options for handling liquids during a possible future well failure are being investigated. After the well is drilled and the capacity is known, the operator will have a better understanding of the amount and quality of fluid requiring management. Onsite storage facilities will be able to store 50,000 gallons of wastewater as needed. Production can then be curtailed until the well can be brought back on line.

Some flexibility exists with respect to anticipated operations at the site. Early operations will be conducted at a much lower capacity than allowed in this permit (start-up capacity expected to be around 50,000 gallons). Production will increase over time, allowing for modifications and optimizations in the wastewater treatment system. The gradual increase in needed injection capacity will allow for a more methodical approach to providing temporary alternatives to injection, should the well fail. If the injection well goes down, production would be curtailed.

The applicant also requests the option to install a back-up injection well to be used in the event of a well failure. This would also provide flexibility with respect to ongoing well maintenance. However, until the first well is installed, the cost and expected performance are unknowns. To avoid future permit modification, CSC requests permission in this permit to install a back-up well in the future, if desired, provided that the additional well will not increase the total amount of injection volume associated with the project. The backup well would be drilled close to the original well such that all distances and details within the area of review and the geological evaluation would also apply to the back-up well.

ATTACHMENT P – Monitoring Program

Requirements

As provided by 40 CFR 146.13, monitoring requirements shall, at a minimum, include:

- The analysis of the injected fluids with sufficient frequency to yield representative data of their characteristics
- Installation and use of continuous recording devices to monitor injection pressure, flow rate and volume, and the pressure on the annulus between the tubing and the long string of casing
- A demonstration of mechanical integrity pursuant to Part 146.8 at least once every five years during the life of the well
- The type, number, and location of wells within the AOR to be used to monitor any migration of fluids into and pressure in USDWs, the parameters to be measured and the frequency of monitoring.

Quarterly reporting requirements include:

- The physical, chemical and other relevant characteristics of injection fluids
- Monthly average, maximum and minimum values for injection pressure, flow rate and volume, and annular pressure
- The results of other monitoring prescribed as above
- Results of periodic tests of mechanical integrity
- Any other test of the injection well conducted by the permittee if required by the Director
- Any well rehabilitation or work-over activities.

Quarterly Reporting of Continuous Pressure and Flow Monitoring

The wellhead will be equipped with a pressure monitoring device to allow for continuous recording of the injection pressure at the wellhead. The monitoring will be conducted with a digital recorder to an accuracy of one psi. The minimum, maximum, and monthly averages of injection pressure and annular pressure will be submitted in quarterly reports. In addition, the flow rate and volume of injectate will be monitored and reported to USEPA as required. The flow rate will be measured in the supply line immediately before the wellhead. Continuous readings will be recorded with a digital totalizer.

All monitoring equipment shall be calibrated and maintained on a regular basis to ensure proper working order of all equipment.

Quarterly Sampling of Injection Fluids

Samples of injection fluid will be taken at or before the wellhead and analyzed for a full suite of chemicals to characterize the fluid and ensure that no hazardous substances are injected into the well. A hazardous waste determination will be performed prior to injection and at any time that wastewater procedures are changed. In addition, injection fluids will be sampled and analyzed on a quarterly basis while the well is in operation. Samples will be taken under appropriate quality assurance/quality control (QA/QC) procedures, following a sampling and analysis plan to be implemented at the site. Samples will be transported to and analyzed by a commercial laboratory certified by the State of California. The following constituents and methods are to be included in the program:

Inorganic Constituents – appropriate USEPA methods for major anions and cations (including an anion/cation balance), TDS, and Total Suspended Solids (TSS).
General and Physical Parameters – appropriate USEPA or certified laboratory methods for turbidity, pH, conductivity, hardness, specific gravity, alkalinity, and biological oxygen demand (BOD)
Trace Metals – USEPA Method 200.8 for trace metals analysis
Volatile Organic Compounds (VOCs) – USEPA Methods 8010/8020 or 8240
Semi-Volatile Organic Compounds – USEPA Method 8270

Annual Well Logging

To ensure that injected fluid is moving into the injection zone only, an annual logging program will be conducted. Temperature, spinner, and natural radioactive logs will be run to evaluate possible fluid migration above the shoe of the 8-5/8 inch diameter casing or around the packer. In addition, as previously described, the annulus of the 8-5/8 inch diameter casing and 4-1/2 inch diameter tubing will be monitored with a continuous pressure recorder at the surface to detect any leaks in the tubing or packer.

Mechanical Integrity Testing

Mechanical integrity tests will be conducted on the injection well every five years or at any time that a work-over is conducted on the well. Test results will be included in the next quarterly monitoring report.

Recordkeeping

Laboratory analyses and flow volume records for all injected fluids will be maintained for three years after all injection wells have been plugged and abandoned. Copies of monitoring reports, calibration and maintenance records, and continuous monitoring readings shall be kept for five years after all injection wells have been plugged and abandoned. Records may be discarded after this retention time only with written approval from USEPA.

ATTACHMENT Q – Plugging and Abandonment Program

Requirements

The plugging and abandonment program must contain details on the following:

1. Type, number, and placement (including elevation of the top and bottom) of plugs to be used.
2. Type, grade, and quantity of cement to be used.
3. Method used to place plugs including the method used to place the well in a state of static equilibrium prior to placement of the plugs.

Plugging and Abandonment Program

An exact plugging and abandonment program cannot be developed for the well until drilling and construction are complete. Plug depths and remaining fluids in the borehole will vary depending on the depth of the injection zone. However, the well will be plugged and abandoned following procedures required by the CDOG including requirements for fluid weight and viscosity. The tubing will be removed from the hole. In general, the following plugs and plate will be used in the abandonment process:

- Plug across injection zone, bringing cement 100 feet into the 8-5/8 inch casing (>300-foot plug)
- Plug at base of the USDW, estimated at 1,789 feet (200-foot plug)
- Plug at surface of the well (100-foot plug)
- Cut casing 5 feet below ground and weld steel plate on top of the casing stub.

USEPA may approve modifications to this program based on information developed during the drilling, construction, and operation of the well. In addition, USEPA may modify the program in the future based on approved work-overs or well modifications. CSC will notify EPA no less than 60 days before conversion, work-over, or abandonment. Within 60 days of abandonment, CSC will provide details of the plugging plan on Form 750-14 to USEPA. Wells will be properly plugged in accordance with the plugging and abandonment program after injection operations have ceased for two years unless the permittee demonstrates that the wells will be used in the future or that the well will not endanger USDWs while temporarily abandoned.

Costs for plugging and abandoning the injection well have been estimated by Irani Engineering at $45,000 for a Miocene injection well and $60,000 for a Cretaceous injection well. Preliminary cost estimates are included in the Supporting Documentation attached to this application.

ATTACHMENT R – Necessary Resources

A surety bond or other financial assurance will be provided to USEPA by CSC prior to operation of the injection well. The amount of the bond will be determined by USEPA and will consider the estimated costs for the proposed plugging and abandonment program. Irani Engineering estimates $45,000 for plugging and abandoning a Miocene injection well and $60,000 for plugging and abandoning a Cretaceous injection well. The preliminary cost estimates are included in the Supporting Documentation attached to this application.

ATTACHMENT T – Existing USEPA Permits

CSC has no existing USEPA permits for this site.

ATTACHMENT U – Description of Business

The CSC facility will produce mozzarella, provolone, and ricotta cheese. The site was purchased from the former owner who conducted similar cheese manufacturing operations. Currently, cheese production is not occurring at the site. When operating at capacity, approximately 210,000 gallons per day (GPD) of raw milk will be delivered to the facility. Milk deliveries are likely to occur seven days a week throughout the year, with little seasonal variation. The facility is expected to operate twenty-four hours per day.

In the production of mozzarella and provolone, pasteurized milk and starter media are added to fermentation vats. After fermentation, the curdled solids and whey are pumped to long tables where the whey drains through screens. The curds are rinsed and salt is added. The whey is transferred to further processing. The rinse water is discharged to the wastewater system. The separated curds are then cooked, molded, chilled, conveyed through brine flumes, wrapped, and stored in a cooler until shipped. Ricotta cheese is curdled with acetic acid, blended to the desired consistency, and placed in tubs and stored in a cooler until shipped.

