Exhibit CAC# 45-3

CAC Manitoba: Book of Documents
NFAT Review

Tab	Document
1	Manitoba Hydro, Submission to the Manitoba Clean Environment Commission: NFAT – The Wuskwatim Project, (April 2003) Chapter 5 p. 35-47
2	Manitoba Hydro, NFAT Filing *Chapter 9: Economic Evaluations* p. 17 *Chapter 10: Economic Uncertainty Analysis* p. 24 *Chapter 12:Economic Evaluations - 2013 Update On Selected Development Plans* p. 7 *Appendix 11.4*
3	Manitoba Hydro, *NFAT Filing: Appendix 3.1 Long-Term Price Forecast for Manitoba Hydro's Export Market in MISO - The Brattle Group* slide 10
4	Manitoba Hydro, *NFAT: Rebuttal Evidence of Manitoba Hydro* (February 28, 2014) p. 125, 126
5	Concentric Energy Advisors Inc., *Authorized Return on Equity for Canadian Gas and Electric Distributors and Select Comparitors,* Volume 1, Octover 1, 2013
6	Public Utilities Board, NFAT, Response to Information Request MIPUG/MH I-031
7	Ron Binz, et al. *Practicing Risk-Aware Electricity Regulation: What Every State Regulator Needs to Know*, Ceres (April 2012) p. 5, 14
8	Consumers Association of Canada (Manitoba), *Review of Manitoba Hydro's Preferred Development Plan,* (February 4, 2014) p.8
9	Dean Murphy, *Guest Commentary – US Should Price Carbon Directly*, Carbon Market North America (June 6, 2007) p. 6, 7
10	Marc Chupka, Dean Murphy, Samuel Newell, *Reviving Integrated Resource Planning for Electric Utilities: New Challenges and Innovative Approaches*, Issue 1, 2008

11	The Brattle Group, *Integrated Resource Plan – Connecticut*, January 1, 2010 p. I-9, I-10, I-11, II-18, II-19, II-31, II-36, 1-19, 7-1, 7-2 to 7-10, 9-2 to 9-6, 9-26, 10-1, 10-2, 10-11, 10-12
12	The Brattle Group, *Overview of Integrated Resource Plan for Connecticut*, January 8, 2010 slide 1, 6, 51, 64, 65, 67, 68, 83, 84, 92, 93
13	Gregory Hamm and Adam Borison, *The Rush to Coal: Is the Analysis Complete* (2008) The Electricity Journal, Volume 21, Issue 1, p. 31-37
14	Minnesota Power, *Application For A Certificate of Need*, October 21, 2013 p. 1, 7, 16, 27, 28, 29,60, 61, 66, 67, 68, 69, 75, 111, 112

TAB 1

5.7 Market Prices for Export

As indicated above, Manitoba Hydro will be able to market all surplus generation from the proposed Wuskwatim G.S. The more important factor in evaluating the feasibility of the Wuskwatim Project is the price of this export. Each year Manitoba Hydro produces a forecast of export prices for the next 30 years using updated information and projections of fundamental drivers of market prices. Following is a description of the current approach used to forecast the prices of export power including factors related to the consideration of environmental impacts of emissions and other pollutants.

In past years, Manitoba Hydro has developed an export price forecast annually based on the traditional approach of relating market prices to cost of generation that can be expected to be on the margin for the purchaser. These past forecasts assumed the wholesale market in the MAPP region would continue to function as it has in the past and power prices would continue to be directly related to the marginal cost of supply.

It is now believed, by many, that the changes in the electric industry in moving toward deregulation will result in a competitive market that is different than that of the past. In order to obtain better insight related to future power prices, Manitoba Hydro retained the services of a consultant (DRI-WEFA, now Global Insight) and also purchased "off the shelf" forecasts from three other consultants – Henwood Energy Services, LCG Consulting, and ICF Consulting. The consultants addressed the issue of how market prices in MAPP may be affected by a fully competitive market and how quickly (if ever) such a market will be realized in MAPP. The consultants also addressed to varying degrees the impact of environmental considerations on the future electricity industry.

Manitoba Hydro used the information from the consultant reports as well as other industry information to conclude that future electricity prices will be influenced by consideration of environmental impacts caused by the emissions of pollutants. However, there is great uncertainty over the degree and timing of regulation and legislation related to emission limits, especially carbon regulation. In order to address the uncertainty, a set of reasonable scenarios that cover the range of possibilities has been developed. It is recognized that the environmental considerations will likely be implicitly reflected in the market price of electricity. However, for the purpose of analysis, Manitoba Hydro and its consultants first developed a reference scenario that represents "business as usual" in the area of environmental consideration of emissions and pollutants. The premiums associated with environmental considerations are assumed to be incremental to the reference scenario.

5.7.1 Market Price Forecast – Reference Price

The reference scenario assumes business as usual for environmental considerations but includes consideration of an evolving market structure for the electricity industry along with other related factors such as assumptions on load growth and escalation of fuel prices. A reference price forecast corresponding to the reference scenario was obtained from each of the four consultants for a period of up to 30 years. A description of views on future export market price for each consultant follows:

<u>DRI-WEFA (Global Insight) Forecast</u>

DRI-WEFA's view of MAPP is that it will change towards a Regional Transmission Organization ("RTO") or an Independent System Operator ("ISO") organization with significant incentives for power trading, adding transmission, and evolving into a power market with standardized products. Wholesale prices for on-peak power will be set in a fully competitive electric power market, and a financially firm product will be traded. DRI-WEFA believe that the financially firm market for firm power will largely replace the current situation of bilateral trades of long-term power that currently occur through the use of Request For Proposals and direct negotiation. This new market will consist of a day-ahead market clearing price and there would be sufficient liquidity to supply all demands. In a mature market, a new entrant with generation would have to compete with participants in the on-peak, financially firm market. DRI-WEFA is

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of the view that the differential between on-peak and off-peak power prices will continue to exist into the long term as a result of technical and equipment limitations.

DRI-WEFA provided a forecast for the MAPP area to the year 2020 indicating an increase in market prices at a rate greater than inflation due to an assumption of a continuing move to cost competition in contrast to traditional cost-based regulation. This forecast is based on the assumption that, although some of the uneconomic coal generation will be retired, over 4000 MW of new coal generation and 1200 MW of combined cycle gas generation will be added in the MAPP area by 2020. The DRI-WEFA analysis concludes that Manitoba Hydro is well positioned with its hydropower because this provides a purchaser assurance of a long-term, secure supply of power. Several additional factors that are expected to enhance Manitoba Hydro's export price are that hydropower adds system operating flexibility to the purchaser, adds flexibility in meeting emissions limits, and provides a unique product in the MAPP market. Therefore, its forecast includes an additional factor to increase the value that Manitoba Hydro can attain from the export market.

Henwood Energy Services Forecast

The Henwood Energy Services 'off the shelf' forecast assumes a change in the MAPP market structure in the long term. Henwood assumes that a RTO will emerge and follow FERC's standardized transmission service and wholesale electric market design. This market will have locational marginal pricing, a day-ahead and real time market, marginal pricing based congestion management with offsetting financial rights, and an installed capacity ("ICAP") market.

The Henwood price forecast for the period to 2027 is low in the early years to 2006 due to an assumed oversupply of generation. This forecast has rapidly rising prices in the mid-term (2007-2012) as markets move to equilibrium and all-in pricing. Prices in this period rise due to load growth, declining reserve margins, and the shift from coal to gas as the marginal fuel. After this period the long-term Henwood price forecast for 5x16 power generally stabilizes and follows the real increase in natural gas prices. Pricing volatility is expected to be high as this is an inherent feature of fully competitive markets. Henwood acknowledges that power markets will have some additional costs due to volatility that is not captured in their analysis.

LCG Consulting Inc. Forecast

LCG Consulting provided an 'off the shelf' forecast for the period to 2022. LCG assumes that the Midwest ISO (MISO) system (this includes MAPP) will follow FERC's standardized transmission service and wholesale electricity market design and that this market will have locational marginal pricing, a day-ahead and real time market and marginal pricing based congestion management. LCG's model computes an "all-in-one" price comprising a market clearing price for energy and a separate capacity price. The capacity price is calculated as the amount of additional revenue required to keep generation available to meet demand plus a capacity reserve requirement in the MAPP region.

Pricing in the early years is low because of an overbuild of merchant plants in the MAPP region, but rises rapidly in the mid-term to 2015 as the supply/demand balance shifts from an overbuild to an underbuild and as natural gas prices increase. After this period, the long-term LCG price forecast for 5x16 power generally stabilizes in real terms with some bias to the up side. LCG Consulting forecasts that new merchant plant entries will be dominated by natural gas-fired generation, especially in the environmental case where the worst performing coal-fired units were replaced by the natural gas-fired capacity and that this will set the marginal price in the Midwest region. The market volatility was addressed to a certain extent by modeling arbitrage between energy and capacity markets. This

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arbitrage occurs because capacity price is the unrecovered cost remaining after energy is sold from a generating unit.

ICF Consulting Inc. Forecast

ICF Consulting provided an 'off the shelf' forecast for the period 2003 to 2030. ICF assumes that the market will reflect competitive conditions and further assumes that MAPP will participate as a member of a broader Regional Transmission Organization. ICF's model computes a market clearing price for energy and a separate capacity price. The market clearing price for energy is the equivalent of the short-run operating costs of the marginal unit to supply the next increment of energy to the grid. The capacity price is driven by the need for reliable energy supply and reflects price spikes above marginal energy costs.

ICF's forecasts rising electricity prices over the forecast period. This price increase is based strongly on the fact that the predominance of new entrants providing generation will be base-loaded combined-cycle natural gas-fired generation that frequently set the marginal price in the Midwest region. An additional factor for the forecast of increasing electricity prices is rising natural gas price. Near the end of the forecast period, real energy prices will gradually fall due to the dominant effect of higher efficiencies at new facilities which are brought online to supplement the increased generation requirements.

All four forecasts as well as other sources have been used in developing a Manitoba Hydro forecast of export prices for a reference case by combining the available information. The Manitoba Hydro forecast consists of an annual price for firm 5x16 export power for each year to 2037. It also includes a set of monthly prices for on-peak and off-peak opportunity export sales. The monthly pattern for prices is developed from current experience in the market. The current forecast assumes a degree of convergence by 2012 between on-peak opportunity prices and long-term firm 5x16 prices.

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5.7.2. Environmental Scenarios and the Reference Scenario

The reference scenario assumes business as usual for environmental considerations but includes consideration of an evolving market structure for the electricity industry along with other related factors such as assumptions on load growth and escalation of fuel prices. Because of the uncertainty related to environmental considerations, three environmental scenarios were selected to be representative of a range of potential developments in the area of regulation and legislation of emissions and pollutants. An environmental price premium that is incremental to the reference price corresponding to the reference scenario is developed for each of the three environmental scenarios.

1) NEEP-3P - No Environmental Export Premium – Reference Scenario
   - No significant additional consideration of 3P (three pollutants – nitrous oxides (NO_X), sulphur dioxide (SO_2), and mercury (Hg)) beyond current restrictions and legislated requirements.
   - No consideration of CO_2 in addition to 3P

The following three scenarios include 4P (4 pollutant) considerations consisting of 3P regulation as in Clear Skies Act of 2002 proposed by the current U.S. Administration plus various intensities of carbon price trajectories. These trajectories of CO_2 allowance prices are shown in **Figure 5.8** and are described as follows:

2) LEEP-4P – Low Environmental Export Premium Scenario
   - 3P plus low carbon price trajectory stabilizing at U.S. $ 10 per ton CO_2 in 2020
   - consistent with a lenient carbon target with great degree of flexibility in achieving reductions

3) MEEP-4P – Medium Environmental Export Premium Scenario
   - 3P plus medium carbon price trajectory stabilizing at $20 per ton CO_2 in 2020

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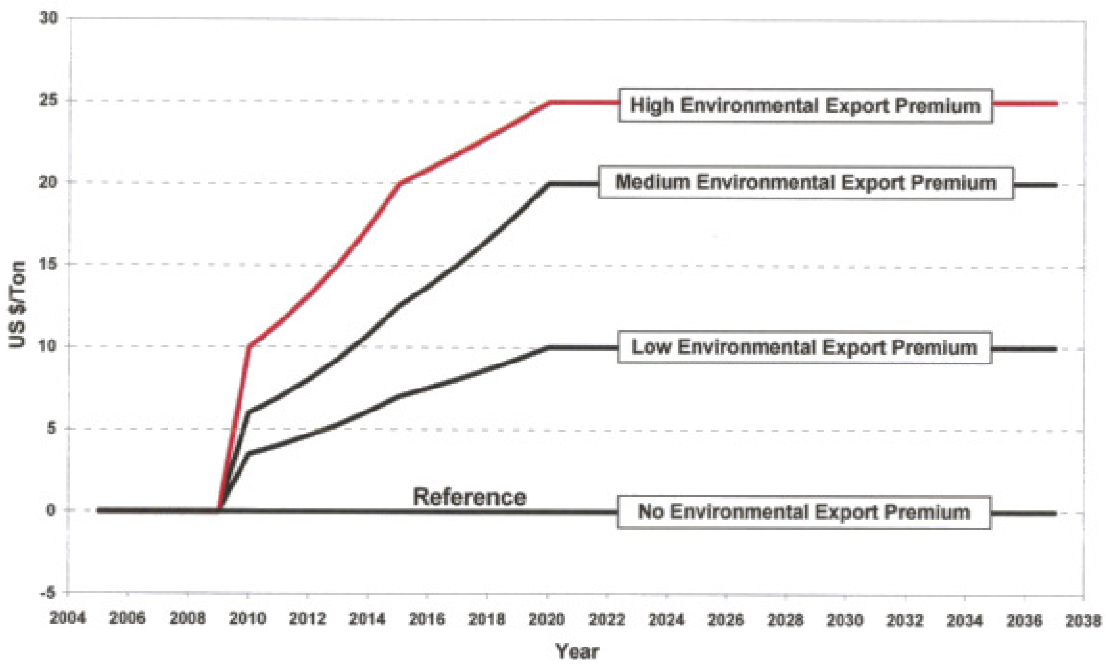
- consistent with a reasonably moderate carbon target such as return to 2000 levels with a slightly lower degree of flexibility then LEEP

4) HEEP-4P – High Environmental Export Premium Scenario

- 3P plus high carbon price trajectory reaching \$25 per ton CO_2 by 2020
- consistent with a reasonably stringent carbon target such as return to 1990 levels with moderate supply of offsets available domestically and from abroad

FIGURE 5.8
C02 Allowance Price Scenarios
2000 Dollars US / Ton



It should be noted that all of the above Greenhouse Gas reduction targets are less onerous than those implied by the Kyoto Protocol. Higher CO_2 scenarios are possible such as a reduction to 7% below 1990 levels with a limited supply of offsets. However, such extreme scenarios were not evaluated in these scenarios.

5.7.3 Probability of Environmental Price Premiums for Export Prices

In consultation with Manitoba Hydro, ICF Consulting developed the set of environmental premium scenarios outlined above. In addition, ICF independently developed a set of associated probability weightings for the selected scenarios. There is much uncertainty as to how much future export prices will increase due to environmental considerations and it is not possible to definitively forecast the most likely environmental scenario. However, it is Manitoba Hydro's judgement that the set of export price scenarios and associated probabilities is a reasonable representation of future export market prices. While the specific probability weightings and the associated environmental price premiums are commercially sensitive, the general assumptions and background to these weightings for the various time periods are discussed below.

The probability weightings reflect that the U.S. will likely take no significant actions toward carbon regulation in the near term. However, in the longer term it is assumed that carbon regulation will be implemented very gradually and become more stringent as the U.S. political climate shifts towards greater and greater degrees of carbon regulation. This shift is described below in general terms for various times into the future.

- **2005**: Since multi-pollutant and/or carbon regulation is not in place in 2003, it is unlikely that the electric market in 2005 will be heavily impacted by such policies. A small probability is given to the 3P Scenario as the announcement of a multi-pollutant policy in 2003 or 2004 may have near-term impacts on market behaviour. There is assumed to be no carbon policy and thus no impact on electricity price in 2005.
- **2010**: By 2010 it is very likely that 3-pollutant regulation, such as the current U.S. Administration's Clear Skies Initiative, will be implemented. Depending on the shifts of political power over the next decade, a mild carbon policy, (LEEP-4P), such as that included in the Clean Power Act

proposal, might also be in place. Another possibility for this period is that the U.S. accepts the need for a more aggressive response to climate change. This would result in a stringent carbon policy similar to the MEEP-4P trajectory.

- **2015:** In 2015 and after, the probability weighting favours policies with carbon constraints more than policies without constraints. The highest probability in 2015 is assigned to a moderate carbon policy with very flexible measures in place for compliance (LEEP-4P), such as the carbon policy proposed in the Clean Power Act. This assumes that a shift in the U.S. brought about by scientific finding, international political pressure or other factors has resulted in a carbon policy aimed at reducing emissions.
- **2020**: By 2020, the probability weighting reflects a transition towards carbon constraints consistent with the somewhat more stringent policy of the MEEP-4P scenario. Once a carbon policy is implemented, as deemed very likely by 2015, continuing growth in electricity demand and/or carbon constraint levels will drive up carbon charges. Such a carbon constraint is consistent with proposals for staged reductions in total emissions that have been tabled by the U.S. Administration for SO_2, NO_X and mercury emissions.
- **2025 and 2030**: As time goes on, the probability weighting shifts towards carbon charges consistent with increasingly more stringent carbon policies. The trend in increasing carbon charges continues for the same reasons as in 2020 – pressure on the carbon market brought about by increasing electricity demand and/or staged reductions in the CO_2 emissions cap. The growth rate in the carbon charges slows, however, as the trajectory nears the upper bound represented by the HEEP-4P scenario. Even in this time frame it is assumed that carbon charges are less than those required under the Kyoto Protocol (7% less than 1990 levels for the U.S.).

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5.7.4 Export Market Price Forecast with Environmental Price Premiums

Manitoba Hydro has developed an "Expected" forecast of power prices for export to the MAPP area. This forecast is comprised of a reference price combined with various weightings on a year by year basis of the environmental price premiums. The forecast for export prices to Canadian markets is equal to the U.S. market because the U.S. market usually determines Manitoba Hydro's price to Canadian markets.

5.7.5 High and Low Export Market Price Forecasts

Generally, forecasts are a "best estimate" and each has an associated degree of inherent uncertainty. In order to establish a reasonable set of bounds to cover the likely range of export prices, Manitoba Hydro has developed a High and a Low forecast, in addition to the Expected price forecast. The High and Low forecasts each have a low probability of occurrence and would have little weighting in determining the expected forecast. Therefore, they were not explicitly used in deriving the Expected export price forecast. However, they are useful for representing a reasonable set of bounds that can be used in a sensitivity analysis to assess the range of economic benefits and also the range of financial impacts.

In order to describe the characteristics of the High and Low export price forecasts, it is useful to first summarize the characteristics of the Expected price forecast, which is comprised of the reference price and various weightings of the environmental price premiums. The Expected price forecast is based on a set of assumptions for factors such as evolving market structure for the electricity industry along with load growth and escalation of fuel prices. The High and Low price forecasts are representative of a reasonable combination of the following uncertainties that may affect electricity prices over the long term: market structure, world economy, growth in demand for energy, natural gas prices and volatility, and U.S. political sentiments such as protectionism and self-sufficiency.

Low Forecast Scenario

The Low export price forecast assumes that prices in the long term are lower than Manitoba Hydro's Expected export price forecast and about equal to prices experienced recently for firm and opportunity export sales. This scenario over the next 20 years could be representative of a world in turmoil with long-term geopolitical instability, low economic growth, aggressive energy conservation policies, low growth in energy demand, loss of momentum in electricity industry re-regulation, low natural gas prices, reduced electricity and natural gas price volatility, and a U.S. move to security and self-sufficiency in energy supply. Because of the lack of volatility in the market price for power combined with other factors described above, it is assumed that the Manitoba Hydro price for long-term firm power is slightly lower for the entire forecast period than long-term prices experienced in recent years. Opportunity export prices are assumed to rise only moderately in the medium term and then stabilize in real terms due to the combination of factors described above.

High Forecast Scenario

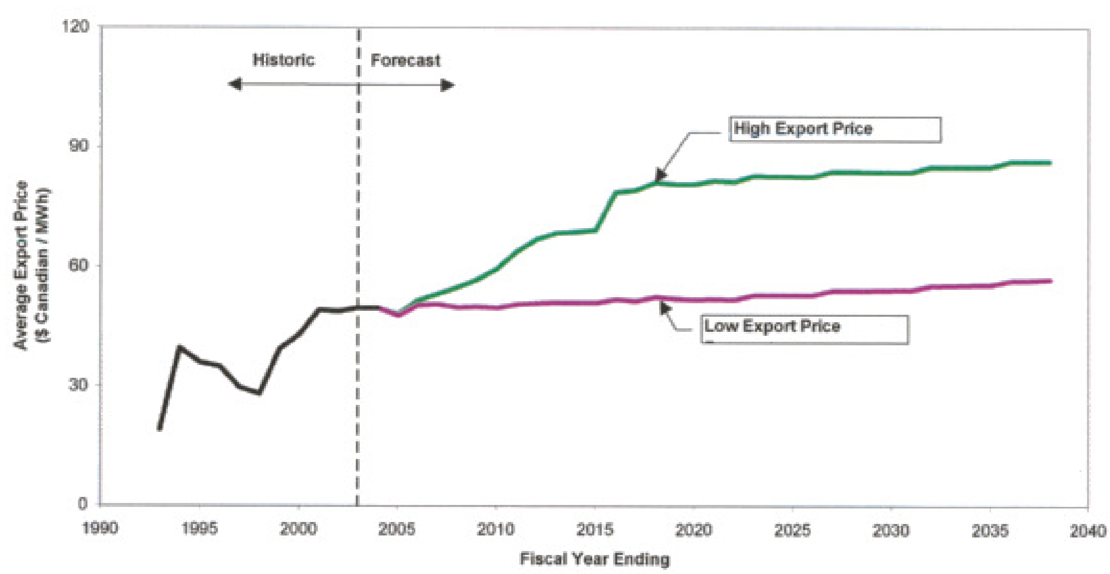
The High export price forecast assumes that prices are even higher than the Expected price forecast and also higher than the reference price combined with the high environmental export price premium (HEEP). The High export price scenario over the next 20 years could be representative of a stable geopolitical world, high economic growth, high growth in energy demand, rapid move to competitive power markets, high and volatile natural gas prices, the U.S. aggressively regulating environmental pollutants such as SO_2, NO_X, mercury and fine particulate emissions, and the U.S. ratifying a Kyoto-like agreement for after 2012. This scenario of a highly competitive market may lead to volatile electricity prices. Because long-term firm sales can protect purchasers from price volatility and because such sales provide increased assurance of supply, it is assumed that this scenario results in increased export prices to Manitoba Hydro for long-term firm products. In addition, the market price of opportunity energy would also increase due to the combination of factors described above.

5.7.6 Forecast of High and Low Export Prices

A computer simulation of the operation of the Manitoba Hydro system of reservoirs and generating resources is utilized to determine the expected export revenue for each year of the project analysis period to 2036/37. A description of the output of the simulation model is provided in **Attachment 6.** The average price for the combination of long-term firm and opportunity export sales for the Low and High scenarios of export prices is provided in **Attachment 6 Table A.15** and **Table A.16** respectively for the case of Wuskwatim G.S. in service in 2009. This average price is shown plotted in **Figure 5.9**. The annual price that has been obtained for export sales since 1992/93 is also shown in **Figure 5.9.** These prices have been adjusted to constant 2002 dollars in order to account for inflation and inherently include the Canadian/U.S. exchange rate corresponding to the exposure management program of the day.

FIGURE 5.9

Annual Export Prices - Historic and Forecast
Average of All Export Sales
Constant 2002 Canadian Dollars



It is noted that the Low export price forecast results in average export prices similar to that experienced in recent years. Furthermore, the High export price forecast results in average export prices that continue to increase and attain a level of about 60 % higher than prices in the Low scenario.

It should be noted that the average prices in **Figure 5.9** above are in Canadian dollars derived from the use of the appropriate exchange rate for U.S. sales for each year in the period. These prices are a composite of long-term firm sales, on-peak and off-peak opportunity sales. In order to provide context for these prices, it is useful to compare these to the on-peak opportunity export prices that have been experienced in recent years as summarized in **Table 5.5** in **Section 5.6.3**. As indicated in that table, the average on-peak opportunity export prices for the years 2000 to 2002 have averaged $38.5/MWh in U.S. dollars or about $60/MWh in Canadian dollars. The average price for the composite of all sales is about $50/MWh Canadian during this period as shown in **Figure 5.9**. This composite export price includes off-peak export prices that are significantly lower than the on-peak. In addition, it includes several long-term firm sales that were negotiated many years ago at prices that are lower than recent on-peak opportunity prices. The combination of low off-peak and long-term firm prices for a large portion of the total export sales results in the composite price being lower than current on-peak opportunity prices.

TAB 2

Conawapa G.S. The Wind/C26 development plan requires an additional increment of investment, making it the development plan with the second-highest capital investment requirement in Table 9.5. Based on the measure of NPV, the CCGT/C26 development plan yields a marginally higher net benefit than the SCGT/C26 development plan and a substantially higher net benefit than the Wind/C26 development plan. In comparing development plans, the net benefit between SCGT/C26 and CCGT/C26 is small enough to result in indifference between the plans.

Of this group of seven development plans listed in Table 9.5, the K22/Gas plan has one of the highest incremental NPVs when compared to the All Gas plan. As stated earlier in this section, the net benefit of the K22/Gas development plan as compared to the K22/C29 development plan is small enough to result in indifference between the plans. However, the significantly greater investment required for the Conawapa G.S. in the K22/C29 development plan results in it being excluded from further evaluation.

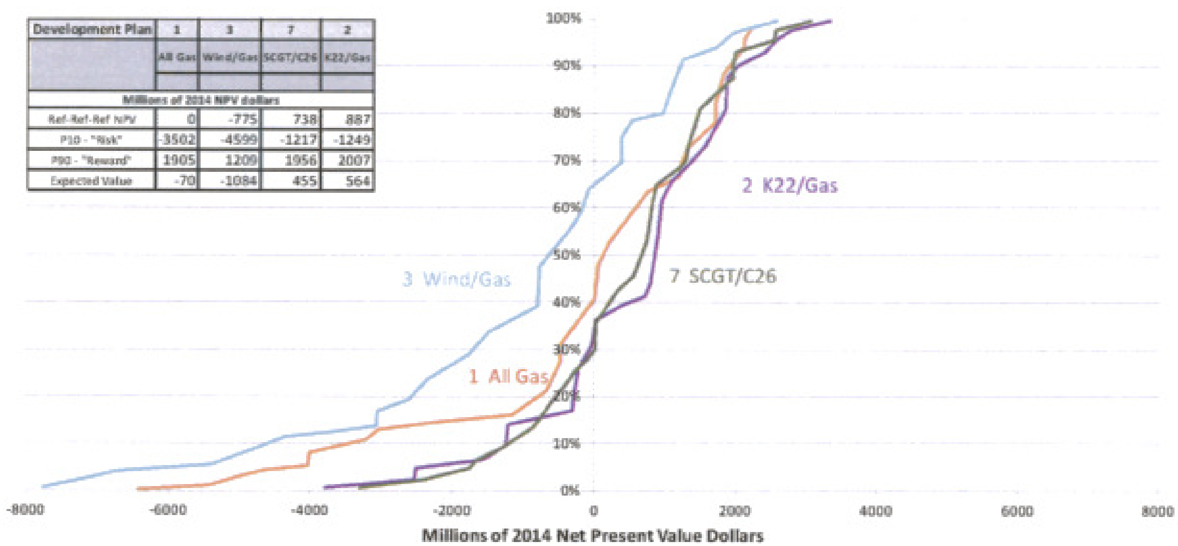
Table 9.5 INCREMENTAL ECONOMICS – NO NEW INTERCONNECTION

Development Plan	Incremental NPV, millions of 2014 Dollars @ 5.05% Discount Rate					
	1 All Gas	2 K22/Gas	3 Wind/Gas	7 SCGT/C26	8 CCGT/C26	9 Wind/C26
1 All Gas						
Lowest Capital Investment Development Plan	-					
2 K22/Gas	2-1					
	$887					
3 Wind/Gas	3-1	3-2				
	($775)	($1,662)				
7 SCGT/C26	7-1	7-2	7-3			
	$738	($149)	$1,513			
8 CCGT/C26	8-1	8-2	8-3	8-7		
	$784	($103)	$1,559	$46		
9 Wind/C26	9-1	9-2	9-3	9-7	9-8	
	$531	($356)	$1,306	($207)	($253)	
10 K22/C29	10-1	10-2	10-3	10-7	10-8	10-9
	$806	($81)	$1,581	$68	$22	$275

Of the seven development plans shown in Table 9.5, three development plans with no new interconnection have been selected for further analysis: All Gas, K22/Gas and

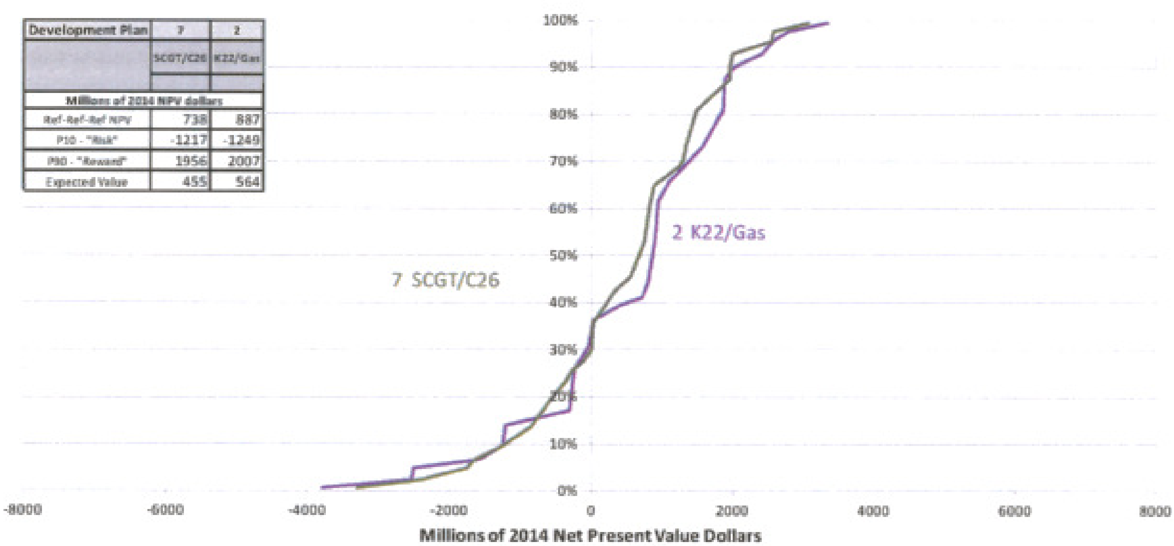
While the All Gas plan dominates the Wind/Gas plan, it has a significantly greater downside potential than the K22/Gas and SCGT/C26 plans due to the greater proportion of thermal generation, particularly under low discount rate scenarios. Therefore, on the basis of the expected values and the risk profile, it can be concluded that the All Gas and Wind/Gas plans are effectively dominated, making both inferior to K22/Gas and SCGT/C26.

Figure 10.11 Probabilistic Analysis: S-Curves Plans With No New Interconnection



Development Plan	1	3	7	2
	All Gas	Wind/Gas	SCGT/C26	K22/Gas
Millions of 2014 NPV dollars				
Ref-Ref-Ref NPV	0	-775	738	887
P10 - "Risk"	-3502	-4599	-1217	-1249
P90 - "Reward"	1905	1209	1956	2007
Expected Value	-70	-1084	455	564

Figure 10.12 Probabilistic Analysis: S-Curves K22/Gas and SCGT/C26 Plans



Development Plan	7	2
	SCGT/C26	K22/Gas
Millions of 2014 NPV dollars		
Ref-Ref-Ref NPV	738	887
P10 - "Risk"	-1217	-1249
P90 - "Reward"	1956	2007
Expected Value	455	564

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Table 12.1 WINTER PEAK CAPACITY BALANCE FOR SELECT YEARS (MW)

@ GENERATION

Winter Peak Capacity, MW				
Fiscal Year	2014/15	2022/23	2023/24	2026/27
Total Base Supply	6,183	6,312	6,312	5,927
Total Peak Demand	5,242	5,436	5,505	5,355
Reserves	510	609	618	643
System Surplus (Deficit)	431	267	189	(71)

Table 12.2 DEPENDABLE ENERGY BALANCE FOR SELECT YEARS (GWH)

@ GENERATION

Dependable Energy, GWh				
Fiscal Year	2014/15	2022/23	2023/24	2026/27
Total Base Supply	30,242	30,018	30,018	29,461
Total Energy Demand	28,628	29,742	30,121	29,785
System Surplus (Deficit)	1,614	276	(103)	(324)

12.1.4 **2013 Electricity Export Price Forecast**

The 2013 Electricity Export Price Forecast was prepared using the consensus forecasting methodology described in ***Appendix 9.3 – Economic Evaluation Documentation***. The 2013/14 electricity export price forecast has resulted in, on average, an approximate increase of 7% to the reference electricity export price forecast relative to the adjusted 2012/13 electricity export price forecast used elsewhere in the NFAT submission.

12.1.5 **Conawapa G.S. Earliest In-Service Date**

For the 2013 update it is assumed the earliest possible in-service date for the Conawapa G.S. is 2026/27, as opposed to 2025/26 used in the 2012 planning assumptions.

