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October 1, 2010

Ontario Energy Board
2300 Yonge Street
P.O. Box 2319
Suite 2700
Toronto ON M4P 1E4

Attention: Ms Kirsten Walli
Board Secretary

Dear Ms. Walli:

Re: A review of an application filed by Hydro One Networks Inc. for an order or orders approving a transmission revenue requirement and rates and other charges for the transmission of electricity for 2011 and 2012.
Board File: EB-2010-002

Attached please find a book of materials for use on cross examination of Panel 6 which is being submitted on behalf of Bruce Power Inc.

Sincerely,

George Vegh
att
c: All Intervenors on record
9694306

EB-2010-0002

IN THE MATTER OF the *Ontario Energy Board Act, 1998* S.O. 1998, c. 15 (Schedule B) (the "**OEB Act**");

AND IN THE MATTER OF a review of an application filed by Hydro One Networks Inc. for an order or orders approving a transmission revenue requirement and rates and other charges for the transmission of electricity for 2011 and 2012.

MATERIALS FOR USE ON CROSS EXAMINATION OF PANEL 6

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Counsel for Bruce Power

EB-2010-0002

Materials for Use on cross Examination of Panel 6

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TAB 1

ieso
Power to Ontario
On Demand

Effective Pricing in Ontario's Hybrid Electricity Market

Presentation to SAC
October 28th, 2009

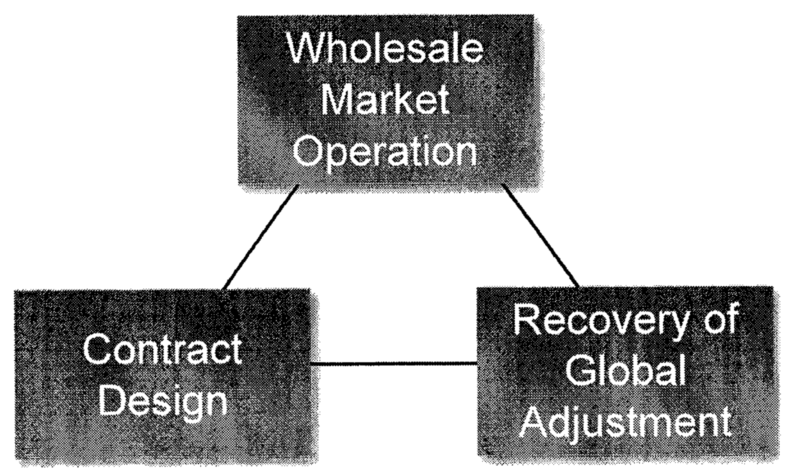
Summary

- Study Objective
- Ontario's Hybrid Electricity Market
- Recent Price Trends
- Identified Issues
  - Wholesale Market Price Fidelity
  - Incentive Design of Contracts or Regulations
  - GA Cost Recovery Impact on Future Electricity Costs and Economic Activity
- Feedback

Ontario Power Authority™

Study Objective

- IESO and OPA, have coordinated efforts to address electricity pricing issues in Ontario.
- This work reviews the effectiveness of the current hybrid structure, specifically the pricing and cost recovery mechanisms, in meeting the government's energy policy objectives.
- Identifies three fundamental aspects that are inter-related, thus requiring consideration as part of an integrated framework.
- Contemplates what, if any, incremental changes might be made to promote key policy objectives to the benefit of the Province.



