

**COMPARAISON DES PRIX DE LA COMBINAISON  
SÉLECTIONNÉE AVEC LES PRIX DES PRINCIPAUX  
PRODUITS DISPONIBLES DANS LES MARCHÉS DU  
NORD-EST DE L'AMÉRIQUE ET LES COÛTS DE  
TRANSPORT APPLICABLES**



***The Competitive Cost of Power in Neighboring  
Northeast Markets***

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# **The Competitive Cost of Power in Neighboring Northeast Markets**

## **1. Introduction**

The Regie de l'energie (Regie) requires that Hydro-Quebec Distribution undertake a comparative analysis of the cost of power from the bids selected through the A/O 2003-01 Biomass Call for Tenders process relative to the cost of power for similar products from neighboring Northeast markets (defined as New England, New York, New Brunswick, and Ontario markets). This report updates and revises the report prepared by Merrimack Energy on the competitive cost of power in the Northeast Market for the A/O 2002-01 Call for Tenders.

The appropriate product against which to compare the biomass options should reflect the long-term nature of the biomass contracts, and the type of product required (i.e. baseload). Given these characteristics and based on the generation technology of choice in the Northeast, the marginal long-term resource in the four markets is generally considered to be the cost of a new gas-fired combined cycle facility. Units in the 250 to 500 MW range have generally been typical of the size of the units developed or proposed in these markets.

In addition, since there is still little evidence of long-term power contracts available in the market, the cost of a new unit should still set the long-term market price. While the Long Island Power Authority continues to assess longer-term resource options, it is expected the selected resource will be a new gas-fired combined cycle facility. This report will therefore provide an update on the long-term costs of power in these markets similar to that provided in the previous analysis for A/O 2002-01.

The methodology undertaken by Merrimack Energy to assess the competitive cost of long-term power in the Northeast compared to the contract prices selected by Hydro-Quebec Distribution in the A/O 2003-01 Biomass Call for Tenders process is based on utilizing known information about the technology option (i.e. gas-fired combined cycle facility) identified above. Information on gas-fired combined cycle power generation costs in the Northeast is generally available and represents the costs associated with actual projects. This analysis will develop an estimate of the total cost of power from this generation option as a basis for comparing the costs to the bids selected.

For this assessment, the cost of providing long-term power from the neighboring Northeast markets to Quebec is based on the long-term economics of delivering power to Quebec from a dedicated power generation facility and will consist of the following cost components typical of this type of analysis:

- (1) A capacity charge that reflects debt service costs, a return on and of capital and selected taxes;

- (2) A fixed O&M cost which reflects fixed labor costs, a maintenance reserve fund, property taxes, and insurance;
- (3) A variable O&M cost that reflects variable operating costs such as labor, materials, and consumables;
- (4) Fuel costs (including gas commodity and pipeline transportation) necessary to deliver the gas to the plant based on a reasonable fuel procurement strategy as implemented by others in the market; and
- (5) Transmission costs for wheeling the power from each of the Northeast markets to the Quebec border.

## **2. Methodology**

In the absence of long-term contracts as a guide for establishing long-term market prices for firm arrangements, a market price proxy needs to be established. To estimate the cost of power under a long-term contract providing a similar product as the power contracted by Hydro-Quebec Distribution under the Biomass Call for Tenders, it is logical to estimate the annual cost stream associated with the cost of building and operating a new combined-cycle plant over the term of the contract. This is based on the theory that long-term market prices should converge to the price associated with the costs of a new gas-fired combined cycle project, which is the incremental source of capacity in the Northeast.

Developers of such facilities will only construct these facilities if the market price of power is sufficient to cover all development and operating cost, including a reasonable rate of return. If market prices are above this level, new power projects will be built to meet market demand. Also, power suppliers (even with existing generation facilities) will not be willing to make long-term commitments below this cost, since they would either have to go to the market to meet their obligations at higher market prices or would forego the opportunity for higher revenues by selling below the long-term market price. In the absence of representative long-term contracts, suppliers will also evaluate the cost of power from the incremental generating source when pricing long-term power supplies.

For this analysis, the cost of building and operating a new combined-cycle plant in each of the Northeast markets will be used as representative competitive options. The capital and operating costs of existing and proposed units in the Northeast will be utilized as the basis for establishing such costs. The fuel costs are assumed to be treated as a “passthrough” and will be based on the pipeline options and fuel procurement strategies followed by power plants in these markets. Finally, the transmission rates associated with moving power from the applicable regions in the Northeast to the Quebec border will be included based on the costs that would be incurred to deliver power to the Quebec border.