Development Plan — K19 Sales C25 750 MW
Development Plan Scenario — Economics:REF Rev:HIGH Cap:REF
ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
In Millions of Dollars

For the year ended March 31	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
REVENUES													
General Consumers Revenue at approved rates	1 331	1 361	1 374	1 390	1 404	1 424	1 447	1 462	1 485	1 506	1 529	1 552	1 575
Additional General Consumers Revenue	-	48	96	147	201	250	320	384	453	525	609	684	771
Extraprovincial	357	344	387	444	468	512	503	551	869	965	986	957	942
Other	14	15	15	15	15	16	16	16	17	17	17	18	18
Total Revenue	1 702	1 768	1 872	1 996	2 088	2 211	2 286	2 412	2 823	3 014	3 134	3 211	3 307
EXPENSES													
Operating and Administrative	455	471	546	559	570	593	605	621	678	690	703	716	730
Finance Expense	452	442	491	518	535	654	770	777	984	1 075	1 069	1 079	1 077
Depreciation and Amortization	399	430	372	391	400	422	458	461	518	553	559	558	561
Water Rentals and Assessments	117	116	112	113	112	112	112	114	124	127	128	128	127
Fuel and Power Purchased	143	166	192	205	221	235	244	246	264	289	300	312	335
Capital and Other Taxes	87	95	101	109	119	127	134	141	149	158	167	175	182
Corporate Allocation	9	9	8	8	8	8	8	8	8	8	8	8	8
Total Expenses	1 663	1 729	1 823	1 903	2 005	2 152	2 331	2 368	2 725	2 901	2 935	2 977	3 019
Non-Controlling Interest	(14)	(24)	(19)	(12)	(10)	(7)	(4)	(3)	1	10	13	17	19
Net Income	54	63	68	105	93	65	(40)	47	97	102	187	217	269
Additional General Consumers Revenue Percent Increase	0.00%	3.50%	3.37%	3.37%	3.37%	3.37%	3.37%	3.37%	3.37%	3.37%	3.37%	3.37%	3.37%
Cumulative General Consumers Revenue Percent increase	0.00%	3.50%	6.98%	10.58%	14.31%	18.15%	22.13%	26.24%	30.49%	34.88%	39.42%	44.11%	48.96%
Debt Ratio	76	78	84	85	86	87	88	88	89	89	89	89	88
Interest Coverage Ratio	1.09	1.10	1.10	1.14	1.11	1.07	0.96	1.04	1.08	1.08	1.13	1.15	1.17
Capital Coverage Ratio	1.09	0.90	0.80	0.97	1.27	1.43	1.12	1.59	1.62	1.61	1.58	1.60	1.73

For the year ended March 31	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
REVENUES												
General Consumers Revenue at approved rates	1 598	1 621	1 644	1 669	1 693	1 717	1 741	1 765	1 790	1 814	1 838	1 862
Additional General Consumers Revenue	853	959	1 061	1 169	1 283	1 403	1 529	828	856	904	913	943
Extraprovincial	1 071	1 417	1 500	1 506	1 495	1 495	1 504	1 482	1 460	1 441	1 418	1 354
Other	18	19	19	19	20	20	21	21	21	22	22	23
Total Revenue	3 550	4 015	4 224	4 363	4 491	4 634	4 795	4 097	4 127	4 181	4 191	4 182
EXPENSES												
Operating and Administrative	760	773	788	804	817	832	840	866	887	906	924	945
Finance Expense	1 187	1 407	1 590	1 558	1 518	1 528	1 466	1 423	1 417	1 435	1 405	1 394
Depreciation and Amortization	600	668	721	724	732	758	766	764	768	752	796	802
Water Rentals and Assessments	135	148	151	151	151	152	153	153	154	154	154	155
Fuel and Power Purchased	276	283	305	317	329	331	346	351	362	375	370	340
Capital and Other Taxes	188	193	194	196	199	201	202	203	204	205	206	208
Corporate Allocation	8	8	8	8	8	7	7	7	7	7	7	7
Total Expenses	3 155	3 479	3 757	3 759	3 753	3 809	3 789	3 768	3 798	3 854	3 863	3 850
Non-Controlling Interest	20	22	25	27	30	32	35	37	39	41	44	50
Net Income	375	514	442	578	708	793	971	292	291	285	284	283
Additional General Consumers Revenue Percent Increase	3.37%	3.37%	3.37%	3.37%	3.37%	3.37%	3.37%	-21.77%	0.63%	1.36%	-0.12%	0.65%
Cumulative General Consumers Revenue Percent increase	53.98%	59.16%	64.51%	70.05%	75.77%	81.69%	87.81%	46.91%	47.85%	49.85%	49.67%	50.65%
Debt Ratio	87	86	84	83	81	78	75	74	73	72	71	70
Interest Coverage Ratio	1.23	1.31	1.27	1.36	1.44	1.51	1.65	1.20	1.20	1.20	1.20	1.20
Capital Coverage Ratio	2.11	2.84	2.46	2.50	2.61	2.66	3.47	1.89	1.69	1.58	1.52	1.46

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Needs For and Alternatives To
Appendix 11.4 Pro Forma Financial Statements

Development Plan — K19 Sales C25 750 MW
Development Plan Scenario — Economics:REF Rev:REF Cap:REF
ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
In Millions of Dollars

For the year ended March 31	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
REVENUES													
General Consumers Revenue at approved rates	1 331	1 361	1 374	1 390	1 404	1 424	1 447	1 462	1 485	1 506	1 529	1 552	1 575
Additional General Consumers Revenue	-	48	104	164	228	297	370	447	530	619	713	814	921
Extraprovincial	357	344	333	370	388	412	402	439	713	817	829	808	795
Other	14	15	15	15	15	16	16	16	17	17	17	18	18
Total Revenue	1 702	1 768	1 826	1 939	2 035	2 148	2 236	2 364	2 745	2 959	3 088	3 191	3 309
EXPENSES													
Operating and Administrative	455	471	546	559	570	593	605	621	678	690	705	716	730
Finance Expense	452	442	491	519	577	658	774	783	989	1 083	1 075	1 083	1 077
Depreciation and Amortization	399	430	372	391	400	422	458	461	518	553	559	558	561
Water Rentals and Assessments	117	116	112	112	112	112	112	114	124	127	128	128	127
Fuel and Power Purchased	143	166	167	178	193	200	205	207	222	239	247	256	270
Capital and Other Taxes	87	95	101	109	119	127	134	141	149	158	166	174	181
Corporate Allocation	9	9	8	8	8	8	8	8	8	8	8	8	8
Total Expenses	1 663	1 729	1 798	1 877	1 978	2 121	2 297	2 335	2 688	2 859	2 887	2 924	2 955
Non-Controlling Interest	(14)	(24)	(23)	(17)	(24)	(13)	(9)	(9)	(7)	1	3	7	9
Net Income	54	63	51	79	72	40	(53)	38	63	100	199	260	345
Additional General Consumers Revenue Percent Increase	0.00%	3.50%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
Cumulative General Consumers Revenue Percent Increase	0.00%	3.50%	7.59%	11.83%	16.25%	20.83%	25.60%	30.56%	35.72%	41.07%	46.64%	52.43%	58.45%
Debt Ratio	76	79	84	85	86	87	88	89	89	90	90	89	88
Interest Coverage Ratio	1.09	1.10	1.07	1.10	1.08	1.04	0.95	1.03	1.05	1.08	1.14	1.17	1.22
Capital Coverage Ratio	1.09	0.90	0.77	0.90	1.21	1.36	1.08	1.55	1.52	1.57	1.58	1.66	1.84

For the year ended March 31	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
REVENUES												
General Consumers Revenue at approved rates	1 598	1 621	1 644	1 669	1 693	1 717	1 741	1 765	1 790	1 814	1 838	1 862
Additional General Consumers Revenue	1 034	1 154	1 282	1 418	1 562	1 715	1 876	1 057	1 076	1 123	1 157	1 211
Extraprovincial	834	1 099	1 165	1 174	1 168	1 176	1 181	1 176	1 163	1 152	1 114	1 032
Other	18	19	19	19	20	20	21	21	21	22	22	23
Total Revenue	3 484	3 892	4 110	4 280	4 443	4 628	4 838	4 020	4 050	4 110	4 131	4 128
EXPENSES												
Operating and Administrative	760	773	788	804	817	832	849	866	887	906	924	945
Finance Expense	1 182	1 403	1 584	1 553	1 515	1 523	1 459	1 413	1 407	1 412	1 408	1 394
Depreciation and Amortization	600	668	721	726	762	758	766	764	768	792	796	802
Water Rentals and Assessments	135	148	150	151	151	152	153	153	154	154	154	154
Fuel and Power Purchased	233	238	256	266	275	282	292	302	312	324	325	309
Capital and Other Taxes	187	190	192	195	197	201	202	203	204	206	207	208
Corporate Allocation	8	8	8	8	8	7	7	7	7	7	7	7
Total Expenses	3 105	3 428	3 700	3 703	3 695	3 756	3 728	3 709	3 739	3 801	3 821	3 820
Non-Controlling Interest	5	7	9	11	14	16	18	20	22	24	25	26
Net Income	371	457	401	567	735	857	1 072	290	289	285	285	283
Additional General Consumers Revenue Percent Increase	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	-25.04%	0.14%	1.12%	0.63%	1.10%
Cumulative General Consumers Revenue Percent Increase	64.70%	71.20%	77.96%	84.98%	92.28%	99.87%	107.76%	59.89%	60.12%	61.90%	62.93%	65.05%
Debt Ratio	87	86	85	83	81	78	75	74	73	72	71	70
Interest Coverage Ratio	1.23	1.28	1.25	1.35	1.46	1.55	1.72	1.20	1.20	1.20	1.20	1.20
Capital Coverage Ratio	2.07	2.67	2.33	2.45	2.61	2.72	3.61	1.84	1.59	1.54	1.48	1.42

Development Plan — K19 Sales C25 750 MW
Development Plan Scenario — Economics:REF Rev:LOW Cap:REF
ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
In Millions of Dollars

For the year ended March 31	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
REVENUES													
General Consumers Revenue at approved rates	1 331	1 361	1 374	1 390	1 404	1 424	1 447	1 462	1 485	1 506	1 529	1 552	1 575
Additional General Consumers Revenue	-	48	113	183	258	339	427	518	618	725	839	962	1 094
Extraprovincial	357	344	264	287	301	319	317	340	526	622	634	634	645
Other	14	15	15	15	15	16	16	16	17	17	17	18	18
Total Revenue	1 702	1 768	1 766	1 876	1 978	2 098	2 206	2 336	2 645	2 870	3 019	3 166	3 332
EXPENSES													
Operating and Administrative	455	471	546	559	570	593	605	621	678	690	703	716	730
Finance Expense	452	442	493	522	583	666	783	791	998	1 087	1 087	1 098	1 091
Depreciation and Amortization	399	430	372	391	400	422	458	461	518	553	559	558	561
Water Rentals and Assessments	117	126	112	112	112	112	112	114	124	127	128	127	127
Fuel and Power Purchased	143	166	145	155	166	172	176	176	182	193	197	205	215
Capital and Other Taxes	87	95	101	109	119	127	134	141	148	157	166	174	181
Corporate Allocation	9	9	8	8	8	8	8	8	8	8	8	8	8
Total Expenses	1 663	1 739	1 777	1 856	1 958	2 100	2 276	2 312	2 657	2 815	2 848	2 886	2 914
Non-Controlling Interest	(14)	(24)	(27)	(21)	(19)	(18)	(13)	(14)	(16)	(10)	(8)	(3)	(1)
Net Income	54	63	15	41	40	15	(57)	38	4	64	179	283	418
Additional General Consumers Revenue Percent Increase	0.00%	3.50%	4.58%	4.58%	4.58%	4.58%	4.58%	4.58%	4.58%	4.58%	4.58%	4.58%	4.58%
Cumulative General Consumers Revenue Percent Increase	0.00%	3.50%	8.24%	13.20%	18.39%	23.82%	29.49%	35.43%	41.63%	48.12%	54.91%	62.01%	69.43%
Debt Ratio	76	78	84	85	87	88	89	89	90	91	90	90	89
Interest Coverage Ratio	1.09	1.10	1.02	1.05	1.04	1.02	0.95	1.03	1.00	1.05	1.13	1.19	1.26
Capital Coverage Ratio	1.09	0.90	0.70	0.82	1.12	1.27	1.05	1.52	1.35	1.47	1.51	1.69	1.98

For the year ended March 31	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
REVENUES												
General Consumers Revenue at approved rates	1 598	1 621	1 644	1 669	1 693	1 717	1 741	1 765	1 790	1 814	1 838	1 862
Additional General Consumers Revenue	1 234	1 383	1 542	1 713	1 896	2 089	2 296	1 319	1 326	1 360	1 414	1 494
Extraprovincial	587	774	825	841	842	849	854	856	849	844	786	681
Other	18	19	19	19	20	20	21	21	21	22	22	23
Total Revenue	3 438	3 795	4 031	4 243	4 451	4 676	4 911	3 959	3 986	4 039	4 058	4 060
EXPENSES												
Operating and Administrative	760	775	788	804	817	832	849	866	887	906	924	945
Finance Expense	1 194	1 417	1 602	1 573	1 535	1 543	1 474	1 425	1 418	1 422	1 416	1 402
Depreciation and Amortization	600	668	721	724	732	758	766	764	768	792	796	802
Water Rentals and Assessments	135	147	150	151	151	152	153	153	153	154	154	154
Fuel and Power Purchased	197	200	210	216	223	228	235	242	249	256	257	252
Capital and Other Taxes	187	191	193	196	198	203	204	205	207	208	209	211
Corporate Allocation	8	8	8	8	8	7	7	7	7	7	7	7
Total Expenses	3 081	3 404	3 673	3 672	3 663	3 723	3 687	3 662	3 688	3 744	3 764	3 773
Non-Controlling Interest	(8)	(7)	(5)	(3)	(1)	1	3	5	7	9	8	4
Net Income	365	398	363	574	788	952	1 221	292	291	287	286	284
Additional General Consumers Revenue Percent Increase	4.58%	4.58%	4.58%	4.58%	4.58%	4.58%	4.58%	-24.64%	-0.36%	0.50%	1.12%	1.88%
Cumulative General Consumers Revenue Percent Increase	77.20%	85.32%	93.81%	102.69%	111.98%	121.70%	131.86%	74.75%	74.10%	74.96%	76.93%	80.25%
Debt Ratio	88	87	86	84	82	79	75	74	73	72	71	70
Interest Coverage Ratio	1.22	1.26	1.22	1.35	1.49	1.60	1.81	1.20	1.20	1.20	1.20	1.20
Capital Coverage Ratio	2.01	2.51	2.72	2.43	3.68	2.83	3.84	1.80	1.56	1.53	1.44	1.38

TAB 3

Needs For and Alternatives To

APPENDIX 3.1

Long-Term Price Forecast for Manitoba Hydro's Export Market in MISO - The Brattle Group

Approach: Scenario Forecasting

Rather than attempting to develop the "best" single point-forecast, a scenario forecasting approach recognizes the inherent uncertainty of the future, characterizes this uncertainty and analyzes its effect

- "Business as usual" or "expected" outcome is not at all certain, particularly over a long horizon. It can be equally important to consider other, "not-expected" potential outcomes
  - Decisions should be informed by other plausible outcomes and potential extremes
- A scenario is an internally consistent narrative describing a plausible future
- Recently, the future seems even more uncertain than usual. E.g.:
  - Uncertainties in long-run environmental policies (coal retirements, climate policy, CO_2 price, renewable requirements/subsidies, Smart Grid, transmission expansion)
  - Evolution of low-carbon generation technologies (wind, solar, nuclear),
  - Long run price effects of unconventional gas development,
  - Coal plant retirements due to new EPA requirements
- Differences between scenarios, and the factors that cause them, may be as instructive as the absolute price level in any given scenario

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TAB 4

MANITOBA PUBLIC UTILITIES BOARD

IN THE MATTER OF *Order In Council 128/2013 and attached Terms of Reference Needs For and Alternatives (NFAT) Review*

AND IN THE MATTER OF *Manitoba Hydro's Filing with Respect to the Need For and Alternatives to Manitoba Hydro's Preferred Development Plan*

REBUTTAL EVIDENCE OF MANITOBA HYDRO

WITH RESPECT TO THE WRITTEN EVIDENCE OF:

- **ELENCHUS RESEARCH ASSOCIATES INC., ("Elanchus"); KNIGHT PIESOLD CONSULTING, ("KP"); LA CAPRA ASSOCIATES, INC., ("LCA"); MNP LLP, ("MNP"); MORRISON PARK ADVISORS, ("MPA"); POTOMAC ECONOMICS, LTD., ("POT") and POWER ENGINEERS INC., ("PE"), Independent Expert Consultants ("IECs") retained by the Public Utilities Board ("PUB")**

- **BILL HARPER, ECONALYSIS CONSULTING SERVICES; KYRKE GAUDREAU & ROBERT GIBSON; JILL GUNN & AYODELE OLAGUNJU, DOUGLAS GOTHAM, WAYNE SIMPSON; and WAYNE SIMPSON & DOUGLAS GOTHAM on behalf of Consumers Association of Canada (Manitoba) ("CAC")**

- **PAUL CHERNICK, RESOURCE INSIGHT, INC. and WESLEY STEVENS POWER ADVISORY LLC on behalf of Green Action Centre ("GAC")**

- **PATRICK BOWMAN, INTERGROUP CONSULTANTS LTD. on behalf of Manitoba Industrial Power Users Group ("MIPUG")**

- **WHITFIELD RUSSELL, WHITFIELD RUSSELL ASSOCIATES on behalf of the Manitoba Métis Federation ("MMF")**

- **PHILIPPE U. DUNSKY, DUNSKY ENERGY CONSULTING on behalf of Consumers' Association of Canada (Manitoba) and Green Action Centre ("CAC/GAC")**

February 28, 2014

Manitoba Hydro

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the incremental NPV under the reference scenario. This also is a valid conclusion. Manitoba Hydro's key conclusion related to the comparison between Plan 4 and Plan 14 in the NFAT Business Case, Chapter 10 page 39 is that careful consideration must be given to the tradeoffs between the plans given the different characteristics of these plans. Further analysis of other perspectives (financial, multiple account and optionality) are important to the overall conclusions provided in Chapter 14.

9.7 Discount Rate Used in Economic Analysis is Appropriate

The selection of the appropriate discount rate is essential for the determination of meaningful present value calculations. Concern has been expressed that Manitoba Hydro has utilized discount rates that do not fully reflect its cost of capital or are not representative of the various constituent groups in Manitoba.

Manitoba Hydro is not regulated on a rate-of-return basis – rates are set to recover costs and to make contributions to retained earnings. Despite this, Manitoba Hydro still utilizes a weighted average cost of capital (WACC) approach to determining the appropriate discount rate for project evaluations. The purpose of this is to recognize the need to have an equity cushion that can accommodate normal business risks and provide a return that can be used to make contributions to retained earnings and/or be used to reduce electricity rates. Allowed rates of return on equity (ROE) for other utilities are used to determine the 3% equity adder that Manitoba Hydro utilizes as a proxy for an allowed rate of return.

Even though this equity adder is used as a proxy for an allowed return on equity, both intervener and independent expert witnesses have challenged the details of the calculation. Manitoba Hydro's reference discount rate is based upon its long term cost of debt, calculated as: forecast long term Canadian bond rate, plus an adjustment for the credit spread between Manitoba and Canada, plus the provincial guarantee fee. With a 0.65% provincial spread and the 1.0% guarantee fee, the 3% equity adder results in an ROE that is 4.65% above the long term *projected* Canadian bond interest rate. Morrison Park cited a single 2009 Ontario Energy Board decision (p. 63 of their evidence) of a 5% spread above Canadian long bonds (although they thereafter recommend 6% or 10% nominal returns) while Econalysis also included an Alberta decision from 2011 and a British Columbia 2013 decision that indicated an acceptable range of 4.68 – 5.50% over the long term bank of Canada rate. Ignoring the specifics of annual adjustment mechanisms and of different provincial spreads, there are issues with using one to three decisions (albeit important and prominent ones) to establish the industry norm. Manitoba Hydro periodically reviews a wide range of sources, including those cited above, to determine the reasonableness of its equity return proxy. One of the most recently reviewed was an October 2013 report from Concentric Energy Advisors: (http://www.ceadvisors.com/news/pdfs/ROENewsletterVolumeI.pdf) which includes 35 Canadian and US electricity and gas distribution utilities. Their subsequent paper (http://www.ceadvisors.com/publications/reportsandpublications/Recent%20Developments%20in%20the%20Cost%20of%20Capital%20for%20Canadian%20Utilities.pdf) supports the appropriateness of using US ROE awards in the data used in a determination of suitable Canadian returns.

Rather than getting mired in the details of calculating the equity premium over the projected cost of debt, Manitoba Hydro recognizes that the underlying interest rate forecast is also subject to uncertainty and that looking at a range of discount rates would be a more appropriate exercise. The 5.05% real discount rate is based upon a projected long term Canadian bond rate of 4.65% nominal or 2.70% real after removing a 1.9% escalation forecast. In order to capture the uncertainty in discount rates, via the underlying interest rates, low and high cases were prepared that reflected the historical range of real interest rates (provided in response to PUB/MH I-165a). Morrison Park erroneously cites historical movements in nominal interest rates (page 62 of their evidence) when criticising the *real* interest range that Manitoba Hydro utilized in its risk analysis. The high interest rate period from 1975 to 1995 that they refer to was accompanied by similarly high rates of inflation: interest rates peaked in 1981 with an average long term Canadian bond rate of 15.22%, but the 12.50% CPI at the time meant that the real interest rate was only 2.42%. The response provided to PUB/MH I-165a also shows that very low real interest rates have also been experienced periodically. Sudden upturns in inflation such as after World War II or in the early 1970's can even produce negative real interest rates until the markets adjust their outlooks of the future. More recently, during 12 of the last 69 months since the April 2008 financial crisis, interest rates have remained below 2.31% (the underlying long Canada rate in the low case), in contrast to Morrison Park's view that there is "little if any support for the low scenario" (page 63 their evidence). La Capra interprets this statement by Morrison Park to mean that "low discount rate scenario postulated by MH is not feasible" and then assign a zero probability to Hydro's low discount rate case. Since real long term Canadian rates have been at or below 1% at various points throughout history, including very recently, there would seem to be little or no support for the assignment of a zero probability – a declaration of absolute impossibility – for Manitoba Hydro's low discount rate case.

TAB 5

Authorized Return on Equity for Canadian Gas and Electric Distributors and Select Comparators

Volume I, October 1, 2013

Concentric Energy Advisors, Inc. (Concentric) is pleased to publish this first edition of a newsletter documenting authorized returns on common equity (ROEs) and common equity ratios for Canadian gas and electric distributors, U.S. gas distributors, and selected bond yields.[1] Up until this point, a common source for this data has not existed. Regulators, stakeholders, and analysts in Canada routinely consider allowed returns in other Canadian jurisdictions, and increasingly consider the comparability of Canadian and U.S. utilities when assessing the cost of capital. This newsletter seeks to assist with these inter-jurisdictional comparisons.

The newsletter and supporting database contain the authorized ROEs and common equity ratios for over 40 Canadian electric and gas utilities. Also presented are seven representative U.S. gas distributors in addition to the average authorized ROE and common equity ratios for all natural gas rate cases decided in a given year as provided by SNL Energy's Regulatory Research Associates.

Concentric observes that the gap between Canadian and U.S. authorized ROEs for gas distributors has narrowed from approximately 100 basis points in 2000 to approximately 50 basis points in 2012. In 2012, the median authorized ROE for Canadian gas distributors was 9.5 percent while the median for U.S. gas distributors was 10 percent. The gap has further narrowed in 2013.

Concentric attributes the closure of the gap between Canadian and U.S. authorized ROEs for gas distributors to the resetting and replacement of formulas widely used in Canada to adjust the authorized ROE on a periodic basis. While the authorized ROEs have converged in the two countries, the authorized common equity ratios have not. For example, in 2012, the average common equity ratio for Canadian gas distributors was approximately 40 percent while the same figure in the U.S. was approximately 51 percent.

Government and corporate bond yields are often considered when setting authorized ROEs and directly incorporated in some formulas, so this newsletter also contrasts government and utility bond yields. The data demonstrate that since 2000, government bond yields (considered risk-free rates of return) in both Canada and the U.S. declined from over 5.5 percent to less than 3 percent in 2012. While government bond yields play an important role in determining the authorized ROE for utilities, changes in government bond yields do not imply a one-for-one change in the cost of equity for utilities. The relationship between government bond yields and the equity risk premium (the spread between government bond yields and the cost of equity) has historically exhibited an inverse relationship.

Moving forward, Concentric anticipates that improving economic conditions and the easing of accommodative monetary policy in both Canada and the U.S. will exert upward pressure on the cost of capital for utilities. The benchmark Canadian Long-Term Bond Yield reached a low of 2.2 percent in July 2012, but pushed past the 3 percent mark in August and September of this year. U.S. long bonds have followed a parallel path, but remain 61 basis points over the Canadian Long-Bond year to date. Corporate debt costs, as reflected in Canadian and U.S. utility bond yields, have also notched higher in 2013, but remain within a tighter band of 26 basis points year to date.

Concentric will publish an update to this newsletter in the first quarter of 2014.

1 Concentric acknowledges the support of the Canadian Gas Association for conducting the research and building the database which serve as the foundation for this newsletter.

Concentric Energy Advisors, Inc.
Creativity • Expertise • Analysis • Insight

Authorized Return on Equity for Canadian Gas and Electric Distributors [1]

	Return on Common Equity (%)			Common Equity Ratio (%)		
	2013	2012	2011	2013	2012	2011
Canadian Gas Distributors [2]						
AltaGas Utilities Inc. [3]	8.75	8.75	8.75	43.00	43.00	43.00
ATCO Gas [3]	8.75	8.75	8.75	39.00	39.00	39.00
Centra Gas Manitoba Inc.	N/A	N/A	N/A	30.00	30.00	30.00
Enbridge Gas Distribution Inc.	8.93	8.39	8.39	36.00	36.00	36.00
Enbridge Gas New Brunswick	10.90	10.90	10.90	45.00	45.00	45.00
FortisBC Energy Inc.	8.75	9.50	9.50	38.50	40.00	40.00
FortisBC Energy Inc. (Vancouver Island) [4]	10.00	10.00	10.00	40.00	40.00	40.00
FortisBC Energy Inc. (Whistler) [4]	10.00	10.00	10.00	40.00	40.00	40.00
Gaz Métro Limited Partnership	8.90	8.90	9.09	38.50	38.50	38.50
Gazifère Inc.	7.82	8.29	9.10	40.00	40.00	40.00
Heritage Gas Limited	11.00	11.00	13.00	45.00	45.00	45.00
Pacific Northern Gas Ltd. [4]	10.15	10.15	10.15	45.00	45.00	45.00
Pacific Northern Gas (N.E.) Ltd. (Fort St. John/Dawson Creek) [4]	9.90	9.90	9.90	40.00	40.00	40.00
Pacific Northern Gas (N.E.) Ltd. (Tumbler Ridge) [4]	10.15	10.15	10.15	40.00	40.00	40.00
SaskEnergy Inc.	8.75	8.75	8.75	N/A	37.00	37.00
Union Gas Limited	8.93	8.54	8.54	36.00	36.00	36.00
Average	9.45	9.46	9.66	39.73	39.66	39.66
Median	8.93	9.50	9.50	40.00	40.00	40.00
Canadian Electric Distributors [2]						
ATCO Electric Ltd. [3]	8.75	8.75	8.75	39.00	39.00	39.00
ENMAX Power Corporation [3]	8.75	8.75	8.75	41.00	41.00	41.00
EPCOR Distribution Inc. [3]	8.75	8.75	8.75	41.00	41.00	41.00
FortisAlberta Inc. [3]	8.75	8.75	8.75	41.00	41.00	41.00
FortisBC Inc. [4]	9.90	9.90	9.90	40.00	40.00	40.00
Hydro-Québec Distribution	6.19	6.37	7.32	35.00	35.00	35.00
Manitoba Hydro	N/A	N/A	N/A	25.00	25.00	25.00
Maritime Electric Company Limited	9.75	9.75	9.75	43.50	41.70	42.70
Newfoundland and Labrador Hydro	4.47	4.47	4.47	20.00	20.00	20.00
Newfoundland Power Inc.	8.80	8.80	8.38	45.00	45.00	45.00
Nova Scotia Power Inc.	9.00	9.20	9.35	37.50	37.50	40.00
Ontario's Electric Distributors [5]	8.98	9.12	9.58	40.00	40.00	40.00
Saskatchewan Power Corporation	8.50	7.40	7.40	40.00	40.00	40.00
Average	8.38	8.33	8.43	37.54	37.40	37.67
Median	8.75	8.75	8.75	40.00	40.00	40.00

[1] Data for an expanded group of Canadian gas and electric transmission companies is contained in the Concentric Energy Advisors Return on Equity Database.
[2] Allowed in rates for the corresponding year: where the year overlaps, the rate/ratio shown prevails for the majority of the year. Sources: Regulatory decisions and documents: annual information forms: annual reports.
[3] The Alberta Utilities Commission has opened a Generic Cost of Capital proceeding in 2013 to review the current allowed ROE for regulated gas and electric utilities in Alberta.
[4] The authorized ROE for 2013 is currently under review by the British Columbia Utilities Commission in Stage 2 of the Generic Cost of Capital proceeding. A decision is expected in January 2014. In Stage 1, the BCUC reduced the allowed ROE for the benchmark utility, FortisBC Energy, Inc., by 75 basis points and reduced its deemed equity ratio by 1.50%.
[5] Rates effective May 1.
* N/A indicates the data is not available.

Authorized Return on Equity for Select U.S. Gas Distributors [1]

	Return on Common Equity (%)			Common Equity Ratio (%)		
	2013	2012	2011	2013	2012	2011
U.S. Gas Distributors						
Atlanta Gas Light Company (GA) [2]	10.75	10.75	10.75	51.00	51.00	51.00
New Jersey Natural Gas Company (NJ) [2]	10.30	10.30	10.30	51.20	51.20	51.20
Northern Illinois Gas Company (IL) [2]	10.17	10.17	10.17	51.07	51.07	51.07
Northwest Natural Gas Company (OR) [2]	9.50	10.20	10.20	50.00	49.50	49.50
Piedmont Natural Gas Company, Inc. (NC) [2]	10.60	10.60	10.60	51.00	51.00	51.00
Southwest Gas Corporation (AZ) [2]	9.50	9.50	10.00	52.30	52.30	43.44
Washington Gas Light Company (VA) [2]	9.75	9.75	10.00	59.63	59.63	N/A
Average of all Rate Cases Decided in the Year [3]	9.50	9.94	9.92	50.31	51.13	52.49
Median of all Rate Cases Decided in the Year [3]	9.40	10.00	10.03	49.20	51.47	52.45

Economic Indicators (% Yields) [4]	2013	2012	2011
Government of Canada Benchmark Long-Term Bond Yield	2.70	2.45	3.29
U.S. Treasury 30-Year Bond Yield	3.31	2.92	3.91
Bloomberg Fair Value Canada A-rated Utility Bond Yield	4.10	3.91	4.77
Moody's A-rated Utility Bond Index (U.S.)	4.36	4.13	5.04

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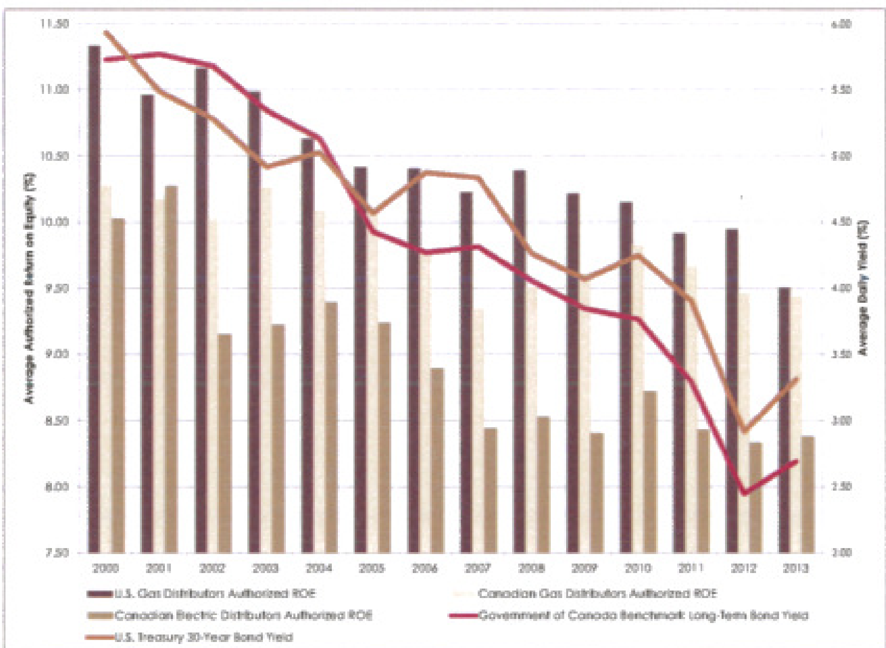


[1] Companies included in this sample are publicly traded, or divisions of publicly traded companies, with investment grade credit ratings, principally focused on the natural gas distribution business. Where more than one state is served, the largest service area is reported.
[2] Allowed in rates for the majority of the corresponding year. Sources: Regulatory decisions and documents; annual reports.
[3] Source: SNL Energy's Regulatory Research Associates Division. Data for 2013 includes decisions through September 13, 2013.
[4] Average daily yield. Source: Bloomberg Finance LP. Data for 2013 through September 16, 2013.

TAB 6

REFERENCE: Chapter 9: Economic Evaluations - Reference Scenario; Page No.: 10

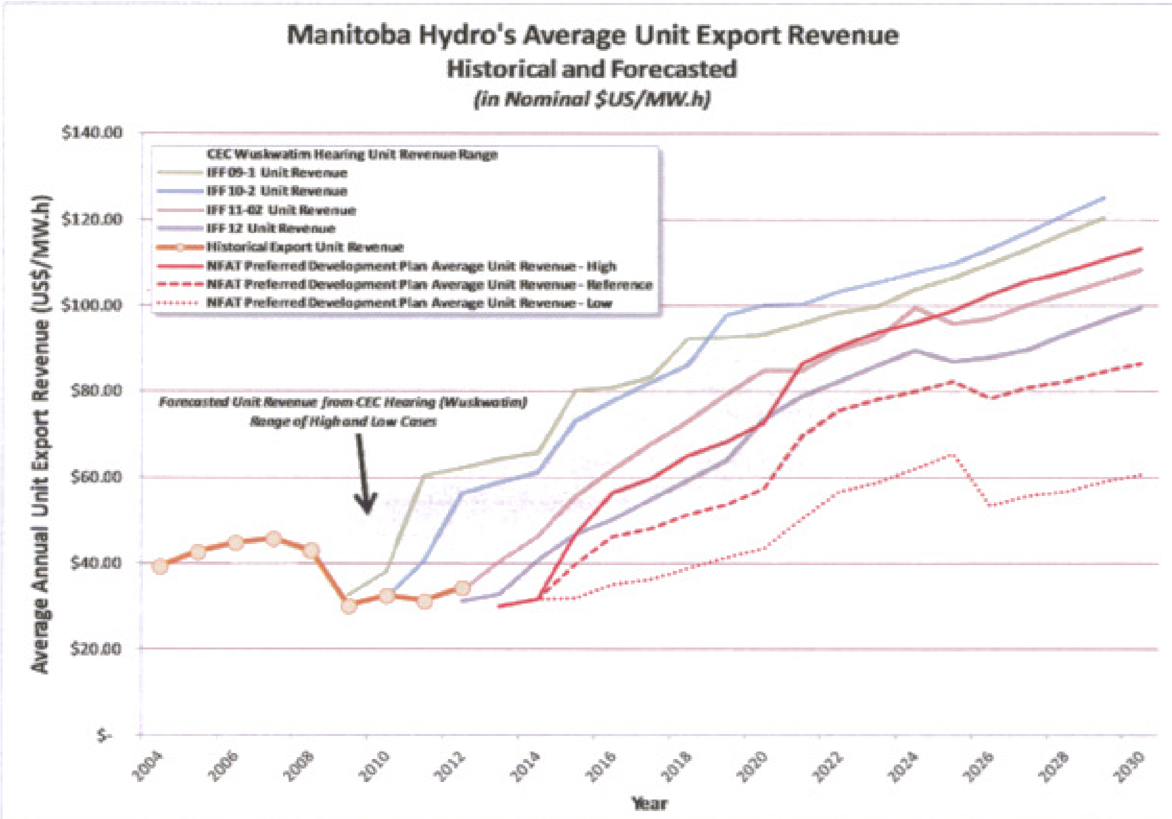
QUESTION:

Please update the response to PUB-19(a) from the 2012/13 GRA, showing the Reference, Low and High average prices for the Preferred Plan, for the K19/Gas24/250MW Plan, and the All Gas Plan. Please provide all the data values used in the chart.

