Natural Gas Electricity Interface Review

A Report by Ontario Energy Board Staff

EB-2005-0306

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1 Executive Summary

In light of the possibility that Ontario may rely more heavily on gas-fired power generation in the future, the Ontario Energy Board has reviewed the regulatory treatment of natural gas infrastructure and services. The specific issue was whether gas-fired power generation, which may replace capacity that is being phased out, puts new types of demands on the natural gas system.

The first concern related to volume. If all current coal-fired generation were replaced with gas-fired power generation, then gas-fired generators would become the largest class of consumers in the province – using more than all natural gas residential customers combined.

The second concern was the consumption pattern. Gas-fired generators produce electricity in response to signals in the wholesale electricity market. Their usage does not resemble the fairly steady load profile of industrial customers and is more volatile than the seasonal heating load profile of residential customers.

This Natural Gas Electricity Interface Review (NGEIR) looked at the Board's current regulatory treatment of natural gas infrastructure and services in terms of cost-effective and predictable treatment of the new demands.

The Review process was divided into two phases. In the first phase, Board staff gathered information to develop scenarios, understand the implications for infrastructure needs, and determine which, if any, new services might be needed. The results show that there will be significant gas infrastructure investment needed in Ontario that could cost from $245 million to $815 million, depending on the increase in gas-fired generation, the location of these generators and their gas storage and deliverability requirements.

The second phase examined how the costs of additional infrastructure and services are considered in the regulatory process and whether changes were needed.

The review, after several months of meetings and study, has led Board staff to the following three conclusions, which are discussed in more detail in the body of the report:

i) First, the natural gas sector may need to make new infrastructure investments for gas-fired power generation, but this should not call for a fundamentally different regulatory approach from the current one. At present, the OEB assesses new facilities on a case-by-case basis, applying cost allocation principles for cost recovery. While gas-fired generation may lead to large infrastructure investments, the nature of these investments will not be so different that this approach would need to change.

ii) Second, the Board should consider in a generic proceeding whether new services should be offered as a rate to gas-fired generators (and other qualifying customers). Specifically, the Board should focus on designing a new rate for generators and other qualifying customers. It would have the following two features:

  - Hourly nominations for distribution, storage and transportation; and
  - Firm high deliverability service.

Board staff have also identified three other services-related issues that need to be addressed in the proceeding:

- Identification of specific barriers to the inter-franchise movement of gas;
- Redirection of gas to a different delivery point at short notice; and
- Whether the transfer of title of gas in storage should be considered a purely administrative matter.

iii) Third, it is clear that the question of rates for new services can be answered only after the context for the economic regulation of storage is made clear. The Natural Gas Forum Report stated that Board would address in a generic hearing the question of the continued economic regulation of storage. Board staff recommend that a single hearing address both the NGEIR issues and the question of storage regulation. At the same time, the Board should also consider the related issue of whether it is appropriate to allow the recovery of premiums above cost for new transmission capacity.

Furthermore, Board staff recommend that issues concerning Union's Binding Open Season and the M12 rate premiums should be addressed in the generic proceeding.

2 Introduction and Structure of the Report

On March 30, 2005 the Ontario Energy Board issued a report entitled "Natural Gas Regulation in Ontario: A Renewed Policy Framework Report on the Ontario Energy Board Natural Gas Forum."[1] In this report, referred to here as the NGF Report, the Board set as an "important and immediate priority" the need to ensure that Ontario's natural gas infrastructure could meet the demands created by new gas-fired generators. As a result, the Board committed to a review of several issues:

- Identification of gas storage and transportation network expansion needs to accommodate additional gas-fired generators;
- Allocation of costs of any additional infrastructure investments;
- Rate design for storage and transportation services for gas-fired generators; and
- Coordination mechanisms between gas and electricity system operations.

To address the first three of these issues, the Board began the Natural Gas Electricity Interface Review. An industry-led process, involving Union Gas Limited (Union), Enbridge Gas Distribution Inc. (Enbridge), TransCanada PipeLines Limited (TCPL), and the Independent Electricity System Operator (IESO), with Board staff as observer, is working on market coordination issues.

In reviewing the first three issues, the Board researched several questions, which helped Board staff to:

- Develop scenarios to the year 2012 (the last year of the Incentive Regulation plan) covering a range of needs for natural gas power generation and looking at the impact on peak demand for natural gas;
- See whether existing assets and services in Ontario meet these needs; and
- Address whether new demands should require reconsideration of the regulatory treatment of gas infrastructure and services.

The services of the consulting firm Elenchus Research Associates (ERA) were retained to support staff work in the Review.

The Review has now been completed. This report covers the following:

- Section 3: the process
- Section 4: an overview of the current situation
- Section 5: a description of the scenarios developed and the results of the scenario analysis
- Section 6: a discussion of additional generator services that could be offered, including those identified by Ontario-based generators, and the results of research on other jurisdictions

[1] The NGF report is on the OEB's website.

- Section 7: a review and analysis of the issues raised in stakeholder discussions in Phase II of this Review
- Section 8: conclusions of Board staff

3 Process

The Review process was divided into two phases. The first involved gathering information to develop scenarios and determine any probable new service needs. The second looked at how the costs and benefits of additional infrastructure and services should be considered in the regulatory process. These phases are described in more detail below.

3.1 Phase I

The first phase of the Review involved:

- Developing high, medium, and low scenarios for new gas-fired power generators for the period 2005-2012;
- Assessing generator mix and utilization rates, generator location, generator services, upstream pipeline capacity, and storage space and deliverability to determine the capacity needed to support the generators; and
- Developing possible ranges of infrastructure needs to support these new generators.

Board staff worked in an iterative process with industry stakeholders in each step of this phase.

For the first step of developing the scenarios, Board staff and ERA met with Ontario Power Authority (OPA), the IESO, Hydro One Networks Inc. and the Ministry of Energy (MOE).

For the second step, Board staff and ERA met with Calpine Corporation, Sithe Canadian Holdings, Coral Energy Canada Inc., Eastern Power, Invenergy LLC, Ontario Power Generation (OPG), TransAlta Cogeneration L.P. and TransAlta Energy Corp., TransCanada Energy, Ontario Energy Association, and Association of Power Producers of Ontario (APPrO).

To help develop estimates of the likely natural gas demand for the period 2005-2012 and related infrastructure needs, Board staff and ERA met with Enbridge, TCPL, Union, Vector Pipelines Limited (Vector), Tribute Resources Inc., and Northern Cross Energy.

Phase I also included discussions and research on generator services. Generators were invited to comment on desired services in the Ontario market, and APPrO and Calpine Corporation responded. During this phase, ERA also completed research on six jurisdictions (Alberta, California, Illinois, Michigan, New York, and Great Britain) as well as a high-level overview of Federal Energy Regulatory Commission (FERC) policy on gas regulation. The research provided an overview of each market (both gas and power), its deregulation evolution, a description of its storage and transmission facilities, and a description of the primary services that are available to gas-fired generators[2].

3.2 Phase II

The second phase of the Review looked at how to consider the costs and benefits of additional infrastructure and services in the regulatory process. During this phase, which

[2] ERA's report on jurisdictional review is on the OEB's website.

took place in August and September 2005, stakeholders received a summary of the Phase I findings that set out the potential infrastructure needs, a summary of research on services to power generators in other jurisdictions, and a preliminary set of regulatory issues.

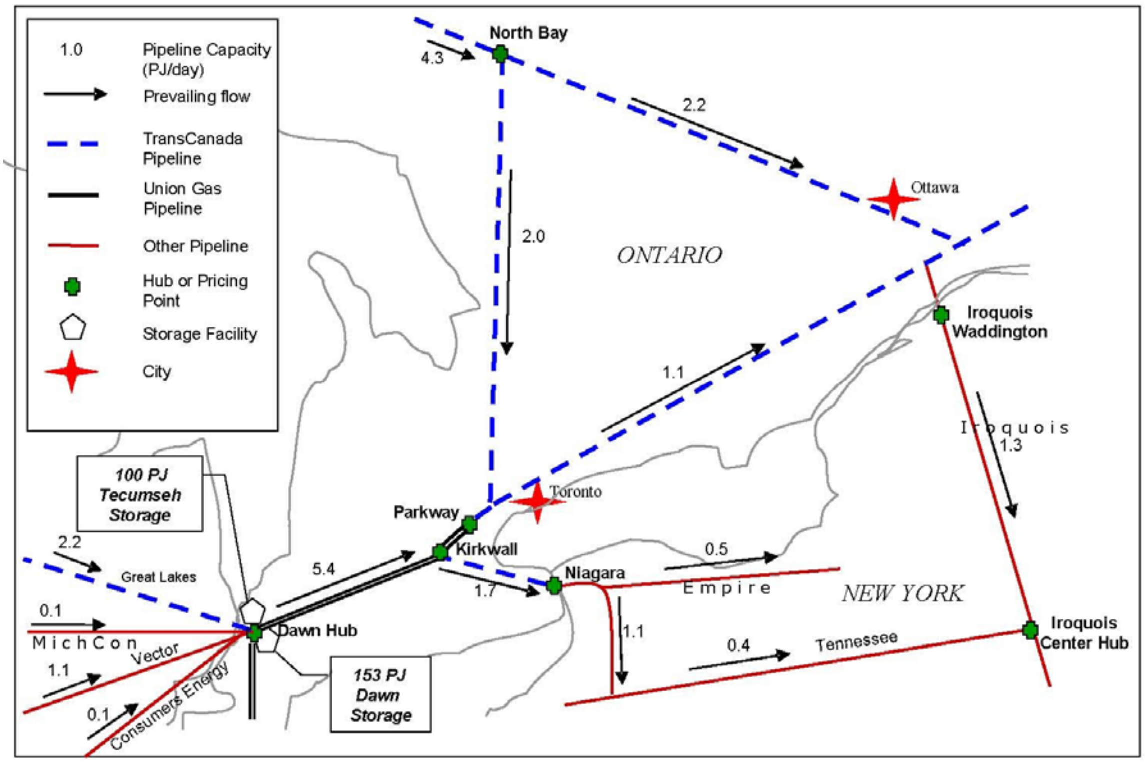
Because the Phase I work suggested a need for major gas infrastructure investment, Board staff asked stakeholders to outline their concerns about the draft set of issues on the regulatory treatment of new facilities. The Board received 12 final written submissions and two responses to support Phase I and II. On September 19, Board staff held a one-day stakeholder meeting to get further input on issues that might be missing and to prioritize issues. Material from that meeting can be viewed on the OEB's website, as well as the summary of the findings from Phase I.

4 Gas Infrastructure and Services in Ontario

4.1 Upstream Pipeline Capacity

Ontario is one of Canada's largest markets for gas. The total market size approaches 1,000 petajoules (PJ)[3] annually, with a peak demand around 3 PJ per day (PJ/d). More than 95% of the gas consumed in Ontario comes from outside the province. The bulk arrives from the Western Canadian Sedimentary Basin (WCSB), mainly through the TCPL system and/or the Vector route (see Figure 1).

Figure 1: Ontario Gas System Schematic



Source: Natural Gas Regulation in Ontario: A Renewed Policy Framework, March 30, 2005

As Figure 1 shows, the gas market is served by several routes. TCPL's northern route provides delivery to Ontario from the WCSB. TCPL pipeline splits at North Bay Junction. About 2.2 PJ/d (of capacity) flows from the junction along the eastern leg to Ottawa and Montreal, and also to the eastern export points at Iroquois Waddington, TransQuébec and Maritimes (TQM), and Portland Natural Gas Transmission system.

TCPL has about 2 PJ/d of capacity for gas flowing south and west from the North Bay Junction to the Toronto area, and also for delivery to the export markets near Niagara. As well, TCPL has additional export capacity to the United States at Niagara, with interconnections to Empire State Pipelines and Tennessee Gas Pipeline (TGP). Capacity along this route, which links the Kirkwall and Niagara market hubs, is about 1.7 PJ/d.

[3] 1 petajoule (PJ) = 10^{15} Joules = 1 million gigajoules (GJ). Throughout this report, it is assumed 1.055 PJ = 1 billion cubic feet (bcf) of natural gas.

TCPL has more than 1 PJ/d of capacity for flow east from Parkway to Montréal along Lake Ontario.

Dawn, in southwestern Ontario, is the meeting point for several major pipelines. It has become a leading market area hub, attracting Midwest and northeast shippers as well as providing service to Ontario shippers and the gas utilities in Ontario and Quebec.

Through its Great Lakes Gas Transmission system, which delivers gas to the Dawn Hub, TCPL has another 2.2 PJ/d of capacity into Ontario. TCPL contracts on the Union system for capacity from Dawn to interconnections at Kirkwall and Parkway, near the western end of Lake Ontario.

Vector provides about 1 PJ/d of capacity into Ontario, also through the Dawn Hub. Vector provides access to a number of United States pipeline systems as well as storage facilities in Michigan. Vector interconnects with Alliance Pipelines in the Chicago area. The Chicago area is a liquid market area hub, providing access to numerous pipelines. Vector recently announced plans to increase its capacity to about 1.3 PJ/d, an increase of about 0.3 PJ/d, by the fall of 2007, and to 1.5 PJ/d by 2010.

Union has interconnections with Panhandle Pipelines near Windsor with a capacity of about 0.2 PJ/d. There are additional smaller inter-ties near Sarnia (Bluewater, St. Clair and Link pipelines) providing about 0.4 PJ/d of capacity.

Substantial exports to the U.S. northeast flow through Ontario. In 2004, almost 3 PJ/d was exported to the U.S. northeast markets from Canada, about 80% through Ontario.

