Exhibit 10.0

Pace Rate Impact Analysis

PACE

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Rate Impact Analysis for Taylorville Energy Center

Prepared for:

Tenaska Taylorville, LLC

February 21, 2010

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EXECUTIVE SUMMARY

APPROACH AND METHODOLOGY

In early 2009, the Illinois legislature passed SB 1987, otherwise known as the Clean Coal Portfolio Standard. This law requires electric utilities and alternative retail electric suppliers ("ARES") in the state to purchase energy from clean coal power plants, specifically from the Taylorville Energy Center ("TEC"), which qualifies as the "initial clean coal facility." In the first quarter of 2009 Pace established four different states of the world to reflect distinct, internally consistent views of major power sector market drivers to quantify the potential rate impact of the TEC under a range of possible market outcomes.

In approaching the rate impact analysis, Pace has evaluated the expected performance of the TEC within the PJM Com-Ed (Northern Illinois) power market to compare project margins with expected capital recovery requirements. Measuring the expected margins of the TEC allows the analysis to incorporate the relative performance of the plant under various future market conditions

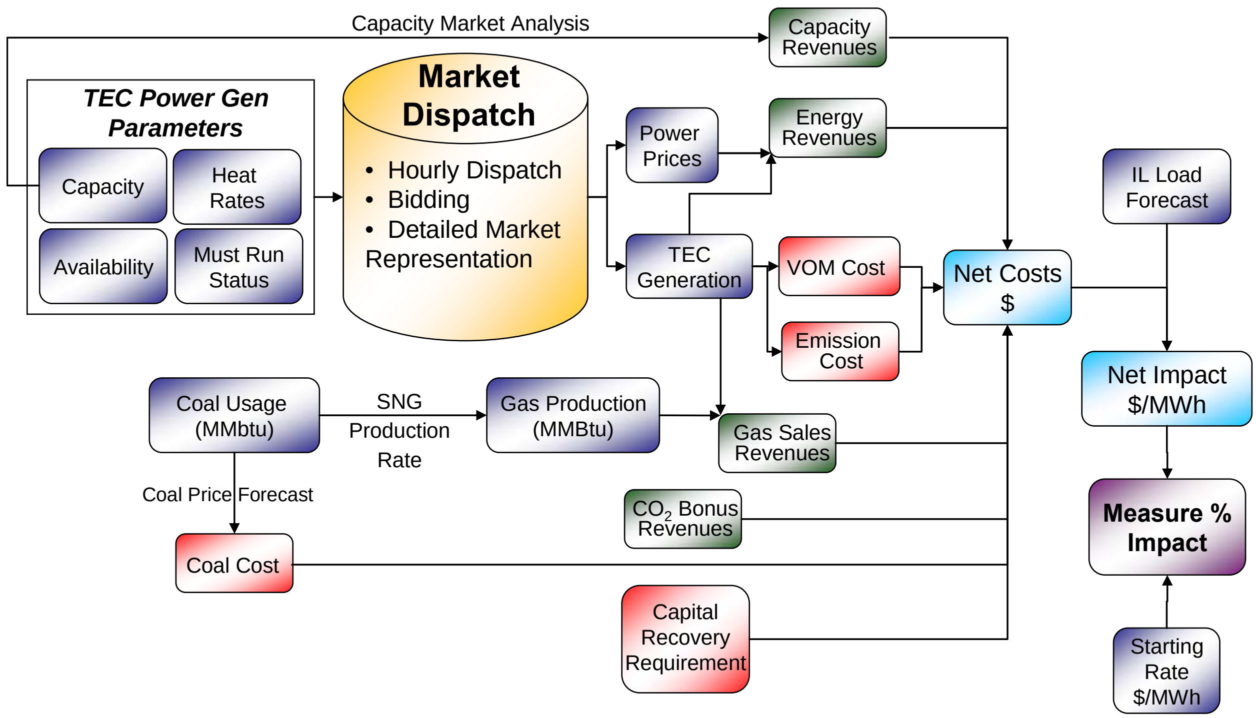
A summary of the rate impact calculation methodology is displayed in Exhibit 1. Pace developed and measured the effects of several cost and revenue categories for the project. These include:

- Costs (shown in red)
    - Coal price multiplied by coal usage rate
    - VOM costs associated with power generation
    - Emission costs, primarily linked with CO_2 emissions, associated with power generation
    - Capital recovery requirement
- Revenues (shown in green)
    - Power sales in the PJM market
    - Natural gas sales from excess substitute natural gas ("SNG"), not used to generate power
    - Capacity value revenues from the PJM market
    - Other potential revenues associated with regulations that encourage CO_2 capture

In Pace's analysis, these costs and revenues were combined to calculate a net cost impact. This impact was combined with expectations for total retail sales by electric and alternative retail electric suppliers within the state from Pace's load forecast to arrive at a per MWh cost, which was evaluated against the 2009 starting rate.

Pace estimated the costs and revenues according to expected operational performance characteristics and through the use of a market dispatch simulation. The dispatch simulation is based on the premise that the TEC will operate in the competitive power market and optimize its opportunities for energy revenues and natural gas sales. In this context, Pace simulated the projected dispatch of the TEC in the PJM Com-Ed region according to expected plant capacity, anticipated annual availability, heat rate, and must run status. An hourly, chronological dispatch analysis was performed in the context of the wider Eastern Interconnect region with representation of the regional supply, demand, and transmission profile.

Exhibit 1: Rate Impact Calculation Methodology



Source: Pace

MARKET DISPATCH ANALYSIS

Plant Configuration and Operational Parameters

In evaluating the performance of the TEC, Pace simulated the operation of the plant in accordance with parameters supplied by Tenaska and detailed in Exhibit 2. As shown, a significant share of the total capacity was simulated with must-run status, indicating power generation output at full availability of one gas turbine and associated steam turbine. The remaining capacity, associated with the second gas turbine, was modeled with must-run status during peak hours and all hours between June 15 and September 15, but simulated to dispatch competitively in the spot power market during other times. These parameters were provided by Tenaska in accordance with initial commercial negotiations. Coal consumption and substitute natural gas production rates were provided by Tenaska and used to calculate fuel costs and potential revenues from natural gas sales.

Exhibit 2: TEC Configuration and Operational Parameters

Category	Units	Unit 1 (Must run)	Unit 2
Net Capacity (Jun-Sep)*	*MW*	262.4	299.2
Net Heat Rate (Jun-Sep)	*Btu/kWh*	7,582.8	6,649.2
Net Capacity (Nov-Feb)	*MW*	303.8	333.1
Net Heat Rate (Nov-Feb)	*Btu/kWh*	7,113.9	6,486.6
Net Capacity (Mar-May & Oct)	*MW*	284.7	317.6
Net Heat Rate (Mar-May & Oct)	*Btu/kWh*	7,224.9	6,476.2
CO2 Emission Rate	*lbs/MMBtu*	115.4	115.4
Variable O&M	*2010 $/MWh*	2.82	2.82

Total SNG production from gasifier: 2,592 MMBtu/Hour
Total Coal consumption: 4,433 MMBtu/Hour

Availability SNG	Island	Generator
Year 1	65%	92%
Year 2	80%	92%
Year 3 and beyond	85%	92%

*For capacity revenue purposes, the total summer rating of the plant is 533 MW.
Source: Tenaska

Cost and Revenue Drivers

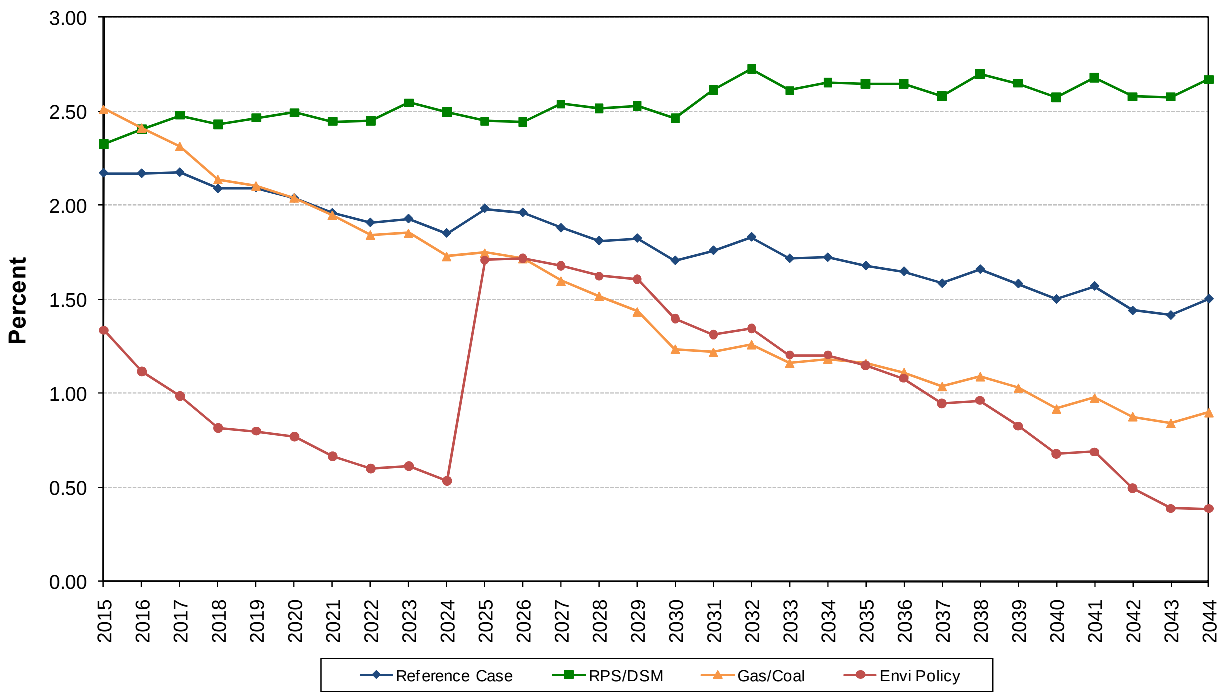
Other major cost and revenue drivers were developed through market analysis. Natural gas prices, electricity demand projections, environmental compliance cost projections, and bonus CO_2 credit values were developed by Pace and are detailed in subsequent chapters. Coal price estimates were developed by Wood Mackenzie. Pace develops its market projections in real terms and converts prices to nominal values using the market rate implied by the yield on treasury bonds and similar maturity Treasury Inflation Protected Securities ("TIPS"). The yield quoted on treasury bonds is equal to the real yield plus inflation, while the yield quoted for TIPS is the real yield. Subtracting the yield of TIPS from the yield of Treasury bonds arrives at the market's forward implied inflation rate. Beyond the time period of available data, Pace uses a general inflation rate of 2.0%.

RATE IMPACT RESULTS

Pace has found that the rate impact of the TEC is dependent on future expectations for the price of natural gas, the market price of energy and capacity, statewide energy demand, and CO_2 policy. Pace projected the TEC's rate impact under four unique states of the world, which were developed around each of these major market drivers. Pace has found that higher natural gas prices, higher energy demand, more stringent CO_2 policy, and limited low-variable cost capacity expansion results in a lower cost impact for the TEC.

Exhibit 3 summarizes the annual rate impact projections for the TEC under four states of the world. Exhibit 4 further details the annual percentage rate impact for the TEC. As shown, Pace's Reference Case produces its highest rate impact in the first several years of the project's operation. Beyond that, the impact is projected to generally decline throughout the study period. In the Gas/Coal state of the world, higher demand growth and higher natural gas and power market prices result in a lower overall expected rate impact which steadily declines. The Environmental Policy state of the world drives the rate impact significantly lower than any of the other states of the world in the early years, primarily due to an additional assumed federal CO_2 bonus for sequestering carbon dioxide emissions and higher CO_2 prices. The RPS/DSM state of the world results in the highest rate impact over the course of the analysis. The rate impact is highest due to low-to-moderate natural gas price expectations and declining energy demand.

Exhibit 3: Annual Percent Rate Impact Summary for TEC



*Note: Capital deferral was deployed for all cases.

Source: Pace

Exhibit 4 presents a summary annual rate impact of TEC under for all states of the world, and a representative summary of the monthly impact on an average customer in Illinois for the Reference Case analysis. In converting the cost per MWh impact of the TEC into a customer impact, Pace used public data from the Energy Information Administration on average customer electricity consumption in the Midwest. Pace's load forecast, U.S. Census state-level population estimates and recent data on the residential share of total electricity consumption were all used to project the per customer consumption rates throughout the Study Period. Exhibit 5 shows the annual rate impact in nominal dollars calculated as the revenue requirement minus the gross margin.

Exhibit 4: Annual Rate Impact Details

	Reference Case (%)	Envir. Policy (%)	Gas/Coal (%)	RPS/DSM (%)	Monthly Impact for Average Res. Customer for Reference Case ($)
2015	2.17%	1.34%	2.51%	2.33%	2.20
2016	2.17%	1.12%	2.41%	2.41%	2.20
2017	2.17%	0.99%	2.32%	2.48%	2.21
2018	2.09%	0.82%	2.14%	2.43%	2.12
2019	2.09%	0.80%	2.11%	2.47%	2.13
2020	2.04%	0.77%	2.04%	2.49%	2.07
2021	1.96%	0.67%	1.95%	2.45%	1.99
2022	1.91%	0.60%	1.84%	2.45%	1.93
2023	1.93%	0.61%	1.85%	2.55%	1.95
2024	1.85%	0.54%	1.73%	2.50%	1.88
2025	1.98%	1.71%	1.75%	2.45%	2.01
2026	1.96%	1.72%	1.72%	2.45%	1.98
2027	1.88%	1.68%	1.60%	2.54%	1.90
2028	1.81%	1.62%	1.52%	2.52%	1.83
2029	1.83%	1.61%	1.44%	2.53%	1.84
2030	1.71%	1.40%	1.24%	2.46%	1.72
2031	1.76%	1.31%	1.22%	2.61%	1.77
2032	1.83%	1.35%	1.26%	2.73%	1.85
2033	1.72%	1.20%	1.16%	2.61%	1.73
2034	1.72%	1.21%	1.19%	2.65%	1.73
2035	1.68%	1.15%	1.16%	2.65%	1.69
2036	1.65%	1.08%	1.11%	2.65%	1.66
2037	1.59%	0.95%	1.04%	2.58%	1.59
2038	1.66%	0.96%	1.09%	2.70%	1.67
2039	1.58%	0.83%	1.03%	2.65%	1.59
2040	1.50%	0.68%	0.92%	2.58%	1.51
2041	1.57%	0.69%	0.98%	2.68%	1.57
2042	1.44%	0.50%	0.88%	2.58%	1.44
2043	1.42%	0.39%	0.84%	2.58%	1.42
2044	1.50%	0.39%	0.90%	2.67%	1.50

*Note: Capital deferral was used for all cases.

Source: Pace; EIA for monthly customer impact

Exhibit 5: Annual Rate Impact in Nominal Dollars

	Reference Case ($)	Envir. Policy ($)	Gas/Coal ($)	RPS/DSM ($)
2015	340,745	212,107	385,184	367,603
2016	341,719	179,212	375,727	379,555
2017	343,738	158,570	364,430	389,542
2018	330,750	132,181	338,991	379,977
2019	332,175	129,608	335,312	384,294
2020	324,014	125,845	327,015	387,163
2021	312,197	108,667	313,963	378,728
2022	304,623	97,844	298,652	378,489
2023	308,533	99,967	301,678	391,957
2024	296,935	87,801	283,116	383,708
2025	318,502	280,020	287,697	374,669
2026	315,663	282,092	284,466	373,406
2027	303,080	276,166	266,104	386,368
2028	292,674	267,918	254,113	381,985
2029	295,473	265,155	241,434	382,871
2030	276,862	231,243	209,292	372,259
2031	286,067	217,069	207,491	393,794
2032	298,323	223,265	215,660	409,882
2033	280,256	200,082	199,858	391,757
2034	281,779	200,447	204,983	396,796
2035	275,018	191,785	201,746	395,239
2036	270,735	180,474	194,505	394,047
2037	260,832	158,700	182,529	383,475
2038	273,635	161,399	192,809	399,611
2039	261,493	138,808	182,983	391,394
2040	248,513	114,104	164,154	379,672
2041	260,434	116,089	175,438	394,073
2042	239,344	83,839	158,631	378,075
2043	235,754	65,816	153,213	376,890
2044	250,656	65,729	164,276	389,476

*Note: Capital deferral was used for all cases

Source: Pace

Key Findings

- Pace has found that the TEC provides an effective hedge against rising natural gas prices and carbon compliance costs, even resulting in a net benefit under very high natural gas price conditions. This is because the TEC can optimize between power generation and natural gas sales as a result of the conversion of coal to SNG.

- The TEC's costs can result in higher rate impacts under conditions with low natural gas prices and low demand.

- *Impact of Natural Gas Price:* The price of natural gas has a significant impact on the rate impact of the TEC. Holding all other market drivers and assumptions constant, a $1/MMBtu increase in the price of natural gas results in roughly a 0.1% decrease in rate impact (for example, from 2.015% to 1.915%) in 2015.

- *Impact of CO_2 Tax Credit and Bonus Allowance:* The TEC's impact is highly sensitive to the price it can receive for CO_2. Going from the Reference Case assumption of $10/tonne for captured CO_2 to the Environmental Policy assumption of $80/tonne decreases the rate impact by about 0.7% in 2015, leaving all other Reference Case assumptions constant.

- *Impact of Energy Demand:* Higher energy demand is expected to increase power market prices, but also allow the cost impact of the TEC to be spread across more megawatt-hours. Holding all other market drivers and assumptions constant, a 1% increase in energy demand in 2015 decreases the rate impact over 0.02% for the Reference Case.

- *Impact of Capacity Market Price*: Capacity prices in PJM have exhibited volatility and represent a significant revenue opportunity for the TEC. Holding all other market drivers and assumptions constant, changing the capacity price from $0/kW-yr to the Reference Case $28/kW-yr results in approximately a 0.05% decrease in the rate impact.

- *Impact of Coal Price*: The TEC will use coal from the Illinois Basin. A 10% decrease in the cost of coal, holding all other Reference Case assumptions constant, causes the rate impact to decrease by 0.04%.

- *Impact of Plant Optimization between Power and Gas Sales:* The ability to optimize plant operations between energy sales and natural gas sales provides the plant flexibility and lowers overall cost impacts. Depending on the state of the world, the ability to optimize such operations lowers the rate impact by 0.2 - 0.3 %.

Cost of Power Projections

Pace has calculated the cost of power per MWh using different TEC generation assumptions. The first set of generation assumptions used the projected dispatch of the TEC in the PJM Com-Ed. These results are shown in Exhibit 6 and Exhibit 7. The other generation assumptions supposes the TEC is dispatched at full output when available, which corresponds to a 92% annual capacity factor. Although the TEC is expected to be dispatched economically at a slightlty lower level in order to take advantage of opportunities for SNG sales, the cost of power at 92% can be used to evaluate total costs under conditions with maximum power generation and without flexibility. Exhibit 8 summarizes the projected cost of power per MWh under each state of the world.

Exhibit 6: Cost of Power at Projected Dispatch for all States of the World (Nominal $/MWh)

	Reference Case	Envir. Policy	Gas/Coal	RPS/DSM
2015	163.05	137.87	153.16	163.41
2016	167.38	136.08	157.05	165.25
2017	169.11	140.50	161.94	172.32
2018	163.96	139.87	162.70	168.41
2019	168.02	142.25	165.62	166.62
2020	176.08	143.53	170.33	174.03
2021	178.47	141.60	172.36	170.85
2022	179.90	140.61	177.02	172.51
2023	188.46	145.98	183.30	183.22
2024	190.79	148.25	185.30	178.22
2025	199.59	194.55	197.01	178.44
2026	206.25	198.71	203.82	182.77
2027	208.49	201.44	206.79	187.81
2028	213.95	206.17	212.40	191.35
2029	222.12	215.18	220.64	195.15
2030	225.65	222.93	225.58	199.82
2031	230.80	228.91	231.32	203.62
2032	239.03	237.66	239.40	210.82
2033	239.86	240.27	242.10	209.89
2034	245.79	248.41	249.91	214.67
2035	249.85	254.93	256.01	217.98
2036	254.74	261.24	261.41	221.52
2037	258.44	265.65	265.97	222.93
2038	268.05	275.88	275.99	230.93
2039	271.66	280.97	281.58	233.20
2040	275.30	286.05	285.35	234.79
2041	285.43	297.51	296.47	242.84
2042	287.57	301.93	301.31	243.72
2043	294.36	310.01	309.14	248.36
2044	306.06	322.62	321.15	256.50

Source: Pace

Exhibit 7: Cost of Power at Projected Dispatch for all States of the World (2010$/MWh)

	Reference Case	Envir. Policy	Gas/Coal	RPS/DSM
2015	150.18	126.93	141.07	150.52
2016	151.69	123.31	142.32	149.76
2017	150.43	125.00	144.05	153.28
2018	142.94	121.96	141.83	146.81
2019	143.62	121.61	141.56	142.43
2020	147.58	120.32	142.75	145.86
2021	146.67	116.40	141.64	140.41
2022	144.97	113.33	142.63	139.00
2023	148.90	115.37	144.81	144.76
2024	147.81	114.88	143.53	138.06
2025	151.60	147.75	149.62	135.54
2026	153.60	147.96	151.77	136.12
2027	152.24	147.07	150.98	137.16
2028	153.17	147.59	152.05	137.02
2029	155.91	151.02	154.85	137.00
2030	155.30	153.39	155.23	137.55
2031	155.74	154.43	156.07	137.44
2032	158.14	157.20	158.37	139.51
2033	155.60	155.82	157.02	136.20
2034	156.34	157.95	158.92	136.58
2035	155.82	158.93	159.62	135.98
2036	155.76	159.68	159.81	135.49
2037	154.95	159.20	159.41	133.70
2038	157.56	162.09	162.18	135.78
2039	156.57	161.86	162.24	134.45
2040	155.57	161.57	161.20	132.73
2041	158.13	164.75	164.20	134.59
2042	156.21	163.93	163.62	132.45
2043	156.78	165.03	164.59	132.34
2044	159.81	168.37	167.63	134.00

Source: Pace

Exhibit 8: Cost of Power at 92% Dispatch for all States of the World (2010$/MWh)

	Reference Case	Envir. Policy	Gas/Coal	RPS/DSM
2015	139.60	123.09	136.54	139.84
2016	135.98	115.11	133.88	134.39
2017	133.71	115.62	134.59	132.90
2018	128.60	114.35	133.21	129.81
2019	129.60	114.88	133.19	129.88
2020	132.44	113.83	134.65	130.43
2021	132.21	110.57	134.12	128.36
2022	130.60	108.23	135.50	127.41
2023	135.06	110.58	137.49	128.07
2024	135.05	110.73	137.27	126.19
2025	137.98	140.84	143.28	125.60
2026	140.54	141.29	145.59	126.68
2027	140.45	140.62	145.42	124.31
2028	141.95	141.29	146.79	125.17
2029	144.66	145.25	149.84	126.33
2030	144.98	148.85	150.67	125.87
2031	145.64	149.94	151.69	125.84
2032	147.84	152.54	153.97	127.54
2033	146.11	151.49	153.09	124.92
2034	147.02	153.62	155.06	125.33
2035	146.90	154.66	155.97	124.89
2036	147.12	155.41	156.45	124.41
2037	146.82	155.20	156.40	123.10
2038	149.30	158.05	159.17	124.97
2039	148.81	157.98	159.53	123.91
2040	148.29	157.78	158.98	122.40
2041	150.79	160.99	161.93	124.21
2042	149.55	160.38	161.76	122.47
2043	150.38	161.57	162.96	122.47
2044	153.23	164.80	166.06	123.86

Source: Pace

STATE OF THE WORLD DEVELOPMENT

STATE OF THE WORLD CONCEPT

Pace has evaluated the impact of the Taylorville Energy Center ("TEC") plant ("the Project") on power prices in Illinois and its rate payers. Pace believes that the best approach for evaluating the project is through the development of not just a reference case, but several plausible *states of the world*. The belief that a reference case is insufficient to capture and evaluate the value of a project is founded on historic observed volatility in the power markets, including capacity expansion boom/bust cycles, recent fuel market swings, potential federal regulation of greenhouse gases, and current economic uncertainty.