RESPONSE:

The requested information is provided by means of three charts on the following pages.

The chart below is an update of PUB 19a, with the Reference, Low and High prices for the Preferred Development Plan added.



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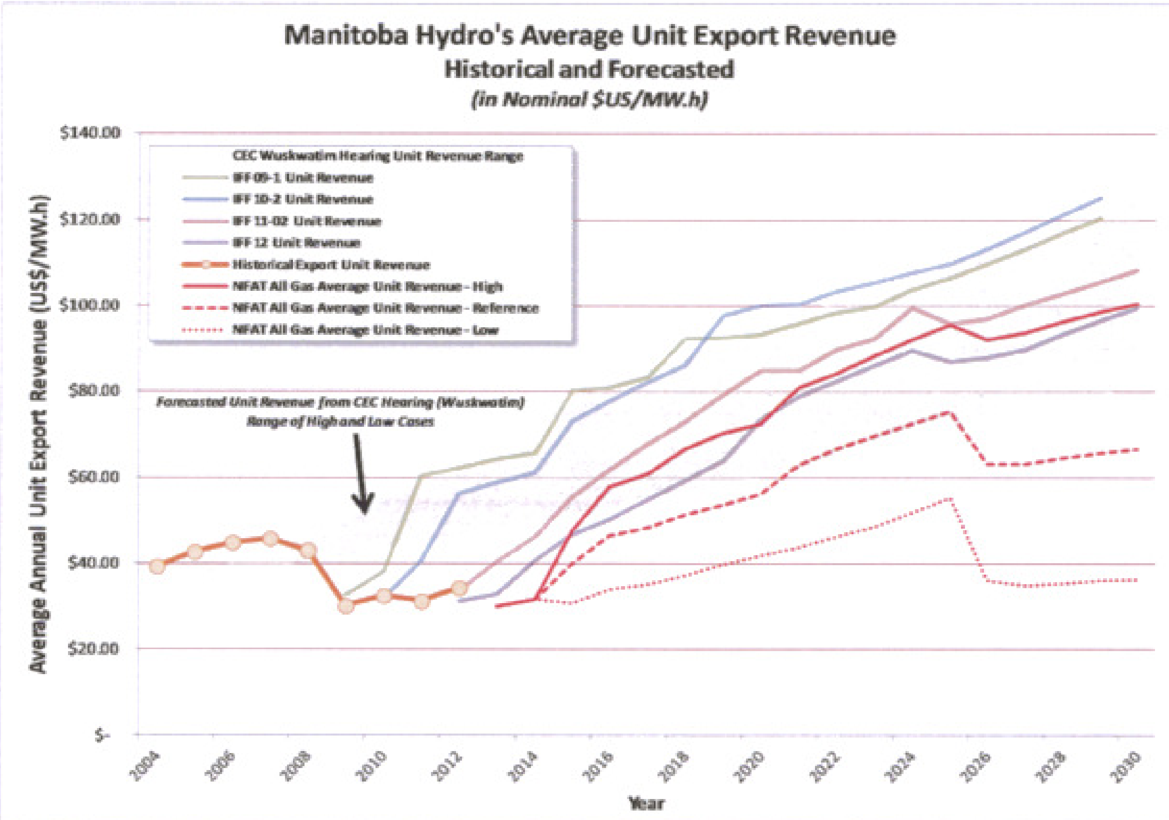
The second chart (below) is an update of PUB 19a, with the Reference, Low and High prices for the All Gas plan added.



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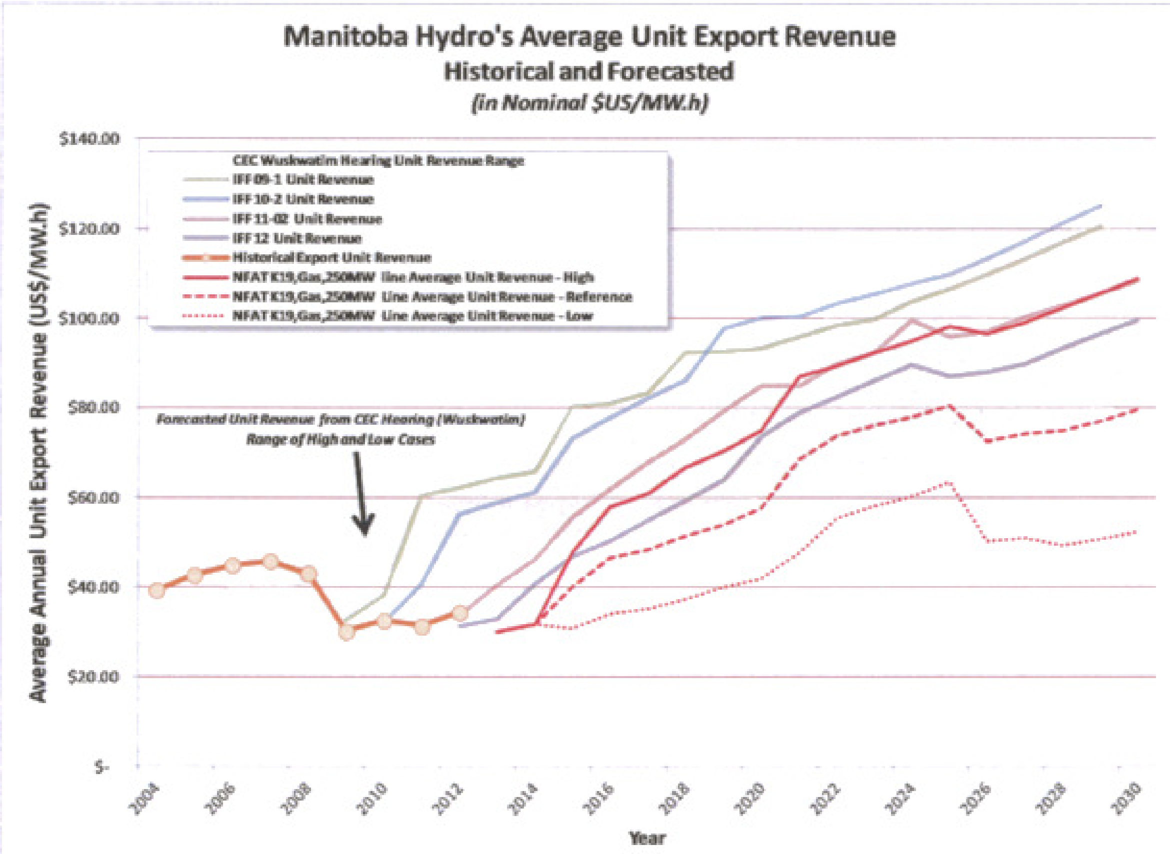
The third chart (below) is an update of PUB 19a, with the Reference, Low and High prices for the Keeyask 2019, Gas, 250 MW line plan added.



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The table below provides all the average unit revenue per MWh for the three NFAT development plans added to the charts above. All data was taken directly from NFAT Appendix 11.3 and converted to U.S. dollars as per the currently approved forecasted exchange rates in Manitoba Hydro's G-911. All prices are nominal U.S. dollars.

Year	Development Plan - ALL GAS			Development Plan - Recommended Plan			Development Plan - Keeyask 19, Gas, 250 MW Line		
	by Export Price Case			by Export Price Case			by Export Price Case		
	High	Reference	Low	High	Reference	Low	High	Reference	Low
2013	$ 30.15	$ 30.15	$ 30.15	$ 30.15	$ 30.15	$ 30.15	$ 30.15	$ 30.15	$ 30.15
2014	$ 31.66	$ 31.66	$ 31.66	$ 31.66	$ 31.66	$ 31.66	$ 31.66	$ 31.66	$ 31.66
2015	$ 47.84	$ 40.08	$ 30.87	$ 46.92	$ 39.85	$ 31.92	$ 47.83	$ 40.07	$ 30.90
2016	$ 58.03	$ 46.57	$ 34.07	$ 56.69	$ 46.26	$ 35.12	$ 58.01	$ 46.56	$ 34.10
2017	$ 61.12	$ 48.56	$ 35.17	$ 59.76	$ 48.33	$ 36.46	$ 61.09	$ 48.55	$ 35.21
2018	$ 66.82	$ 51.47	$ 37.25	$ 65.23	$ 51.48	$ 38.87	$ 66.83	$ 51.55	$ 37.41
2019	$ 70.44	$ 53.90	$ 39.78	$ 68.42	$ 53.87	$ 41.56	$ 70.55	$ 54.05	$ 40.01
2020	$ 72.67	$ 56.40	$ 41.92	$ 72.90	$ 57.44	$ 43.63	$ 75.03	$ 57.70	$ 41.92
2021	$ 80.95	$ 63.17	$ 43.75	$ 86.59	$ 69.94	$ 50.50	$ 87.08	$ 68.63	$ 47.65
2022	$ 84.29	$ 66.93	$ 46.30	$ 90.45	$ 75.66	$ 56.81	$ 89.32	$ 73.75	$ 55.52
2023	$ 88.33	$ 69.75	$ 48.72	$ 93.83	$ 78.12	$ 59.03	$ 92.33	$ 76.08	$ 58.25
2024	$ 92.15	$ 72.68	$ 51.89	$ 96.11	$ 79.98	$ 62.08	$ 94.84	$ 77.91	$ 60.35
2025	$ 95.76	$ 75.35	$ 55.42	$ 98.92	$ 82.31	$ 65.67	$ 98.26	$ 80.63	$ 63.56
2026	$ 92.17	$ 63.32	$ 36.09	$ 102.55	$ 78.42	$ 53.54	$ 96.48	$ 72.73	$ 50.29
2027	$ 93.73	$ 63.37	$ 35.01	$ 105.85	$ 81.07	$ 55.81	$ 99.15	$ 74.30	$ 50.94
2028	$ 96.36	$ 64.73	$ 35.35	$ 107.95	$ 82.35	$ 56.92	$ 102.29	$ 74.99	$ 49.29
2029	$ 98.71	$ 65.95	$ 36.19	$ 110.81	$ 84.61	$ 59.16	$ 105.64	$ 77.04	$ 50.69
2030	$ 100.61	$ 66.90	$ 36.28	$ 113.31	$ 86.65	$ 60.83	$ 108.96	$ 79.52	$ 52.46
2031	$ 103.33	$ 69.09	$ 37.70	$ 115.73	$ 88.69	$ 62.24	$ 112.18	$ 52.93	$ 53.96

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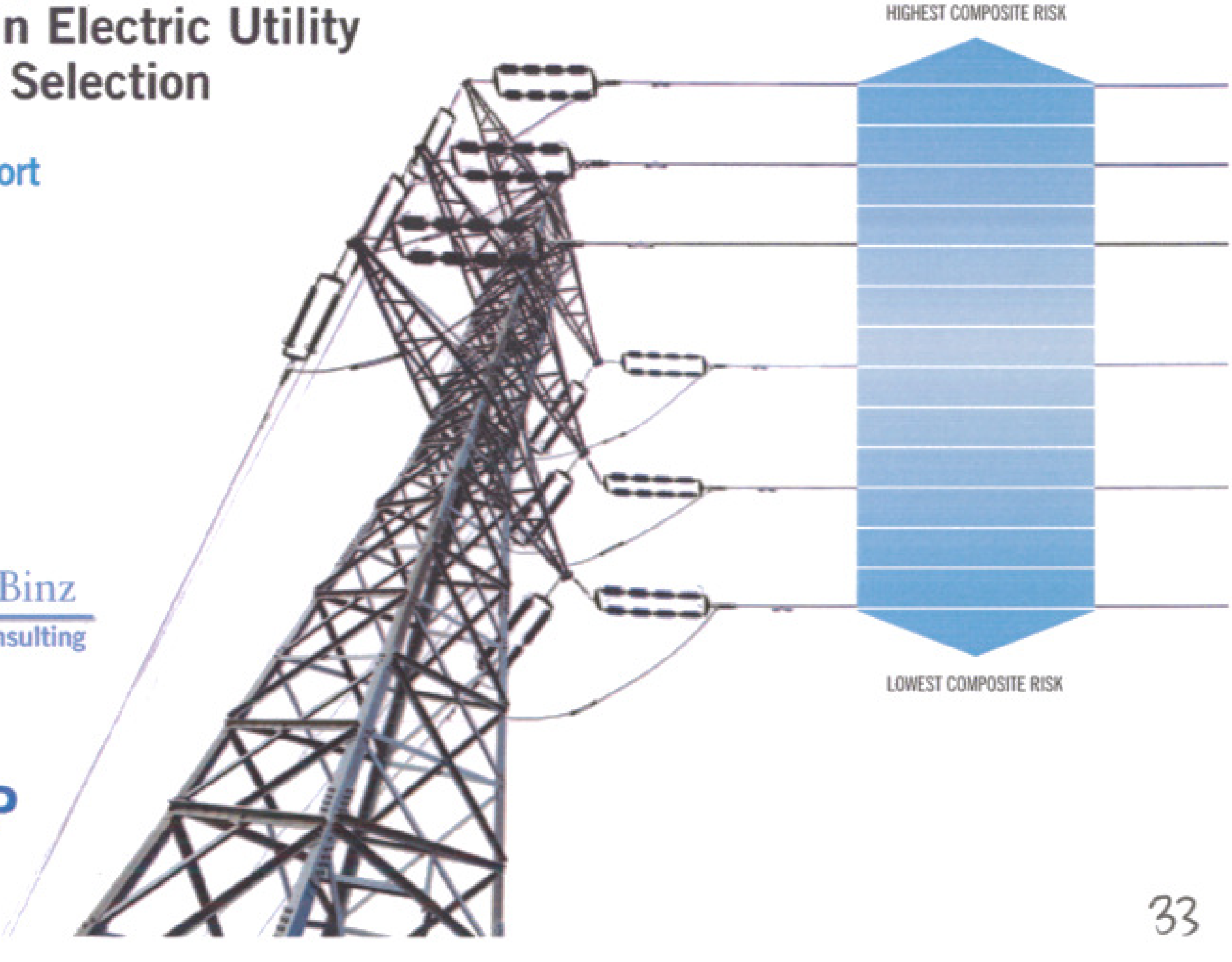
TAB 7

Ceres

PRACTICING RISK-AWARE ELECTRICITY REGULATION: What Every State Regulator Needs to Know

How State Regulatory Policies Can Recognize and Address the Risk in Electric Utility Resource Selection



A Ceres Report
April 2012

Authored by
Ron Binz
and
Richard Sedano
Denise Furey
Dan Mullen

Ronald J. Binz
Public Policy Consulting

RAP

EXECUTIVE SUMMARY

CONTEXT: INCREASING CAPITAL INVESTMENT BY U.S. ELECTRIC UTILITIES AMID HISTORIC UNCERTAINTY AND RISK

The U.S. electric utility industry, which has remained largely stable and predictable during its first century of existence, now faces tremendous challenges. Navigant Consulting recently observed that "the changes underway in the 21st century electric power sector create a level and complexity of risks that is perhaps unprecedented in the industry's history."[1] These challenges include:

- an aging generation fleet and distribution system, and a need to expand transmission;
- increasingly stringent environmental regulation limiting pollutants and greenhouse gases;[2]
- disruptive changes in the economics of coal and natural gas;
- rapidly evolving smart grid technologies enabling greater customer control and choice;
- increased policy maker emphasis on demand-side resources requiring new regulatory approaches and utility business models;
- competition from growth in distributed generation;
- slow demand growth due to protracted economic recovery and high unemployment;
- substantially weakened industry financial metrics and credit ratings, with over three-quarters of companies in the sector rated three notches or less above "junk bond" status.[3]

Many of these same factors are driving historic levels of utility investment. It is estimated that the U.S. electricity industry could invest as much as $100 billion each year for 20 years[4]—roughly twice recent investment levels. This level of investment will double the net invested capital in the U.S. electricity system by 2030. Moreover, these infrastructure investments are long lived: generation, transmission and distribution assets can have expected useful lives of 30 or 40 years or longer. This means that many of these assets will likely still be operating in 2050, when electric power producers may be required to reduce greenhouse gas emissions by 80 percent or more to avoid potentially catastrophic impacts from climate change.

1 Forrest Small and Lisa Frantzis, *The 21st Century Electric Utility: Positioning for a Low-Carbon Future*, Navigant Consulting (Boston, MA: Ceres, 2010), 28, http://www.ceres.org/resources/reports/the-21st-century-electric-utility-positioning-for-a-low-carbon-future-1.

2 Estimates of U.S. coal-fired generating capacity that could be retired in the 2015-2020 timeframe as a result of forthcoming U.S. Environmental Protection Agency (EPA) air quality regulations range from 10 to 70 gigawatts, or between three and 22 percent of U.S. coal-fired generation capacity. Forthcoming EPA water quality regulations could require the installation of costly cooling towers on more than 400 power plants that provide more than a quarter of all U.S. electricity generation. See Susan Tierney, "Electric Reliability under New EPA Power Plant Regulations: A Field Guide," *World Resources Institute*, January 18, 2011, http://www.wri.org/stories/2011/01/electric-reliability-under-new-epa-power-plant-regulations-field-guide.

3 Companies in the sector include investor-owned utilities (IOUs), utility holding companies and non-regulated affiliates.

4 Marc Chupka et al., *Transforming America's Power Industry: The Investment Challenge 2010-2030*, The Brattle Group (Washington DC: The Edison Foundation, 2008), vi, http://www.brattle.com/_documents/UploadLibrary/Upload725.pdf. Brattle's investment estimates apply to the entire U.S. electric utility industry, including IOUs, electric cooperatives and government-owned utilities. From 2000-05, overall annual capital expenditures by U.S. IOUs averaged roughly $48 billion; from 2006-10 that number climbed to $74 billion; see Edison Electric Institute, *2010 Financial Review: Annual Report of the U.S. Shareholder-Owned Electric Utility Industry* (Washington DC: Edison Electric Institute, 2011), 18, http://www.eei.org/whatwedo/DataAnalysis/IndusFinanAnalysis/finreview/Documents/FR2010_FullReport_web.pdf.

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1. CONTEXT:

INCREASING CAPITAL INVESTMENT BY U.S. ELECTRIC UTILITIES AMID HISTORIC UNCERTAINTY & RISK

U.S. ELECTRIC UTILITIES ARE FACING A SET OF CHALLENGES UNPARALLELED IN THE INDUSTRY'S HISTORY, PROVIDING MANY REASONS TO CONCLUDE THAT THE TRADITIONAL PRACTICES OF UTILITIES AND THEIR REGULATORS MUST BE UPDATED TO ADD A SHARPER FOCUS ON RISK MANAGEMENT IN THE REGULATORY PROCESS.

Consider the forces acting on the electricity sector in 2012:

- an aging generation fleet;
- infrastructure upgrades to the distribution system;
- increasingly stringent environmental regulation limiting pollutants and greenhouse gases;[16]
- disruptive changes in the economics of coal and natural gas;
- new transmission investments;
- rapidly evolving smart grid technologies enabling greater customer control and choice;
- increased policy maker emphasis on demand-side resources requiring new regulatory approaches and utility business models;
- competition from growth in distributed generation;
- slow demand growth due to protracted economic recovery and high unemployment;
- tight credit in a difficult economy and substantially weakened industry financial metrics and credit ratings.

In a recent book, Peter Fox-Penner, principal and chairman emeritus of the Brattle Group, concluded that the sum of these forces is leading to a "second revolution" in the electric power industry.[17] Navigant Consulting has observed that "the changes underway in the 21st century electric power sector create a level and complexity of risks that is perhaps unprecedented in the industry's history."[18]

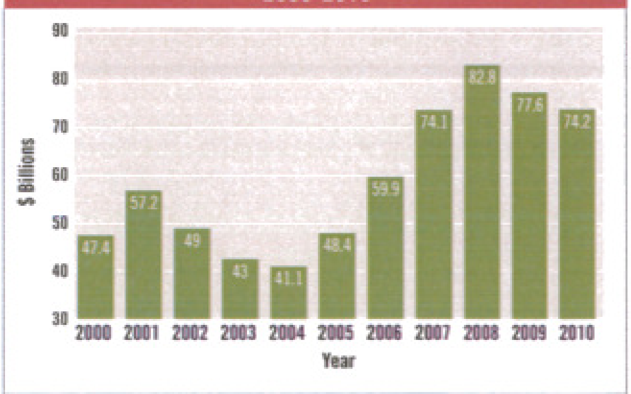
THE INVESTMENT CHALLENGE

The United States electric utility industry is a network of approximately 3,300 investor-owned utilities (IOUs), cooperative associations and government entities. In addition, about 1,100 independent power producers sell power to utilities, either under contract or through auction markets. The net asset value of the plant in service for all U.S. electric utilities in 2010 was about $1.1 trillion, broken down as $765 billion for IOUs, about $200 billion for municipal (publicly-owned) utilities (or "munis"), and $112 billion for rural electric cooperatives (or "co-ops").[19]

IOUs therefore constitute the largest segment of the U.S. electric power industry, serving roughly 70 percent of the U.S. population. **Figure 1** illustrates IOUs' capital expenditures from 2000-2010 and captures the start of the current "build cycle," beginning in 2006.[20] Between 2006 and 2010, capital spending by IOUs—for generation, transmission and distribution systems—was about 10 percent of the firms' net plant in service.

Figure 1

CAPITAL EXPENDITURES BY U.S. INVESTOR-OWNED UTILITIES, 2000-2010



16 See footnote 2.

17 Peter Fox-Penner, *Smart Power* (Washington DC: Island Press, 2010). The "first revolution" was triggered by George Westinghouse, Thomas Edison, Nicola Tesla, Samuel Insull and others more than a century ago.

18 Small and Frantzis, *The 21st Century Electric Utility*, 28.

19 See U.S. Energy Information Administration, "Electric Power Industry Overview 2007," http://www.eia.gov/cneaf/electricity/page/prim2/toc2.html; National Rural Electric Cooperative Association, "Co-op Facts and Figures," http://www.nreca.coop/members/Co-opFacts/Pages/default.aspx; Edison Electric Institute, "Industry Data," http://www.eei.org/whatwedo/DataAnalysis/IndustryData/Pages/default.aspx. Note that these numbers do not include investment by non-utility generators.

20 Edison Electric Institute, *2010 Financial Review*, 18.

TAB 8

NEEDS FOR AND ALTERNATIVES TO (NFAT)
REVIEW OF MANITOBA HYDRO'S
PREFERRED DEVELOPMENT PLAN

REPORT PREPARED FOR

THE CONSUMERS ASSOCIATION OF CANADA (MANITOBA) INC.

BY

ECONALYSIS CONSULTING SERVICES

FEBRUARY 4, 2014

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ECS Table #1 – Summary of Manitoba Hydro's Alternative Development Plans

Table 9.3 LIST OF FIFTEEN DEVELOPMENT PLANS

Order of Capital Investment (Plan Number)	Development Plan Short Name	Description of Development Plan
1	All Gas	Natural Gas-Fired Generation starting in 2022/23
2	K22/Gas	Keeyask 2022/23, Natural Gas-Fired Generation starting in 2029/30
3	Wind/Gas	Wind Generation starting in 2022/23 supported by Natural Gas-Fired Generation starting in 2025/26
4	K19/Gas24/250MW	Keeyask 2019/20, Natural Gas-Fired Generation starting in 2024/25, 250 MW Export/50 MW Import U.S. Interconnection 2020/21, 250 MW MP Sale
5	K19/Gas25/750MW (WPS Sale & Inv)[2]	Keeyask 2019/20, Natural Gas-Fired Generation starting in 2025/26, 750 MW Import/Export U.S. Interconnection 2020/21, 250 MW MP Sale, Proposed 300 MW WPS Sale
6	K19/Gas31/750MW	Keeyask 2019/20, Imports, Natural Gas-Fired Generation starting in 2031/32, 750 MW Import/Export U.S. Interconnection 2020/21, 250 MW MP Sale
7	SCGT/C26	Simple Cycle Gas Turbine in 2022/23, Conawapa 2026/27, Natural Gas-Fired Generation starting in 2038/39
8	CCGT/C26	Combined Cycle Gas Turbine in 2022/23, Conawapa 2026/27, Natural Gas-Fired Generation starting in 2039/40
9	Wind/C26	Wind in 2022/23, Conawapa 2026/27, Natural Gas-Fired Generation starting in 2036/37
10	K22/C29	Keeyask 2022/23, Conawapa 2029/30, Natural Gas-Fired Generation starting in 2040/41
11	K19/C31/250MW	Keeyask 2019/20, Natural Gas-Fired Generation starting in 2024/25, Conawapa 2031/32, 250 MW Export/50 MW Import U.S. Interconnection 2020/21, 250 MW MP Sale
12	K19/C31/750MW	Keeyask 2019/20, Imports, Conawapa 2031/32, Natural Gas-Fired Generation starting in 2041/42, 750 MW Import/Export U.S. Interconnection 2020/21, 250 MW MP Sale
13	K19/C25/250MW	Keeyask 2019/20, Conawapa 2025/26, Natural Gas-Fired Generation starting in 2040/41, 250 MW Export/50 MW Import U.S. Interconnection 2020/21, 250 MW MP Sale
14	K19/C25/750MW (WPS Sale & Inv)[2] Preferred Development Plan	Keeyask 2019/20, Conawapa 2025/26, Natural Gas-Fired Generation starting in 2041/42, 750 MW Import/Export U.S. Interconnection 2020/21, 250 MW MP Sale, Proposed 300 MW WPS Sale
15	K19/C25/750MW	Keeyask 2019/20, Conawapa 2025/26, Natural Gas-Fired Generation starting in 2041/42, 750 MW Import/Export U.S. Interconnection 2020/21, 250 MW MP Sale

[2] Inv refers to WPS investment in the U.S. portion of the 750 MW interconnection facilities.

TAB 9

GUEST COMMENTARY - US SHOULD PRICE CARBON, DIRECTLY

By Dean Murphy, Principal, The Brattle Group

An increasing number of US businesses, recognising the threat of climate change and seeing that national greenhouse gas regulation has become a near-term likelihood, have begun to call for meaningful federal climate legislation. One of the business community's primary concerns is that it wants "regulatory certainty" – to reduce the risk surrounding potential carbon regulation so that businesses can move forward confidently with strategies and investment plans.

Proposals based on a cap-and-trade approach dominate policy discussions, and are often advocated by many of these forward-thinking firms. But ironically, cap-and-trade does not offer the kind of certainty that business wants, nor the kind needed to encourage effective climate change solutions.

Cap-and-trade does not offer the kind of certainty that business wants

A cap on overall emissions does not give much certainty about price, and price is what really matters. To plan effectively, business and society in general must know what it will cost to emit greenhouse gases, for many years to come. Capping the emissions quantity does "put a price on carbon" to discourage emissions – but it leaves one to wonder what that price will be.

Of course, given an overall quantity cap, we can guess at which sectors might contribute how much reduction, at what cost, based on which new technologies, and how those costs will change over time as the cap tightens. Putting all this together, we can forecast allowance prices – except that the forecast will be highly uncertain at best, both in the near term and the long term.

The European Union's emissions trading scheme (ETS) offers a striking example. As of this writing, ETS CO_2 allowances are selling for €0.29/tonne – almost exactly 1/100th what they cost about a year ago. Even allowing that changes to ETS rules (e.g. allowing banking) would help reduce price volatility, the fact is that an emissions cap will create and maintain substantial uncertainty about CO_2 price. This makes all types of business planning more difficult, but it particularly interferes with the development and deployment of capital-intensive, long-lived carbon-reducing technologies (low-carbon energy sources, renewables, efficiency) that offer the only real answer to the climate problem.

Fortunately, there is another market-based solution. Rather than capping emissions, price them directly. An increasing, revenue-neutral carbon fee on fossil fuels (don't call it a tax; see below) avoids price uncertainty. The fee should start low to allow a gradual phase-in, but increase on a known long-term trajectory.

The policy should make clear from the start that the CO_2 price will get high enough, during the planning horizon of our energy infrastructure investments, to encourage deployment of carbon-reducing technologies. An increasing carbon fee allows sufficient time to adapt, combined with the foreseeable incentives needed to get the necessary adaptations started immediately. The recent House Bill by Representative Stark provides an example.

Rather than capping emissions, price them directly

Many dismiss a carbon fee as politically untenable because it resembles a "tax," and people hate taxes. But make it revenue-neutral, returning proceeds directly to consumers to offset increased energy costs, and it is much less onerous. Besides, cap-and-trade also amounts to a tax, except that the tax rate is unknown and variable and, if allowances are allocated for free, the "proceeds" may become windfalls to producers that are then unavailable for consumer refunds or program funding.

Some environmentalists worry that a carbon fee would not guarantee emission reductions. But with greenhouse gases, it is long-term atmospheric concentrations that matter; short-term targets are less relevant. In the long run, a fee is likely to lead to greater and more economical reductions than a cap, because it more effectively encourages the development and deployment of low-carbon technologies.

Point Carbon is happy to consider your proposals for Guest Commentaries in Carbon Market North America
Please submit ideas to Elizabeth Zelljadt at ez@pointcarbon.com

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LEGISLATION

Bills with cap-and-trade systems for greenhouse gases proposed in the 110th US Congress

Title and sponsors	Reduction target and timeframe	Important attributes
Climate Stewardship and Innovation Act S. 280 Senators Lieberman (I-CT) and McCain (R-AZ)	Bring emissions to 2004 levels by 2012, to 1990 levels by 2020, to 22% below 1990 levels by 2030, and to 60% below 1990 levels by 2050.	Caps electric power, industrial, commercial, and transport sectors (economy-wide). Includes provision for clean development mechanism through which US companies gain credits for emission reductions they sponsor in developing countries. Provisions for expansion of nuclear power.
Global Warming Pollution Reduction Act S.309 Senators Sanders (I-VT) and Leahy (D-VT)	Stabilise global greenhouse gas concentrations below 450 parts per million: US reductions to 1990 levels by 2020 and 80% below that by 2050.	Economy-wide caps. National renewable energy quotas and energy efficiency goals with credit trading programmes.
Electric Utility Cap-and-Trade Act S.317 Senators Feinstein (D-CA) and Carper (D-DE)	Caps current emissions through 2011, then at 2001 levels by 2012, thereafter cap lowers further 1% each year through 2020, subject to EPA review.	Power sector only. Specifies auctioning of credits, use of offsets. Establishes independent scientific panel to make recommendations to the EPA every four years on the reduction rate required.
Climate Stewardship Act H.R. 620 House Reps. Olver (D-MA) and Gilchrest (R-MD)	Emissions stabilise at current levels from 2012 to 2019, then are reduced 15% by 2020, 38% in 2030, 75% by 2050 (which equals 70% below 1990 levels).	Same as Lieberman and McCain's, except offset credits may account for only 15% of emissions reductions, and "early action" credits limited to 20% of cap. Does not contain Senate version's nuclear provisions.
Global Warming Reduction Act S.485 Senators Kerry (D-MA) and Snowe (R-ME)	Reduce emissions to 60 per cent below 1990 levels by 2050, through increasing annual reductions starting at 1.5% a year for the first ten years.	Economy-wide caps. Nationwide renewable fuels standard. National renewable energy quota of 20% by 2020.
Safe Climate Act H.R.1590 Rep. Waxman (D-CA)	Emissions freeze at 2009 level in 2010. Beginning in 2011, emissions cut ~ 2% per year, falling to 1990 levels by 2020. Beginning in 2021, annual cuts of ~ 5%, falling to 80% below 1990 levels by 2050.	National renewable energy quota: 20% by 2020. Energy efficiency targets: increase gradually from 0.25% of electricity sales in 2010 to 1% of sales in 2012 and each following year through 2020.
Clean Air Planning Act S.1177 Senator Carper (D-DE)	Caps power plant CO2 emissions at today's levels in 2012, at 2001 levels in 2015. Thereafter, annual reductions to achieve levels 25% below 1990 by 2050.	Power sector only, offsets allowed, output-based allocation, includes a new entrant reserve (carbon credits reserved for allocation to newly-built installations).
S.1168 Senators Alexander (R-TN) and Lieberman (I-CT)	Power plant CO2 emissions capped at 2.3 billion tonnes (2006 levels) in 2011, at 2.1 billion in 2015, 1.8 billion in 2020 (1990 levels), and 1.5 billion tonnes in 2025 and beyond (~17% below 1990 level).	Power sector only, allows offsets, includes new entrant reserve of no more than 5% of the year's allowances, includes emissions performance standard for plants built after 2015 (no more than 1100 lbs. CO2/MWh).
Clean Power Act Senator Sanders (I-VT)	Same as S.1168 for CO2, and specifies that if no economy-wide greenhouse gas bill has been passed by 2012, then CO2 emissions from power plants must be decreased each year by 3%.	Power sector only, CO2 performance standards for new plants, renewable energy quota: 20% by 2020. Energy efficiency targets with credit trading system: gradual reduction of peak demand and overall electricity use.

TAB 10

ISSUE 01 | 2008

Energy

Current Topics in Energy Markets & Regulation

About this Newsletter

In this issue of ENERGY, we look at how changes in the power industry are affecting integrated resource planning (IRP). Fundamental changes in fuel markets, capital costs, and new environmental concerns have upset utility resource planning, creating much more uncertainty than traditional IRP can accommodate. In this new environment, a different approach is necessary.

Contents

For more information on the authors or *The Brattle Group*, please visit **www.brattle.com.**

Reviving Integrated Resource Planning for Electric Utilities:
New Challenges and Innovative Approaches

By **Marc Chupka, Dean Murphy, and Samuel Newell**

Introduction

The electric industry is in the midst of some of the most difficult issues of our time, including climate change, national security, and the impact of high fuel costs on our economy. With unprecedented uncertainty and tradeoffs regarding these issues, resource planning has become a particularly daunting undertaking. It is increasingly difficult to identify the best resource choices, since uncertainties affect alternative resources in different ways, and the resource that is best under some circumstances may perform poorly in others.

In this context, many stakeholder processes have become deadlocked over differences in world views and policy priorities. Yet resource needs are looming in the power industry, with demand in most regions of the country soon to outgrow the capacity surplus created in the last generation boom. Major resource commitments for generation supply, transmission, and demand-side resources will have to be made, despite the uncertainties and risk.

In the current environment, the value of a resource option depends, perhaps primarily, on factors that are largely beyond the control of state regulators and generation suppliers. Such options include changes in fuel markets, rapidly rising construction costs, federal climate legislation, economic growth, organized electricity market conditions, and technological upgrades.

These external factors have created much more uncertainty than has been experienced in the last two decades, when fuel markets and construction costs were more stable and climate change was not a consideration. Today's challenges offer an opportunity to renew focus on the importance of integrated resource planning (IRP).