### **3. Analysis Assumptions**

Merrimack Energy has used two models for undertaking this analysis. The first model is designed to calculate the annual capacity cost for a power generation facility based on the capital cost assumed and using a standard capital cost recovery methodology. The second model combines the results of the above analysis with the other project costs listed above to determine the annual costs associated with operating the facility and delivering the power from a specific market to the Quebec border. The discounted cost stream is used as the basis for calculating the real levelized cost of each option. More details regarding the underlying inputs and assumptions for these models will be described in this section of the report.

As noted, the assumptions used in the analysis are based on the construction and operation of a gas-fired combined cycle power plant. Merrimack Energy has compiled cost information on a number of representative units in the Northeast, as a basis for establishing cost and operations information. The capital cost derived for this analysis is based on the reported cost for 7 projects developed and in operation in the New England market. The same cost information is applied to the New York market, although the costs for a plant built in the New York City or Long Island area will be greater. This information is utilized in conjunction with United States Federal and state tax rates as well as specified depreciation rates for estimating the capacity cost for a US based power project. The same capital cost information is combined with Canadian tax and depreciation rates for estimating costs for a project in New Brunswick and Ontario.

To ensure consistency in the evaluation process, the underlying analysis compares the real levelized cost of the selected biomass contracts with the real levelized costs for the proxy unit in each market. This analysis relies upon the same input assumptions used by Hydro-Quebec Distribution in its Step 2 analysis of the bids received in response to the A/O 2003-01 Call for Tenders. This includes inflation rates for Canada and the US, the exchange rate, and Hydro-Quebec Distribution's discount rate. Hydro-Quebec Distribution had no need to update the natural gas price forecast for the Biomass Call for Tenders. Thus, to reflect recent expectations about trends in the gas market, Merrimack Energy has utilized the recent price forecast prepared by the US Department of Energy, Energy Information Administration's Annual Energy Outlook 2004 as the basis for this analysis.

#### **A. Capital Cost**

The first component in the analysis is the capital cost and the associated capacity price which needs to be recovered as a fixed cost to pay for debt service, return on equity, taxes, depreciation and insurance. In this analysis, a levelized cost is established to reflect a fixed annual contribution to capital necessary to adequately compensate the developer. As noted, Merrimack Energy has developed and utilized a capital cost recovery financial model designed to estimate the annual capacity payment required to generate a specified return on equity. The major financial assumptions used in this component of the analysis are listed in Table 1 below. All costs in this stage of the analysis are in US dollars.

**Table 1**  
**Financial Assumptions**  
**For a Specific Power Project**

Project Capital Cost	\$675/kW (US \$)
Project Size	250 to 500 MW
Debt/Equity Ratio	65%/35%
Debt Cost	8%
Implied Return on Equity	16%
Debt Term	15 years
Heat Rate	6,850 Btu/KWh

The estimated capital cost is based on the capital cost reported by 7 completed projects in New England. This information is derived from financing documents and public information sources. Additionally, the information is consistent with information reviewed by Merrimack Energy in other recent Request for Proposals for power supplies. This cost is slightly higher than the estimate used in the A/O 2002-01 assessment, which also reflects the influence of inflation over the past year. The other assumptions reflect typical financial parameters in the merchant generation industry. It should be noted that given the current financial state of the market it is possible that debt costs may be higher and more equity may be required to support financing of a new merchant power plant, particularly if the level of power contracted is limited in amount and duration. This would result in a higher required capacity charge.

The result of this assessment is a levelized capacity charge of \$116.58 per kW-year in US dollars for the New England and New York projects and a levelized capacity charge of \$115.18 per kW-year (\$US) for projects located in Canada. The calculated value is then converted to Canadian dollars using the estimated exchange rates assumed by Hydro-Quebec Distribution in the Step 2 analysis for the Biomass Call for Tenders.

### **B. Operation and Maintenance Costs**

The second major cost component is Operations and Maintenance (O&M) Costs. While it was not possible to gather specific O&M cost information for the same 7 units used to determine the capital cost, the O&M costs are based on an analysis of eight gas-fired combined cycle plant proposals from various regions of the US from the 1999-2000 time frame. Seven of the eight projects had estimated O&M costs that were fairly consistent and one had an O&M cost dramatically above all others. This outlier was eliminated and the average O&M cost for the other seven projects were used in the estimate for O&M costs. Based on this analysis, it is assumed that Fixed O&M costs would equal \$1.13 per kW-month (US \$) and variable O&M costs would equal \$1.48/MWh (US \$) in 2001 and would escalate by the rate of inflation thereafter. O&M costs are also adjusted by the exchange rate to convert the cost stream into Canadian dollars for comparison purposes.

