Appendix 1:

2013 Special Reliability Assessment:

Accommodating an Increased Dependence on Natural Gas for Electric Power

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NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

2013 Special Reliability Assessment:

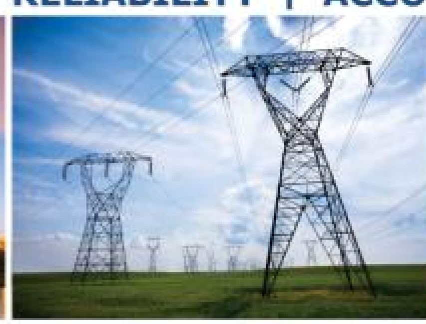
Accommodating an Increased Dependence on Natural Gas for Electric Power

Phase II: A Vulnerability and Scenario Assessment for the North American Bulk Power System

May 2013

RELIABILITY | ACCOUNTABILITY



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Acknowledgements

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NERC Board of Trustees
NERC Members Representative Committee Members
NERC Planning Committee Members
NERC Operating Committee Members
NERC Reliability Assessment Subcommittee Members
The Interstate Natural Gas Association of America
The Natural Gas Supply Association
The Electric Power Supply Association
ICF International, Inc.
Energy Ventures Analysis

NERC also expresses appreciation to the regional study groups across North America that have spearheaded robust regional analysis efforts to better understand the gas and electric interface and associated risks.

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Executive Summary

A comprehensive understanding of the complexity of the changing bulk power system is key to developing prompt industry actions that achieve effective reliability outcomes. NERC Reliability Assessments provide a technical platform for important policy discussions on challenges facing the interconnected North American bulk power system. The trends identified in previous Long-Term Reliability Assessments have highlighted significant increases in gas-fired generation to meet increasing electric demand as well as replace retiring coal-fired generation. By identifying and quantifying the risks of emerging reliability issues, NERC is able to provide risk-informed recommendations and support a learning environment for industry to pursue improved reliability performance.

NERC's statutory role is to conduct periodic, independent assessments of the reliability and adequacy of the BPS. NERC's *2011 and 2012 Long-Term Reliability Assessments* identified that increased dependency on gas-fired generation can amplify the exposure of the BPS to disruptions in fuel supply, fuel transportation, and delivery. In light of NERC's effort to incorporate gas–electric interdependencies into its periodic reliability assessments, this report (1) determines the different risks that can affect BPS reliability, (2) identifies ways to minimize vulnerabilities, and (3) identifies areas where coordinated interindustry efforts could provide enhanced system reliability.

The combination of growth in natural gas demand within the electricity sector and its changing status among the gas-consuming sectors continues to significantly increase the interdependencies between the gas and electricity industries. As a result, the interface between the two industries has become the focus of industry discussions and policy considerations. In its effort to maintain and improve the reliability of North America's bulk power system (BPS), NERC examined this issue in detail and developed recommendations for the power industry. These recommendations will help improve existing coordination between the gas and electricity sectors and facilitate the reliable operation of the two industries. NERC approached this issue solely from a reliability point of view.

Addressing interdependence issues requires a coordinated approach for minimizing the risks and vulnerabilities on bulk power and gas systems. This report focuses on the electric industry's dependence on natural gas and offers recommendations for reducing BPS exposure to increasing natural gas dependency risks. As described in NERC's *2011 Special Assessment Report: A Primer of the Natural Gas and Electric Power Interdependency in the United States*, the key findings and recommendations presented in this report apply to natural gas used for power generation for several reasons:

1. Over the past decade, natural gas-fired generation rose significantly from 17 percent to 25 percent of U.S. power generation and is now the largest fuel source for generation capacity. Gas use is expected to continue to increase in the future, both in absolute terms and as a share of total power generation and capacity.

2. Unlike coal and fuel oil, natural gas is not easily stored on-site. As a result, real-time delivery of natural gas through a network of pipelines and bulk gas storage is critical to support electric generators.

3. Natural gas is widely used outside the power sector, and the demand from other sectors—particularly coincident end-user gas peak demand during cold winter weather—critically affects the ability to deliver interruptible transportation service in the power sector. Additionally, demand for natural gas is expected to grow in other sectors (e.g., transportation, exports, and manufacturing).

4. While extremely rare, disruptions in natural gas supply and/or transportation to power generators have prompted industry to seek an understanding of the reliability implications associated with increasing gas-fired generation. Contracts for firm natural gas supply and transportation affect the risk profile of each power plant (or group of power plants); therefore, a framework for analysis is needed to understand the cumulative impacts of an area's gas-fired capacity.

5. Natural gas is expected to play a growing role in offsetting the variability and uncertainty associated with renewable resources, mainly wind generation. As variable generation increases, swings in variable generation may call for dispatch of gas-fired generation at a larger and less predictable rate.