The Changing Role of IRP

Identifying the best future resource options is difficult, in part because of limitations in the traditional analytic approach to IRP. The IRP approach of minimizing the present value of revenue requirements (PVRR) in an assumed-certain future (augmented with a few sensitivity analyses on what that future might look like) does not sufficiently address either the uncertainties or the multi-attribute nature of the problem.

Traditional IRP does not address whether it is advantageous to make a bet on a promising technology that nonetheless has significant disadvantages in some possible futures. It does not commit only to a plan that performs reasonably well under any potential future state of the world, nor does it pursue short-term strategies such as market purchases that may buy time in the hope that some uncertainties will be resolved. It also does not address the diminished degree of control that utilities and state regulators have over regional market outcomes, particularly in restructured states.

A broader approach must be taken in order to address the enormous uncertainty and tradeoffs among competing policy objectives. Rather than optimizing resources against an assumed future, explicit consideration of the wide range of uncertainty can add valuable insight. Traditional IRP can be enhanced in the following ways:

♦ *Identify and characterize a wider scope of potential resource solutions, including aggressive demand-side programs and renewable generation, in addition to conventional supply options.*

♦ *Construct a range of plausible, internally consistent scenarios that characterize the range of uncertainty.*

♦ *Evaluate resource solutions against the scenarios using metrics of performance along multiple outcome dimensions, such as cost, environmental impact, reliability, and fuel diversity. Also, take into consideration future flexibility or options that may be created by resource solutions.*

♦ *Consider tradeoffs implied by the different resource solutions across scenarios and outcome dimensions, and utility and policy makers' ability to influence outcomes.*

All of these elements are necessary in both traditionally regulated states and in restructured states, because both face new uncertainties that are not controllable. However, there is a particular irony in restructured states. Although these states largely abandoned utility-based resource planning in favor of market-based provision of electric supply, many state governments have recently become concerned about the pace and type of new resources being developed in the market environment, and they question whether and how market-based supply addresses climate and fuel diversity issues.

Several restructured states have recently required that their utilities begin to submit resource plans again (e.g., Delaware and Connecticut) and/or have had government agencies conduct resource planning studies (e.g., New Jersey) to inform their policy options.

While these regulators may have less control over resource strategy than in non-restructured states (with correspondingly less cost responsibility assigned to ratepayers), they may still be able to influence the resource mix through a variety of policy levers. ■

Key Elements of IRP in Today's Policy Environment

Identify and Characterize Feasible Resource Solutions

The scope of potentially viable resource solutions is broader than it once was. In addition to traditional coal-fired and gas-fired supply options, there is also much interest in:

♦ *Emerging low-carbon baseload technologies, primarily new nuclear or coal with carbon capture and sequestration.*

♦ *Renewable generating resources, particularly to meet rapidly escalating renewable portfolio standards in many states.*

♦ *Demand-side solutions, including both energy efficiency/conservation and demand response programs.*

♦ *Transmission projects with broad market benefits.*

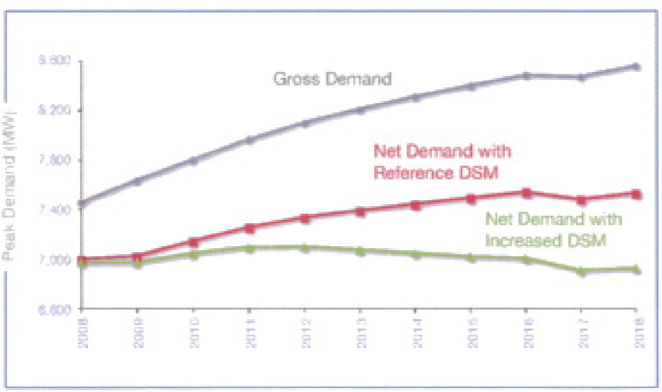
Identifying and accurately representing such candidate resource solutions can require detailed characterization of supply, demand, and transmission.

1. Generation Supply. Competing supply options differ in their installed and operating costs as well as their feasibility, lead time, and performance characteristics. Capital costs are most uncertain for new technologies, but the costs of conventional gas- and coal-fired resources are also in flux due to a recent, dramatic rise in construction costs.[1] These widespread cost increases affect technologies differentially and future cost uncertainty is particularly pronounced with capital-intensive technologies such as coal, wind, and nuclear.

Feasibility and lead times for new technologies have always been prone to uncertainty, but increased intervenor objections to traditional technologies such as coal have also created uncertainty about the ability to install new resources in a timely fashion. For renewables, resource quality (such as wind patterns) and state requirement rules must also be considered.

2. Demand-Side Resources. While demand-side resources have always been a conceptual part of IRP, in practice they have not always been an important focus. The current uncertainties facing supply resources, and in some cases regulatory pressure, are causing a resurgence of interest in demand-side alternatives. The key questions regarding demand-side resources include: what will they actually cost, how quickly can they be deployed, and what will be the ultimate customer penetration rates and program effectiveness?

Alternative Demand-Side Resource Solutions



Source: *The Brattle Group*

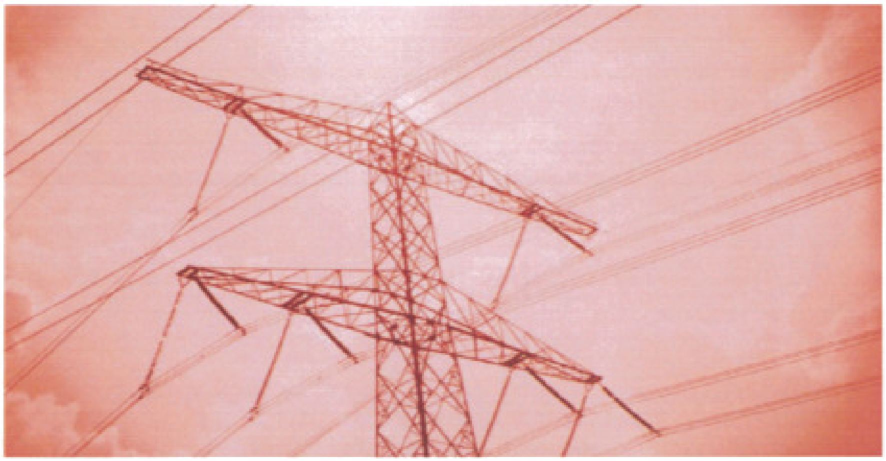
1. Chupka, M. and Basheda, G., "Rising Utility Construction Costs: Sources and Impacts," *The Brattle Group*, for The Edison Foundation, September 2007.

These questions can be addressed by either a "top-down" approach in which lessons from other jurisdictions are adapted, or a "bottom-up" approach in which potentially dozens of different program types are considered explicitly. In either case, a familiarity with the lessons learned from around the U.S. can greatly expand the range of options to be considered. It is also necessary to account for the existing programs, infrastructure, and customer base in the area.

3. Transmission. Transmission can provide numerous economic and reliability benefits, and facilitate better utilization of existing and potential new generation resources, including renewables. However, more transmission may not always improve performance on all dimensions. Transmission that allows better access to remote fossil generation can in some cases reduce costs but increase emissions, and even when it has clear benefits, they must be weighed against its costs.

Assessing transmission options against competing local generation or demand-side options requires characterizing specific potential projects and modeling them in both reliability and economic models. However, transmission planning is often performed separately from IRP, e.g., by a Regional Transmission Organization (RTO) or by retail utilities that have been separated from the generation company.

Even in an integrated utility, the resource planning and transmission planning functions are often separated. Therefore, it is important to assess the likely future additions to the transmission system and to incorporate them into the analysis of resource options. ■



Construct Plausible, Internally Consistent Scenarios

The external, uncontrollable effects of fuel prices, construction costs, climate change legislation, economic growth, and technological change may not simply vary by a few percent along a well-behaved continuum. Rather, they may exhibit significant, discontinuous shifts in ways that are interrelated with other factors. In this context, the traditional approach of forecasting a deterministic (expected) future and performing single-factor sensitivity analyses may not be sufficiently informative. Testing candidate resource solutions against scenarios that address the range of plausible future trajectories of external factors, and their interrelationships, can more effectively support planning in an uncertain environment.

Constructing internally consistent scenarios that capture plausible (and interrelated) future settings of uncertain, external factors requires expertise in energy and climate policy, fuel market relationships, the impact of retail price changes on electricity load forecasting, and the market impacts of future load and resource balances in electricity markets.

1. Climate Policy and Legislation. In addition to emerging state and regional climate change policies, most observers believe that federal climate change legislation is likely to be enacted within the next several years. The most likely regulatory framework is a CO_2 allowance cap-and-trade system, either applied upstream (and raising fossil fuel prices in proportion to carbon content) or directly on generators, requiring them to submit CO_2 emission allowances based on their use of fossil fuels.

The potential for CO_2 prices to have a significant financial impact on carbon-intensive resource options can no longer be ignored in long-run resource planning, or even relegated to a sensitivity case. However, the future CO_2 price-trajectory is still highly uncertain and potentially extremely volatile, particularly under a cap-and-trade policy approach that lacks a "safety valve" price cap. Scenario analyses should not

CASE STUDY:
CONNECTICUT INTEGRATED RESOURCE PLAN STUDY

In response to legislation requiring Connecticut utilities to jointly prepare a 10-year integrated resource plan, The Connecticut Light & Power Company and The United Illuminating Company retained *The Brattle Group* to conduct the analysis and help prepare the plan. The plan was submitted to the Connecticut Energy Advisory Board (CEAB) in January 2008.

Resource solutions were analyzed in the context of the ISO-NE energy and capacity markets, across four scenarios spanning a range of plausible futures. These scenarios characterized uncontrollable external factors such as fuel prices, climate change legislation, economic growth, and generation capital costs. All cases were analyzed using DAYZER, a locational marginal price (LMP) market simulation model, with a detailed representation of the ISO-NE transmission system. They also characterized the ISO-administered energy market.

Multiple evaluation metrics were examined in order to inform policy recommendations that addressed the economic and environmental policy objectives specified in the legislation. These metrics included market prices, resource costs, customer costs, natural gas consumption, and CO_2 emissions.

Key findings included:

Resource Outlook

♦ *Resource Adequacy: ISO-NE's resource adequacy needs are satisfied for the next several years, and Connecticut's local resource adequacy needs are satisfied for the foreseeable future, owing to recent and soon-to-be completed investments in transmission and generation.*

♦ *Markets: External, uncontrollable factors are the primary drivers of customer costs. Natural gas dependence will persist, and market prices for energy will continue to be high and volatile. However, high energy prices will also lower the net cost of new entry for combined-cycle capacity, thus mitigating capacity prices.*

♦ *Renewable Generation: Renewable portfolio standards are unlikely to be fully met with renewable generation.*

Comparison of Resource Solutions

♦ *Aggressive DSM that offsets growth for ten years has the lowest, or nearly lowest, cost across all scenarios, while also reducing emissions and natural gas usage.*

♦ *Nuclear and DSM mitigate CO_2 emissions more effectively than other resource solutions.*

♦ *Non-gas baseload generation would significantly reduce dependence on natural gas.*

Effect of Market-Based Pricing

♦ *Mechanisms such as long-term contracting or utility ownership can help to mitigate customers' exposure to volatile short-term market prices.*

Resulting policy recommendations, which recognize the realities of Connecticut's restructured electricity market, included:

♦ *Substantially increase utility investment in demand-side management (including energy efficiency).*

♦ *Allow the utilities to explore alternative procurement structures such as longer-term contracting.*

♦ *Reevaluate the structure of Connecticut's Renewable Portfolio Standard.*

♦ *Consider ways to enable the development of non-gas-fired baseload generation resources to mitigate customer exposure to the price and availability of natural gas.*

This was one of the first IRPs to be conducted in a restructured state and to address the challenges of managing customer costs in an RTO-type market while also addressing CO_2 emissions, dependence on natural gas, and renewable portfolio standards.

only include a carbon price case, but a range of carbon prices, as well as their interaction with other factors like fuel prices and electric demand.

2. Fuel Markets. Fuel prices, particularly for natural gas (which sets the power price most of the time in many markets) have been higher and more volatile than at any other time during the past three decades. Moreover, fuel prices could shift again to very different levels, depending on natural gas demand growth (potentially influenced by climate legislation), the development of LNG infrastructure, and supply conditions. Constructing realistic scenarios requires considering current futures market data, U.S. and global fundamentals, and the relationship between fuel prices and climate policy.

3. Load Forecasting. Load forecasting has always been the starting point for resource planning. In a scenario analysis, it becomes necessary to consider the long-term load forecast in the context of other scenario variables. For example, electricity demand will fall (or grow more slowly) when power prices are higher, all else equal. This effect can be analyzed via the long-term price elasticity of power demand considering the effect of fuel and CO_2 prices, and whether customers pay a market price or a regulated cost-of-service price. Load can also be affected by the effectiveness of demand-side management (DSM) programs and changing efficiency standards, both of which may interact with price responsiveness.

4. Capacity Balance and Capacity Markets. In restructured states, the value of new capacity depends on the amount, pace, and mix of merchant development and unit retirements, as balanced against power demand. The value of capacity can also be affected by the structure and rules that govern capacity, which can feed back into the amount of development and retirements. ■

Evaluate Resource Solutions on Multiple Dimensions

After constructing and identifying scenarios and candidate resource solutions, some form of electricity system simulation model is likely to be necessary to evaluate outcomes. This is conceptually similar to the resource planning models that have long been used. However, rather than focusing on optimizing the resource mix in the context of a deterministic future, there is more attention paid to simply evaluating specified resource solutions and comparing them across potential scenarios.

Since it is difficult to fully characterize the potential range of uncertainties and their interrelationships, it can be very helpful to illuminate the potential range of outcomes and the sources of value and risk under a given set of resource solutions. Armed with these insights, further refinements can be made to the most advantageous resource solutions.

A locational marginal price (LMP) market simulation model may be useful for resource planning in regions that are part of an RTO because it can accurately reflect the RTO's operation of the transmission system as well as the locational market environment.

In some markets, however, a simple production costing model will suffice. In any case, simulating the market makes it possible to evaluate the total cost, environmental, and fuel diversity impacts of each candidate resource solution. Locational market simulation is important when resources are location-specific (e.g., many renewable resources) and when transmission congestion and investment are associated with certain resource choices. Designing the metrics that best describe these many impacts presents its own challenges.

Customer Cost. State policy makers and regulators are often interested primarily in mitigating customer costs. The factors determining customer costs can depend strongly on the regulatory regime governing generation. Under a market-based regime, customer costs are determined by market prices for energy (including the overall impact of financial transmission rights), capacity, ancillary services (accounting for various settlement charges or rebates), and renewable energy credits, as well as transmission and distribution costs.

Addressing competing challenges in the context of increased uncertainty and limited regulatory control demands a new approach to resource planning.

Under a cost-based regime, customer costs are determined based on utilities' actual costs of fuel, O&M, emission allowances, and the embedded costs of the generation capacity potentially influenced by regulatory rates on cost recovery.

Many customers face a combination of market- and cost-based or fixed-price generation; cost-based utilities make some wholesale purchases and sales at market prices, and some customers in restructured states are served in part via long-term contracts that are not exposed to current market forces. The appropriate metric for a jurisdiction must account for customers' actual exposure to market vs. regulated prices.

Total Resource Cost. Policy makers may also be interested in quantifying the total going-forward resource cost to serve load. This reflects the total economic cost irrespective of who pays or benefits, and does not consider market prices or ratemaking principles. This metric is relevant even to customers in a market-based environment because resource costs can affect customers in the long run.

Average Costs/Rates. From the customer cost and resource cost, one can also calculate the average rates or average resource costs (in ¢/kWh). However, caution must be used with this measure, since average rates and costs can easily be misinterpreted. Average costs or rates may not accurately reflect value when the quantity of consumption is not constant, as is typically the case when comparing demand-side programs with more traditional supply-side solutions, or when evaluating scenarios in which price affects demand.

Environmental Impacts. Emissions of CO_2, NO_X, and SO_2 are readily quantified from the outputs of a simulation model and are an important outcome measure in their own right. However, care must be taken to ensure that the study captures effects such as whether a CO_2 emissions decrease in one region might imply an emissions increase in another region due to changes in power flows.

Fuel Diversity. Fuel diversity is rarely defined or quantified, except in terms of percentage of generation by fuel type. Care must be taken with such a measure, since the ultimate objective of fuel diversity is usually to reduce dependence on fuels with unstable prices, potential availability or deliverability constraints, and uncertain environmental costs. In such cases, the absolute quantities of fuels used, rather than their percentage share, may better reflect the underlying concerns in cases where overall generation levels may differ. It must also be recognized, however, that fuel diversity can come at considerably higher average costs.

In many states, renewable portfolio standards require load-serving entities to source a given percent of retail sales from renewable resources - and the required percentages are beginning to escalate rapidly in many regions. The resource planning process must account for the prospects of additional renewable development, as well as the potential financial consequences of failing to attain the required targets.

Renewables Standards. Promoting renewables and satisfying state-mandated renewable portfolio standards is often listed as an explicit policy objective, and progress against such objectives is easily tracked. However, the value of renewables overlaps with climate and fuel diversity objectives (while putting upward pressure on costs) and should be considered accordingly.

Transmission Investments. Traditional resource planning efforts have generally been focused on evaluating supply resources without explicit evaluation of associated transmission investments. With the location-specific nature of many supply resources and a competitive generation environment where it is difficult to control the location of supply additions, it has become increasingly important to evaluate supply or demand options in the context of transmission constraints and transmission investment requirements. This generally requires planning models, such as LMP simulation models, that can evaluate generation in the context of the existing grid and transmission investment options.

These metrics can provide policy makers with the kinds of information they need to identify preferred resource solutions in the face of large uncertainties. However, it is important to recognize from the start that it is unlikely that a single resource solution will be superior on every metric across all scenarios. Often a "robust second best" solution will present a more favorable value/risk profile than a solution that appears optimal in some scenarios (on some dimensions), but may perform poorly in others.

Compared to focusing on optimizing a single cost-based metric (such as minimizing PVRR) in a narrowly-defined forecast of future conditions, a multi-attribute scenario analysis can be more difficult to perform, but is likely to lead to much greater insight into potential tradeoffs and risks. These considerations can lead to the selection of a resource solution that performs fairly well across a broad range of scenarios, even if it dominates none. ■

Consider Tradeoffs and Options to Influence Outcomes

In non-restructured states, utilities and public utility commissions have substantial control over resource development, and customers must pay for approved projects. In restructured states, market participants make resource decisions and face the financial consequences, and regulators and indeed the utilities themselves, have much less control.

However, regulators in restructured states can typically still control the amount and types of demand-side management programs that are developed by retail providers, and this should be informed by IRP studies. State governments can also exert substantial influence over the generation resource mix through a number of mechanisms, including:

♦ *Allowing utilities to own certain assets or sign long-term contracts for certain resources to serve customers who have not migrated to competitive suppliers, while guaranteeing recovery through rates.*

♦ *Providing tax credits or other incentives to encourage development of desired resources.*

♦ *Setting renewable portfolio standards.*

♦ *Permitting utilities to procure energy under longer-term contracts (with guaranteed recovery) to mitigate customers' exposure to short-term market prices.* ■

CONCLUSION

The need to address rising customer costs, climate change, and fuel diversity is motivating a resurgent interest in integrated resource planning. Addressing competing challenges in the context of increased uncertainty and limited regulatory control demands a new approach to resource planning.

The four enhancements to traditional IRP efforts described herein provide the needed analytic framework, as demonstrated in their application to the Connecticut IRP study. Executing IRP with these enhancements requires up-to-date expertise in related analytic fields that have not traditionally played an important role in IRP, including: generation economics, fuel markets, climate policy analysis, demand response program evaluation, and RTO market and transmission simulation modeling.

Companies that are willing to do this will be able to better assess uncertainty and manage tradeoffs in today's challenging resource planning environment. In doing so, they will also improve their ability to influence stakeholders and regulators, thereby enhancing their ability to implement the resource strategy they ultimately select.

The Brattle Group's Capabilities

Energy utilities in both regulated and restructured energy markets must assess the value and risk of resource strategies to meet future energy needs. Recent market events have amplified the uncertainties facing utilities: future fuel and power prices, the cost and performance of supply- and demand- side resources, evolving environmental and climate regulations, and customer behavior.

Against this backdrop of uncertainty, utility resource planning faces intensive scrutiny from both regulators and investors who seek assurance that a company has properly balanced the potential value of an investment program with its inherent risks.

This places a premium on coherent analytical approaches that address fundamental value and risk characteristics and provide meaningful insights into key opportunities and tradeoffs.

The Brattle Group offers this planning advice to electric, gas, and other utilities, regulatory authorities, and government agencies. We offer a blend of energy market experience in the U.S. and abroad, with expertise in finance, market structure, market design, and regulation. Our economists have a deep understanding of the uncertain factors that drive energy resource decisions.

We have extensive analytic expertise in a wide variety of applications, including resource and business planning decisions, energy policy matters, and commercial disputes. Our clients benefit from *Brattle's* comprehensive skills in system simulation and financial modeling, market analysis and forecasting, cost of capital, option pricing, decision analysis, and risk management. We also understand the importance of incorporating energy risk management strategies, utility rate proceedings, and transmission analysis.

Our broad experience in analyzing the interrelated factors that influence energy markets makes us ideally qualified to help utilities plan in the face of the much greater uncertainties that now prevail. Our energy resource planning experience includes engagements in the following areas:

- *Utility resource planning and economics*
- *Integrated supply-demand and power systems modeling*
- *Demand response, demand-side management, and load forecasting*
- *Climate policy analysis and modeling*

About the Authors

Principal

Mr. Marc Chupka has over two decades of public and private sector experience analyzing the market impacts of both domestic and international energy and environmental policy. He has focused on electricity and fuel procurement policies, integrated resource planning, reliability analysis, litigation in Clean Air Act matters, renewable energy policy design, and estimating the impact of climate change policies on the energy industry and other sectors. He formerly served as the acting assistant secretary for policy and international affairs at the U.S. Department of Energy.

Mr. Chupka holds an M.S. and M.Phil in Economics from Yale University and a B.A. in Economics from Yale College.

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Dr. Dean Murphy is an economist and engineer with expertise in the areas of competitive and regulatory economics, finance and quantitative modeling, and risk analysis. His work has centered on the electric industry, encompassing issues such as climate change policy, contract disputes, competitive industry structure and market dynamics, market rules and mechanics, and price forecasting. He has addressed these issues in the context of litigation, regulatory compliance filings and hearings, and in support of business strategy and decisions. Prior to joining *The Brattle Group*, he was an associate director for air, energy and transportation at the White House Office for Environmental Policy.

Dr. Murphy holds a Ph.D. in Industrial Engineering and Engineering Management and an M.S. in Engineering-Economic Systems, both from Stanford University, and a B.E.S. in Materials Science and Engineering from the Johns Hopkins University.

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Dr. Samuel Newell is an economist and engineer with expertise in the analysis of electricity markets and their relationship to the transmission system. He supports clients in litigation cases, regulatory proceedings, and strategy matters. He has assisted utilities in incorporating the likelihood of climate change legislation and fuel price volatility into their resource plans. He also has project experience with major market simulation models and leads *The Brattle Group's* locational electricity market modeling efforts in all U.S. RTOs. Prior to joining *The Brattle Group*, he was director of the transmission service at Cambridge Energy Research Associates.

Dr. Newell holds a Ph.D. in Technology Management and Policy from the Massachusetts Institute of Technology, an M.S. in Materials Science and Engineering from Stanford University, and an A.B. in Chemistry and Physics from Harvard University.

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LATEST FIRM-WIDE NEWS

The Brattle Group Estimates $1.5 Trillion Needed in Utility Infrastructure Investment Through 2030

Brattle has determined that growing demand for electric services will require investment on the order of $1.5 trillion between now and 2030. Peter Fox-Penner, co-chairman, presented the preliminary findings in April at The Edison Foundation conference "Keeping the Lights On – Our National Challenge."

The study projects generation, energy efficiency, transmission, and distribution investment needed in the U.S. between 2010 and 2030, factoring in a range of capacity deferrals that are possible through the implementation of energy efficiency programs. The study notes that new and replacement generating plants will cost about $560 billion through 2030, absent a significant expansion of efficiency programs or new climate initiatives. Transmission and distribution will require nearly $900 billion by 2030, under current trends and policies.

The full report, on which these preliminary findings are based, is sponsored by The Edison Foundation and will be available this fall.

Brattle Recommends Incentives to Improve Energy Efficiency in Europe

Senior advisor David Robinson has proposed guidelines for the economic regulation of energy suppliers and recommended incentives for suppliers to help encourage energy efficiency and cost savings throughout the industry.

The paper, "Energy Efficiency: The Belle of the Ball in Bali," recommends incentives for the industry, whether in a regulated or competitive market. Guidelines include the importance of reflecting accurate underlying whole energy prices, ensuring that environmental benefits are explicitly included in any analyses, and providing incentives to keep economic costs as low as possible.

Principal Coleman Bazelon Testified Before U.S. Congress on Recent Wireless Spectrum Auction

At a Congressional hearing on April 15 regarding the recently concluded Federal Communication Commission's 700 MHz spectrum auction, Coleman Bazelon, a principal in our telecommunications practice, described how ill-configured spectrum license blocks and a poorly designed auction resulted in an unfortunate outcome for the wireless industry.

Bazelon, who was involved in the auction on behalf of clients, testified that the auction failed to meet the goals set forth by the FCC. He noted that the spectrum license blocks were poorly configured, stating *"If the spectrum blocks had been configured differently, the auction could have raised as much as an additional $5 billion from bidders that were shut out."*

Brattle Offers Issue Brief on Litigation Risks of Expanding Subprime Crisis

Principal George S. Oldfield has authored a brief on the increased litigation risks of late regarding the fallout of the subprime mortgage crisis. This piece follows up a 2007 newsletter "Subprime Mortgage Problems: What to Look For and Where to Look." This latest brief offers a view of spreading credit and insurance problems in the finance industry, and explains possible litigation risk in light of current uncertainty.

Principal Hannes Pfeifenberger Presented at WIRES Meeting on Assessing Transmission Benefits

Hannes Pfeifenberger, a principal in *Brattle's* Cambridge office, presented at the Working Group for Investment in Reliable and Economic Electric Systems (WIRES) meeting in Washington, DC in February. His presentation, "Assessing the Benefits of Transmission Investments," noted that while most transmission investments are justified through reliability projects, there are significant opportunities to improve transmission grid and power markets through economically-justified transmission projects. His presentation also discussed quantifying a wide range of transmission benefits, showing that, because of complex market interactions and the broad economic costs of inadequate transmission, economic analyses of transmission investment frequently understate the facilities' true benefit.

Study on Benefits of Dynamic Pricing Presented at NARUC Annual Meeting

At the annual meeting of the National Association of Regulatory Utility Commissioners held in February, a whitepaper on the benefits of dynamic pricing in the electric industry was distributed by The Edison Electric Institute, the paper's sponsor. The paper helps utilities faced with problems posed by aging infrastructure by laying out a methodology for quantifying the costs and benefits of implementing dynamic pricing and advanced metering infrastructure. Principal Ahmad Faruqui was the lead author of the study "Quantifying the Benefits of Dynamic Pricing in the Mass Market."

To learn more or obtain a copy of our publications or reports, please go to www.brattle.com.

Our Functional Practice Areas

- Antitrust/Competition
- Commercial Damages
- Environmental Litigation and Regulation
- Forensic Economics
- Intellectual Property
- International Arbitration
- International Trade
- Product Liability
- Regulatory Finance and Accounting
- Risk Management
- Securities
- Tax
- Utility Regulatory Policy and Ratemaking
- Valuation

Our Industry Practice Areas

- Electric Power
- Financial Institutions
- Natural Gas
- Petroleum
- Pharmaceuticals, Medical Devices, and Biotechnology
- Telecommunications and Media
- Transportation

About The Brattle Group

The Brattle Group provides consulting services and expert testimony in economics, finance, and regulation to corporations, law firms, and governments around the world.

We combine in-depth industry experience, rigorous analysis, and principled techniques to help clients answer complex economic questions in litigation, develop strategies for changing markets, and make critical business decisions.

We are distinguished by:

- *Thoughtful, timely, and transparent analyses of industries and issues*
- *Affiliations with leading international academics and highly credentialed industry specialists*
- *Clearly presented results that withstand critical review*

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TAB 11

Integrated Resource Plan for Connecticut

January 1, 2010

Prepared by:

The Brattle Group

Connecticut Light & Power

The Northeast Utilities System

The United Illuminating Company

52

5. Nuclear Power

- Nuclear generation has significant environmental benefits, including displacing fossil generation and associated greenhouse gases, while making Connecticut less reliant on natural gas generation.
- Nuclear capacity expansion is a long-term prospect – 10 to 15 years from the start of preparing a license application to commercial online date.
- New merchant nuclear capacity is unlikely to be developed in New England without a cost recovery approach that can mitigate the risks of high and uncertain capital costs, long lead time, and the potential for costly delay.

6. Combined Heat and Power (CHP)

- Connecticut already enjoys high penetration of CHP for the most attractive large industrial applications, so there is limited remaining potential in this sector.
- Smaller, mostly commercial and institutional applications have significant remaining technical potential in Connecticut.

7. Environmental Regulations Affecting Electricity

- While there is uncertainty regarding future Federal climate legislation, the prospects appear likely enough for a range of CO_2 prices to be reflected in our analysis.
- Because Connecticut and other parts of New England are not in attainment with air quality standards, additional NO_X control requirements will likely be imposed on generators. The EDCs and CTDEP worked together to establish likely future NO_X emission requirements which were reflected in the simulation of the New England electricity market. The cost of these controls is projected to cause retirements of older fossil steam units in our analysis.
- Emission allowance prices – for SO_2, NO_X and CO_2 – will raise the costs of generation in proportion to unit emission rates, and will impact the dispatch of resources in New England and thereby reduce overall emissions. Although the prices of allowances for each pollutant are determined by aggregate emissions relative to an emission cap, these markets are not wholly independent. In particular, the price of CO_2 allowances can influence the price of SO_2 and NO_X allowances, an effect that was reflected in the analysis.
- The imposition of new regulations for other environmental sectors (not air) have the potential to introduce greater costs to generators, though the potential impact of these costs cannot be determined at this time and thus were not reflected in the analysis.

8. Energy Security

- The power system is planned, designed, and operated to maintain high energy security, building in spare capacity, redundancy, and operational flexibility. A number of organizations at the national, regional, and state levels oversee and enforce reliability.

- Key resources for energy security include natural gas and nuclear generation, because of the system's heavy reliance on these generation types and the risks that could affect their operability, as well as the electric transmission system. Other resources – oil, coal, renewables – are unlikely to pose energy security concerns of comparable magnitude, due to the smaller role these resources play in providing power, and also because of a lack of exposure to significant risks.
- Natural Gas: The New England power system's reliance on natural gas was stress-tested by analyzing the loss of access to natural gas for several days during the winter months. This analysis suggests that there would be adequate other generation resources available to serve winter load, with no or virtually no reliance on natural gas. This is due to several seasonal factors that improve the winter resource balance, plus dual fuel capability that allows many gas-fired generators to utilize oil if gas is not available.
- Nuclear: A prolonged, simultaneous shutdown of multiple nuclear units at peak load times could stress the system's ability to serve load. However, it appears that even with the loss of both Connecticut nuclear units, the implementation of existing emergency operating procedures and additional reliance on imports from neighboring regions would allow the system to continue to serve load.
- Transmission: The electric transmission system is designed and operated with a level of redundancy that allows it to absorb isolated failures with no impact on customers. If an extreme event were to cause a more widespread transmission failure, the transmission owners' recovery capabilities and procedures ensure that any service interruption would be brief.

9. Natural Gas

- The overall supply picture for domestic natural gas appears promising, due particularly to the advent of new unconventional gas supplies such as shale gas. This expanding supply should be adequate to accommodate even increased gas demand, though the ultimate extent and pace of the new supplies coming online is not certain.
- Pipeline and LNG delivery capacity to New England have increased over the past several years, with additional new expansion projects still in development for the near future. Gas delivery capacity to serve average and peak needs has improved measurably from a few years ago (though this does not address gas local distribution company (LDC) deliverability issues, where additional expansions may be necessary).
- LNG and Canadian conventional gas may be less important for augmenting New England gas supplies than was expected in the recent past, due to the advent of new domestic supplies at lower prices. They will nonetheless continue to serve as a backstop for the availability and price of domestic gas supplies. Regardless of whether it actually does substitute for domestic gas more widely, LNG will remain a

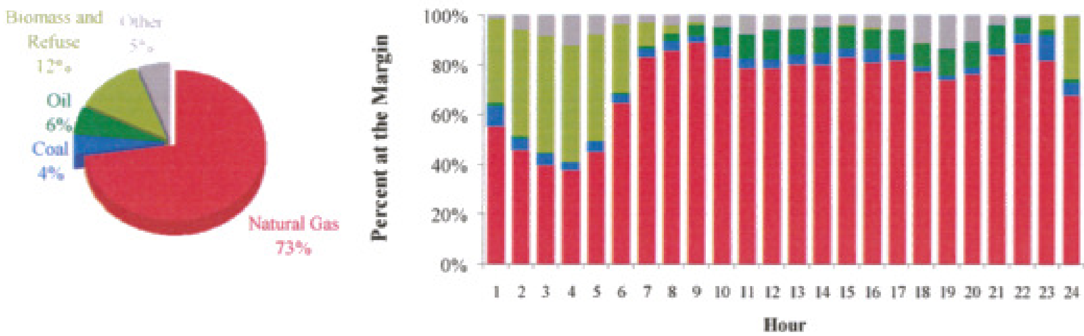
crucial component of New England's ability to meet peak gas demands in the winter heating season.

- Natural gas prices are expected to remain reasonable at around $7.00/MMBtu (real dollars) in the long term, driven largely by new unconventional supply sources. However there is no certainty that these current price expectations will be fulfilled; a long-term gas price range of approximately $4-10/MMBtu was examined in this study. Regardless of what happens to the long-term price of gas, short-term gas prices can be volatile.

10. Emerging Technologies

- Because of the growing commitments to plug-in electric vehicle (PEV) manufacturing and charging infrastructure on the part of vehicle manufacturers and electric utilities, PEVs appear poised to achieve an uncertain but potentially significant fleet penetration over the next decade.
- A 5 percent level of fleet penetration by 2020 represents an optimistic view of PEV vehicle sales over the next decade, but one that is worth exploring for its potential impact on the New England electricity system.
- Even an optimistic view of PEV penetration in New England over the next two decades is unlikely to pose any unmanageable issues for maintaining reliable electric service.
- An optimistic view of PEV penetration in New England is likely to produce a modest environmental benefit, with net CO_2 and NO_X emissions decreasing and only a negligible increase in SO_2 emissions.
- Widespread implementation of advanced metering infrastructure (AMI) has the potential to decrease peak loads. The magnitude of the decrease will depend on customer participation rates in dynamic pricing programs and their responsiveness to near-term price signals.
- Enabling technologies can help customers respond more effectively to price signals, and AMI programs that encourage these technologies are more likely to yield more pronounced responses.