4.2 Storage

The costs of shipping a given amount of gas over a year on a long haul pipeline can be optimized if the same quantity is hauled every day. Storage can be used to balance the difference between gas delivered and the actual daily demand for gas. Storage is particularly useful for gas-fired generators that operate with a highly variable daily load.

Union and Enbridge own and operate 253 PJ of high quality reef storage (Enbridge about 100 PJ and Union about 153 PJ) at or near Dawn. In addition, Northern Cross Energy and Tribute Resources Inc. are planning to develop reef storage in the Goderich area. Current estimated capacity that could be developed over the forecast period is about 16-21 PJ[4].

4.3 Gas-Fired Power Generation

According to the IESO, Ontario currently has 20 licensed gas-fired power generators with a total capacity of 4774 MW. The three largest plants, OPG's Lennox (near Kingston), TransAlta's Sarnia plant and ATCO's Brighton Beach (near Windsor) have a total capacity of 3190 MW.

Lennox, the largest generator, can operate on gas or on Heavy Fuel Oil (HFO), and has significant onsite HFO storage. Choice of fuel depends on relative prices, interruptible

[4] Northern Cross Energy and Tribute Resources Inc. have indicated that they may require new storage delivery services (i.e., firm service with the flexibility to move gas). Without these services, the developers may consider the construction of new pipeline facilities to allow for the connection of the new storage facilities to one of the Ontario high pressure systems to allow access to the Dawn and Parkway trading points.

gas supply arrangements or balancing arrangements. Lennox is a peaking facility operating at a relatively low load factor. It generally contracts for gas supply on an interruptible basis and has very little firm gas transportation underpinning its operations.

Union provides service to more than 90% of the gas-fired power generation in Ontario (2200 MW of independent power and 2140 MW to Lennox). In southern Ontario, it provides no-notice T1 service (that bundles distribution and storage) to about 1300 MW of independent power. In northern and eastern Ontario, Union provides service under rates 20/25/100 and Customer Balancing Service (CBS) to roughly 900 MW of independent power.

Generators in Enbridge's franchise area access the Dawn Hub and storage through Union's Dawn/Trafalgar transmission system. This service is provided under M12 or C1 rates. These generators may need transmission service from TCPL and from the Union interconnect to the Enbridge interconnect. For generators accessing storage outside Ontario, transportation arrangements are needed to move the gas from the storage facilities to Ontario and then through the Ontario transportation system.

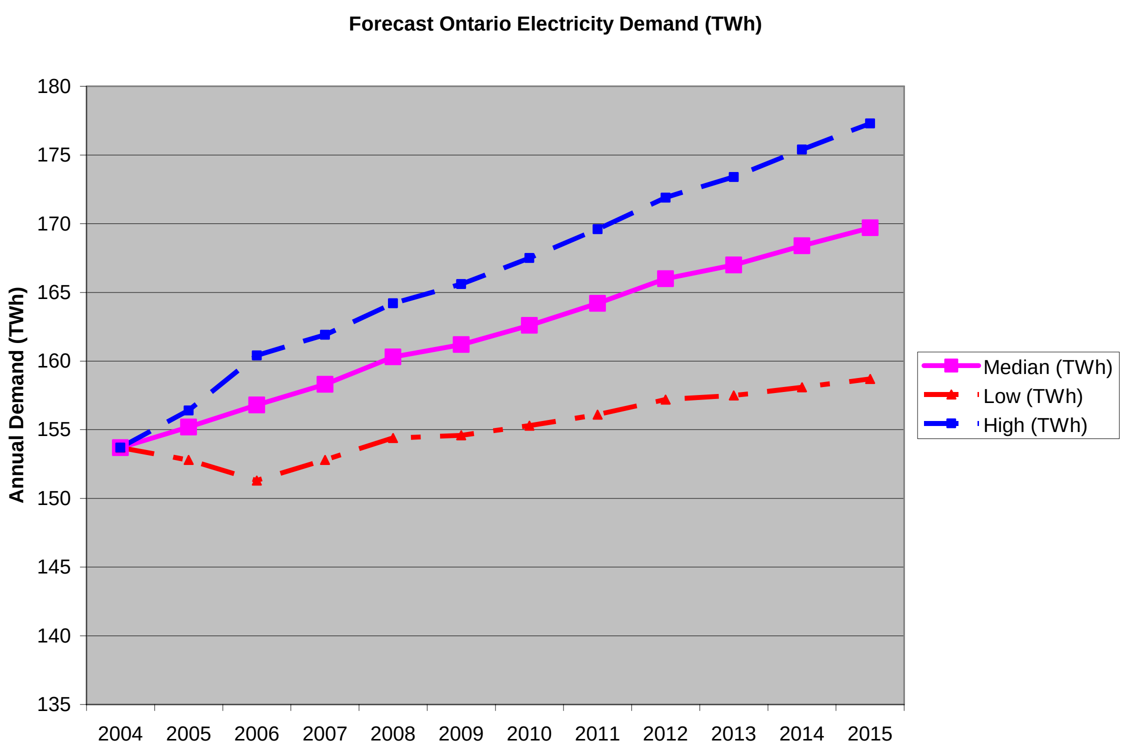
5 Scenario Analysis

5.1 Scenario Development

The starting point for developing the scenarios was the IESO's Ten-Year Outlook, issued on July 8, 2005. The outlook provides a low, median, and high load forecast, as well as different assumptions about the availability of existing and new generating resources to 2015.

The scenarios for this report were developed based on the Coal Replacement Scenario in the outlook, which assumes that the capacity of existing coal-fired power plants will be replaced by 2009 with a combination of increased renewable energy, conservation, return to service of nuclear units, and gas-fired generation. Figure 2 shows the load forecasts.

Figure 2: Electricity Load Forecasts from the IESO 10-Year Outlook



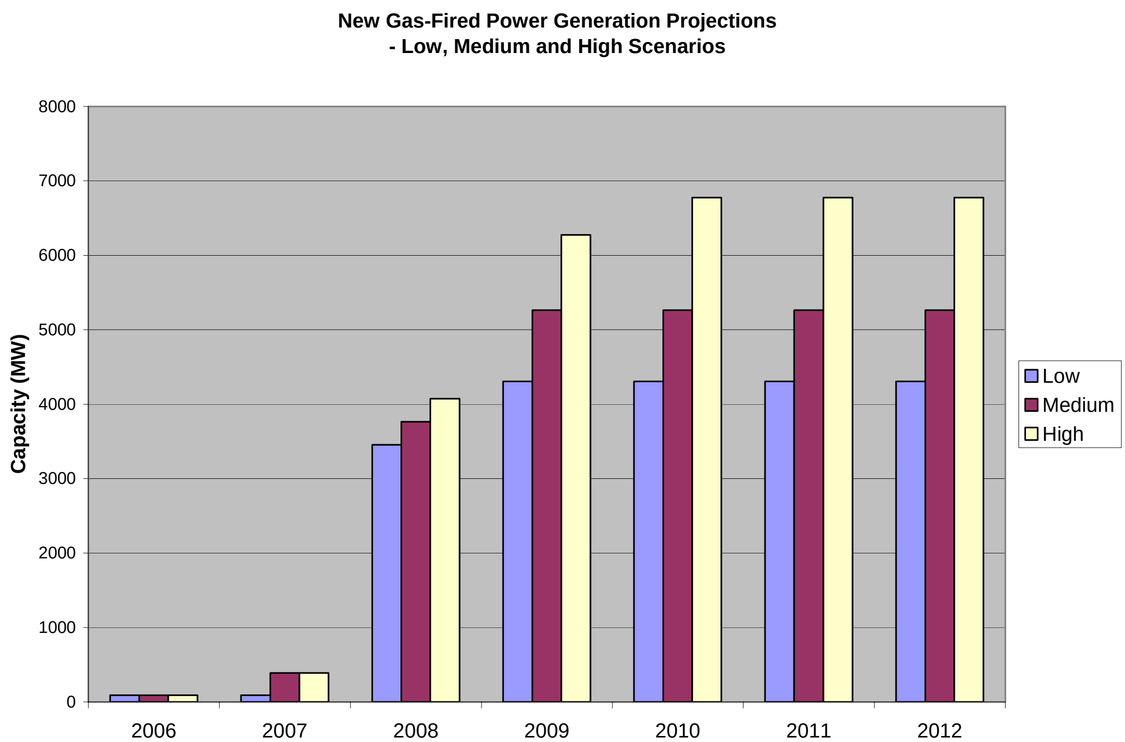
The capacity assumptions for the three scenarios were the following:

- The medium scenario, which this review used as the base case, includes the gas-fired generating capacity (5025 MW listed in Appendix 2, Table A1) identified in the IESO's coal replacement scenario and an additional 240 MW to meet load growth by the year 2012. It is assumed that all capacity is in service by 2010.
- The high scenario assumes 6775 MW owing to higher load growth and lower availability of nuclear generation.
- The low scenario assumes 4305 MW owing to lower demand and higher availability of nuclear generation.

OEB staff and ERA met with the OPA, IESO, Hydro One and the MOE to discuss these assumptions and to confirm that the scenarios were reasonable.

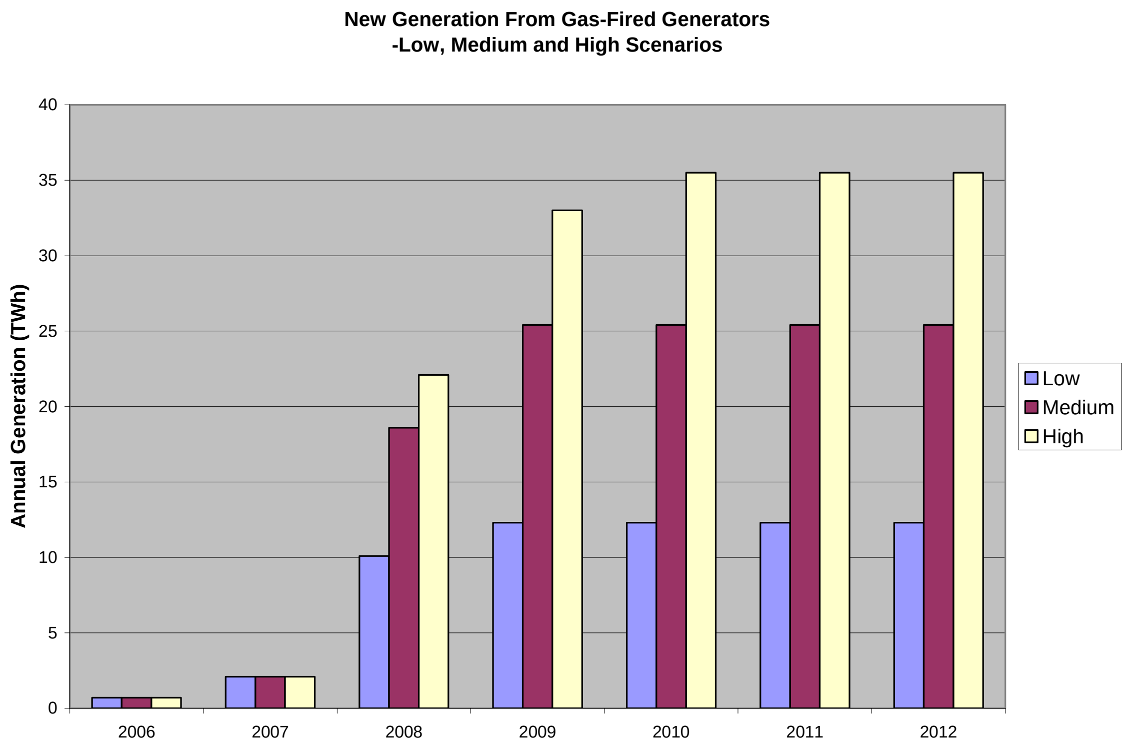
Based on these capacity numbers, the annual new gas-fired power generation capacity for each of the three scenarios is shown in Figure 3.

Figure 3: New Gas-Fired Power Generation Capacity in Low, Medium and High Scenarios



The electricity production of gas-fired generation was estimated using the forecast demand and expected production of nuclear and renewable power. Gas-fired generation output is assumed to “fill the gap” between the forecast load and generation from other sources. Figure 4 shows the gas-fired generation output in terms of terawatt-hours of electricity produced.

Figure 4: Electricity Production from New Gas-Fired Generation



5.2 Scenario Assessment

To develop gas infrastructure estimates from the projected annual output, several factors had to be considered: the mix of gas-fired generation (baseload, intermediate, and peaking); the utilization rates of each type; generator location; available upstream pipeline capacity; and storage space and deliverability needs. These factors and the assumptions used are outlined in detail below.

5.2.1 Generator Mix and Utilization Rates

The way that generation is used affects the infrastructure requirements. Generally, baseload gas-fired generation requires more gas supply and transport to Ontario per megawatt of capacity than for a peaking plant. On the other hand, peaking generation would require higher storage deliverability per megawatt of capacity.