Screened whey passes through specialized equipment for removal of solids and whey cream, respectively, which are sold. The remaining whey is processed through ultrafiltration (UF) for protein removal, and reverse osmosis (RO) for lactose removal. The whey protein concentrate and lactose are also sold. The RO permeate will be discharged to the wastewater treatment system. Equipment cleaning operations will also add to the wastewater stream. Sanitary wastewater from employee restrooms will be treated separately and not combined with the food-processing wastes. Wastewater will be treated prior to injection as described in Attachment H and shown on Table 4.

The CSC management team and the parent corporation have a demonstrated commitment to responsible operation of facilities and compliance with environmental requirements. Two facilities that are a part of the parent corporation recently received recognition for excellence.

Tampa Bay Fisheries, Inc. received the **WATEREUSE ASSOCIATION 2005 Small Project of the Year Award** for a wastewater reuse project at their Florida facility. This award was presented at the Twentieth Annual WateReuse Symposium in Denver, Colorado in September of this year.

Fisherman’s Pride Processing, Inc. received a **Certificate of Recognition** in June 2005 from the Sanitation Districts of Los Angeles County. The Certificate was presented to Fisherman’s Pride Processing, Inc. for consistently complying with USEPA and County Sanitation Districts’ industrial wastewater discharge limits and permit requirements. This certificate is provided in the Supporting Documentation included with this application.

References

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Table 1
Wells Within Area of Review
California Specialty Cheese UIC Permit Application

Owner and Well No.	Date Drilled	Total Depth (ft, bgs)	Perforations	Well Use	Status
Water Supply Wells					
DeGroot - Jersey Crown Dairy #1	1972	160	142 - 157	Industrial	Active
DeGroot No. 2 #2				Industrial	Inactive - backup
DeGroot	1977	320	110 - 320	Irrigation	Unknown
Jersey Crown Dairy	1977	160	145 - 160	Irrigation	Unknown
DeGroot	1992	295	180 - 270	Irrigation	Unknown
DeGroot	1973	141	124 - 131	Domestic	Unknown
Aufdermaur	1977	172	116 - 126	Domestic	Unknown
Western Stone Products	1994	250	200 - 240	Domestic	Unknown
Manteca Unified School District		170	119 - 159	Municipal	Unknown
Crabtree	1959	100		Domestic	Unknown
Cardoza	1975	110	105 - 110	Domestic	Unknown
Vanetti	1966	130	100 - 130	Domestic	Unknown
Oil and Gas Wells					
Owner unknown - Record from a State Mineralogist Report	1888	1,042	None	Exploration	Abandoned
Monitoring Wells					
Suprema Specialties West MW2	2000	25	15 - 25	Monitoring	Active
Suprema Specialties West MW3	2000	25	15 - 25	Monitoring	Active
Suprema Specialties West MW4	2000	24	11 - 23	Monitoring	Active
Suprema Specialties West MW5	2000	25	15 - 25	Monitoring	Active
DDJC - Sharpe MW428A	1984	32	22 - 32	Monitoring	Active
DDJC - Sharpe MW429A	1984	30	20 - 30	Monitoring	Active
DDJC - Sharpe MW441A	1987	25	15 - 25	Monitoring	Active
DDJC - Sharpe MW441B	1987	75	65 - 75	Monitoring	Active
DDJC - Sharpe MW441C	1987	113	103 - 113	Monitoring	Active
DDJC - Sharpe MW478A	1994	22	11 - 21	Monitoring	Active
DDJC - Sharpe MW489A	1997	28	13 - 28	Monitoring	Active
DDJC - Sharpe MW502A	1984	35	25 - 34	Monitoring	Active
DDJC - Sharpe PZ018	2002	23	13 - 23	Monitoring	Active
DDJC - Sharpe PZ019	2002	25	15 - 25	Monitoring	Active

bgs - below ground surface
see text for sources of well information

Table 2
Deep Wells Within 2 Miles of Proposed Injection Well California Specialty Cheese UIC Permit Application

Operator	Well Name	Location	Distance from CSC Site (ft)	Date Drilled	Total Depth (ft)	Date Abandoned	Abandonment Plug Depths (ft)
Quintana Petroleum	S.P. No. 1	25-1S-6E	4,385	Apr-1970	9,471	Apr-1970	4,216'-3,936'; 1,045'-847'; 25'-sfc
Pan Petroleum Company	Hayre Egg Farms No. 1	18-1S-7E	4,520	Dec-1969	8,455	Dec-1969	7,716'-7,416; 1,311'-900'; 15'-sfc
Christiana Oil Corp.	Schleiss No. 1	30-1S-7E	9,826	Dec-1959	5,756	Dec-1959	956'-593'; 10'-sfc
S.I. Corporation	Great Basins Unit No. 22	22-1S-6E	10,236	Jul-1962	8,993	Jul-1962	795'-sfc
E.B. Towne	Southeast Lathrop Unit A1	14-1S-6E	9,456	Oct-1967	8,493	Dec-1971	7,391'; 3,150'-2,887; 25'-sfc
U.S. Natural Resources	Towne S.P. Unit Two No. 1	14-1S-6E	8,040	Nov-1968	8,147	Nov-1968	7,300'-7,008'; 952'-780'; 25'-15'
E.B. Towne	S.P. Unit One No. 1	14-1S-6E	8,208	Feb-1968	8,479	Mar-1968	950'-720'; 10'-sfc

See Figure 1 for well locations.
Table includes all wells within a 2-mile radius of the proposed CSC site that have penetrated the target injection zones.

Table 3

Industrial Process Water Treatment

Material Balance and Conceptual Design

California Specialty Cheese UIC Permit Application

BASIS: 24 HOUR BASIS AND YEAR 2000 WATER USE

CONVERSION DATA			GALLONS/DAY		
GRAM =	1000	MILLIGRAMS	WATER SUPPLY WELL	310,460	CALCULATED FROM DATA BELOW
GALLON=	3.785	LITERS	PRODUCT/PROCESS LOSS	24,960	ASSUMED AVERAGE GALLONS DAILY FLOW
DENSITY WATER=	8.33	LB/GALLON	DOMESTIC SEWAGE	5,000	ASSUMED AVERAGE GALLONS DAILY FLOW
POUND=	454	GRAMS	MAIN SUMP	249,600	AVERAGE GALLONS DAILY FLOW
			RINSE WATER	30,900	

STREAM NUMBER	1	2	3	4	5		6	MAIN EQUALIZATION	
STREAM DESCRIPTION	RAW FEED MAIN SUMP	ROTARY SCREEN SCREENINGS	ROTARY SCREEN EFFLUENT	INDUSTRIAL WASTEWATER PRETREATMENT			UIC WELL INJECTION	VOLUME GALLONS	
								50,000	
COMPONENT									
FLOW, GALLONS	249,600	500	249,100		280,000		280,000	UIC EQUALIZATION	
SUSPENDED SOLIDS, MG/L	1,300	1,300	1,300		1,300		19.91	VOLUME GALLONS	
SUSPENDED SOLIDS, LBS.	2,705	5	2,700		2,700		41.00		
DISSOLVED SOLIDS, MG/L	3,300	3,300	3,300		3,300		3,300	50,000	
DISSOLVED SOLIDS, LBS.	6,867	14	6,853		6,853		6,795		
DEBRIS, POUNDS	300	300	-		-		-		