Figure 15
New England Marginal Generation by Fuel Type in 2020
Based on DAYZER Simulations for the Base Case



Gas prices, as well as CO_2 prices, will be driven largely by factors that are external to the New England power market. Load is driven by economic growth, but to a significant extent it is also influenced by the price of power – higher prices tend to suppress load, and vice versa. Power prices are in turn heavily affected by gas and CO_2 prices, as well as other factors, such as the supply-demand balance, through a set of feedback relationships that evolve over time.

For each of the scenario variables – gas price, CO_2 price, and load – we characterized possible outcomes, capturing fairly extreme, yet plausible, values of the factors, and the relationships with other factors. The development of Gas Price and CO_2 price scenarios are discussed in Section III.9 (Natural Gas) and Section III.7 (Environmental Regulations Affecting Electricity), respectively. To characterize demand, we begin with ISO New England's current load forecast. This forecast is assumed to be consistent with current expectations for gas price and CO_2 price, and this set of factors together makes up the "Current Trends" scenario – *i.e.*, the outlook in which all factors tend to follow current expectations. When considering other values of Gas Price and/or CO_2 price, we developed a demand elasticity relationship to characterize the effect of power price on load, treating peak and energy load separately, and phasing in both short-term and long-term demand elasticity effects. Independently, we also evaluate a case of high demand that may reflect demand growth independent of price influences (*e.g.*, in response to high regional economic growth).

Almost any combinations of the key factors could be considered a scenario, but only a limited number of scenarios can be evaluated. To select the scenarios that will be most informative, we developed combinations of the external factors – Gas Price, CO_2 Price, and Load – that are relatively likely and internally consistent, but that also stress the resource strategies being considered and help to distinguish between strategies. The particular scenarios chosen are characterized in Table 1. The constituent Low, Medium, and High trajectories of gas price and CO_2 price are shown in Figure 16, and the load trajectories associated with the scenarios are in Figure 17.

Table 1
Scenario Definitions

Scenario	**Gas Price**	**CO_2 Price**	**Load Growth**
"Current Trends"	Medium: futures extrapolated	Medium: EIA "Basic Case" for Waxman-Markey	CELT forecast
"Lo Gas/Lo CO_2"	Low	Low: EIA "High Offset Case" for Waxman-Markey	CELT adjusted up by price elasticity
"Med Gas/Hi CO_2"	Medium	High: EIA "No International Case" for Waxman-Markey	CELT adjusted down by price elasticity
"Hi Load Growth"	Medium	Medium	CELT High Economic Growth forecast
"Hi Gas/Hi CO_2"	High	High	CELT adjusted down by price elasticity

Figure 16
Price Trajectories for Scenarios

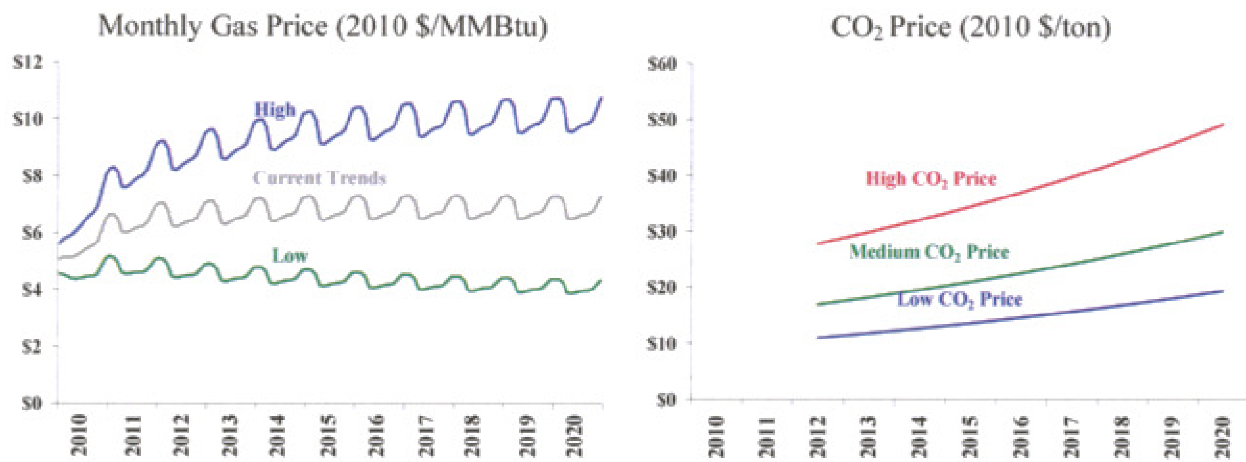


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Figure 29
Connecticut Customers' Annual Power Supply-Related Costs in 2020 (2010 $Mill)

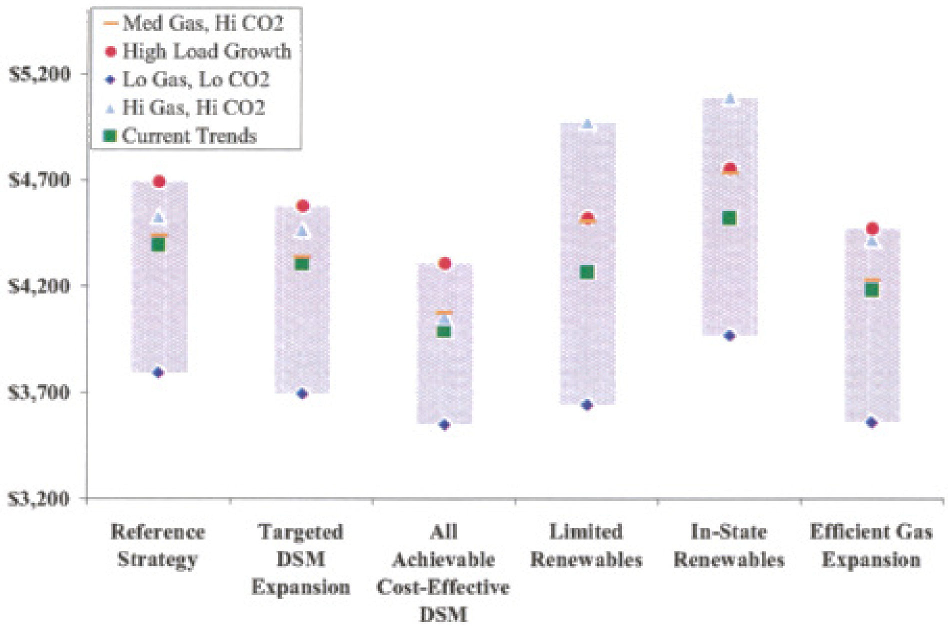

Figure 30
Connecticut Customers' Annual Average Power Supply-Related Costs in 2020 (2010 ¢/kWh)

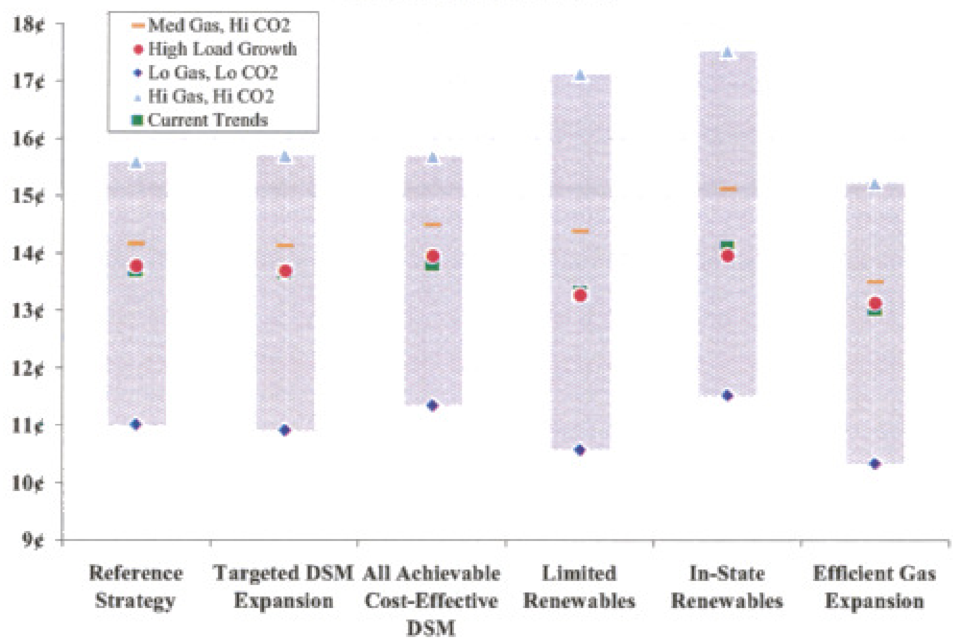

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Figure 39
Winter Gas Use in ISO-NE in 2020 (MMBtu 000)

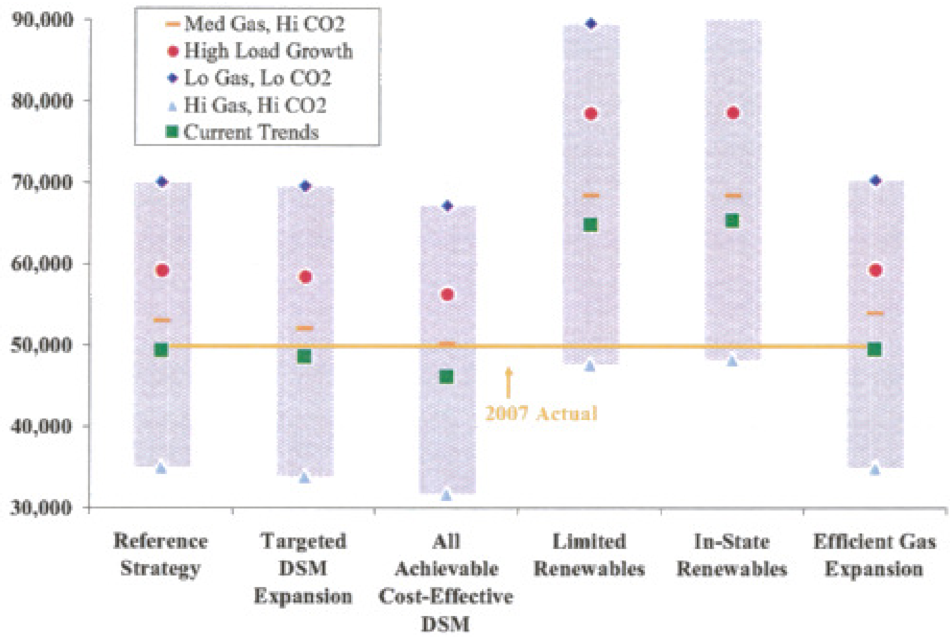
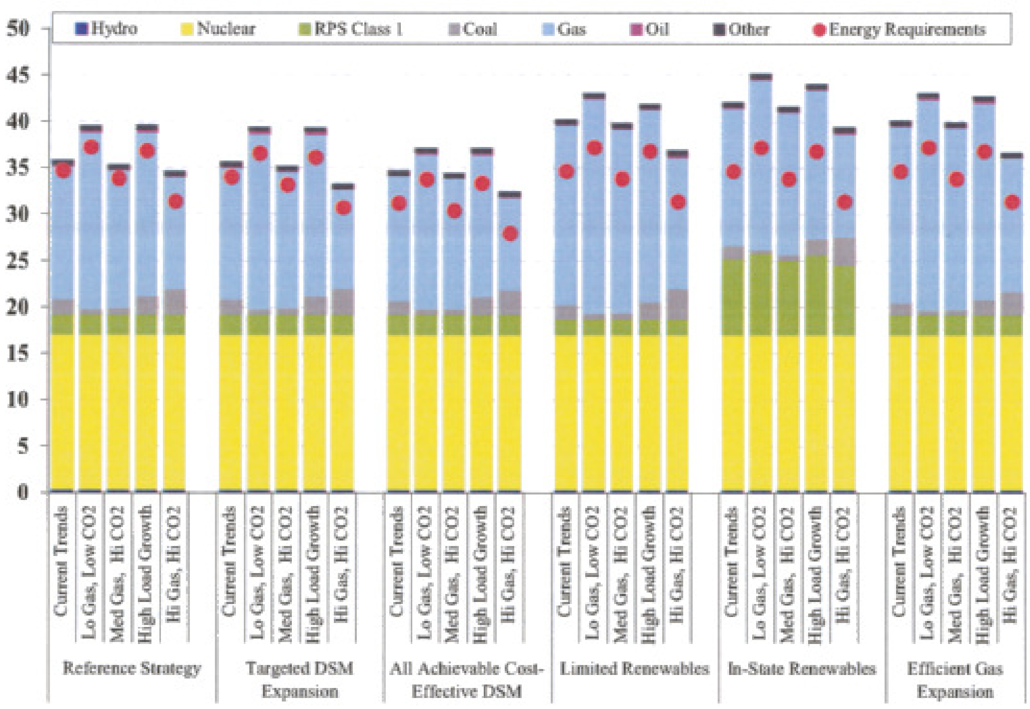


Figure 40
Connecticut Generation by Fuel Type in 2020 (TWh)



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- **Permanently retired units in other states (942 MW):** Cleary 8, West Springfield 3, Yarmouth 1-4.
- **Mothballed units:** none.

Table 1.10 shows the resulting impact on ICR resource adequacy. With 2,446 in unit retirements the ISO still has sufficient resources through 2020, although the resource surplus drops from 2,686 to 240. Connecticut would also have sufficient resources through 2020 to meet requirements under both CT LSR and CT TSA.

In addition for the Base Case, several sensitivities to address some uncertainties in this analysis that could have significant impacts on the results were performed:

- **No emission rate limit**: This sensitivity tests for potential economic retirements without additional capital cost requirements. Prices reach the 2013-2015 price floor, drop to extremely low levels (about $1/kW-month) after the price floor is removed, and do not recover until 2024. Capacity prices increase thereafter and reach net CONE by 2027. In this sensitivity there are only 459 MW in permanent retirements ISO-wide, and 330 MW in Connecticut.
- **High mothball cost:** This sensitivity increases the cost to mothball from 50 percent of FOM to 75 percent of FOM, testing the impact of lower cost savings for mothballed units. With this cost increase there are 410 MW in additional retired capacity, including Middletown 4 (CT) and Cabot 8 (MA). Both units are marginal, and retire due to much lower capacity prices in 2016-19, which causes them to carry cumulative net losses even eight years after SCR installation in 2017. Prices are lower initially (then higher) than the original case. This is because the high mothball cost allows prices to drop a lot before there would be scarcity. The lower prices in turn cause slightly higher retirements.
- **No emission rate limit and extended price floor:** This sensitivity tests for potential retirements under continued surplus conditions. Capacity permanently retired is the same as under the no emission rate limit sensitivity, but capacity prices remain at the price floor through 2026, before reaching net CONE in 2027.
- **High merchant cost of equity:** This sensitivity examines merchant risk associated with uncertain SCR capital cost values by raising return on equity (ROE). Assumed merchant ROE is increased from 15 percent to 20 percent. This increases the total capital cost of a SCR by increasing the levelized annual revenue requirement from 19.4 percent to 22.5 percent. It also increases the value of short-term net revenues by increasing the real discount rate on cash flows from 7.3 percent to 9.7 percent.

7. ENVIRONMENTAL REGULATIONS AFFECTING ELECTRICITY

7.A SUMMARY AND KEY FINDINGS

Summary

This section builds upon the earlier 2009 summary of existing and potential future environmental regulations and legislation, and provides some additional detail on the environmental selection criteria applied to certain modeling assumptions in this year's modeling effort. Further, some greater detail has been provided on the two "front runner" bills working their way through Congress on greenhouse gas emissions (GHG), especially carbon dioxide (CO_2). Additional discussion has been added regarding allowance pricing for CO_2, sulfur dioxide (SO_2), and nitrogen oxides (NO_X).

Controlling the environmental impacts from electricity production entails both complex regulations and market-based interventions such as cap-and-trade systems. Such environmental controls impose costs and introduce additional sources of uncertainty into resource planning, particularly when proposals to address chronic or emerging environmental issues are not yet finalized. Such is the situation facing generators in Connecticut and New England.

Chief among these uncertainties is the anticipation of a federally mandated, economy-wide approach to limit or discourage CO_2 emissions from fossil fuel combustion. Recent bills in Congress have adopted a cap-and-trade allowance system for CO_2 as the primary mechanism to limit CO_2 emissions, but important policy details are not yet determined. In response to a recent U.S. Supreme Court ruling, the Environmental Protection Agency (EPA) has determined that CO_2 is a pollutant under the Clean Air Act. This report assumes the implementation of federal GHG policy and adopts estimates of CO_2 prices applied to fossil-fuel fired generation that are derived from recent analyses by the Energy Information Administration. These CO_2 prices can have a direct and material influence on generation costs, system dispatch, new resource selection and retirement decisions.

Another significant influence on generation costs and potential retirements are state and regional efforts to control NO_X from existing fossil-fired generating units, especially on days when hot weather coincides with high electricity demand and ground-level ozone concentrations exceed federal limits. The Connecticut Department of Environmental Protection (CT DEP) has expressed interest in the EDC analysis on likely future emissions from generation during these episodes. The EDCs and the CT DEP established a collaborative process in order to provide the CT DEP with the results of specific simulations that could assist their efforts to craft regulatory approaches to address these emissions. This collaboration has yielded benefits for the EDCs (insofar as the analysis can better reflect the current policies of the CT DEP) as well as for the CT DEP, which can utilize the simulation results to determine possible impacts of emission controls on Connecticut generation and capacity availability.

Customers and generators bear the costs of existing and potential environmental controls in different ways, depending on how such programs are implemented and the nature of the costs

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incurred. In general, market-based programs that operate through emission allowance markets affect the operating cost of generating facilities, and generators will reflect these costs in supply bids into the wholesale market. If such supply bids are setting the wholesale price in any hour, then prices will rise and consumers will bear those costs through increased generation rates. Supply bids that reflect allowance costs, but which remain "inframarginal" (*i.e.*, below the market price) will not affect price. The energy margins of inframarginal generators will be reduced by the amount of allowance cost, but these losses can be offset (at least in part) as a result of higher market prices due to allowance costs of marginal suppliers.

Environmental regulations that require existing generators to install emission control equipment will impose capital costs that are born exclusively by generators, since fixed costs are not recovered in higher wholesale prices. However, these requirements can induce generating units to retire if their energy margins are insufficient to cover the additional fixed cost. This is a key concern for older, infrequently operating generating units facing NO_X controls to address ozone concentrations, particularly on hot days when such units are typically dispatched to meet higher loads. The implications of such requirements on generator retirements are examined in Section III.1 (Resource Adequacy).

Finally, there are myriad environmental regulations that address the air, water, and land-use impacts of existing and future generation capacity and transmission facilities. Many of these regulations are subject to periodic review and tightening. The evolution of such regulation is likely to impose additional costs on electricity supply, and such costs are often difficult to predict.

Key Findings

- While there is uncertainty regarding future Federal climate legislation, the prospects appear likely enough for a range of CO_2 prices to be reflected in our analysis.
- Because Connecticut and other parts of New England are not in attainment with air quality standards, additional NO_X control requirements will likely be imposed on generators. The EDCs and CTDEP worked together to establish likely future NO_X emission requirements which were reflected in the simulation of the New England electricity market. The cost of these controls is projected to cause retirements of older fossil steam units in our analysis.
- Emission allowance prices – for SO_2, NO_X, and CO_2 – will raise the costs of generation in proportion to unit emission rates, and will impact the dispatch of resources in New England and thereby reduce overall emissions. Although the prices of allowances for each pollutant are determined by aggregate emissions relative to an emission cap, these markets are not wholly independent. In particular, the price of CO_2 allowances can influence the price of SO_2 and NO_X allowances, an effect that was reflected in the analysis.
- The imposition of new regulations for other environmental sectors (not air) have the potential to introduce greater costs to generators, though the potential impact of these costs can not be determined at this time and thus were not reflected in the analysis.

7.B CLIMATE CHANGE POLICY

7.B.1 Regional Greenhouse Gas Initiative (RGGI)

The Regional Greenhouse Gas Initiative (RGGI) is a market-based program designed to reduce CO_2 emissions in the Northeast and Mid-Atlantic states. The program targets fossil fuel-fired electricity generating units with a capacity of at least 25 MW, and it implements a regional CO_2 emissions cap and allowance trading program. RGGI is the first regional greenhouse gas emissions reduction program and the first mandatory greenhouse gas allowance trading system in the United States.

RGGI was proposed in April 2003 and implementation began on January 1, 2009. Ten states, including Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont, have agreed to participate in the program. RGGI set the regional base for the annual CO_2 emissions budget for the ten states at 188,076,983 tons, and apportions CO_2 emission allowance budgets to each state. The state budgets remain unchanged between 2009 and 2014. Beginning in 2015, each budget declines by 2.5 percent of the original budget per year so that each state's budget in 2018 is 10 percent below its initial budget. RGGI is an auction-based program, and not a free allocation program and therefore each covered unit must obtain credits for CO_2 emissions through a regional auction.

The impact of the RGGI CO_2 prices on electricity markets and emissions in New England has been minimal and is expected to remain modest based on the current low prices of about $2/ton. A $2/ton cost adder is not high enough to trigger much dispatch switching from CO_2-intensive generation plants (coal plants or oil-fired peakers) to low-CO_2 generation plants (*e.g.*, renewables, gas combined-cycle (CC) plants). In the absence of any significant dispatch switching, the operating margins of the peakers and gas CCs, which typically set the electricity market prices when they run, are not materially affected as they are able to pass the cost of allowances to the electricity prices through higher offer prices in the energy market. The operating margins of coal plants are reduced as a result of RGGI CO_2 allowance costs, but not enough to cause retirement.

7.B.2 Federal GHG Policy Initiatives

Numerous federal policy proposals have been introduced to curtail emissions of CO_2 and other GHG emissions. The proposals exhibit differences such as types of policy mechanisms (*e.g.*, CO_2 fee, mandatory CO_2 controls, cap-and-trade), differing levels of emission caps or targets over time, covered sectors and emission sources, free allocation or auctioning of emission allowances or tax credits, treatment of domestic and international offsets, *etc*.

Although the policies being considered are both regulatory and legislative, this report focuses on legislative options for inclusion in the analysis. At this time, legislative options have been more developed, are moving forward more quickly and have been analyzed by several organizations. These developments do not preclude regulatory options that might affect generation at some point in the future. In response to a recent U.S. Supreme Court ruling, the Environmental Protection Agency (EPA) has determined that CO_2 is a pollutant under the Clean Air Act. Accordingly, they have proposed regulations to limit CO_2 emissions from major stationary sources. Should the regulatory options become more developed and/or supersede legislation, their impacts can be incorporated into subsequent analyses.

As the climate debate moves on in Congress, it is apparent that any Federal legislation will likely take the form of an economy wide cap-and-trade. Two bills, Waxman-Markey and Kerry-Boxer, are currently thought of as the fore-runners in the policy debate. At this time, analysts expect that the two bills will eventually be merged into one (probably in 2010) and that the resultant bill will go forward and become law. The summaries below are for each of the bills.

Waxman-Markey

Representatives Waxman and Markey introduced the American Clean Energy and Security Act of 2009 (ACESA, HR 2454, or "Waxman-Markey") on May 15, 2009. It was passed by the House on July 26, 2009.

Title III of the Act establishes a cap and trade system for greenhouse gas emissions. The cap gradually reduces covered greenhouse gas emissions to 17 percent below 2005 levels by 2020, and 83 percent below 2005 levels by 2050. The bill covers 85 percent of domestic emission sources, including electricity producers, oil refineries, natural gas suppliers, and energy-intensive industries like iron, steel, cement, and paper manufacturers. The bill allows unlimited banking of allowances, with borrowing limited from 2 to 5 years ahead.

Under Waxman-Markey, certain sources and programs will receive free allowances, known as "allocations." About 85 percent of emission permits would be given away free at the start of the program, with the percentage decreasing over time. The remaining allowances are auctioned to sources, with the resulting revenues dedicated to various programs such as low-carbon energy technology development and deployment. Additionally, the bill included a weak price collar with a floor of $10 and a minimum strategic reserve auction price at 60 percent above a rolling 36-month average of the daily closing price.

Kerry-Boxer

The Senate version bill, known as "Kerry-Boxer" (S. 1733) was released in draft form in late September 2009. Since then it has undergone some revisions and the "chairman's mark" passed out of committee in November. The bill will next be heard on the Senate floor, but this is not expected to occur until Spring 2010. The Kerry-Boxer bill and the Waxman-Markey bill are very similar. Key provisions of the Kerry-Boxer bill include:

- **Emissions Reduction Targets:** The Kerry-Boxer bill includes a declining cap on carbon pollution from 20 percent below 2005 levels by 2020 (versus 17 percent in Waxman-Markey) to an 83 percent reduction below 2005 levels by 2050.
- **Cap and Trade and Allowances:** The Kerry-Boxer bill calls for cap and trade program "pollution reduction" as the primary mechanism for attaining the emissions reduction targets, similar to Waxman-Markey.
- **Allocations:** Kerry-Boxer gives similar percentage of overall allocations (free allowances) to sources. However, the bill gives a greater portion of the initial auction

revenues to deficit reduction, the pool of free allowances is smaller. Therefore, the overall number of allocations that sources may receive is fewer than those under Waxman-Markey.

- **Clean Air Act:** Unlike Waxman-Markey, the Kerry-Boxer bill allows the development of new source performance standards (NSPS) for sources that could be covered by the bill. It also establishes performance standards for coal-fired power plants permitted in 2009 or after, and different standards for those permitted in 2020 or after.

7.C ALLOWANCE PRICING

7.C.1 CO_2 Allowance Prices

For purposes of utility, state, or regional level resource planning, it is generally sufficient to use a CO_2 allowance price projection to reflect the imposition of national climate policies. These CO_2 prices are then added to the fuel costs of fossil-fueled generation (both existing and new) and influence both the dispatch of existing units and the economics of new investments in generation, transmission and efficiency resources. Of course, any price forecast is subject to substantial uncertainty and analyses of climate change proposals show a very wide range of possible CO_2 prices. This, in turn raises significant issues regarding the choice of CO_2 price in resource modeling.

The most carefully studied recent proposal was the Waxman-Markey bill, which was described above. Many organizations generated economic analyses of Waxman-Markey, including the Energy Information Administration (EIA), the EPA and several private consultants on behalf of advocacy groups.[1] This report uses EIA analysis as the source for CO_2 prices in the electricity market analysis, primarily because EIA is statutorily non-partisan and independent, and therefore the results are generally recognized as unbiased and free from any advocacy position.[2]

The EIA analysis of Waxman-Markey is based on reference case projections of economic growth, fuel prices and emissions that are updated annually in the *Annual Energy Outlook* (AEO), which reflects a 25-year energy forecast without new federal policy to combat climate change. The EIA Waxman-Markey analysis started with the most recent AEO reference case, which included the impacts of the economic stimulus bill.[3] It incorporated key provisions of the Waxman-Markey bill into the policy simulations, such as:

- The combined efficiency and renewable electricity standards;
- Carbon capture and storage (CCS) demonstrations and early deployment;

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1 The Congressional Research Service produced useful summary of results and key issues identified by the economic analyses conducted on W-M. See *Climate Change: Costs and Benefits of the Cap-and-Trade Provisions of H.R. 2454* by Larry Parker and Brent D. Yacobucci, September 14, 2009.

2 *Energy Market and Economic Impacts of H.R. 2454, the American Clean Energy and Security Act of 2009*, Energy Information Administration, August 2009 SR/OIAF/2009-05.

3 *Annual Energy Outlook 2009,* Energy Information Administration, DOE/EIA-0383(2009), March 2009.

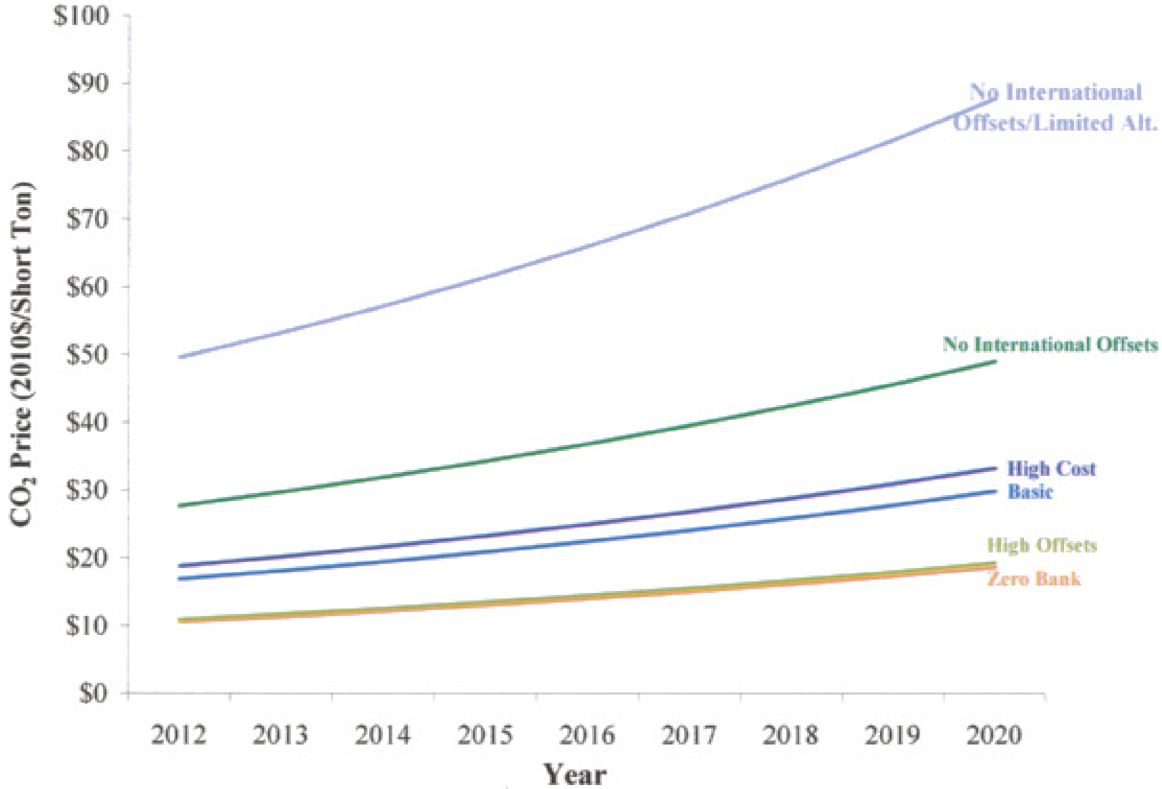
- Building code revisions for residential and commercial buildings;
- Federal appliance and lighting efficiency standards;
- Technology improvements as a result of federal program support; and
- Smart grid peak savings program.

EIA then simulated the imposition of the greenhouse gas emission cap-and-trade program on the energy sector, which produced forecasts of CO_2 prices. EIA analyzed alternative policy implementation scenarios for analysis under different assumptions regarding the availability, cost, and market penetration of new low-carbon energy technologies over time; the amount of allowance banking assumed; and the availability, cost and utilization of emission offsets (domestic and international) that are permitted. The six primary cases EIA examined were:

- The *Basic Case*, which reflects expected improvements in technology, a moderate degree of domestic and international offset use, and significant banking of allowances through 2030;
- The *Zero Bank Case*, which did not assume any accumulated banked allowances;
- The *High Offset Case*, which assumed that international offsets are available and used to the ceiling imposed by the W-M bill;
- The *High Cost Case*, which assumed higher costs for low-CO_2 generation technologies;
- The *No International Case*, which significantly constrained the availability of international offsets; and
- The *No International/Limited Case* which constrained both international offset use and the deployment of low-CO_2 generation technologies.

Figure 7.1 shows the range of CO_2 allowance price forecasts from the EIA analyses of Waxman-Markey.

Figure 7.1
CO_2 Allowance Price Forecasts from EIA Analysis of Waxman-Markey



Source: Energy Information Administration.

7.C.2 CO_2 Allowance Price Projection: Current Trends Scenario

The electricity market analysis in this report adopts the assumption that a climate policy similar to Waxman-Markey is enacted. This assumption does not reflect an endorsement of the Waxman-Markey approach, but provides an analytic basis to explore the impacts of a range of CO_2 prices under different scenarios. The EIA analysis suggests that a significant source of uncertainty regarding near-term (*i.e.*, through 2020) CO_2 allowance prices under the Waxman-Markey approach is the degree to which international and/or domestic offsets are utilized, and the cost of obtaining such offsets. There is a wide disparity of opinion on this, ranging from almost no utilization (due to regulatory and/or cost barriers) to full utilization up to the limits contained in the Waxman-Markey proposal. Another large uncertainty (particularly through 2030) is the timing, cost and adoption of low- and no- carbon technologies, which itself might be affected by an allowance price that is influenced by the degree of offset usage.

The EIA Basic Case takes a "middle ground" view of both offset usage and technology development under the Waxman-Markey bill. As described by EIA in their August 2009 analysis:

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The ACESA [Waxman-Markey] *Basic Case represents an environment where key low-emission technologies, including nuclear, fossil with CCS, and various renewables, are developed and deployed on a large scale in a timeframe consistent with the emission reduction requirements of ACESA without encountering any major obstacles. It also assumes that the use of offsets, both domestic and international, is not severely constrained by cost, regulation or the pace of negotiations with key countries covering key sectors.*[4]

This report adopts the EIA Basic Case for CO_2 prices in the "Current Trends" scenario. The EIA Basic Case recognizes that offsets might be available in some quantities at a price lower than that of domestic abatement, but does not assume that valid, low-cost offsets would be available in quantities that would be constrained by the near-term limits in the Waxman-Markey bill. Thus, the EIA Basic Case offers a plausible view of an aggressive climate policy with some offset use, but one not dominated by cheap offsets in the compliance mix. The EIA Basic Case CO_2 allowance prices rise from $17/ton in 2012 to $30/ton in 2020 (2010 dollars).

7.C.3 CO_2 Allowance Prices For Alternative Scenarios

Since the availability, cost and ultimately the degree of offset utilization appears to be the most influential determinant of near-term (*e.g.*, 2020) CO_2 allowance prices, suitable high/low allowance price cases can be fashioned from varying assumptions regarding offset utilization. The IRP process adopted the EIA High Offset Case as a low CO_2 allowance price scenario, and the EIA No International Case as a high CO_2 allowance price scenario. These two cases represent upper and lower bounds on the availability of cost-effective international offsets used for domestic compliance in the near term, and the resulting range of projected allowance prices is broad enough to encompass many of the other sources of uncertainty in allowance prices, such as economic growth, fuel prices and the near-term cost of domestic CO_2 abatement.

The High Offset case assumes that international offsets are available in sufficient quantities and at moderate costs so that they are utilized for compliance at levels at or near the limits contained in the Waxman-Markey bill. As a result of larger amounts of low-cost international offsets available for domestic compliance with the emission targets, the CO_2 allowance price is $19/ton in 2020 (about 35 percent lower than in the Basic Case). In contrast, the No International Case reflects a scenario where the use of international offsets is severely constrained by cost, regulation or slow progress in obtaining agreements with key countries. In this case, the CO_2 allowance prices are $49/ton in 2020, or about 65 percent higher than in the Basic Case.