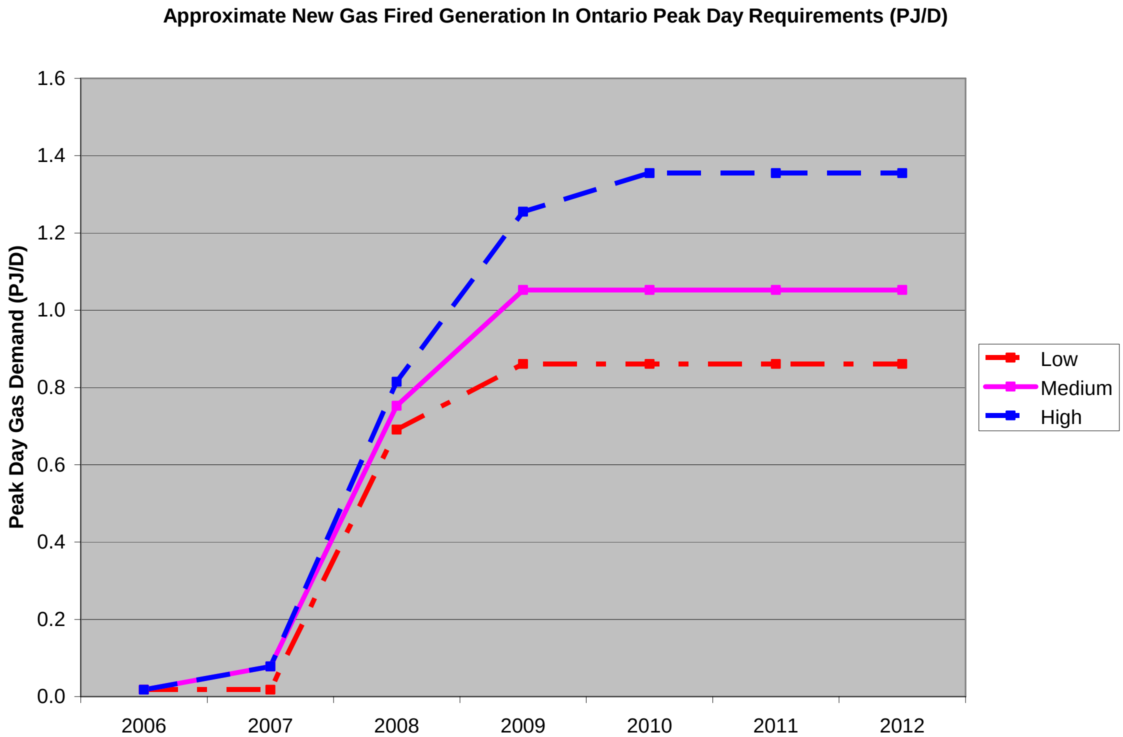
Table 1 illustrates the utilization rates that ERA used to assess the facilities and gas requirements for the three scenarios. In the medium scenario, ERA provided a mix of generation to match as reasonably as possible the following: announced cogeneration plans, annual coal replacement requirements, and capacity requirements. The IESO, OPA and MOE reviewed the scenarios, and the proposed generation mix, for general reasonableness.

Table 1: Assumed Utilization Rates for Gas-Fired Power Generation

MEDIUM SCENARIO	2006	2007	2008	2009	2010	2011	2012
Baseload	85%	65%	65%	65%	65%	65%	65%
Intermediate	45%	45%	45%	45%	45%	45%	45%
Peaking	5%	5%	5%	5%	5%	5%	5%
Average Utilization	85%	62%	56%	55%	55%	55%	55%
Capacity (MW)	90	390	3765	5265	5265	5265	5265
Generation (TWh)	0.7	2.1	18.6	25.4	25.4	25.4	25.4
LOW SCENARIO	2006	2007	2008	2009	2010	2011	2012
Baseload	85%	40%	40%	40%	40%	40%	40%
Intermediate	25%	25%	25%	25%	25%	25%	25%
Peaking	5%	5%	5%	5%	5%	5%	5%
Average Utilization	85%	31%	33%	33%	33%	33%	33%
Capacity (MW)	90	90	3455	4305	4305	4305	4305
Generation (TWh)	0.7	0.2	10.1	12.3	12.3	12.3	12.3
HIGH SCENARIO	2006	2007	2008	2009	2010	2011	2012
Baseload	85%	70%	70%	70%	70%	70%	70%
Intermediate	50%	50%	50%	50%	50%	50%	50%
Peaking	8%	8%	8%	8%	8%	8%	8%
Average Utilization	85%	57%	62%	60%	60%	60%	60%
Capacity (MW)	90	390	4075	6275	6775	6775	6775
Generation (TWh)	0.7	0.4	22.1	33.0	35.5	35.5	35.5

Based on the generation mix and utilization rate assumptions, annual gas requirements were estimated for each scenario. By 2012, gas use by gas-fired generators would grow to about 164 PJ/year in the low scenario and about 320 PJ/year in the high scenario. ERA assumed that the aggregate plant peak day requirement would equal the rated capacity of the new gas-fired generation. In-Ontario peaks could range from a low of about 0.86 PJ/d to a high of about 1.35 PJ/d. Figure 5 shows the range of estimates over the forecast period.

Figure 5: Peak Day Requirements for Gas-Fired Generators



5.2.2 Generator Location

Generator location is a key factor determining gas flows and infrastructure requirements.

In looking at where new generation might be located, stakeholders identified these factors:

- Proximity to power transmission
- Proximity to gas transmission
- Proximity to load centres
- The influence of the OPA RFP and the Clean Energy Supply (CES) contracts
- Environmental and zoning issues
- Assumptions about the location of new gas-fired generation development were based on:
- Locations of projects already awarded contracts by the government (2225 MW), outlined in Appendix 2
- Locations for future contracts specified by the government in subsequent announcements (1000 MW in the Western Greater Toronto Area and 500 MW in the Greater Toronto Area), outlined in Appendix 2

Locations for the remaining generation in each scenario were assigned based on input from the OPA, IESO and the MOE and using the factors identified by stakeholders.

Table A2 in Appendix 2 provides a summary of the location assumptions for new generation and cogeneration for each year and scenario.

5.2.3 Upstream Pipeline Capacity

Upstream pipeline capacity is needed to deliver gas from the production basin or from a liquid hub to Ontario. Generators usually contract for a smaller amount of capacity than their average day requirements, which allows for variation in annual gas needs.

Marketers can also provide upstream capacity to generators.

Actual upstream pipeline capacity to meet the new needs would depend on the entry point of gas into Ontario (the gas supply source) and the in-Ontario delivery point for new generation. Based on generator location outlined in Appendix 2, Table A2, ERA made the following gas flow assumptions:

> **Generators east of Dawn**: Gas received at Dawn would flow via the Dawn-to-Parkway system. For generators in Enbridge's franchise, gas could be received via the Dawn-to-Parkway system and/or TCPL from the north. If gas moved along Union's Dawn-to-Parkway system, generators could also need capacity for a short haul along the TCPL system to interconnect with the Enbridge system. In this circumstance generators (and/or their supplier[s]) could have three contracts: a long haul transmission contract with TCPL, a transmission contract with Enbridge or TCPL from the west interconnect with Union, and a contract to provide distribution services
>
> **Generators west of Dawn**: Gas deliveries from TCPL's Great Lakes system and/or Vector with deliveries at Dawn without a need to transport gas along the Dawn to Parkway system.
>
> **Generators in northern Ontario:** Gas delivery along the TCPL system with distribution services from Union.
>
> **Generators in eastern Ontario and along the Toronto to Montreal corridor line**: Gas deliveries could be made via the Dawn-to-Parkway system from the Dawn delivery point and then along the TCPL Montreal line with distribution to the generators site. An alternative could be delivery directly from the TCPL system and then distribution to the generator's site.

Another factor that would influence the actual upstream pipeline capacity is the extent to which supply is interruptible. Interruptible supply does not require the guaranteed capacity, so only the firm component is used for pipeline design calculations.

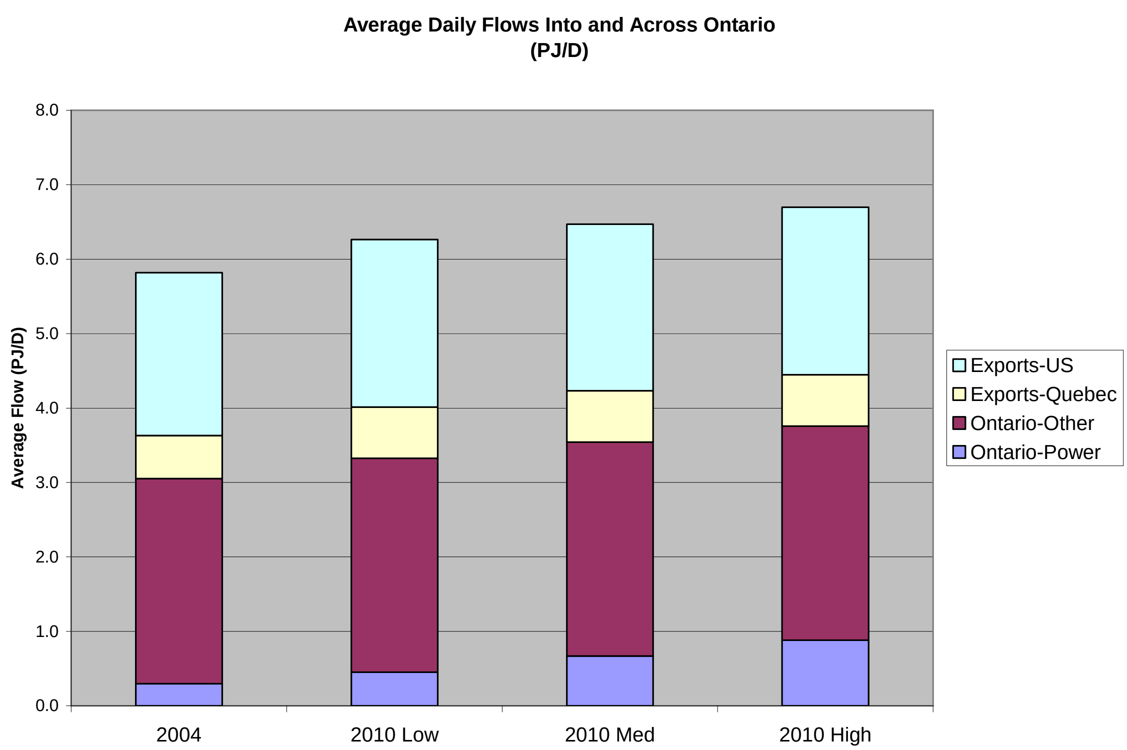
Because not all of the TCPL mainline capacity is contracted for long-term, it is possible that some of the existing capacity could be made available. It is not possible, however, to predict the quantity available over the period 2007-2012 with any certainty. For purposes of this report, ERA has assumed that generators will either acquire existing available capacity or will provide enough notice to allow new capacity to be built. In the latter case, the generator would likely be required to enter into a longer-term contract to underwrite the new capacity.

ERA assumed that new baseload and intermediate gas-fired generation projects would rely on firm upstream supply (and/or transportation) arrangements and on firm storage deliverability. This is because power obligations in the CES contracts and future power purchase agreements would likely result in generators requiring firm services to meet their power contract commitments, given the substantial increase in gas-fired generation.

Based on the gas flow assumptions, ERA assumed it would be necessary to expand upstream pipeline capacity. For the medium and high scenarios, TCPL's Montreal line would need to be expanded by about 0.26 PJ/d. Three reasons underlie this assumption: the expansion would provide incremental flow to generators east of Toronto; it would support generation development in Quebec and the northeast using the Dawn market centre for short-haul and balancing purposes; and it would provide additional capacity and flexibility beyond 2010 for LNG flow from one new LNG facility along the St. Lawrence. Also, as noted earlier, Vector plans to expand capacity by an additional 0.5 PJ/d by 2010.

In addition, the gas flow assumptions were used to estimate the average daily additional upstream flows to Ontario arising from each scenario. As Figure 6 shows, gas delivered to and through Ontario could grow from the 2004 average day level of 5.8 PJ/d to about 6.3 PJ/d in the low case and 6.7 PJ/d in the high case. In 2004, 0.3 PJ/d was for Ontario based power generation. The upstream average day flow for new gas-fired power generators could grow to about 0.45-0.88 PJ/d by 2010. In-Ontario peak day requirements were assumed to be met through balancing services from marketers or from storage.

Figure 6: Total Average Daily Gas Flows into and through Ontario



5.2.4 Storage Space and Deliverability

Space is the amount of capacity that generators contract for to balance their needs (hourly, daily and seasonally) at the generation site. Storage deliverability is the amount of gas that generators can withdraw from storage on a daily basis. Injection capacity is the amount of gas that can be injected into storage on a daily basis.

Storage space has many uses. Generators can use it for load balancing to allow for daily, hourly, and seasonal variations between their gas supply and generation plant requirements. When gas supplies are greater than the generator needs, the surplus can either be sold into the market or injected into storage for later use. Generators can also use storage space to help manage price volatility by hedging against prices that vary by season and that, within a season, vary by day and by hour. In addition, generators can use storage space for arbitrage, by buying gas when it is cheaper and using (or reselling) it when prices rise.

The amount of new storage space and deliverability required to meet the needs of new gas-fired generators will depend on:

- the type of new generation that is built;
- generator location;
- how new generators or their suppliers choose to flow gas to Ontario;
- the cost of storage; and
- the risk that the generator is permitted or prepared to take based on their power contract commitments.

Peaking generators who have alternative fuel choices (such as OPG's Lennox generating station) could rely on off-peak storage deliverability and balancing services when available and economic, and use their alternative fuel when gas capacity is unavailable.

Gas-only peaking plants, however, need high levels of deliverability to meet the few peak hours that they would run. Baseload plants need less deliverability and space, while intermediate operations would need to meet weekday peaks while disposing of surplus gas to balance off-peak periods (evenings and weekends). Generators' choices about gas flow routing could also influence the deliverability from storage that generators need.

The storage needed to meet new gas-fired generator demands is uncertain. Union may be able to "claw back" storage currently sold at market rates so it is available to its new in-franchise generator customers[5]. However, as noted earlier, there are other uses for storage space besides load balancing. These other uses, combined with the increase in gas consumption by the new generators led ERA to assume a significant demand for new storage space, even with a Union "claw back".

