Hyperion Energy Center

Best Available Control Technology (BACT) Analysis for Emissions of Carbon Dioxide

March 2009

Prepared for:

Hyperion Refining LLC

Prepared by:

RTP Environmental Associates, Inc.
304-A West Millbrook Rd.
Raleigh, NC 27609

Exhibit 35
AEWC & ICAS

TABLE OF CONTENTS

Exhibit 35
AEWC & ICAS

Exhibit 35
AEWC & ICAS

Chapter 1. Introduction

1.1 Overview

Hyperion Refining LLC ("Hyperion") has requested RTP Environmental Associates, Inc. ("RTP") prepare a Best Available Control Technology ("BACT") analyze for the increase in carbon dioxide (CO_2) emissions from the Hyperion Energy Center ("HEC") in Union County, South Dakota. This report presents the results of that analysis. It is assumed that the reader has access to the air quality permit application submitted to the South Dakota Department of Environment and Natural Resources in December 2007; the facility description and emissions calculations presented in that application are not repeated herein.

The proposed HEC will comprise a greenfield petroleum refinery and an integrated gasification combined cycle ("IGCC") power plant. The planned refinery is a 400,000 barrel per day, highly-complex, full-conversion refinery that will produce clean transportation fuels such as ultra-low sulfur gasoline and ultra-low sulfur diesel.

By its nature, petroleum refining requires transforming crude oil into products that can be combusted efficiently in internal combustion engines. To support the refining process, significant energy sources are required to provide process heat, steam, electricity and hydrogen. The HEC is unique in that it is designed to be nearly self-sufficient with regard to generation of hydrogen, steam, and electric power. This self-sufficiency will be achieved using petroleum coke that is produced on site, as a byproduct of the refining process, as the fuel source for the gasification process.

1.2 CO_2 Emissions

As with other refineries, the carbon input to the HEC will be primarily in the form of crude oil feedstock and will include other sources such as natural gas. In the HEC, approximately 82 percent of the carbon entering the facility will exit in the form of liquid fuel products, primarily gasoline and diesel fuel. The remaining approximately 18 percent of carbon input will exit as CO_2 emissions resulting from the combustion and chemical processes used to produce the heat, steam, electricity, and hydrogen required by the refinery.

The HEC will produce approximately 19 million short tons per year (STPY) of CO_2. These emissions will occur primarily from three categories of emissions units:

- Petroleum coke gasification process (approximately 50 percent of total),
- Combustion turbines in the power block (approximately 26 percent of total), and
- Refinery process heaters (approximately 24 percent of total).

Exhibit 35
AEWC & ICAS

Carbon dioxide is a combustion product of any carbon-containing fuel. All fossil fuels contain significant amounts of carbon. In the combustion of a fossil fuel, the fuel carbon is oxidized into carbon monoxide (CO) and CO_2. Full oxidation of fuel carbon to CO_2 is desirable because CO has long been a regulated pollutant with established adverse health impacts, and because full combustion releases more useful energy within the process. In addition, emitted CO gradually oxidizes to CO_2 in the atmosphere.

Table 1.2-1 presents the amount of CO_2 formed when combusting fossil fuels, including the fuels that will be used at the HEC.

Table 1.2-1. CO2 Emission Factors

FUEL	Pounds CO2 per Million Btu
Petroleum Coke	225 *
Coal	210 *
Residual Oil	174 *
Refinery Fuel Gas	≈ 120
Natural Gas	117 *
HEC Syngas	≈ 76

* Energy Information Administration at http://www.eia.doe.gov/oiaf/1605/coefficients.html

As the table shows, gaseous fossil fuels contain the least amount of carbon and solid fossil fuels contain the highest amount of carbon. The primary other combustible element in fossil fuels is hydrogen, which when combusted or oxidized becomes water vapor.

Unlike fossil fuel-fired electric power plants, which emit CO_2 from one stack or a small number of stacks located in proximity to one another, petroleum refinery CO_2 emissions are generated and emitted from sources and stacks scattered throughout the facility. As such, full capture of CO_2 emissions from the many stacks located throughout the HEC would be inefficient, challenging, and costly. Additionally, most of CO_2-emitting units at the HEC combust relatively low-carbon refinery fuel gas and natural gas, yielding exhaust gas CO_2 concentrations half that of solid fuel combustion sources. Table 1.2-2 lists the CO_2-emitting units at the HEC and the quantities of CO_2 emitted.

1.3 Premise for BACT Analysis

Under federal and South Dakota law and regulations, the requirement for BACT applies to pollutants that are subject to regulation under the federal Clean Air Act. Current regulations do not extend to CO_2, so BACT is not applicable to CO_2 emissions from the HEC. However, Hyperion and RTP recognize adding CO_2 emissions is an important issue, on which the political, regulatory, and legal framework may be changing. For purposes of this analysis, RTP assumes, *arguendo*, that CO_2 is subject to the BACT requirement applicable to regulated pollutants under 40 CFR § 52.21.

Exhibit 35
AEWC & ICAS

Table 1.2-2. HEC CO_2 Emissions

# of Units[1]	Fuel	Max. Firing Rate [MMBtu/hr]	Emission Rate Total	Emission Rate per Unit	% of Total
	IGCC	(HHV)	[ton/yr]	[ton/yr]	
2	CO2 Vent	NA	8,541,956	4,270,978	48%
4	Combustion Turbines	1677.4	3,986,530	996,633	23%
	PROCESS HEATERS				
2	CCR Platforming	824.52	933,155	466,577	5%
2	Hydrocracker Frac Section	675.52	764,524	382,262	4%
1	Oleflex	604.43	342,037	342,037	2%
2	CDU/VDU	530.15	600,002	300,001	3%
2	CCR Platforming	492.85	557,792	278,896	3%
1	NHT with Splitter	246.84	139,684	139,684	1%
2	Delayed Coker Unit	242.46	274,401	137,201	2%
2	Delayed Coker Unit	242.46	274,401	137,201	2%
2	CDU/VDU	214.66	242,946	121,473	1%
1	NHT with Splitter	199.60	112,949	112,949	1%
1	NHT with Splitter	168.78	95,507	95,507	1%
1	DHT	140.55	79,533	79,533	0%
1	CCR Reformate Splitter	138.00	78,090	78,090	0%
2	Hydrocracker Rxn Section	66.86	75,671	37,835	0%
2	Hydrocracker Rxn Section	66.86	75,671	37,835	0%
2	Hydrocracker Rxn Section	66.86	75,671	37,835	0%
2	Hydrocracker Rxn Section	64.91	73,457	36,729	0%
2	Hydrocracker Rxn Section	64.91	73,457	36,729	0%
	MISCELLANEOUS				
17	SRUs, Flares, etc.	NA	264,110	15,536	1%
			17,661,544		

As with the BACT analyses performed for regulated pollutants, this BACT analysis for CO_2 covers only emissions occurring from emissions units at the HEC. Emissions that will occur offsite due to combustion of the transportation fuels produced at the HEC are not subject to the BACT requirement. Similarly, this analysis does not cover CO_2 emissions that may occur at other sites or facilities to which CO_2-containing exhaust gases from the HEC may be transferred or transported. This BACT analysis conservatively assumes that any CO_2 that is captured at the HEC and transported offsite for use or disposal, such as through sequestration, will be 100 percent effective. In practice, the effectiveness of such disposition would be less, and some fraction of the CO_2 emissions capture that would be achieved at the HEC would be emitted from transportation pipelines or offsite sources. Those emissions are omitted from this analysis for simplicity, which may have the effect of overstating the environmental benefit of certain CO_2 control options considered in the analysis.