A *state of the world* is a distinct, internally consistent view of power sector market drivers, which incorporate a range of plausible economic recovery and growth outcomes, governmental policy, and technological innovation. These power market drivers guide the development of Pace's projections for natural gas prices, environmental compliance costs, energy demand, and expansion expectations. Conducting state of the world analysis elucidates the potential performance of the project under a range of possible, plausible market outcomes.

Pace formed four distinct states of the world through integration with power market, engineering, fuels, and carbon experts throughout the company. The following chapter outlines the key drivers behind each state of the world, with Appendix chapters on fuel markets, environmental markets and policy, and energy demand forecasts providing additional supporting material.

Pace developed a reference case with initial estimates for key market drivers and an assumption of moderate environmental and economic policies that affect the power sector. Key attributes of this state of the world include:

- Moderate recession in North America, with economic recovery by 2010
- Widespread adoption of carbon control measures
- Federal Renewable Portfolio Standard ("RPS") of 17% by 2020
- Moderate deployment of energy efficiency and demand side measures, partly in response to federal RPS
- Rapid development of zero-emission resources, especially renewables in response to economic signals regarding the price of carbon and renewable energy credits
- North America remains largely self-sufficient (LNG imports are generally less that 10% of total supply) with natural gas supply
- A CO2 sequestration tax credit of $10/tonne as currently provided under Section 45Q of the Internal Revenue Code.[1]
- A set of NOx market regulations similar to CAIR

[1] The CO2 sequestration tax credit is subject to an inflation adjustment factor which is determined annually pursuant to Internal Revenue Code Section 45(d)(7). Pace is assuming that the inflation adjustment factor will be the same as its inflation projections. Internal Revenue Code Section 45Q currently provides for this credit to apply to the first 75 million MT sequestered nationally.

Other states of the world were developed by varying key policy, technology, and market drivers that impact the expected performance of the Project in the Illinois market. Internally consistent states of the world were developed in accordance with expectations for either positive or negative rate impact effects for the Project. Exhibit 9 summarizes a selection of these drivers and their anticipated directional rate impacts.

High natural gas prices are expected to raise power market prices relative to the coal variable costs incurred by the TEC and provide greater revenue opportunities for natural gas sales. High CO_2 prices are expected to raise the variable costs of many carbon-intensive generating plants in the market greater than those of the TEC, due to the Project's ability to capture and sequester CO_2. Overall, the Project is expected to serve as a hedge against price increases for natural gas and CO_2.

Higher energy demand growth would result in more megawatt-hours over which to spread the TEC's costs, resulting in a lower overall rate impact. Capacity expansion in the wider power market impacts the performance of the TEC due to influence over economic dispatch and power market clearing prices. Higher variable cost expansion like natural gas capacity would be less likely than renewable and nuclear capacity expansion to negatively affect the TEC's dispatch position and expected market energy revenues.

Exhibit 9: Key Market Driver Impacts

	Positive (Lower Rate Impact)	*Negative (Higher Rate Impact)*
Natural Gas Price	**High Price**	**Low Price**
Energy Demand	**High Demand**	**Low Demand**
CO_2 Prices	**High Price**	**Low Price**
Expansion Plan Impacts on Market Price	Higher variable cost expansion (natural gas)	Lower variable cost expansion (renewables and nuclear)

Source: Pace

Positive (Low Rate Impact) States of the World

The *Gas/Coal Future* state of the world was developed around an analysis of the market drivers and conditions that could result in a positive outcome for the Project. This state is driven by the following assumptions:

- Longer deeper recession, but stronger economic recovery in North America
- Economic growth policies trump environmental protection

- Lower RPS and CO_2 requirements
- Natural gas-fired capacity (with some coal) dominates expansion as a result of less stringent environmental policies, increasing demand for natural gas
- Disappointing shale and other unconventional domestic gas production, and competition with Europe and Asia for LNG

The *Environmental Policy* state of the world was developed around a set of primary policy drivers that are expected to lead to several market outcomes that are favorable to the Project. The state is driven by the following key assumptions:

- Quick recovery from current recession
- Strong, centrally coordinated energy and environmental policies at the federal level, specifically around strict carbon dioxide cap-and-trade policy
- No new conventional coal-fired plants and closure of significant amounts of existing coal-fired plants
- Natural gas a major bridge fuel in the power sector until significant renewable deployment is achieved
- Strong GDP growth and power demand throughout the Study Period

Negative (High Rate Impact) State of the World

In analyzing a scenario that could result in an unfavorable rate impact for the Project, Pace considered the drivers and market conditions that could move many of the important performance levers in an adverse direction for the Project. This state is referred to as the *RPS/DSM* state of the world, and key drivers include:

- Relatively short recession in North America, with strong recovery by 2010
- Widespread adoption of carbon control measures
- Aggressive renewable energy or demand side directives at the federal or state levels
- Energy efficiency and demand side management effectively reduce load in response to policy and market signals
- Comparatively more renewable development than reference case
- Moderating demand for natural gas in the long run in both North America and throughout the world.

A summary of the key market drivers across states of the world is displayed in Exhibit 10.

Exhibit 10: Summary of Key Market Drivers across States of the World

State	Natural Gas Price in 2030	Energy Demand Growth Rate (2015-2030)	CO_2 Price in 2030
	(2010$/MMBtu)	*Compound Annual Growth Rate in MWh (%)*	*(2010$/tonne)*
Reference	11.95	0.2%	59
Gas/Coal	16.77	0.7%	32
Environmental Policy	9.90	0.3%	80
RPS/DSM	6.03	-0.3%	59

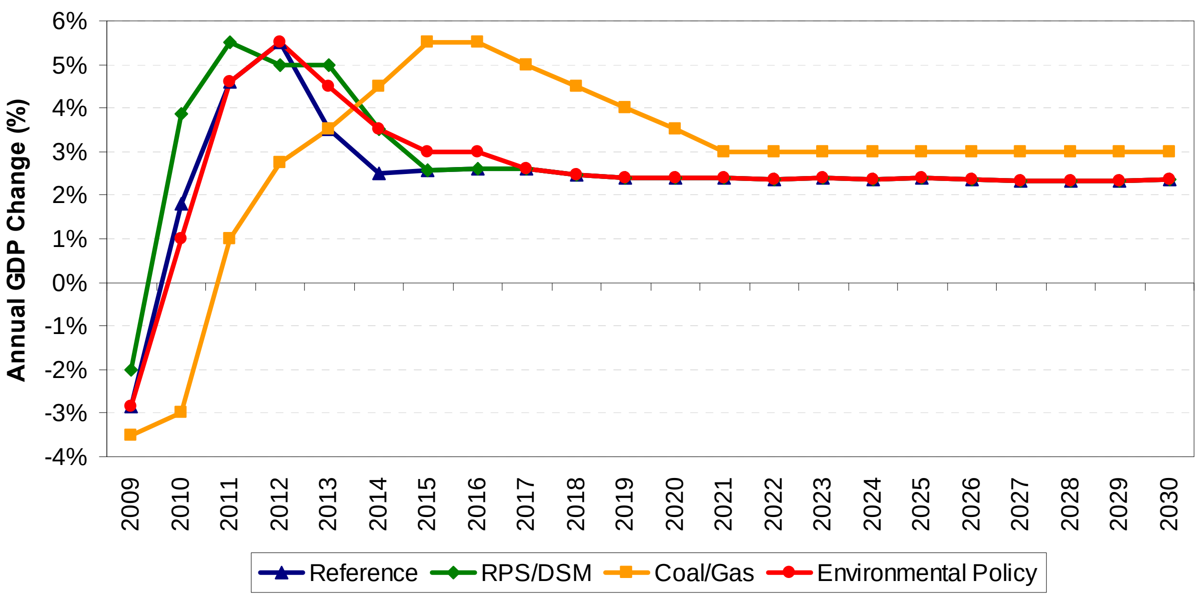
Source: Pace

DETAILS ON MARKET DRIVER ASSUMPTIONS

GDP Growth

Economic growth rates are a key determinant for load growth, and annual GDP growth rate expectations for the United States for each of the states of the world are displayed in Exhibit 11. For the Reference state, Pace assumes that economic recovery will begin this year (2010) and then be followed by accelerated growth until 2012, moderating to around 2.5% per year by 2015. The RPS/DSM state follows a similar trend, but economic recovery is expected sooner. Early recovery is also expected in the Environmental Policy state, with strong macroeconomic growth making it more politically palatable to pass stringent environmental regulations. In the Gas/Coal state, the current recession is anticipated to deepen in the near-term and have delayed recovery. In 2015 and beyond, however, GDP growth rates are expected to be higher than the other states of the world as economic growth remains the over-riding public policy goal.

Exhibit 11: National GDP Projections (%)



Source: Pace

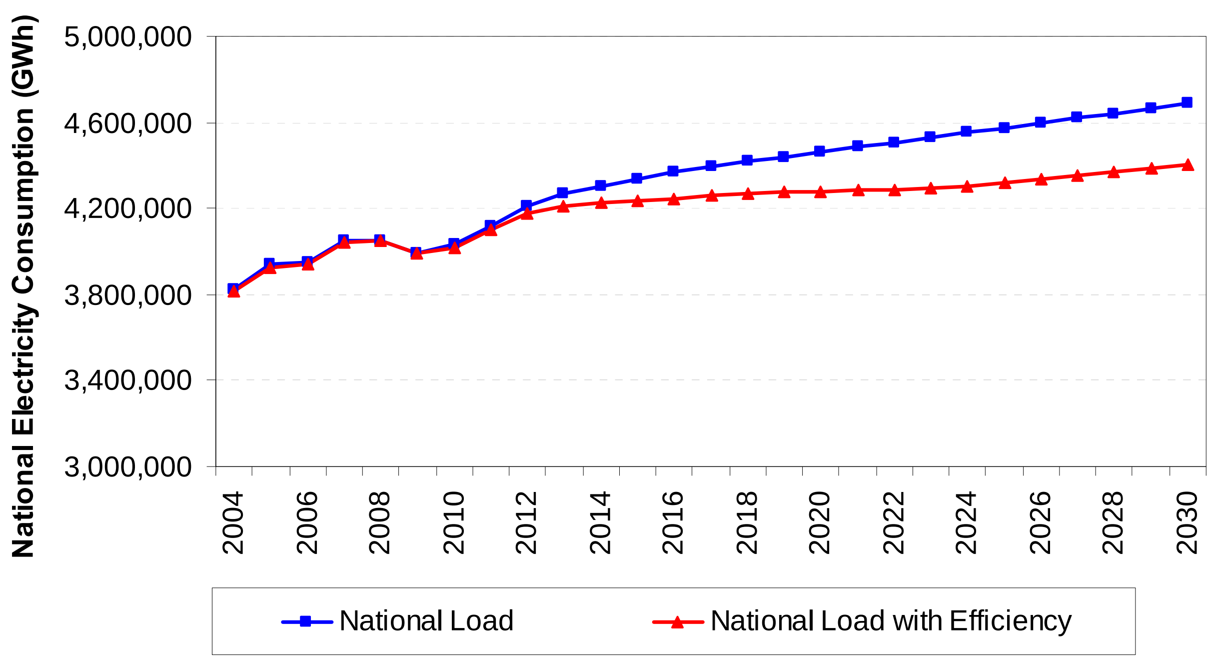
Impacts of GDP Growth

Electricity demand is strongly correlated with GDP growth. Pace has developed national and regional demand projections that tie directly to the underlying assumptions for economic growth. For most states, there is a direct relationship between GDP growth assumptions and demand growth. For instance, in the Coal/Gas state, prolonged recession and delayed recovery results in lower near term electricity demand, but higher long term economic growth expectations result in more significant electricity demand increases in the out years.

In addition, Pace has considered the impact of efficiency and demand side management standards on overall growth trends. In the RPS/DSM state, energy efficiency measures are assumed to take hold and actually decrease load growth. To determine potential impacts of energy efficiency, Pace surveyed state level demand response and energy efficiency goals and also looked to historical actual demand reduction achievements in states that have had a longer history with these programs. Through this analysis, Pace capped state-level demand reductions at 0.5 percent per year and assumed about one quarter of the federal RPS standard will be met with efficiency measures. This resulted in an aggressive, but plausible negative load growth scenario in Illinois and relatively flat load growth nationally.

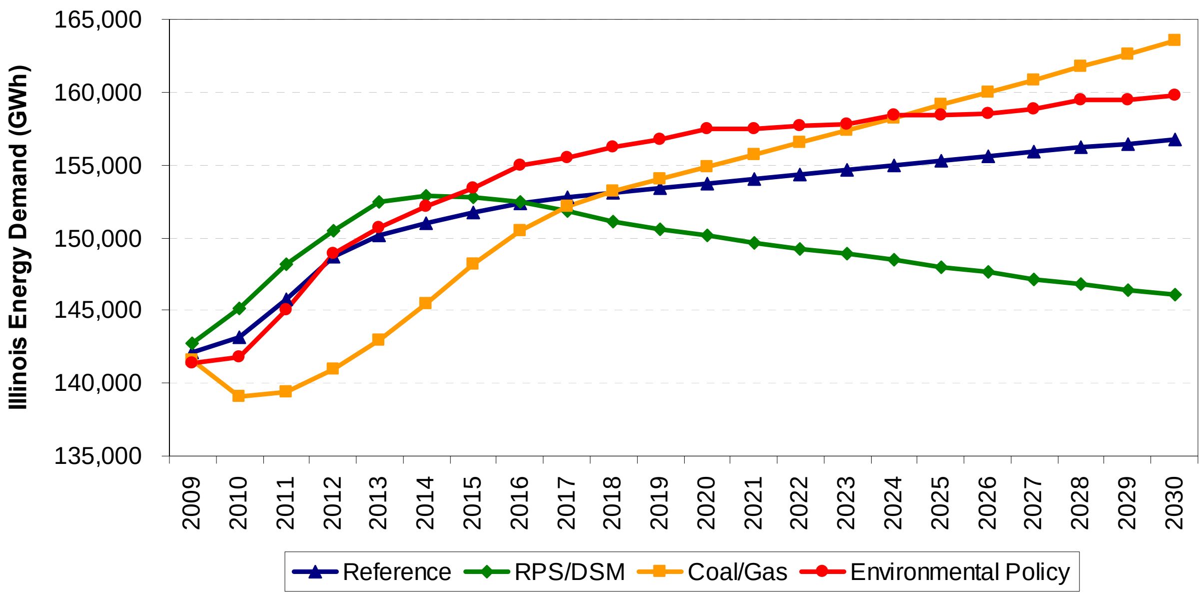
Exhibit 12 displays the national load projections for the Reference state of the world, along with the impact of efficiency and demand side management improvements assumed under the RPS/DSM state. In Illinois, state-level efficiency goals ramp up to two percent per year by 2015. However, Pace has limited incremental annual savings to 0.5 percent per year in this analysis. Exhibit 13 displays total Illinois retail sales expected in each of the states of the world throughout the Study Period.

Exhibit 12: National Energy Demand Projections (GWh)



Source: Pace

Exhibit 13: Illinois Electricity Demand Projections (GWh)



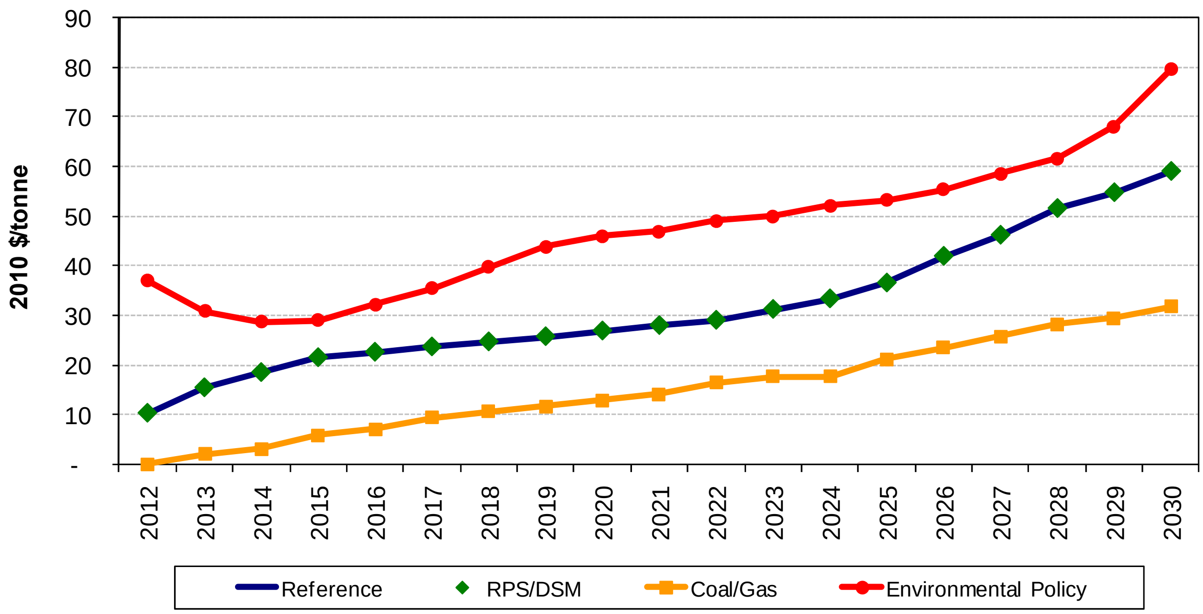
Source: Pace

Economic growth also has secondary and tertiary impacts for the different states of the world beyond just load. For example, the sustained economic downturn witnessed in the Gas/Coal state would likely see decreased demand for power plant construction materials in the near term and could serve to lower anticipated capital costs for the Project. Furthermore, in the Gas/Coal case, lingering economic stagnation is assumed to affect policymaking, shifting focus away from environmental regulation that could have negative economic impacts. In the Reference state, however, it is unlikely that with a normal economic recovery such a paradigm shift in environmental attitudes would occur.

CO_2 Prices

In the Gas/Coal state, environmental policies are expected to be relaxed and lower both the national RPS and CO_2 requirements as discussed above. The Reference and RPS/DSM states are assumed to have a similar CO_2 price projection, as shown in Exhibit 14. In these states of the world, federal energy legislation is anticipated to pass that includes RPS standards, as well as create a cap and trade system through which carbon compliance will be enforced. In the Environmental Policy state, Pace expects the federal government to enact stricter carbon caps, resulting in more expensive mitigation measures and higher market prices for CO_2 allowances.

Exhibit 14: CO_2 Price Projections (2010 $/tonne)



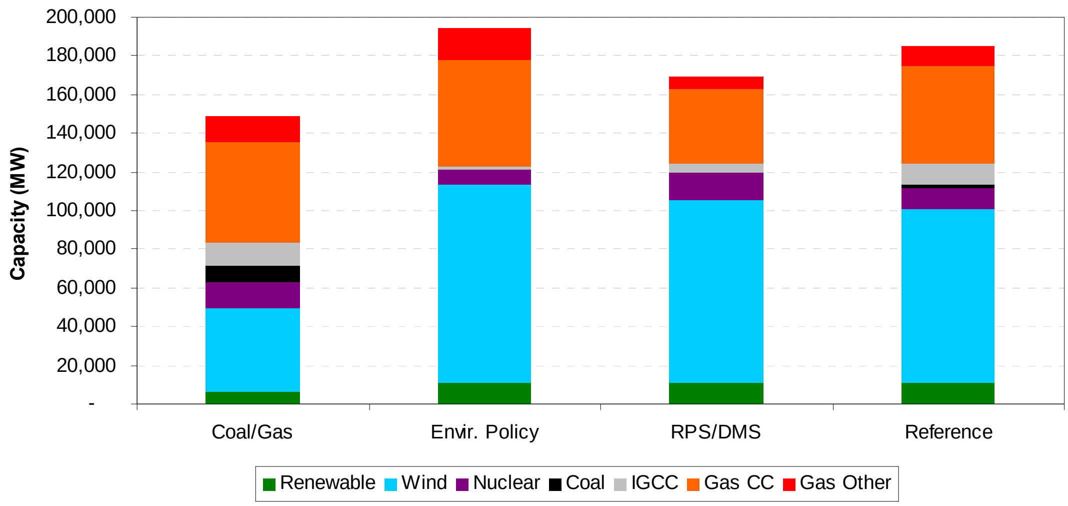
Source: Pace

Capacity Expansion

The combination of load expectations, policy outcomes, and technological assumptions are synthesized in generation expansion expectations. Exhibit 15 details the expected capacity additions nationally by 2027 in order to display relative differences. In the Gas/Coal state, less capacity is needed early on because of delayed economic growth and reduced energy demand. Because of the de-emphasis on RPS and CO_2 reductions, the economic feasibility of extensive renewable development is weakened nationwide, and natural gas and coal fired generation are economically more attractive. Higher availabilities of such generating resources result in the lowest total nameplate capacity additions across all cases.

The RPS/DSM state, by contrast, results in strong development of renewable and non – emitting capacity additions, driven by policy incentives and regulations. In the Environmental Policy state, the economics of new renewable additions also look favorable due to higher CO_2 market prices. In addition, significant gas-fired capacity is also expected in order to meet more robust demand growth and to replace retiring coal capacity. In the PJM and MISO zones alone, Pace projects around 14,000 MW of coal-fired capacity to retire under this state of the world. The Reference state is somewhere in between, while still having substantial renewable capacity additions as a result of federal RPS and CO_2 policy assumptions.

Exhibit 15: Expansion Plan 2027



Source: Pace

Natural Gas Prices

Natural gas prices are a main driver behind power market clearing prices. Pace's projections by state of the world are shown in Exhibit 16. In the Reference Case, Pace's projections track the futures market for natural gas for the next five years. Longer term, Pace has developed market projections based on key supply and demand drivers. On the demand side, Pace expects carbon reduction policy to lead to an increase in gas demand over time, as the power sector shifts away from coal and towards natural gas generation and renewable sources that require flexible natural gas-based backup.

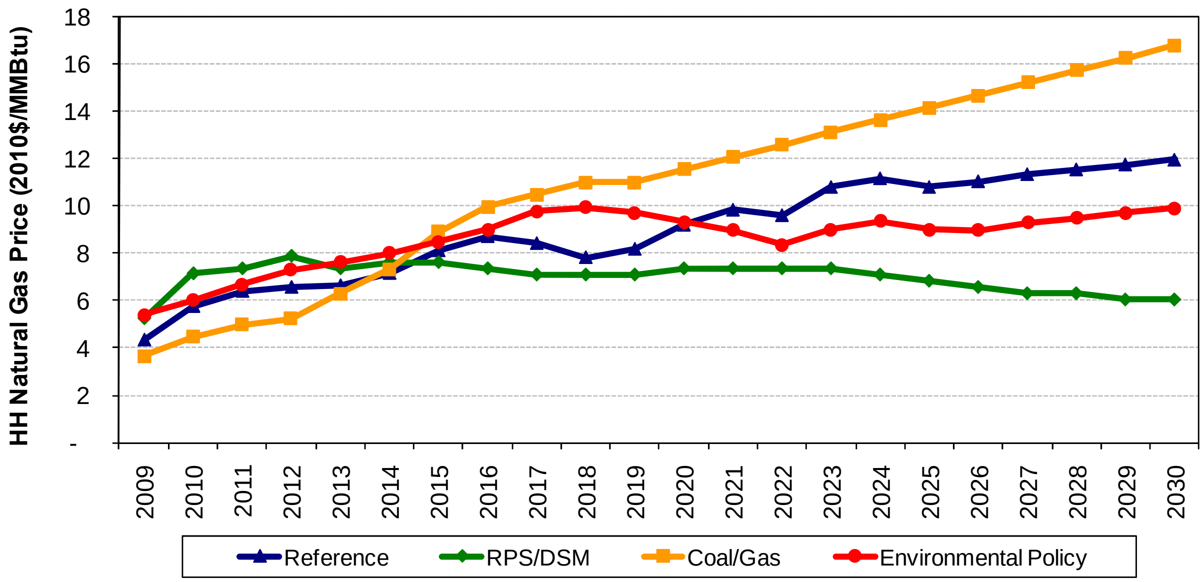
Although significant new domestic supply sources have contributed to low prices throughout 2009, such conditions are not expected to persist in the face of growing demand. Longer term on the supply side, North American gas producers and LNG importers are going to be competing for market share in a volatile price environment. Under these circumstances, significant multi-year price cycles could be expected to be added to seasonally cyclical price movements and short-term volatility in shaping long-term market prices. The extent and duration of these multi-year cycles would be attributed in part to global LNG pricing as well as domestic market conditions, periodically drawing the North American market into at least temporary alignment with European and Asian markets until growing domestic deliverability created competition once again for market share.