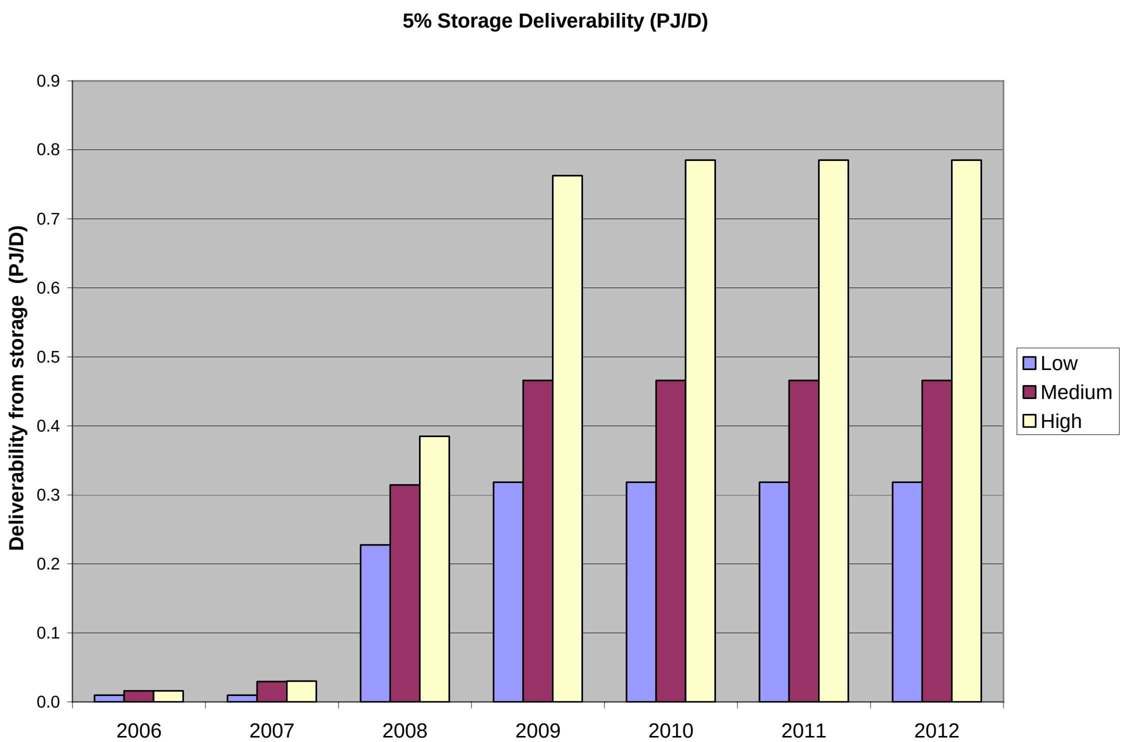
ERA also assumed that the demand for Ontario storage from ex-franchise storage customers would continue to be significant, even though these customers could turn to storage developments elsewhere (for example, in Michigan). As a result, ERA estimated

[5] Enbridge does not have storage that is excess to its in-franchise peak day requirements and, therefore, is not able to "claw back" incremental storage capacity.

that storage space for new gas-fired generators could range from a low of about 7.1 PJ to a high of about 17.5 PJ.

The actual deliverability was estimated based on the peak day requirements of generators and the mix of deliverability from storage and pipeline use. Currently, firm deliverability from storage is normally about 1.2% of the contracted space. However, to meet their dispatch requirements effectively on short notice and manage variations in their consumption, generators could require as much as 10% deliverability for a portion of their deliveries from storage. Figure 7 shows the increase in deliverability, assuming that generators required 5% deliverability. Storage deliverability at 1.2 % could range from 0.085 PJ/d to about 0.21 PJ/d and at 10% from 0.71 PJ/d to about 0.86 PJ/d.

Figure 7: Storage Deliverability Demand for New Gas-Fired Generation (assuming 5% deliverability)



5.3 *Infrastructure Costs and Timing*

Using the results from the scenario assessment above, ERA created a standardized template (outlined in Appendix 2).

The template outlined the key assumptions used to assess infrastructure requirements:

- Annual estimates of potential new generation and generation location for years 2005 to 2012;
- Estimates of the mix of baseload, intermediate and peaking generation;
- Options for delivery of gas to Ontario;
- Approximations of peak daily requirements for new gas fired generation;

- Estimates of annual gas requirements; and
- Estimates of storage space requirements and storage deliverability.

The templates (with the key assumptions) were given to Enbridge, TCPL, Union, and Vector to assess the likely gas loads and required facilities on an annual basis to accommodate the new gas-fired power generators. Northern Cross Energy provided high-level storage and pipeline costs for storage development in the Goderich area.

Based on high-level estimates of possible loads and potential costs provided by Enbridge, TCPL, Union and Vector, ERA developed preliminary estimates of potential gas requirements, facilities, and costs for each of the scenarios. These estimates were reviewed and modified based on feedback from the four stakeholders.

In assessing facility needs and costs, ERA assumed that a delay beyond 2009 in building new generation capacity could necessitate a build on upstream facilities. This was because existing available upstream capacity could be subsequently contracted and used by normal growth opportunities in-Ontario or in markets adjacent to Ontario. In addition, ERA assumed that a number of projects that could deliver more gas to Ontario would go ahead, even though some may compete with other proposals. This is because they aim to serve multiple markets and/or will offer timing and system benefits to shippers.

These scenarios provided stakeholders with a common framework to better understand the key issues. The intent was to create a range of possible costs, not to determine or prescribe any particular choice.

From ERA's analysis, new facilities would be required for new gas-fired generation to operate efficiently in Ontario. Table 2 provides a high-level summary of the possible costs, which reflect these likely needs:

- **In-Ontario transmission and compression (i.e., Dawn-to-Parkway).** Moving gas from the Dawn Hub or the receipt point requires expanding in-Ontario transmission from Dawn-to-Parkway. This capacity would be higher than the average day requirements, with a closer match to the peak day requirements of the generator. This capacity would also allow the movement of gas to and from storage facilities.

  ERA assumed that the peak day requirements to the generation sites east of Dawn would require capacity on the Dawn-to-Parkway system. ERA determined the capacity required for each year to meet the needs of the generators peak day requirements.

  Beyond 2010, ERA assumed that one LNG facility would be built along the St. Lawrence and connected to the TCPL system for east-west flow. As noted earlier, ERA assumed in the medium and high scenarios that TCPL's Montreal line would be expanded to accommodate 25% of the LNG plant. The lower-cost cases assumed that this would reduce the overall facilities required on the Dawn-to-Parkway system. On the other hand, the high-cost cases assumed that the LNG facility would use Dawn storage for balancing services to optimize the LNG operation.

- **Storage space and deliverability.** Unit costs were estimated based on input from Union and Enbridge, and by drawing on recent North American storage development costs. Northern Cross provided further storage cost information.

  In particular, Enbridge and Union provided ERA a range of costs for each scenario. For the low-cost case, ERA assumed that there would be only high deliverability on a best-efforts basis and that some deliverability would be provided from TCPL's pipeline capacity, which would provide capacity at Parkway. For the high-cost case, ERA assumed that generators would source their supply at Dawn and required at least 25% of their deliverability from storage, at 10% deliverability, with the balance of their daily peak requirements being satisfied from pipeline capacity.

- **Pipeline laterals, services, meters, and regulation**. Generators would receive gas from in-Ontario transmission facilities and deliver it to their plants via pipeline laterals and service laterals. Metering would also be needed at each generation site to regulate and measure the flow of gas delivery. Metering would likely be advanced electronic measurement with full time of use capability recording and providing telemetry of all key gas measurement components. These costs would not be included in gas utilities costs if generators were able to bypass the distribution system.

  Enbridge and Union provided ERA a range of costs for each scenario. These costs were based on the generator locations that were known at the time of the estimate and/or locations that ERA provided to Enbridge and Union based on the discussions with the MOE, OPA, Hydro One, and the IESO. Where a specific estimate had not been completed, Enbridge and Union used standard average costs and made assumptions regarding lateral length, size, and rights of ways (ROWs) and road crossings.

- **Upstream pipeline capacity**. Unit costs were estimated based on input from TCPL and Vector, while also considering recent North American pipeline development costs.

Table 2: 2012 TOTAL FACILITIES COST ESTIMATES ($ Million)

	Low Scenario (4305 MW)		Medium Scenario (5265 MW)		High Scenario (6775 MW)	
	Low	**High**	**Low**	**High**	**Low**	**High**
Dawn-To-Parkway	75	115	110	170	145	230
Storage (Space & Deliverability)	40	240	55	255	90	270
Laterals/Reg/Meters	130	225	150	250	205	315
TOTAL Ontario Only	245	580	315	675	440	815
Upstream	30	60	210	255	460	560
TOTAL	275	640	525	930	900	1375

1. Preliminary high level estimates. Costs could vary significantly due to: plant location, lead times, land acquisition, highway crossings and ROWs.

2. Assumes in the high case 3725 MW served east of Dawn and 3050 MW in the Northwest and cogeneration sourced via TCPL or west of Dawn.

3. Assumed LNG on St. Lawrence in the medium and high scenarios as of 2010.

The estimates above show a wide range of potential in-Ontario expenditures needed for natural gas infrastructure over the next few years, from $245 million to $815 million.

As is apparent from Figures 3 to 7, gas demand jumps starting in 2008 and increases through 2009 as new gas-fired generation comes on-line. Significant supporting infrastructure will be needed by that time.

6 Generator Services

6.1 Identification of Generator Services

As noted in the NGF report, the issue of services to gas-fired power generators has already come before the Board. In particular, a generator requested that a special rate for generators be offered. The Board has also received an application from a generator awarded a CES contract requesting to connect directly to a high-pressure pipeline.

A major reason for generators' concern is their limited ability to manage the risks associated with volatile demand and the price of natural gas. These risks can be managed more effectively if generators have access to more flexible services.

6.2 Desired Generator Service Offerings – Views of Generators

Board staff sought the views of generators on what flexible service offerings to effectively manage the risks of demand and price volatility. These views were outlined in particular in a response from the Association of Power Producers of Ontario (APPrO) and in other submissions,[6] and through discussions with Board staff and the consultant. At these meetings, generators identified their desire for:

1. Enhanced hourly services that allow non-uniform delivery of gas over the day on a firm basis; greater intra-day nomination flexibility (preferably hourly nominations), including hourly imbalance management services.
2. Higher deliverability from storage and on the transportation and distribution system. Current storage deliverability is about 1.2% of a customer's contracted storage space. Generators may require higher storage deliverability – as much as 10% of the space each day. Hourly flow rates on transmission and distribution systems generally allow for uniform flow rates with the maximum hourly flow rate not exceeding 1/20 of the daily contract quantity. Generators may require flow rates of 1/16, or higher, to closer match their operations through the power day. Although services such as Union's T1 have high deliverability available as an option, the high deliverability service is not truly firm but rather is available only on a "best efforts" basis. Some generators indicated that with greater volatility of demand that "best effort" was not likely to be sufficient and that firm high deliverability would be required.
3. Consistency of gas utility service across Ontario and seamless operational flexibility across gas utilities franchises within Ontario, as well as into and out of Ontario.
4. The right to redirect gas to and acquire gas from different delivery points inside and outside of Ontario on short notice. Generators expect that this will be necessary due to short notice changes in the dispatch of their generation.
5. The ability to easily and economically transfer their contractual rights to other parties. In particular, the ability to access to their gas inventory in storage, and to

[6] Material on Board's website. See APPrO and Calpine Corporation submissions.

easily enable transactions within their storage space, including transferring title to gas in storage without operational restrictions or withdrawal charges.

6. Assignable rights for the use of key infrastructure (storage/deliverability and Dawn-Parkway transmission). For customers taking a bundled service, the use of storage/deliverability and Dawn-to-Parkway transmission are guaranteed, but there is no effective way to resell their rights to another user should they not need it. Being able to do so obviously has value that would enable generators to manage the costs associated with storage and transmission (particularly for those generators with low and uncertain load factors).
7. Access to fully unbundled services along with a right to select only those services that they require or desire. For example, generators would like to have storage and balancing services unbundled from distribution services.

Generators also raised additional concerns, including:

- Generators would like access to cost-based storage. Union provides its in-franchise customers cost-based storage based on an allocation methodology. Storage space that is in excess of that allocated amount is sold at effectively unregulated rates. Enbridge provides its in-franchise customers cost-based storage for the storage that it owns and operates. However, Enbridge must purchase additional storage services at market-based rates from Union and these costs are passed to its customers.
- Generators would like to have certain contractual requirements (i.e., minimum annual volumes, daily delivery obligations, restricted delivery points, restrictive nomination windows, and imbalance penalties) removed because they can unnecessarily increase costs and reduce flexibility.
- Generators would like to have gas utilities contracts redesigned specifically to address the needs of the new generator services, including multi-year contracts with negotiated service and pricing for term of the agreement.
- Generators believe that there is a need for greater standardization of commercial terms such as:
    - Prudential requirements
    - Events of default
    - Third-party lenders' rights
    - Excuses for non-performance
    - Dispute resolution

They would also like standard terms and conditions to be part of the OEB-approved tariffs to provide greater certainty for investors.

6.3 Generator Services in Other Jurisdictions

Since 1998, more than 200,000 MW of new gas-fired power generating capacity has been built in the United States. Many jurisdictions in the U.S. and elsewhere have therefore had to deal with the question of supplying services to gas-fired power generation. Board staff commissioned the consultant to prepare a research report reviewing the availability of services in other jurisdictions[7].