---

[1] There will actually be 5 combustion turbines, including one spare. Emissions are calculated as if four units will operate continuously at 100 percent capacity; in actuality, all five units will operate at less than 100 percent capacity.

Chapter 2. BACT Overview

2.1 Best Available Control Technology Definition

The PSD regulations define BACT at 40 CFR § 52.21(b)(12) as follows:

> "[BACT] means an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results."

2.2 Methodology for BACT Analyses

The PSD regulations do not prescribe a procedure for conducting BACT analyses. Instead, the U.S. EPA has consistently interpreted the BACT requirement as containing two core criteria: First, the BACT analysis must include consideration of the most stringent available technologies, *i.e.*, those that provide the "maximum degree of emissions reduction." Second, any decision to require as BACT a control alternative that is less effective than the most stringent available must be justified by an analysis of objective indicators showing that energy, environmental, and economic impacts render the most stringent alternative unreasonable or otherwise not achievable.

U.S. EPA has developed what it terms the "top-down" approach for conducting BACT analyses and has indicated that this approach will generally yield a BACT determination satisfying the two core criteria. Under the "top-down" approach, progressively less stringent control technologies are analyzed until a level of control considered BACT is reached, based on the environmental, energy, and economic impacts. The top-down approach was utilized in this BACT analysis.

The five basic steps of a top-down BACT analysis are listed below:

Exhibit 35
AEWC & ICAS

1. Identify all available control technologies with practical potential for application to the specific emission unit for the regulated pollutant under evaluation;
2. Eliminate all technically infeasible control technologies;
3. Rank remaining control technologies by effectiveness and tabulate a control hierarchy;
4. Evaluate most effective controls and document results; and
5. Select BACT, which will be the most effective practical option not rejected, based on economic, environmental, and/or energy impacts.

2.3 BACT Baseline

The statutory definition of BACT states:

> "In no event shall application of 'best available control technology' result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section 111 or 112 of [the Clean Air Act]."

Because CO_2 is not currently regulated under sections 111 or 112 of the Clean Air Act, there are no regulatory CO_2 emission limitations that would establish a control technology "baseline" for this BACT analysis. The performance and costs of identified CO_2 control technologies are therefore compared to uncontrolled baselines in this analysis.

2.4 BACT Technical Feasibility Criteria

In the second step of the BACT analysis, control technologies are evaluated for technical feasibility. Technical infeasibility will be demonstrated through clear physical, chemical, or other engineering principles that demonstrate that technical difficulties preclude the successful use of the control option. In addition, the technology must be commercially available for it to be considered as a candidate BACT technology. U.S. EPA's draft New Source Review Manual summarizes the technical feasibility criteria as follows:

> Technologies which have not yet been applied to (or permitted for) full scale operations need not be considered available; an applicant should be able to purchase or construct a process or control device that has already been demonstrated in practice.

In general, a technically feasible control technology is one that has been demonstrated to function efficiently on an emissions unit that is identical or similar to the emissions unit under review. For the purposes of assessing technical feasibility, the determination of whether an emissions unit should be considered to be identical or similar is based upon the physical and chemical characteristics of the gas stream to be controlled. A control method applicable to one emissions unit may not be technically feasible for an apparently similar source depending on differences in physical and chemical gas stream characteristics.

Exhibit 35
AEWC & ICAS

Chapter 3. BACT for CO_2 Vents

3.1 Step 1 – Identify Control Options

The only identified strategy for mitigating CO_2 emissions from the acid gas removal process at the HEC is carbon capture and storage ("CCS," also referred to as "carbon capture and sequestration"). As indicated by the name, this technique involves capturing CO_2, transporting it as necessary, and permanently storing it instead of releasing it into the atmosphere. The process involves three main steps:

- Capturing CO_2 at its source by separating it from other gases produced by an industrial process;
- Transporting the captured CO_2 to a suitable storage location (typically in compressed form); and
- Storing the CO_2 away from the atmosphere for a long period of time, for instance in underground geological formations, in the deep ocean, or within certain mineral formations.

It should be noted that one other identified option for achieving the hydrogen, steam, and electric power production that will be achieved by the IGCC power plant at the HEC is the use of natural gas as feed to a hydrogen production process and as fuel for a combined-cycle power plant. The petroleum coke produced at the HEC would be sold as a product for off-site use, such as in a pulverized coal-fired power plant. This option is fundamentally inconsistent with the design of the HEC, which is a petroleum refinery that maximizes the utilization of petroleum and petroleum intermediates. Because the use of natural gas in this manner would fundamentally redefine the design of the HEC, it is not considered further in this analysis.

3.1.1 Capture

Isolation of relatively pure CO_2 is inherent to the acid gas removal process at the HEC.

3.1.2 Transportation

As discussed in Section 3.1.3, below, carbon storage is possible only in a very limited number of sites, and the site of the HEC is not a suitable storage location. Accordingly, the captured CO_2 must be transported to a suitable storage site in order to achieve any environmental benefit. Pipelines are the most common method for transporting large quantities of CO_2 over long distances.

The oldest long-distance CO_2 pipeline in the United States is the 140 mile Canyon Reef Carriers Pipeline (in Texas), which began service in 1972 for Enhanced Oil Recovery ("EOR") in regional oil fields. Other large CO_2 pipelines have been constructed since then, mostly in the mid-continent, Western United States, to transport CO_2 for EOR. These pipelines carry CO_2 from naturally-occurring underground reservoirs, natural gas processing facilities, ammonia

Exhibit 35
AEWC & ICAS

manufacturing plants, and a large coal gasification project to oil fields. Altogether, approximately 3,600 miles of CO_2 pipeline operate today in the United States.

Pipeline transportation of CO_2 is typically accomplished with CO_2 that is compressed to its supercritical state, involving pressures of 1200 to 2000 pounds per square inch. This compression requires high levels of energy consumption. In addition, water must be eliminated from CO_2 pipeline systems, as the presence of water results in formation of carbonic acid, which is extremely corrosive to carbon steel pipe. The primary compressor stations are located at the CO_2 source and where the CO_2 is injected, and booster compressors located as needed along the pipeline. In overall construction, CO_2 pipelines are similar to natural gas pipelines, requiring the same attention to design, monitoring for leaks, and protection against overpressure, especially in populated areas. All of these technical issues can be addressed through modern pipeline construction and maintenance practices.

3.1.3 Storage

There are several options being explored and employed for permanent storage of CO_2. These options include gaseous storage in various deep geological formations (including saline formations, exhausted oil and gas fields, and unmineable coal seams), liquid storage in the ocean, solid storage by reaction of CO_2 with metal oxides to produce stable carbonates, and terrestrial sequestration.

3.2 Step 2 – Eliminate Technically Infeasible Control Options

Capture, compression, and transportation of CO_2 from the acid gas removal process at the HEC are technically feasible. Of the CO_2 storage options listed in Section 3.1.3, only a limited number are technically feasible, as discussed below.