In the RPS/DSM state, the price of natural gas is elevated in the near term due to increased power demand resulting from higher economic growth. In the middle and later years, when load begins to decline, power sector gas demand is displaced by renewables, and domestic supply is assumed to be relatively abundant, prices are expected to remain below $7/MMBtu. A low price of LNG and sustained domestic supply would also be expected to be sufficient to meet decreased domestic demand and keep a low price for natural gas.

In the Coal/Gas state, near term demand is expected to be low for natural gas. Once out of the recession, however, this state assumes more robust electricity demand growth in the power sector, high demand for natural gas domestically and abroad, and disappointing unconventional production. These assumptions result in price expectations of around $16/MMBtu by 2030.

In the Environmental Policy state, quick economic recovery and strict environmental policy is expected to lead to increasing natural gas demand in the near-to-intermediate term, as natural gas becomes a bridge fuel until more widespread renewable deployment can be achieved. This is expected to increase prices to nearly $10/MMBtu by 2017. Thereafter, it is expected that power demand will be robust, but renewable deployment will moderate natural gas demand to some extent, keeping prices in the $8-10/MMBtu range throughout the Study Period.

Exhibit 16: Natural Gas Price Projections (2010 $/MMBtu)



Source: Pace

IMPACT OF TEC ON MARKET PRICES

IMPACT ON MARKET PRICES OF TAYLORVILLE ENERGY CENTER

Pace projected the impact of the Taylorville Energy Center ("TEC") on Illinois ratepayers (exempting municipalities and coops) using projected changes in market energy and capacity prices that result with TEC operating in Northern Illinois in the PJM market.[2] Using consistent market assessments developed in the analysis of the overall rate impact of the project, this analysis was completed through the following steps:

- The annual savings realized from a decrease in energy prices in Illinois was calculated.
- The annual savings realized from a decrease in capacity prices in Northern Illinois was calculated.
- The resulting total savings in thousands of dollars and $/MWh for eligible customers and ARES ratepayers in Illinois was calculated.

REFERENCE CASE MARKET PRICE PROJECTIONS

In order to create a baseline, Reference Case market-clearing price projections for the Northern Illinois and Gateway (Southern Illinois) power regions were developed without the TEC operating in the market. These projections are presented in Exhibit 17 and Exhibit 18, respectively. In both Northern Illinois and Gateway, peak prices are expected to be around $77/MWh between 2015 and 2019, and increase thereafter in line with expected increases in the price of natural gas and the cost of carbon compliance. Pace expects off-peak prices to be driven primarily by the cost of operating coal-fired resources. The costs of complying with expected carbon dioxide regulations are expected to be a primary driver in the expected increase in off-peak prices through the end of the Study Period.

Capacity price expectations in Northern Illinois are based on PJM's Reliability Pricing Model ("RPM"), a forward-looking market for capacity. Pace's projections include representations of the key drivers in the market construct, including the cost of new entry, the regional reserve margin, and expected energy and ancillary services revenues for new market participants.

[2] We are advised that the current intention is for TEC to be interconnected to PJM at ComEd's Kincaid substation.

Exhibit 17: Northern Illinois Market Price Forecast (2010$)

Year	Peak	Off-Peak	All-Hours	Capacity
	$/MWh	$/MWh	$/MWh	$/kW-Yr
2015	76.62	51.88	63.66	32.29
2016	78.61	53.95	65.69	32.55
2017	79.66	53.19	65.80	35.90
2018	76.74	52.94	64.27	42.54
2019	77.10	55.02	65.54	38.97
2020	82.47	58.47	69.90	39.70
2021	85.89	58.36	71.47	43.97
2022	84.92	59.15	71.42	52.06
2023	89.37	60.32	74.16	55.79
2024	92.04	60.88	75.72	62.50
2025	92.70	61.95	76.59	64.36
2026	95.45	66.55	80.31	66.92
2027	97.96	68.75	82.66	67.81
2028	103.42	72.82	87.39	66.45
2029	106.58	74.43	89.74	68.04
2030	110.34	77.03	92.89	71.49

Source: Pace

Exhibit 18: Gateway Market Price Forecast (2010$)

Year	Peak	Off-Peak	All-Hours
	$/MWh	$/MWh	$/MWh
2015	78.24	52.20	64.60
2016	80.19	54.25	66.60
2017	80.82	53.67	66.60
2018	78.35	53.55	65.36
2019	78.82	55.79	66.76
2020	84.16	59.40	71.19
2021	87.79	59.24	72.83
2022	86.97	60.06	72.87
2023	91.36	61.34	75.63
2024	93.92	62.10	77.25
2025	94.41	63.24	78.08
2026	97.57	67.66	81.90
2027	99.75	70.13	84.24
2028	105.44	74.06	89.00
2029	108.73	75.56	91.36
2030	112.17	78.36	94.46

Source: Pace

PRICE PROJECTIONS WITH THE TAYLORVILLE ENERGY CENTER

In addition to the Reference Case results, Pace performed an analysis of market prices with the addition of the TEC in the Northern Illinois power region. With the TEC in the system, new energy and capacity prices were developed.

The addition of the TEC to Northern Illinois is expected to result in an average decrease in average annual energy market prices of about $0.25/MWh over the period from 2015 to 2030. This is due to the expectation that the TEC will generally displace less efficient natural gas and coal-fired generating capacity during many hours of the year, lowering the marginal cost of electricity. While this is expected, the difference between the costs of TEC and alternative capacity that would otherwise be expected to enter the market does not result in persistently significant energy cost savings. The addition of the 533 MW plant, however, also affects the supply/demand balance within the region, temporarily lowering expected capacity prices in the PJM capacity market. This results in a capacity price forecast that is slightly lower when compared with the Reference Case for a short period of time.

Exhibit 19 presents the Northern Illinois price forecast in which the TEC is directly connected into Northern Illinois.

Exhibit 19: Market Price Forecast (2010$) with the Taylorville Energy Center

Year	Northern Illinois Prices				Gateway Prices		
	Peak	Off-Peak	All-Hours	Capacity	Peak	Off-Peak	All-Hours
	$/MWh	$/MWh	$/MWh	$/kW-Yr	$/MWh	$/MWh	$/MWh
2015	75.52	52.17	63.30	28.87	77.15	52.53	64.27
2016	77.95	54.12	65.45	26.50	79.59	54.42	66.39
2017	77.84	53.75	65.19	29.60	79.21	54.20	66.08
2018	74.80	53.79	63.81	36.00	76.28	54.47	64.87
2019	76.87	54.92	65.38	36.20	78.61	55.66	66.60
2020	82.05	58.42	69.70	39.70	83.94	59.26	71.04
2021	84.46	58.72	70.99	43.97	86.34	59.62	72.36
2022	84.26	59.32	71.16	52.06	86.20	60.33	72.62
2023	88.93	60.27	73.88	55.79	90.89	61.34	75.37
2024	91.82	60.66	75.53	62.50	93.89	61.74	77.08
2025	92.19	61.71	76.24	64.36	94.26	62.87	77.83
2026	95.26	66.65	80.29	66.92	97.33	67.78	81.87
2027	98.70	67.65	82.45	67.81	100.84	68.81	84.08
2028	102.78	72.86	87.03	66.45	104.81	74.20	88.70
2029	106.63	74.31	89.72	68.04	108.64	75.59	91.35
2030	110.94	76.44	92.89	71.49	112.84	77.71	94.46

Source: Pace

Savings from the Energy Price Decrease

Pace multiplied the change in average annual energy prices due to the inclusion of the TEC ($/MWh) by its long-term projection of total annual energy demand (MWh) for eligible customers and ARES customers in Illinois in order to calculate the annual savings realized from the decrease in energy prices.

Savings from the Capacity Price Decrease

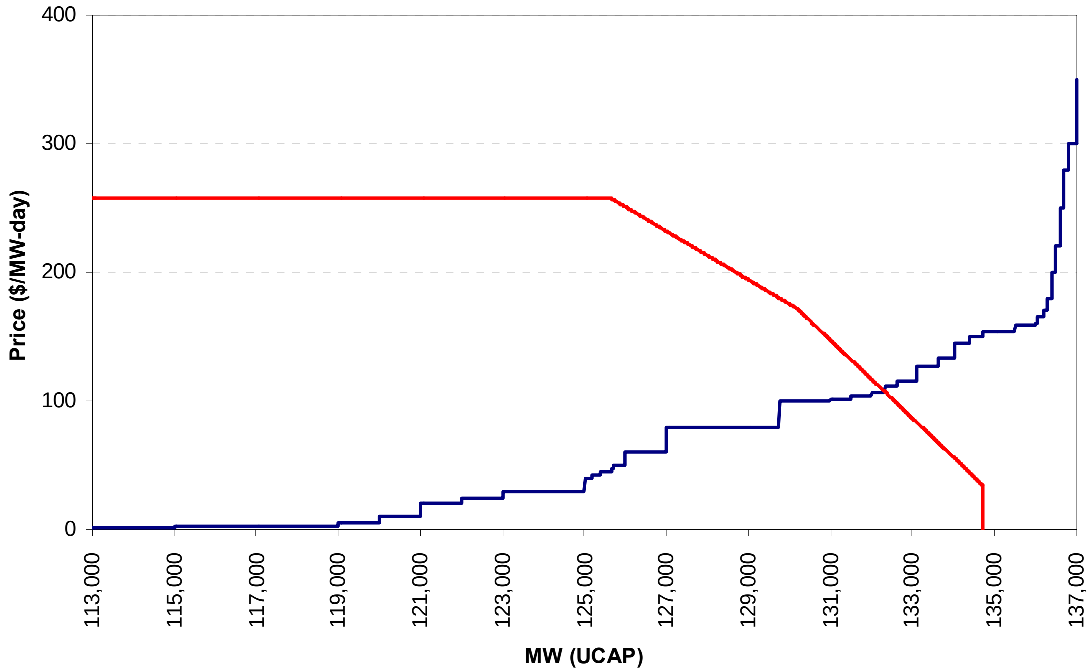
Pace multiplied the change in the annual capacity price in Northern Illinois due to the inclusion of the TEC ($/kW) by the annual total capacity projected to be procured in the RPM auction for Illinois (kW) in order to calculate the annual savings realized from the decrease in capacity prices.

This methodology is based on PJM's capacity market construct, the Reliability Pricing Model ("RPM"). The RPM clears offer-based supply curves against administratively-set demand curves in the Base Residual Auctions ("BRA"). The VRR curve or demand curve is set by PJM, based off of the assumed Cost of New Entry ("CONE") and the targeted reserve margin. Changes to either of these two assumptions will affect the clearing price of capacity, as the maximum, minimum and point of inflection are all determined as functions of those assumptions.

To illustrate the concept, a representation of the 2010/2011 auction is shown in Exhibit 20. The demand curve in this auction established a maximum price around $257/MW-day, a target of close to $171/MW-day and a low price of $34/MW-day. These points create the basis of the VRR curve illustrated in red.

For every auction, resources bid their incremental capacity into the market. This creates a supply curve for capacity (illustrated in blue). PJM assembles these bids and then determines at what price level the necessary capacity is met. The intersection of this bid-in supply curve and administratively-set demand curve create the clearing price for the capacity market. In the 2010/2011 auction, this was $110/MW-day.

Exhibit 20: Representative Base Residual Auction



Source: PJM ISO and Pace

If we were to assume that 500 additional MW of Unforced Capacity enters the Auction, this would impact the bid curve. If this capacity were to bid into the market at zero, holding all else constant, the supply curve would shift to the right by 500 MW. The impact of this shift is determined by the bid levels around the intersection point (the clearing price) and is expected to generally be around $5/kW-yr or about $14/MW-day.

Savings to the Ratepayers

These two savings (energy and capacity) were added together and divided by the total forecasted energy demand for eligible customers and ARES customers in Illinois in order to arrive at a $/MWh estimate of the benefits. Exhibit 21 presents this estimate of total savings to the Illinois eligible customers and ARES ratepayers. The largest savings occur between 2015 and 2018 when the capacity payment in PJM-Northern Illinois is projected to be lower due to the addition of the TEC. During this time, savings average about $1.40/MWh. The average savings across all ratepayers from 2015 to 2030, however, is less consistent and only estimated to be around $0.60/MWh. Beyond 2030, Pace does not project a significant market cost impact.

Exhibit 21: Total Savings to Illinois Ratepayers

Year	Energy Savings (000s of 2010$)	Capacity Savings in PJM (000s of 2010$)	Total Savings to Illinois Ratepayers (000 of 2010$)	Total Savings to Illinois Ratepayers (2010$/MWh)	Total Savings to Illinois Ratepayers (nominal$/MWh)
2015	47,847	79,279	127,126	0.93	1.01
2016	32,341	146,398	178,739	1.30	1.44
2017	80,294	152,356	232,650	1.69	1.90
2018	65,275	164,856	230,130	1.67	1.92
2019	21,147	69,991	91,139	0.66	0.77
2020	26,214		26,214	0.19	0.23
2021	66,375		66,375	0.48	0.58
2022	35,509		35,509	0.26	0.32
2023	37,587		37,587	0.27	0.34
2024	24,959		24,959	0.18	0.23
2025	45,351		45,351	0.32	0.43
2026	3,170		3,170	0.02	0.03
2027	27,759		27,759	0.20	0.27
2028	48,917		48,917	0.35	0.49
2029	2,040		2,040	0.01	0.02
2030	398		398	0.00	0.00

Source: Pace

Pace has combined the total projected savings with the TEC's expected cost impact to estimate a net impact of the project for the Reference Case. The adjusted percent rate impact, customer monthly cost impact, and cost of power at a 92% capacity factor are summarized in Exhibit 22. These impacts are displayed under the Reference Case only.

Exhibit 22: Rate Impacts Inclusive of Market Savings

Year	Rate Impact with Market Savings (%)	Monthly Impact for Average Res. Customer with Market Savings (Nominal $)	Cost of Power at 92% with Market Savings (2010$/MWh)
2015	1.30%	1.31	113.31
2016	0.92%	0.93	99.13
2017	0.52%	0.53	85.60
2018	0.42%	0.43	81.01
2019	1.42%	1.44	110.75
2020	1.84%	1.87	127.04
2021	1.45%	1.47	118.48
2022	1.63%	1.65	123.26
2023	1.63%	1.65	127.28
2024	1.65%	1.67	129.90
2025	1.61%	1.63	128.60
2026	1.94%	1.96	139.88
2027	1.64%	1.66	134.71
2028	1.39%	1.40	131.87
2029	1.81%	1.82	144.24
2030	1.70%	1.72	144.90

Source: Pace

LEVELIZED COST ANALYSIS

In this analysis, Pace defines levelized cost as the present value of the total cost of building and operating a generating plant over its economic life, converted to equal annual payments and divided by average annual units of generation. Pace has performed an economic comparison of future levelized busbar electricity production costs across seven traditional and renewable technology options and the TEC. The various technologies included in this analysis are: nuclear, pulverized coal, coal with post-combustion carbon capture and sequestration ("CCS"), natural gas combined cycle, wind, solar, and natural gas combustion turbine.

Pace's analysis has been undertaken through the development of a detailed pro-forma economic model that incorporates engineering cost estimates and power market price and economic dispatch projections. Rather than perform the analysis based on one set of assumptions, Pace has incorporated a wide range of uncertainty based upon installed costs and market conditions. The uncertainty around market conditions correspond with the four unique states of the world, which are driven by various potential changes in economic growth and regulatory policy over time. Pace has analyzed the cost structure of each of the technologies under consideration and has assessed the appropriate rate of return to derive a resulting "all-in" levelized cost of electricity. The remaining sections of this chapter present the following:

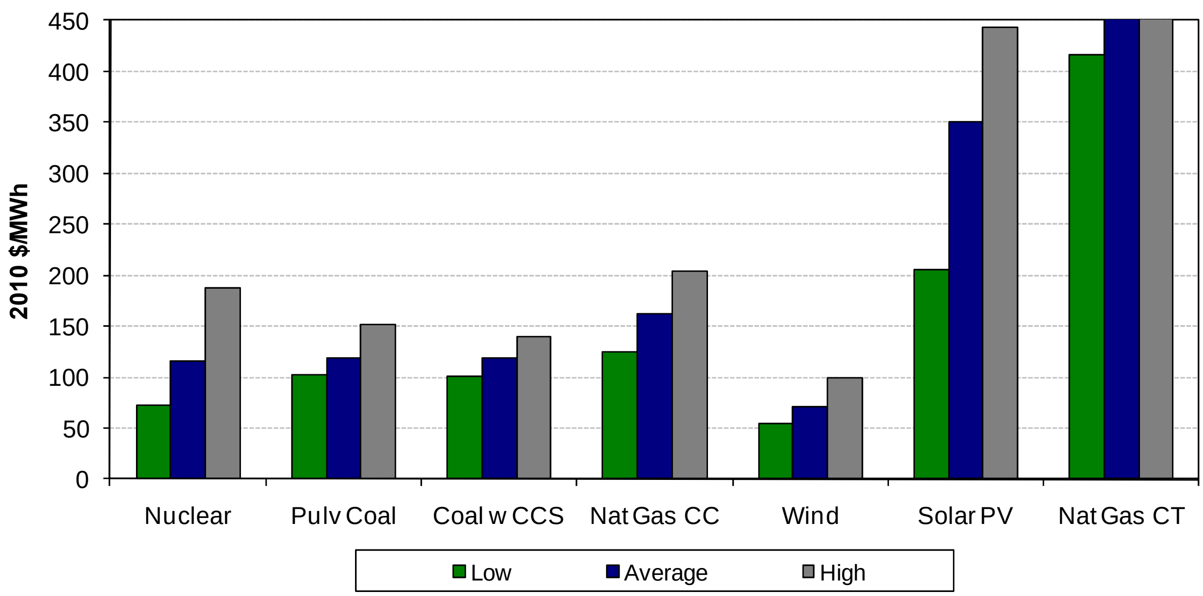
- Range of levelized costs across actual observed installed costs;
- Results by cost component across four unique states of the world for each technology showing the impact of market uncertainty unrelated to variations in installed costs;
- Key market driver inputs that varied across states of the world; and
  Key financial inputs.

LEVELIZED COST SUMMARY RESULTS

Exhibit 23 displays levelized cost results by technology across observed low and high installed costs as applied to the reference case market conditions. The range of installed costs by technology is based on Pace's recent experience in the marketplace as well as publicly available information.

Exhibit 23: Levelized Cost Results by Technology (2010$/MWh)

Technology Av	erage	High	Low
Nuclear	115	188	73
Pulv. Coal	119	152	102
Coal w CCS	119	140	101
Nat Gas CC	163	203	125
Wind	71	100	54
Solar PV	351	443	205
Nat Gas CT	690	981	417
Taylorville	150		



*Note that most values for Nat. Gas CT are excluded for display purposes.

Source: Pace analysis

Exhibit 24 summarizes the levelized cost estimates by technology and across states of the world. Although it does not provide reliable or dispatchable power, wind technology is consistently a low cost option, with capital costs driving the uncertainty. Capital costs also drive the major uncertainty for the nuclear and solar technologies, while fuel price and dispatch uncertainty drive the range for the natural gas options. The uncertainty around the coal-based options is driven by varying capital costs, dispatch, and environmental compliance costs.

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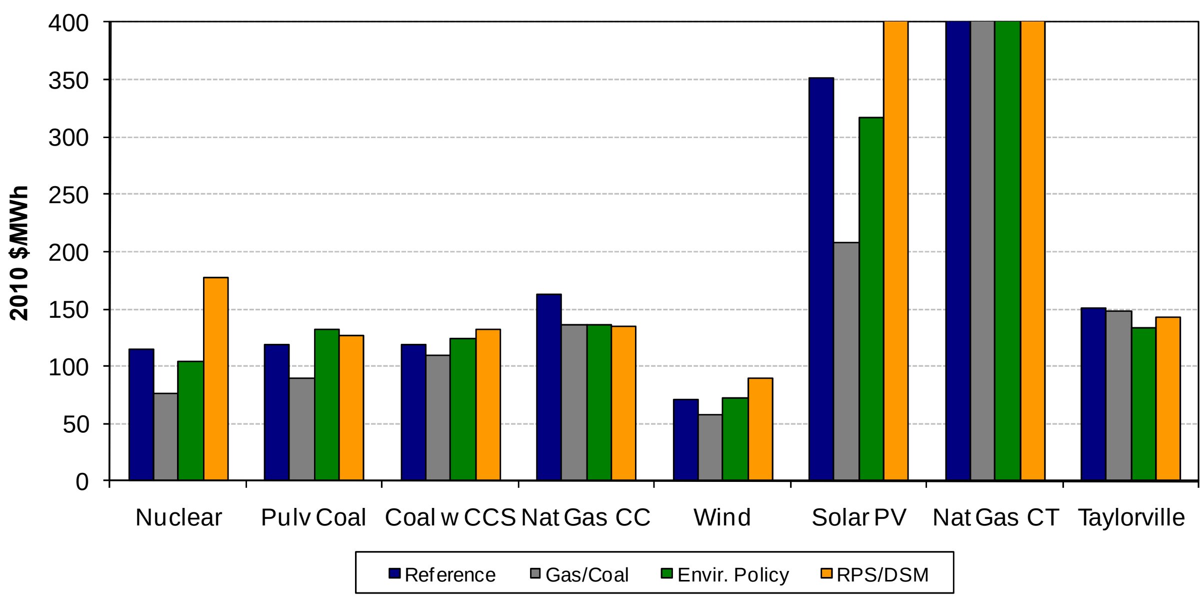
The levelization of the TEC's costs includes the net benefits of all commercial and financial incentives. As expected, these levelized costs for the TEC are generally higher than other baseload technologies, and lower than Solar PV and Natural Gas CT on a per unit of energy (MWh) basis. The TEC's levelized costs are very close to those of a conventional combined cycle under Reference Case conditions, and lower than Nuclear under the RPS/DSM assumptions due to Nuclear's very high capital costs assumed in that state of the world.