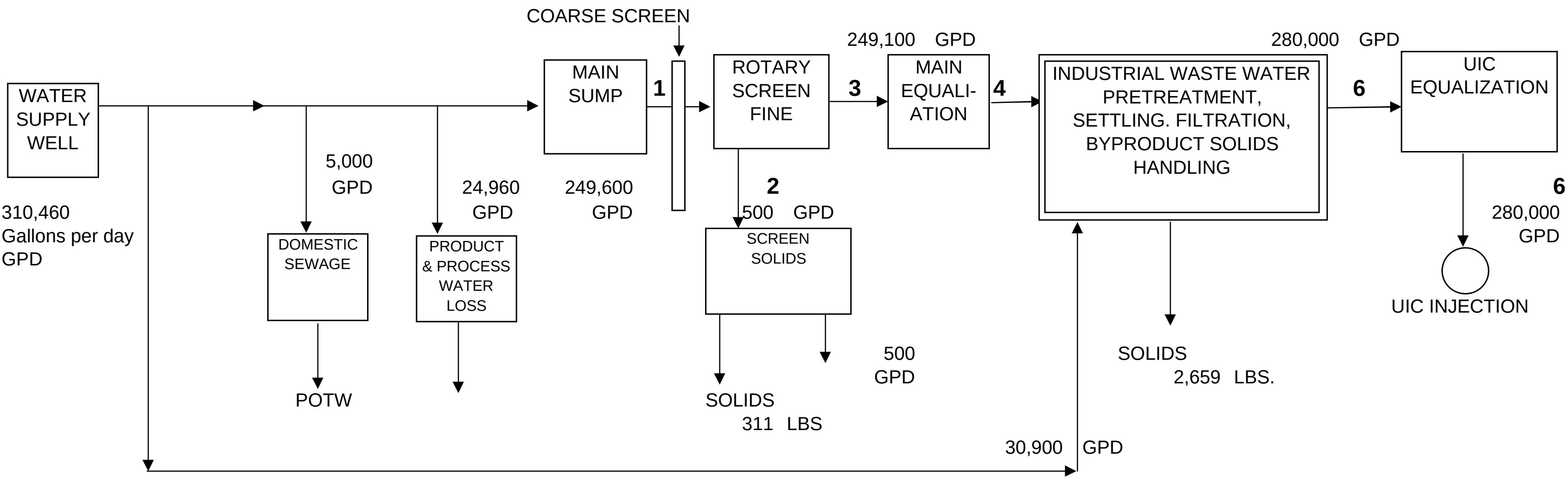
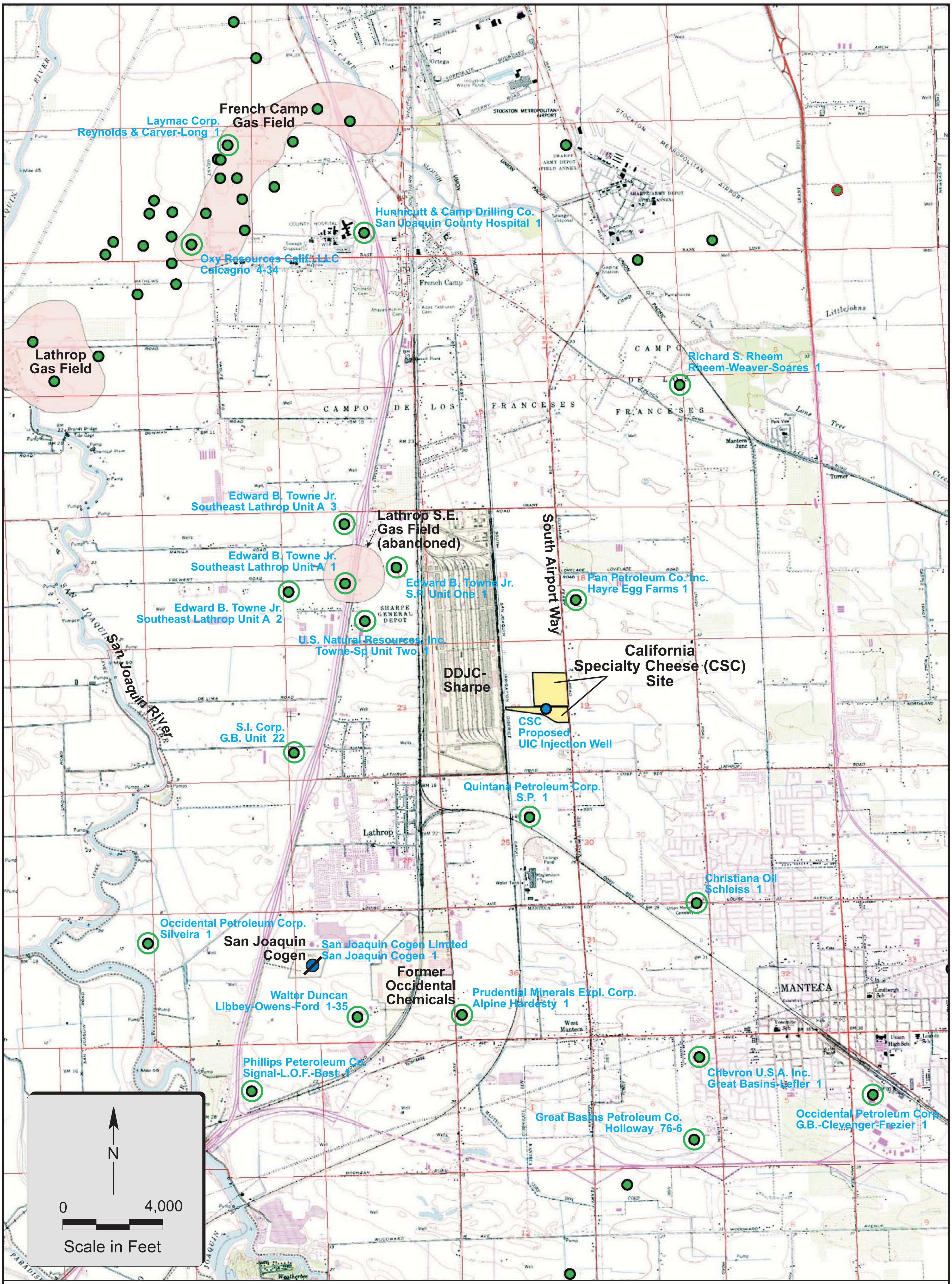


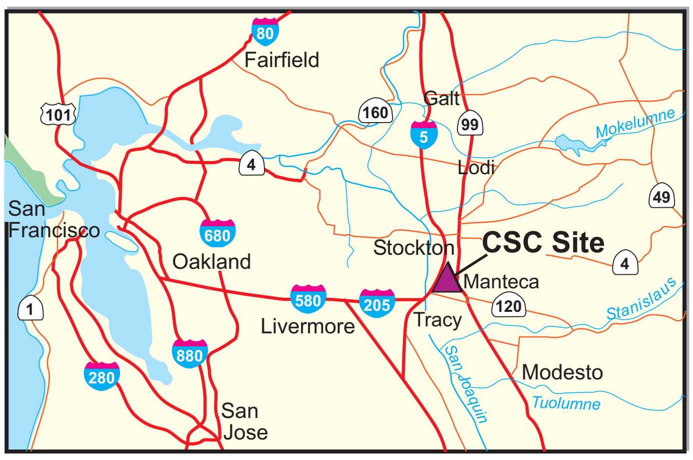
Table 4
Wastewater Characterization
California Specialty Cheese UIC Permit Application

Compiled data are on a 24-hour basis.
Anticipated wastewater volume of 300,000 gallons per day.

WASTEWATER CONSTITUENT/PARAMETER	SUMP MG/L 8/9/2002	SUMP LB/DAY 8/9/2002	SUMP MG/L 9/11/2000	DAF FEED MG/L 9/11/2000	DAF EFFLUENT MG/L 9/11/2000	DAF EFFECIENCY PERCENT	EQUALIZATION MG/L 8/9/2000	DAF EFFLUENT MG/L 8/9/2000	DAF EFFECIENCY PERCENT	SUMP MG/L 8/1/2000	EQUALIZATION MG/L 8/1/2000
TOTAL SUSPENDED SOLIDS	1300	3251		633	273	56.9	4900	610	87.6		
TOTAL DISSOLVED SOLIDS	3300	8254					2400	2400			
FIXED DISSOLVED SOLIDS	1300	3251									
VOLATILE DISSOLVED SOLIDS	2000	5002									
ELECTRICAL CONDUCTIVITY	2800	7003					3300	3400			
BOD	3900	9754		5265	2185		8400	2500		3026	2797
BOD5							1900				
SOLUBLE BOD				1586	1405			2000			
COD										8056	6928
pH	9.8						6	6			
TKN	940	2351					260	150			
AMMONIA NITROGEN			33.8	320.9	263.5		68				
ORGANIC NITROGEN			99.6	57.4	50.7		190				
NITRATE			227								
CHLORIDE	1110	2776		1110	1110		1110	1110			1110

NOTES:
DAF = Dissolved air flotation
DAF efficiency based on equalization/feed and effluent information.
All data from previous operations on CSC site by former operator.