3.2.1.1 Geologic Formations

The geologic formations considered appropriate for CO_2 storage are layers of porous rock deep underground that are "capped" by a layer or multiple layers of non-porous rock above them. In this application a well is drilled down into the porous rock and pressurized CO_2 is injected into it. Under high pressure, CO_2 turns to liquid and can move through a formation as a fluid. Once injected, the liquid CO_2 tends to be buoyant and will flow upward until it encounters a barrier of non-porous rock, which can trap the CO_2 and prevent further upward migration.

There are other mechanisms for CO_2 trapping as well: CO_2 molecules can dissolve in brine, react with minerals to form solid carbonates, or adsorb in the pores of porous rock. The degree to which a specific underground formation is amenable to CO_2 storage can be difficult to determine. Research is being performed today which is aimed at developing the ability to characterize a formation before CO_2 injection in order to predict its CO_2 storage capacity. Another area of research is the development of CO_2 injection techniques that achieve broad dispersion of CO_2 throughout the formation, overcome low diffusion rates, and avoid fracturing the cap rock.

Exhibit 35
AEWC & ICAS

Several of the major unresolved issues with respect to CO_2 sequestration pertain to the legal framework for closing and remediating geologic sites, including liability for accidental releases from these sites. The Federal government has recently proposed regulations outlining requirements that owners or operators must demonstrate and maintain with respect to financial responsibility. These regulations are proposed under the authority of the Safe Drinking Water Act and do not address ambient air impacts.[2] Until the financial responsibility issues are defined and codified by the Federal government, companies and most likely states will not undertake commercial geologic CO_2 sequestration activities beyond those states that already have regulations for EOR. There are several types of geologic formations in which CO_2 can be stored, and each has different opportunities and challenges as briefly described below:

3.2.1.1.1 *Depleted oil and gas reservoirs*

These are formations that held crude oil and natural gas at some time. In general, they are characterized by a layer of porous rock with a layer of non-porous rock which forms a dome. This dome offers great potential to trap CO_2 and makes these formations excellent sequestration opportunities.

As a value-added benefit, CO_2 injected into a depleting oil reservoir can enable recovery of additional oil and gas. When injected into a depleted oil bearing formation, the CO_2 dissolves in the trapped oil and reduces its viscosity. This improves the ability of oil to move through the pores in the rock and flow with a pressure differential toward a recovery well. A CO_2 flood typically enables recovery of an additional 10 to 15 percent of the original oil in place. Enhanced oil recovery and enhanced gas recovery are commercial processes and in demand recently with high commodity prices. It is estimated that 50 to 90 billion metric tons of sequestration potential exists in mature oil and gas reservoirs identified by the Regional Carbon Sequestration Partnerships (RCSPs). Formed by the U.S. Department of Energy in 2003, the seven Partnerships span 40 states, three Indian nations, and four Canadian provinces.[3] There are no known oil or gas reservoirs providing CO_2 sequestration opportunities within the immediate vicinity of the HEC, but there are oil fields in Otsego County, in southwestern Nebraska, approximately 300 miles from HEC, and in southwestern North Dakota approximately 400 miles from HEC, that have significant EOR opportunity.[4] These oil fields provide a sequestration opportunity that is considered technically feasible for the HEC.

3.2.1.1.2 *Unmineable coal seams*

Unmineable coal seams are those that are too deep or too thin to be mined economically. All coals have varying amounts of methane adsorbed onto pore surfaces, and wells can be drilled into unmineable coal beds to recover this coal bed methane (“CBM”). Initial CBM recovery methods, dewatering and depressurization, leave an appreciable amount of CBM in the reservoir. Additional CBM recovery can be achieved by sweeping the coal bed with nitrogen or CO_2, which preferentially adsorbs onto the surface of the coal, releasing the methane. Two or three molecules of CO_2 are adsorbed for each molecule of methane released, thereby providing an excellent storage sink for CO_2. Like depleting oil reservoirs, unmineable coal beds are a good early opportunity for CO_2 storage.

---

[2] 40 CFR Parts 144 and 146: Federal Requirements under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2G4) Geologic Sequestration (GS) Wells.

[3] “Carbon Sequestration Atlas of the United States and Canada”, page 13 of: http://www.netl.doe.gov/technologies/carbon_seq/refshelf/atlas/National%20Perspectives.pdf

[4] *Ibid.* Page 69.

Exhibit 35
AEWC & ICAS

One potential barrier to injecting CO_2 into unmineable coal seams is swelling. When coal adsorbs CO_2, it swells in volume. In an underground formation swelling can cause a sharp drop in permeability, which not only restricts the flow of CO_2 into the formation but also impedes the recovery of displaced CBM. Two possible solutions to this challenge include angled drilling techniques and fracturing.

It is estimated that 150 to 200 billion metric tons of CO_2 sequestration potential exists in unmineable coal seams identified by the RCSPs. [5] Such seams are known to exist in the vicinity of the HEC in southwestern North Dakota, approximately 400 miles from HEC, and central Iowa, approximately 200 miles from HEC.[6] Although CO_2 sequestration in unmineable coal seams may be technically feasible, it is much less developed and proven relative to EOR. As such, CO_2 sequestration in unmineable coal seams will not be considered further in this analysis based on the limited development and because the coal seams are not any closer to HEC as the EOR sites.

3.2.1.1.3 Saline formations

Saline formations are layers of porous rock that are saturated with brine. They are much more commonplace than coal seams or oil and gas bearing rock, and represent an enormous potential for CO_2 storage capacity. The RCSPs estimate a range of 3,300 to 12,000 billion metric tons of sequestration potential in saline formations.[7] However, much less is known about saline formations than is known about crude oil reservoirs and coal seams, and there is a greater amount of uncertainty associated with their ability to store CO_2. Saline formations contain minerals that could react with injected CO_2 to form solid carbonates. The carbonate reactions have the potential to be both a positive and a negative. They can increase permanence but they also may plug up the formation in the immediate vicinity of an injection well. Additional research is required to better understand these potential obstacles and how best to overcome them.[8] Such saline formations are known to exist in the vicinity of the HEC in northwestern South Dakota, approximately 250 miles from HEC, and southwestern Nebraska, approximately 300 miles from HEC.[9] Although CO_2 sequestration in saline formations may be technically feasible, it is much less developed and proven in comparison to EOR. As such, CO_2 sequestration in saline formations will not be considered further in this analysis based on the limited development and because the saline formation are not any closer to HEC as the EOR sites.

3.2.1.1.4 Basalt formations

Basalts are geologic formations of solidified lava. Basalt formations have a unique chemical makeup that could potentially convert all of the injected CO_2 to a solid mineral form, thus permanently isolating it from the atmosphere. Current research is focused on enhancing and utilizing the mineralization reactions and increasing CO_2 flow within a basalt formation. Although oil and gas-rich organic shale and basalt research is in its infancy, these formations may, in the future, prove to be optimal storage sites for sequestering CO_2 emissions. This CO_2

---

[5] Ibid. page 14.
[6] Ibid. page 63.
[7] Ibid. page 20.
[8] Ibid, page 15
[9] Ibid. page 63.

sequestration technique is considered technically infeasible for the HEC at this time due to its limited development, and it will not be considered further in this analysis.