Exhibit 24: Levelized Cost Results by Technology and State of the World (2010$/MWh)

Technology	Reference	Gas/Coal	Envir. Policy	RPS/DSM
Nuclear	115	77	104	178
Pulv. Coal	119	90	132	126
Coal w CCS	119	110	124	133
Nat Gas CC	163	136	137	135
Wind	71	57	73	89
Solar PV	351	207	318	413
Nat Gas CT	690	631	508	1152
Taylorville	150	148	133	142

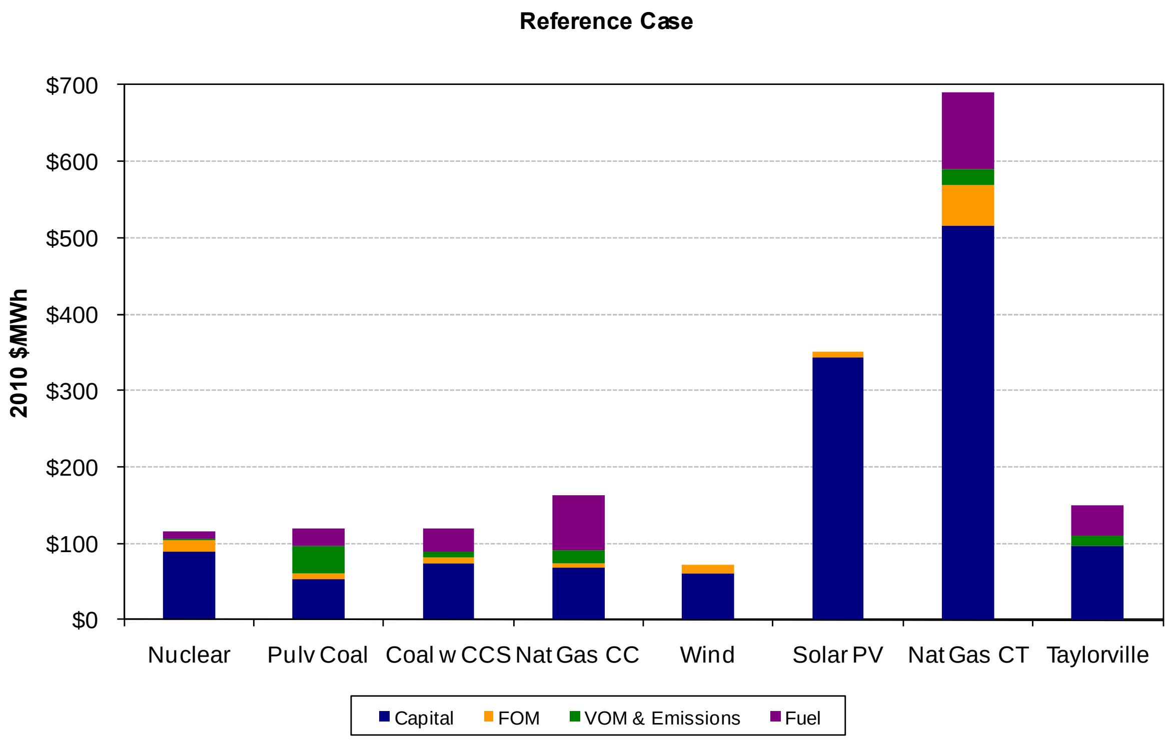


*Note that most values for Nat. Gas CT are excluded for display purposes.

Source: Pace analysis

The cost components are summarized for each technology and for each state of the world in Exhibit 25, Exhibit 26, Exhibit 27, and Exhibit 28. These displays indicate the relative impact of various components on the overall costs and across technology options. As can be seen, the natural gas-fired combustion turbine costs are dominated by the capital component, which is spread over a very small expected amount of generation in most cases. Capital costs are also the main factors driving cost estimates for nuclear and renewable technologies. Fuel costs and emission costs vary across states for the coal and gas-fired options.

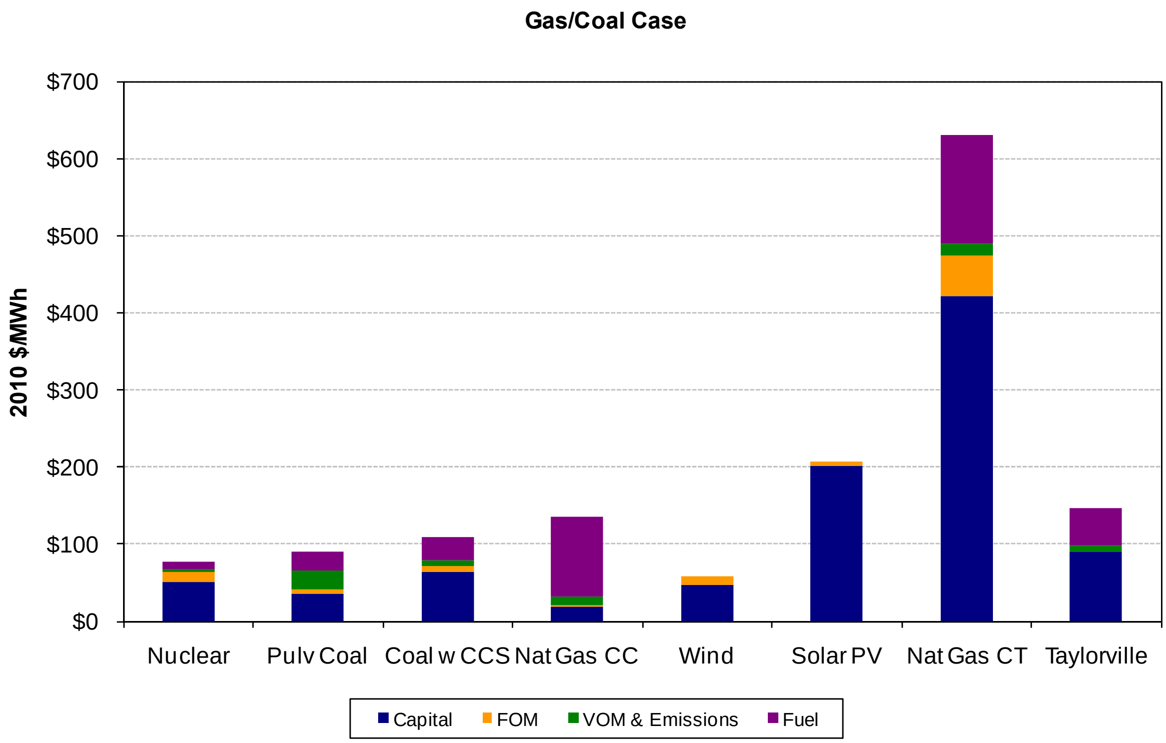
Exhibit 25: Reference Case Levelized Cost Projections by Component



Note: Taylorville's Capital cost estimate as illustrated here includes FOM, the revenue impact of natural gas sales, the net costs of oxygen purchases and other unique cost items not directly comparable to other technologies.

Source: Pace analysis

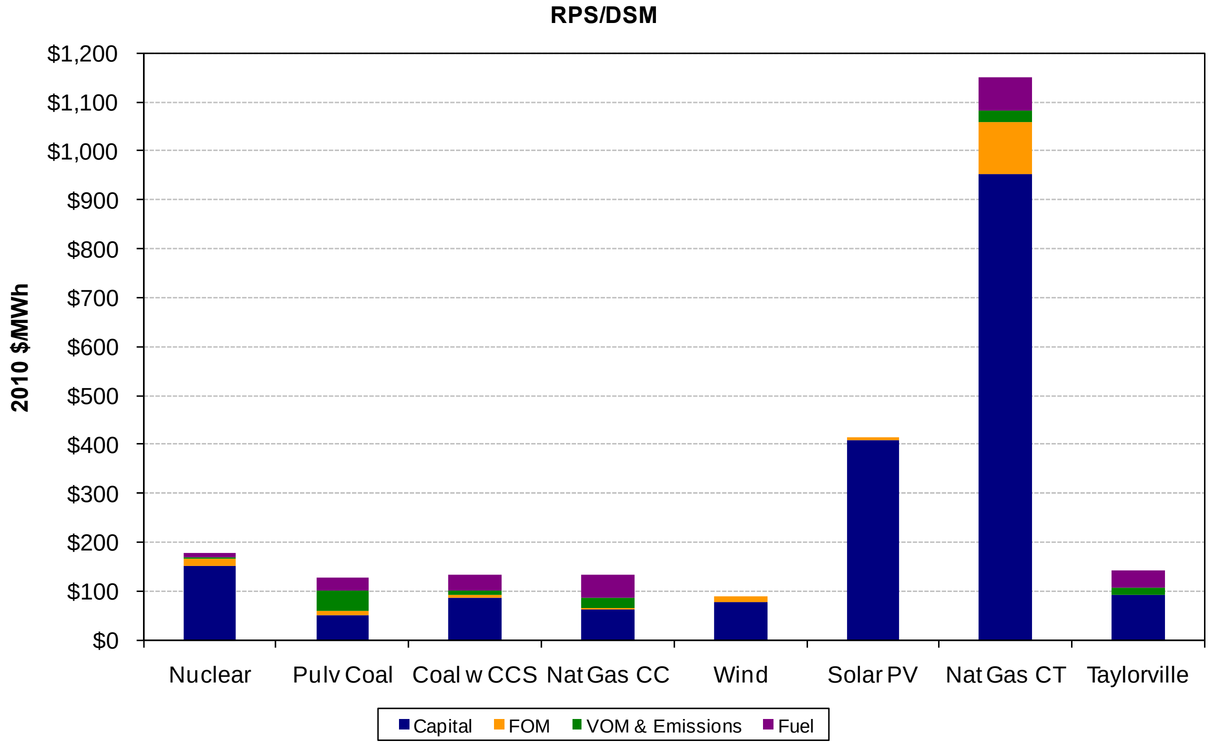
Exhibit 26: Gas/Coal State Levelized Cost Projections by Component



Note: Taylorville's Capital cost estimate as illustrated here includes FOM, the revenue impact of natural gas sales, the net costs of oxygen purchases and other unique cost items not directly comparable to other technologies.

Source: Pace analysis

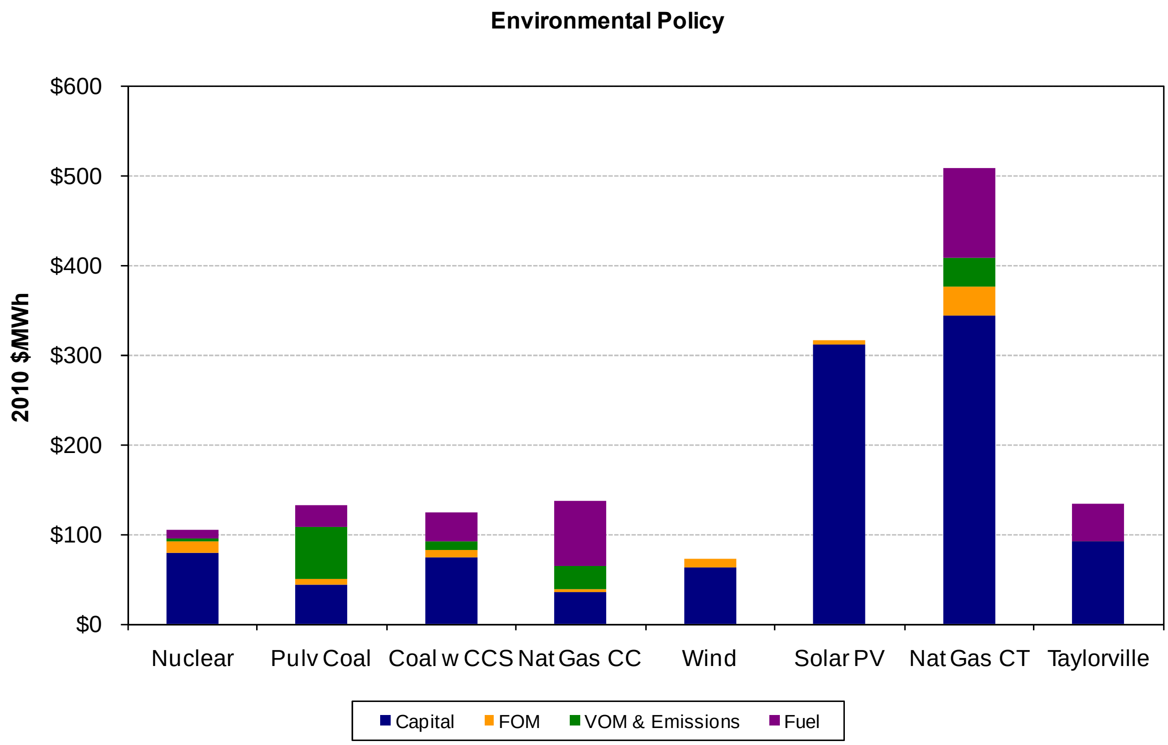
Exhibit 27: RPS/DSM State Levelized Cost Projections by Component



Note: Taylorville's Capital cost estimate as illustrated here includes FOM, the revenue impact of natural gas sales, the net costs of oxygen purchases and other unique cost items not directly comparable to other technologies.

Source: Pace analysis

Exhibit 28: Environmental Policy State Levelized Cost Projections by Component



Note: Taylorville's Capital cost estimate as illustrated here includes FOM, the revenue impact of natural gas sales, the net costs of oxygen purchases and other unique cost items not directly comparable to other technologies.

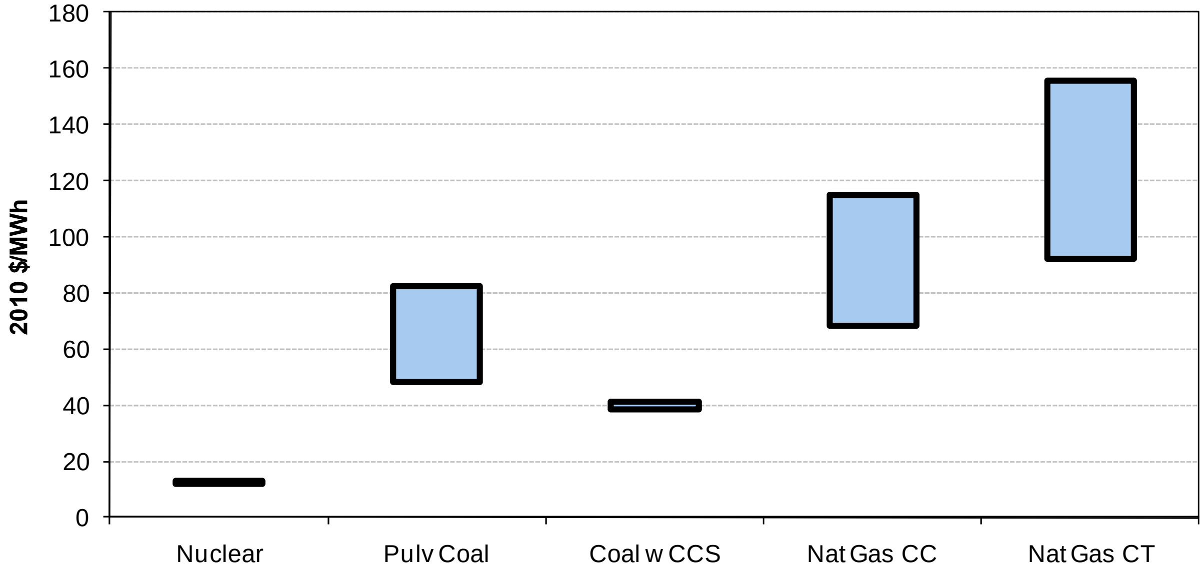
Source: Pace analysis

Exhibit 29 and Exhibit 30 display the full ranges of both variable (fuel costs, variable operations & maintenance, and emission compliance costs) and fixed costs (capital and fixed operations & maintenance) across states of the world and for each technology type.

On a variable cost basis, renewable resources (wind and solar) have minimal costs in general, so they are excluded from Exhibit 29. Expectations for nuclear fuel costs across states are narrow, as are those associated with coal w/CCS, due to narrow expected bands around coal prices and limitations on CO_2 cost exposure due to carbon capture. The range in costs for conventional pulverized coal is driven primarily by carbon compliance costs, ranging low in the Gas/Coal state and high in the Environmental Policy state. In addition to carbon compliance uncertainty, a wide range of possible natural gas prices drive the uncertainty in variable costs for natural gas-fired options.

The TEC cost components are not included in this analysis as the TEC project has unique cost elements that are not directly comparable to other technologies. These include the netting effect of the sale of natural gas produced by the gasification process and sold rather than used to generate power, commercial arrangements that result in net purchases of electricity at retail for the acquisition of oxygen, etc.

Exhibit 29: Variable Cost Ranges across States by Technology

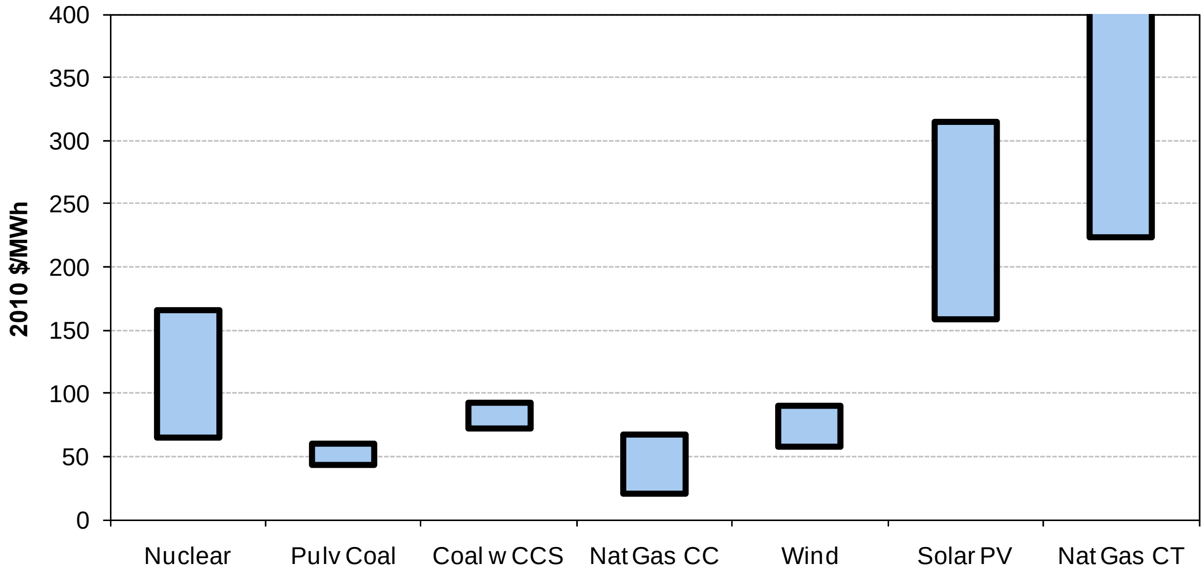


Source: Pace analysis

The range in fixed costs is shown in Exhibit 30. This range is dependent on two major factors: capital cost uncertainty and dispatch uncertainty across states of the world. Dispatch uncertainty is important because total expected fixed costs are amortized over expected power generation to provide $/MWh estimates.

Each technology displays some variance in at least one of these factors across the four states of the world. However, as is shown in the table in Exhibit 30, the magnitude of these uncertainties varies. For instance, nuclear and solar technologies have large uncertainty in upfront costs of construction, but have fairly certain operational dispatch expectations, given that they are low in variable cost. On the other hand, traditional coal or natural gas-fired combustion plants have much lower uncertainty around capital costs, but may vary widely in actual operational dispatch, depending on market variables like fuel prices and environmental compliance costs.

Exhibit 30: Fixed Cost Ranges across States by Technology



	Capital Cost Risk	Dispatch Risk
Nuclear	High	Low
Pulv. Coal	Low	Medium
Coal w/CCS	Medium	Low
Nat Gas CC	Low	High
Wind	Medium	Low
Solar PV	High	Low
Nat Gas CT	Low	High

*Note: Nat gas CT ranges above $800/MWh, due to low expected capacity factor.

Source: Pace analysis

KEY MARKET DRIVER INPUTS

Several key market drivers shape each of the states of the world and drive the range of levelized cost outcomes for the seven technologies. The following drivers and cost components are key to Pace's state of the world development:

- o Capital costs
- o Natural gas fuel costs
- o Emission costs for CO_2
- o Impact of variable cost parameters on plant dispatch

Capital Costs

As part of the capital cost uncertainty analysis, Pace assessed the relationship between GDP growth and capital cost components and then analyzed the distribution around materials, equipment, and labor cost estimates as well as the uncertainty around technology costs. The

Reference Case conditions possess a significant range of uncertainty based on plant components and technology. These estimates are displayed in Exhibit 31.[3] Based on expected near-term GDP projections and other potential cost drivers in the various states of the world, Pace developed three sets of capital costs for each technology option. These are shown in Exhibit 32.

Exhibit 31: Range of Capital Cost Estimates for Reference Case (2010$)

	High All-in Capital Costs ($/kw)	Average All-in Capital Costs ($/kw)	Low All-in Capital Costs ($/kw)
Nuclear	8,743	5,141	2,743
Pulv Coal	3,981	2,599	1,797
Coal w CCS	5,306	4,287	3,268
Nat Gas CC	1,551	993	448
Wind	2,853	1,979	1,431
Solar PV	7,306	5,872	3,424
Nat Gas CT	1,418	931	458

Source: Pace analysis, including EIA AEO 2009, CEC, NETL, and other project closings

Exhibit 32: Capital Cost Estimates by State of the World (2010$)

	Reference All-in Capital Costs ($/kW	Envir. Policy All-in Capital Costs ($/kW)	Gas/Coal All-in Capital Costs ($/kW)	RPS/DSM All-in Capital Costs ($/kW)		Fixed O&M ($/kW-yr)
Nuclear	5,141	5,145	3,282	10,067		111.12
Pulv Coal	2,599	2,666	2,295	3,076		33.79
Coal w CCS	4,287	4,902	4,221	5,656		50.40
Nat Gas CC	993	1,066	922	1,208		9.33
Wind	1,979	2,243	1,683	2,843		26.80
Solar PV	5,872	5,834	3,751	7,680		7.85
Nat Gas CT	931	1,004	744	1,277		7.99

Source: Pace analysis, including EIA AEO 2009, CEC, NETL, and other project closings

Plant Dispatch

The variable cost inputs drive expected capacity factors for those technologies that are dispatchable in the market. Pace has performed full dispatch analysis for each technology type

[3] While the total capital cost estimates for alternate technologies are based primarily on general industry information, the totoal capital cost per kW for Taylorville is based on a detailed, bottom up quantity based estimate developed through more than 120,000 hours of engineering effort, as described in the TEC Facility Cost Report. To this extent, the capital cost estimates are not directly comparable.

to estimate capacity factors for each of the states. Exhibit 33 summarizes the capacity factor expectations by technology across states of the world. While capacity factors are expected to change over time, a representative range is shown over the entire Study Period, where applicable.

Exhibit 33: Capacity Factor Projections by Technology and State of the World

Technology	Reference	Gas/Coal	Envir. Policy	RPS/DSM
Nuclear	92%	92%	92%	92%
Pulv Coal	60-75%	70-75%	50-75%	65-75%
Coal w CCS	75-80%	75-80%	80%	75-80%
Nat Gas CC	15-22%	40-45%	25-50%	40-50%
Wind	30%	30%	30%	30%
Solar PV	19%	19%	19%	19%
Nat Gas CT	1-3%	1-2%	2-5%	1-3%
Taylorville	74-77%	79-81%	75-86%	75-81%

Source: Pace analysis

KEY FINANCIAL INPUTS

Exhibit 34 summarizes the major financial inputs and assumptions used in the analysis.

Exhibit 34: Major Financing Assumptions and Inputs

Construction/Term Leverage Ratio (D/E)	55%
Construction/Debt Rate	5.3%
Debt Term (1)	30 Years
Debt Amortization Methodology	Mortgage Style
Rate of Return (ROE)	11.5%
Return of Capital (Depreciation/Amortization Expense) (2)	Varies
Effective Tax Rate (3)	39.7%
Property Tax Rate (4)	N/A
Discount Rate Utilized in the Levelization of Production Costs (6)	9%

Notes:

(1) Debt term indicated is for the combined construction and project debt term. The project debt is assumed to be 26 years and the construction loan is assumed to be secured at the date of groundbreaking. For example, the coal-fired units have a 4 year construction cycle, so the construction loan is for 4 years and the term loan is for 26 years.

(2) Each technology type is assumed to recover cost of capital through recovery of depreciation expenses, which is computed through the MACRS accelerated depreciation methodology. The depreciable life utilized depends upon the technology type. Additionally, the solar project is assumed to be eligible for bonus depreciation of 50% of the total capitalizable asset basis in the first year of operation.

The following is the depreciable life utilized for each of the technology types:

Technology Type	MACRS Life
Nuclear	20 years
Supercritical coal	20 years
Supercritical coal with CCS	20 years
Natural Gas Combined Cycle	20 years
Wind	5 years
Solar PV	5 years
Natural Gas Combustion Turbine	15 years

(3) State tax rate is assumed to be 7.25%.

(4) Property taxes are assumed to be included in the “all-in” fixed operating costs figures provided.