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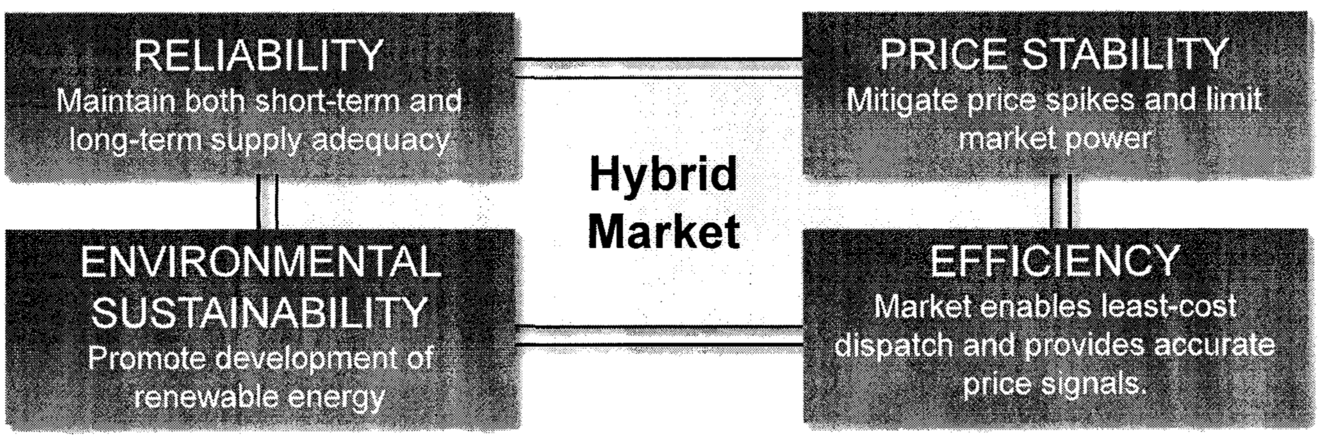
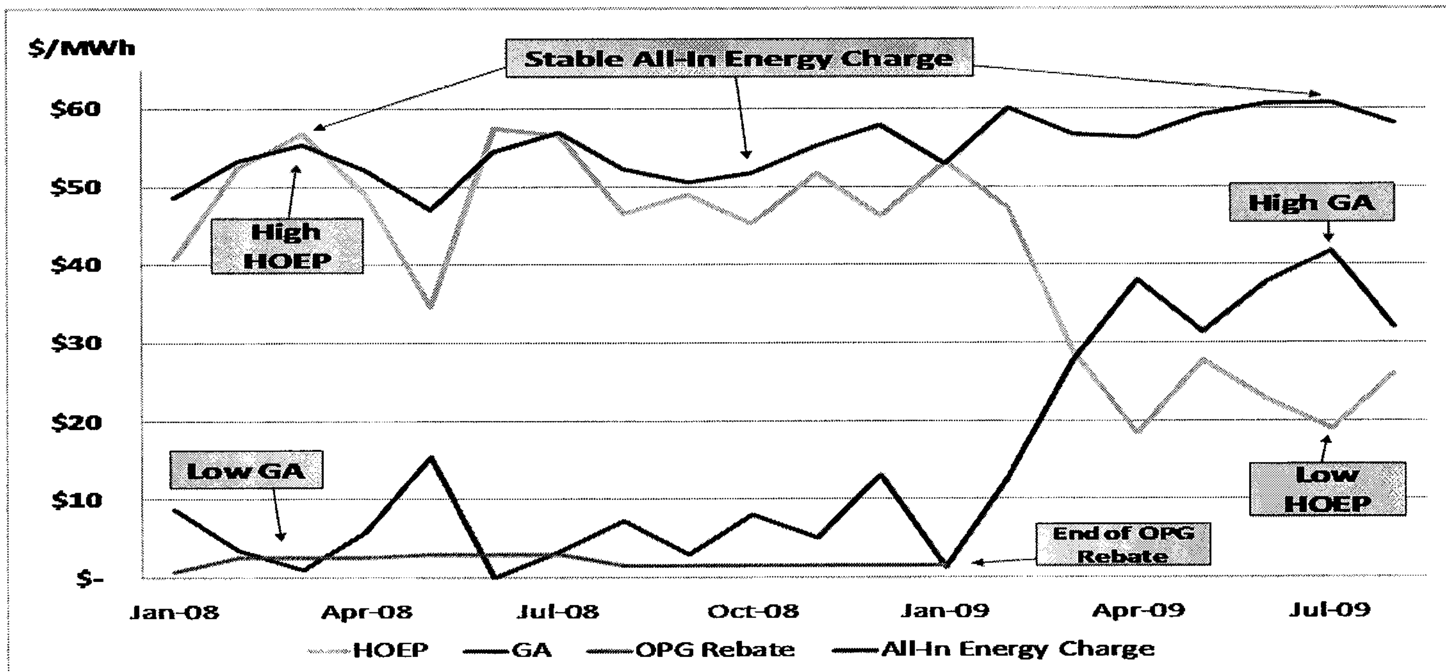
The Hybrid Market

- Ontario has a hybrid market structure, consisting of a competitive wholesale energy market and significant amounts of centrally procured or regulated supply.
  - o The wholesale energy market is used to dispatch generation efficiently and to produce price signals that coordinate the actions of the many diverse participants.
  - o Central procurement and regulated prices are used to ensure that key government energy policy objectives are achieved.



Recent Price Trends

- Recent electricity prices have led commentators to question the "sensibility" of electricity prices in Ontario.
  - The HOEP portion of the energy cost on the customer bill has decreased significantly, while the Global Adjustment (GA) charge has risen.



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Factors Affecting HOEP

Recent changes in average monthly HOEP can be explained by changes in fundamental macro factors.

- HOEP has declined 37% from the year before*.

Lower Demand	7% decrease
Increased Supply	+ 3,700 MW new capacity
Lower Fuel Costs	48% decline in Natural Gas prices
Regional Trade	41% fall in price in competing markets**
Changing Supply Mix	More low marginal cost supply (i.e.: wind)