3.2.1.2 Terrestrial Ecosystems

Terrestrial sequestration is the enhancement of CO_2 uptake by plants that grow on land and in freshwater and, importantly, the enhancement of carbon storage in soils where it may remain more permanently stored. Terrestrial sequestration provides an opportunity for low-cost CO_2 emissions offsets. Early efforts include tree-plantings, no-till farming, and forest preservation. To date, there are no applications that would be large enough to handle 10 to 19 million tons per year of CO_2.

Carbon can be sequestered in terrestrial ecosystems by:[10]

1. Increasing the amount of aboveground biomass in an ecosystem. Biomass is matter originally created by living organisms such as trees, leaves, and bacteria. The ultimate origin of the carbon in virtually all biomass is atmospheric CO_2, so storing biomass is storing atmospheric carbon. Dry biomass is roughly 50% carbon by weight. Forest ecosystems contain more living biomass than any other ecosystem so converting grasslands or croplands to forest is one way of sequestering carbon.
2. Increasing the amount of carbon held in soils. Soil carbon originates primarily from plant and fungal material which is then processed by other fungi and bacteria. Soil carbon can also originate from charcoal or char created when an ecosystem burns. Many factors control how much carbon goes into soil and how long the carbon stays in the soil.

Both approaches can be addressed simultaneously on the same piece of land. In general croplands store less carbon than grasslands which store less carbon than forests. Grasslands are particularly good at storing carbon in soils because they often have extensive and deep roots. Soil carbon is less vulnerable to rapid loss than aboveground biomass which can be quickly lost to the atmosphere in a fire.

Sequestration of carbon in terrestrial ecosystems is a low-cost option that may be available in the near-term to mitigate increasing atmospheric CO_2 concentrations, while providing additional benefits. Storing carbon in terrestrial ecosystems can be achieved through maintenance of standing aboveground biomass, utilization of aboveground biomass in long-lived products, or protection of carbon (organic and inorganic) compounds present in soils. There are potential co-benefits from efforts to sequester carbon in terrestrial ecosystems. For example, long-lived valuable products (wood) are produced, erosion would be reduced, soil productivity could be improved through increased capacity to retain water and nutrients, and marginal lands could be improved and riparian ecosystems restored. Another unique feature of the terrestrial sequestration option is that it is the only option that is “reversible” should it become desirable and permissible. For example, forests that are created are thus investments which could be harvested should CO_2 emissions be reduced in other ways to acceptable levels 50-100 years from now.

---

[10] “Carbon Sequestration in Terrestrial Ecosystems: A Status Report on R&D Progress”, Gary K. Jacobs, et. al., Oak Ridge National Laboratory, Oak Ridge, TN. August 2000.

Exhibit 35
AEWC & ICAS

However, due to the undemonstrated cost and effectiveness of terrestrial ecosystem sequestration options for storing 10 to 18 million tons per year of CO_2 over the life of the HEC, this sequestration option is considered technically infeasible and will not be further evaluated as BACT.

3.3 Step 3 - Characterize Control Effectiveness of Technically Feasible Control Options

The only technically feasible strategy for mitigating CO_2 emissions from the acid gas removal process at the HEC is CCS. For the purposes of this analysis, depleted oil and gas reservoirs with EOR potential are assumed to represent the best option for long-term storage. This control option is assumed to be 100 percent effective and to result in a CO_2 emission reduction of approximately 8.5 million tons per year.

3.4 Step 4 - Evaluate More Effective Control Options

The exhaust stream from the CO_2 vent will be suitable for transporting by pipeline, with a purity of approximately 98 percent CO_2, but will need to be dried and boosted in pressure from 900 pounds per square inch to 2000 pounds per square inch.[11] These requirements would increase the electrical load on the IGCC power plant by 267 megawatts ("MW"), which would significantly increase fuel and energy use and would increase air emissions by approximately 175 tons of PM-2.5, 86 tons of NO_X, 50 tons of SO_2, 53 tons of CO, and 13 tons of VOC per year. The estimated capital costs for equipment needed for compression, pipeline transportation, and injection/storage are approximately $650 million. The levelized annual cost, including operating cost, is estimated to be approaicmately $300 million per year. The resulting avoided cost of CO_2 CCS is approximately $43 per ton CO_2 sequestered.

It has been assumed for this analysis that the recovered CO_2 from the acid gas removal process at the HEC could be used to provide value in an EOR opportunity. The IPCC special report on CCS estimated a credit of $10 to $16 per metric tonne of CO_2 for EOR but does not include long term monitoring and maintenance costs.[12] Assuming the cost benefit of EOR, this reduces the avoided cost of CO_2 for CCS $10 per ton, making the net levelized annual cost approximately $33 per ton of CO_2.

In RTP's experience, there is no precedent for determining the costs that are reasonable for CO_2 emission reduction in the context of a BACT analysis. In the absence of such precedent, market values of these reductions have been used for comparison. Currently, the market price of carbon credits traded on the Chicago Climate Exchange is less than $2/metric tonne of CO_2, or approximately $1.80 per short ton; the current market price on the European Climate Exchange, where the market is more established, is approximately $12 per short ton. Based on these values, the cost of CCS for the acid gas removal process at the HEC is not reasonable. In conjunction

---

[11] Compressing captured CO_2 to pipeline pressure (1,200–2,000 pounds per square inch (psi)) represents a large parasitic load. http://www.netl.doe.gov/technologies/carbon_seq/core_rd/co2capture.html.

[12] *IPCC Special Report on Carbon Dioxide Capture and Storage*. Intergovernmental Panel on Climate Change. 2005. Page 345.

Exhibit 35
AEWC & ICAS

with the adverse energy and environmental impacts of CCS, this control option does not represent BACT.

3.5 Step 5 - Establish BACT

Because no control option more effective than the baseline has been identified as BACT for CO_2 emissions from the acid gas removal process at the HEC, no emission limitation is appropriate. Appendix A presents the basis for the impacts analysis for the HEC combustion turbines and process heaters.

Exhibit 35
AEWC & ICAS

Chapter 4. BACT for Combustion Turbines and Process Heaters

4.1 Step 1 – Identify Control Options

There are two broad strategies for reducing CO_2 emissions from stationary combustion processes such as the combustion turbines and process heaters at the HEC. The first is to minimize the production of CO_2 through the use of low-carbon fuels and through aggressively energy-efficient design. As shown in Table 4.1-1, the use of gaseous fuels, such as natural gas and refinery gas, reduces the production of CO_2 during the combustion process relative to burning solid fuels (e.g., coal or coke) and liquid fuels (e.g., distillate or residual oils). Additionally, a highly efficient operation requires less fuel for process heat, which directly impacts the amount of CO_2 produced. Establishing an aggressive basis for energy recovery and facility efficiency will reduce CO_2 production and the costs to recover it.

The second strategy for CO_2 emission reduction is CCS. Unlike the exhaust stream associated with the acid gas removal process, the inherent design of the the combustion turbines and process heaters at the HEC produce a dilute CO2 stream that requires capture.

The CO_2 emissions from the combustion sources at the HEC can theoretically be captured through pre-combustion methods or through post-combustion methods. In the pre-combustion approach, oxygen instead of air is used to combust the fuel and a concentrated CO_2 exhaust gas is generated. This approach significantly reduces the capital and energy cost of removing CO_2 from conventional combustion processes using air as an oxygen source, but it incurs significant capital and energy costs associated with separating oxygen from the air.