The research is summarized in Appendix 3, Table B1 of this report. In addition, ERA identified, with the help of stakeholders, five services (Portland Natural Gas Transmission, Vector, Centerpoint Energy, ANR Pipeline, and Texas Eastern) that are representative of those available to generators in other jurisdictions. These services are described in Appendix 3; generators have used them to varying degrees, depending on the nature of the power market, power market contract requirements, pipeline utilization rates, available pipeline capacity to the generator, availability of storage, demand charges, and degree of gas wholesale market development.

Ontario generators have indicated that they would be interested in having some of these services available in this province. Calpine, in its submission, also identified services in other jurisdictions that are particularly useful for generators. For example, they point out that existing services elsewhere allow variable delivery over the day but that such increases in delivery are not truly firm. They cite examples from ANR Pipeline (FTS-3 service), Panhandle Eastern ETS service, and Gulfstream's FTS service. Details of these services are discussed in the Appendix. Calpine also noted that a system that allowed hourly scheduling of deliveries (such as offered on Vector's FT-H service) would also provide this flexibility.

Calpine also provided examples of services that deal with imbalances that cannot be managed through nominations. They note that Union's T1 service provides balancing using Union storage, but does not permit balancing provided by a third party. Calpine cites Tennessee Gas' Storage Swing Option as an example of a service that allows customers to use third party storage to deal with daily imbalances.

[7] Summary of Gas Practices in Other Jurisdictions, A Report Prepared by Elenchus Research Associates Inc., November 21, 2005.

7 Analysis of Key Issues

7.1 Facilities

As noted, the potential facility needs developed in Phase I were not intended to be determinative nor a recommendation, but rather to indicate a range of possible costs. These cost estimates were used to examine whether the Board's current regulatory treatment of natural gas infrastructure was robust, in light of significant infrastructure investment.

Phase I results show a high likelihood that investment in new facilities to serve the needs of the new gas-fired power generators will be needed. On August 31, 2005, Board staff drafted a set of issues for stakeholder comment. The focus was:

- The appropriateness of the Board's current process for determining cost recovery; and
- The method of cost recovery for the additional facilities from gas customers (e.g., incremental basis, rolled-in basis or some combination).

7.1.1 Process and Method of Cost Recovery

<u>Stakeholder Views</u>

Aegent Energy Advisors (Aegent), Canadian Manufacturers & Exporters (CME), and Low Income Energy Network (LIEN) stated that the costs caused or incurred by generators should be fully paid for by these generators. CME suggested that the full cost of providing service to gas-fired power generators should be recovered in the cost of electricity. Aegent also agreed with CME and felt that gas users should not subsidize power users.

School Energy Coalition, Wholesale Gas Service Purchasers Group (WGSPG), and Vulnerable Energy Consumers Coalition (VECC) stated that costs incurred by generators should be fully paid for by these generators and that shared costs, which benefit customers beyond the gas-fired generators, should be allocated to these customer classes.

London Property Management Association (LPMA) indicated that whatever methodology is adopted, there should not be any negative impact on rates or services from the other classes of natural gas ratepayers.

Aegent and TCPL believed that the possible ranges of infrastructure investment could be minimized if optimum use is made of existing facilities. This will ensure that these facilities are used efficiently before additional infrastructure is built.

In addition to the issues surrounding the method of cost recovery, many stakeholders raised concerns regarding the risks associated with underutilized capacity from overbuilding and/or stranded assets. In particular, who should be responsible for these costs – generators, gas ratepayers, electricity ratepayers, or some combination?

<u>Recommendation</u>

The Board currently reviews new infrastructure investment and determines cost recovery on a case-by-case basis. The process involves assessing each application for the following: project need; customer impact; competitive market impact; alternative options; facilities specifications; project costs; financial risk; construction and in-service schedule;

and environmental impact. Details of this process are outlined in Appendix 4. In addition, the NGF report states that the Board will develop a pre-approval process for long-term supply and/or upstream transportation contracts to be used by the gas utilities. The Board deemed that offering gas utilities the opportunity to apply for pre-approval of long-term supply and/or upstream transportation contracts will assist them in making necessary investment commitments in a timely manner.

To determine who should pay infrastructure costs, the Board applies cost allocation principles. Costs from shared or common infrastructure are allocated to current and new customers (i.e., rolled-in tolls). The Board's policy is that when there is a shared benefit to facility expansion, these costs should be allocated to all customers that benefit from the expansion. As a result, the costs of distribution expansions for the benefit of the gas system are borne by all distribution customers.

On the other hand, costs from a dedicated pipeline lateral to serve a sole customer – a generator or other load – are allocated to that customer. This type of expansion benefits the customer only and so costs should be the responsibility of that customer (i.e., incremental tolls). The Board's decision in RP-2004-0015/EB-2004-0002 is an example of how costs from a dedicated pipeline lateral were allocated. In this decision, the Board stated that the project costs were to be recovered from the customer through its rates.

The Board also considers costs of developing and operating gas utility storage facilities to serve in-franchise customers as shared or common infrastructure costs that benefit all in-franchise customers. These costs are recovered from in-franchise customers through their rates. The Board's current practice with respect to new storage development that is incremental to the allocation provided to in-franchise customers is to allow storage companies to conduct an open season bidding process and/or negotiations between parties. This allows parties who want access to additional storage services to contract and pay a market rate for these services. In the case of regulated gas utilities, most of the economic premium associated with these facilities is allocated to in-franchise customers through transactional services revenues. However, it should be noted that the treatment of gas utility storage facilities will depend on the how the Board rules with respect to the section 29 proceeding on storage.

With respect to shared or common infrastructure costs, the most recent example is the Board's decision regarding the Dawn-Trafalgar Pipeline Transmission Expansion, EB-2005-0201. The Board applied the foregoing principles so that expansion costs have been allocated to in-franchise customers through their distribution rates and ex-franchise customers through Union's M12 transportation rate. In this case, the Board allowed Union to receive a "market premium" above the cost based M12 rate and apply the premium to the benefit of M12 customers. The amount of premium was small, approximately $145,000. However, the Board noted that the issue with respect to the appropriateness of negotiated rates for transmission services was a complex one that should be addressed in the context of a generic hearing.

The Board also applies the same division of responsibility between common and individual costs in the electricity sector where all customers pay for the IESO-controlled grid and connection costs are paid by the sole customer.

In terms of cost allocation principles, Board staff believe that neither the volume to be consumed nor the pattern of consumption (i.e., load profile) imposed by gas-fired generation require a reconsideration of the Board's current policy. It is expected that there will be new facilities to serve this new load; however, the new load does not impose unique considerations that cannot be taken into account under the Board's current cost allocation approach. In staff's view, the Board should treat generators like any other load and therefore, a fundamental change in the method of cost recovery is not necessary. Although the allocation between common benefit and individual cost and benefit may be contentious in any given case, the principles are straight forward.

Furthermore, Board staff believe that the current process for determining the need for facilities and cost recovery is adequate to assess infrastructure requirements to support the needs of new gas-fired generators. This approach combined with the pre-approval process for long-term supply and/or upstream transportation contracts provides a robust regulatory framework. Stakeholder concerns can be addressed in this regulatory framework since the Board analyzes in detail the project need, alternative options, costs and risks. Board staff do not consider generators to be a unique load that requires a fundamental change to this approach. Also, stakeholders play an important role in determining whether the infrastructure requirements are necessary, the costs are reasonable and the risks to customers are minimized.

Board staff recommends that, as a general matter, the current process for determining cost recovery and the method of cost recovery do not need to be examined in the generic proceeding. Rather, the Board should consider facilities' applications on a case by case basis as they arise using the principles that are currently in place.

7.1.2 Other Issues

7.1.2.1 Integrated Solution

Stakeholder Views

Some stakeholders indicated that the Natural Gas Electricity Interface Review was a good opportunity to examine natural gas and electricity infrastructure requirements together. Stakeholders also stated that the location of new gas-fired power generators would impact both gas and electricity transmission systems in terms of infrastructure development and costs.

In its final submission, LPMA noted the lack of a central planning function in natural gas, and that no planning function exists across the electricity and gas sectors. In particular, both sectors may not be aware of each other's needs in terms of required facilities and timing of these facilities. LPMA submitted that parties (utilities and non-utilities) with current or future plans for major facility investments should be encouraged to bring them forward so potential synergies can be identified.

Recommendation

Board staff agree that it would be beneficial if both the natural gas and the electricity markets were more aware of each others needs with regard to infrastructure investments and the timing of these investments. This type of information could assist stakeholders in their planning processes. A central planning function exists in the electricity market primarily through the IESO and OPA, while no provincial agency exists in the natural gas market. Board staff are not advocating a central planning function in the gas market, but information exchanges could be valuable to stakeholders. This Review is the first step in understanding the implications of new gas-fired power generators for the province's natural gas infrastructure. However, Board staff realize that there is great uncertainty with respect to future infrastructure requirements, and periodic updates might be necessary to assist with electricity planning. If this type of information is required, the Board can consult with stakeholders and modify the Gas Reporting and Record Keeping Requirements (RRRs).

7.1.2.2 Bypass

Stakeholder Views

The generators and APPrO wanted the issue of bypass to be addressed in this Review. These stakeholders would like the option to connect directly to a transportation pipeline without contracting for distribution service from the gas utilities.

LPMA and WGSPG indicated that the issue of bypass could impact the required infrastructure investment (and associated costs) needed to support the new gas-fired power generators, which in turn could affect customer rates.

Recommendation

The issue of bypass is currently before the Board in a proceeding. Therefore, at this time, Board staff do not recommend that this issue be examined in the generic proceeding.

7.1.2.3 Miscellaneous Issues Identified

i) Ontario Power Generation raised the concern that when new gas-fired power generation is added to the Province's generation portfolio, the amount of load-following capability available in the market will decline. This decline will exacerbate the current problem with generators that are capable of ramping up and down. These generators will then be required to reverse direction with greater frequency.

   Board staff feel that the OPA and IESO should be informed of this situation.

ii) Some stakeholders in their written submissions and at the one-day stakeholder meeting thought that the Review should include the following:

   - Scenarios with detailed assumptions on type and size of new gas-fired generators and distributed generation;
   - The economic implications of using gas-fired generators on gas price levels, price volatility, security of supply, and long-term supply contracts; and
   - Surrounding jurisdictions regarding additional capacity for storage and transmission.

   Board staff are not incorporating these factors into the Review. The purpose of this Review was to develop possible ranges of infrastructure requirements to support the new gas-fired generators and to examine the issue of cost recovery. High level assumptions were made on generator type (i.e., baseload, intermediate and peaking) but the assessment of economic implications is not required for determining cost recovery and the method of cost recovery.

With respect to additional transmission capacity to provide better access to storage outside of Ontario such as Michigan, it is the staff's view that the Board should not have a central planning function in the gas market. However, the ability of parties to access and use storage in neighbouring jurisdictions is information that will be examined in the section 29 generic storage hearing.

iii) In the Board's decision regarding the Dawn-Trafalgar Pipeline Transmission Expansion (EB-2005-0201), the Board stated that it will examine Union's Transmission Binding Open Season process in terms of rates and contractual terms for allocating transportation capacity in a generic hearing. In particular, the issues concerning the M12 rate premiums identified by the Board need to be addressed in a generic hearing. Therefore, Board staff recommend that issues concerning Union's Binding Open Season and the M12 rate premiums should be addressed in the generic proceeding.

7.2 Rates and Services

Gas-fired power generators face particular challenges in managing their gas supply to respond to varying demands for their electricity. As the marginal source of power production in Ontario's electricity system, production of electricity from gas-fired generation can be expected to be quite uncertain on both a daily and an annual basis. Thus the quantity of gas that any gas-fired generator operating at the margin might require on a daily or annual basis could be expected to be relatively volatile and difficult to predict compared to other large users of natural gas.

Recognizing that this greater volatility would imply greater demand for more flexible services, the Natural Gas Forum report recommended that this Review include the issue of "rate design for storage and transportation services for gas-fired generators." At its most general level, the question is whether there should be a rate available to generators and what services could be included in such a rate.

In their submissions, generators have indicated that additional tools will be needed for them to manage their gas supply in this environment. As summarized in sections 6.2 and 6.3 above, generators identified the following:

- **New service offerings** including enhanced hourly services and the right to redirect gas, connect directly to transportation pipelines, including those from third parties.
- **Greater unbundling** of existing service offerings;
- **Access to cost-based storage**;
- **Changes to contractual arrangements** by encouraging longer-term contracts, less restrictive contractual requirements, and standardized commercial terms.

While the issue of service offerings is central to this Review, some of the other issues raised are to be addressed by the Board elsewhere. The question of access to cost-based storage will be addressed as part of the storage review. Furthermore, as noted in section 6.1, the issues raised by direct connection to the transportation system (also referred to as issues related to bypass) are currently being addressed in another Board proceeding.

The question of unbundling of services impact interruptible customers is addressed in Section 7.2.4 below.

The submissions also identified restrictive contracting practices as an impediment to flexibility. In Board staff's view contracting practices, while relevant to generators, affect a much broader group of stakeholders. The Board has required the gas utilities to negotiate service level agreements with some customers (specifically gas vendors) under the Gas Distribution Access Rule. In staff's view, that Rule is a more appropriate venue to address detailed contract terms than a generic proceeding.

Based on the concerns raised, Board staff proposed the following draft set of issues pertaining to rates and services:

a) What is needed to encourage provision of the service (by utilities and/or third parties);

b) The costs of providing the service; and

c) Operational flexibility in providing the service.