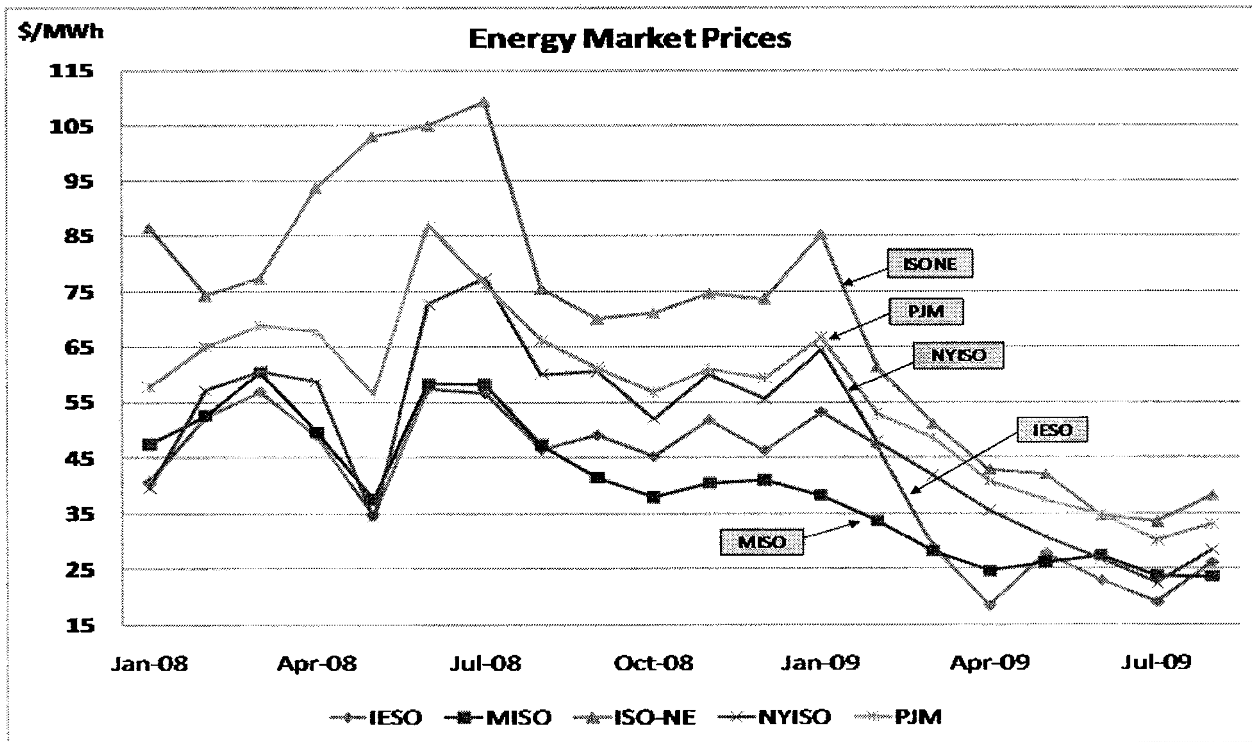
- All of these factors put downward pressure on the market price.

** Weighted HOEP for the period January to August 2009 compared to January to August 2008.*

*** Simple average of price in NYISO, MISO, PJM and ISO-NE*

Prices in Competing Markets

- Regional market prices have fallen considerably, driven by analogous supply and demand factors. Trade helps to stabilize prices and facilitates price convergence between markets.



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Negative Prices

- Negative prices can occur when demand is less than the supply of self-scheduling/intermittent generation and baseload generation.
- Off-peak demand has decreased, while off-peak supply has grown.
- Negative prices reflect an unwillingness or inability of generators to reduce their output, offering to pay to stay on-line.
  - *(i.e.: Nuclear or hydro units limited by operational or environmental constraints)*
- Exports play an important role in achieving an efficient outcome.
- Other jurisdictions have also experienced negative prices, though to a lesser degree.

The frequency of negative prices in Ontario has been aggravated by generators incented by their contract design to produce in all hours, regardless of market conditions.

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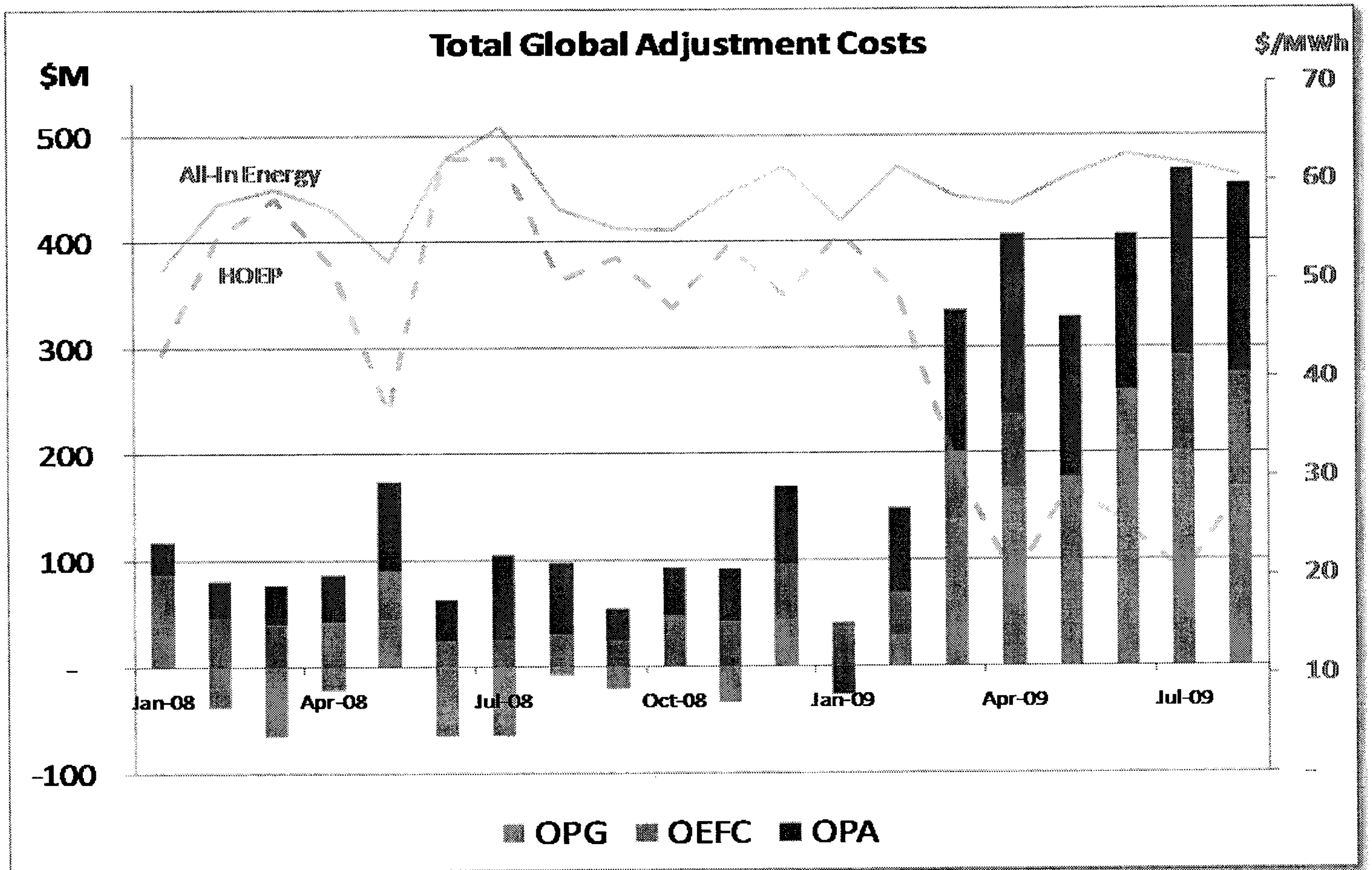
Factors Affecting GA