Figure 7.2 shows the range of CO_2 prices used in our scenarios, expressed in 2010 constant dollars.

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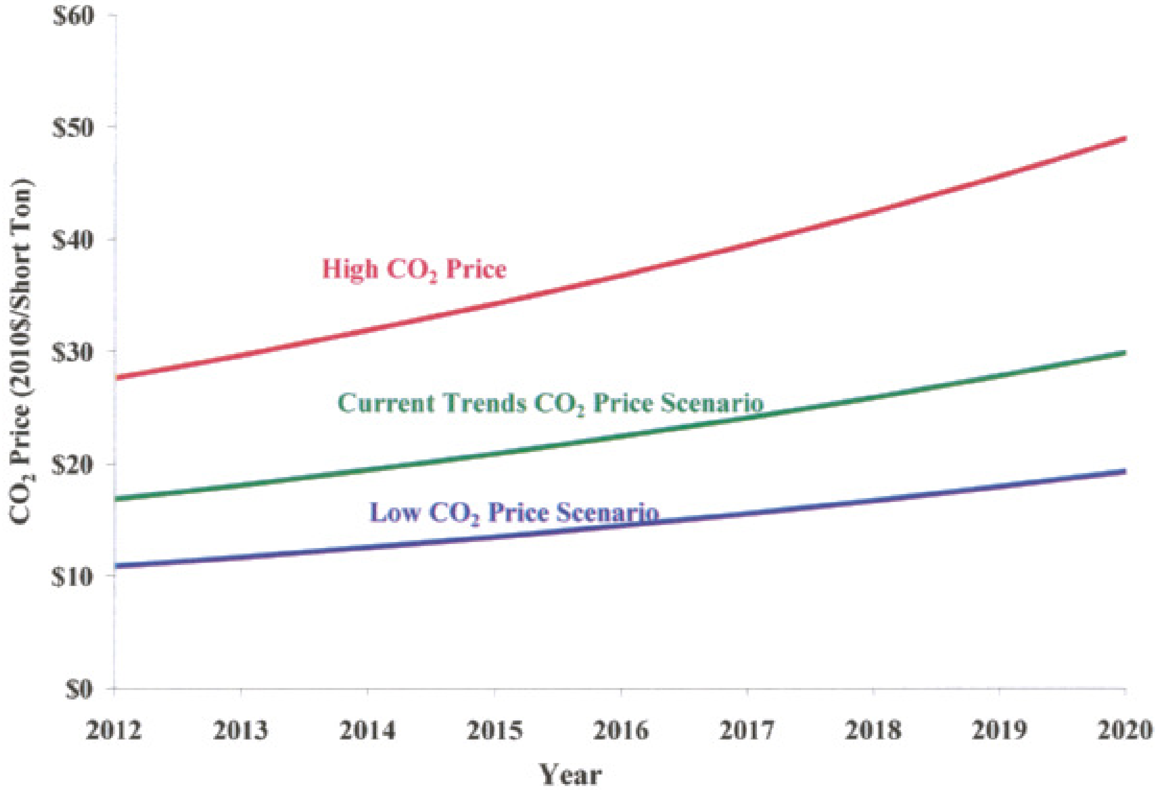
4 *Energy Market and Economic Impacts of H.R. 2454, the American Clean Energy and Security Act of 2009*, Energy Information Administration, August 2009 SR/OIAF/2009-05, p viii.

Figure 7.2 CO_2 Allowance Prices Used In Scenarios



Source: Energy Information Administration.

7.C.4 NO_X and SO_2 Allowance Pricing

This analysis also uses EIA as a source for NO_X and SO_2 allowance price projections. In the EIA modeling framework, allowance prices for CO_2, NO_X and SO_2 are determined simultaneously by the model to attain the relevant emission targets. *The Brattle Group* obtained the SO_2, NO_X and CO_2 allowance price forecasts from the EIA analysis of Waxman-Markey, which displayed an inverse relationship between CO_2 allowance prices and NO_X and SO_2 allowance prices; see Table 7.1

Table 7.1
Emissions Price Forecast Under Waxman-Markey

	(units)	**2013**	**2015**	**2020**
REFERENCE CO2				
CO_2	*($/ton)*	18	21	30
NO_x	*($/ton)*	1962	2147	0
SO_2	*($/ton)*	726	831	301
HIGH CO2				
CO_2	*($/ton)*	30	34	49
NO_x	*($/ton)*	0	105	0
SO_2	*($/ton)*	339	160	3
LOW CO2				
CO_2	*($/ton)*	12	14	19
NO_x	*($/ton)*	2423	2592	2417
SO_2	*($/ton)*	756	762	936

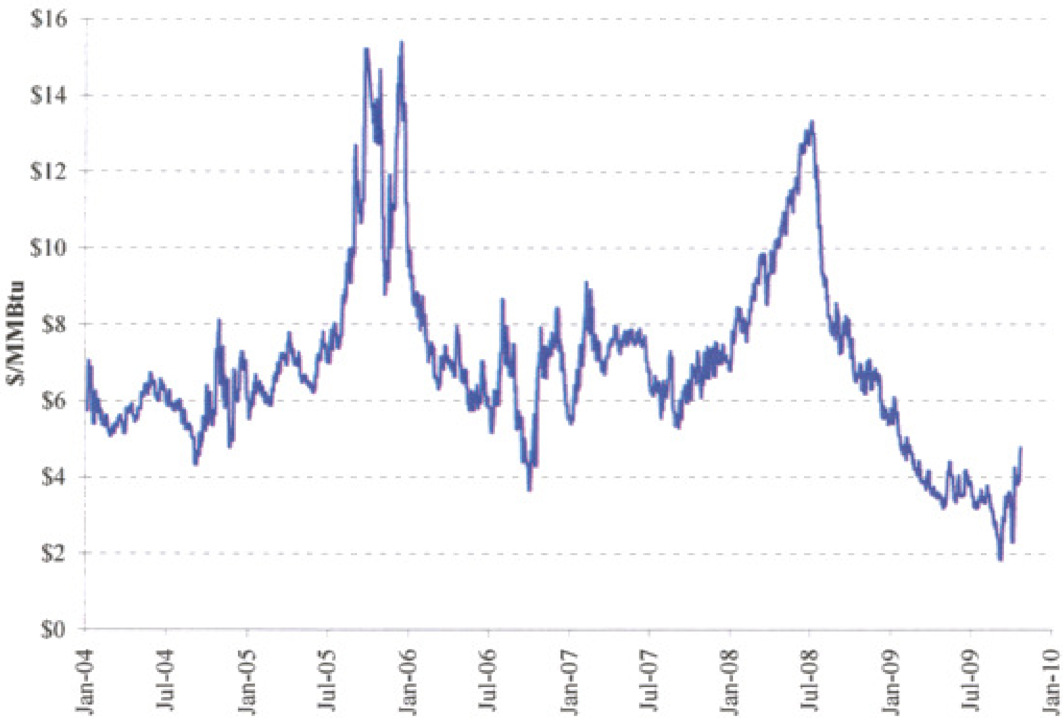
Sources and Notes:
U.S. Energy Information Administration.
All values are in 2010$ per short ton.

As CO_2 allowance prices increase, the generation from coal-fired capacity decreases and this reduces NO_X and SO_2 emissions as well, reducing the allowance prices necessary to attain compliance with national and regional NO_X and SO_2 emission targets. This effect is clearly seen in comparisons between the High and Low CO_2 price forecasts. Under a High CO_2 price, the prices of NO_X and SO_2 allowances fall significantly relative to the Reference CO_2 price case, while in the Low CO_2 price forecasts, NO_X and SO_2 emission allowances remain at much higher levels. In scenarios that assumed higher or lower CO_2 prices than in the Current Trends scenario, the allowance prices for NO_X and SO_2 from the corresponding EIA analysis cases were used in the simulations.

7.C.5 Collaborative Effort with the CT DEP

In its 2009 IRP report the EDCs recommended that the CT DEP and the EDCs collaborate on modeling inputs for the 2010 IRP and jointly review the assumptions underlying emission rates in the production cost simulations. To that end, the EDCs and *The Brattle Group* worked collaboratively with the CT DEP to develop realistic assumptions regarding future regulations that will ensure compliance with National Ambient Air Quality Standards (NAAQS). The effort was informed by extensive analysis using the DAYZER market simulation model. Together with the CT DEP, *The Brattle Group* and the EDCs validated the input data in the model, including comparison of generating unit emissions rates to publicly available historical data. As specified by the CT DEP, the initial simulations assumed no new environmental regulations, no new investment in environmental controls, and no environmentally-driven retirements. This

Figure 9.1
Henry Hub Spot Price



Source: Platts, Gas Daily.

Recent developments suggest that the long term outlook for natural gas in New England is positive. There has been a dramatic improvement in the outlook for long-term U.S. natural gas supply and price in the last year, driven primarily by increasing "unconventional gas" production and reserves – mostly shale gas, but also coal bed methane and other "tight" gas formations. These unconventional sources have been called a "game changer" and the "biggest energy innovation of the decade" that could "transform the debate over generating electricity."[2] Analysts have forecast that the major shale gas plays can cover their break-even costs for around $4.00/MMBtu.[3] Of particular interest to the Northeast is the Marcellus Shale, due to the magnitude of the supply potential, its expected low cost and its nearby Appalachian location. Additional supplies are coming via new pipeline capacity from the Rocky Mountains and from new LNG terminals, and additional infrastructure is being developed to deliver these supplies into New England. Both short-term and long-term gas prices have declined markedly. While this new potential supply, particularly shale gas, has yet to be fully realized, and factors could yet hinder its development, the outlook for natural gas supply for power generation in New England is significantly improved compared to even just a few years ago.

2 "America's Natural Gas Revolution," Wall Street Journal, November 2, 2009.

3 *E.g.*, see the November 30, 2009 report by Scotiabank Group analyst Patricia Mohr.

Key Findings

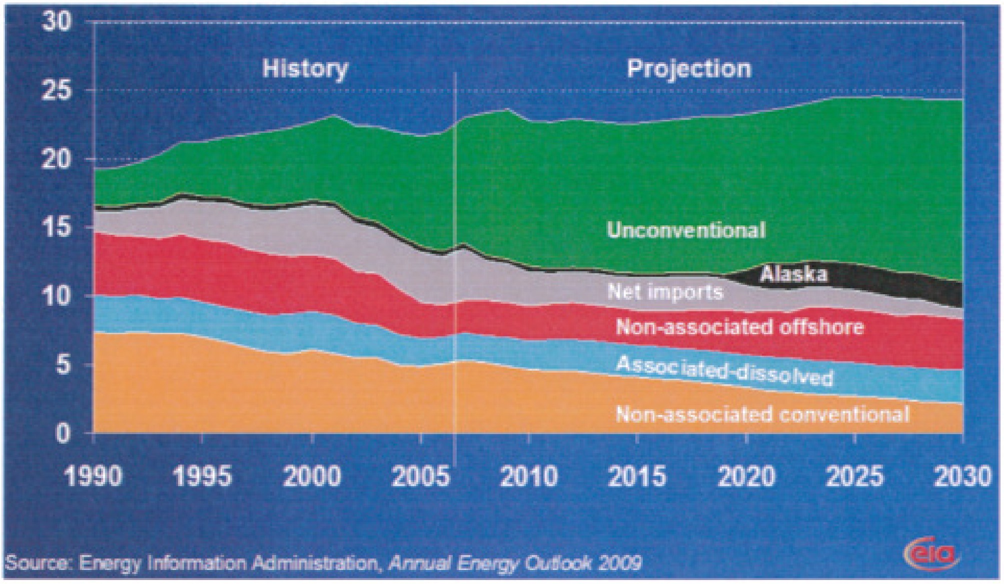
- The overall supply picture for domestic natural gas appears promising, due particularly to the advent of new unconventional gas supplies such as shale gas. This expanding supply should be adequate to accommodate even increased gas demand, though the ultimate extent and pace of the new supplies coming online is not certain.
- Pipeline and LNG delivery capacity to New England have increased over the past several years, with additional new expansion projects still in development for the near future. Gas delivery capacity to serve average and peak needs has improved measurably from a few years ago (though this does not address gas local distribution company (LDC) deliverability issues, where additional expansions may be necessary).
- LNG and Canadian conventional gas may be less important for augmenting New England gas supplies than was expected in the recent past, due to the advent of new domestic supplies at lower prices. They will nonetheless continue to serve as a backstop for the availability and price of domestic gas supplies. Regardless of whether it actually does substitute for domestic gas more widely, LNG will remain a crucial component of New England's ability to meet peak gas demands in the winter heating season.
- Natural gas prices are expected to remain reasonable at around $7.00/MMBtu (real dollars) in the long term, driven largely by new unconventional supply sources. However there is no certainty that these current price expectations will be fulfilled; a long-term gas price range of approximately $4-10/MMBtu was examined in this study. Regardless of what happens to the long-term price of gas, short-term gas prices can be volatile.

9.B U.S. NATURAL GAS SUPPLY

As indicated in Figure 9.2 below, U.S. production from conventional sources has declined recently and is projected to continue to decrease. Similarly, though Canada has been a valuable supplier of gas to the U.S. and the Northeast for decades and will remain important for years, its share of the U.S. market is expected to decline over the long term as Western Canadian sources decline and Canada's own gas demand increases. Offsetting these trends, however, production from unconventional sources has exploded, more than making up for the decline in conventional production. This production increase has occurred despite a drop in U.S. drilling activity. U.S. gas-targeted drilling activity dropped by 42 percent from January through July 2009, but there was only a 1.5 percent decline in U.S. natural gas production in the third quarter compared to the same quarter in 2008. According to Scotiabank Group analyst Patricia Mohr, "This apparent disconnect between drilling activity and production reflects much greater individual well productivity with horizontal, multiple-fracturing drilling and considerably greater initial flow rates from shale developments than conventional vertical wells."[4]

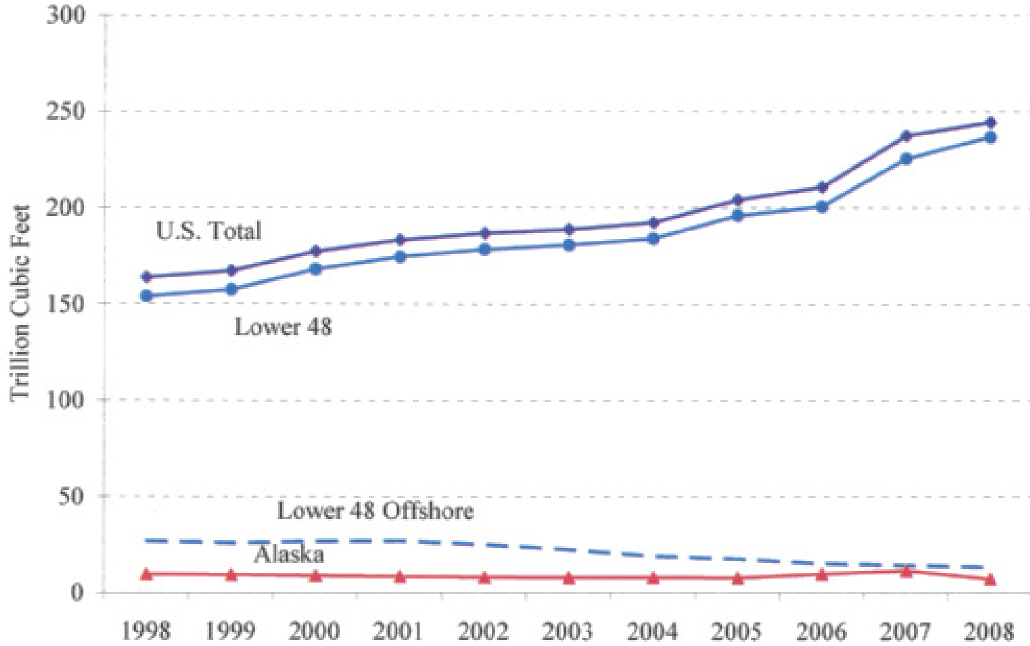
[4] November 30, 2009 report by Scotiabank Group.

Figure 9.2
Sources of Natural Gas Supply (Tcf)



Furthermore, overall U.S. reserves are increasing as indicated in Figure 9.3 below, largely due to these unconventional sources. The U.S. EIA reported that in 2008, proved natural reserves rose enough not only to replace production, but also to grow by almost 3 percent over 2007. Proved reserves attributable to shale reservoirs grew dramatically, up 51 percent to 32.8 trillion cubic feet (Tcf), or 13 percent of the 245 Tcf total. In a June 2009 resource assessment, the Potential Gas Committee estimated total U.S. natural gas resources at 1,836 Tcf, the highest resource evaluation in their history. At current consumption rates, this represents over 80 years of supply.

Figure 9.3
U.S. Dry Natural Gas Proved Reserves



Source: EIA, Dry Natural Gas Reserves.

While geologists have known for decades that shale contained large quantities of natural gas, only in the last few years have producers been able to develop this resource economically. The key to unlocking it has been a new drilling technique that combines horizontal drilling and hydraulic fracturing. Shale formations have low permeability, meaning that gas molecules do not flow easily through the rock. With horizontal drilling, producers drill parallel to grade of the formation, reaching a far larger area of productive capacity than with traditional vertical wells. Improved hydraulic fracturing techniques inject a mixture of water and sand under high pressure to open pathways through which gas molecules can flow. Drilling success with shale gas is far more certain than with conventional resources, and shale gas wells tend to produce a large volume of gas initially, after which they drop quickly to a much lower long-term production rate. This drilling technique, developed by U.S. independent gas producers, dramatically increases the amount of gas that can be developed at relatively low cost compared to only a few years ago. It is perhaps surprising that this technological development, which could have such a dramatic impact on U.S. and potentially on world energy supplies, has occurred with so little fanfare. Figure 9.4 shows the location of U.S. shale deposits now being commercially developed.

Figure 9.4
U.S. Gas Shale Gas Plays

Source: Energy Information Administration, Office of Oil and Gas

Particularly encouraging for New England is that one of the most promising shale deposits, the Marcellus Shale, is located within 300 miles of Connecticut. In early 2008, geology professors Terry Engelder and Gary Lash estimated the Marcellus might contain more than 500 Tcf of gas, about 10 percent of which might be recoverable.[5] Figure 9.5 shows projected production from the Marcellus Shale. To put these numbers in context, total New England natural gas usage currently averages about 2,000 MMcf/d.

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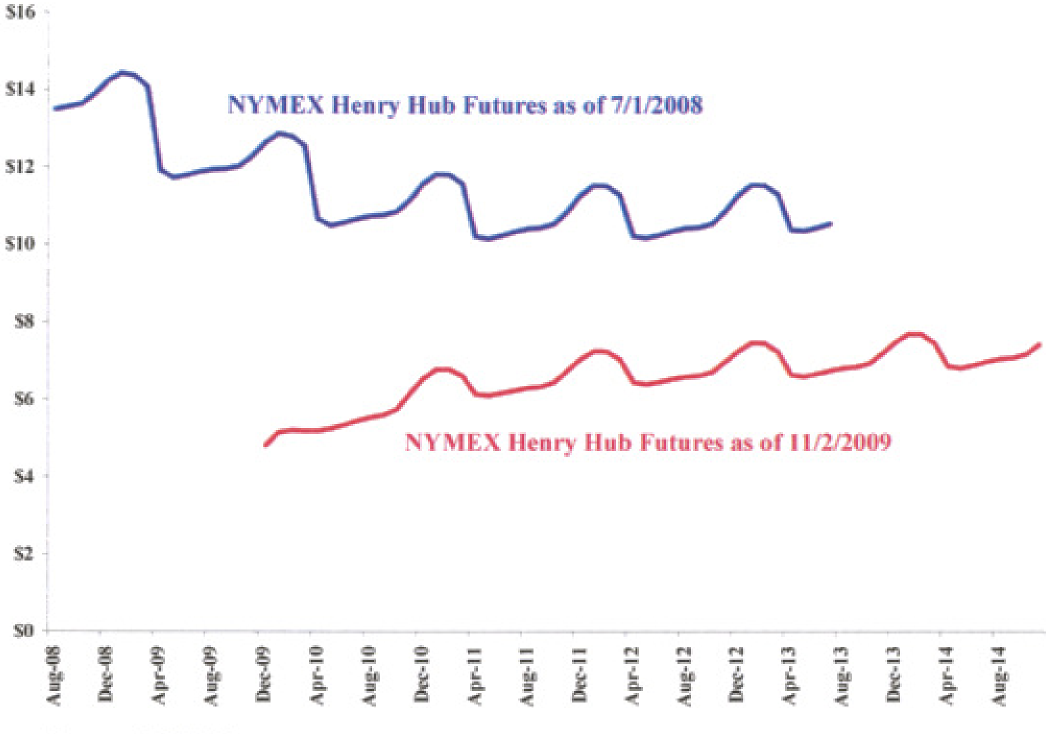
5 For example, see http://geology.com/articles/marcellus-shale.shtml. Also, Engelder, Terry and Lash, Gary (2008). "Unconventional Natural Gas Reservoir Could Boost U.S. Supply," Penn State Live, http://live.psu.edu/story/28116.

Figure 9.19
Natural Gas Futures Price Change – July 2008 to November 2009



Source: NYMEX.

Current gas futures prices show gas prices increasing for several years from depressed near-term prices, and then staying essentially level in real terms thereafter (*i.e.*, growing roughly with expected inflation), illustrated in Figure 9.20. The upper curve is the actual NYMEX futures prices, which are in nominal dollars; the lower curve is the same values converted to real 2010 dollars. Hereafter, prices are in real dollars unless otherwise indicated. As this figure shows, the market is essentially predicting that long term gas prices are expected to be flat at about $7.00/MMBtu in real 2010 dollars.

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10. EMERGING TECHNOLOGIES

10.A SUMMARY AND KEY FINDINGS

Summary

A number of uncertainties come into play in resource planning, and one is the potential for new or emerging technologies to change the planning landscape. In the 2009 IRP, we explored a range of new technologies, several of which were found to have limited relevance or application to New England, such as geothermal, concentrating solar thermal electric and carbon capture and storage. Other technologies were potentially more relevant, but their prospects showed little change over the past year, such as energy storage. Two technologies more likely to affect resource planning over the next decade are examined in other sections of this report: photovoltaic (PV) systems are discussed in the Renewables Section and fuel cells are incorporated into the Combined Heat and Power Section.

In this section, we examine two emerging technologies that were addressed in the 2009 IRP and which appear to have gained momentum in their prospects for influencing electricity demand over the next decade. These are plug-in electric vehicles (PEVs) and advanced metering infrastructure (AMI), which is a critical component of the "Smart Grid" concept that has gained momentum over the past several years. Although advances in these technologies over the past year warrants additional analysis, their potential impacts over the next decade are not yet sufficiently clear to incorporate into the simulation analyses presented in Section II.

Key Findings

- Because of the growing commitments to plug-in electric vehicle (PEV) manufacturing and charging infrastructure on the part of vehicle manufacturers and electric utilities, PEVs appear poised to achieve an uncertain but potentially significant fleet penetration over the next decade.
- A 5 percent level of fleet penetration by 2020 represents an optimistic view of PEV vehicle sales over the next decade, but one that is worth exploring for its potential impact on the New England electricity system.
- Even an optimistic view of PEV penetration in New England over the next two decades is unlikely to pose any unmanageable issues for maintaining reliable electric service.
- An optimistic view of PEV penetration in New England is likely to produce a modest environmental benefit, with net CO_2 and NO_X emissions decreasing and only a negligible increase in SO_2 emissions.
- Widespread implementation of advanced metering infrastructure (AMI) has the potential to decrease peak loads. The magnitude of the decrease will depend on customer participation rates in dynamic pricing programs and their responsiveness to near-term price signals.

- Enabling technologies can help customers respond more effectively to price signals, and AMI programs that encourage these technologies are more likely to yield more pronounced responses.

10.B Plug-In Electric Vehicles (PEV)

Powering a vehicle using a rechargeable battery and an electric motor is not a new concept; electric vehicles (EVs) have been around for more than a century. However, due to their relatively limited driving range, long recharging times, high costs and lack of availability, EVs have not had a significant market penetration.[1] The introduction of hybrid electric vehicles (HEVs) offers a new way to capture some of the advantages of EVs by combining the internal combustion engine of a conventional vehicle with the battery and electric motor of an electric vehicle. HEV sales have grown by more than 80 percent annually in the US over the last 8 years, and they currently represent about 3 percent of total U.S. vehicle sales.[2,3]

Plug-in electric vehicles (PEVs) are seen as a next step in advanced vehicle technologies. There are several types of PEVs, ranging from pure electric vehicles (EVs) to plug-in hybrid electric vehicles (PHEVs) that combine grid-rechargeable electric motors with internal combustion engines. A PHEV is essentially a hybrid vehicle with a much larger battery, and the ability to be plugged into the electric grid for charging that battery. Its primary source of power is electricity, so it can potentially provide a cleaner option than conventional hybrids, depending on the electricity source. Toyota announced its plug-in version of the Prius hybrid in December 2009, with an all-electric range of about 14 miles. There are also extended range electric vehicles (EREVs) that primarily operate on battery power with a small gasoline engine available to charge batteries, instead of providing power directly to the drivetrain as in a conventional hybrid. General Motors plans to launch an extended-range (40 mile) EREV, the Chevy Volt, by late 2010. It is also possible that all-electric vehicle technology may become a viable alternative; recent and projected improvements in battery technology may finally make all-electric vehicles attractive. Ford intends to start selling a battery-powered version of its Transit Connect commercial van in 2010, followed by an electric Ford Focus sedan in 2011. Nissan is introducing its electric car, the Leaf, to selected business fleets next year and to consumers by 2011.

The electric utility industry has begun to consider investments in charging infrastructure. In Connecticut, the EDCs participate in the Governor's Electric Vehicle Infrastructure Council established under Executive Order No. 34, and also have joined the Regional Electric Vehicle Initiative (REVI), a collaborative effort of New England utilities to promote the development of electric transportation infrastructure.

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1 According to Annual Energy Review 2007 (EIA), there are about 55,000 electric vehicles in use in the United States by 2007 (less than 0.05 percent of total light-duty vehicles).

2 Lemoine, D., *et al. An innovation and policy agenda for commercially competitive plug-in hybrid electric vehicles*, Environmental Research Letters 3, 1-10 (2008).

3 Madian, A. L., *et al. U.S. Plug-In Hybrid and U.S. Light Vehicle Data Book: Hybrid Vehicles, Battery Technology, Travel Patterns, Vehicle Stock, Sales Trends, Performance Trends*. LECG (2008).

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10.C ADVANCED METERING INFRASTRUCTURE

10.C.1 Technology and Pricing Systems

Advanced metering infrastructure (AMI) is a critical component of the "Smart Grid" concept that has gained momentum over the past several years. The Smart Grid represents a broad vision in electricity supply and transmission management, real-time communication, and customer participation. Whether this broad vision is achieved over the next decade or several, the growing interest and investment in AMI and associated enabling customer technologies represents the initial stages of Smart Grid development.

AMI refers to a measurement and two-way data collection system that includes meters at the customer site, communication networks between the customer and a service provider, and data reception and management systems that make the information available to the service provider.[13] Unlike automated meter reading (AMR), it is capable of two-way communication between the customer and the service provider, enabling customers to receive pricing signals and respond to dynamic pricing programs such as critical-peak-pricing (CPP), peak time rebates (PTR) or real-time pricing (RTP).[14] AMI also enables time-of-use (TOU) pricing on a broad scale. Dynamic pricing can decrease the need for peaking generation capacity, reducing energy and capacity costs (generation, transmission, and distribution). AMI also offers operational benefits including faster outage detection, improved energy theft detection capability, enhanced communications with customers, better management of connects and disconnects and avoided meter reading costs (either manual or from an existing automated meter reading system) and could facilitate the integration of distributed generation. However, these benefits must be weighed against the costs of installing AMI systems, which encompasses a range of equipment such as meters, communication systems and IT systems.[15]

The installation of an AMI system would also open the door to a new suite of enabling technologies which would allow customers to take advantage of the enhanced communication capability and more granular usage information that the system provides. One such technology is the programmable communicating thermostat (PCT). With a PCT, a customer's thermostat can receive signals directly from the utility and automatically reduce air-conditioning load in response to critical events. The presence of this technology has been shown to significantly increase customer response to dynamic rates.[16] This concept could be extended to other end-uses within the home as well, such as smart appliances (*i.e.*, washer dryers, refrigerators, etc.), leading to even greater peak reductions (a concept often referred to as "prices-to-devices"). In fact, the Auto-DR system for commercial and industrial customers does exactly that, by coordinating energy reductions at multiple end-uses through a facility's energy management system. These

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[13] Electric Power Research Institute (EPRI).

[14] TOU: price depends on time of use, prices typically varies modestly; CPP: high prices at declared critical peak times, timing is unknown in advance; RTP: linked to hourly wholesale prices, either day-ahead or hour-ahead basis.

[15] Faruqui, A. and L. Wood. *Quantifying the Benefits of Dynamic Pricing in the Mass Market.* Prepared for Edison Electric Institute, January 2008.

[16] *Ibid.*

systems have been shown to produce large incremental increases in customer response as well, depending largely on the size and type of customer that is equipped with the system.[17]

A second type of technology that is enabled by an AMI system is the in-home display (IHD). Whereas the smart meter provides real-time electricity consumption data to the utility, the IHD provides this information to the consumer. The IHD essentially acts as a speedometer for the customer's electricity consumption. It can provide recent information on hourly (or even quarter-hourly) consumption patterns as well as pricing information. Information can also be sent to a website where utilities can give recommendations to customers for easy ways to consume electricity more efficiently to reduce costs. By increasing customer awareness of the relationship between the amount of electricity they consume and the cost of consuming it, IHDs have been shown to produce an overall conservation effect of anywhere between 0 and 28 percent.[18] IHDs can take many forms, from internet websites to simple electrical socket plug-ins to more advanced and interactive display modules.

10.C.2 Recent Activity in AMI in Connecticut

The potential impact of AMI deployment on system peak reduction depends on several factors such as dynamic rate design, customer participation level, and customer responsiveness, factors that interact at the customer levels. For example, alternative rate designs can attract different levels of customer participation and influence the degree of responsiveness to price signals. The amount of peak reduction achievable depends on the type of pricing program that is offered. Time-of-use (TOU) pricing, although not a dynamic pricing program, typically generates less peak reduction than critical-peak-pricing (CPP) or peak-time rebates (PTR).

Of course, some loads in Connecticut and New England, particularly large industrials, already have some version of advanced metering installed, and the Demand-Side Management section evaluates the effect of existing and planned DSM programs, some of which rely on AMI. UI has had a version of advanced metering in place for nearly a decade, which has enabled about 13 percent of its residential customers to elect TOU pricing rates, and over 25 percent of its commercial customers. UI has also proposed to enhance their metering system to AMI and explore dynamic pricing systems.[19] UI's approved plan outlines the manner in which UI intends to "migrate" to an enhanced (*i.e.*, full mesh, two-way communication) AMI system in a scalable and flexible manner that maintains full current system capabilities while allowing for full deployment of "smart" meters throughout the service territory, where appropriate and where required. This approach meets customer, supplier and regulatory needs, is a cost effective approach and maintains UI's "smart metering system" for all consumers and rate payers. This approach is a low cost solution that will enable the utilization of emerging technologies, allow for a more robust communication network, and be capable of incorporating "smart" meter

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17 G. Wikler *et al.* "Enhancing Price Response Programs through Auto-DR: California's 2007 Implementation Experience," prepared for Lawrence Berkeley National Laboratory, January 2008.

18 EPRI. Characterizing and Quantifying the Societal Benefits Attributable to Smart Metering Investments. July 2008.

19 UI submitted its proposal *Advanced Metering Infrastructure Plan* to the DPUC (Docket No. 07-07-02) in July 2007. The DPUC approved the UI plan in a March 19, 2008 decision.