Stakeholders were asked to comment on this list of issues in writing. A workshop was held on Sept. 19th, at which stakeholders were invited to comment on the completeness of this list of issues and on the relative priorities. While there was generally strong support for the issues identified above, the input received from stakeholders led to a further elaboration of the issues, and also identified other issues for further consideration. For example, the impact of the additional gas-fired generation on other consumers under interruptible contracts was also considered. Each of these issues will be discussed below.

7.2.1 Encouraging the provision of services by utilities and/or third parties

Stakeholder Views

Several submissions also addressed the question of what the Board needed to do to encourage new types of services to be offered to generators. Calpine suggested that generators should be allowed equal access to transportation and storage services offered by third parties, and encouraged more flexible nomination provisions. Calpine also recommended that the Board allow greater flexibility in rate design and establish clear guidelines for utilities to use in negotiating rates and terms of service. TransCanada Energy suggested that utilities had to be more transparent about operating limitations that they cite as a reason for not providing certain services. The Low Income Energy Network noted that OEB had in the past encouraged the development of services by allowing additional incentives to the utilities to develop such rates in the form of higher profits for these services. London Property Management Association noted that balancing and storage services appear to be already available in the market from third parties.

Recommendation

Additional services may be required to ensure that the Ontario natural gas market can more efficiently meet the demand by the new gas-fired generators for increased flexibility. The Natural Gas Forum report identified the key question: whether a new rate should be designed for generators and what services should be included in such a rate. The NGF report noted that this issue has arisen before, specifically in the case of

Brighton Beach, where the Board directed Union Gas to submit detailed evidence about the anticipated load profile, and to determine whether a basis exists for a new rate class and, if so, to apply for Board approval. While Union suggested that a separate rate class was unnecessary, the Board made the question of a rate designed for generators a central one for this Review[8].

Generators and others have proposed a wide range of possible changes to the menu of service offerings. Staff have reviewed these proposals, assisted by the consultant, and identified key elements for the Board to consider to determine whether it should order gas utilities to offer a more flexible rate that will meet the needs of generators.

Staff recommend that the Board focus the generic proceeding on whether there should be a new rate for generators (which would, of course, be available to all qualifying customers) that would include these features:

a) Hourly nominations for distribution, storage and transportation; and

b) Firm high deliverability service.

A short description of each of these services is below.

Hourly nominations

One change in operating practices that would afford generators and other gas users responsible for the deliveries of gas greater operational flexibility would be the introduction of hourly nominations for transportation, distribution and storage. Hourly nomination periods would enable these users to reduce their daily imbalances significantly while providing the operator with more accurate information about the user's gas requirements over the day.

Staff agree with the APPrO submission that the development of hourly nominations for transportation and storage could encourage development of similar hourly services in major pipelines serving Ontario. Indeed, as noted in the research on other jurisdictions, Vector Pipeline already offers a Firm Hourly Service. TransCanada Pipelines Limited has indicated that it is developing hourly services that Ontario customers could use. However, as noted by APPrO, the usefulness of Vector's service to Ontario customers is limited without corresponding hourly services for in-Ontario distribution, transportation and storage. This suggests the need for stronger co-ordination of such offerings. There could be additional administrative costs for the utilities if they were to provide hourly nominations for transportation and storage. While no cost estimates have been discussed, staff recommend that the Board require the utilities to develop a proposal to provide the Board with the information necessary to examine the costs and benefits of moving to hourly nominations. This proposal will help the Board to consider whether it is in the public interest to do so.

High deliverability from storage

There was a consensus among industry experts that generators are likely to require higher deliverability from storage since generators will have two seasonal peaks (summer and

[8] Furthermore, the Union analysis assumed storage charges would not be different and so set these aside in their analysis.

winter) and will likely be required to switch on their plants and operate on relatively short notice. Standard deliverability from storage is available on a firm basis at 1.2%. Higher deliverability can be negotiated at market rates under certain tariffs (Union T1), but this is on the understanding that higher deliverability is offered on a "best efforts" basis. Generators indicated to Board staff that this level of firmness was not sufficient, and a firm service of higher deliverability was required.

One unresolved question with respect to the tariff is the level of firm deliverability that should be offered. Consistent with the analysis in the previous sections, Board staff recommend that the tariff be developed based on both 5% and 10% firm deliverability. Finally, it is equally clear that the basis for the tariff will depend strongly on how the Board rules with respect to the section 29 proceeding on storage. Therefore, Board staff recommend that utilities include in the generator tariff an option for higher firm deliverability from storage at 1.2% (standard), 5% and 10% under three pricing scenarios:

a) The current pricing (i.e., the generator has access to cost-based storage in accordance with current allocation methodology, and market-based storage above that);

b) Assuming all the storage the generator uses is priced at cost; and

c) Assuming all the storage is priced at market prices.

7.2.2 Costs of providing additional services

Stakeholder Views

As with infrastructure cost recovery, the Schools Energy Coalition, the Low Energy Income Energy Network, and the London Property Management Association specifically expressed the broad concern that any rates for such services follow cost allocation principles and be cost-reflective.

Recommendation

Staff agree with this position. Board staff recommend that Union and Enbridge be directed to file for the generic proceeding a proposed rate that will provide hourly nominations and high deliverability storage. The Board may consider the costs and benefits of such a rate so that it may determine whether it is appropriate to require these gas utilities to provide it. Board staff also recommend that other service providers, specifically though not exclusively TCPL and Vector, be invited to file proposals that are either complementary to or as an alternative to the rates offered by Union and Enbridge. All parties will then be in a position to examine and debate the costs and benefits of this service, and the Board may make a determination after considering all the positions of all parties.

7.2.3 Operational Flexibility Issues

There are three key areas where the addition of greater operational flexibility should be considered: with respect to access to services across Ontario; the ability to redirect gas to a different delivery point on short notice; and with respect to the ability to transfer gas within storage.

i) Access to service across Ontario

Stakeholder Views

The question of access to service across Ontario was addressed in two different ways by stakeholders. APPrO argued in its submission that "utility service consistency across Ontario with seamless operational flexibility" would allow customers to maximize their efficiency by being permitted to use assets and services offered by one utility to a customer located in the franchise of another. TransCanada Pipelines noted that in the Natural Gas Forum report, the Board had identified that "the ability (or inability) to move gas between Union and Enbridge" was an issue that needed to be discussed at a generic proceeding.

Some stakeholders also raised the question of whether to price distribution services by location. Calpine and London Property Management Association both suggested that departures from postage stamp pricing should be considered in order to signal to generators to locate where new gas infrastructure investment could be minimized. By contrast, Vulnerable Energy Consumers Coalition argues that postage stamp rates should continue to apply within a gas utility service territory.

Recommendation

The Board has already indicated in the Natural Gas Forum report that the question of moving gas between Union and Enbridge needed to be addressed at a generic proceeding. The Board also stated that it "needs to be satisfied that access to Enbridge's and Union's systems is not only non-discriminatory, but also well coordinated and sufficiently transparent …". Staff recommends that the Board focus its review by reference to specific barriers to the inter-franchise movement of gas, whether to a customer's own account or a sale to a third party. However, participants in the NGEIR did not identify specific barriers and how they may be remedied. In order to effectively address this issue, the Board should include it on the issues list and invite parties to file evidence on specific barriers to cross-franchise movement of gas so that the Board may evaluate the costs and benefits of removing them.

On the question of postage stamp rates, the current practice is to make distribution service available at a postage stamp rate. However, charges do vary for customers because of transmission services, even within the Union franchise, depending on their location relative to storage. Board staff are of the view that these differences provide a sufficient price signal for generators and did influence the location of many of the successful participants in the original CES contract generation. Furthermore, it appears that the location of much of the remaining gas-fired generation will be determined largely by specific electric system locational needs, and/or by the availability of suitable heat loads for cogeneration.

ii) Redirection of gas at short notice

Stakeholder views

As noted in Section 6.2 above, generators have indicated that being permitted to redirect or acquire gas at short notice to a different delivery point would provide important flexibility to the generator. The submission from Calpine argued that such flexibility would reduce the storage requirements of the generators.

Restrictions in transportation contracts on alternative delivery points exist principally because of operational limitations in the gas system, for example the direction of the flow or availability of spare capacity on the Dawn-to-Parkway system. The submission from TransCanada Energy noted that greater clarity is required concerning these limitations.

Recommendation

Just as hourly nominations would provide generators with greater temporal flexibility, enhancing spatial flexibility by allowing gas to be redirected at short notice to a different delivery point would add flexibility to the gas system for generators and shippers. Just as operational capabilities can be enhanced to permit hourly nominations, the assessment and publication of the state of the system and its operating limits on an hourly basis could permit greater flexibility in the movement of gas. Board staff recommend that this issue be examined in the generic proceeding.

iii) Title Transfers in storage

One of the ways in which customers may wish to manage changes in their gas requirements and effectively use their storage is to transfer gas in storage to other customers. In such a case, the transfer would be treated as a withdrawal for the transferring party and an injection by the transferee. This has both a financial impact (because it attracts injection and withdrawal fees), and a services impact (because it is treated as a physical withdrawal or injection of gas and thus triggers the injection and withdrawal parameters of a customer's contract)[9]. Generators have argued that treating a transfer of title as if it were an injection and withdrawal of gas is inappropriate, because there is actually no physical movement of gas. Instead, they argue that it should be treated as an administrative accounting matter. Staff recommends that the Board add as an issue to the generic proceeding whether title transfers of gas in storage should be subject to injection and withdrawal fees and storage contract parameters.

7.2.4 Other issues

Unbundling

Most of the concerns raised by generators in this Review have identified the unbundling of storage and load balancing services from distribution, and the terms under which they can access these unbundled services as the most important issues to be addressed.

Board staff note that Enbridge and Union currently offer unbundled rates through their 300 and U Rate series, respectively. However, no customers have taken up service under those rates. Although generators have argued that rates should be more effectively unbundled, they have not specified how this should be done. Nor have potential service providers of alternative services indicated that they would be prepared to offer competitive alternatives to unbundled rates. Finally, even though the gas utilities do not have any unbundled customers, they offered no suggestion of how an unbundled service may be made more effective or more attractive. As a result, staff has not been provided

[9] It should be noted that there is a different treatment for Union's unbundled (U Series) customers. These customers may transfer title by paying an administrative charge – and not an injection or withdrawal fee. However, these transfers are also constrained by the withdrawal and injection parameters of storage contracts.

with specific enough information for it to recommend that the Board should convene a hearing to address unbundling of storage and distribution. If gas consumers (whether generators or others), utilities or wholesale service providers can identify how specific limitations to the current unbundled rates may be improved, they may bring that forward to the Board at any time. However, at this stage, staff does not believe that the resources of the Board or stakeholders will be well used by a review of further unbundling of storage and distribution services in the absence of a specific proposal.

Impact of gas-fired generation on interruptions of gas supply

The Industrial Gas Users Association (IGUA) indicated a number of concerns in its submission related to the impact of gas-fired generation on the demand for interruptible supply. A particular concern is that large users, the group most likely to be operating as interruptible consumers, may become subject to more frequent interruption. IGUA's main recommendations aim to minimize this possibility by asking the Board to require that power generators be able to show that they have contracted for sufficient firm gas supplies and upstream transportation.

Board staff view the increased demand for flexibility as an opportunity for suppliers of flexibility, including those industrial customers willing to be interrupted. Additional infrastructure and increased operational flexibility should help meet this demand for increased flexibility. Prices for such flexibility, including regulated tariffs for interruptible services, should be expected to reflect this increased demand. While Board staff agree that the rates for interruptible services may need to be reviewed, it is recommended that this is best carried out in the context of a rate case.

8 Board Staff Conclusions

Board staff recommend that the Board commence a hearing on its own motion to determine whether a new rate should be ordered that provides greater firm deliverability, nomination entitlements, and operational flexibility. Specifically, the Board should determine whether gas-fired generators and other qualifying customers should be entitled to new tariffed rates containing the following key features:

a) Hourly nominations; and

b) A menu of firm deliverability entitlements at 1.2%, 5% and 10%.

In making this determination, the Board should have an appreciation of the costs and benefits of making this service available. Because these services may put additional demands on gas storage and related infrastructure, and because the pricing of gas storage in the long run is not clear, the determination of costs and benefits requires considering three scenarios for the pricing of storage:

a) The current pricing (i.e., the generator has access to cost-based storage in accordance with current allocation methodologies, and market-based storage above that);

b) Assuming all the storage the generator uses is priced at cost; and

c) Assuming all the storage is priced at market prices.

Board staff was not able to gather specific information in the course of its research that would allow it to quantify the costs and benefits of providing these services both to potential new customers and to other types of customers. Enbridge and Union are the only ones in a position to provide this evidence on a system-wide basis. Staff therefore recommend that, as part of the generic proceeding, the Board direct Enbridge and Union to file evidence quantifying the cost of the service to generator customers and to other customers. Other potential service providers may also have information on how they might cost this service to generator customers. They should therefore be invited to provide this evidence as well. Following receipt of this information, other parties – including customer representatives, generators and other stakeholders – should be invited to file evidence. In this way, the Board will acquire a variety of perspectives on the costs and benefits of providing this service.

Board staff have also identified other issues that would enhance the operational flexibility of the natural gas network. The other issues are:

- Moving natural gas across franchises;
- Redirecting gas to a different delivery point at short notice; and
- Transfer of title to gas in storage.

These issues should also be addressed in the generic proceeding.

Furthermore, Board staff recommend that issues concerning Union’s Binding Open Season and the M12 rate premiums should be addressed in the generic proceeding.