The electricity sector's growing reliance on natural gas raises concerns from Independent System Operators (ISOs), Regional Transmission Organizations (RTOs), market participants, industrial electricity and gas consumers, national and regional regulatory bodies, and other government officials regarding the ability to maintain electric system reliability when the capacity to deliver natural gas supplies to power generators is constrained. The extent of these concerns vary from region to region; however, they are most acute in areas where power generators rely on interruptible gas pipeline transportation and where the growth in gas use for power generation is growing the fastest.

Accordingly, this has refocused gas supply and infrastructure adequacy concerns in some areas, causing industry and policymakers to refocus attention on gas–electric interactions. Several regional efforts have been made—including NERC's own—to analyze the potential problem and to consider fuel supply and transportation adequacy as a formal part of electric reliability assessments.

NERC assesses reliability concerns based on fundamental principles: BPS reliability must be maintained, regardless of the generation mix and all generation must contribute to system reliability within its physical capabilities. Therefore, solution sets that are implemented in the future should consider the reliability concepts presented in this report. Additionally, a constant theme throughout this report is the need for inter-industry coordination be focused at the regional level, because of both significant differences in operational characteristics as well as regulatory rules and market environments.

NERC will determine if further action on this issue is necessary by using an advisory committee for strategic guidance. This includes organizing a group of subject matter experts, allowing for technical committee reviews, and prioritizing risks. Risk management is inherent in the electricity industry's role in providing reliable power to its customers. However, it is important to acknowledge that reliability comes at a cost, and the electricity industry must be positioned to maintain reliability taking into account future changes to the resource mix. Policymakers and regulators should address the issue of cost and find the right balance between electric reliability and the increased costs associated with it.

This report is an effort to explain the main analytic issues, offer suggestions on how natural gas supply and pipeline adequacy can be measured, and incorporate those results into both short-term and long-term resource adequacy assessments that are conducted by the electricity industry. When analyzing and discussing risks from gas dependencies, it is essential that vulnerabilities and associated impacts are distinctly discussed—those that are related to unexpected disruptions to natural gas facilities (leading to natural gas curtailments) and those that are related to gas transportation interruptions.

The degree of industry response and action is dependent on the region-specific challenges. In regions where this issue is emerging on a broader scale, enhancements to planning processes that integrate gas availability into resource planning analyses will likely be the first course of action. Through comprehensive analysis, vulnerabilities can be identified in the planning stages (1 to 10 years) and risks can effectively be managed. These studies provide the foundation for state, federal, and provincial regulators, policymakers, and system planners to implement changes and send accurate signals to the electricity market for future needs of the bulk power system. Additionally, these studies allow for solution sets to be measurable and achievable. Accurate representations of potential vulnerabilities through comprehensive planning studies are key in aiding risk-informed policy decisions.

From an operations perspective, seasonal preparations, operational planning, and real-time operating procedures need to reflect formalized coordination with the gas pipeline industry, with specific focus on emergency procedures during extreme events.

Key Findings and Recommendations

NERC's key findings in this report are categorized into two planning and operating timeframes: Long- and Short-Term Planning and Operational Planning and Operations. The recommendations presented below are intended to provide a platform for further technical and policy input. More details on the key findings and recommendations can be found in Chapter 9.

Long- and Short-Term Planning Findings	Operational Planning and Operations Findings
•Reliability assessment and resource adequacy studies •Gas supply and fuel security •Transportation expectations •Generator availability •Back-up fuel and fuel-switching capabilities	•Seasonal and day-ahead observability •Coordinated operational procedures •Coordinated outage schedules •Increasing flexibility •Information sharing and situation awareness •Emergency operating procedures

Long- and Short-Term Planning Summary

Key Finding: Risk-based approaches are needed to study the impact and regional challenges associated with an increasing dependence on natural gas.

The power sector's growing reliance on natural gas has raised concerns by ISOs, RTOs, market participants, national and regional regulatory bodies and other government officials regarding the ability to maintain electric system reliability when natural gas supplies to power generators are constrained. The extent of these concerns varies from region to region; however, concerns are most acute in areas where power generators rely on interruptible gas pipeline transportation and where the growth in gas use for power generation is growing the fastest. Because it typically takes three to four years to build pipeline infrastructure, solution sets that call for increased pipeline capacity must be developed as quickly as possible so the electric industry is well postured to manage the regional challenges and emerging risks associated with an increasing dependence on natural gas.

Recommendations:

- Implement advanced modeling and analysis approaches. NERC recommends the Three-Layer approach or similar advanced probabilistic techniques.
- Enhance the NERC Generator Availability Data System (GADS) to increase the effectiveness of trending gas-fired generator outages and causes related to fuel issues.

Key Finding: Enhancements to reliability and resource assessments should reflect risks to gas-fired generation as a result of various fuel disruptions.

Natural gas is a reliable fuel source that is expected to fire electric generation serving more than 50 percent of the electric peak demand in North America by 2015. However, because natural gas is largely delivered on a just-in-time basis, vulnerabilities in gas supply and transportation from a planning perspective must be sufficiently evaluated to inform BPS operators about credible contingencies and flexibility options. Resource planning and adequacy assessments in some areas do not fully account for the risk of disruptions in the natural gas and other fuel supply chains.