Post-combustion methods are applied to conventional combustion techniques using air and carbon-containing fuels in order to isolate CO_2 from the combustion exhaust gases. Because the air used for combustion contains nearly 80 percent nitrogen, the CO_2 concentration in the exhaust gases is only 5 to 20 percent depending on the amount of excess air and the carbon content of the fuel.

4.2 Step 2 – Eliminate Technically Infeasible Control Options

4.2.1 Low-Carbon Fuels

Numerous fuels are available for use at the HEC. Several of these fuels will be produced at the refinery as a result of the petroleum refining process. Historically, petroleum refineries have

Exhibit 35
AEWC & ICAS

burned wide range of fuels, including high-carbon fuels such as residual oil and petroleum coke, in sources such as boilers and process heaters. As Table 1.2-1 shows, combustion of refinery gas and natural gas yields 40 to 50 percent less CO_2 than does combustion of coal and petroleum coke and approximately 30 percent less CO_2 than does combustion of residual oil. Combustion of the syngas produced at the HEC IGCC power plant yields approximately 65 percent less CO_2 than does combustion of coal and petroleum coke and approximately 55 percent less CO_2 than does combustion of residual oil. Accordingly, the preferential burning of these low-carbon gaseous fuels to meet the refinery's energy needs is an extremely effective CO_2 control technique. This control technique is technically feasible for all process heaters and combustion turbines at the HEC and is an inherent part of the facility's design.

4.2.2 Energy Efficiency

There are numerous strategies for achieving a highly energy-efficient design of a greenfield petroleum refinery. All identified strategies are technically feasible for application to the HEC and all are inherent in the design of the facility. These include the following.

4.2.2.1 Combustion Air Preheat

Air preheat is a method of recovering heat from the hot exhaust gas of a combustion process by heat exchange with the combustion air before it enters the combustion chamber or furnace. Preheating the combustion air reduces the amount of fuel required in the furnace because the combustion air does not have to be heated all the way from ambient temperature to the fuel combustion temperature by combusting fuel. The achievable reduction in fuel usage and CO_2 emissions is typically 10 to 15 percent. This heat recovery approach is commonly used on large process heaters at petroleum refineries. However, as energy costs have increased the boiler and heater size for which it is economically practical has steadily decreased. To equip a process heater with air preheat requires the addition of a draft fan and heat exchanger incurring capital, operating, and maintenance costs; for heaters of sufficient size, these costs can be offset by the fuel savings. Although combustion air preheat reduces the amount of CO_2 emitted, it increases emissions of NO_X because preheating the combustion air increases combustion temperature. The HEC will employ air preheat on 9 of 30 process heaters representing 70 percent of the facility-wide heat input to process heaters. This is equivalent to approximately 0.15 million tons per year of CO_2 that would be emitted firing additional natural gas or refinery fuel gas to make up the heat lost in the heater flue gas.

4.2.2.2 Use of Process Heat to Generate Steam

One method that petroleum refiners use to be more energy efficient is to cool hot process streams by generating steam. This is done by passing the hot process stream through a heat exchanger to transfer the heat to boiler feed water. The HEC will generate both high pressure (600 psig steam) and low pressure steam (50 psig steam) using this approach. Approximately 15 percent of the refinery's steam demand will be generated using process heat recovery. This is equivalent to approximately 0.3 million tons per year of CO_2 that would be emitted if natural gas or refinery fuel gas was used to generate this steam instead.

4.2.2.3 Process Integration and Heat Recovery

Traditionally, petroleum refinery process units such as crude distillation units send the various product streams directly to intermediate storage tanks after the product has been cooled using

Exhibit 35
AEWC & ICAS

cooling water. Then the downstream processing unit, for example a Diesel Hydrotreating unit, is fed by pumping the cooled diesel stream from the intermediate storage tank. This requires the diesel feed stream to be heated up from its cooled storage temperature to its processing temperature. Energy is saved if the hot diesel stream from the crude unit is pumped directly to the Hydrotreating unit. The HEC will make use of the most advanced design approaches to integrate the process units and to maximize energy efficiency.

4.2.2.4 Continuous Excess Air Monitoring and Control

Excessive amounts of combustion air used in process heaters results in energy inefficient operation because more fuel combustion is required in order to heat the excess air to combustion temperatures. This can be alleviated using state-of-the-art instrumentation for monitoring and controlling the excess air levels in the combustion process, which reduces the heat input by minimizing the amount of combustion air needed for safe and efficient combustion. This requires the installation of oxygen monitor in the heater stack and damper controls on the combustion air dampers. Additionally, lowering excess air levels, while maintaining good combustion, reduces not only CO_2 emissions but also NO_X emissions. All of the HEC process heaters and combustion turbines will be equipped with oxygen monitors as part of the continuous emission monitoring system.

4.2.2.5 Cogeneration as a CO_2 Reduction Technique

Cogeneration is the simultaneous production of electric power and thermal energy from a single fuel. A typical configuration is the use of combustion turbines to generate electricity, with the waste heat used to generate steam in a heat recovery steam generator (“HRSG”), from which steam is made available for use in providing heat to refinery process units. The reduction in CO_2 emissions from employing cogeneration comes from the reduced fuel use at electric utility power plants; thus, the amount of CO_2 reduction is dependent upon the type of electric utility power generation displaced. Where coal-based generation is displaced, CO_2 reductions of 30 percent or more are achievable. The HEC will make use of IGCC to cogenerate steam and electricity using a low value fuel, petroleum coke generated at the refinery. This approach is more energy efficient than purchasing electricity from a electric utility and generating steam by burning coke, residual oil, or natural gas.

Note, the efficiencies above are not additive when layering technology options (e.g., addition of air preheat and continuous monitoring of excess air), some options may preclude the use of other options in certain equipment, and some options are not practical for application to small combustion sources.

4.2.3 Carbon Capture and Storage

4.2.3.1 CO_2 Capture

There are two pre-combustion CO_2 capture techniques with the potential for use with combustion sources at the HEC: indirect use of oxygen and direct use of oxygen. The indirect approach involves partial combustion of a carbon-containing fuel (e.g., refinery gas, residual oil, or coke) with oxygen and steam to produce a synthesis gas (“syngas”) composed of carbon monoxide (CO) and hydrogen (H_2). The CO is reacted with steam in a catalytic reactor, called a shift converter, to yield CO_2 and additional H_2. The CO_2 is then separated, usually by a physical or chemical absorption process, resulting in a hydrogen-rich fuel which can be combusted in

Exhibit 35
AEWC & ICAS

boilers, furnaces, gas turbines, engines and fuel cells. This approach would work only with new equipment specifically designed to burn hydrogen because existing equipment would not be configured appropriately. The combustion of hydrogen as fuel in boilers, process heaters, and combustion turbines has not been demonstrated at the scale required for petroleum refineries and is considered technically infeasible.

The direct approach to pre-combustion CO_2 separation involves substituting oxygen for air during the combustion process. Because the heaters and combustion turbines at the HEC are designed to use air for combustion, the use of oxygen would require substantial redesign. No commercially proven equipment meeting these design requirements is available. Accordingly, CCS involving pre-combustion CO_2 separation and capture is technically infeasible.

Technical feasibility of post-combustion CO_2 capture technologies is addressed in the following paragraphs.