(6) Since the financial model computes the levelized cost of power is in real dollars, the ROE of 11.5% is discounted for an assumed 2.5% inflation rate over the 30-year model period.

Source: Pace analysis and consultation with Tenaska

APPENDIX – MARKET OVERVIEW

MARKET STRUCTURE AND OPERATIONS

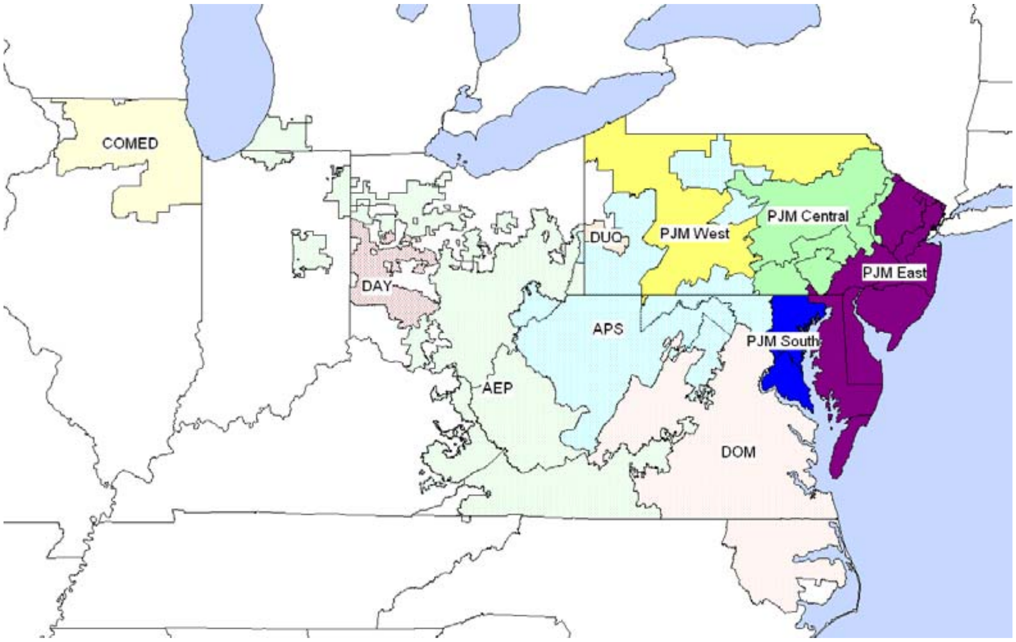
PJM Regional Overview

The electric power pool encompassing the Pennsylvania, New Jersey, and Maryland service territories was named the Pennsylvania-Jersey-Maryland Interconnection ("PJM") in 1956. PJM was designated a Regional Transmission Organization ("RTO") by the Federal Energy Regulatory Commission ("FERC") in 2001. Since then, PJM's service territory has grown to include all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia.

The PJM Independent System Operator (the "PJM ISO") is tasked with administering the world's largest wholesale market and operating the world's largest centrally dispatched wholesale electric grid. The PJM ISO dispatches about 163,500 megawatts (MW) of generating capacity over more than 56,000 miles of transmission lines and ensures electric reliability to 51 million customers.

Exhibit 35 illustrates the current PJM footprint. The TEC is planning on connecting in the ComEd region in Northern Illinois. The majority of PJM's territory is also part of the Reliability First Corporation ("RFC"), one of the regional organizations of the North American Electric Reliability Corporation ("NERC"). The Dominion service territory is part of the SERC Reliability Corporation.

Exhibit 35: Pace PJM Zonal Designations



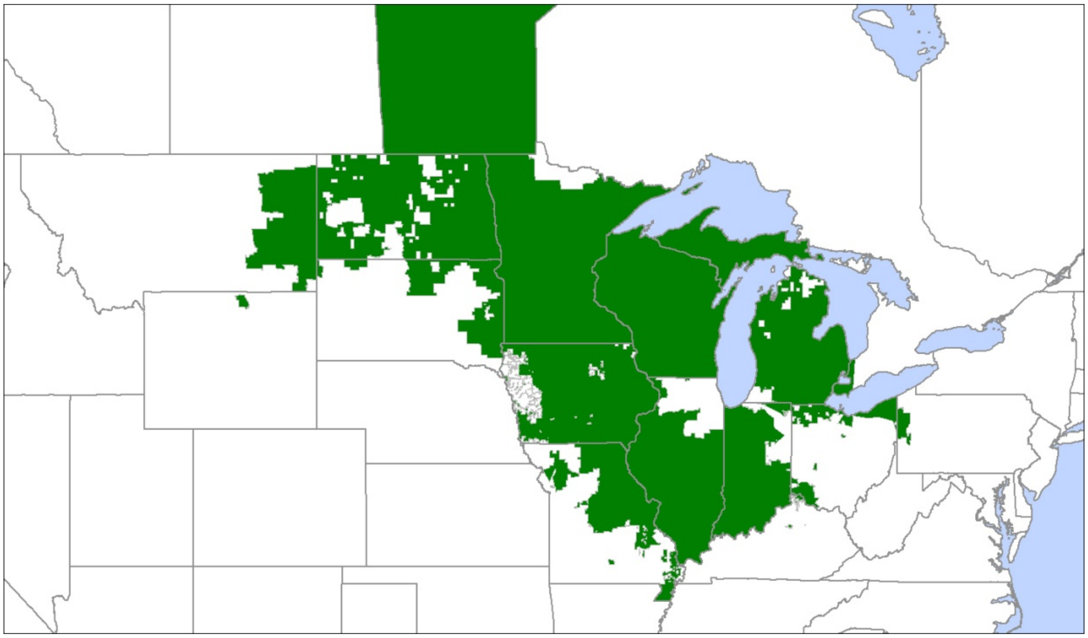
Source: Pace and Energy Velocity®

MISO Regional Overview

MISO was created by the FERC in order to provide an efficient electricity market that would also lead to highly competitive wholesale power prices in the Midwest. The MISO footprint, shown in Exhibit 36, encompasses 13 states and one Canadian province covering a total 750,000 square miles. MISO dispatches 138,556 MW of capacity over 95,600 miles of transmission.

MISO administers a day-ahead and real-time market called the Day-2 market, which started on April 1, 2005. Since Day-2 market's inception, MISO has been centrally dispatching wholesale electricity and transmission service throughout its control area. The wholesale market produces Locational Marginal Pricing ("LMP") for five-minute intervals at various locations. The hourly location marginal pricing from the market is rolled up into five regional hub prices: Cinergy, FirstEnergy, Illinois, Michigan, and Minnesota.

Exhibit 36: MISO Service Territory

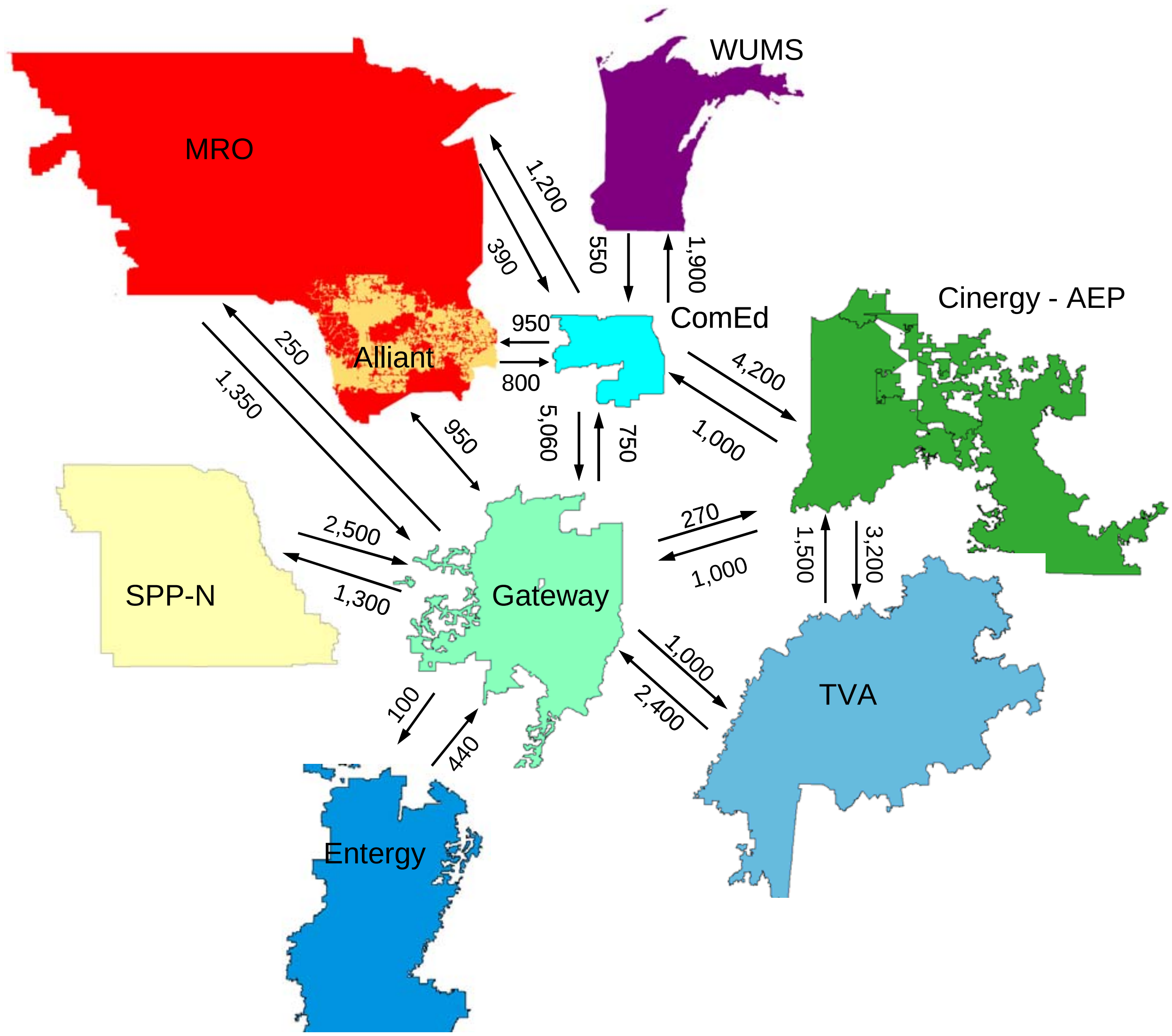


Source: Pace and Energy Velocity®

Transmission Overview

Pace develops its competitive price forecasts based on regional designations that represent areas with persistent and significant transmission congestion, which are the cause of long-term price divergence. For market simulations involving Illinois, Pace models the entire Eastern Interconnect. Exhibit 37 provides a representation of Pace's modeling regions for the areas around Illinois and the inter-regional transfer capability between the relevant zones. The transfer capabilities represented are based on data obtained from recent NERC Seasonal Reliability Assessments, the respective regional Reliability Assessments for the power market areas within the modeled regional consolidation, and historical wholesale transactions as reported to the FERC.

Exhibit 37: Pace Zonal Modeling Regions and Transmission



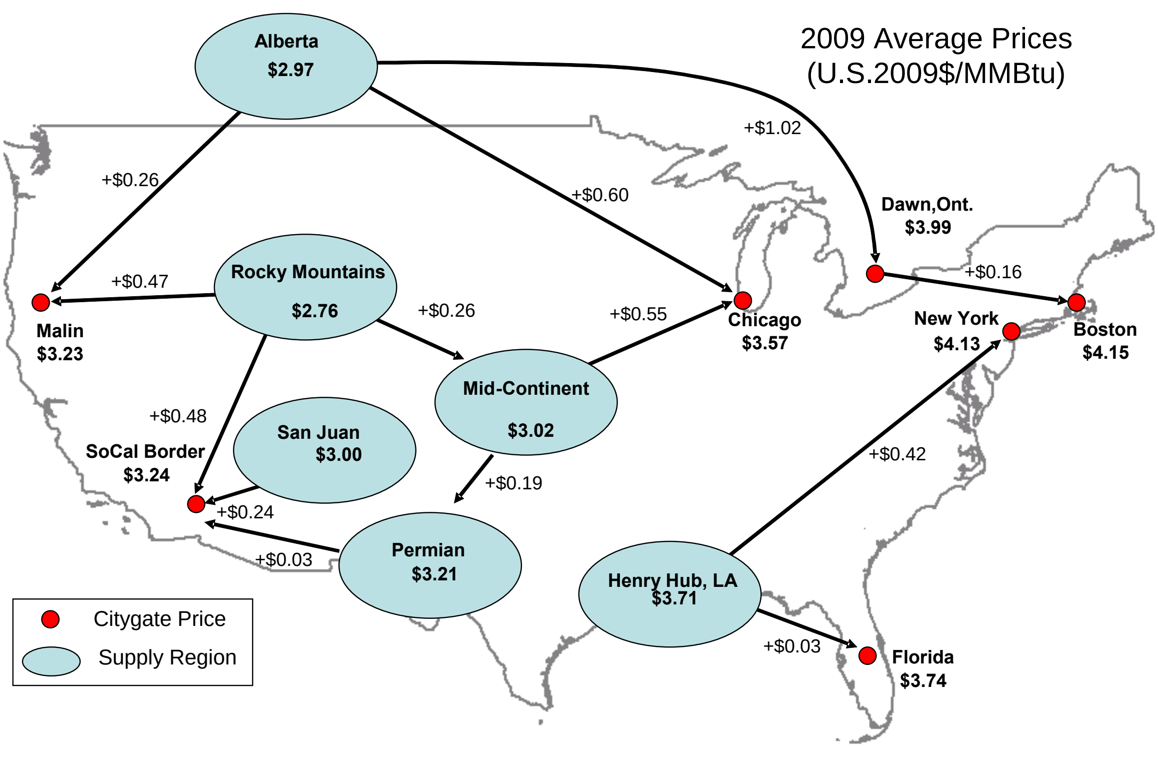
Source: Pace and Energy Velocity®

APPENDIX – FUEL MARKET

NATURAL GAS MARKET OVERVIEW

The principal location for natural gas trading in the U.S. is the Henry Hub in Louisiana. Due to the volume of physical trading at this location, Henry Hub has also become the location for financial market trading on the NYMEX. Regional gas prices are based on basis differentials from the Henry Hub to other delivery locations. Regional basis rises (widens) when local production declines and the cost of transporting gas between regions increases and when rising demand causes pipeline and storage utilization to grow. Conversely, increases in local production, the available pipeline and storage capacity relative to demand for transportation and storage cause the basis differentials to decline (to narrow). The map in Exhibit 38 shows the flows of gas and the prevailing market prices for the major North American trading hubs as of June 1, 2009. The regional basis is the difference between the price in a regional market and the price at Henry Hub.

Exhibit 38: North American Average Natural Gas Prices in 2009 ($/MMBtu)



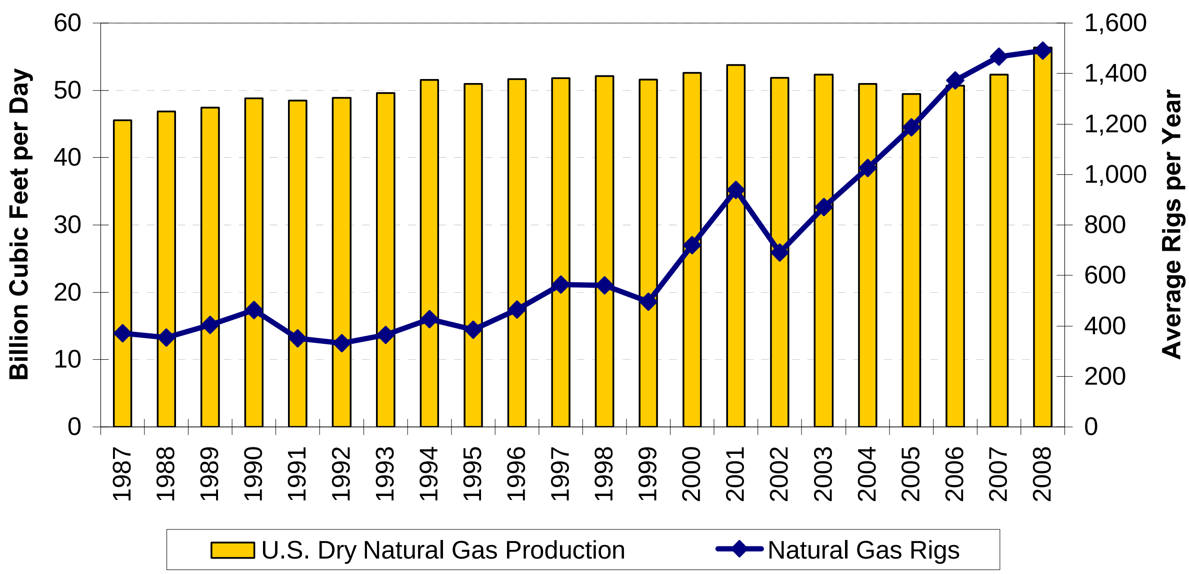
Sources: Pace and Platts

Henry Hub Price Forecast

Pace projects the price of natural gas over time by combining futures market information with expectations around longer-term fundamental supply and demand drivers. In developing distinct states of the world, Pace has assessed the potential price response of these drivers around a Reference Case view.

Perspectives regarding long-term natural gas supply sources are being routinely re-evaluated in light of ongoing developments with respect to unconventional natural gas supply. Due to a price-driven U.S. drilling boom for unconventional onshore gas supplies and the technological advances it supported and sustained, the idea that North American gas supply was in irrevocable decline is being routinely questioned. Conventional wisdom with respect to resource estimates is moving toward a resurgence in natural gas supply in the lower 48 states. However, good data on shale gas is limited and the sustainability of the upward production trend in a lower price environment is unclear given that much of the incremental production reaching the market today took a decade to develop and much of today's drilling is driven by the requirements to hold onto leases.

Exhibit 39: U.S. Natural Gas Production and Drilling Rig Count



Sources: Rig count – Baker Hughes; production – EIA.

The decline in demand as a result of the financial crisis coupled with the incremental supply has resulted in cash and futures prices declining from the highs of summer, 2008. A collapse in drilling activity has accompanied this price collapse. Although not exclusively, much of the reduction in drilling activity has been in the conventional resources. Because of the rapid deliverability declines observed in the shale gas wells that are the proximate cause of the oversupply situation, market observers are awaiting declines in total marketed production in the coming months, bringing the supply/demand balance into better balance, which should bolster prices. However, this is partially offset by producer hedging programs and an inventory of shutin gas waiting for higher prices. Pace would then expect to see drilling activity begin to increase as prices climbed past $6.00/MMBtu, allowing for unavoidable logistical lags.

However, a combination of weak economic recovery, ample gas in storage and rising LNG imports from a global market that is also experiencing a supply glut – again due to the combination of weak demand and fast-growing LNG production and transportation capacity stimulated by a decade of increasing price expectations – could keep spot prices at or below $4.00/MMBtu during the off-season for heating demand for several years as increasing LNG imports replace declining North American production capacity as drilling activity remains subdued by the weak price environment.

Longer term on the supply side, North American gas producers and LNG importers are going to be competing for market share in a volatile price environment. Given the inherent commercial and logistical lags for major increases in drilling activity and the fact that natural gas liquefaction plants generally will continue operating at near capacity in both down and up markets, LNG will tend to flow into North American markets as domestic deliverability declines and prices steadily rise until growing domestic production from increased drilling activity sends the opposite price signal. Under these circumstances, significant multi-year price cycles would be added to seasonally cyclical price movements and short-term volatility in shaping long-term market prices. The extent and duration of these multi-year cycles would be attributed in part to global LNG pricing as well as domestic market conditions, periodically drawing the North American market into at least temporary alignment with European and Asian markets until growing domestic deliverability created competition once again for market share.

On the demand side, major long-term uncertainties include the power sector response to eventual mandatory carbon emissions limits and whether industrial gas demand will recover and grow or stagnate and decline as heavy industry continues to relocate and the domestic petrochemical industry sees its market share erode as new production capacity is built closer to cheaper sources of feedstock. On the power generation side, a rapid implementation schedule for achieving interim targets for carbon emissions reductions could induce a “dash to gas” and an exodus from older coal-fired plants, leading to a rapid increase in gas demand. A massive investment in wind power would make gas-fired generation the most practical source of standby and supplemental power as wind speeds and electric load vary. Demand swings on regional gas transmission systems will have lasting effects on system operations as well as pipeline and storage capacity pricing.

Pace’s scenario-based gas demand forecasts for the Northeast U.S. over the next 20 years range from a modest decline to a roughly 10-20 percent increase above current average daily demand should gas-fired generation shoulder a larger share of the electricity load. Exhibit 40 provides a summary of Pace’s independent forecast of annual natural gas prices at Henry Hub across the different states of the world.

Exhibit 40: Natural Gas Price Forecasts (2010 $/MMBtu)

Year	Reference	RPS/DSM	Environmental Policy	Coal/Gas
2009	4.33	5.24	5.39	3.67
2010	5.75	7.13	6.01	4.45
2011	6.39	7.34	6.68	4.98
2012	6.56	7.86	7.29	5.24
2013	6.64	7.34	7.60	6.29
2014	7.15	7.60	8.01	7.34
2015	8.11	7.60	8.47	8.91
2016	8.71	7.34	8.99	9.96
2017	8.42	7.08	9.76	10.48
2018	7.82	7.08	9.92	11.01
2019	8.18	7.08	9.72	11.01
2020	9.19	7.34	9.31	11.53
2021	9.83	7.34	8.96	12.05
2022	9.60	7.34	8.35	12.58
2023	10.80	7.34	9.00	13.10
2024	11.16	7.08	9.37	13.63
2025	10.80	6.81	9.00	14.15
2026	11.04	6.55	8.98	14.68
2027	11.34	6.29	9.29	15.20
2028	11.54	6.29	9.49	15.72
2029	11.75	6.03	9.70	16.25
2030	11.95	6.03	9.90	16.77

Source: Pace

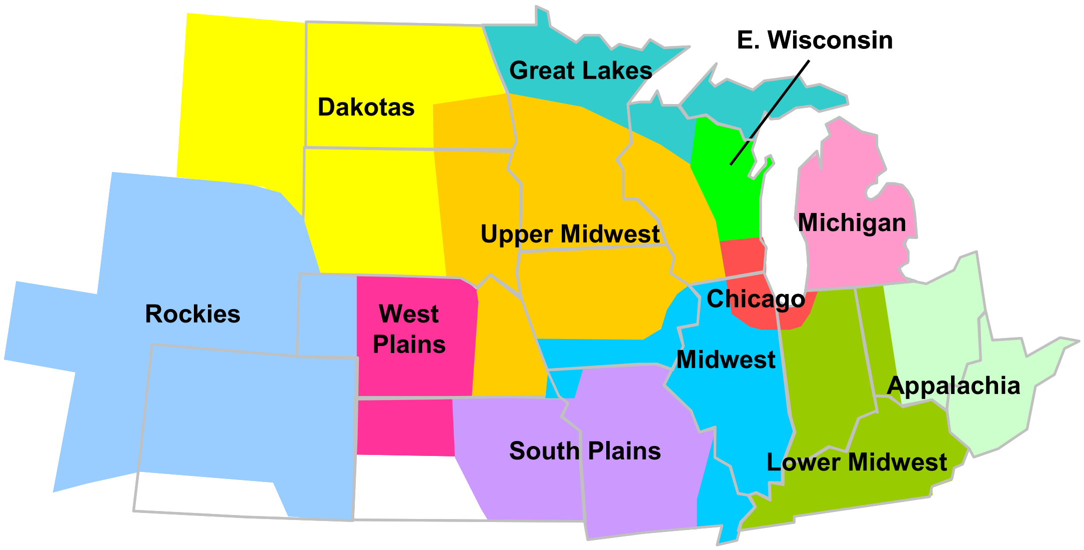
Regional Basis

New and emerging domestic production regions, the ongoing reconfiguration of the North American gas transmission network, and growing LNG import capacity on the Atlantic Seaboard and Gulf Coast will all work to reshape prevailing price disparities among local markets in coming years.