LEGEND

- ● Deep Gas Exploratory Well
- ◉ Well used in regional mapping
- ● Proposed UIC Injection Well
- ⊘ Abandoned UIC Injection Well
- ● Gas Field

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Figure 1
Project Location Map

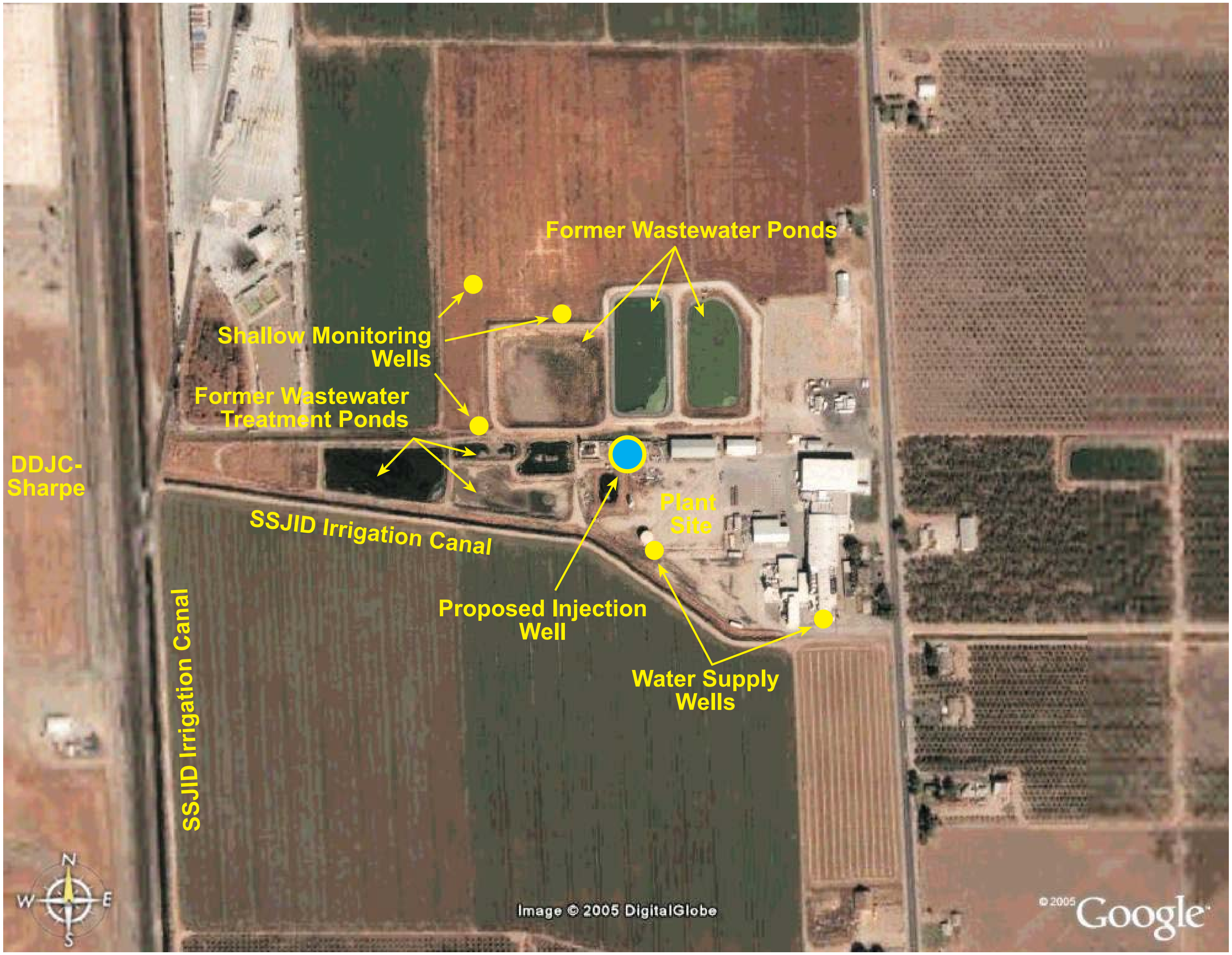

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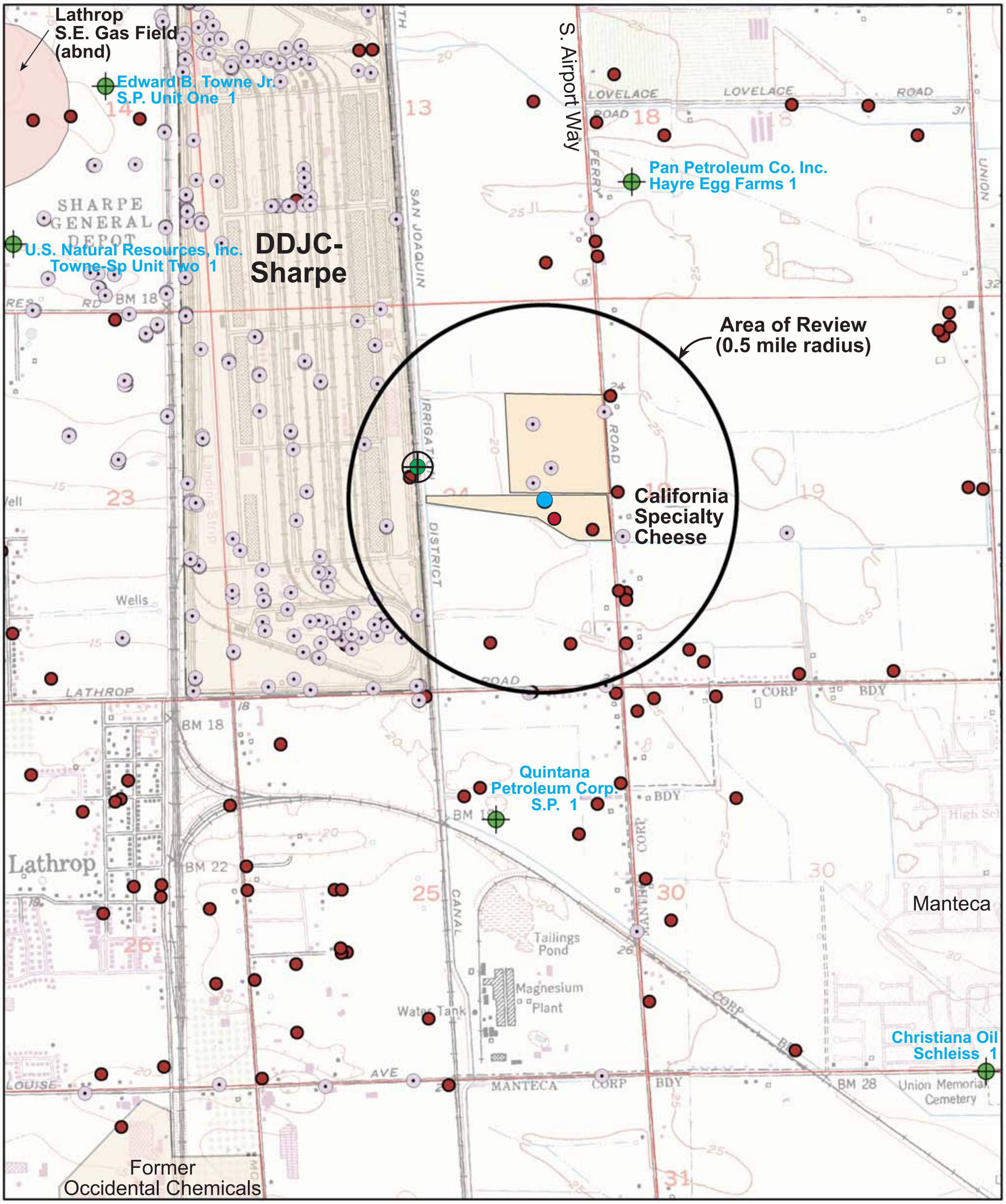
Figure 2
Air Photo
California Specialty
Cheese Site



Legend

- ● Proposed Injection Well
- ⊙ Facility Monitoring or Extraction Well (CSC or DDJC-Sharpe)
- ● Water Supply Well
- ⊕ Abandoned Gas Exploration Well
- ⊕ Abandoned Gas Well not drilled to injection zones. Operator and location unknown. Drilled in 1888 to 1,042 feet.

Note: All well locations are approximate.