4.2.3.1.1 Chemical absorption.

This is the most common method for CO_2 capture. Monoethanolamine ("MEA") solvent has the advantage of fast reaction with CO_2 at low partial pressure. The primary concerns with MEA and other amine solvents are corrosion in the presence of O_2 and other impurities, high solvent degradation rates due to reactions with SO_2 and NO_X, and the large amount of energy required for solvent regeneration. These difficulties can be overcome, and this capture method is technically feasible.

4.2.3.1.2 Physical absorption (e.g., Selexol®).

These absorption processes, which are commonly used for CO_2 rejection from natural gas, operate at high pressure and low temperature. Use of physical absorption for CO_2 capture from combustion exhaust gas would entail a significant amount of gas compression capacity and a significant energy penalty. These difficulties can be overcome, and this capture method is technically feasible.

4.2.3.1.3 Calcium cycle separation.

This is a quicklime-based capture method that yields limestone. When heated, the limestone releases CO_2, producing quicklime again for recycling. Work is still required on sorbent stability after regeneration.

4.2.3.1.4 Cryogenic separation.

This capture method is based on solidifying the CO_2 component of the exhaust stream by frosting it to separate it out. The low concentration of CO_2 in the exhaust gas from conventional air-based combustion processes, such as the process heaters and combustion turbines at the HEC, renders this technology infeasible for this application.

4.2.3.1.5 Membrane separation.

This method is commonly used for CO_2 removal from natural gas at high pressure and high CO_2 concentration. Membrane technology is not fully developed for low CO_2 concentrations and gas flow at the scale required for the HEC.

Exhibit 35
AEWC & ICAS

4.2.3.1.6 Adsorption.

This method involves feeding the exhaust gas through a bed of solid material with high surface areas, such as zeolites or activated carbon. These materials can preferentially adsorb CO_2 while allowing nitrogen and other gasesto pass through. The fully saturated bed is regenerated by either pressure swing (low pressure), temperature swing (high temperature), or electric swing (low voltage) desorption. Adsorption would require either a high degree of compression or multiple separation steps to produce high CO_2 concentration from exhaust gas. This capture method is presumed for the purposes of this analysis to be technically feasible, but its capital and operating costs exceed those of available chemical absorption techniques, so adsorption will not be considered further.

4.2.3.2 CO_2 Transportation and Storage

Compression, transportation, and storage of CO_2 from the combustion processes at the HEC are technically feasible, as discussed in Section 3.2 herein.

4.3 Step 3 - Characterize Control Effectiveness of Technically Feasible Control Options

The use of low-carbon fuels and aggressively energy-efficient design to reduce CO_2 emissions from combustion turbines and process heaters is inherent in the design of the HEC and is considered the baseline condition.

The only technically feasible strategy for further controlling CO_2 emissions from the process heaters and combustion turbines at the HEC is CCS. For the purposes of this analysis, chemical absorption is assumed to represent the best capture option depleted oil and gas reservoirs with EOR potential are assumed to represent the best option for long-term storage. This control option is assumed to be 90 percent effective and to result in a CO_2 emission reduction of approximately 8.0 million tons per year.

4.4 Step 4 - Evaluate More Effective Control Options

Using CCS to reduce CO_2 emissions from the process heaters and combustion turbines at the HEC will have substantial impacts on the facility in many respects, as discussed in detail below.

4.4.1 Design Considerations

As shown in Table 1.2-2, emissions of CO_2 from the four combustion turbines and the thirty process heaters are approximately 9 million tons per year. This represents 50 percent of the CO_2 emissions from the HEC, but these combustion sources are scattered throughout the facility. The largest of these sources are the four equal-sized combustion turbines in the IGCC power plant. In order to capture the CO_2 from the combustion turbine exhaust, because these units will be in close proximity, their vents would be ducted together and CO_2 recovery would be accomplished using a single, large solvent scrubbing/regeneration system.