- GA is the difference between the total payments made to certain contracted or regulated facilities and any offsetting market revenues.
  - There is an inverse relationship between GA and HOEP.
  - This creates a moderating effect on the volatility of the all-in energy price paid by consumers, providing price stability.
- GA costs have increased almost five-fold compared to last year*.
- Low market prices mean reduced wholesale market revenues, thereby increasing the need for revenue recovery through GA.
- Other factors (outside of HOEP) have also driven GA costs upwards.

Rates paid to OPG regulated nuclear and hydro assets increased by 11 %.
OEFC entered into a Contingency Support Agreement for Lambton and Nanticoke facilities as part of OPG's carbon dioxide reduction strategy **.
3,700 MW of OPA contracted supply has come online in the last 12 months.

** Jan – Aug 2008: $545M, Jan – Aug 2009: $2,562M* *** Q1-2009: $39M , Q2-2009: $141M* ieso Power to Ontario. On Demand.

Monthly GA Costs by Category



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Issues to Address

- Efficiency of Wholesale Market Prices and Price Fidelity
- Incentive Design of Contracts or Regulations
- GA Cost Recovery

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Efficiency of Wholesale Market Prices

- **Issue:** Are wholesale market prices efficient?
- Efficient pricing - price is equal to the marginal (opportunity) cost of the last increment of generating capacity used to balance supply and demand at any point in time.
- Prices that do not equal marginal cost at each point in time induce inefficient production and consumption decisions.

There are specific changes within the IESO administered wholesale market that would provide for a more efficient scheduling of resources. These changes will resolve current distortions in price formation and provide for more efficient pricing.

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Incentive Design of Contracts or Regulations

- **Issue:** Do supply contracts provide the incentives for suppliers to operate in the wholesale market when efficient to do so?

Well-designed contracts maintain the financial incentives for generators to offer their supply into the wholesale market at prices that reflect marginal costs. This helps to ensure efficient dispatch and efficient pricing.

- Clean Energy Supply contracts, using deemed dispatch, motivates units to offer at their marginal cost.
- NUG contracts pay a fixed price for output. While innovative at contract inception (pre-market), these contracts create distortions under our hybrid market structure. Contribute to SBG and inefficient pricing.

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GA Cost Recovery (1)

- **Issue:** Does the current approach to GA cost recovery encourage demand response that will reduce the need for costly new capacity?

- A large share of GA costs represent the fixed cost of capacity that was built to meet demand in a few peak hours.
- However, these fixed costs are currently recovered equally in all hours based on consumption.

Spreading these costs evenly across all hours is likely to induce too little consumption in the relatively low demand hours, and too much consumption in the hours when demand is at its peak.

- This means there may not be sufficient incentive to reduce our system peak demand and avoid the need to build new capacity.

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GA Cost Recovery (2)

- **Issue:** Is the current approach to GA cost recovery harmful to the province's industrial competitiveness?
- GA costs are fixed and largely sunk cost that must be recovered from consumers. These costs are sunk, as they have been contractually incurred and generally cannot be avoided.

The manner in which sunk costs are recovered is important. Too high of a cost burden may cause some of the more mobile consumers to stop consuming, leaving the same total costs to be recovered from a smaller pool of customers.

- Many of the more mobile consumers are businesses that create jobs. The exit of these consumers can lead to a reduction in economic activity and the loss of jobs in the province.

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Alternative Approaches

- The **Coincident Peak** allocation methodology - GA costs are allocated to consumers based upon their demand during the system peak hour(s) of demand in a given period (monthly, annually, etc.)
  - Consistent with methodology used by OEB for allocating transmission system costs.
- OEB 's **Time-of-use allocation** for RPP customers
  - GA payments made to different sources of generation allocated in different hours (off-peak, mid-peak and peak) according to when assets are most like to operate. Objective is to restore the 1:2:3 ratio for TOU prices.