Regulation of Gas Storage

In the NGF Report, the Board noted the need to address the issue of whether and how it should regulate the price of storage. It stated that “the Board will determine, through a generic hearing, whether it should refrain, in whole or in part, from regulating the rates charged for natural gas storage in Ontario."

The NGF Report also recognized that the storage review should be informed by the gas electricity interface review. It is clear from staff research and analysis of the gas electricity interface, and from the central role of firm deliverability in this analysis, that greater clarity is required on the regulation of gas storage on a going forward basis. Essentially, the central issue coming out of the review is whether generators should be provided with greater firm deliverability options and operational flexibility. There may be a significant price difference between the cost of providing increased deliverability and flexibility if storage is provided at cost of service rates or at market rates or some combination of the two. Consumers require clarity on how effective the market will be at providing this service and, as well, how this service will be priced when provided by gas utilities.

The impact of regulating storage goes beyond the needs of gas-fired generators. Even in the absence of increased reliance on gas fired generation, there are questions that should be addressed about the current regulation of storage. The central issue whether there is competition in storage services "sufficient to protect the public interest". In making its determination, the Board will need to focus on the questions surrounding market power. These questions include:

1. Do gas utilities either collectively or individually have market power in the provision of storage services for all or some categories of customers in Ontario?
2. If gas utilities do have market power in storage, is it appropriate for them to charge "market rates" for transactional and long-term storage services?
3. If gas utilities do not have market power, is it in the public interest that all or some customers continue to pay storage rates at cost as opposed to market rates?
4. If the Board determines, based on considerations of market power and the public interest more generally, that some customers should pay for storage services at cost and others should pay for storage services at market prices, how should the line be drawn between the two types of customers and, specifically, should there be a constraining allocation of physical storage facilities to some types of customers based on measures such as aggregate excess or whether customers are considered "in-franchise" or "ex-franchise"?

None of these questions are new to the Board. However, the context of increased reliance on gas-fired generation has made the need to resolve these questions acute. Board staff therefore recommend that, as part of the generic proceeding to address the issues relating to the new service for gas-fired generators, the Board also determine whether, under s. 29 of the *OEB Act*, it should refrain from regulating the rates charged for gas storage services.

Appendix 1: Public Processes

Stakeholder Meetings

Board staff held ten Stakeholder meetings. Below is the list of Stakeholders who participated in each of the meetings:

1. Ontario Energy Association (OEA), Association of Major Power Consumers of Ontario (AMPCO), Association of Power Producers of Ontario (APPrO)
2. Hydro One Networks Inc. (HO)
3. TransCanada Pipelines Limited, Union Gas Limited, Enbridge Gas Distribution Inc., Vector Pipelines
4. Sithe Canadian Holdings, Calpine Corporation, Coral Energy Canada Inc., TransCanada Energy, Invenergy LLC, Brighton Beach, Eastern Power, Ontario Power Generation, TransAlta Cogeneration L.P. and TransAlta Energy Corp.
5. Ontario Energy Savings Corp (OESC), Direct Energy Marketing Ltd., ECNG Ltd., Sempra
6. Ontario Power Authority (OPA)
7. Ministry of Energy (MOE)
8. Independent Electricity System Operator (IESO)
9. Tribute Resources Inc., Northern Cross Energy
10. Natural Gas Exchange Inc. (NGX)

Final Submissions

The following stakeholders made final submissions:

Aegent Energy Advisors Inc.

Calpine Corporation

Canadian Manufacturers and Exporters

Enbridge Gas Distribution Inc.

Low-Income Energy Network

London Property Management Association

Ontario Power Generation

School Energy Coalition

TransCanada Energy

TransCanada Pipelines Ltd.

Vulnerable Energy Consumers Coalition

Wholesale Gas Service Purchasers Group

Responses to support Phase I and Phase II of the Review:

Association of Power Producers of Ontario

Industrial Gas Users Association

Appendix 2: Template and Assumptions

The first section of the template below outlined the estimates from IESO's Ten Year Market Outlook for annual capacity, above reserve and demand. This identifies the annual demand-supply gap for the three scenarios – low, medium and high. The IESO's median forecast was considered the base case for this analysis.

The template also contained assumptions regarding:

1. The amount of generation by location (i.e., west of Dawn, downtown GTA, east of GTA, west of GTA and northwest Ontario) for each year.
2. The type of generation anticipated to come on stream (baseload, intermediate and peaking) along with a calculated average utilization for the overall gas-fired generation fleet for each scenario and year.
3. The amount of gas supply required to meet the needs of the new gas-fired generation.
4. Gas supply sources – east or west of Dawn Hub.
5. Storage – space and deliverability

The Output section of the template was completed by Enbridge, Union, TCLP and Vector for the years 2006 to 2012. These stakeholders provided both capacity and cost estimates for Dawn-to-Parkway transmission, upstream capacity, storage space and deliverability, Meters and Regulation and Pipeline Laterals. The template also provided annual estimates of total TWh of new gas-fired generation for each scenario as well as an estimate of the percentage share of the total Ontario demand that gas-fired generation would represent.

Similar templates were provided for the same time period but with the 2007-2012 new gas-fired generation fleet delayed one year.

Sample Scenario Template

2006	LOW		MEDIUM		HIGH	
	Available	Required	Available	Required	Available	Required
2006 Capacity (MW)	28655	27003	28655	28037	28655	28151
Above Reserve		1652		618		504
Demand (TWh) 2006		151		157		160
GENERATION LOCATION						
West of Dawn		0		0		0
Downtown GTA		0		0		0
East of GTA		0		0		0
West of GTA		90		90		90
North West		0		0		
SUBTOTAL NEW		90		90		90
NEW COGENERATION						
West of Dawn						
Downtown GTA						
East of GTA						
West of GTA						
North West						
SUBTOTAL NEW COGEN		0		0		0
TOTAL NEW GFG		90		90		90
GENERATION TYPE	**LF**	**MW**	**LF**	**MW**	**LF**	**MW**
Baseload	85%	90	85%	90	85%	90
Intermediate	25%	0	45%	0	50%	0
Peaking	5%	0	5%	0	7.5%	0
Average Utilization	85%		85%		85%	
ANNUAL GAS SUPPLY REQ'D						
New Generation (BCF)						
New Cogen (BCF)						
Delta Existing (BCF)						
TOTAL (BCF)						
GAS SUPPLY SOURCE						
East of Dawn						
West of Dawn						
STORAGE						
Space (BCF)						
Deliverability						
OUTPUTS	**Capacity**	**Cost**	**Capacity**	**Cost**	**Capacity**	**Cost**
Dawn to Parkway						
Upstream Capacity East						
Upstream Capacity West						
Storage Space						
Storage Deliverability						
Meters and Regs						
Distribution Laterals						
TWh New GFG		0.7		0.7		0.7
% Gas Share New GFG		0.4		0.4		0.4

Assumptions

The following assumptions were made to develop the estimates in the scenarios:

Base Case Assumptions

1. Adequate transmission would be built to and across Ontario.
2. Required expansion of storage space and deliverability would be provided by Ontario service providers.
3. Ontario Distribution infrastructure can be built to meet needs of generators on a timely basis (1-2 years).
4. One LNG facility on St. Lawrence would be completed post 2010 and would be tied into the eastern end of TCPL system.
5. All major TCPL contracts would either be renewed or converted to short haul contracts during the forecast period.
6. There would be a significant move to short haul Dawn delivery versus long haul TCPL and or Alliance/Vector.
7. The misalignment of the Ontario power and gas dispatch windows would be resolved by November 2007.
8. New gas services for generators would be developed and introduced into Ontario.
9. The OPA power contracts, incentives and pricing would not preferentially discriminate against nor favour a gas delivery route.
10. Some form of Day Ahead Market will be introduced post 2008.
11. Generation from coal generation facilities will be replaced at approximately 40% utilization for a total of about 26.8 TWh.
12. New gas services for generators developed and introduced into Ontario.

Table A1 - IESO's New Gas-Fired Generation Timeline was incorporated into the scenario development discussed in section 5.2.2.		
DATE	FACILITY	CAPACITY (MW)
2005	Greater Toronto Airports Authority	90
2007	Thunder Bay 3 converted	150
2007	Thunder Bay 2 converted	150
2007	Greenfield South Power Project	280
2007	Greenfield Energy Centre	1005
2007	Cogeneration 1st tranche	500
2008	St. Clair Power[10]	570
2008	Cogeneration 2nd tranche	500
2009	West GTA	1000
2008	Downtown Toronto	500
2009	Greenfield North Power Project[*]	280
TOTAL		5025 MW

[*] Cancelled August 2005.

Table A2

GENERATION LOCATION – MEDIUM SCENARIO (MW)							
NON-COGENERATION	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**
West of Dawn	0	0	1575	1575	1575	1575	1575
Downtown GTA	0	0	0	500	500	500	500
East of GTA	0	0	0	0	0	0	0
West of GTA	90	90	650	1650	1650	1650	1650
North West	0	0	300	300	300	300	300
SUBTOTAL	90	90	2525	4025	4025	4025	4025
COGENERATION							
West of Dawn	0	0	40	40	40	40	40
Downtown GTA	0	0	430	430	430	430	430
East of GTA	0	0	30	30	30	30	30
West of GTA	0	0	240	240	240	240	240
North West	0	300	500	500	500	500	500
NEW COGENERATION	0	300	1240	1240	1240	1240	1240
TOTAL NEW GFG	90	390	3765	5265	5265	5265	5265
GENERATION LOCATION – LOW SCENARIO (MW)							
NON-COGENERATION	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**
West of Dawn	0	0	1575	1575	1575	1575	1575
Downtown GTA	0	0	0	500	500	500	500
East of GTA	0	0	0	0	0	0	0
West of GTA	90	90	650	1000	1000	1000	1000
North West	0	0	300	300	300	300	300
SUBTOTAL	90	90	2525	3375	3375	3375	3375
COGENERATION							
West of Dawn	0	0	30	30	30	30	30
Downtown GTA	0	0	323	323	323	323	323
East of GTA	0	0	23	23	23	23	23
West of GTA	0	0	180	180	180	180	180
North West	0	0	375	375	375	375	375
NEW COGENERATION	0	0	930	930	930	930	930
TOTAL NEW GFG	90	90	3455	4305	4305	4305	4305
GENERATION LOCATION – HIGH SCENARIO (MW)							
NON-COGENERATION	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**
West of Dawn	0	0	1575	1575	2075	2075	2075
Downtown GTA	0	0	500	500	500	500	500
East of GTA	0	0	0	200	200	200	200
West of GTA	90	90	1650	2150	2150	2150	2150
North West	0	300	300	300	300	300	300
SUBTOTAL	90	390	4025	4725	5225	5225	5225
COGENERATION							
West of Dawn	0	0	40	50	50	50	50
Downtown GTA	0	0	430	538	538	538	538
East of GTA	0	0	30	38	38	38	38
West of GTA	0	0	240	300	300	300	300
North West	0	0	500	625	625	625	625
NEW COGENERATION	0	0	1240	1550	1550	1550	1550
TOTAL NEW GFG	90	390	5265	6275	6775	6775	6775

Key Events

On June 15, 2005 Minister Duncan requested that the OPA commence renegotiation of certain "Early Mover Projects" supply contracts. Subject to the objective of displacing coal-fired generation, OPA has been directed by Minister Duncan, in a letter dated June 15, 2005, to negotiate, execute and deliver contracts for certain power generation projects. These renegotiated contracts will be subject to Ontario Energy Board approval.

- The applicable projects are those which: entered into service subsequent to passage of the Electricity Act, 1998; have no existing contract with a government body for any part of their generation; are not eligible for consideration under the Renewables Request for Proposals; and, apart from timing (hence the term "Early Mover Projects"), otherwise would have been eligible for consideration under the government's Clean Energy Supply Request for Proposals. Approximately 1315 MW of capacity are included in the renegotiation. It is possible, assuming successful conclusion of these negotiations that as a consequence of renegotiation of these contracts that incremental gas supplies could be required to provide additional gas service to these existing plants that have been running at lower utilization rates. The OPA is targeting to complete these negotiations by December 15, 2005.

On August 12, 2005 Ontario Power Generation announced (http://www.opgdirect.com/info/news/NewsAug12_05-NRUnit2and3.asp) that OPG had decided not to proceed with refurbishment of Pickering A units 2 and 3.

On September 6, 2005 the OPA announced that the OPA and Greenfield North Project proponents had mutually agreed not to proceed with this project.

On September 16, 2005 the OPA announced the RFP for the West GTA and Combined Heat and Power projects.
(http://www.powerauthority.on.ca/downloads/OPA_Procurement_Release.pdf)

- West GTA Timetable
    - Procurement processes to be launched as soon as possible, and no later than fall 2005. Contracting for some of the projects to be conducted by early 2006.
- Combined Heat and Power Timetable
    - Procurement processes to be launched as soon as possible, and no later than fall 2005. Contracting for some of the projects to be conducted by early 2006.

On September 28, 2005 St. Clair Township denied an application for rezoning by Invenergy.

On October 17, 2005 Bruce Power announced its intention to proceed with the refurbishment of Bruce 1 and 2.

On October 28, 2005 OPA announced that it was negotiating directly with proponents of the Goreway project (in Brampton) for up to 900 MW of gas-fired capacity.

Appendix 3: Generator Services Summary

ERA completed research on six jurisdictions (Alberta, California, Illinois, Michigan, New York and Great Britain) as well as a high level overview of Federal Energy Regulatory Commission policy regarding gas regulation. Table B1 summarizes the jurisdictional review. The jurisdictional research provides: an overview of each market (both gas and power), its deregulation evolution, a description of its storage and transmission facilities, and a description of the primary services that are available to gas fired generators. The complete report is available on the OEB's website.