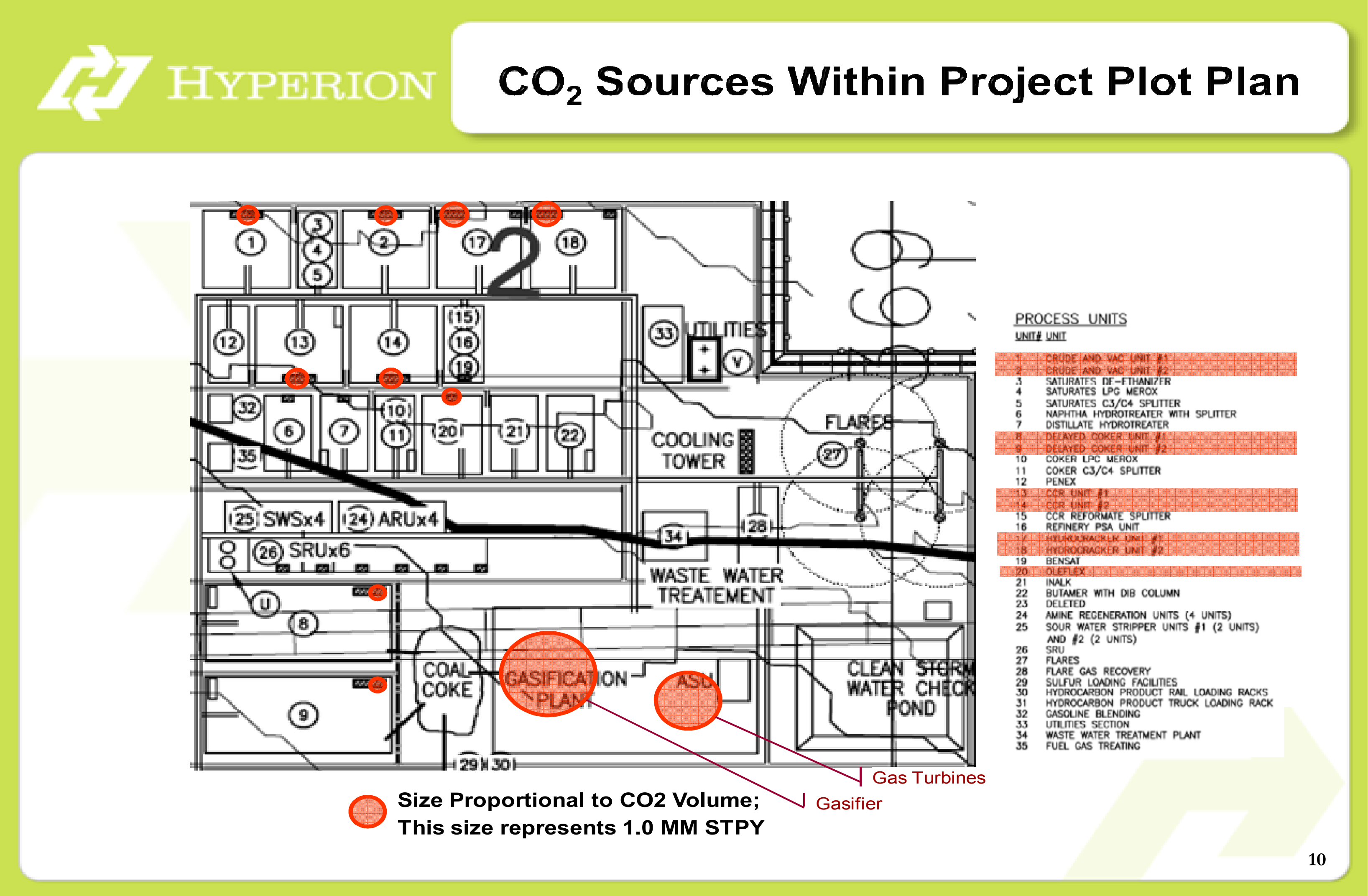
Exhibit 35
AEWC & ICAS

The refinery process heaters are much more numerous and spaced further apart than the turbines. As a result, multiple scrubbers will be installed as it is more economical to pump the solvent throughout the refinery than it is to duct all of the flue gases into a single scrubbing system. The CO_2-rich solvent from the scrubbers is then pumped to a regeneration system for CO_2 removal and reuse. These systems will be collectively more costly than for the combustion turbine exhaust system due to the need for multiple scrubbers. Of the 30 heaters in the refinery, 26 can be combined into nine combined furnace stacks. These heaters are located in the Delayed Coking Units (2), Continuous Catalytic Reformers (2), the Crude and Vacuum Units (2), the Hydrocracking Units (2), and the Oleflex Unit (1). A scrubbing system would be located at each of these units for CO_2 capture. These scrubbing systems would control approximately 90 percent of the total CO_2 emissions from heaters. The four heaters that are not covered by the scrubbing systems in this analysis represent only two percent of the facility-wide CO_2 emissions from the HEC; these heaters are omitted from the analysis because they are less cost-effective to control than are the other heaters and including them would skew the overall cost-effectiveness analysis. The combined collection and control of the four combustion turbines and 26 process heaters represents approximately 7.4 million tons per year of CO_2 capture.

Figure 4.4-1 shows the HEC plot plan and the location of the nine process heater stacks where the scrubbing systems would be located. (This figure also shows the location of the CO_2 vents from the acid gas removal process as discussed in Chapter 3 herein.) It is assumed that MEA absorption systems will be used to scrub the CO_2 from the combustion turbine and large process heater flue gases. The MEA is regenerated with steam to produce a CO_2-rich stream. The CO_2 stream will need to be dried, compressed from low pressure up to 2000 pounds per square inch, and transported by an approximately 300 mile-long pipeline to an appropriate storage site.

Exhibit 35
AEWC & ICAS

FIGURE 4.4-1. HEC PLOT PLAN AND THE LOCATION OF THE NINE PROCESS HEATER STACKS AND CO$_2$ SCRUBBERS



CO$_2$ Sources Within Project Plot Plan

● Size Proportional to CO2 Volume;
This size represents 1.0 MM STPY

PROCESS UNITS

UNIT#	UNIT
1	CRUDE AND VAC UNIT #1
2	CRUDE AND VAC UNIT #2
3	SATURATES DE-ETHANIZER
4	SATURATES LPG MEROX
5	SATURATES C3/C4 SPLITTER
6	NAPHTHA HYDROTREATER WITH SPLITTER
7	DISTILLATE HYDROTREATER
8	DELAYED COKER UNIT #1
9	DELAYED COKER UNIT #2
10	COKER LPC MEROX
11	COKER C3/C4 SPLITTER
12	PENEX
13	CCR UNIT #1
14	CCR UNIT #2
15	CCR REFORMATE SPLITTER
16	REFINERY PSA UNIT
17	HYDROCRACKER UNIT #1
18	HYDROCRACKER UNIT #2
19	BENSAT
20	OLEFLEX
21	INALK
22	BUTAMER WITH DIB COLUMN
23	DELETED
24	AMINE REGENERATION UNITS (4 UNITS)
25	SOUR WATER STRIPPER UNITS #1 (2 UNITS) AND #2 (2 UNITS)
26	SRU
27	FLARES
28	FLARE GAS RECOVERY
29	SULFUR LOADING FACILITIES
30	HYDROCARBON PRODUCT RAIL LOADING RACKS
31	HYDROCARBON PRODUCT TRUCK LOADING RACK
32	GASOLINE BLENDING
33	UTILITIES SECTION
34	WASTE WATER TREATMENT PLANT
35	FUEL GAS TREATING

Exhibit 35
AEWC & ICAS

4.4.2 Impacts Analysis

The use of CCS for the combustion sources at the HEC would entail significant, adverse energy and environmental impacts due to increased fuel usage in order to meet the steam and electric load requirements of these systems. The estimated 7.4 million tons per year of CO_2 captured from the combustion turbines and 26 process heaters would require the equivalent to 582 MW of electric power and steam generation capacity for capture, drying compression, and transpoert to a suitable EOR site. If all of the power generation is based on combined cycle combustion turbines firing natural gas, the increase fuel use and would increase air emissions by approximately 381 tons of PM-2.5, 188 tons of NO_X, 109 tons of SO_2, 115 tons of CO, and 29 tons of VOC per year. The estimated capital costs for the CCS equipment needed for capture, compression, pipeline transportation, and injection/storage are approximately $900 million. The levelized annual cost, including operating cost, is estimated to be approximately $500 million per year. The resulting avoided cost of CO_2 CCS is approximately $101 per ton of CO_2 sequestered. Assuming a $10 per ton cost benefit of EOR, the avoided cost of CO_2 for CCS becomes $91 per ton of CO_2 sequestered from the combustion turbines and 26 process heaters.

4.5 Step 5 - Establish BACT

Because no control option more effective than the baseline has been identified as BACT for CO_2 emissions from the combustion turbines and process heaters at the HEC, no emission limitations are appropriate. Appendix B presents the basis for the impacts analysis for the HEC combustion turbines and process heaters.

Exhibit 35
AEWC & ICAS

APPENDIX A – IMPACTS ANALYSIS FOR HEC CO2 VENT

PARAMETER	GASIFICATION CO2 VENT	
	BASELINE - No Compression, Transport, Sequestration	Compression+Transport +Sequestration
Environmental Impacts:		
CO2 Emitted, TPY	8,500,000	0.0
CO2 Incremental % Control	Baseline	100%
CO2 Reduced, TPY	Baseline	8,500,000
CO2 from Compression, TPY	Baseline	952,669
Net CO2 Reduced, TPY	Baseline	7,500,000
Increase in NOx, TPY	Baseline	79
Increase in SO2, TPY	Baseline	44
Increase in CO, TPY	Baseline	46
Increase in VOC, TPY	Baseline	12
Increase in PM2.5, TPY	Baseline	155
Energy Impacts:		
Additonal Power Generation, MW	Baseline	267
NG Use MMSCFY	Baseline	15,567
Economic Impacts:		
Total Capital Cost	Baseline	$649,800,000
Total Annual Cost	Baseline	$288,700,000
CO2 Capture Cost Effectiveness	Baseline	$38
CO2 Transport Cost Effectiveness	Baseline	$5
CO2 EOR Cost Effectiveness	Baseline	-$10
Total CO2 CCS Cost Effectiveness	Baseline	$33

HEC ESTIMATED COST OF CO2 CAPTURE BASED ON IPPC REPORT TABLE 3.15 - Gasification CO2 Vent