The completion of the Rockies Express – East pipeline later has added to downward basis pressure. Adding about 1.5 Bcf/d of year-round delivery capacity, the Rockies Express is the first direct link between the gas deliverability surpluses currently depressing gas prices throughout the Rockies and high-priced East Coast markets. The producers financing the pipeline construction hope to raise their wellhead prices enough to cover the cost of transcontinental transportation, but basis effects are always felt on both ends of a new interconnection between major supply and demand nodes.

Pace's delivered gas price forecast incorporates regional price differentials and the cost of transportation to Midwest gas price sub-regions, as depicted in Exhibit 41. Developments in the pipeline sector will change the basis differentials.

Exhibit 41: Pace Gas Price Midwest Region



Sources: Pace and Platts.

Each gas price region is defined by its primary liquid supply source, interstate transporter, and that transporter's applicable market-based transportation rates. The regional basis from the Henry Hub to these gas price regions is driven primarily by the following fundamentals:

- The Midwest receives its supplies from four major regions: The Rockies, Canada, Mid-Continent and the US Gulf Coast.
- Eastern Wisconsin receives its supply from the ANR Pipeline. Because this region is located down stream of Chicago, its price is affected by the Chicago price plus transportation along the ANR pipeline.
- Rockies production enters the Dakotas via Williston Basin Interstate Pipeline. Northern Border and Northern Natural interconnect with Williston and transport gas east and south.
- West Plains receives its gas from Mid-Continent production.
- Great Lakes Gas Transmission supplies the Great Lakes region with Western Canadian gas priced at Emerson, Canada.
- The Upper Midwest receives nearly all of its supply from Northern Natural Pipeline, which receives supply from the Permian Basin, Mid-Continent, and Western Canada via interconnects with Viking Gas Transmission and Northern Border Pipeline. The Alliance pipeline is not designed to make any deliveries in this region. Because of the competition between inexpensive Canadian supply and nearby Mid-Continent supply, receipt point gas in the Upper Midwest is competitively priced.
- Numerous pipelines deliver supply from the Rockies, Western Canada, Gulf region and the Mid-Continent to the Midwest region. Much of this supply is otherwise destined for markets in Chicago and Michigan.

Petroleum

WTI Crude Oil Prices

After ranging between $20 and $40/bbl for two decades, crude oil prices have shown significant increase in volatility during the past five years. In the past 18 months the market value of a barrel of West Texas Intermediate ("WTI") crude oil has varied by roughly $110, with crude prices spiking to $147/bbl in July 2008 before dropping to below $40/bbl in January and February of 2009. Market fundamentals were a significant part of the large price swings, but clearly the worsening financial and economic downturn – first in the U.S. but quickly spreading around the world – played a substantial role, as well as the uncertainties in the geopolitical situation and the role of speculators in the futures market. Although crude oil prices do not have a significant impact on the clearing prices of power in the Midwest, the price of crude is the driver behind enhanced oil recovery ("EOR") revenues the Project may receive from the sale of CO2. Tenaska has calculated the revenue for the CO2 stream based on the range of WTI forecasts detailed in Exhibit 42.

In Pace's Reference Case, annual average prices for benchmark WTI crude oil are projected to rise steadily throughout the Study Period to $105/bbl by 2020 and $130/bbl by 2030 (expressed in constant 2010 dollars.) These prices are predicated on Pace's view of global demand and supply. In the Reference Case natural gas and crude oil are assumed to maintain a loose equivalency on a Btu basis as North American gas producers and LNG importers compete for market share. Pace anticipates that there is a cyclical nature to this volatility which will draw the North American market in and out of alignment with European and Asian markets as demand for natural gas and indigenous production changes. These prices are subject to uncertainty, and Pace has developed three other alternate growth scenarios consistent with the other States of the World previously described around its reference price to capture the possible range of uncertainties in future crude prices (and therefore risks in Project economics.)

In the Coal/Gas Scenario, near term demand is expected to be depressed, but once there is global recovery from the economic downturn high global demand for crude oil will return. This increase in global demand increases the price of crude beyond Reference Case price levels by 2026.

In the Environmental Policy Scenario, quick global economic recovery is expected to increase crude prices in the near term. A focus on renewable development, as well as concern over human's impact on the environment leads to moderated global demand in later years.

In the RPS/DSM Scenario, a major international supply disruption in crude oil supplies to the West is assumed dramatically increasing the price of crude during and after the event. This disruption further reinforces the intense governmental emphasis placed on the development of domestic resources, alternatives fuels (such as biofuels), renewables, and demand side management programs especially in the US. While crude prices reach high levels, gas prices are moderated by an intense drilling response that successfully brings on new domestic supplies from shale and other non-conventional sources and moderates prices somewhat. In the out-years crude oil prices collapse as Western countries are able to diversify away from imported hydrocarbons, and oil and gas prices approach but do not reach equilibrium.

Exhibit 42: WTI Crude Oil Price Forecasts for Four States of the World (2010$/bbl)

	Reference	Coal/ Gas	Environmental Policy	RPS/DSM
2015	86	74	70	124
2016	88	78	72	116
2017	93	83	73	107
2018	96	87	74	99
2019	99	91	76	91
2020	105	96	77	83
2021	107	100	77	82
2022	112	104	76	81
2023	114	109	76	80
2024	116	113	75	79
2025	119	117	75	77
2026	121	122	76	74
2027	124	126	78	71
2028	126	130	79	68
2029	128	135	81	65
2030	130	139	82	62

Source: Pace

COAL PRICE PROJECTIONS

Coal price estimates were developed by Tenaska's coal consultant, Wood Mackenzie, for Illinois basin coal to be delivered to the TEC. Exhibit 43 presents the expected coal prices through 2030.

Exhibit 43: Delivered Coal Price (2010 $/MMBtu)

Year	Price
2015	2.21
2016	2.24
2017	2.24
2018	2.17
2019	2.15
2020	2.17
2021	2.18
2022	2.20
2023	2.16
2024	2.16
2025	2.12
2026	2.13
2027	2.20
2028	2.21
2029	2.22
2030	2.32

Source: Tenaska

APPENDIX – ENVIRONMENTAL MARKETS AND POLICY

EMISSIONS REGULATIONS

Carbon Dioxide (CO2)

To date, the U.S. has declined to implement regulated carbon constraints either at the national level or through binding international climate change agreements such as the Kyoto Protocol. Carbon regulatory bills have been proposed sporadically in Congress since the mid 1990s. However, their sponsors have recently become more determined towards enacting mandatory, economy-wide, market-based caps on carbon emissions. This drive to pass federal legislation is borne from increasing pressure stemming from constituencies both domestically and internationally.

Momentum for climate change legislation has slowed some of late: congressional attention to comprehensive climate legislation was diverted by health care debates for much of the second half of 2009; in December 2009, the world leaders failed to come to terms on a binding climate agreement to replace Kyoto; and most recently the Democrats lost their filibuster-proof 60 seat majority in the Senate after the Republican upset in Massachusetts.

EPA continues to push forward to regulate GHGs under the existing provisions of the Clean Air Act (CAA). In December they finalized their endangerment finding for GHG emissions from mobile sources and beginning January 1st this year, major stationary sources are required to calculate and report their annual GHG emissions to EPA.

Expected Near-Term Outlook

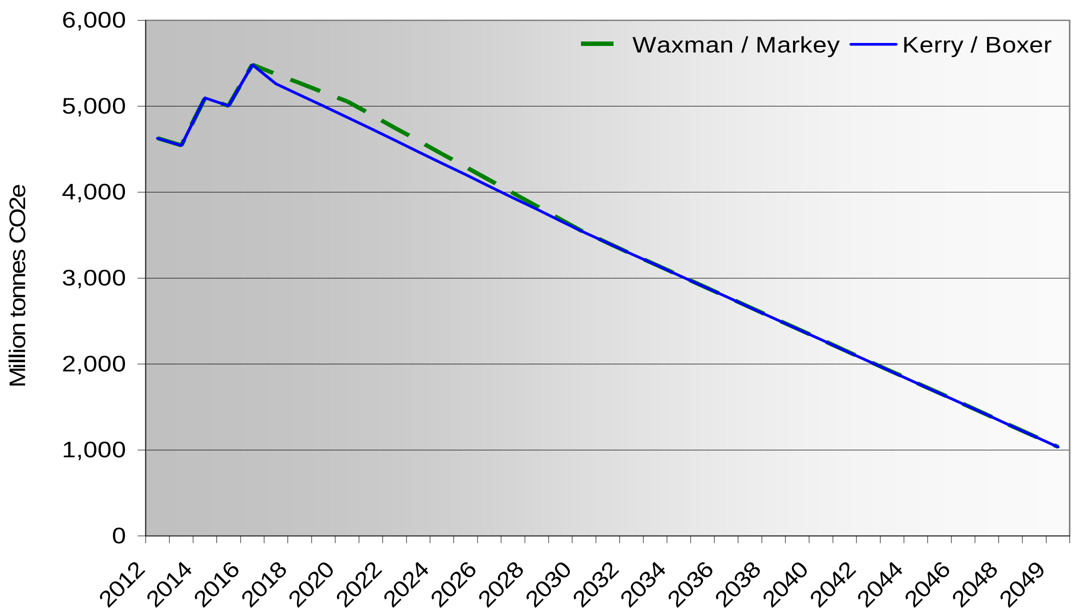
EPA is expected to release rules that would regulate emissions from mobile sources in spring 2010, an event that will likely require EPA to take similar action for stationary sources soon after. When and in what manner EPA will regulate ultimately GHG emissions from stationary sources is still largely unknown at this point, as interested parties debate EPA's authority and requirements under the CAA. Depending on which provisions of the CAA EPA regulates GHGs, major regulation may still be 4 or 5 years off giving time to Congress to pass legislation. While a cap and trade program under EPA unilateral action would still be a few years off, some additional permitting requirements could be implemented within the next year or two.

Federal carbon regulation through legislation in the U.S. remains the most likely scenario for long term GHG regulations. Pace expects the passage of federal carbon legislation sometime between the first half of 2010 and the end of 2011, with compliance requirements likely to become effective in 2012 or 2013. Prominent policy mechanisms and how they work in the framework of carbon regulation are presented below:

- **Carbon reduction targets** – Pace anticipates that U.S. carbon legislation will require significant carbon reduction caps over a long-term reduction timeframe. The leading climates bills in the House and Senate[4] both call for 83% reduction of 2005 year emissions by 2050 (see Exhibit 44).

- **Cap & trade** – Pace anticipates that any passed legislation will impart carbon reductions via a market-based cap & trade scheme. Virtually all U.S. carbon bills introduced to date call for a cap & trade system as opposed to a straight carbon tax.
- **Supply flexibility mechanisms** – Pace anticipates that the U.S. carbon legislation will include a number of different options for procuring supply of compliance instruments. These compliance mechanisms are likely to include direct allowance allocation, allowance auctions, banking of unused allowances for use in future years, borrowing forward year allowances, and tapping into international carbon trading schemes. Most importantly, Pace expects a healthy offset market with 20 percent - 50 percent of covered entities' compliance positions allowed to be covered with offsets supplied from reductions made from emission sources outside of the legislated cap.
- **Allowance price controls** – Pace expects the carbon market design to include provisions intended to mitigate against market price spikes. These market protections may come in the form of a set cap on the price of allowances, or more likely in the form of market control authority to inject more supply into the market or other market based approaches to ward off undue price levels of compliance instruments.

Exhibit 44: Emission Cap Under Prominent and Recent U.S. Climate Bills



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Source: Referenced Legislation and Pace

[4] On June 26, 2009 the House passed the 'American Clean Energy and Security Act of 2009,' ("ACES") sponsored by Rep. Waxman (D, CA) and Rep. Markey (D, MA) marking it the first comprehensive climate bill to pass either house of Congress. The leading climate bill in the Senate is the Clean Energy Jobs and American Power Act," sponsored by Senators Kerry (D, MA) and Boxer (D, CA) which is currently in committee review.

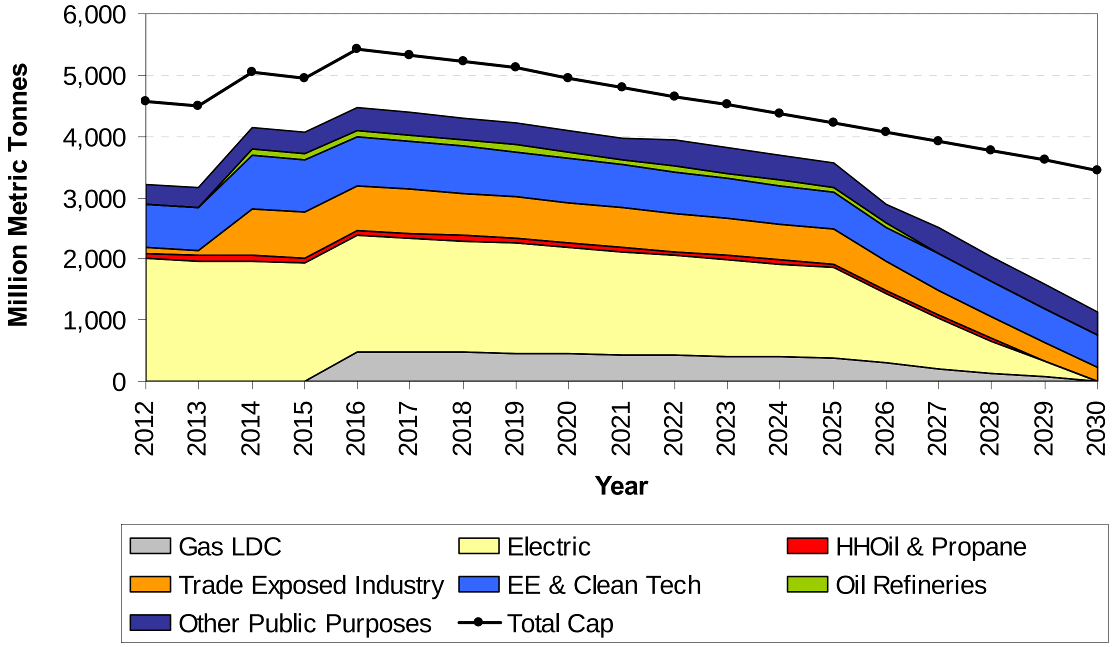
Waxman-Markey's American Clean Energy and Security Act of 2009

Pace does not base its assumptions or price models on any one piece of carbon legislation. Rather, the price inputs used and assumptions made are based on years of detailed tracking of all climate change bills while taking into account our expertise in environmental markets to arrive at what we believe to be fair and accurate forecast. That said, the leading federal climate bill to date is Rep. Waxman (D, CA) and Rep. Markey's (D, MA) 'American Clean Energy and Security Act of 2009,' ("ACES") which passed the House June 26, 2009, marking it the first comprehensive climate bill to pass either house of Congress. The economy-wide carbon cap & trade bill calls for a reduction of GHG emissions 83 percent below 2005 levels by 2050, provides free allowance allocations to retail electric providers, and includes provisions for emissions allowance price controls.

Electricity providers, enumerated industrial processes, and industrial processes that exceed a 25,000 mt $CO_{2(e)}$ threshold are covered "downstream" at the point of emission. Refiners and other fossil-fuel based liquid fuel producers and importers are regulated "upstream" along with producers and importers of GHGs. Natural gas Local Distribution Companies ("LDCs") are regulated at the facility level and are responsible for the emissions from the combustion of their delivered natural gas.

Regulated entities will be required to submit allowances for each tonne of $CO_{2(e)}$ that they emitted the previous calendar year. The bill allocates approximately 85 percent of the total allowances to various sectors in the early years of the cap. The percentage of freely allocated allowances distributed each year remains fairly constant in the first 10 to 12 years of regulation, reducing at the same rate as the overall declining cap. Beginning in 2025, the allocations decline more rapidly, reaching zero for most sectors by 2030 (see Exhibit 45). As fewer free allocations are distributed, entities will increasingly need to seek other methods for meeting their compliance position (i.e. buying allowances from auction, procuring from the market, investing in or procuring offset credits, or reducing emissions).

Exhibit 45: Free Allowance Allocation Summary under ACES



Source: Waxman-Markey ACES and Pace

The power/electricity sector receives 43.75 percent of the allowance pool in the initial years and 35 percent of the total allowances beginning in 2016 when natural gas LDCs are first regulated (resulting in a spike of the total number of allowances in the cap). The electricity sector splits their allocated allowances amongst LSEs, merchant coal generators, and generators operating under long term power contracts – with the majority (about 85 percent of the allocations to the electricity sector) going to LSEs. LSEs are directed to use the value of these allowances "for the benefit of the retail ratepayer" however some ambiguity exists as to what constitutes a "benefit". The ultimate determination will likely be left to the state PUCs. As with most other sectors regulated under the cap, the power/electricity sector will stop receiving allowance allocations beginning in 2030.

An emission allowance may be "banked" and used in any subsequent year under the cap. Allowances can be "borrowed" one year forward at no interest (i.e. an allowance with a 2015 vintage number can be used toward 2014 compliance). Up to 15 percent of an entity's compliance obligation can be borrowed for emissions allowances for compliance years up to 5 years in the future, at 8 percent interest.

Along with using free allocations and purchasing allowances at an auction or through the market, covered entities can also procure offset credits to meet their compliance position. Offsets are compliance mechanisms, created through government approved projects that reduce GHG levels. Under this bill for each tonne of $CO_{2(e)}$ removed from the atmosphere through an offset project, the owner of the project would receive 1 offset credit that can be used to meet a covered entities compliance position. The types of offset projects that will be eligible to receive compliance credits is still largely unknown as the ultimate determination of project eligibility will be made by the EPA (or other like governmental agency) after a rulemaking procedure. Pace anticipates at this time that at a minimum offset project categories to be included in federal carbon legislation are likely to include including forestry (reforestation) and methane destruction projects.

New Coal-Fired Power Plant Performance Standards

ACES amends the Clean Air Act ("CAA") by adding CO_2 reduction performance standards for new coal-fired generating units. The performance standards only apply to units that are "initially permitted" on or after January 1, 2009. Units that have been initially permitted prior to January 1, 2009 would be exempt from the performance standards under ACES. A unit is "initially permitted" (as opposed to "finally permitted") when an owner or operator of the unit has received a CAA preconstruction approval or permit, but there still exists the possibility for administrative review and/or appeal of such approval.

For covered generating units that are initially permitted between 2009 and 2020, a 50% reduction of CO_2 emitted by that unit must be achieved. The deadline for achieving a 50% reduction in CO_2 emissions is dependent on when the EPA makes a determination that Carbon Capture and Sequestration ("CCS") is commercially viable. The EPA will publish a finding of commercial viability once the following milestones have been achieved across the entire electricity generating sector:

1. There is a cumulative generating capacity of at least 4GW equipped with CCS technology;
2. There exists at least 2 electricity generating units which have a nameplate generating capacity of 250 MWs or greater, that successfully capture and sequester carbon into geological formations other than oil and gas fields; ***and***
3. There are units cumulatively capturing and sequestering in aggregate at least 12 million tons of CO_2 per year

The deadline for achieving a 50% reduction in CO_2 emissions (for units initially permitted between 2009 and 2020) will be the earlier of the following events:

1. 4 years from the date that EPA makes a finding of CCS's commercial viability (see above definition), or
2. January 1, 2025

Units that are initially permitted after January 1, 2020, will be required to achieve a 65% reduction in CO_2 emissions from that unit upon commencement of operations, regardless of EPA making a commercial viability finding.

If the EPA makes a determination at some point that the degree of emission reduction achievable, through the application of the best available technology, is lower than the requirements of this section, they may reduce the required emission reduction rate for new units. The Senate is debating the CCS portions in their bill, with many arguing for delayed CCS requirements for fear that CCS will not be commercially viable in the time frame established under the House bill. It is likely that the final CCS provisions of the Senate bill will be different than the current House provisions.

Carbon Compliance Cost Price Projections

Pace's range of expected carbon pricing represents costs mitigated through price control measures and/or other market forces to prevent major near-term shifts in the power generation supply. All forecasts are supported by representative pricing demonstrated in other active regulated and voluntary carbon market pricing. Pace develops a range of cases (summarized in Exhibit 46), based on the general drivers described below.

Low Case – This case represents low to moderate carbon caps with an initial compliance period starting around 2013. It assumes long term reduction targets to be less than 75 percent, significant direct allocations, and offset provisions allowing for 30 percent or more of the supply side of the market to be covered by offset project reductions.

Mid Case – This case reflects either moderate to stringent carbon caps with flexible compliance provisions or a scenario of low to moderate caps with more stringent compliance provisions implemented in 2012. Legislation under the Mid case is assumed to include provisions for 20-40 percent use of offsets, emission reduction requirements of approximately 75 to 80 percent by 2050, and moderate level of free allowance coverage to significantly impacted entities in the power and industrial sectors.

High Case – This case represents the earliest expected impacts of carbon compliance costs either through early (2012) commencement of the initial compliance period or active pre-compliance trading. The initial uptick and curvature represents potential market reactions to compliance risk and the availability of banking once the compliance market is in effect. Higher prices in the latter years of the forecast period result from constrained offset provisions limiting the flexibility through which compliance can be achieved and / or rigorous carbon caps. In addition to speculative market price drivers, characteristics of legislation driving the High case include stringent ultimate reduction targets of 80 percent or greater by 2050, constrained use of offsets for compliance and limited free allowance allocations to covered entities.

Exhibit 46: CO_2 Compliance Costs (2010$/tonne of CO_2)

Year	Reference	Low Case	High Case
2012	10	-	37
2013	15	2	31
2014	18	3	29
2015	21	6	29
2016	23	7	32
2017	24	9	35
2018	25	11	40
2019	26	12	44
2020	27	13	46
2021	28	14	47
2022	29	16	49
2023	31	18	50
2024	33	18	52
2025	37	21	53
2026	42	24	55
2027	46	26	58
2028	52	28	62
2029	55	29	68
2030	59	32	80

Source: Pace

Other Compliance Cost Price Projections

The allowance prices Pace uses for SO_2, NO_X annual and NO_X seasonal are based on the original Clean Air Interstate Rule (CAIR) which was originally promulgated in 2005. In July 2008, the D.C. Circuit Court remanded CAIR back to EPA to cure numerous legal issues. The SO_2 and NO_X markets have been in a period of relative flux as the rules for these markets going forward are still largely uncertain. For this reason, Pace continues to model the allowance prices based on the original CAIR rules. These prices are presented in Exhibit 47.

Exhibit 47: NO_x Compliance Costs (2010$/ton)

Year	NOx Annual	NOx Seasonal	NOx Both
2015	3,609	67	3,637
2016	3,755	70	3,785
2017	3,983	74	4,014
2018	4,224	78	4,257
2019	4,317	78	4,350
2020	4,413	82	4,447
2021	4,511	87	4,547
2022	4,611	92	4,649
2023	4,713	98	4,753
2024	4,817	104	4,860
2025	4,924	110	4,970
2026	5,033	117	5,082
2027	5,145	124	5,196
2028	5,145	124	5,196
2029	5,145	124	5,196
2030	5,145	124	5,196

Source: Pace

Tax Credits and Bonus Allowances for CO2 Sequestration

CO_2 tax credits and bonus allowances were valued in accordance with current law and legislative proposals. The federal Energy Improvement and Extension Act of 2008 created Section 45Q of the Internal Revenue Code to provide for credits associated with carbon capture and sequestration at $10 per tonne. Final rules still need to be adopted by the Internal Revenue Service and the Environmental Protection Agency. A credit value of $10 per tonne serves as the basis of Pace's Reference Case CO_2 tax credit estimate for the TEC. It is assumed that this credit lasts for the first ten years of commercial operation, although if the current total national credit pool of 75 million tones is not increased, the pool may be exhausted before this point. In addition, current climate change legislative proposals (Waxman-Markey in the House and Kerry-Boxer in the Senate) provide bonus credits for new power plants that capture and sequester carbon dioxide in the range of $50 to $90 per tonne. The TEC would potentially be eligible for bonus allowances around $70 per tonne based on its likely CO_2 capture characteristics. Pace includes this bonus allowance in addition to the the reference case tax credit for the Environmental Policy state of the world.