### C. Electric Transmission Costs

The third cost component is electric transmission costs. The seller of the power in the Northeast will have to contract for firm electric transmission service to deliver the power to the Quebec border. If the power is provided from a supplier in New England, the supplier would have to contract for Through or Out Service with ISO New England, as well as contract with an owner of the New England/Hydro-Quebec Interconnection facilities (HVDC line connecting the New England Power Pool and the Hydro-Quebec system) to deliver the power to the Quebec border. Through or Out Service has a current rate of \$15.60/kW-year (US \$), which is an increase from the rate of \$15.14/kW-year (US \$) used in the previous assessment. The US portion of the HVDC system is financed through annual support payments from current owners. The current annual support payment for such facilities equates to approximately \$66/kW-year (US \$), although the owners could charge less for such service because any sale would contribute to reducing the fixed cost obligations. Also, it is possible the US portion of the HVDC system may be rolled-in to the New England transmission system at a future date.

For this analysis, it is assumed that the supplier will contract for Through or Out service at the full firm rate, as well as service on the US portion of the HVDC facilities at 25% of the full rate to move the power to the Quebec border. While the full rate is based on the annual support payments required of the utility owners of the HVDC facilities, in the current market there is a low probability that an owner will recover its full cost. Therefore, we have assumed that even a small contribution to costs would be acceptable to an owner, particularly in the near term.

The analysis further assumes that the cost of this service will increase annually by the rate of inflation. This assumption may be conservative, since ISO New England has reported that it plans major expenditures for transmission system improvements and upgrades (estimated at \$900 million).

In New York the transmission service and rates are slightly different. To transmit power from a utility service area in New York to the Quebec border would require the supplier to pay a revenue-requirements based Transmission Service Charge (TSC), as well as other charges (i.e. NYPA Transmission Adjustment Charge, ancillary service and operating reserve charge). The TSC is the fee paid by all wholesale transmission customers to the appropriate Transmission Owner. For exports, the rate is based on the transmission rate for the utility from whose territory the power leaves New York. In this case, the utility transmission owner would be the New York Power Authority (NYPA). The latest reported rate for service from the New York Power Authority to Chateaugay is \$2.19 per MWh (US \$) plus \$1.67 per MWh (US \$) for other charges for a total of \$3.86 per MWh (US \$).

Transmission service from New Brunswick to Quebec would be provided as a Point-to-Point service by New Brunswick Power. A supplier would have to reserve capacity for the transmission of energy from a point of receipt to a point of delivery. This point-to-point rate is a postage stamp rate, meaning that the rate is the same for all users of this



service regardless of the point of delivery. The current rate for point-to-point service in New Brunswick is \$25.90/kW-year (Cn \$). In addition, the transmission customer is responsible for replacing losses associated with transmission service of 3.30%.

The transmission service from Ontario to Quebec would be provided by Hydro One under an established tariff. The transmission charge is comprised of three components: (1) an export fee; (2) a usage fee; and (3) an uplift charge, which includes ancillary services, losses, and reserves. The total for the three components is estimated to be \$3.959/MWh (Cn \$). The rates are derived as follows: the export fee equals \$1.00/MWh, the usage fee equals \$.959/MWh, and the uplift charge (which can vary from less than \$1.00/MWh to over \$6.00/MWh) is estimated to equal \$2.00/MWh.

#### **D. Fuel Costs**

The final major cost component is fuel costs. There are several options available for merchant generators to source their natural gas supplies. However, it should be noted that most power projects either contract for limited amounts of firm pipeline capacity and purchase their gas at a liquid hub or rely on a marketer for delivered service.

In the previous analysis for A/O 2002-01, forecasts of natural gas commodity prices were prepared for the Call for Tenders to evaluate the bids, many of which were gas-fired combined cycle facilities. Merrimack Energy used these forecasts in conjunction with current gas transportation rates and associated pipeline losses to develop cost estimates for delivering gas supply to the various neighboring markets (i.e. New England and New York). Since natural gas price forecasts were not required for the Biomass Call for Tenders, a comparable (and recent) gas price forecast was not available.

While there may be options for adjusting the previous forecast to account for recent changes in the gas market, all options involved speculation about a number of key pricing issues (i.e. calculation of basis, projected pattern of changes in gas prices, etc.). Our primary objective was to use a current forecast to reflect a recent view on gas prices rather than adjust the previous forecast.

For this analysis, as previously noted Merrimack Energy has relied upon the United States Department of Energy, Energy Information Administration's Annual Energy Outlook 2004 forecast of commodity prices as the basis for assessment. To move gas to the Northeast US, Merrimack Energy has used the firm transportation rates on the pipeline paths to the Northeast in conjunction with the commodity forecast. Although this methodology is largely consistent with the methodology used in the previous study (i.e. delivered gas price based on commodity plus firm transportation to the market), few projects in these markets rely on domestic supplies plus firm pipeline transportation back to the wellhead. Most power generators in the Northeast source gas at the market area or hub (i.e. Dawn, M3, Transco Zone 6, etc.). As a result, the cost of these options may be slightly higher than the typical strategy followed by merchant generators.