Feedback

- Have we properly characterized the issues?
- Are there other issues to be addressed?

TAB 2

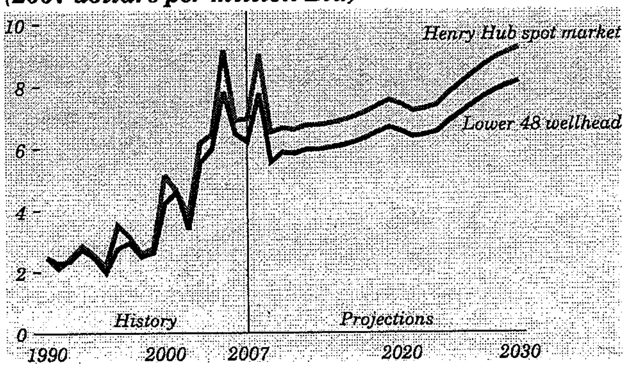
DOE/EIA-0383(2009)
March 2009

Annual Energy Outlook 2009

With Projections to 2030

Natural Gas Prices Rise As More Expensive Resources Are Produced

Figure 64. Lower 48 wellhead and Henry Hub spot market prices for natural gas, 1990-2030 (2007 dollars per million Btu)



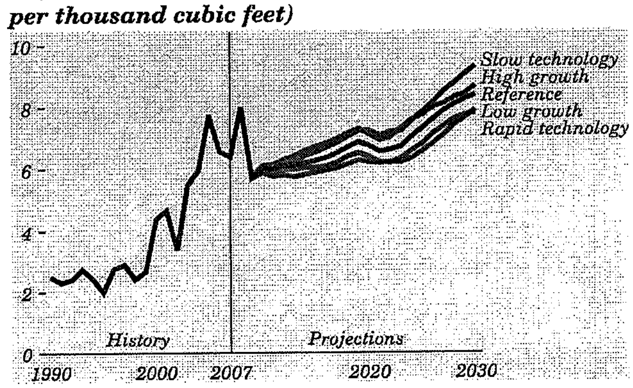
Average lower 48 wellhead prices for natural gas generally increase in the reference case, as more expensive domestic resources are used to meet demand. Prices decline for a brief period after the Alaska pipeline begins operation in 2020, but the market quickly absorbs the additional natural gas supplies from Alaska, and prices resume their rise (Figure 64).

Henry Hub spot market prices and delivered end-use natural gas prices generally follow the trend in lower 48 wellhead prices; however, delivered prices also are subject to variation in average transmission and distribution rates and resulting margins, as reflected in the difference between the average delivered price and the average supply price for natural gas. Some new pipelines are built to bring supplies to market and to reach new customers, but the bulk of the pipeline system is already in place, and revenue requirements for those segments decline as capital is depreciated. Consequently, transmission and distribution margins for natural gas delivered to the industrial and electric power sectors either remain flat or decline.

Natural gas distribution rates are determined in large part by consumption levels per customer, which decline in the residential and commercial sectors over the projection period. As a result, fixed costs are distributed over a smaller customer base, leading to slight increases in transmission and distribution margins in those sectors. In the transportation sector, transmission and distribution margins for natural gas used as fuel in CNG vehicles decline in real terms, as motor fuels taxes remain constant in nominal terms.

Prices Vary With Economic Growth and Technology Progress Assumptions

Figure 65. Lower 48 wellhead natural gas prices in five cases, 1990-2030 (2007 dollars per thousand cubic feet)



The extent to which natural gas prices increase in the *AEO2009* reference and alternative cases depends on assumptions about economic growth rates and the rate of improvement in natural gas exploration and production technologies. Technology improvements reduce drilling and operating costs and expand the economically recoverable resource base.

Technology improvement is particularly important in the context of growing investment in production of natural gas from shale formations, which generally can be produced more efficiently than the natural gas contained in conventional formations, but which require relatively high capital expenditures. The reference case assumes that annual technology improvements follow historical trends. In the rapid technology case, exploration and development costs per well decline at a faster rate, which allows for more growth in production. More rapid technology improvement puts downward pressure on natural gas prices, mitigated somewhat by higher levels of consumption than in the reference case. In the slow technology case, slower declines in exploration and development costs lead to higher natural gas prices than in the reference case.

In the *AEO2009* high economic growth case, natural gas consumption grows more rapidly, and natural gas prices rise more sharply, than in the reference case. In the low economic growth case, natural gas consumption grows more slowly, and natural gas prices are lower, than in the reference case (Figure 65).