TAB 12

Connecticut Light & Power
The Northeast Utilities System

The Brattle Group

The United Illuminating Company

Overview of Integrated Resource Plan for Connecticut

- Key Topics -

Presented to the
Connecticut Energy Advisory Board

January 8, 2010

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Scenario Definitions

Scenario	Gas Price	CO_2 Price	Load Growth
"Current Trends"	**Medium**: futures extrapolated	**Medium**: EIA "Basic Case" for Waxman-Markey	**CELT forecast**
"Lo Gas/Lo CO_2"	**Low**	**Low**: EIA "High Offset Case: for Waxman-Markey	**CELT adjusted up** by price elasticity
"Med Gas/Hi CO_2"	**Medium**	**High**: EIA "No International Case" for Waxman-Markey	**CELT adjusted down** by price elasticity
"Hi Load Growth"	**Medium**	**Medium**	**CELT High Economic Growth** forecast
"Hi Gas/Hi CO_2"	**High**	**High**	**CELT adjusted down** by price elasticity

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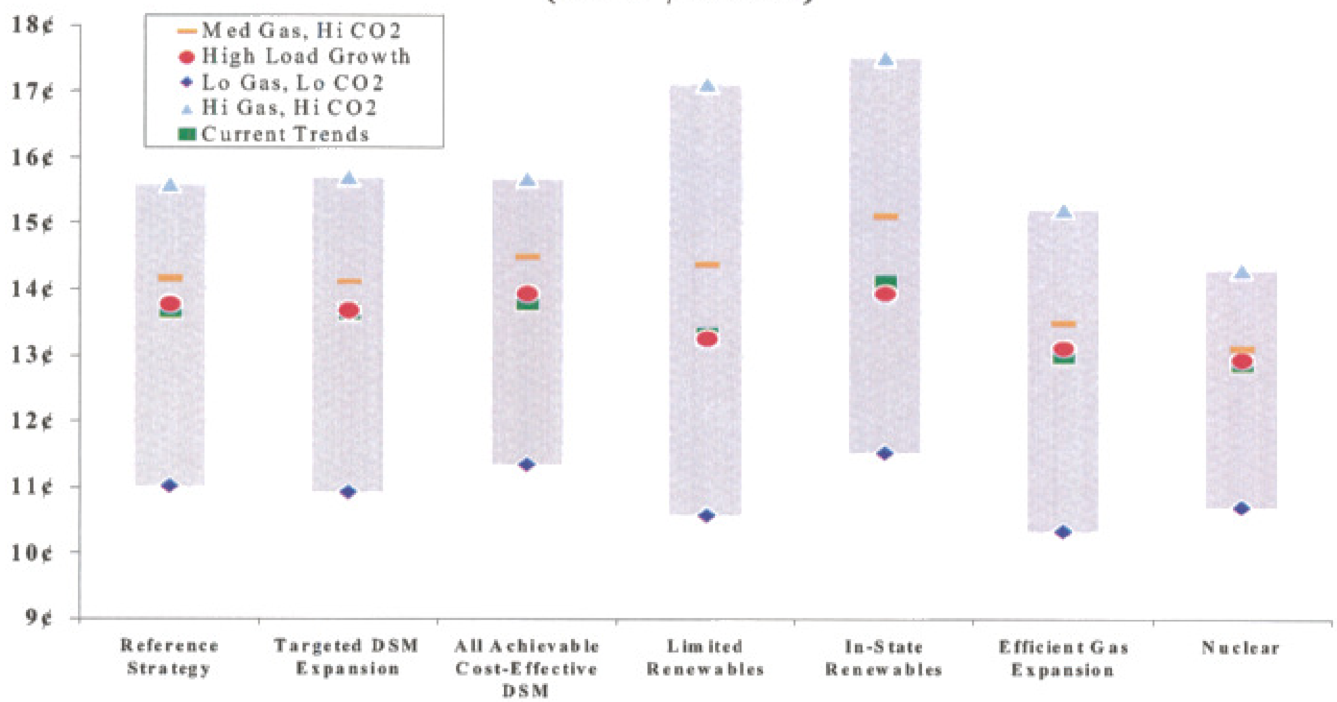
Average Cost of Nuclear Strategy Across Scenarios

Average power supply-related cost of nuclear strategy analyzed compares well to other resource strategies, with less variation across scenarios

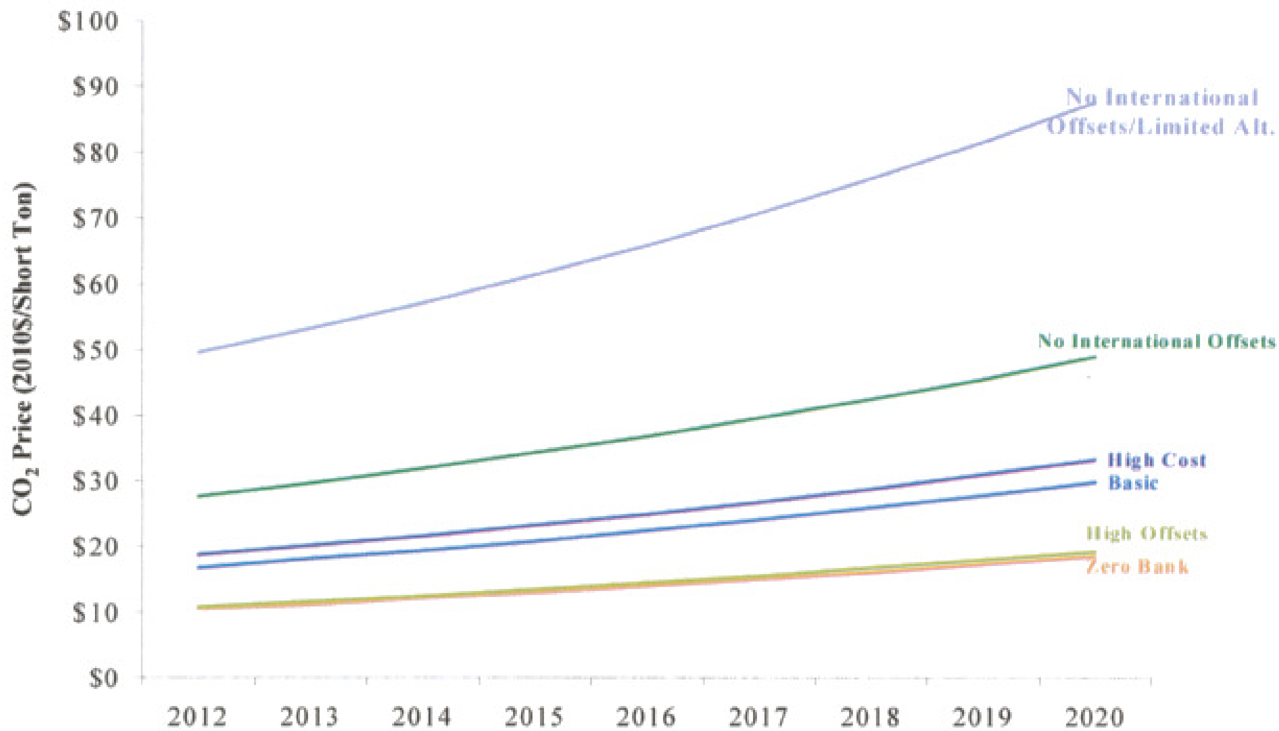
2020 Average Power Supply-Related Cost (2010 ¢/kWh)



CO_2 Price Forecasts Show Wide Range

The availability and use of domestic and international offsets (credits) for CO_2 emission reduction has significant impact on near-term CO_2 allowance prices

CO_2 Allowance Price Forecasts from EIA Analysis of Waxman-Markey



Source: EIA, Energy Market and Economic Impacts of H.R. 2454, Aug. 4, 2009.

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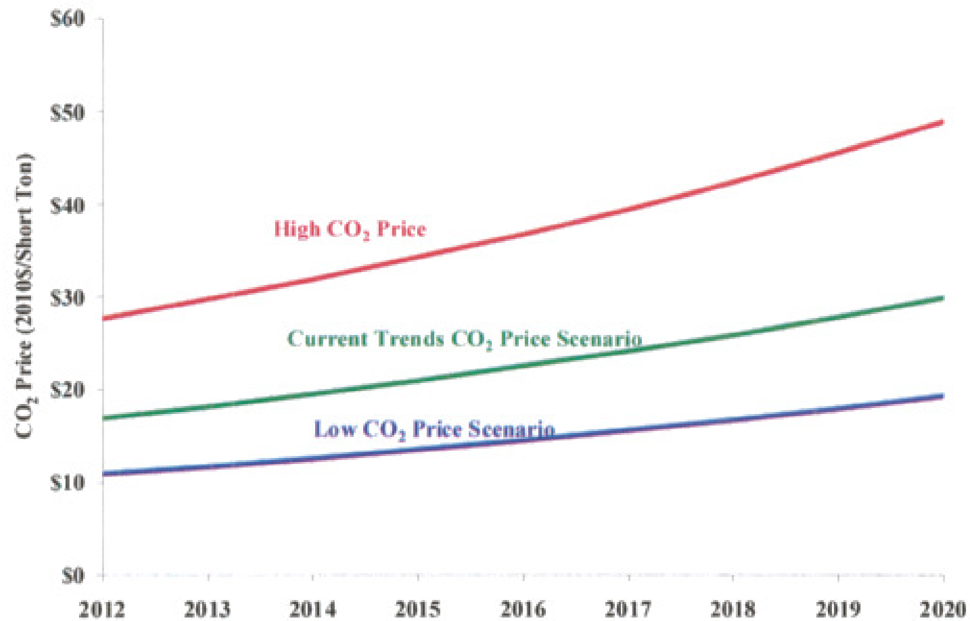
CO_2, NO_X and SO_2 Allowance Prices Are Related

We selected reference, high and low CO_2 prices based on EIA forecasts under different assumptions regarding offsets, and adjusted SO_2 and NO_X allowance prices accordingly

CO_2 Allowance Prices Used in Scenarios



CO_2, NO_X and SO_2 Prices

	(units)	2013	2015	2020
REFERENCE CO2				
CO_2	*($/ton)*	18	21	30
NO_x	*($/ton)*	1962	2147	0
SO_2	*($/ton)*	726	831	301
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CO_2	*($/ton)*	30	34	49
NO_x	*($/ton)*	0	105	0
SO_2	*($/ton)*	339	160	3
LOW CO2				
CO_2	*($/ton)*	12	14	19
NO_x	*($/ton)*	2423	2592	2417
SO_2	*($/ton)*	756	762	936

Sources and Notes:
U.S. Energy Information Administration.
All values are in 2010$ per short ton.

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Findings: Environmental Regulation

- While there is uncertainty regarding future Federal climate legislation, the prospects appear likely enough for a range of CO_2 prices to be reflected in our analysis.
- Because Connecticut and other parts of New England are not in attainment with air quality standards, additional NO_X control requirements will likely be imposed on generators. The EDCs and CTDEP worked together to establish likely future NO_X emission requirements which were reflected in the simulation of the New England electricity market. The cost of these controls is projected to cause retirements of older fossil steam units in our analysis.

Findings: Environmental Regulation (continued)

- Emission allowance prices – for SO_2, NO_X, and CO_2 – will raise the costs of generation in proportion to unit emission rates, and will impact the dispatch of resources in New England and thereby reduce overall emissions. Although the prices of allowances for each pollutant are determined by aggregate emissions relative to an emission cap, these markets are not wholly independent. In particular, the price of CO_2 allowances can influence the price of SO_2 and NO_X allowances, an effect that was reflected in the analysis.

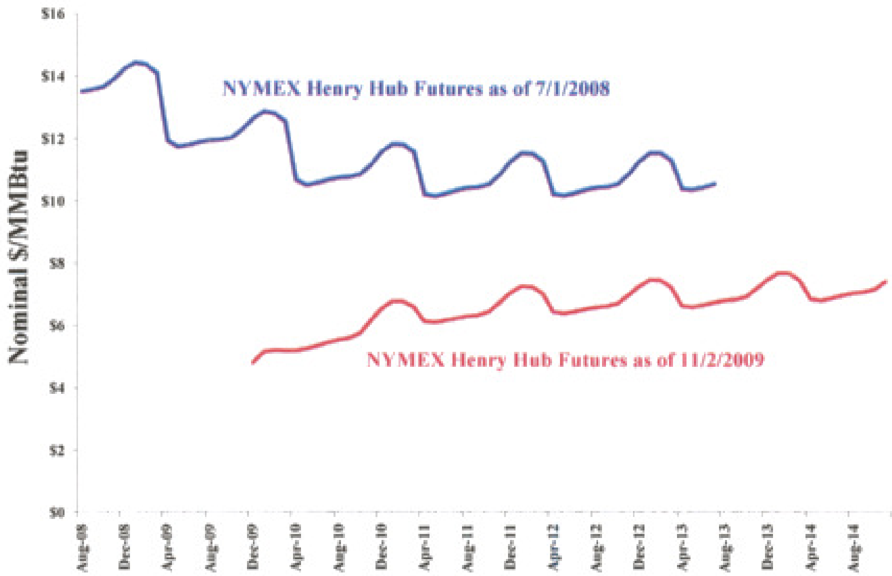
- The imposition of new regulations for other environmental sectors (not air) have the potential to introduce greater costs to generators, though the potential impact of these costs can not be determined at this time and thus were not reflected in the analysis.

Gas Price Scenarios

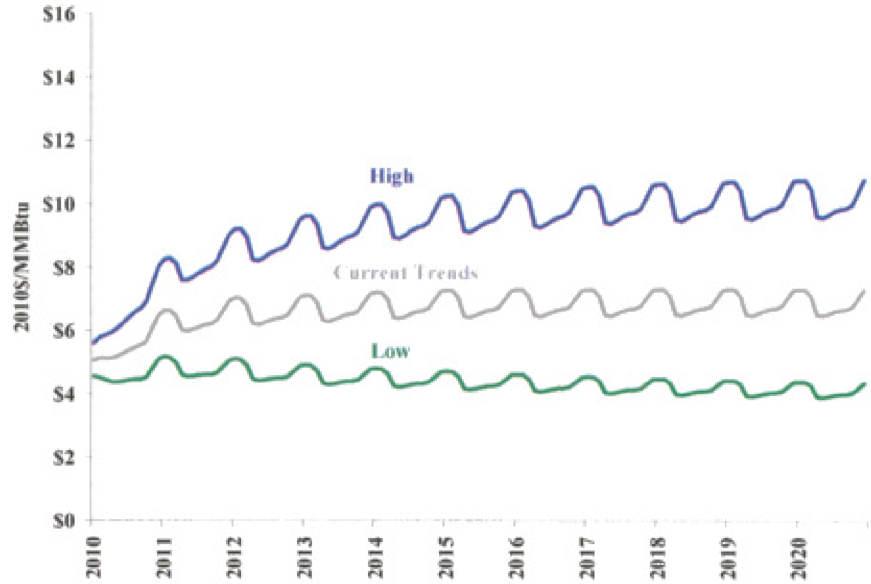
Natural gas futures prices have fallen considerably; future gas prices remain uncertain, though around a lower expected price

- Gas prices are expected to remain around $7/MMBtu in real terms

Natural Gas Futures Price Change
July 2008 to November 2009



Natural Gas Price Scenarios
for Simulation Analyses



Findings: Natural Gas

- The overall supply picture for domestic natural gas appears promising, due particularly to the advent of new unconventional gas supplies such as shale gas. This expanding supply should be adequate to accommodate even increased gas demand, though the ultimate extent and pace of the new supplies coming online is not certain.

- Pipeline and LNG delivery capacity to New England have increased over the past several years, with additional new expansion projects still in development for the near future. Gas delivery capacity to serve average and peak needs has improved measurably from a few years ago (though this does not address gas local distribution company (LDC) deliverability issues, where additional expansions may be necessary).

AMI Investments Are Happening in Connecticut

AMI has gained momentum in Connecticut and elsewhere as part of the expanding "Smart Grid" Concept

- UI began to implement its meter enhancement plan
- CL&P conducted a pilot project to test AMI, dynamic pricing and enabling technology on residential, commercial and industrial (C&I) customers during the summer
  - Examined customer responses to critical peak pricing (CPP), peak time rebate (PTR) and time-of-use (TOU) rates

Rate Price Differentials by Rate Design ($/kWh)

	RATE->	TOU		PTR		CPP	
Customers	**Period**	Low	High	Low	High	Low	High
Residential (Rate 1 &5)	Peak	0.071	0.142	0.655	1.614	0.655	1.614
	Off-Peak	-0.029	-0.058	0.000	0.000	-0.015	-0.036
C&I (Rate 30 & 35)	Peak	0.069	0.138	0.650	1.601	0.650	1.601
	Off-Peak	-0.031	-0.062	0.000	0.000	-0.020	-0.049

8

AMI & Dynamic Pricing: Impacts on Peak Demand

AMI coupled with dynamic pricing (CPP and PTR) had the largest impact on peak demand reductions. Customers with access to enabling technology demonstrated larger reductions

Demand Impact Results of CL&P Pilot Program

Customers	Period	TOU High Diff.	TOU With Tech	PTR High Diff.	PTR With Tech	CPP High Diff.	CPP With Tech
Residential (Rate 1 &5)	Peak Load Reduction	-3.1%		-10.9%	-17.8%	-16.1%	-23.3%
	Monthly consumption change	-0.1%		-0.2%		+0.2%	
C&I (Rate 30 &35)	Peak Load Reduction	0%		0%	-4.1%	-2.8%	-7.2%
	Monthly consumption change	0%		0%		0%	

TAB 13

The Rush to Coal: Is the Analysis Complete?

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Real options theory is clear that as volatility increases there is an increasing value to delay and learning. Given current conditions in the utility industry, it seems a critical time for the industry to recognize the value of caution and learning, particularly with respect to the construction of new coal plants. Utilities do have options such as delaying retirements and/or allowing prices to rise.

Gregory Hamm and Adam Borison

"Truth is confirmed by inspection and delay; falsehood by haste and uncertainty."

– Publius Cornelius Tacitus

I. Overview

After a period of very low activity, a large number of new coal power plants are under development in the U.S. – nearly 100 GW. At the same time, the costs of construction materials and services have seen increases unprecedented in 20 years. Perhaps of the most significance for coal plant development, legislation limiting greenhouse gas (GHG) emissions has been adopted in several states and has been proposed in many other states and at the federal level. GHG regulation can impact coal plants particularly because of their high emissions of CO_2. In addition, anticipation of GHG regulation has led to a rush to develop renewable power technologies, nuclear power, and new cleaner coal power technologies.

History, economic theory, and experience all suggest that, in times of high uncertainty, learning has high value and investments should face a higher hurdle. The question arises, "Are coal plant developers adequately considering the potential for learning about GHG regulation, construction cost trends, new technologies, and the consequent impacts on coal plant economics when making decisions about building new coal plants?"

We begin with a discussion of the fundamental principle that the hurdle for investment should rise in times of high uncertainty. We then present some empirical evidence regarding the value of waiting and learning. The empirical evidence comes from outside and within the electric power industry. We present both statistical and, for illustration, anecdotal evidence. Finally, we argue that this is a period of especially high uncertainty for coal-based power and that alternatives exist to rapid expansion of traditional coal capacity.

II. The Value of Learning: Fundamental Principles

What is the appropriate response when considering an investment in the face of uncertainty? Consider your last investment in a cell phone, computer, or other high-tech device. If a highly anticipated new device was soon to be released, did you delay your purchase? If a "bubble" of demand seemed to be pushing prices up, did you consider postponing your purchase? Did you wait to learn what the new value-to-price tradeoff would be? Many people do. The high-tech industry anticipates a slowdown in sales just prior to the release of blockbuster products such as the iPhone, major new processor releases from Intel, or a new operating system from Microsoft or Apple. Frequently, prices are slashed prior to the new product's release to try and keep buyers buying, but still many of us delay to learn.

In a period of high uncertainty for coal-based power, alternatives exist to rapid expansion of traditional coal capacity.

A fundamental result of real options theory is that a tradeoff must be made between the cost of delay and the value of learning. The greater the uncertainty, the higher are the rewards to learning. This includes uncertainty with respect to input costs, output prices, and regulatory actions. We illustrate this with a simple example, similar to that used by Dixit and Pyndyck in their classic text on real options.[1]

Consider a potential investment of $1,000 million in a coal-fired power plant. The investment is made at the start of Period 1, and we are confident of receiving $200 million in net revenue at the end of this period. Returns following Period 1 are uncertain; however, we believe that by the end of Period 1 we will learn that the net present value (NPV) of future net revenues is $1,300 million or $800 million. Finally, we assume that the probability p of the high value is 50 percent and the returns are uncorrelated with markets.[2] The payoffs from investment are illustrated in **Figure 1**. If we don't invest, the cost and payoff are $0.

Should we invest or not? The traditional rule is that if the discounted expected NPV is positive, we should invest. Assuming a 10 percent discount rate, the calculations of expected NPV including investment are:

$$-\text{Investment} + \frac{\text{Period 1 Return}}{\text{Period 1 Discount}} + \frac{\text{Period 2 Return}}{\text{Period 2 Discount}} = \text{NPV}$$

or

$$-\$1000 + \frac{\$200}{1.1} + \frac{0.5 \times \$1300 + 0.5 \times \$800}{1.1^2} = \$49.60$$

NPV is positive; the traditional rule says invest.

Now assume that we have the option to invest at the end of Period 1, after we learn about the long-run returns. If we delay, we

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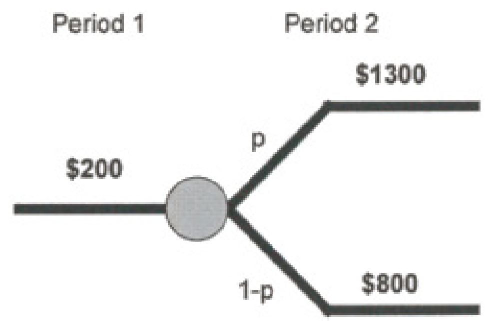

Figure 1: Payoffs from Investment

will forego the revenue of $200 million in the first period. If we learn that future net revenues will be $1,300 million, we will invest. If we learn that future net revenues will be $800 million, we will not invest. If we delay one period, the calculations of expected NPV including investment are:

$$0.5 \times \left(\frac{-\$1000}{1.1} + \frac{\$1300}{1.1^2}\right) + 0.5 \times 0 = \$82.64$$

Delay and learning increase our returns dramatically.

Figure 2 illustrates the NPV and strategy in our example as the probability of the high payoff changes.

If "Act-Now" was our only alternative, we would not invest unless the probability of the high payoff was greater than 30 percent. This means that we actually lose money more than 50 percent of the time, but the chance at high returns makes it a good investment. In the range of approximately 30 percent to 60 percent, we delay our investment when the option to invest later is available. With over 60 percent probability of the high outcome, we invest now even with the delay option.

Our model is extremely simple but it illustrates that in the face of uncertainty with the option of delayed investment, it is often optimal to wait. Dixit and Pyndyck develop and test a number of more realistic models where learning is incomplete and investment can occur at any time.

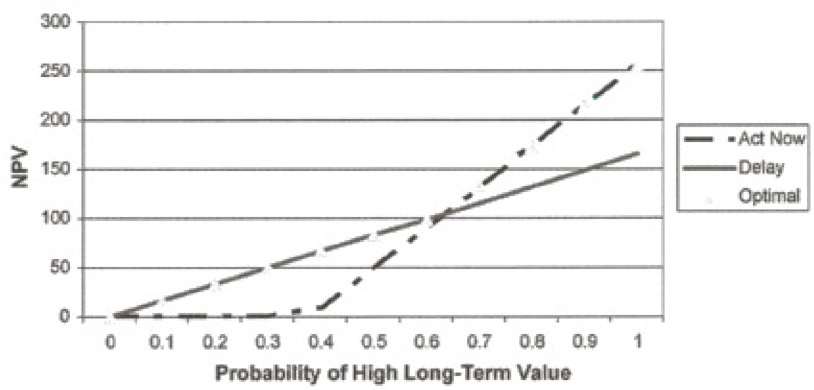

Figure 2: NPV and Optimal Policy as Probability Varies

Their conclusion, "Hence the simple NPV rule is not just wrong; it is often very wrong."[3]

This principal of the value of delay and learning has also been studied in the realm of regulated utilities. This analysis has shown that if regulation reduces the uncertainty in future returns, it may modify but it does not eliminate the value of learning.[4]

III. The Value of Learning: Experience

The prior section illustrated the logic of balancing act-now versus delay-and-learn. For individual companies, we see many cases where the most aggressive "first-to-market" firms lose out to firms that learn from the experience of these leaders. Also, we see examples where entire industries seem to get caught up in investment rushes that end in disaster. In this section, we look at examples outside and within the electric power industry. We first review a few limited cases where statistical analysis has been possible and then review some of the more anecdotal evidence for the value of learning.

A. Experience outside the electric power industry

Some statistical analysis:

- Bulan conducted two studies of the impact of uncertainty on investment. The first study was of 1,200 real estate developments in Vancouver, B.C. The second

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study was of 2,300 publicly traded firms with a total of 17,000 observations. The major finding was that greater uncertainty in prices significantly reduces the pace of investment.[5]

- In a study of 80 Internet companies, McKinsey found that speed at the expense of developing a solid business plan and gathering the right resources rarely paid off.[6]
- Cotrell and Sick examined individual competitive situations. They found that delay to learn about market development, technology change, or input or output prices provided significant advantages in nine different industries. They cite similar results for 28 other consumer products.[7]

Perhaps the best recent example of an industry-wide rush to invest in the face of very high uncertainty was the 1996–2001 telecom investment spree followed by the 2001–2002 worldwide telecom meltdown. The telecom industry raised $650 billion in debt and equity between 1996 and 2001.[8] The uncertainties in this period included whether an extremely sudden and rapid growth in bandwidth demand would continue, how fast and which new telecom technologies would develop, and how much demand there would be for personal communication and data services.

In the U.S. beginning about 1996, deregulation and demand for Internet services created a frenzy to acquire network resources. Established companies began spending wildly on network installation, many new network companies started up, and companies with high-speed lines were purchased at 10 times the value of their assets.[9] Demand failed to materialize. By 2001, seven new American telecom companies had filed for bankruptcy and more than $100 billion in junk bonds were rated as high risk.[10] By 2002, half a million jobs in telecom were lost and the market value of sector had dropped $2 trillion.[11]

The early estimates of compliance costs for installing scrubbers, switching to low-sulfur coal, or buying allowances were extremely inaccurate.

In Europe, the focus was on Third Generation (3G) mobile networks and the licenses to operate these networks. The investment and collapse happened more quickly than in the U.S. In 2000, Martin Bouygues, who ran France's No. 3 cell phone network, wrote an open letter saying that it was crazy to bid billions of dollars to buy licenses and build networks, when technologies to use the networks were still under development and the services to be sold were undefined. No one paid attention, but Bouygues proved to be right. In just two years, "Europe's phone giants – after spending half a trillion dollars on licenses, acquisitions, and networks – are treading madly to stay afloat in a sea of debt. But 3G phones may well cost $800 – and devour batteries. Worse yet is bandwidth's dirty secret: Without compelling content and services to sell, high-speed networks are a waste of money. The [phone companies] are paying through the nose for something that's not very valuable."[12] The biggest spenders had to sell off prime assets to cover debt or make share offerings. On average, European telecom stocks fell nearly 60 percent from May 2000 to June 2001.[13]

B. Experience inside the U.S. power industry

The 1990 Clean Air Act Amendments were a revolution in U.S. environmental regulation. The Act was performance based providing great flexibility in meeting the requirements. It introduced trading of pollution allowances, creating the opportunity for the market to efficiently distribute the emissions reductions. Here we consider the sulfur dioxide controls in the Act.

The major choices for compliance were installing scrubbers, switching to low-sulfur coal, and buying allowances. The early estimates of the costs of these approaches were extremely inaccurate. **Table 1**[14] shows a pre-1989 industry

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Table 1: Predicted and Actual Allowance Prices

Industry Estimates Pre-1989	EPA 1990 Estimate	Early Allowance Trades	Early 1995 Allowance Trades	1993 CBOT Allowance Auction	1994 CBOT Allowance Auction	1995 CBOT Allowance Auction
$1,500	$750	$250	$170	$122	$140	$126

estimate of allowance prices, an EPA 1990 estimate of allowance prices, and actual trade prices from 1993 to 1995. The actual prices were one-fifth to one-tenth of the estimated prices.

In 1990, many analysts projected that the average price for low-sulfur Central Appalachian coal would reach $40 per ton by 1995, but the actual price was less than $25 per ton. Scrubber prices fell through out the early years of the regulation while at the same time increasing in efficiency.[15] At least in retrospect, it is obvious that there was great uncertainty about the costs of compliance.

Logic would suggest that utilities would avoid investment and choose flexible approaches for compliance until the cost of different approaches became more clear. **Table 2**[16] shows early compliance strategies.

"Install Scrubbers," the most capital-intensive approach, was used by a limited number of utilities, even though utilities that scrubbed were eligible for an "extra" 3.5 million allowances – a political concession to reduce the Act's impact on states producing high-sulfur coal. Coal-switching was by far the most popular strategy. This is a fairly flexible strategy with relatively low upfront costs.

But why did the most flexible strategy, "Purchase Allowances," get so little use? There have been a number of reasons advanced: transaction costs, cost savings not shared with utilities, asymmetry of regulatory risk, legislative trading prohibitions, negative public reaction to buying the right to pollute. We feel another reason was a lack of recognition of the uncertainty of allowance prices and the value of waiting and learning.

One major utility, Illinois Power, did pick a Purchase Allowances approach.[17] The utility used a simple real options analysis of the regulations and considered its maverick approach highly successful.[18]

Table 2: Choice of Compliance Strategies

Compliance Approach	% of Utilities Using Approach
Switch and/or blend coals	55% to 63%
Pre-phase I compliance	10% to 18%
Install scrubbers	10% to 16%
Purchase allowances	3% to 15%

IV. Uncertainty and Alternatives

A. Uncertainty

Both capital and operating costs for coal power plants are highly uncertain at this time. Recently, utilities have seen rapid changes in capital costs. For example, Duke Energy has seen the total price of two new 800 MW coal units escalate from $2 billion to $3 billion[19] **Figure 3** illustrates that the recent escalation of key components of generating facility construction costs is unprecedented over the last 20 years. The producer price indices for new construction, steel mill products, and concrete are shown.[20] All three graphs show a significant acceleration in costs beginning in 2004 and continuing to the present.

Is this a short-term run-up due to supply-demand imbalances that will go away as supply increases, or does it mark a more permanent move of these commodities to higher prices? No one knows the answer to that question. Because the run-up has been both sudden and unique, we believe it indicates a period of high price uncertainty.

Operating costs for coal are highly dependent on environmental regulation, and it

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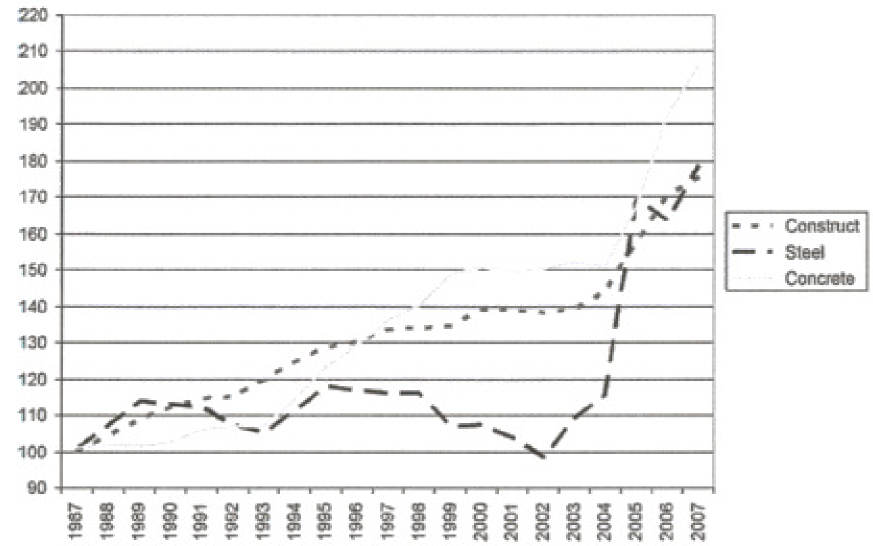

Figure 3: Construction Cost Increases

is likely that the most important environmental regulation ever for fossil fuel power will be enacted in the next few years. Currently, there are 10 GHG emission bills in Congress. One bill would cap the cost of CO_2 emissions at $7/ton of CO_2 released. Some advocates of strict limits suggest that $30/ton is needed to significantly affect the production of CO_2 from coal. These represent an increase of 25 percent to over 100 percent in the operating costs of coal plants. Some utilities see the passage of GHG legislation with some type of an allowance trading provision as a virtual certainty, but there is still much to be learned. The bills differ significantly in the following dimensions:

- Severity of limits;
- Existence of a safety valve (maximum) allowance price;
- Economy-wide versus electric-utility-only trading;
- Ability to use international credits, forestation, and sequestration;
- Allowance distribution rules; and
- Percent of free versus auctioned allowances.

This regulation and the way the federal law and state regulators distribute costs between companies and consumers pose huge risks for utilities now developing coal.

B. Alternatives

Capacity margin levels are projected to drop below minimum target levels in Texas, New England, the Mid-Atlantic, the Midwest, and the Rocky Mountain area in the next two to three years.[21] NERC expects 141 GW of demand growth by 2015.[22] NERC estimates 16 percent growth in energy needs and 17 percent growth in peak demand, from 2006 to 2014. The EIA estimates 14.5 percent (reference case) and 17 percent (high case) electric energy demand growth over the same period.

The industry is rushing to build new capacity and new coal capacity in particular to meet this need. Some 246 coal-fired units totaling over 85 GW are in various stages of development in North America. Of the new units, 233 are proposed for the U.S., 11 for Canada, and two for Mexico. Combined, these projects represent an investment of more than $127 billion. Of the 246 coal-fired units that have been proposed, 72 (representing 27 GW) were planning to break ground in 2007, and another 95 units totaling 31 GW may get under way in 2008. (In addition, 82 GW of gas, 51 GW of renewables, and 40 GW of new nuclear are under development or have been proposed.)[23]

If new capacity is the only way to bring supply and demand into balance, perhaps building coal now is the only alternative. But, utilities have a number of alternatives to deal with this growth. In order of increasing flexibility, alternatives include: invest in large plants, invest in transmission, invest in smaller plants, invest in demand-side management, delay planned retirements, and let prices rise. Consider the two most flexible: delay planned retirements and let prices rise.

- Between now and 2010, it is assumed that 20 GW are likely to be decommissioned. Delays in these retirements would significantly reduce the short-run need for new capacity.

 1040-6190/$–see front matter doi:/10.1016/j.tej.2007.12.003

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- The current EIA estimate assumes that approximately 10 percent of recent price increases will disappear moving into the future. If prices held constant – a 10 percent rise over the current EIA reference case through 2014 – it is estimated that demand growth in the 2006-2014 period would be reduced from 14.5 percent to 10.6 percent. This is approximately a 25 GW reduction in needed plants between 2006 and 2014.[24]

These alternatives would allow time to learn more about carbon regulation, costs, and new technologies.

V. Summary and Recommendations

Coal plants in particular face an extremely uncertain future. The cost of constructing plants has experienced a rapid increase over a short period. It is uncertain if a new plateau has been established or if prices may revert to lower levels. The most dramatic environmental legislation in the history of the industry is on the horizon. But the nature of this legislation and its implementation is uncertain.

Real options theory is clear that as volatility increases there is an increasing value to delay and learning. Investments should only be undertaken when the returns cover both the investment costs and this shadow cost of lost learning.

Historical patterns show that companies vaguely recognize this principal; however, it does not seem to be systematically applied and followed.

Given current conditions in the utility industry, it seems a critical time for the industry to recognize the value of caution and learning, particularly with respect to the construction of new coal plants. Utilities do have options such as delaying retirements and/or allowing prices to rise. Further, utilities have the capability of analyzing their alternatives with consideration of the value of learning. Real options analysis is a practical tool for the examination of risky and flexible investments.■

Endnotes:

1. Avinash Dixit and Robert Pindyck, INVESTMENT UNDER UNCERTAINTY (Princeton, NJ: Princeton Univ. Press, 1994).

2. Assuming that the uncertainties are not market-correlated means that returns are fully diversifiable and allows us to use the risk free discount rate.

3. Dixit and Pindyck, *supra* note 1.

4. Elizabeth Olmsted Teisberg, *Capital Investment Strategies under Uncertain Regulation*, RAND J. ECON., Winter 1993, at 591.

5. Laarni Tobia Bulan, *Firm Investment Behavior in a Real Options Framework: Empirical Evidence*, PROQUEST DISSERTATIONS AND THESES, 2001, Section 0054, Part 0508. Ph.D. dissertation, Columbia Univ., 2001.

6. Marty Bates, Syed Rizvi, Prashant Tewari and Dev Vardhan, *How Fast Is Too Fast?* MCKINSEY Q., Issue 3, 2001, at 52.

7. Tom Cottrell and Gordon Sick, *Real Options and Follower Strategies: The Loss of Real Option Value to First-Mover Advantage*, ENGINEERING ECONOMIST, Vol. 47, Issue 3, 2002, at 232.

8. Peter Elstrom and Heather Timmons, *Telecom Meltdown: Profits Are Vanishing. Companies Are Going Belly-Up. And This Industry's Troubles Just Might Flatten the Economy*, BUSINESS WEEK, April 23, 2001, at 54.

9. *Id.*

10. *Id.*

11. Steve Rosenbush, Roger O. Crockett, Charles Haddad and Jack Ewing, *The Telecom Depression: When Will It End?* BUSINESS WEEK, Oct. 7, 2002, at 66.

12. Stephen Baker and Mark Clifford, *Tale of a Bubble: How the 3G Fiasco Came Close to Wrecking Europe*, BUSINESS WEEK, June 3, 2002, at 48.

13. Almar Latour, *Disconnected: How Europe Tripped Over a Wireless Phone Made for the Internet*, WALL ST. J. (Eastern ed.), June 5, 2001, at A1.

14. Dallas Burtraw, *The SO2 Emissions Trading Program: Cost Savings without Allowance Trades*, CONTEMPORARY ECON. POLICY, April 1996, at 79.