		IGCC	**IGCC**			**HEC**	**Comments**
Parameter	**Units**	**low**	**high**	**Parameter**	**Units**		
Plant Size	MW	400	800	Plant Size	MW	1368	(1) This is 507 MW Power plus 2.4 MMlb/hr steam equivalent MW (see below)
Emission Rate wo Capture	kgCO2/MWh	628	846	Emission Rate wo Capture	ton/year	8,541,956	From Table 1.2-2. HEC CO2 Emissions
Percent Reduction	%	81	91	Percent Reduction	%	100	Post Rectisol
Emission Rate w Capture	kgCO2/MWh	65	152	Emission Rate w Capture	ton/year	0	
				CO2 Captured	ton/year	8,541,956	
Capture Energy Required	% MWh	14	25	Capture Energy Required	MW	267	Average of 14 & 25 % MWh
				NG Use for Incremental MW	MM SCFY	15,566	6,796 Btu/kwh
				Incremental CO2 w Capture	ton/year	952,669	120 lb CO2/MMBtu for NG
Total Capital wo Capture	US$/kw	1169	1565	Total Capital wo Capture	Millions $	$1,870	Average of 1169 and 1565 US$/kw
Total Capital w Capture	US$/kw	1414	2270	Total Capital w Capture	Millions $	$2,520	Average of 1414 and 2270 US$/kw
						$650	delta US$
				Annualized Capital Costs	Millions $/yr	$97	15% of capital costs
				Annualized NG Costs	Millions $/yr	$159	$10 per MMBtu for NG
				Annual O&M Costs	Millions $/yr	$32	5% of total captial
				Total Annual Costs	Millions $/yr	$289	
Cost of CO2 Captured	US$/tonne CO2	11	32	Cost of CO2 Captured	US$/st CO2	$34	
Cost of CO2 avoided	US$/tonne CO2	13	37	Cost of CO2 avoided	US$/st CO2	$38	
Note 1:	2.4	MMlb/hr steam at 720 oF/600 psig					
	1,420	Btu/lb enthalpy of 720F/600psig steam					
	196	minus Btu/lb enthaly for saturated steam at 5 psig					
	2938	mmbtu/hr steam					
	861	MW in form of steam					

Exhibit 35
AEWC & ICAS

APPENDIX B – IMPACTS ANALYSIS FOR HEC COMBUSTION TURBINES AND PROCESS HEATERS

PARAMETER	COMBUSTION TURBINES & PROCESS HEATERS	
	BASELINE - No CCS	With CCS
Environmental Impacts:		
CO2 Emitted, TPY	8,200,000	800,000
CO2 Incremental % Control	Baseline	90%
CO2 Reduced, TPY	Baseline	7,400,000
CO2 from Compression, TPY	Baseline	1,930,000
Net CO2 Reduced, TPY	Baseline	5,300,000
Increase in NOx, TPY	Baseline	188
Increase in SO2, TPY	Baseline	109
Increase in CO, TPY	Baseline	115
Increase in VOC, TPY	Baseline	29
Increase in PM2.5, TPY	Baseline	381
Energy Impacts:		
Additonal Power Generation, MW	Baseline	582
NG Use MMSCFY		33,991
Economic Impacts:		
Total Capital Cost	Baseline	$904,100,000
Total Annual Cost	Baseline	$527,500,000
CO2 Capture Cost Effectiveness	Baseline	$100
CO2 Transport Cost Effectiveness	Baseline	$5
CO2 EOR Cost Effectiveness	Baseline	-$10
Total CO2 CCS Cost Effectiveness	Baseline	$95

Exhibit 35
AEWC & ICAS

HEC ESTIMATED COST OF CO2 CAPTURE BASED ON IPPC REPORT TABLE 3.15 – Combustion Turbines (4)

		IGCC	IGCC			HEC	Comments
Parameter	Units	low	high	Parameter	Units		
Plant Size	MW	400	800	Plant Size	MW	1368	(1) This is 507 MW Power plus 2.4 MMlb/hr steam equivalent MW (see below)
Emission Rate wo Capture	kgCO2/MWh	344	379	Emission Rate wo Capture	ton/year	3,986,530	From Table 1.2-2. HEC CO2 Emissions
Percent Reduction	%	83	88	Percent Reduction	%	85.5	Average of 83 & 88 % MWh
Emission Rate w Capture	kgCO2/MWh	40	66	Emission Rate w Capture	ton/year	578,047	14.5% not captured
				CO2 Captured	ton/year	3,408,484	
Capture Energy Required	% MWh	11	22	Capture Energy Required	MW	226	Average of 11 & 22 % MWh
				NG Use for Incremental MW	MM SCFY	13,172	6,796 Btu/kwh
				Incremental CO2 w Capture	ton/year	806,105	120 lb CO2/MMBtu for NG
Total Capital wo Capture	US$/kw	515	724	Total Capital wo Capture	Millions $	$847	Average of 515 and 724 US$/kw
Total Capital w Capture	US$/kw	909	1261	Total Capital w Capture	Millions $	$1,484	Average of 909 and 1261 US$/kw
						$637	delta US$
				Annualized Capital Costs	Millions $/yr	$96	15% of capital costs
				Annualized NG Costs	Millions $/yr	$134	$10 per MMBtu for NG
				Annual O&M Costs	Millions $/yr	$32	5% of total captial
				Total Annual Costs	Millions $/yr	$262	
Cost of CO2 Captured	US$/tonne CO2	33	57	Cost of CO2 Captured	US$/st CO2	$77	
Cost of CO2 avoided	US$/tonne CO2	37	74	Cost of CO2 avoided	US$/st CO2	$101	
Note 1:	2.4	MMlb/hr steam at 720 oF/600 psig					
	1,420	Btu/lb enthalpy of 720F/600psig steam					
	196	minus Btu/lb enthaly for saturated steam at 5 psig					
	2938	mmbtu/hr steam					
	861	MW in form of steam					

Exhibit 35
AEWC & ICAS

HEC ESTIMATED COST OF CO2 CAPTURE BASED ON CO2 CAPTURE PROJECT -Refinery Process Heaters

Parameters	Units	Grangemouth	HEC	Comments
Refinery Size - CO2 Emitted	Millions st/yr	2.4	4.2	HEC From Table 1.2-2. HEC CO2 Emissions
Percent Reduction	%	93%	93%	assumed
CO2 Captured	Millions st/yr	2.2	3.9	
Capture Energy Required	MW fired	396	710	HEC ratioed from reference
Capture Energy Required	MMBtu/hr	1,351	2,424	HEC ratioed from reference; equivalent to 357 MW
NG Use for Incremental MW	MM SCFY	11,604	20,819	based on 1020 Btu/scf for NG
Capture Energy CO2	Millions st/yr	0.7	1.3	
Percent Reduction	%	93%	93%	
CO2 Captured	Millions st/yr	0.66	1.18	
Total Captial	Millions US$	$149	$267	HEC ratioed from reference
Annualized Capital Costs	Millions US$/yr	$22	$40	15% of capital costs
Annualized NG Costs @ $10	Millions US$/yr	$118	$212	$10 per MMBtu for NG
Annual O&M Costs	Millions US$/yr	$7	$13	5% of total captial
Total Annual Costs	Millions US$/yr	$148	$266	
Cost of CO2 Captured	US$/st CO2	$67	$67	
Cost of CO2 Avoided	US$/st CO2	$99	$99	
REFERENCE: "A Study of Very Large Scale Post Combustion CO2 Capture At a Refining & Petrochemical Complex", Grangemouth, , UK.				

Exhibit 35
AEWC & ICAS