For New Brunswick, we have assumed the gas commodity is priced consistent with a delivered supply to New England from the US Gulf less the toll associated with the US and Canadian portions of the Maritimes & Northeast Pipeline. Thus, the cost of gas in New Brunswick will reflect a commodity cost at the outlet of the liquids plant in Goldsboro plus the pipeline transportation cost on the Canadian portion of the Maritimes & Northeast Pipeline.

For Ontario, we have used as a starting point the recent historical relationship between Henry Hub and AECO gas prices and assumed this differential would remain throughout the forecast period. In addition, the transportation cost includes the firm NOVA toll from AECO to Empress and the firm TransCanada toll from Empress to the Eastern Zone.

Proxy plants were used as theoretical examples of competitive alternatives to supply power to Quebec. All four plants are gas-fired combined cycle plants with one located in New York, one in New England, one located in New Brunswick, and a fourth in Ontario. The gas supply/transportation options evaluated include:

- a) Source gas at Henry Hub and deliver the gas to central New England via Texas Eastern/Algonquin Gas Transmission to the market.
- b) Source gas at Henry Hub and deliver gas to the New York market via the Tennessee Gas Pipeline (Zone 5).
- c) Source gas at Henry Hub and transport gas to New England via the Tennessee Gas Pipeline and subtract the US portion of the rates associated with the Maritimes & Northeast Pipeline to replicate a delivery of gas into the New Brunswick market.
- d) Source gas at AECO and transport the gas to Ontario (Toronto area) via the NOVA and TransCanada systems.

The New England plant is assumed to source gas in the US Gulf Coast (e.g. Henry Hub reference point) and uses the Texas Eastern Transmission and Algonquin Gas Transmission systems to transport the gas on a firm basis to New England. Also, it has been assumed that a lateral will be required to attach the plant to the Algonquin system (All cases assume a lateral to the plant needs to be constructed). This is a common route and tariff rates were used to estimate the transportation costs. A number of the new merchant plants in New England are attached to the Algonquin system. The existing transportation rate on Texas Eastern/Algonquin system is currently \$0.90 US/MMBtu (without fuel).

The second plant was assumed to be located in New York State off of the Tennessee system in eastern New York. The gas is again sourced in the Gulf and the transportation path includes using the Tennessee Gas Pipeline system to transport gas from the Gulf to Zone 5 on the Tennessee system in New York. The existing transportation rate on the Tennessee Gas Pipeline is \$0.57 US/MMBtu (excluding fuel). Expansion of the

Tennessee Gas Pipeline on a long-haul route would result in a significant increase in the existing toll.

The third facility is assumed to be located in New Brunswick and will receive gas via the Maritimes and Northeast Pipeline. The commodity cost of the gas is assumed to equal the Henry Hub price plus the cost of transporting the gas to New England on the Tennessee system, less the Canadian and US tolls on Maritimes and Northeast to get the gas back to Goldboro. The transportation toll would reflect only the Canadian tolls on Maritimes and Northeast.

The fourth facility is assumed located in the Toronto area in Ontario, requiring delivery of gas to the eastern zone on TransCanada. For this case, it is assumed the commodity cost of gas will be the forecast of the Henry Hub price less the recent average differential between Henry Hub and AECO of \$.72/MMBtu (US \$). The cost of transporting gas on NOVA and TransCanada to the eastern zone would be approximately \$1.35/MMBtu (Cn \$), not including fuel.

#### **4. Results of the Analysis**

The results of the analysis are illustrated in Table 2 below. The results are presented on a real levelized cost analysis basis, using the same methodology used by Hydro-Quebec Distribution and Merrimack Energy in the Step 2 analysis of the biomass bids. In this analysis, the real levelized cost of power is reported in 2008 dollars (Cn \$) for consistency purposes.

**Table 2  
Analysis Results**

<b>Market Option</b>	<b>Real Levelized Cost (cents/KWh 2008) (Cn \$)</b>
Combination of Biomass Contracts	6.70 cents
New England	7.46 cents
New Brunswick	6.62 cents
New York	6.98 cents
Ontario	6.96 cents

The results of the analysis clearly indicate that the selected combination or portfolio of biomass resources provides long-term baseload power supplies to Hydro-Quebec Distribution at prices comparable to or lower than the cost of long-term power in the New England, New York, and Ontario markets. This is largely due to the projected increases

in long-term gas prices in recent long-term forecasts, at levels exceeding the rate of inflation, as well as the higher cost of transmission to deliver power from neighboring regions, particularly New England, into Quebec. Long-term power supply from New Brunswick is estimated to cost less than the biomass option due primarily to lower fuel costs and relatively lower electric transmission rates.