N

0 2000

Scale in Feet

Figure 3
Wells in Area of Review

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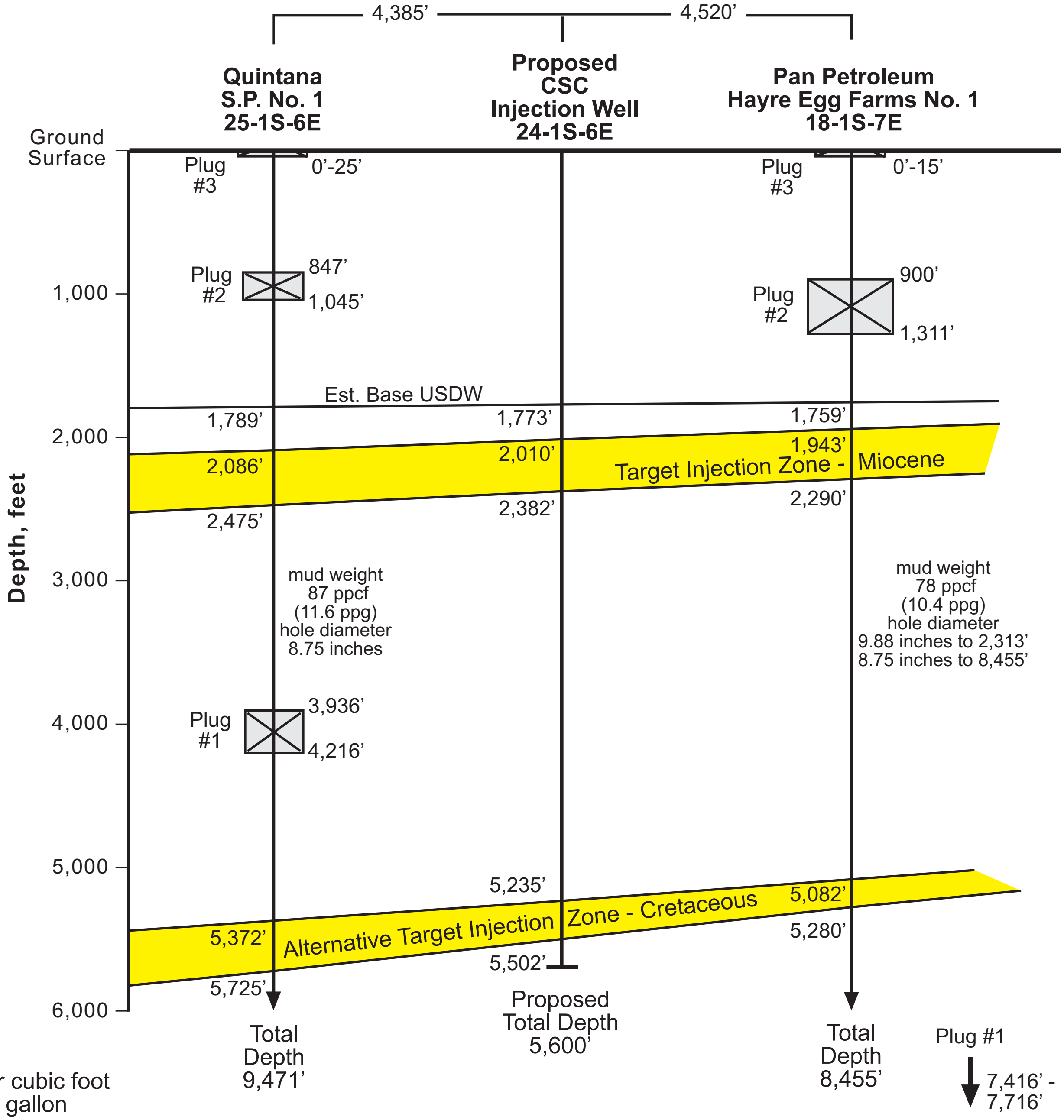

Note: These are the only 2 wells that penetrate either of the 2 target injection zones within 1.5 miles of CSC site.

ppcf = pounds per cubic foot
ppg = pounds per gallon

No horizontal scale

Figure 4
Abandoned
Deep Wells

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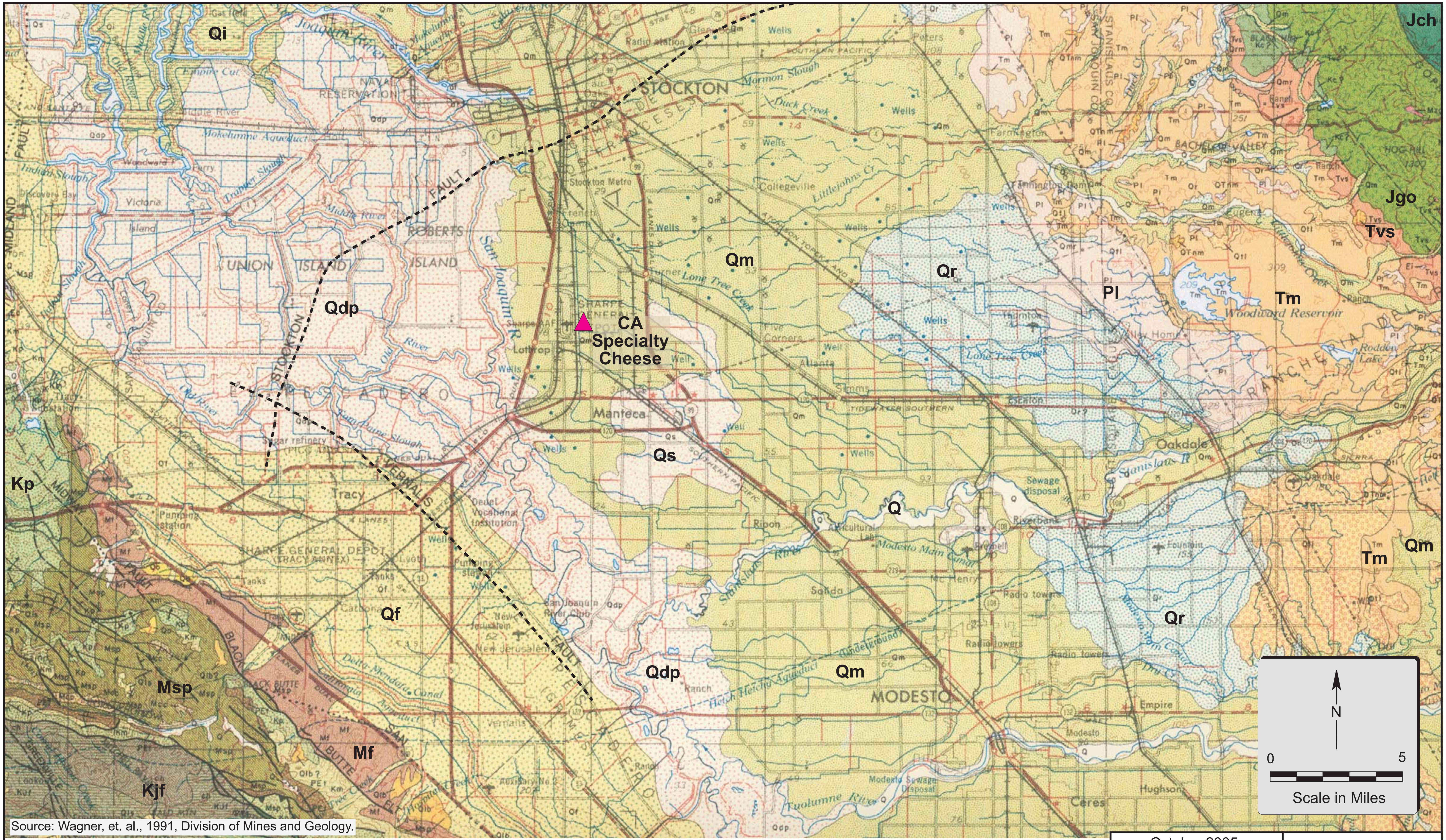

Source: Wagner, et. al., 1991, Division of Mines and Geology.