Price Case Comparisons

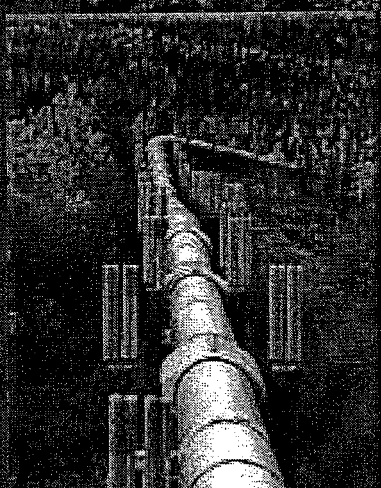
Table C1. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2007	Projections 2010 Low Oil Price	2010 Reference	2010 High Oil Price	2020 Low Oil Price	2020 Reference	2020 High Oil Price	2030 Low Oil Price	2030 Reference	2030 High Oil Price
Production										
Crude Oil and Lease Condensate	10.73	12.19	12.19	12.20	11.60	14.06	15.54	11.60	15.96	18.31
Natural Gas Plant Liquids	2.41	2.60	2.58	2.57	2.55	2.57	2.59	2.42	2.61	2.67
Dry Natural Gas	19.84	21.09	20.95	20.88	21.20	22.08	22.47	22.86	24.26	26.04
Coal[1]	23.50	24.22	24.21	24.18	24.89	24.43	24.03	26.18	26.93	26.40
Nuclear Power	8.41	8.45	8.45	8.45	8.89	8.99	9.10	9.14	9.47	9.57
Hydropower	2.46	2.67	2.67	2.67	2.97	2.95	2.95	2.98	2.97	2.98
Biomass[2]	3.23	4.20	4.20	4.23	6.28	6.52	7.50	7.81	8.25	8.63
Other Renewable Energy[3]	0.97	1.50	1.54	1.59	1.71	1.74	1.77	2.22	2.19	2.20
Other[4]	0.94	0.85	0.85	0.89	1.07	1.07	1.28	1.15	1.15	1.21
Total	**72.49**	**77.77**	**77.64**	**77.66**	**81.15**	**84.41**	**87.24**	**86.37**	**93.79**	**98.02**
Imports										
Crude Oil	21.90	18.05	17.76	17.59	21.51	16.09	12.08	24.99	15.39	9.64
Liquid Fuels and Other Petroleum[5]	6.97	6.07	5.59	5.53	7.07	5.67	5.33	7.58	6.33	5.74
Natural Gas	4.72	3.27	3.27	3.27	3.90	3.37	3.21	3.27	2.58	2.15
Other Imports[6]	0.99	0.89	0.89	0.89	0.57	1.19	1.43	1.12	1.35	1.67
Total	**34.59**	**28.28**	**27.51**	**27.28**	**33.06**	**26.31**	**22.05**	**36.96**	**25.65**	**19.19**
Exports										
Petroleum[7]	2.84	2.58	2.56	2.55	2.81	2.90	2.90	3.18	3.17	2.96
Natural Gas	0.83	0.70	0.70	0.70	1.48	1.44	1.41	1.97	1.87	1.80
Coal	1.51	2.05	2.05	2.05	1.34	1.33	1.23	1.09	1.08	0.82
Total	**5.17**	**5.33**	**5.31**	**5.30**	**5.64**	**5.66**	**5.54**	**6.24**	**6.12**	**5.57**
Discrepancy[8]	**0.01**	**-0.09**	**-0.02**	**0.01**	**-0.52**	**-0.39**	**-0.25**	**-0.52**	**-0.25**	**-0.16**
Consumption										
Liquid Fuels and Other Petroleum[9]	40.75	38.73	37.89	37.72	43.21	38.93	36.87	47.48	41.60	38.83
Natural Gas	23.70	23.34	23.20	23.10	23.70	24.09	24.18	24.23	25.04	25.72
Coal[10]	22.74	22.92	22.91	22.88	23.93	23.98	23.86	25.99	26.56	26.53
Nuclear Power	8.41	8.45	8.45	8.45	8.89	8.99	9.10	9.14	9.47	9.57
Hydropower	2.46	2.67	2.67	2.67	2.97	2.95	2.95	2.98	2.97	2.98
Biomass[11]	2.62	2.99	2.99	3.00	4.51	4.58	5.04	5.35	5.51	5.72
Other Renewable Energy[3]	0.97	1.50	1.54	1.59	1.71	1.74	1.77	2.22	2.19	2.20
Other[12]	0.23	0.21	0.21	0.22	0.17	0.19	0.22	0.21	0.22	0.25
Total	**101.89**	**100.80**	**99.85**	**99.62**	**109.09**	**105.44**	**104.00**	**117.61**	**113.56**	**111.80**
Prices (2007 dollars per unit)										
Petroleum (dollars per barrel)										
Imported Low Sulfur Light Crude Oil Price[13]	72.33	58.61	80.16	91.08	50.43	115.45	184.60	50.23	130.43	200.42
Imported Crude Oil Price[13]	63.83	55.45	77.56	88.31	46.77	112.05	181.18	46.44	124.60	197.72
Natural Gas (dollars per million Btu)										
Price at Henry Hub	6.96	6.08	6.66	6.89	6.93	7.43	7.80	8.70	9.25	9.62
Wellhead Price[14]	6.22	5.37	5.88	6.09	6.12	6.56	6.89	7.68	8.17	8.49
Natural Gas (dollars per thousand cubic feet)										
Wellhead Price[14]	6.39	5.52	6.05	6.26	6.29	6.75	7.09	7.90	8.40	8.73
Coal (dollars per ton)										
Minemouth Price[15]	25.82	28.93	29.45	29.75	26.97	27.90	29.13	27.41	29.10	29.85
Coal (dollars per million Btu)										
Minemouth Price[15]	1.27	1.42	1.44	1.46	1.34	1.39	1.45	1.37	1.46	1.50
Average Delivered Price[16]	1.86	1.94	1.99	2.02	1.89	1.99	2.10	1.96	2.08	2.18
Average Electricity Price (cents per kilowatthour)	9.1	8.8	9.0	9.1	9.1	9.4	9.7	10.1	10.4	10.6