Below is a summary of five jurisdictions that currently offer services to generators. These jurisdictions were selected because they illustrate a range of services that Ontario generators have indicated that they would be interested in having available in Ontario. These services provide generators with the flexibility to receive and deliver gas on a firm basis at an hourly rate of delivery that enables generators' to more closely match their gas supply arrangements with their power dispatch requirements. These services assist generators to more effectively manage their gas supply acquisition and risk management activities. In addition, generators are allowed flexibility to terminate supply and/or redirect gas on short notice.

Portland Natural Gas Transmission System

HRS (Hourly Reserve Service) - Approved March 25, 2004

Service Characteristics:

- Designed to provide options and flexibility to shippers serving electric generators, whose requirements are: non-uniform intra-day delivery, accelerated flow rates, and minimum delivery pressures during particular periods of the gas day.
- Firm transportation (FT) service up to a specified Maximum Hourly Quantity (MHQ), and Maximum Daily Quantity (MDQ);
- Delivery of MDQ at accelerated rate over a specified number of hours during gas day;
- Non-discriminatory, first-come, first-served basis;
- Single Primary Delivery Point with right to utilize any other delivery point on a secondary basis at a uniform hourly flow basis
- 4.16% up to 8.33% of MDQ (Note that normal pipeline delivery rates are 5% of the MDQ taken over a 20 hour period while 4.16% would be the MDQ taken over a 24 hour period and 8.33% would be the MDQ accelerated over a 12 hour period).
- Higher reservation rate for the additional firm capacity required to provide the higher hourly deliverability.

Rates:

- Bifurcated reservation rate
    - capacity reservation rate; and
    - deliverability reservation rate
- Derived from the FT reservation rate of $25.8542/month.

- Maximum capacity reservation rate (for 8.33%) = $12.9271/month/Dth (i.e. one-half of the existing FT reservation rate). The deliverability reservation rate varies based on firm hourly flow rate elected. The higher the firm hourly flow rate, the higher the deliverability reservation charge.
- Zero usage rate (i.e., the variable rate component of the tariff is zero)

Vector Pipelines L.P.

Hourly Firm Service (FT-H) - Approved January 29, 2004

Service Characteristics:

- Accommodate needs of electric generators who require accelerated flow rates on short notice during limited periods of time within a gas day.
- FT-H service is available to any shipper that satisfies eligibility criteria;
- Can take up to its MDCQ within designated periods of time in one hour increments between one and twenty-four hours;
- Shipper elects a contract quantity and selects whether to receive its entire contract capacity over any hourly period within the gas day, but for not less than a four hour period
- Chooses an hourly delivery quantity within the delivery day;
- Eligible for FT-H service only at points directly connected to Vector's system that have electronic flow equipment. FT-H service is restricted to only one contract per delivery point because Vector cannot distinguish among multiple contracts delivering at the same point; and
- Nominated and scheduled daily but may nominate by telephone up to one hour before the start of delivery.

Rates:

- Derivative of FT-1 service, adjusted to reflect the value of accelerated delivery;
- The maximum reservation rate is the product of: 1) the contract quantity times 24 hours divided by the minimum hourly delivery period and 2) the maximum reservation rate for FT-1 service;
- The usage rate for FT-H is $0.00 per Dth (Decatherm); and
- Dth charge for each Dth taken in excess of its contracted hourly delivery quantity. Charge based on Unauthorized Overrun Charge.

CenterPoint Energy Gas Transmission Company

Hourly Firm Transportation Service (HFT) - Approved June 16, 1999

Service Characteristics:

- Designed to serve peaking needs of electric generation customers and others with similar requirements by allowing them to purchase capacity on an hourly basis.

- Adapted from existing FT with the essential difference being that minimum duration of service HFT is one hour
- Contracting for service will be done over the internet;
- Maximum term of service agreement is 90 days;
- Service agreements may not be entered into more than 30 days prior to the effective dates;
- Imbalance resolution will be tailored to the hourly nature of the service;
- Shippers will have capacity release and flexible receipt and delivery point rights corresponding to those of FT shippers; and
- HFT may bump interruptible service on as little as one hour's notice.

Rates:

- The rate comprised of a reservation rate, a commodity rate and an overrun rate.
- Reservation rate is derived from the maximum FT reservation rate by converting the FT rate from a monthly to a unit rate, then multiplying the unit rate by 24 hours to derive the daily recovery rate, which is then divided by the projected 8 hours of usage per day
- Commodity rate same as FT

Regulatory:

- No costs relating to existing services were reallocated to service under HFT.
- HFT revenues included as short-term firm revenues in the crediting calculations provided for in GT&C.

ANR Pipeline Company

FTS-3 Service - Approved March 20, 2000

Characteristics:

- Permits shippers to have variable hourly flow rights, short notice commencement and shut-down of service and flexibility to manage variances between receipts and deliveries.
- Shippers select a Maximum Daily Quantity (MDQ) and a Maximum Hourly Quantity (MHQ) set at no less than 1/24th of the MDQ and no greater than 1/4th of the MDQ;
- The highest rate of hourly flow that a shipper can elect enables delivery of daily entitlement in four hours
- Above MDQ further capacity only is available on an interruptible basis as overrun of the MDQ or MHQ.

Rates:

- Priced higher on a unit basis than the other firm services to reflect the additional features and flexibility underlying the services.
- Calculated using other firm service rates such as no-notice service and storage service.
- Pay three parts:

  a) deliverability reservation rate for the amount of MHQ reserved;

  b) capacity reservation rate for the amount of MDQ reserved; and

  c) a commodity rate for each dekatherm of gas delivered.
- The unit rate is the result of hourly flow election. As it increases, monthly charges increase proportionately.

  Note: ANR also introduced Rate Schedule ITS-3, an interruptible hourly service.

Texas Eastern Transmission

MLS-1 (Lateral Line only) Service - Approved June 12, 2002

Characteristics:

- Will build necessary facilities to provide firm hourly flexibility under MLS-1.
- Available to any party requesting firm or interruptible service on a portion of Texas Eastern's system designated as a Market Lateral;
- A 'lateral line only' service with no transportation rights, secondary or otherwise, other than on the designated Market Area Lateral;
- the Maximum Daily Quantity (MDQ) and the Maximum Hourly Quantity (MHQ) to be delivered, not to exceed for the Gas Day MDQ;
- Required to pay incremental facilities required to provide requested service, including cost of the lateral if necessary;
- Service restricted to lateral and is entirely separate and distinct from Texas Eastern's service under other open access rate schedules;
- Firm customers will have secondary and capacity release rights only on the lateral;
- The firm hourly rights applicable only as to flows between the Primary Receipt Point and Primary Delivery Point(s) on the lateral; and
- The firm hourly swing service provided by the creation of additional line pack in Texas Eastern's pipeline system and installation of a new compressor unit (for this particular customer).

Rates:

- Customer pays an incremental rate for this service, based on cost of facilities needed to provide the service.

- Incremental reservation rate charged for the service includes cost of the line pack necessary to provide the required pack and draft service.
- The recourse rate for service under MLS-1 is a 100% reservation rate.
- This rate is over and above the rate paid for firm transportation on Texas Eastern’s mainline from the receipt point to the lateral where the MLS-1 service is provided.

Table B1: Service Summary

UTILITY	SCHEDULES/SERVICES
Alberta	
Nova Gas Transmission Ltd	Facilities Connection Service
EnCana Gas Storage	A multi-time nomination schedule with intra-day nominations and the possibility of multiple storage cycles
ATCO Midstream Carbon Storage	Multi-cycling and intra-day nominations
California	
El Paso Natural Gas	-Firm transportation service (FT-1 and FT-2) -Interruptible transportation service (IT-1) -Interruptible parking and lending service (PAL)
Mojave Pipeline Company	-Interruptible authorized loan service (ALS-1) -Parking service (APS-1)
SoCalGas	-Electric generation rate GT-F5 -GN-10 gas rate is a 3-tier gas rate that includes both transportation and the cost of natural gas
PG & E	-Schedule G-EG for electric generators - A "Timely Nomination" -An "Evening Nomination" -An "Intraday 1 Nomination" -An "Intraday 2 Nomination"
SoCalGas Storage	-BSS, or "Basic Storage" -LTS, or "Long Term Storage" -TBS, or "Transaction Based Storage"
Illinois	
ANR	Firm transportation service, FTS-3
Panhandle Eastern	-Hourly Firm Transportation Service -Enhanced Firm Transportation Service -Quick Notice Transportation Service
Midwestern Gas	-Firm Transportation Service

UTILITY	SCHEDULES/SERVICES
Peoples Energy	-Contract Service for Electric Generation - Standby Service
Northern Illinois Gas Company	-Rate 11 includes the provision of gas supply -Rate 81 is a transportation rate -Large Volume Transportation Service, Rate 77
Panhandle Eastern	-Flexible Storage service -Parking and loan service
Michigan	
ANR Pipeline Company (ANR)	FTS-3 (firm transport) ITS-3 (Interruptible transport) Premium no-notice service ("NNS")
Panhandle Eastern PipeLine Company, LP	-Standard FT and IT services -Hourly Firm Transportation -Quick Notice Transportation -Enhanced Firm Transportation -Gas Parking Service -Flexible Storage Service -No Notice Service -Flexible Field Zone Firm Transport -Intraday Gas Parking Service -Delivery Variance Service
New York	
Iroquois Gas Transmission System, L.P	-Firm (RTS) and Interruptible (ITS) transportation -Park and Loan Service (PALS)
Empire State Pipeline-Intrastate	-Timely Nomination Cycle -Evening Nomination Cycle -Intra-day 1 Nomination Cycle -Intra-day 2 Nomination Cycle
The New York State Electric & Gas Corporation	Basic electric generation transportation service

Appendix 4: Assessment of New Facilities/Expansions

The description in this section of the Board's approach to new facilities' investment is necessarily a summary of a fairly thorough review. As indicated in the section 7.1.1 of the Report, Board staff are of the view that the Board's current approach is sufficiently robust to incorporate the concerns respecting investments in facilities to serve new gas-fired power generation. In light of this, a more detailed discussion of the current approach is set out below:

- **Project Need**

  For the Board to be satisfied that the construction of a transmission pipeline and/or storage facility is in the public interest, the gas utility must outline the project need in detail. Project need includes information on economic feasibility, security of supply and safety. The economic feasibility of the project is a three–stage analysis based on the principles outlined in EBO 134 dated June 1, 1987[11]. *Stage 1* consists of a discounted cash flow (DCF) where all incremental cash inflows (i.e., projected revenues based on demands) and outflows (i.e., project costs) are identified. The net present value (NPV) of the cash inflows is divided by the NPV of the cash outflows to arrive at a profitability index (P.I.). The P.I. must be equal to or greater than 1.0 for the project to be considered economic based on current approved rates. *Stage 2* occurs when the NPV is less than $0 (or the PI is less than 1.0) and this consists of a benefit/cost analysis to quantify benefits and costs accruing to customers. The NPV of the net benefits need to be greater than $0 for the project to be considered in the public interest. *Stage 3* analysis considers additional benefits and costs related to the construction of the proposed facility.

  For projects with a negative DCF, the gas utility must identify the revenue required and the sources of the necessary additional revenue. The sources could include contribution in aid of construction (CIAC) or a proposal to increase rates. With a dedicated pipeline lateral, the generator would be the source of the additional revenue (i.e., CIAC would be required to recover the costs of any NPV shortfalls). On the other hand, if the pipeline and/or storage space is used by many customers (e.g., LDCs, industrial users, power producers, other pipelines, marketers, etc.), NPV shortfalls are recovered through a rate increase to all customers.

  To calculate the projected revenues in stage 1, the gas utility must provide evidence that the need is long-term and not a temporary or short-term requirement. This will include providing the Board with revenues from transportation/storage capacity contracts. These contracts can be obtained through an Open Season bidding process. The open season will determine the firm transportation and/or storage contracts to support the gas utilities proposed expansion plans.

  In addition, information on improvements to security, reliability and diversity of supply will be assessed.

[11] EBO 188 dated January 30, 1988 also outlines principles to determine economic feasibility using a portfolio approach. Distribution expansion activities are managed to ensure the portfolio P.I. is equal to 1.1 and on a project-by-project basis the P.I. must be at least 0.80.

- **Customer Impacts.** Customer impacts include benefits, reliability improvements, quality of service, any rate impacts, etc. Community benefits include increased employment.
- **Competitive Market Impacts.** Competitive market impacts include ensuring liquid market hubs, reducing barriers for competitive supplier to enter market, increasing price transparency, and improving supplier flexibility.
- **Alternative Options.** Other options and associated economic feasibility and the reasons why these alternative options were not chosen.
- **Facilities Specifications.** Outline of the proposed expansion will include general routing description, design specifications and capacity. In addition, the Board requires evidence that the pipeline will operate in accordance with current CSA standards.
- **Project Costs.** Outline of the estimated costs to allow the Board to determine the reasonableness of the costs. These estimated costs of the proposed facilities will include: labour costs, material costs, land acquisition costs, overhead costs, and external costs associated with environmental measures. This will also include the least cost alternative to the proposed facilities.
- **Financial Risk.** Financial status and financial structure are sufficient. Outline financial agreements (and associated conditions and terms) between parties to allow the Board to identify and minimize risks to consumers.
- **Construction and In-Service Schedule.** Outline of the major construction activities and in-service schedule to provide the Board with time estimates and service dates.
- **Environmental Impacts.** Project must comply with the latest edition of the OEB's Environmental Guidelines. Other material such as right-of-way matters, easement agreements, etc. are to be outlined.