LEGEND

Q Alluvium
Qi Intertidal deposits
Qf Alluvial Fan deposits
Qls Landslide deposits
Qdp Dos Palos Alluvium
Qm Modesto Formation
Qr Riverbank Formation
Qs Dune Sand
Qlb Los Banos Alluvium
Qtl Turlock Lake Formation
Pl Laguna Formation
Msc Santa Cruz Mudstone
Msp San Pablo Group
Mf Fanglomerate
Tm Mehrten Formation
Tvs Valley Springs Formation
Kp Panoche Formation
KJf Franciscan Complex
Jch Copper Hill Volcanics
Jgo Gopher Hill Volcanics

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Figure 5
Geologic Map
California
Specialty Cheese

Hydrostratigraphy in Vicinity of CSC Site

AGE		Geologic Units	Approximate Thickness (feet)	Physical Character	Water-bearing Properties
Quaternary	Recent	Modesto Formation, Riverbank Formation, Victor Formation, Misc. Alluvial Deposits	150	Unconsolidated gravel, sand, silt and clay deposits with extensive sand and gravel stringers.	This material is moderately permeable and yields fresh water.
	Pleistocene	Corcoran or equivalent	50	Lacustrine Clay.	Confining layer.
Tertiary	Pliocene	Laguna Formation	800	Semiconsolidated, poorly sorted silt, sand and clay with some gravel.	Permeability varies. Generally permeable and yields fresh water.
	Miocene	Mehrten Formation	800	Conglomerate, silt and clay with interbedded lenses of black sands and agglomeratic material derived from andesitic mudflows.	The conglomerate, silt and agglomeratic material are relatively impermeable. Black sands are highly permeable and yield saline water in the Stockton area.
		Valley Springs Formation	500?	Consolidated rhyolitic tuffs, conglomerates, clay-shales, and sandstones.	This material is only slightly permeable and contains saline water in the Stockton area.
	Eocene-Paleocene	Undifferentiated Lower Tertiary/Upper Cretaceous	1,200	Consolidated marine sediments.	These deposits are only slightly permeable and contain saline water in the Stockton area.
Cretaceous		Undifferentiated Cretaceous Sediments	>8,500	Consolidated marine sandstones, shales, and conglomerates.	Saline water.
Pre-Cretaceous		Pre-Cretaceous Basement Complex	Unknown	Igneous and/or metamorphic rocks.	Fracture permeability only. No water quality data.

Modified from DWR, 1955.

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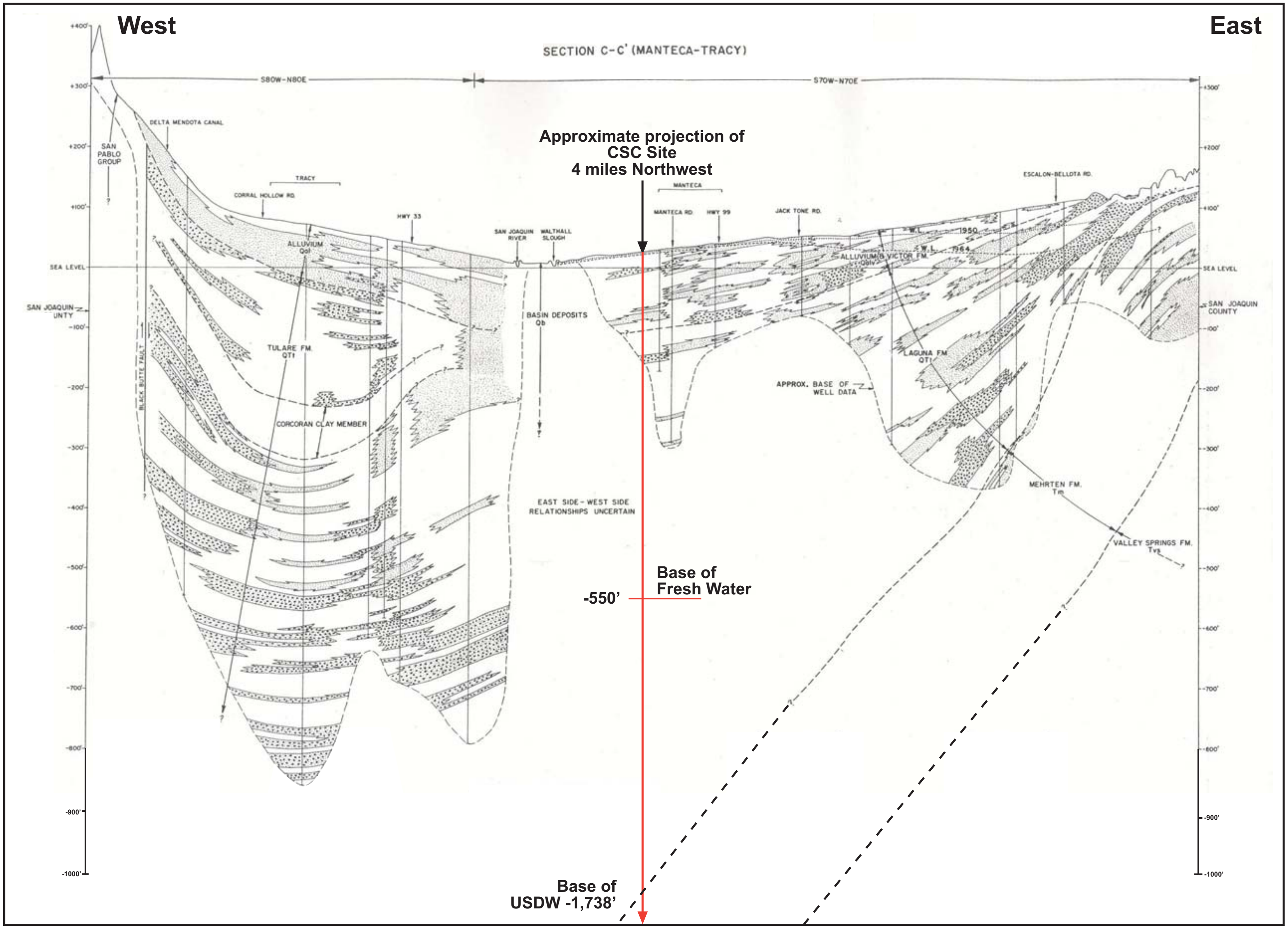
Figure 6
Hydrostratigraphic Units
San Joaquin County



Source: From DWR, 1967, modified below -800 feet.

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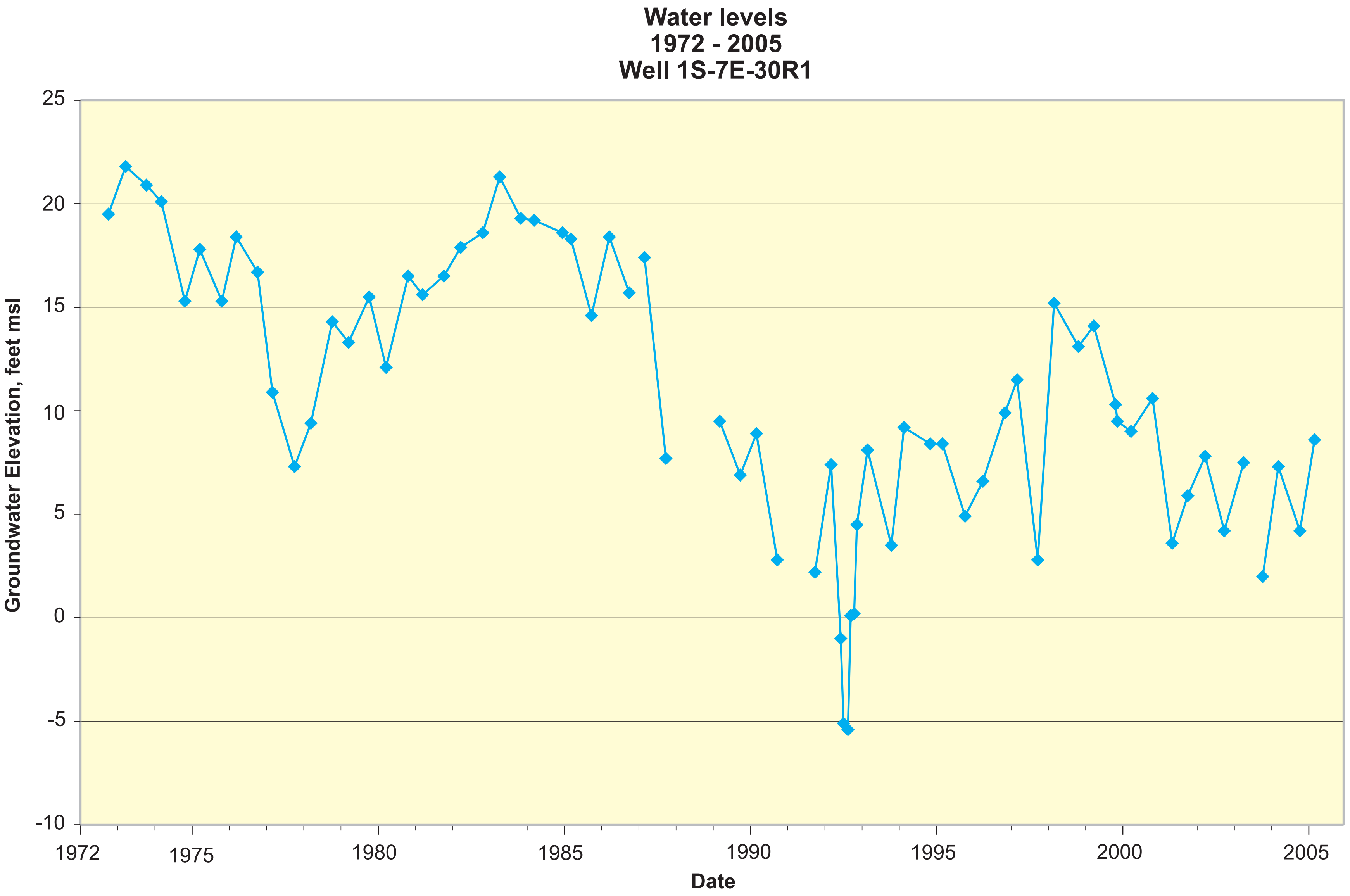
Figure 7
USDW
Cross Section