APPENDIX – ENERGY DEMAND

Electricity prices in a given market are highly dependent on electricity demand. Pace developed an independent energy and peak demand forecast for each of its model regions, including Illinois. This section presents Pace's forecasting methodology as well as the projected national and regional demand forecasts.

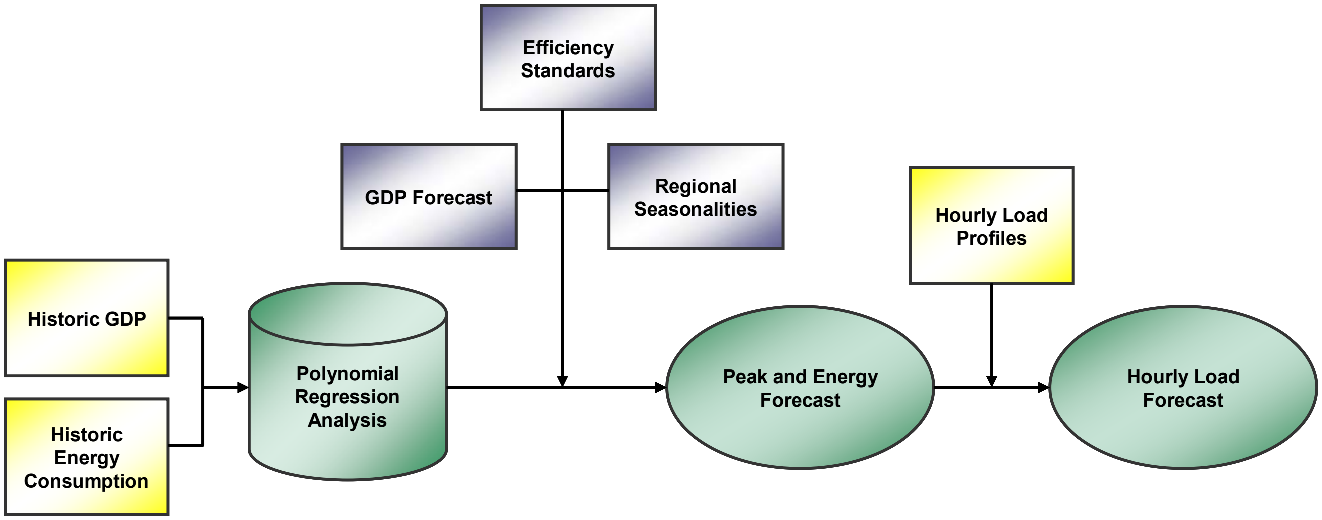
PACE'S INDEPENDENT LOAD FORECASTING METHODOLOGY

Pace's independent demand forecast was developed according to the methodology illustrated in Exhibit 48. As shown, the foundation of Pace's load forecasting methodology is an econometric approach. This methodology has two primary components. The first is the use of econometric models to forecast annual peak demand and energy levels based on changes in GDP. The second component of the methodology is the translation of historical hourly demand levels and forecasted peak demands to create predicted hourly load for each forecast year.

To generate this demand forecast, Pace:

- Established the historical relationship between net energy for load and GDP. Pace used the best-fitting econometric relationship between these two variables in order to project a national load over the Study Period. Pace's regression analysis indicated a strong correlation between electricity demand and GDP. Specifically, the analysis produced an adjusted R^2, or "fit", of 0.997.
- Forecasted demand based on the historical trends of GDP and energy consumption and projected GDP growth. Pace used an independent GDP forecast (Moody's) for its Reference Case, but varied growth rates across states of the world.
- Calculated regional load growth based on historic growth patterns in all modeled regions.
- Defined bounds around resulting regional growth rates based on regional characteristics and known drivers of historic energy demand trends.
- Calculated seasonal energy and summer/winter peaks according to historical usage patterns and load factors.

Exhibit 48: Pace Load Forecasting Methodology



Source: Pace

HOURLY LOAD FORECASTING

The characterization and replication of daily, weekly, and seasonal load variations significantly impact the usage, type, and cost of resources required by a utility system. Therefore, Pace projects hourly demand profiles in order to account for seasonal variations in load.

Pace's methodology applies annual growth factors derived from peak demand and energy forecasts to the actual 8,760 hours of load occurring in a utility system. In this way, our market modeling system reflects not only the cost to serve certain levels of load but also how hourly changes impact the use of different types of generation units.

Pace uses an Hourly Load Module tool to translate annual peak demand and energy growth factors into future hourly demand for a given Study Period for every case simulated. The translation process is a two-step process:

- Step 1: The first step involves aggregating actual utility hourly loads as reported to the FERC. This aggregation creates an integrated hourly system load profile for all relevant market areas.
- Step 2: The second step involves applying annual growth factors and seasonal peak demand forecasts to the base system hourly load file (created in step 1) to create an hourly demand profile for each year in the Study Period.

The result of this process is an hourly demand shape that replicates actual market fluctuations and allows for representative dispatch patterns of the generating resources in the market.

Pace's national and Illinois load forecasts are summarized in Exhibit 49.

Exhibit 49: Demand Forecasts (GWh)

	National Load	National Load With Efficiency	IL Reference	IL RPS/DSM	IL Coal/Gas	IL Environmental Policy
2009	3,994,905	3,990,480	142,107	142,744	141,627	141,389
2010	4,030,732	4,020,862	143,135	145,133	139,117	141,745
2011	4,117,556	4,101,928	145,773	148,131	139,442	145,059
2012	4,212,112	4,175,328	148,666	150,477	141,005	148,947
2013	4,266,981	4,208,933	150,148	152,443	142,988	150,726
2014	4,303,125	4,223,707	150,965	152,870	145,445	152,142
2015	4,336,857	4,235,961	151,691	152,720	148,186	153,423
2016	4,367,810	4,245,328	152,315	152,443	150,496	154,915
2017	4,395,108	4,258,562	152,807	151,847	152,127	155,515
2018	4,417,512	4,266,851	153,127	151,070	153,150	156,243
2019	4,439,476	4,274,657	153,427	150,592	153,985	156,693
2020	4,461,549	4,274,706	153,729	150,112	154,825	157,431
2021	4,483,730	4,282,640	154,031	149,629	155,670	157,424
2022	4,506,020	4,282,684	154,334	149,245	156,519	157,657
2023	4,528,419	4,294,511	154,638	148,861	157,373	157,823
2024	4,550,929	4,306,424	154,942	148,479	158,232	158,431
2025	4,573,549	4,322,124	155,247	147,989	159,096	158,379
2026	4,596,281	4,337,997	155,553	147,610	159,965	158,486
2027	4,619,123	4,353,151	155,860	147,117	160,838	158,788
2028	4,642,079	4,369,239	156,167	146,771	161,717	159,468
2029	4,665,146	4,385,434	156,475	146,428	162,600	159,419
2030	4,688,328	4,401,739	156,784	146,116	163,488	159,733

Source: Pace

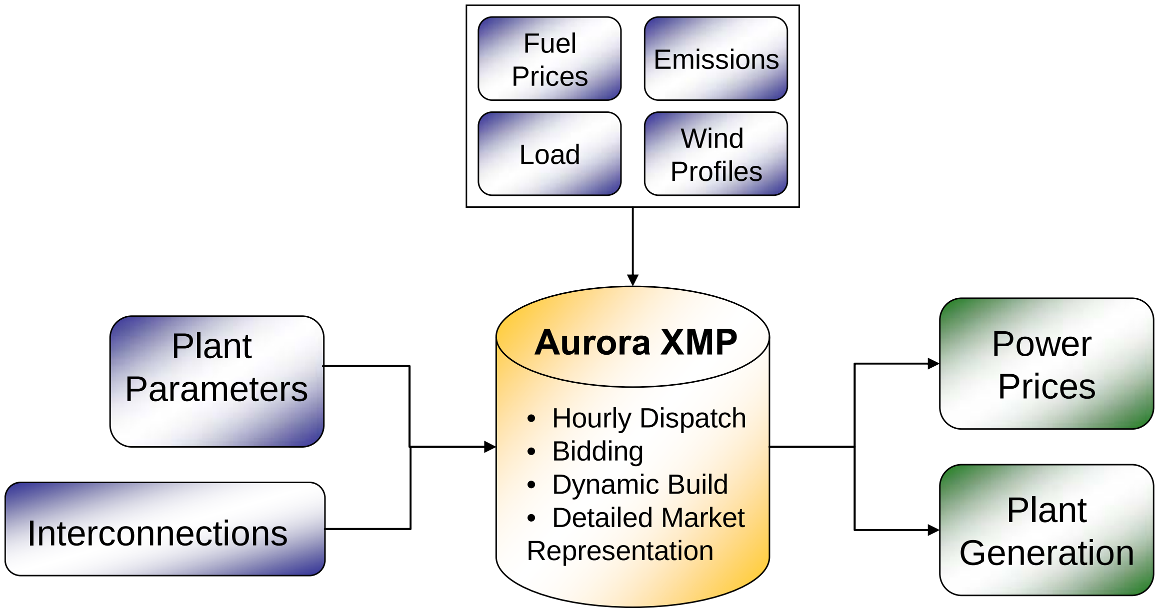
APPENDIX – MARKET POWER PRICE FORECAST METHODOLOGY

Pace utilizes an hourly chronological dispatch model to simulate the economic dispatch of power plants within a competitive framework. Pace's long-term forecasts include detailed assessments on the fundamental drivers of power plant dispatch within each relevant market area. Key components of our forecasting methodology include:

- **Load Forecast:** Pace independently develops regional load forecasts based on the historic relationship between economic drivers, weather, and load.
- **Regional Fuel/Emission Forecasts:** Pace develops independent forecasts of fuel and emission pricing inputs based the fundamental drivers of each market and a comprehensive review of regulatory environments. Pace integrates plant-level environmental compliance decisions with expected emission allowance price outcomes.
- **Renewable Generation Profiles:** Pace analyzes the historic generation of renewable technologies throughout its modeling regions in order to characterize renewable generation profiles.
- **Regional Expansion:** Pace builds new generating units based on regional reserve margin targets, RPS requirements, and an assessment of the economics of different technology types considered feasible within a region. Pace incorporates dynamic build algorithms so that capacity expansion is reactive to market conditions.
- **Bidding Function:** Pace's market simulations incorporate bidding behavior and scarcity premiums in the dispatch algorithm. Each region's bidding function is based on hourly analyses of the historic relationship between prices and reserve margins.

Exhibit 50 summarizes Pace's forecasting methodology, including key inputs and a summary of the features of the Aurora XMP dispatch model that is used. Key outputs from the dispatch analysis include hourly market clearing prices and plant generation expectations.

Exhibit 50: Pace Forecasting Methodology



Source: Pace

APPENDIX –RATE IMPACT SUMMARY DETAILS BY STATE OF THE WORLD

Reference Case

Please Select a Case or Use The Manual Overrides Below

Load Assumptions: Ref. Load
Cost Recovery: Ref. Captial Recovery
Coal Price: Ref. Coal
Natural Gas Price: Ref. NG
Natural Gas Use: Ref. NG
Inflation Rate: Market Based
☐ Check for Real Values
☐ Include Projected Market Cost Savings

% Customer Class: Ref. Customer Cat.
CO2 Bonus: Ref. Tax Credit
Capacity Revenues: Ref. Capacity
Energy Revenues: Ref. Energy
Emissions Cost: Ref. Emissions
VOM Cost: Ref. VOM
☑ Use Capital Cost Deferral

114.92	2009 Start Rate $/MWh	114.92	Start Rate

Total Rate Impact of Taylorville

Year	% Impact	IL Load	Capital Recovery Requirement	Gross Margins	Energy Revenue	Capacity Revenue	Generation	Capacity Factor	Coal Use	Coal Cost	SNG Production	Gas Use for Power Generation	Gas Sales	VOM	Power Gen. CO2 Emission Cost	Power Gen. Other Emission Cost	Captured CO2	CO2 Credit	Net Emissions Cost	Cost of Power	Cost of Power at 92% Capacity Factor
	Tab: Cap Rec Req and Deferral	Tab: Load	Tab: Cap Rev Req and Deferral	Col F + Col G + Col N - Col K - Col O - Col T	Tab: Energy	Tab: Capacity	Tab: Energy	(Col H * 1000) / (602 MW * Hours in a Year)	Tab: Coal	Col J * Coal Price	Tab: Gas	Tab: Gas	Tab: Gas	Tab: VOM	Tab: Emissions	Tab: Emissions	Col J (Converted to Tonnes) * 63%	Tab: Tax Credit	-1 * (Col S * Col R - Col Q - Col P)	(Col D + Col K + Col O + Col T - Col N) / Col H	Tab: 92% CF
Name	*Percent*	*GWh*	*$000*	*$000*	*$000*	*$000*	*GWh*	*Percent*	*MMBTU*	*$000*	*MMBTU*	*MMBTU*	*$000*	*$000*	*$000*	*$000*	*tonnes*	*$/tonne*	*$000*	*$/MWh*	*$/MWh*
2015	2.17%	136,522	439,514	98,769	282,457	16,645	3,924	74.42	25,241,502	60,470	14,758,848	27,417,170	(110,899)	12,015	32,541	404	1,478,699	11	16,948	163.05	151.01
2016	2.17%	137,084	462,690	120,971	296,748	15,579	3,907	73.89	31,151,578	77,015	18,214,502	27,311,930	(87,138)	12,197	34,707	427	1,824,923	11	15,007	167.38	149.97
2017	2.17%	137,527	475,883	132,145	303,135	17,750	3,930	74.53	33,008,118	83,147	19,300,032	27,453,950	(77,082)	12,514	37,289	464	1,933,683	11	15,997	169.11	150.44
2018	2.09%	137,814	467,417	136,667	307,888	22,029	4,029	76.41	33,008,118	82,156	19,300,032	28,099,660	(78,962)	13,094	40,726	514	1,933,683	11	19,037	163.96	147.66
2019	2.09%	138,085	474,969	142,794	321,961	22,595	4,028	76.38	33,008,118	83,122	19,300,032	28,088,410	(84,086)	13,350	43,314	536	1,933,683	12	21,204	168.02	151.78
2020	2.04%	138,356	482,384	158,370	343,339	25,279	3,934	74.39	33,008,118	85,431	19,300,032	27,481,370	(89,038)	13,299	45,033	547	1,933,683	12	22,480	176.08	158.21
2021	1.96%	138,628	475,387	163,190	354,832	28,558	3,898	73.91	33,008,118	87,524	19,300,032	27,243,420	(94,868)	13,441	47,363	566	1,933,683	12	24,367	178.47	161.09
2022	1.91%	138,901	475,990	171,368	361,933	34,484	3,897	73.90	33,008,118	90,207	19,300,032	27,239,810	(94,430)	13,707	50,146	591	1,933,683	12	26,705	179.90	162.32
2023	1.93%	139,174	488,565	180,032	382,863	37,697	3,869	73.36	33,008,118	90,178	19,300,032	27,055,990	(105,791)	13,880	54,580	613	1,933,683	13	30,679	188.46	171.21
2024	1.85%	139,448	488,057	191,122	403,774	43,078	3,898	73.72	33,008,118	92,250	19,300,032	27,252,760	(113,639)	14,267	59,934	644	1,933,683	13	35,575	190.79	174.63
2025	1.98%	139,723	490,487	171,985	414,433	45,245	3,899	73.93	33,008,118	92,501	19,300,032	27,251,930	(112,921)	14,554	67,044	673	1,933,683	-	67,716	199.59	181.98
2026	1.96%	139,998	499,623	183,959	445,090	47,987	3,921	74.35	33,008,118	94,646	19,300,032	27,397,590	(119,965)	14,929	78,871	706	1,933,683	-	79,577	206.25	189.06
2027	1.88%	140,274	489,728	186,648	471,417	49,593	3,953	74.95	33,008,118	99,834	19,300,032	27,603,050	(129,068)	15,350	89,368	742	1,933,683	-	90,110	208.49	192.73
2028	1.81%	140,551	494,014	201,340	509,143	49,569	3,979	75.25	33,008,118	102,317	19,300,032	27,780,280	(136,112)	15,764	102,417	762	1,933,683	-	103,179	213.95	198.68
2029	1.83%	140,828	508,501	213,029	534,387	51,777	3,969	75.27	33,008,118	104,644	19,300,032	27,709,270	(140,972)	16,038	110,706	775	1,933,683	-	111,482	222.12	206.53
2030	1.71%	141,106	501,101	224,239	570,451	55,488	4,001	75.87	33,008,118	111,736	19,300,032	27,914,230	(149,999)	16,489	122,680	797	1,933,683	-	123,477	225.65	211.12
2031	1.76%	141,384	504,505	218,439	580,743	56,598	4,001	75.87	33,008,118	117,714	19,300,032	27,914,230	(155,294)	16,819	128,262	813	1,933,683	-	129,075	230.80	216.32
2032	1.83%	141,663	523,757	225,434	600,275	57,730	4,001	75.66	33,008,118	120,751	19,300,032	27,914,230	(159,737)	17,155	134,098	829	1,933,683	-	134,927	239.03	223.97
2033	1.72%	141,943	512,062	231,806	620,534	58,884	4,001	75.87	33,008,118	122,618	19,300,032	27,914,230	(166,451)	17,498	140,200	845	1,933,683	-	141,045	239.86	225.79
2034	1.72%	142,223	520,404	238,625	641,550	60,062	4,001	75.87	33,008,118	125,371	19,300,032	27,914,230	(172,327)	17,848	146,579	862	1,933,683	-	147,441	245.79	231.74
2035	1.68%	142,503	520,879	245,861	663,353	61,263	4,001	75.87	33,008,118	128,013	19,300,032	27,914,230	(178,410)	18,205	153,248	880	1,933,683	-	154,128	249.85	236.18
2036	1.65%	142,784	526,279	255,544	685,974	62,488	4,001	75.66	33,008,118	129,717	19,300,032	27,914,230	(183,515)	18,569	160,221	897	1,933,683	-	161,118	254.74	241.26
2037	1.59%	143,066	523,855	263,023	709,446	63,738	4,001	75.87	33,008,118	131,567	19,300,032	27,914,230	(191,228)	18,941	167,511	915	1,933,683	-	168,426	258.44	245.58
2038	1.66%	143,348	544,136	270,501	733,804	65,013	4,001	75.87	33,008,118	134,952	19,300,032	27,914,230	(197,979)	19,320	175,133	933	1,933,683	-	176,066	268.05	254.74
2039	1.58%	143,631	538,699	277,206	759,082	66,313	4,001	75.87	33,008,118	139,463	19,300,032	27,914,230	(204,967)	19,706	183,101	952	1,933,683	-	184,053	271.66	258.98
2040	1.50%	143,914	536,395	287,882	785,319	67,639	4,001	75.66	33,008,118	141,741	19,300,032	27,914,230	(210,832)	20,100	191,432	971	1,933,683	-	192,403	275.30	263.23
2041	1.57%	144,198	554,330	293,897	812,552	68,992	4,001	75.87	33,008,118	146,320	19,300,032	27,914,230	(219,693)	20,502	200,142	991	1,933,683	-	201,133	285.43	273.02
2042	1.44%	144,482	542,108	302,764	840,823	70,372	4,001	75.87	33,008,118	149,812	19,300,032	27,914,230	(227,449)	20,912	209,249	1,010	1,933,683	-	210,259	287.57	276.20
2043	1.42%	144,767	549,347	313,593	870,173	71,780	4,001	75.87	33,008,118	151,751	19,300,032	27,914,230	(235,477)	21,330	218,770	1,031	1,933,683	-	219,800	294.36	283.27
2044	1.50%	145,053	575,379	324,723	900,646	73,215	4,001	75.66	33,008,118	155,391	19,300,032	27,914,230	(242,215)	21,757	228,724	1,051	1,933,683	-	229,775	306.06	294.41

PACE

Envi Policy

Please Select a Case or Use The Manual Overrides Below

Load Assumptions	Cost Recovery	Coal Price	Natural Gas Price	Natural Gas Use	Inflation Rate		
Envi Policy Load	Envi Policy Captial Rec	Ref. Coal	Envi Policy NG	Envi Policy NG	Market Based	☐ Check for Real Values	☐ Include Projected Market Cost Savings
% Customer Class	**CO2 Bonus**	**Capacity Revenues**	**Energy Revenues**	**Emissions Cost**	**VOM Cost**		
Ref. Customer Cat.	CO2 Bonus	Ref. Capacity	Envi Policy Energy	Envi Policy Emissions	Envi Policy VOM	☑ Use Capital Cost Deferral	

114.92	2009 Start Rate $/MWh	114.92	Start Rate

Total Rate Impact of Taylorville

	Tab: Cap Rec Req and Deferral	Tab: Load	Tab: Cap Rev Req and Deferral	Col F + Col G + Col N - Col K - Col O - Col T	Tab: Energy	Tab: Capacity	Tab: Energy	(Col H * 1000) / (602 MW * Hours in a Year)	Tab: Coal	Col J * Coal Price
Year	**% Impact**	**IL Load**	**Capital Recovery Requirement**	**Gross Margins**	**Energy Revenue**	**Capacity Revenue**	**Generation**	**Capacity Factor**	**Coal Use**	**Coal Cost**
Name	*Percent*	*GWh*	*$000*	*$000*	*$000*	*$000*	*GWh*	*Percent*	*MMBTU*	*$000*
2015	1.34%	138,081	444,026	231,919	328,878	16,645	4,045	76.69	25,241,502	60,470
2016	1.12%	139,423	469,047	289,835	350,199	15,579	4,005	75.74	31,151,578	77,015
2017	0.99%	139,963	485,822	327,252	378,591	17,750	3,950	74.89	33,008,118	83,147
2018	0.82%	140,619	480,255	348,074	411,079	22,029	4,042	76.64	33,008,118	82,156
2019	0.80%	141,024	488,309	358,700	436,627	22,595	4,139	78.50	33,008,118	83,122
2020	0.77%	141,688	494,882	369,037	450,233	25,279	4,190	79.23	33,008,118	85,431
2021	0.67%	141,681	487,732	379,065	461,283	28,558	4,227	80.15	33,008,118	87,524
2022	0.60%	141,891	488,427	390,583	474,807	34,484	4,318	81.88	33,008,118	90,207
2023	0.61%	142,041	500,473	400,506	493,155	37,697	4,321	81.94	33,008,118	90,178
2024	0.54%	142,587	500,740	412,939	516,714	43,078	4,368	82.61	33,008,118	92,250
2025	1.71%	142,541	503,535	223,515	532,031	45,245	4,407	83.56	33,008,118	92,501
2026	1.72%	142,637	511,560	229,468	548,567	47,987	4,422	83.85	33,008,118	94,646
2027	1.68%	142,910	500,463	224,297	563,177	49,593	4,413	83.68	33,008,118	99,834
2028	1.62%	143,521	504,563	236,644	594,765	49,569	4,425	83.67	33,008,118	102,317
2029	1.61%	143,477	520,020	254,865	641,188	51,777	4,453	84.43	33,008,118	104,644
2030	1.40%	143,759	517,254	286,010	724,245	55,488	4,535	86.00	33,008,118	111,736
2031	1.31%	144,004	521,405	304,336	764,462	56,598	4,535	86.00	33,008,118	117,714
2032	1.35%	144,250	541,078	317,813	796,813	57,730	4,535	85.76	33,008,118	120,751
2033	1.20%	144,495	531,477	331,395	830,646	58,884	4,535	86.00	33,008,118	122,618
2034	1.21%	144,742	546,084	345,637	866,034	60,062	4,535	86.00	33,008,118	125,371
2035	1.15%	144,988	552,492	360,708	903,052	61,263	4,535	86.00	33,008,118	128,013
2036	1.08%	145,235	558,929	378,455	941,778	62,488	4,535	85.76	33,008,118	129,717
2037	0.95%	145,483	553,565	394,865	982,299	63,738	4,535	86.00	33,008,118	131,567
2038	0.96%	145,731	572,949	411,550	1,024,700	65,013	4,535	86.00	33,008,118	134,952
2039	0.83%	145,979	566,777	427,969	1,069,074	66,313	4,535	86.00	33,008,118	139,463
2040	0.68%	146,228	562,760	448,657	1,115,519	67,639	4,535	85.76	33,008,118	141,741
2041	0.69%	146,477	581,806	465,717	1,164,137	68,992	4,535	86.00	33,008,118	146,320
2042	0.50%	146,726	569,824	485,985	1,215,034	70,372	4,535	86.00	33,008,118	149,812
2043	0.39%	146,976	574,655	508,839	1,268,325	71,780	4,535	86.00	33,008,118	151,751
2044	0.39%	147,227	598,108	532,378	1,324,127	73,215	4,535	85.76	33,008,118	155,391