15. *Id.*

16. *Id.*

17. Doug Bohi, *Utilities and State Regulators Are Failing to Take Advantage of Emission Allowance Trading*, ELEC. J., March 1994, at 20.

18. Personal knowledge.

19. Steve Blankinship, *Construction Costs Won't Deter Duke's Coal Plans*, POWER ENG'G., Jan. 2007, at 12.

20. Bureau of Labor Statistics.

21. Steve Blankinship, *NERC Issues Worrisome Assessment*, POWER ENG'G., Nov. 2006, at 28.

22. Rebecca Smith. *U.S. Electricity Demand Is Outpacing New Resources, Report Warns*, WALL ST. J. (Eastern ed.), Oct. 16, 2006, at A2.

23. Britt Burt and Shane Mullins, Industrial Info Resources, *2007 Future Forecast: Near-Term Capital Spending in the North American Power Industry*, POWER, Jan. 2007, at 40.

24. Peter S. Fox-Penner, Marc Chupka, Gregory Basheda, Adam Schumacher and Eric R. Blume, *The Demand Effect*, ELEC. PERSPECTIVES, Sept./Oct. 2006, at 32.

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TAB 14

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION
121 Seventh Place East, Suite 350
St. Paul, Minnesota 55101-2147

Beverly Jones Heydinger	Chair
Dr. David C. Boyd	Commissioner
Nancy Lange	Commissioner
J. Dennis O'Brien	Commissioner
Betsy L. Wergin	Commissioner

In the Matter of the Request of Minnesota Power for a Certificate of Need for the Great Northern Transmission Line

MPUC Docket No. E-015/CN-12-1163

Application For A Certificate Of Need

October 21, 2013

minnesota power

AN ALLETE COMPANY

GREAT NORTHERN TRANSMISSION LINE

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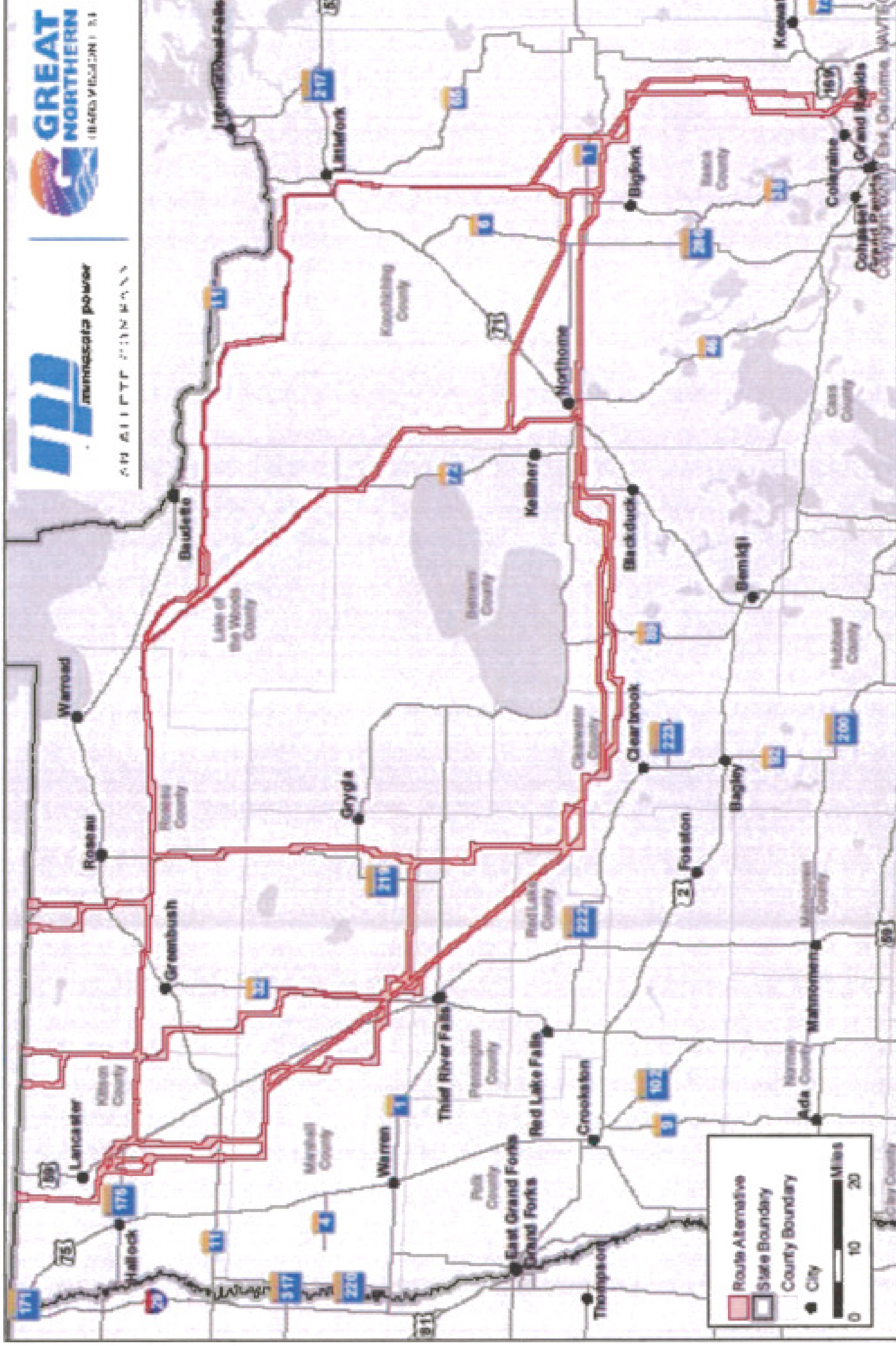
FIGURE 1.5B - Route Alternatives Currently Under Consideration



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3. GENERAL INFORMATION

3.1. Project Ownership

Minnesota Power, an operating division of ALLETE, Inc., will have majority ownership (51%) of the Project. Minnesota Power is a public utility in the State of Minnesota under Minn. Stat. § 216B.02, with its principal place of business at 30 West Superior Street, Duluth, Minnesota 55802. The balance of the Project (49%) will be owned by a subsidiary of Manitoba Hydro. As discussed in the Term Sheet, Minnesota Power and Manitoba Hydro and its subsidiary are still evaluating the ownership structure that fully addresses federal and state regulatory, MISO, legal and tax issues. Minnesota Power will provide the Commission final ownership terms upon completion, as the Commission has required in previous transmission dockets.[15] Minnesota Power will also provide the Commission updates regarding all applicable MISO facilities construction and interconnection agreements.

While Minnesota Power will own 51% of the Project, Minnesota Power's customers will be financially responsible for only 33.3% of the Project's revenue requirements. Minnesota Power will receive an amount equal to the balance of the revenue requirements associated with its ownership percentage (17.7%) from Manitoba Hydro by way of a scheduling fee arrangement included in the proposed 133 MW Renewable Optimization Agreements. Given this arrangement, while the Project will have a transfer capability of approximately 750 MW, Minnesota Power and its customers will be responsible for the revenue requirements associated with 250 MW of that total capability. The rate impacts of this are discussed in Section 4.3.5, below.

Minnesota Power will serve as the construction manager for all assets within the United States and will also operate and maintain all Project assets located within the United States. Minnesota Power, through an Operation and Maintenance agreement will invoice the minority owner monthly for its 49% pro rata share of Operation and Maintenance expenses associated with the Project. Once in-service, functional control of the entire Project will be turned over to MISO.

3.2. Project Participants

The Project represents the United States segment of an overall project to increase the transmission capability between Manitoba and Minnesota and the Upper Midwest. The

[15] *See, e.g., In the Matter of the Application Of Great River Energy, Northern States Power Company (d/b/a Xcel Energy) and Others for Certificates of Need for Three 345 kV Transmission Lines with Associated System Connections*; MPUC Docket No. ET-2, E-002, et al./CN-06-1115; Order Granting Certificates of Need, May 22, 2009, Order Point 4, requiring Applicants to "make a compliance filing disclosing each project's transmission capacity, owners and ownership structure."

4.3. Cost and Service Characteristics

4.3.1. Total Cost in Current Dollars

The Project will traverse a large section of Northern Minnesota. The geographical topology of Northern Minnesota is very diverse and the route upon which the line will be built has not been determined. Therefore, in order to develop a meaningful estimate, Minnesota Power has developed a "proxy route" that engineers could review and apply design standards to. The result of this process is an estimate based on a proxy route of 240 miles. Minnesota Power estimates that construction of the Project on this proxy route, including substation construction, will cost between $406 million and $609 million (2013 dollars), with a mid-point of $507 million. This range divided by the proxy route of 240 miles will generate a total cost per mile of approximately $1.7 to $2.5 million.

The major components of the above estimates are shown in Table 4.3.1, below.

Table 4.3.1: Project Cost Estimates

	GNTL Project Estimates (2013 Dollars)		
Project Components	Low End (in Millions)	Mid Point (in Millions)	High End (in Millions)
Project Management & Engr	$ 75.3	$ 94.1	$ 112.9
Land and Clearing	$ 53.1	$ 66.4	$ 79.7
Transmission Line Construction	$ 235.6	$ 294.6	$ 353.5
Substation Construction	$ 42.2	$ 52.7	$ 63.3
Project Totals	$ 406.2	$ 507.8	$ 609.3
Based on 240 Miles Dollars per M	$ 1.692	$ 2.116	$ 2.539

4.3.2. Service Life

Minnesota Power has submitted to the Minnesota Public Utilities Commission its 2013 Transmission Plant Depreciation Study (Docket No. E-015/D-13-252). Included in that study Minnesota Power has requested a 55 year life be established for certain transmission line assets and a 44 year service life for substation equipment. If approved, those service lives would apply to the Project's 500 kV line and the substation assets. As

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a practical matter, a 500 kV line and substation equipment is rarely completely retired, but is repaired, replaced or upgraded to meet future needs.

4.3.3. Average Annual Availability

Transmission assets have very few mechanical elements and will be built to withstand severe weather extremes. Transmission assets are controlled by computer based protection and outages should be momentary. Scheduled maintenance outages also are very infrequent. As a result, the average annual availability of transmission assets is very high, near or above 99%.

4.3.4. Estimated Annual Operations and Maintenance Costs in Current Dollars

Transmission lines require a minimal amount of routine maintenance. The primary annual maintenance expense for transmission line is aerial inspection. These inspections will look for broken insulators or structural defects which could compromise the line. If issues are identified, ground crews will be dispatched to correct the defect. In addition to structural maintenance the right-of-way also must be kept clear of vegetation. Vegetation control is performed on a scheduled and routine basis. Additional vegetation management will also be performed if the aerial inspection discovers issues. The cost for routine maintenance will depend on the topology of the terrain and the type of maintenance required, but typically will run from $1,100 to $1,600 per mile.

Transmission facilities require a certain amount of maintenance to keep them functioning in accordance with good utility practices, manufacturers' recommendations and North American Electric Reliability Corporation ("NERC") standards.

4.3.5. Estimate of Effect on Rates System-Wide and in Minnesota

Minnesota Power recognizes the value and importance of affordable rates in all customer classes. While the Project will impact the rates that Minnesota Power charges both its retail and wholesale customers, Minnesota Power and Manitoba Hydro have taken steps to minimize that impact.

As part of the 938 Docket, Minnesota Power indicated that a 230 kV transmission option for the delivery of 250 MW Agreements from Manitoba Hydro would cost Minnesota Power (and by extension, its customers) from $200 to $240 million (2020 dollars). In addition, Minnesota Power and its customers would bear the full maintenance costs associated with such a line.

In contrast, as discussed in Section 3.1 above, Minnesota Power will be asking its customers to be responsible for only one-third of the Project cost, corresponding to the portion of the line needed for the delivery of the 250 MW Agreements. Using the Project cost estimates provided in Section 4.3.1, escalated to 2020 dollars, Minnesota Power's customers' revenue requirements would be based on an investment of \$164 to \$245 million. In order to provide a meaningful comparison, the rate impacts were based on an investment at the midpoint of the above 2020 range, or \$204.5 million, compared to a midpoint range of the 230 kV estimates of \$220 million, representing a cost reduction of approximately ten percent (10%) from the transmission cost in the 938 Docket. Going forward, Minnesota Power customers will also be responsible for only one-third of the maintenance costs associated with the Project. As such, the Project provides a more cost-effective and longer-term solution for Minnesota Power ratepayers than constructing the 230 kV option.

The effect of the Project on rates will be discussed in two sections. The first will be the effect on Minnesota Power's retail rates and the second will be the effect on FERC (MISO) jurisdictional rates.

4.3.5.1. Minnesota Power Retail Rates

The Project is project to have an effect on the rates of Minnesota Power's retail customers. Table 4.3.5.1 summarizes the estimated Minnesota jurisdictional revenue requirements and rate impacts by customer class for the expected in-service year beginning June 1, 2020. The Minnesota jurisdictional and class requirements were derived by multiplying the total Minnesota Power customer revenue requirements by Minnesota Power's current D-02 Transmission Demand jurisdictional and class allocators. For the average residential customer, the rate impact in 2020 would be approximately \$2.51 per month. If compared to the estimated average current residential rate in 2014, this would represent an increase of approximately 3.3 percent. By 2020, however, the percent increase is expected to be lower because base rates will likely increase as other system costs change and are incorporated into base rates through future rate cases and other mechanisms. For Large Power customers, the estimated rate impact for the year 2020 would be approximately 0.261¢ per kWh of energy. If compared to the estimated average current Large Power rate for 2014, this would represent an increase of approximately 4.9 percent. As with residential rates, the percent increase is expected to be lower by 2020 because base rates will likely increase due to changes in other system costs that will be incorporated into base rates through future rate cases and other mechanisms. These estimates would also be impacted by future changes in Minnesota Power's D-02 Transmission Demand jurisdictional and class allocators.

economic analysis, these models were modified to exclude the Blackberry – Arrowhead 345 kV project and better align with Minnesota Power's identified resource planning philosophy concerning such issues as coal retirements, coal unit conversion to natural gas, and future wind development plans. The analysis will look at model years 2022 and 2027 and also include scenarios simulating a business as usual (BAU) and High Demand in Energy ("HDE") future. These scenarios will be simulated both with and without the Project to capture economic impacts.

A sensitivity analysis looking at the additional impact assuming a carbon tax was also added to the economic analysis. The cost of coal assumptions were based on a mid-level CO2 tax meant to capture environmental and socioeconomic costs, docket Nos. E-999/CI-93-583 and E-999/CI-00-1636. The economic analysis is ongoing and is expected to be completed the end of October 2013 with the carbon sensitivity analysis completed shortly thereafter. While not a requirement for completeness under the Commission's rules, Minnesota Power will supplement this Docket as soon as the GNTL Economic Impact Study is finalized.

6.4. The Project will Comply With Relevant Policies and Regulations of Other State and Federal Agencies and Local Governments

Minnesota Power is committed to full compliance with relevant policies and regulations related to the Project. As detailed in Section 3.3, above, Minnesota Power has engaged in extensive stakeholder discussions prior to filing the Application, including discussions with tribal, federal, state and local representatives and authorities. As part of this process, Minnesota Power has participated in several multi-agency meetings and has appreciated the efforts of federal and state agencies to coordinate activities regarding this project. Table 3.5 provides a listing of the permits required for the Project and Minnesota Power anticipates receiving all such permits prior to construction.

6.5. Delay or Denial Would Adversely Impact Minnesota Power, the State and the Region

Denial of a certificate of need for the Project would adversely impact Minnesota Power, its customers, the state and the region. For Minnesota Power, the immediate and direct impact of denial would be the inability to take delivery of needed power from Manitoba Hydro under the Commission-approved 250 MW Agreements. In approving the 250 MW Agreements, the Commission has already determined that the hydropower resources proposed in the PPA represent the most appropriate resources to meet Minnesota Power's resource needs over the period 2020 through 2035 and that the 250 MW Agreements are in the public interest. Thus, denial of a certificate of need for the Project, and the resulting inability for Minnesota Power to take delivery of the contracted hydropower, would leave Minnesota Power with significant unmet needs and would compel addition of less appropriate resources to fill those needs. Loss of the contracted-for hydropower would come with an economic cost, as well as a cost in diversification of generation resources.

Moreover, the Company and its customers would lose the ability to receive the benefits of the additional 133 MW Renewable Optimization Agreements, meaning again the Minnesota Power would have to look to other, less optimal resources to fill its needs.

Importantly, by losing the ability to deliver the benefits of the 250 MW Agreements and 133 MW Renewable Optimization Agreements, and the associated renewable energy storage provisions, Minnesota Power and its customers would lose the advantages brought about by the synergies possible through the coordination of wind and hydropower contemplated by Minnesota Power and Manitoba Hydro, as identified in the Manitoba Hydro Wind Synergy Study.

Finally, denial of a certificate of need would mean the loss of the regional benefits that can be brought about by the Project, including the additional ability to meet regional needs with hydropower, building a more reliable system by reinforcing the connections between Minnesota and Manitoba, thereby addressing the single largest contingency in MISO's northern region, and increasing the transfer capability between Manitoba and the United States.

6.6. Minnesota Right of First Refusal

In 2012, in response to FERC Order No. 1000 that eliminated federal rights of first refusal ("ROFR") in federal tariffs, Minnesota enacted a state ROFR for new transmission lines that connect to the facilities of incumbent electric transmission owners.[22] The state ROFR is triggered when a transmission line has been approved for construction by a federally registered planning authority transmission plan and connects to facilities owned by that incumbent electric transmission owner.

For purposes of this Project, the federal planning entity is MISO and the facility that will be connected to is Minnesota Power's Blackberry Substation. While the Project has been submitted to the MISO MTEP process and is currently in Appendix B in that process, until a Facilities Construction Agreement ("FCA") is executed and submitted to FERC for approval, the Project will not meet the statutory criteria of being approved by MISO. Minnesota Power and Manitoba Hydro are working closely with MISO to finalize a FCA and will provide updates in this Docket regarding the status of the FCA and MISO approval.

While State ROFR rights are applicable to this Project, because the MISO process is still ongoing, the Commission procedure set forth under Minn. Stat. § 216B.246, subd. 3 does not yet apply. The Commission procedure requires that the incumbent electric

[22] *See* Minn. Stat. § 216B.246.

MISO's northern footprint is not cost-effective based on production cost savings, under current business as usual conditions. Economic benefits for MISO from a new potential Manitoba Hydro to MISO tie-line could be realized with minimal incremental transmission investment. Other than a few local area congestion issues, the economic potential for the Northern Area Study footprint is relatively little; this is a result of the MISO Multi-Value Project ("MVP") Portfolio being assumed in-service, low natural gas prices, and relatively flat demand and energy growth rates. Given the hypothetical nature of the study drivers, transmission solutions stemming from the Northern Area Study analysis were not intended to be recommended for MTEP Appendix A or B consideration. Rather, the Northern Area Study's results and findings will determine and feed future studies.

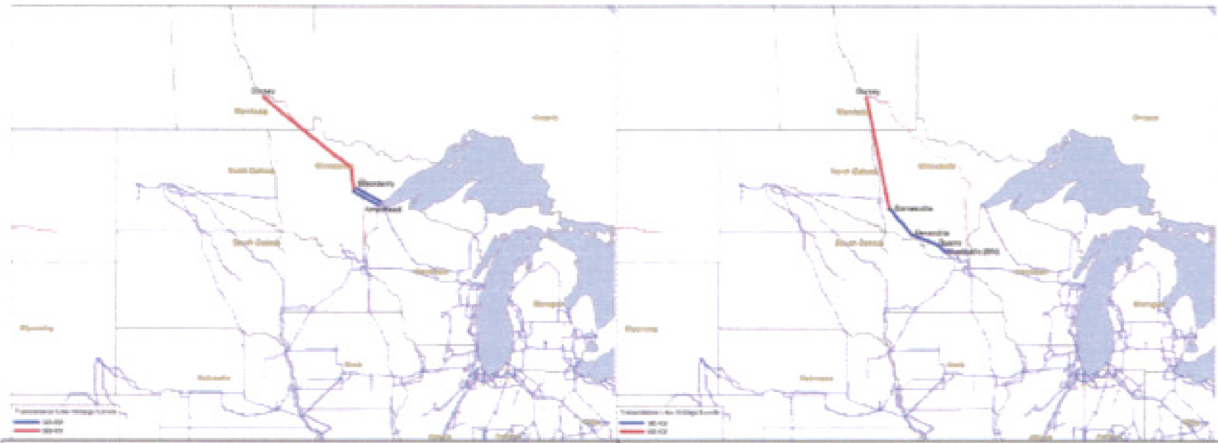
The draft study report was published in April 2013 with the final report completed on June 2013. The final report for the Northern Area Study is attached as Appendix M.

7.2.2. MISO Manitoba Hydro Wind Synergy Study

The variable and non-peak nature of wind creates integration challenges within MISO. Manitoba Hydro, with its large and flexible system, offers potential solutions for meeting these challenges. At the prompting of Manitoba Hydro and the potential customers of output from their new hydroelectric dams, MISO conducted the Manitoba Hydro Wind Synergy Study to evaluate whether the cost of expanding the transmission capacity between Manitoba and MISO would enable greater wind participation in the MISO market. MISO currently has 12 gigawatts ("GW") of wind online and 15 GW of active wind projects in the queue. Manitoba Hydro is looking to expand its hydro system by 2,230 MW over the next 15 years. Manitoba Hydro's current firm export capacity to MISO is limited to 1,850 MW which is insufficient to meet the needs of future wind generation in MISO for synergy with hydropower. Thus, this study looked at expanding transmission capacity between MISO and Manitoba Hydro to facilitate an increase in the realization of these benefits.

MISO completed its first comprehensive study that looks at the synergy between hydropower and wind power in 2013. The Manitoba Hydro Wind Synergy Study, Appendix I, found significant benefits can be realized from the addition of either an eastern 500 kV line between Winnipeg, Manitoba, and the Iron Range in northeastern Minnesota, or a western 500 kV line between Winnipeg, Manitoba, and Barnesville, Minnesota, shown below in Figure 7.2.2.

FIGURE 7.2.2 - MISO Manitoba Hydro Wind Synergy Study – Study Options



East Option: Dorsey to Blackberry	West Option: Dorsey to Fargo/Moorhead Area
- 500 kV line from Winnipeg to Grand Rapids - 345 kV double circuit line from Grand Rapids to Duluth	- 500 kV line from Winnipeg to Fargo/Moorhead Area - 345 kV line from Fargo/Moorhead to Monticello

The Manitoba Hydro Wind Synergy Study set out to evaluate the benefits and costs of expanding the interface between Manitoba Hydro and MISO. The study looked at adding an additional hydro generator in Manitoba Hydro along with the addition of one of three potential new tie lines. The combined benefits were examined including production cost savings, modified production cost savings, load cost savings, reserve cost savings, thermal generator ramping changes and wind curtailment changes. Given the wide variety of benefit metrics along with the exploratory nature of the study, the specific allocation of benefits was not possible. This study simply showed that the total benefits in the MISO area are greater than the costs to build either line.

The benefit metrics used in the Manitoba Hydro Wind Synergy Study are indicative of savings MISO may experience if either of the transmission plans were constructed, but they cannot be used to justify cost sharing of either project under the current MISO tariff. MISO conducted a hypothetical Market Efficiency Project ("MEP") eligibility test and found that MISO would receive no Adjusted Production Cost benefit from the construction of either line under the current MISO tariff and using the current MTEP12 models. Looking at these projects from a market efficiency perspective does not capture the purpose of the transmission plans, which are designed specifically to facilitate increased transfer capability between Manitoba and the United States.

Wind synergy benefits from the expanded use of hydro resources in Manitoba Hydro are demonstrated in three ways: by wind curtailment reduction in MISO; by an inverse correlation between imports from Manitoba Hydro and MISO wind generation; and by a better utilization of both wind and hydro resources. Wind curtailment in the northern MISO region was reduced by 50 to 100 GWh, depending on the plan studied and the

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scenario examined during the 2027 planning year. The interface between Manitoba Hydro and wind generation in northern MISO showed an inverse correlation between the two demonstrating the strong response of the hydro generators to fluctuations in MISO wind. The wind synergy between Manitoba Hydro and MISO wind resources appears to be economically beneficial for both MISO and Manitoba Hydro.

Based on the analyses from the Manitoba Hydro Wind Synergy Study, MISO recommended both transmission projects for inclusion in MTEP13 Appendix B. The final report was published in September 2013 and is attached as Appendix I.

7.2.3. MISO MH-US Transmission Service Request Study

MISO continues to process generation interconnection requests and Transmission Service Requests ("TSRs") on the transmission system that they operate. One group of these TSRs involves an increase in the ability to transfer power from Manitoba into the United States. The original Manitoba Hydro TSRs requested delivery totaling 1,100 MW from Manitoba Hydro to four TSR customers in the United States (north to south), and 1,100 MW from utilities in the United States to Manitoba Hydro (south to north).

An initial System Impact Study ("SIS") was completed in July 2009 for Firm Transmission Service between Manitoba Hydro and the TSR customers. The initial study considered several 500 kV transmission options for increasing the capability of the Manitoba – United States interface by 1100 MW flowing north or south. The study was conducted by Siemens PTI and an ad hoc study group consisting of Manitoba Hydro, MISO, and several utilities in the Upper Midwest. The two main transmission options considered in the SIS generally extended from the Winnipeg area into the United States via either northeastern Minnesota or the Red River Valley.[24] A follow-up SIS completed in April 2010 evaluated the impact of a new 500 kV interconnection from the Winnipeg area to the planned CapX2020 Bison Substation near Fargo, North Dakota.[25]

Recently, MISO has conducted a series of sensitivities on the original option to evaluate alternative transmission scenarios for achieving 250 MW, 750 MW, or 1100 MW of increased transfer capability from Manitoba to the United States. The MISO TSR Sensitivity Studies have included a "Western Plan" extending new 500 kV transmission to the Barnesville area in western Minnesota, an "Eastern Plan" extending new 500 kV transmission to the Iron Range in northeastern Minnesota, and a "230 kV Option" extending new 230 kV transmission to the Iron Range. While the two 500 kV options could facilitate increased transfers of 750 MW, 1,100 MW or more, the 230 kV Option would facilitate only Minnesota Power's 250 MW Agreements with Manitoba Hydro. The MISO TSR Sensitivity Studies have demonstrated that the alternative transmission

[24] MHEB Group TSR System Impact Study Executive Summary, July 17, 2009.

[25] MHEB Group TSR System Impact Study Transmission Options W.1 and W.2, April 19, 2010.

options at their associated transfer levels do not result in negative impacts to the bulk electric system. While MISO has not yet issued a final report for this series of studies, draft reports for the Eastern Plan and the Western Plan sensitivities are included in Appendix Q. The final reports will be filed in this docket when MISO makes them available

In order to facilitate delivery of power under Minnesota Power's 250 MW Agreements, which requires new transmission to be in service by June 1, 2020, Minnesota Power and Manitoba Hydro have elected to begin moving forward with an Eastern 500 kV project. This project involves extension of a new 500 kV line from the Dorsey Substation in Manitoba to the Blackberry Substation on the Iron Range. The new 500 kV tie line will facilitate increased transfers of approximately 750 MW, including Minnesota Power's 250 MW Agreements and 133 MW Renewable Optimization Agreements and also provide additional capability for Manitoba Hydro to deliver power to the remaining TSR customers or others. A future 345 kV build from Blackberry to the Arrowhead Substation near Duluth, MN would facilitate a further increase in total transfer capability from Manitoba to the United States to at least the 1100 MW originally required by the TSRs when the additional capability is requested and needed.

7.3. Generation Alternatives

7.3.1. Role of Hydro in State and Region

The Project makes possible the delivery of the 250 MW of hydroelectric power from Manitoba Hydro to Minnesota Power, approved by the Commission in the 938 Docket. This new substantial purchase, in addition to the 133 MW Renewable Optimization Agreements currently being finalized by the parties, represents the latest example of a long and mutually beneficial energy trading relationship between Minnesota utilities and Manitoba Hydro. Manitoba Hydro, Minnesota and regional utilities have enjoyed a decades-long trading relationship, as evidenced in part by several Commission-approved PPAs between Manitoba Hydro and utilities such as Minnesota Power. Indeed, for the past several years Manitoba Hydro has supplied approximately ten per cent of the electrical needs of Minnesota customers. Since 1970, Manitoba Hydro has exported 161,791 GWh of hydro-generated electricity to United States utilities, which Manitoba Hydro estimates translates to displacing greenhouse gas emissions amounting to nearly 200 million tons of carbon dioxide.

Going forward, Manitoba Hydro is positioned to continue supplying the needs of Minnesota and regional customers with reliable and environmentally sound hydropower, in a manner consistent with Minnesota state energy policy. For example, as Manitoba Hydro stated in its recent NFAT filing:

> Manitoba Hydro is committed to protecting the environment, contributing to the global reduction of greenhouse gas ("GHG") emissions and

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system would almost certainly increase the cost and complexity of the Project as well as the overall risk to the reliability of the system.[32]

Finally, loss of D602F and the associated HVDC reduction is currently the largest single contingency in MISO. In the current system, the maximum reduction in Manitoba – United States transfers is 1500 MW. This is calculated as the difference between the system intact transfer limit of the interface (2175 MW) and steady-state transfer limit of the interface after loss of D602F (675 MW), which is often referred to as the prior outage limit. Increasing the rating of D602F in order to increase the total system intact transfer limit on the Manitoba – United States interface would therefore require a corresponding increase in the prior outage transfer limit of the interface for loss of D602F in order to avoid increasing the size of the largest single contingency in the MISO footprint. Depending on the level of increased firm capability required, it may not be possible to increase the prior outage transfer limit without building a new Manitoba – United States tie line.[33]

Aside from the reasons given above, Minnesota Power believes that upgrading existing facilities is not a feasible long-term solution given the likelihood of significant increases in hydroelectric power imports from Manitoba including and exceeding Minnesota Power's power purchase and Renewable Optimization Agreements representing 383 MW. Appropriate long-term capacity for the interface between Manitoba and the United States can be achieved more efficiently, economically, and reliably with a single new transmission line build large enough to facilitate Minnesota Power's 383 MW and additional transfer capability up to 750 MW to meet future needs in the region.

7.4.2. Alternative Voltages

Minnesota Power considered the possibility of developing a transmission line with a different design voltage to accommodate increased hydropower transfers between Manitoba and the United States. Lower voltages considered include 230 kV and 345 kV, while one design voltage higher than 500 kV (765 kV) was also considered.

7.4.2.1. 230 kV Alternative

One transmission project considered for delivery of Minnesota Power's 250 MW agreements with Manitoba Hydro was a new Winnipeg – Iron Range 230 kV line. Minnesota Power and Manitoba Hydro do not believe that such a project would meet the long-term needs of the region and would not prove to be cost-effective for customers or environmentally preferable over the long-term.

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[32] Id.
[33] Id.

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8. SUMMARY

8.1. Denial Would Adversely Affect Minnesota Power, its Customers, the State and the Region

Through Minnesota power's 2010 Integrated Resource Plan, the 938 Docket and the 2013 Integrated Resource Plan, the Commission has thoroughly reviewed Minnesota Power's need for and the benefits of the 250 MW of hydropower provided by the 250 MW Agreements. Indeed, in the 938 Docket, the Commission found both that the hydropower resources proposed in the 250 MW Agreements are the most appropriate resources to meet the Company's needs over the period 2020 through 2035 and that the 250 MW Agreements are in the public interest. At the same time, the Commission recognized that new transmission facilities were required to deliver these positive results to Minnesota Power's customers. Denial of the Project not only forfeits these benefits and adversely impacts the Company and its customers, it also forecloses the benefits of the additional 133 MW Renewable Optimization Agreements.

In addition, denial of a Certificate of Need for the Project would impact the State and the region. The Project provides a necessary additional interconnection between the United States and Manitoba at a time when Manitoba Hydro plans to add significant hydroelectric capacity to its system. The Project can provide other utilities access to these carbon-free resources, while also increasing the reliability of the transmission system as a whole. Moreover, the Project can facilitate even greater additions of wind energy to the system, with the attendant benefits identified in the Manitoba Hydro Wind Synergy Study. With no more feasible and prudent alternative, denial of the Certificate of Need would have adverse impacts beyond those to Minnesota Power and its customers.

8.2. No More Reasonable and Prudent Alternative Has Been Demonstrated

The Project provides the appropriate means of addressing the need for new transmission infrastructure between Manitoba and the United States. When the Commission considered the 250 MW Agreements between Minnesota Power and Manitoba Hydro, it analyzed the following question: "Do the resources proposed in the PPA represent the most appropriate resources to meet [Minnesota Power's] resource needs over the period 2020 through 2035?" The Commission answered in the affirmative and also recognized the need for new transmission facilities to make delivery of the power possible. No changes have occurred since the Commission's February 1, 2012 Order in the 938 Docket that yield a different result.

In this Application, Minnesota Power has analyzed various alternatives to the Project, including: (1) a "no-build" alternative; (2) other generation alternatives, including distributed generation; and (3) various transmission system alternatives, including various size lines, various terminal points, and upgrades of existing facilities. No alternative considered more reasonably or prudently meets the need for increased transmission capabilities to serve Minnesota Power, its customers and the region than the Project.

Moreover, denial of a Certificate of Need for the Project would severely impact Minnesota Power and its customers, as the Company would be unable to effectuate the Commission-approved 250 MW Agreements with Manitoba Hydro and would be unable to deliver these needed resources to its customers, denying them the environmental, economic and reliability benefits the 250 MW Agreements and the 133 MW Renewable Optimization Agreements together will provide. Denial of a Certificate of Need would also harm the State and the region, through the loss of wind-hydro synergies, the loss of the ability to access additional hydropower resources, and the loss of increased regional reliability by addressing the need for an additional tie line between Manitoba and the United States.

8.3. The Project will Protect the Environment and Provide Benefits to Minnesota Power's Customers, the State and the Region

The Project represents the next important step in Minnesota Power's Energy***Forward*** resource strategy, designed to supply its customers with a safe, reliable, and affordable power supply while reducing the Company's use of coal-fired resources, diversifying its supply portfolio and successfully integrating significant additions of wind and other renewable energy resources. These efforts will lead to lower emissions, benefitting the environment and allowing Minnesota Power to better manage risk associated with any future federal or state air quality regulations.

Minnesota Power has already solicited substantial stakeholder and public input regarding the Project and performed substantial analysis regarding alternative routes. Through these efforts, the Company has identified route corridors for the Project that allow optimum performance of the proposed transmission line, while minimizing the impacts to social, economic and environmental resources. As permitting processes move forward, Minnesota Power will continue to receive public, landowner, agency and other stakeholder input, as well as field survey and additional analysis, to determine the final route alternatives that will be presented to the Commission.

In addition, the Project will provide substantial economic benefits to northern Minnesota and the region. The Project will create over 200 construction jobs and generate significant tax revenues, stimulate increased business for hotels, restaurants, and other services along the final route, and have other indirect benefits estimated to total approximately $850 million in northern Minnesota. While providing these benefits, the Project also ensures a reliable supply of power to an area poised for significant economic growth.