Note: Well is approximately 1.5 miles southeast of California Specialty Cheese site.

Source: Department of Water Resources, July 31, 2005.

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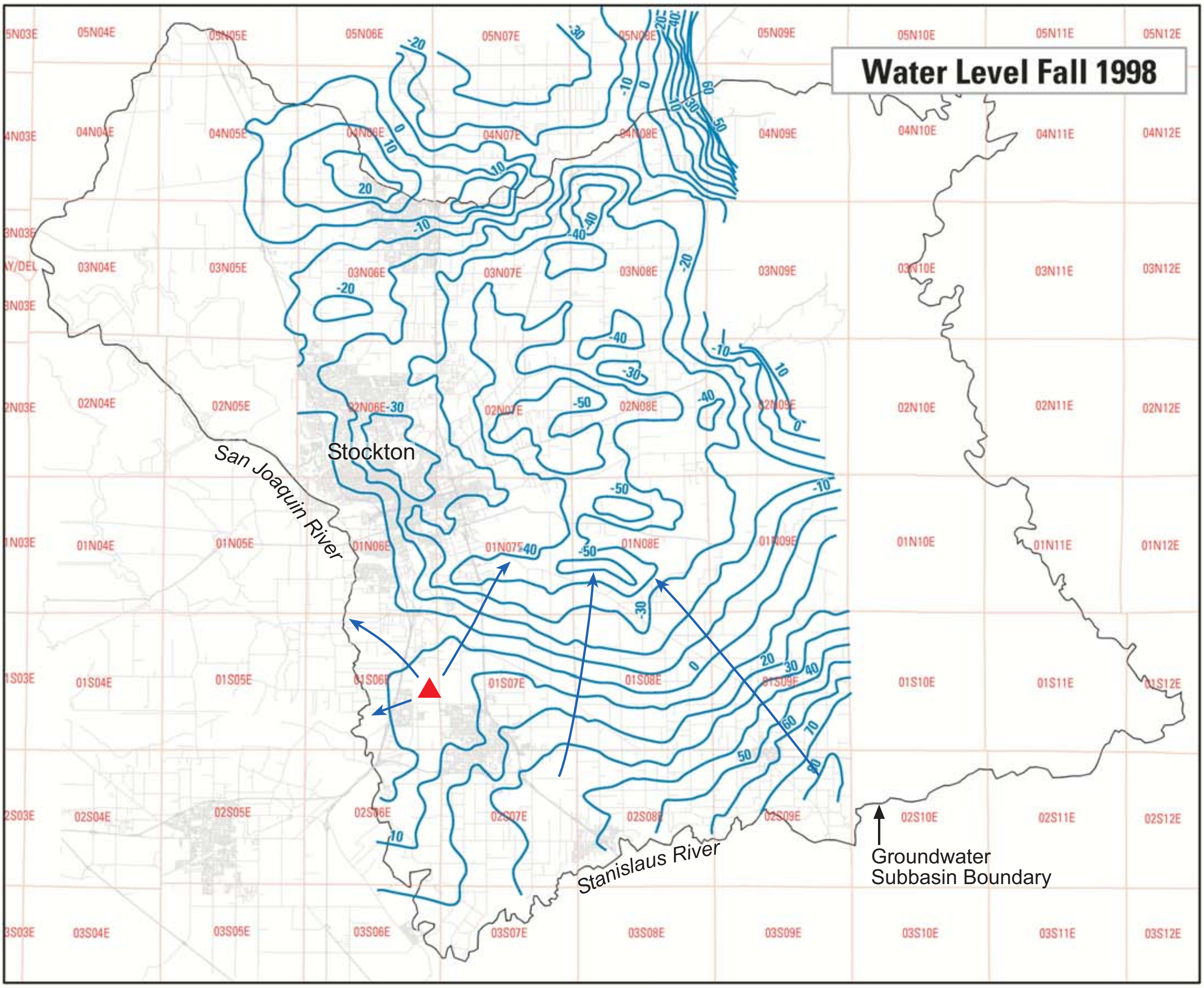
Figure 8
Groundwater Elevations near California Specialty Cheese Site



Source: USGS, DWR, and San Joaquin County, 1998.

Groundwater elevation contour, feet above mean sea level

Groundwater flow direction (not on original map)