TAB 3

ANNUAL ENERGY OUTLOOK 2010

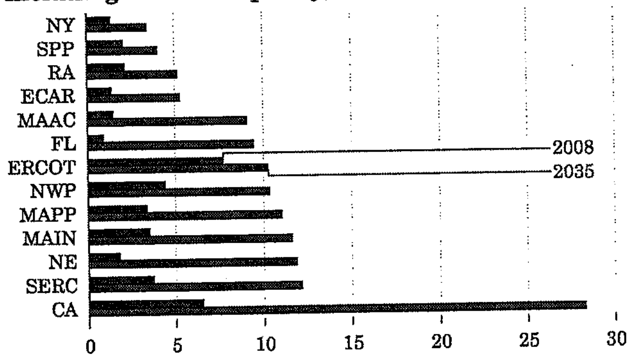
WITH PROJECTIONS TO 2035



U.S. Energy Information Administration

State portfolio standards increase renewable generating capacity

Figure 68. Regional growth in nonhydroelectric renewable electricity generation capacity, including end-use capacity, 2008-2035 (gigawatts)

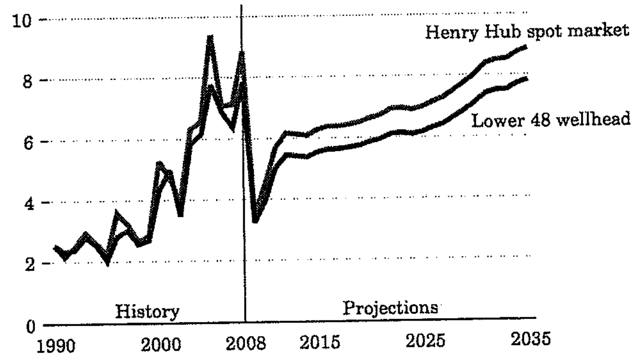


Regional additions of renewable generating capacity depend for the most part on State RPS programs. As of October 31, 2009, there were mandatory RPS programs in 30 States and nonbinding renewable goals in 5 States [*84*]. From 2008 to 2035, California installs the most renewable capacity, 22 gigawatts (Figure 68), primarily new wind capacity but also including 3.1 gigawatts of distributed PV capacity. New England installs more than 8 gigawatts of new wind capacity, representing the second-largest regional growth of the technology (see Figure F2 in Appendix F for a map of the regions). Florida and the Mid-Atlantic account for 80 percent of the dedicated biomass capacity installed by 2035 in the electric power sector (mostly later in the period).

Distributed biomass capacity corresponds largely with the location of cellulosic ethanol plants. Although the Southeast has ample biomass resources, only small amounts of renewable capacity are installed in the region's electric power sector in the absence of State RPS programs, whereas distributed biomass capacity increases by more than 6 gigawatts from 2008 to 2035. Geothermal energy, which is constrained geographically by the availability of local resources, is installed exclusively in the Southwest and California. The same regions have the greatest resource potential for large-scale solar capacity, but because of its high cost only a small amount is installed. Most of the increase in solar capacity consists of distributed PV, and some States in the Northeast (New Jersey, for example) have mandates or provide other incentives for PV installations. Approximately 1.6 gigawatts of distributed PV capacity is installed in the Mid-Atlantic region by 2035.

Natural gas prices rise but remain attractive relative to oil

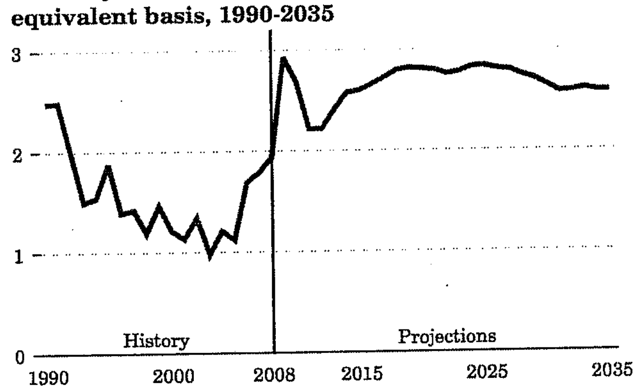
Figure 69. Annual average lower 48 wellhead and Henry Hub spot market prices for natural gas, 1990-2035 (2008 dollars per million Btu)



Average natural gas prices generally increase in the Reference case, as higher cost resources are brought on line to meet demand growth (Figure 69). The price increase is tempered by improvements in technology. There is a great deal of uncertainty about the long-term trend in natural gas prices, however, particularly in light of the growing development of shale gas resources.

The ratio of low-sulfur light crude oil prices to Henry Hub natural gas prices on an energy equivalent basis remains high relative to the historical average throughout the projection (Figure 70). The ratio is maintained by growing worldwide demand for transportation fuels and robust North American natural gas supply relative to demand. Still, increased use of natural gas as a substitute for petroleum in some transportation uses and/or as a GTL feedstock could increase natural gas prices and narrow the ratio.