	Tab: Gas	Tab: Gas	Tab: Gas	Tab: VOM	Tab: Emissions	Tab: Emissions	Col J (Converted to Tonnes) * 63%	Tab: Tax Credit	-1 * (Col S * Col R - Col Q - Col P)	(Col D + Col K + Col O + Col T - Col N) / Col H	Tab: 92% CF
Year	**SNG Production**	**Gas Use for Power Generation**	**Gas Sales**	**VOM**	**Power Gen. CO2 Emission Cost**	**Power Gen. Other Emission Cost**	**Captured CO2**	**CO2 Credit**	**Net Emissions Cost**	**Cost of Power**	**Cost of Power at 92% Capacity Factor**
Name	*MMBTU*	*MMBTU*	*$000*	*$000*	*$000*	*$000*	*tonnes*	*$/tonne*	*$000*	*$/MWh*	*$/MWh*
2015	14,758,848	28,198,290	(123,123)	12,383	45,184	415	1,478,699	87	(82,372)	137.87	133.16
2016	18,214,502	27,944,640	(96,270)	12,501	50,741	437	1,824,923	88	(109,842)	136.08	126.96
2017	19,300,032	27,581,410	(90,752)	12,576	56,193	466	1,933,683	90	(117,385)	140.50	130.08
2018	19,300,032	28,178,570	(101,157)	13,133	65,693	515	1,933,683	92	(111,412)	139.87	131.29
2019	19,300,032	28,814,160	(108,395)	13,721	75,906	550	1,933,683	94	(104,717)	142.25	134.54
2020	19,300,032	29,146,140	(108,946)	14,166	82,149	580	1,933,683	96	(102,067)	143.53	135.98
2021	19,300,032	29,381,160	(110,120)	14,576	86,438	610	1,933,683	97	(101,443)	141.60	134.73
2022	19,300,032	29,974,690	(110,899)	15,188	94,026	650	1,933,683	99	(97,586)	140.61	134.51
2023	19,300,032	29,996,100	(122,025)	15,504	98,068	679	1,933,683	101	(97,360)	145.98	140.18
2024	19,300,032	30,304,440	(132,583)	15,986	105,348	716	1,933,683	103	(93,966)	148.25	143.18
2025	19,300,032	30,551,700	(133,508)	16,449	110,549	754	1,933,683	-	111,303	194.55	185.75
2026	19,300,032	30,651,240	(137,173)	16,836	117,642	789	1,933,683	-	118,431	198.71	190.08
2027	19,300,032	30,593,930	(143,975)	17,138	126,702	822	1,933,683	-	127,525	201.44	192.96
2028	19,300,032	30,673,030	(150,372)	17,527	136,633	841	1,933,683	-	137,474	206.17	197.76
2029	19,300,032	30,851,690	(159,932)	17,991	154,669	863	1,933,683	-	155,532	215.18	207.37
2030	19,300,032	31,387,490	(174,310)	18,690	188,092	895	1,933,683	-	188,987	222.93	216.75
2031	19,300,032	31,387,490	(180,463)	19,064	198,568	913	1,933,683	-	199,482	228.91	222.71
2032	19,300,032	31,387,490	(185,973)	19,445	209,629	932	1,933,683	-	210,560	237.66	231.11
2033	19,300,032	31,387,490	(193,429)	19,834	221,305	950	1,933,683	-	222,255	240.27	234.10
2034	19,300,032	31,387,490	(200,257)	20,231	233,631	969	1,933,683	-	234,601	248.41	242.14
2035	19,300,032	31,387,490	(207,326)	20,636	246,645	989	1,933,683	-	247,633	254.93	248.66
2036	19,300,032	31,387,490	(213,656)	21,048	260,383	1,008	1,933,683	-	261,391	261.24	254.86
2037	19,300,032	31,387,490	(222,221)	21,469	274,886	1,029	1,933,683	-	275,915	265.65	259.60
2038	19,300,032	31,387,490	(230,066)	21,899	290,197	1,049	1,933,683	-	291,246	275.88	269.66
2039	19,300,032	31,387,490	(238,187)	22,337	306,361	1,070	1,933,683	-	307,431	280.97	274.92
2040	19,300,032	31,387,490	(245,460)	22,783	323,426	1,091	1,933,683	-	324,517	286.05	280.07
2041	19,300,032	31,387,490	(255,300)	23,239	341,440	1,113	1,933,683	-	342,554	297.51	291.48
2042	19,300,032	31,387,490	(264,312)	23,704	360,459	1,136	1,933,683	-	361,594	301.93	296.18
2043	19,300,032	31,387,490	(273,642)	24,178	380,536	1,158	1,933,683	-	381,695	310.01	304.35
2044	19,300,032	31,387,490	(281,997)	24,661	401,732	1,181	1,933,683	-	402,914	322.62	316.65

Gas/Coal

Please Select a Case or Use The Manual Overrides Below

Load Assumptions	Cost Recovery	Coal Price	Natural Gas Price	Natural Gas Use	Inflation Rate		
Gas/Coal Load	Gas/Coal Captial Reco	Ref. Coal	Gas/Coal NG	Gas/Coal NG	Market Based	☐ Check for Real Values	☐ Include Projected Market Cost Savings
% Customer Class	**CO2 Bonus**	**Capacity Revenues**	**Energy Revenues**	**Emissions Cost**	**VOM Cost**		
Ref. Customer Cat.	Ref. Tax Credit	Ref. Capacity	Gas/Coal Energy	Gas/Coal Emissions	Gas/Coal VOM	☑ Use Capital Cost Deferral	

114.92	2009 Start Rate $/MWh	114.92	Start Rate

Total Rate Impact of Taylorville

	Tab: Cap Rec Req and Deferral	Tab: Load	Tab: Cap Rev Req and Deferral	Col F + Col G + Col N - Col K - Col O - Col T	Tab: Energy	Tab: Capacity	Tab: Energy	(Col H * 1000) / (602 MW * Hours in a Year)	Tab: Coal	Col J * Coal Price	Tab: Gas	Tab: Gas	Tab: Gas	Tab: VOM	Tab: Emissions	Tab: Emissions	Col J (Converted to Tonnes) * 63%	Tab: Tax Credit	-1 * (Col S * Col R - Col Q - Col P)	(Col D + Col K + Col O + Col T - Col N) / Col H	Tab: 92% CF
Year	**% Impact**	**IL Load**	**Capital Recovery Requirement**	**Gross Margins**	**Energy Revenue**	**Capacity Revenue**	**Generation**	**Capacity Factor**	**Coal Use**	**Coal Cost**	**SNG Production**	**Gas Use for Power Generation**	**Gas Sales**	**VOM**	**Power Gen. CO2 Emission Cost**	**Power Gen. Other Emission Cost**	**Captured CO2**	**CO2 Credit**	**Net Emissions Cost**	**Cost of Power**	**Cost of Power at 92% Capacity Factor**
Name	*Percent*	*GWh*	*$000*	*$000*	*$000*	*$000*	*GWh*	*Percent*	*MMBTU*	*$000*	*MMBTU*	*MMBTU*	*$000*	*$000*	*$000*	*$000*	*tonnes*	*$/tonne*	*$000*	*$/MWh*	*$/MWh*
2015	2.51%	133,368	436,188	51,003	240,183	16,645	4,192	79.49	25,241,502	60,470	14,758,848	29,154,780	(138,550)	12,834	9,538	429	1,478,699	11	(6,029)	153.16	147.70
2016	2.41%	135,446	459,657	83,930	274,055	15,579	4,237	80.12	31,151,578	77,015	18,214,502	29,450,430	(123,345)	13,225	11,787	460	1,824,923	11	(7,880)	157.05	147.66
2017	2.32%	136,914	475,153	110,724	304,061	17,750	4,238	80.36	33,008,118	83,147	19,300,032	29,451,960	(119,671)	13,494	16,033	498	1,933,683	11	(5,225)	161.94	151.42
2018	2.14%	137,835	469,060	130,069	329,612	22,029	4,245	80.50	33,008,118	82,156	19,300,032	29,497,620	(128,847)	13,794	18,436	539	1,933,683	11	(3,227)	162.70	152.96
2019	2.11%	138,587	476,546	141,233	347,146	22,595	4,257	80.73	33,008,118	83,122	19,300,032	29,577,290	(132,406)	14,111	20,951	564	1,933,683	12	(1,131)	165.62	155.99
2020	2.04%	139,343	484,026	157,011	374,246	25,279	4,265	80.66	33,008,118	85,431	19,300,032	29,636,460	(141,618)	14,421	23,554	590	1,933,683	12	1,045	170.33	160.85
2021	1.95%	140,103	477,119	163,156	390,485	28,558	4,253	80.64	33,008,118	87,524	19,300,032	29,550,400	(150,512)	14,665	26,133	614	1,933,683	12	3,186	172.36	163.43
2022	1.84%	140,867	479,698	181,047	419,566	34,484	4,252	80.63	33,008,118	90,207	19,300,032	29,546,300	(160,138)	14,957	31,094	641	1,933,683	12	7,702	177.02	168.40
2023	1.85%	141,636	491,313	189,636	432,484	37,697	4,211	79.85	33,008,118	90,178	19,300,032	29,277,830	(165,437)	15,108	33,673	663	1,933,683	13	9,822	183.30	174.29
2024	1.73%	142,409	491,391	208,276	465,712	43,078	4,274	80.82	33,008,118	92,250	19,300,032	29,688,440	(182,100)	15,640	34,828	702	1,933,683	13	10,526	185.30	177.49
2025	1.75%	143,186	496,297	208,601	508,794	45,245	4,273	81.02	33,008,118	92,501	19,300,032	29,678,390	(193,641)	15,949	42,615	732	1,933,683	-	43,347	197.01	188.98
2026	1.72%	143,968	505,438	220,971	536,496	47,987	4,263	80.84	33,008,118	94,646	19,300,032	29,618,500	(203,672)	16,232	48,199	763	1,933,683	-	48,962	203.82	195.86
2027	1.60%	144,754	495,363	229,259	566,614	49,593	4,267	80.91	33,008,118	99,834	19,300,032	29,640,610	(215,627)	16,570	54,120	797	1,933,683	-	54,917	206.79	199.54
2028	1.52%	145,545	499,655	245,542	603,075	49,569	4,269	80.73	33,008,118	102,317	19,300,032	29,659,400	(226,803)	16,911	60,259	813	1,933,683	-	61,072	212.40	205.45
2029	1.44%	146,340	515,253	273,819	649,658	51,777	4,273	81.03	33,008,118	104,644	19,300,032	29,682,090	(240,801)	17,266	64,074	830	1,933,683	-	64,904	220.64	213.92
2030	1.24%	147,140	509,680	300,388	699,345	55,488	4,274	81.05	33,008,118	111,736	19,300,032	29,687,520	(253,651)	17,614	70,597	847	1,933,683	-	71,444	225.58	219.40
2031	1.22%	147,943	515,137	307,646	724,581	56,598	4,274	81.05	33,008,118	117,714	19,300,032	29,687,520	(263,899)	17,967	73,089	864	1,933,683	-	73,953	231.32	225.30
2032	1.26%	148,751	534,489	318,828	749,814	57,730	4,274	80.82	33,008,118	120,751	19,300,032	29,687,520	(273,088)	18,326	75,669	881	1,933,683	-	76,550	239.40	233.28
2033	1.16%	149,564	528,505	328,648	775,965	58,884	4,274	81.05	33,008,118	122,618	19,300,032	29,687,520	(285,652)	18,693	78,340	899	1,933,683	-	79,239	242.10	236.58
2034	1.19%	150,381	544,463	339,480	803,070	60,062	4,274	81.05	33,008,118	125,371	19,300,032	29,687,520	(297,193)	19,066	81,106	917	1,933,683	-	82,023	249.91	244.41
2035	1.16%	151,202	552,609	350,863	831,163	61,263	4,274	81.05	33,008,118	128,013	19,300,032	29,687,520	(309,199)	19,448	83,969	935	1,933,683	-	84,904	256.01	250.77
2036	1.11%	152,028	559,869	365,364	860,282	62,488	4,274	80.82	33,008,118	129,717	19,300,032	29,687,520	(319,966)	19,837	86,933	954	1,933,683	-	87,887	261.41	256.56
2037	1.04%	152,858	559,270	376,741	890,465	63,738	4,274	81.05	33,008,118	131,567	19,300,032	29,687,520	(334,687)	20,233	90,001	973	1,933,683	-	90,974	265.97	261.62
2038	1.09%	153,693	581,604	388,795	921,752	65,013	4,274	81.05	33,008,118	134,952	19,300,032	29,687,520	(348,209)	20,638	93,179	992	1,933,683	-	94,171	275.99	271.56
2039	1.03%	154,533	583,211	400,227	954,184	66,313	4,274	81.05	33,008,118	139,463	19,300,032	29,687,520	(362,276)	21,051	96,468	1,012	1,933,683	-	97,480	281.58	277.64
2040	0.92%	155,377	580,588	416,435	987,805	67,639	4,274	80.82	33,008,118	141,741	19,300,032	29,687,520	(374,891)	21,472	99,873	1,033	1,933,683	-	100,906	285.35	282.20
2041	0.98%	156,225	602,278	426,840	1,022,660	68,992	4,274	81.05	33,008,118	146,320	19,300,032	29,687,520	(392,139)	21,901	103,399	1,053	1,933,683	-	104,452	296.47	293.18
2042	0.88%	157,078	599,542	440,911	1,058,794	70,372	4,274	81.05	33,008,118	149,812	19,300,032	29,687,520	(407,982)	22,339	107,048	1,074	1,933,683	-	108,123	301.31	298.74
2043	0.84%	157,936	610,324	457,111	1,096,256	71,780	4,274	81.05	33,008,118	151,751	19,300,032	29,687,520	(424,464)	22,786	110,827	1,096	1,933,683	-	111,923	309.14	306.97
2044	0.90%	158,799	638,851	474,575	1,135,096	73,215	4,274	80.82	33,008,118	155,391	19,300,032	29,687,520	(439,245)	23,242	114,740	1,118	1,933,683	-	115,857	321.15	319.06

RPS/DSM

Please Select a Case or Use The Manual Overrides Below

Load Assumptions	Cost Recovery	Coal Price	Natural Gas Price	Natural Gas Use	Inflation Rate		
RPS/DSM Load	RPS/DSM Captial Recc	Ref. Coal	RPS/DSM NG	RPS/DSM NG	Market Based	☐ Check for Real Values	☐ Include Projected Market Cost Savings
% Customer Class	**CO2 Bonus**	**Capacity Revenues**	**Energy Revenues**	**Emissions Cost**	**VOM Cost**		
Ref. Customer Cat.	No Tax Credit	Low Capacity	RPS/DSM Energy	RPS/DSM Emissions	RPS/DSM VOM	☑ Use Capital Cost Deferral	

114.92	2009 Start Rate $/MWh	114.92	Start Rate

Total Rate Impact of Taylorville

Year	% Impact	IL Load	Capital Recovery Requirement	Gross Margins	Energy Revenue	Capacity Revenue	Generation	Capacity Factor	Coal Use	Coal Cost
	Tab: Cap Rec Req and Deferral	Tab: Load	Tab: Cap Rev Req and Deferral	Col F + Col G + Col N - Col K - Col O - Col T	Tab: Energy	Tab: Capacity	Tab: Energy	(Col H * 1000) / (602 MW * Hours in a Year)	Tab: Coal	Col J * Coal Price
Name	Percent	GWh	$000	$000	$000	$000	GWh	Percent	MMBTU	$000
2015	2.33%	137,448	435,135	67,531	270,967	8,077	3,957	75.04	25,241,502	60,470
2016	2.41%	137,199	457,202	77,647	272,470	8,987	4,000	75.64	31,151,578	77,015
2017	2.48%	136,662	470,943	81,401	265,022	9,563	3,854	73.08	33,008,118	83,147
2018	2.43%	135,963	463,950	83,973	277,253	10,195	3,963	75.15	33,008,118	82,156
2019	2.47%	135,533	472,101	87,807	299,895	10,873	4,171	79.10	33,008,118	83,122
2020	2.49%	135,100	478,930	91,767	303,082	11,176	4,030	76.22	33,008,118	85,431
2021	2.45%	134,666	471,962	93,234	321,695	11,128	4,165	78.97	33,008,118	87,524
2022	2.45%	134,320	472,408	93,920	330,590	11,418	4,177	79.20	33,008,118	90,207
2023	2.55%	133,975	482,974	91,017	314,183	11,937	3,919	74.32	33,008,118	90,178
2024	2.50%	133,631	482,186	98,477	346,033	12,664	4,166	78.78	33,008,118	92,250
2025	2.45%	133,190	485,535	110,867	371,694	14,014	4,261	80.80	33,008,118	92,501
2026	2.45%	132,849	494,540	121,134	397,081	15,027	4,298	81.50	33,008,118	94,646
2027	2.54%	132,405	480,242	93,874	366,268	15,894	4,092	77.59	33,008,118	99,834
2028	2.52%	132,094	483,950	101,966	395,406	16,714	4,150	78.48	33,008,118	102,317
2029	2.53%	131,785	496,960	114,089	423,477	16,713	4,218	79.98	33,008,118	104,644
2030	2.46%	131,504	487,924	115,666	439,542	16,788	4,147	78.63	33,008,118	111,736
2031	2.61%	131,170	489,925	96,131	433,463	17,123	4,147	78.63	33,008,118	117,714
2032	2.73%	130,836	509,133	99,251	446,886	17,466	4,147	78.42	33,008,118	120,751
2033	2.61%	130,503	494,457	102,699	460,794	17,815	4,147	78.63	33,008,118	122,618
2034	2.65%	130,171	502,749	105,953	475,206	18,171	4,147	78.63	33,008,118	125,371
2035	2.65%	129,840	504,744	109,505	490,142	18,535	4,147	78.63	33,008,118	128,013
2036	2.65%	129,509	508,787	114,741	505,625	18,906	4,147	78.42	33,008,118	129,717
2037	2.58%	129,180	502,407	118,932	521,675	19,284	4,147	78.63	33,008,118	131,567
2038	2.70%	128,851	521,959	122,348	538,317	19,669	4,147	78.63	33,008,118	134,952
2039	2.65%	128,523	516,250	124,856	555,574	20,063	4,147	78.63	33,008,118	139,463
2040	2.58%	128,196	510,090	130,418	573,471	20,464	4,147	78.42	33,008,118	141,741
2041	2.68%	127,870	526,796	132,722	592,036	20,873	4,147	78.63	33,008,118	146,320
2042	2.58%	127,545	515,027	136,952	611,294	21,291	4,147	78.63	33,008,118	149,812
2043	2.58%	127,220	519,875	142,985	631,275	21,717	4,147	78.63	33,008,118	151,751
2044	2.67%	126,896	537,700	148,224	652,008	22,151	4,147	78.42	33,008,118	155,391

Year	SNG Production	Gas Use for Power Generation	Gas Sales	VOM	Power Gen. CO2 Emission Cost	Power Gen. Other Emission Cost	Captured CO2	CO2 Credit	Net Emissions Cost	Cost of Power	Cost of Power at 92% Capacity Factor
	Tab: Gas	Tab: Gas	Tab: Gas	Tab: VOM	Tab: Emissions	Tab: Emissions	Col J (Converted to Tonnes) * 63%	Tab: Tax Credit	-1 * (Col S * Col R - Col Q - Col P)	(Col D + Col K + Col O + Col T - Col N) / Col H	Tab: 92% CF
Name	MMBTU	MMBTU	$000	$000	$000	$000	tonnes	$/tonne	$000	$/MWh	$/MWh
2015	14,758,848	27,631,660	(105,724)	12,116	32,796	407	1,478,699	-	33,203	163.41	151.28
2016	18,214,502	27,913,390	(78,401)	12,486	35,472	436	1,824,923	-	35,908	165.25	148.23
2017	19,300,032	26,963,740	(60,685)	12,272	36,623	456	1,933,683	-	37,079	172.32	149.52
2018	19,300,032	27,671,850	(67,828)	12,879	40,106	506	1,933,683	-	40,612	168.41	149.05
2019	19,300,032	29,024,440	(80,701)	13,827	44,758	554	1,933,683	-	45,311	166.62	152.11
2020	19,300,032	28,112,760	(76,806)	13,627	46,067	560	1,933,683	-	46,627	174.03	155.81
2021	19,300,032	28,981,540	(86,716)	14,362	50,384	602	1,933,683	-	50,987	170.85	156.40
2022	19,300,032	29,058,540	(89,065)	14,691	53,495	630	1,933,683	-	54,125	172.51	158.35
2023	19,300,032	27,384,460	(75,001)	14,062	55,242	620	1,933,683	-	55,863	183.22	162.36
2024	19,300,032	28,991,250	(88,282)	15,245	63,757	685	1,933,683	-	64,442	178.22	163.17
2025	19,300,032	29,606,660	(92,867)	15,906	72,837	730	1,933,683	-	73,567	178.44	165.66
2026	19,300,032	29,845,930	(93,277)	16,364	85,919	768	1,933,683	-	86,688	182.77	170.43
2027	19,300,032	28,509,290	(79,494)	15,892	92,302	767	1,933,683	-	93,068	187.81	170.58
2028	19,300,032	28,888,490	(84,104)	16,439	106,503	792	1,933,683	-	107,295	191.35	175.20
2029	19,300,032	29,327,600	(86,423)	17,042	117,172	820	1,933,683	-	117,993	195.15	180.35
2030	19,300,032	28,863,260	(84,164)	17,090	126,851	824	1,933,683	-	127,675	199.82	183.29
2031	19,300,032	28,863,260	(85,847)	17,432	132,623	840	1,933,683	-	133,463	203.62	186.92
2032	19,300,032	28,863,260	(87,055)	17,781	138,657	857	1,933,683	-	139,514	210.82	193.23
2033	19,300,032	28,863,260	(89,315)	18,136	144,966	874	1,933,683	-	145,840	209.89	193.05
2034	19,300,032	28,863,260	(91,101)	18,499	151,562	891	1,933,683	-	152,453	214.67	197.54
2035	19,300,032	28,863,260	(92,923)	18,869	158,458	909	1,933,683	-	159,367	217.98	200.80
2036	19,300,032	28,863,260	(94,231)	19,246	165,668	927	1,933,683	-	166,595	221.52	204.03
2037	19,300,032	28,863,260	(96,677)	19,631	173,206	946	1,933,683	-	174,152	222.93	205.91
2038	19,300,032	28,863,260	(98,611)	20,024	181,087	965	1,933,683	-	182,052	230.93	213.22
2039	19,300,032	28,863,260	(100,583)	20,424	189,326	984	1,933,683	-	190,310	233.20	215.64
2040	19,300,032	28,863,260	(101,999)	20,833	197,940	1,004	1,933,683	-	198,944	234.79	217.26
2041	19,300,032	28,863,260	(104,647)	21,249	206,947	1,024	1,933,683	-	207,971	242.84	224.90
2042	19,300,032	28,863,260	(106,740)	21,674	216,363	1,044	1,933,683	-	217,407	243.72	226.18
2043	19,300,032	28,863,260	(108,875)	22,108	226,207	1,065	1,933,683	-	227,273	248.36	230.70
2044	19,300,032	28,863,260	(110,407)	22,550	236,500	1,087	1,933,683	-	237,586	256.50	237.99