California Specialty Cheese Site

N

0 6

Scale in Miles

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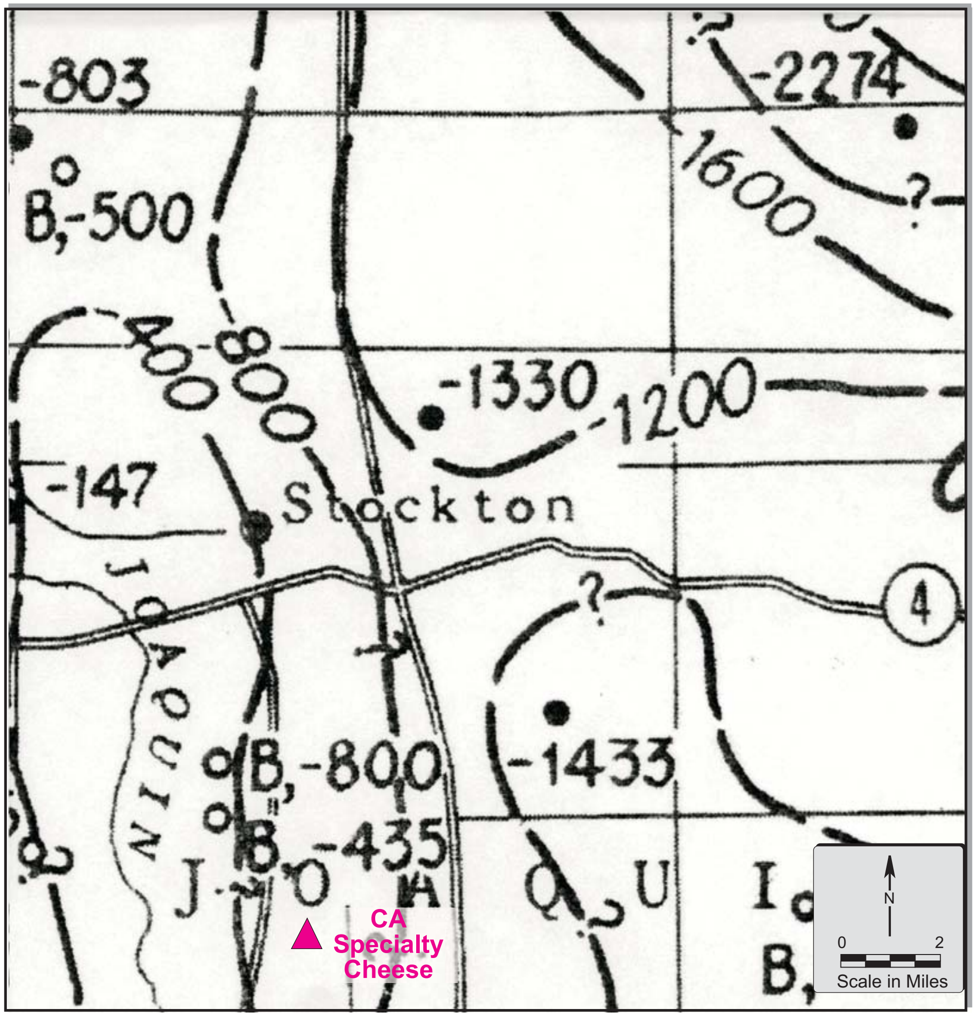
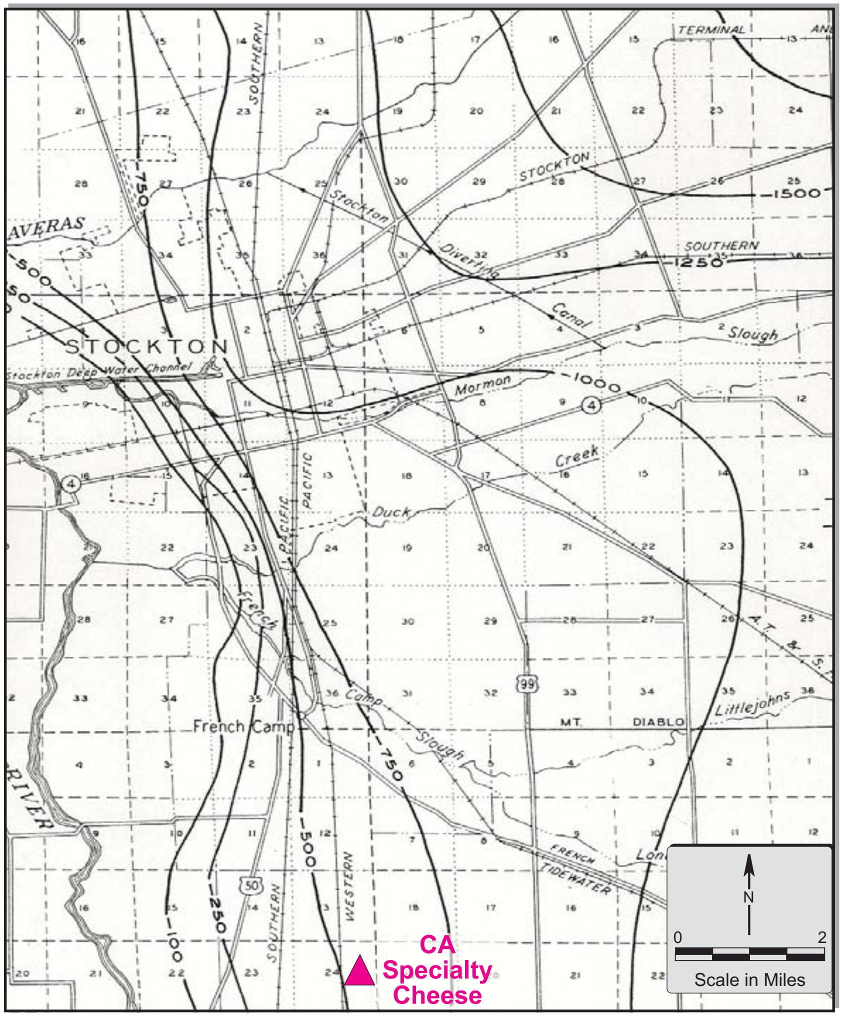
Figure 9
Groundwater Flow
Eastern San Joaquin
Subbasin



Base of Fresh Groundwater - C.F. Berkstresser, Jr., December 1973.

Defined as <2,000 mg/L TDS.

Estimated -550 feet below MSL at CA Specialty Cheese site.



Subsurface Contours of the Base of Fresh Water, DWR, March 1955.

Defined as <300 mg/L chloride; equivalent to 2,000 mg/L TDS.

Estimated -550 feet below MSL at CA Specialty Cheese site.

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Figure 10
Base of Fresh Water
near
CA Specialty Cheese

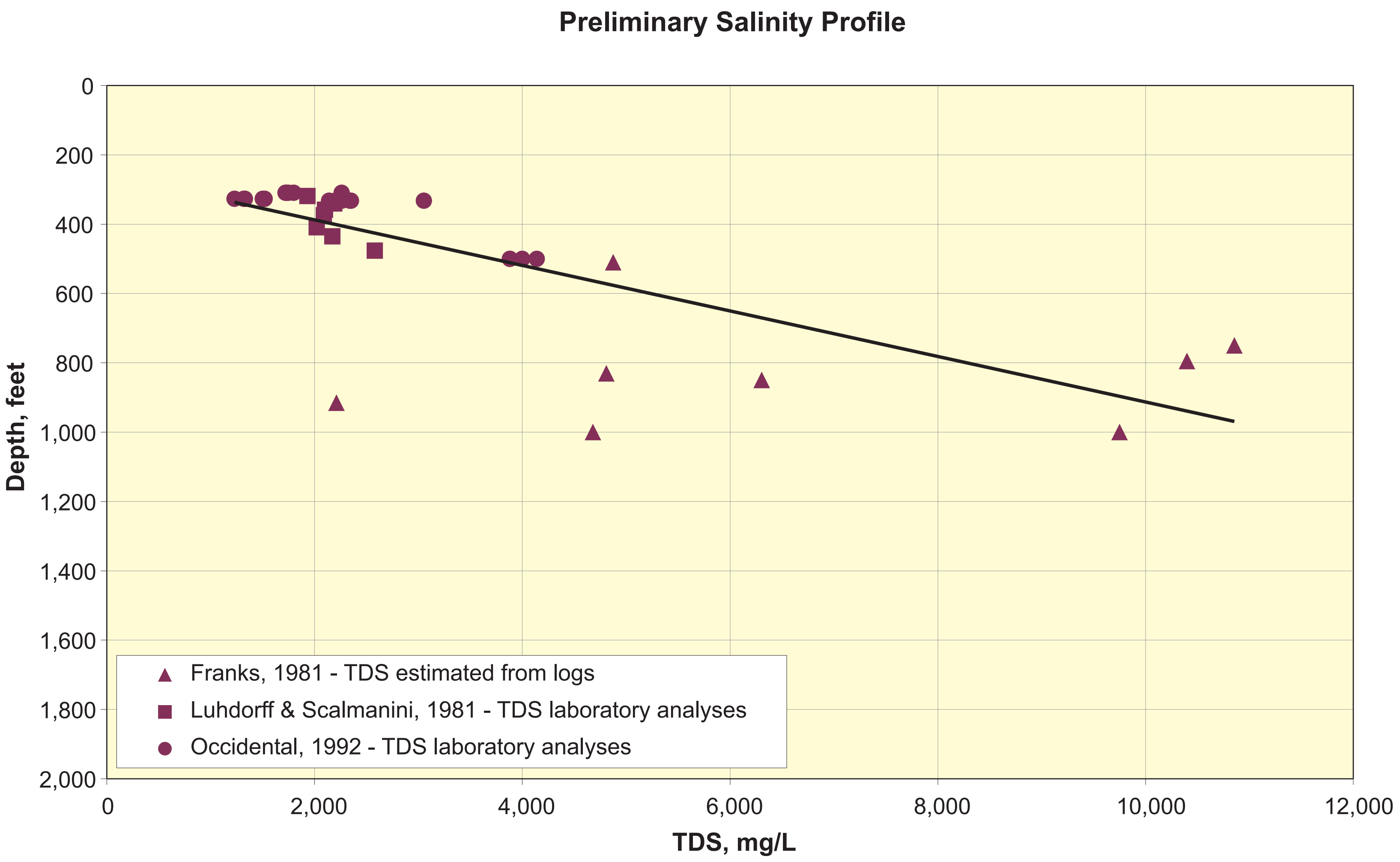

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Figure 11
Salinity Profile
TDS with Depth