Figure 70. Ratio of low-sulfur light crude oil price to Henry Hub natural gas price on an energy equivalent basis, 1990-2035



Price Case Comparisons

Table C1. Total Energy Supply, Disposition, and Price Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2008	Projections								
		2015			2025			2035		
		Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price
Production										
Crude Oil and Lease Condensate	10.51	11.95	12.41	12.56	10.64	13.22	14.67	9.40	13.50	14.83
Natural Gas Plant Liquids	2.57	2.32	2.27	2.22	2.36	2.24	2.26	2.40	2.37	2.35
Dry Natural Gas	21.14	20.43	19.83	19.39	21.52	21.90	22.96	24.64	23.92	25.61
Coal[1]	23.86	22.97	23.31	23.61	24.12	24.36	25.74	24.64	25.19	27.57
Nuclear Power	8.46	8.75	8.75	8.75	9.29	9.29	9.29	9.26	9.41	9.44
Hydropower	2.46	2.95	2.96	2.96	2.97	2.98	2.96	2.98	2.99	3.01
Biomass[2]	3.97	4.63	4.60	4.64	6.32	6.90	8.68	6.78	9.27	12.08
Other Renewable Energy[3]	1.17	2.55	3.01	3.03	2.68	3.07	3.10	2.88	3.36	3.40
Other[4]	0.10	0.53	0.73	1.18	0.68	0.94	1.39	0.66	0.81	1.07
Total	**74.23**	**77.08**	**77.88**	**78.36**	**80.58**	**84.91**	**91.06**	**83.65**	**90.83**	**99.36**
Imports										
Crude Oil	21.39	22.19	19.66	18.25	25.70	19.21	13.21	29.87	19.34	11.95
Liquid Fuels and Other Petroleum[5]	6.38	5.79	5.54	5.29	6.35	5.76	4.78	7.29	6.08	4.96
Natural Gas	4.06	3.90	3.59	3.46	4.50	3.94	3.24	3.68	3.49	2.84
Other Imports[6]	0.96	0.79	0.79	0.78	0.59	0.88	1.36	0.47	1.32	1.78
Total	**32.79**	**32.67**	**29.58**	**27.79**	**37.14**	**29.80**	**22.58**	**41.31**	**30.23**	**21.54**
Exports										
Petroleum[7]	3.71	3.52	3.53	3.58	3.90	3.91	3.71	4.08	4.12	3.86
Natural Gas	1.01	1.17	1.14	1.12	1.80	1.69	1.64	2.16	1.96	1.84
Coal	2.07	1.49	1.49	1.49	1.05	1.20	1.19	0.75	0.79	0.83
Total	**6.80**	**6.18**	**6.16**	**6.18**	**6.76**	**6.80**	**6.54**	**7.00**	**6.87**	**6.53**
Discrepancy[8]	**0.13**	**-0.23**	**-0.30**	**-0.31**	**-0.22**	**-0.35**	**-0.30**	**-0.20**	**-0.32**	**-0.38**
Consumption										
Liquid Fuels and Other Petroleum[9]	38.35	40.88	38.81	37.75	43.83	40.14	37.45	47.61	42.02	38.94
Natural Gas	23.91	23.22	22.35	21.81	24.28	24.24	24.28	26.21	25.56	25.80
Coal[10]	22.41	22.05	22.35	22.59	23.41	23.63	24.63	24.10	25.11	26.59
Nuclear Power	8.46	8.75	8.75	8.75	9.29	9.29	9.29	9.26	9.41	9.44
Hydropower	2.46	2.95	2.96	2.96	2.97	2.98	2.96	2.98	2.99	3.01
Biomass[11]	3.10	3.21	3.17	3.18	4.52	4.70	5.48	4.89	5.83	7.32
Other Renewable Energy[3]	1.17	2.55	3.01	3.03	2.68	3.07	3.10	2.88	3.36	3.40
Other[12]	0.24	0.20	0.20	0.20	0.21	0.21	0.22	0.24	0.22	0.25
Total	**100.09**	**103.80**	**101.61**	**100.27**	**111.19**	**108.26**	**107.41**	**118.17**	**114.51**	**114.75**
Prices (2008 dollars per unit)										
Petroleum (dollars per barrel)										
Imported Low Sulfur Light Crude Oil Price[13]	99.57	51.59	94.52	144.78	51.73	115.09	196.01	51.44	133.22	209.60
Imported Crude Oil Price[13]	92.61	43.88	86.88	137.01	41.36	104.49	185.85	41.99	121.37	199.65
Natural Gas (dollars per million Btu)										
Price at Henry Hub	8.86	5.59	6.27	6.78	6.88	6.99	7.39	8.12	8.88	9.49
Wellhead Price[14]	7.85	4.94	5.54	5.99	6.08	6.18	6.53	7.18	7.84	8.38
Natural Gas (dollars per thousand cubic feet)										
Wellhead Price[14]	8.07	5.08	5.70	6.16	6.25	6.35	6.71	7.38	8.06	8.62
Coal (dollars per ton)										
Minemouth Price[15]	31.26	29.00	30.38	31.40	26.66	28.19	29.71	26.45	28.10	30.08
Coal (dollars per million Btu)										
Minemouth Price[15]	1.55	1.45	1.52	1.57	1.36	1.44	1.53	1.35	1.44	1.57
Average Delivered Price[16]	2.16	1.99	2.11	2.21	1.95	2.07	2.21	1.98	2.13	2.28
Average Electricity Price (cents per kilowatthour)	9.8	8.5	8.9	9.2	9.0	9.3	9.5	9.9	10.2	10.5