For example, electric system impacts due to a single point of failure within the natural gas fuel supply chain can impact electric generators downstream from the disruption. Impacts of potential wide-spread common-mode failure events, such as a major failure along an interstate gas pipeline or major supply source, although rare, must be well understood to foster enhanced planning and design insights.

Pipelines are able to operate with temporary supply disruptions, provided the gas pressures are maintained within acceptable limits. However, within a relatively short time, a major failure could result in a loss of electric generating capacity that could exceed the electric reserves available to compensate for these losses. The likelihood of pipeline failures occurring during electric peak periods, however, is extremely low.

By integrating these risks into planning studies, potential generator outages due to natural gas interruptions and curtailments can be better understood. Through rigorous analysis, vulnerabilities can be identified in the planning stages (1 to 10 years) and risks can effectively be minimized. These studies provide the foundation for state, federal, and provincial regulators, policymakers, and system planners to implement changes and send accurate signals to the electricity market for future needs of the bulk power system. Additionally, these studies allow for solution sets to be measurable and achievable.

Recommendations:

- Incorporate natural gas fuel availability or natural gas-fired generation availability into the NERC Long-Term Reliability Assessment and Seasonal Reliability Assessments.
- Identify how risk assessments are performed in different regions and use this information to develop recommendations for a uniform seasonal and long-term reliability assessment process for consideration by NERC Planning Committee.
- Improve Generator Owner procedures and methods to maintain fuel switching capabilities.
- Enhancements to market products supporting higher levels of fuel certainty should be considered (i.e., adequate level of fuel inventories and functional capability testing and/or firm natural gas transportation).
- NERC should support further studies for enhancing planning processes that relate to fuel availability and resource adequacy.

Key Finding: Regional solutions will likely include a mix of mitigating strategies, increased gas and/or electric infrastructure, and dual or back-up fuel capability.

Dual-fuel capabilities and a variety of storage options may help bridge the gap between the uncertainties of gas availability during extreme events and maintaining a reliable source of operable capacity available to meet seasonal peak demands.

Based on the reserve margin scenario assessments performed as part of this report's efforts, many of the NERC assessment areas have sufficient reserve margins to mitigate the loss of a significant portion of their gas-fired generation.

Electric transmission increases the bulk power system's flexibility and resilience to various disruptions. Efforts to manage gas supply and transportation disruptions should consider the benefits of electric transmission.

Although generators may have contractual obligations to perform, performance incentives, particularly in competitive wholesale electricity markets, may not be strong enough to incentivize generators to procure firm or otherwise reliable fuel supplies (natural gas supply and transportation, oil, or other mitigating strategies).

Risks to gas supply shortages can largely be mitigated or reduced with the abundance and geographic diversification of shale plays across North America. With unconventional shale gas production spread across the continent, vulnerabilities in gas supply due to weather events can be mitigated or reduced by increasing production in unaffected areas.

Recommendations:

- Policymakers and regulators should consider developing solutions that provide the right balance between electric reliability and the increased costs associated with it.

Key Finding: Enhancements to data sharing and planning coordination can provide insights through additional studies and scenario analysis.

There is no compiled statistical data on gas system outages that would be the equivalent to NERC GADS databases. Therefore, outage data would have to be estimated from various surrogate sources, including pipeline bulletin board notices, accident reports filed with government agencies, surveys of pipeline and distribution companies in the study region, and maintenance and repair information from equipment manufacturers and service companies. This type of information is important for complex analyses that rely on past performance to achieve an acceptable level of prediction and certainty. Increased coordination and information exchange for planning purposes could aid in developing confidence around a distribution of potential scenarios.

Recommendations:

- Work jointly with the natural gas industry to identify data requirements that can be used for electric reliability analysis.
- Planning Coordinators and/or Reliability Coordinators should identify critical gas-fired electric generation to ensure "critical generators" have the ability to mitigate or reduce the risks associated with fuel disruptions and curtailments.

Operations and Operational Planning

Key Finding: Sharing information for operational planning purposes is essential to fully understanding generator availability risks in the season ahead.

While Generator Owners are generally able to schedule and secure gas during the summer to meet seasonal peak demand, this flexibility decreases during winter months when pipeline use tend to peak and firm transportation customers have scheduled their full entitlements. Cold weather can also be responsible for increased infrastructure and supply disruptions, which are generally caused by freezing. Risks to gas wellheads, generators, and pipeline infrastructure due to freezing can expose the electric industry to significant capacity shortages. While firm gas transportation significantly decreases the likelihood that fuel delivery will be curtailed, extreme events, such as wellhead freeze-offs causing decreased gas production (a force majeure event), could potentially lead to common-mode failures of a significant amount of gas-fired generators. The expected increases in gas-fired generation on the BPS will increase the amount of operational uncertainty that the system operator must factor into operating decisions.

Recommendations:

- Increased situation awareness of the natural gas supply and pipeline system enhances the electric system operator's ability to make risk-informed decisions.
- In preparation for summer and winter extreme conditions, electric system operators need enhanced observability of pipeline conditions, capacity availability, supply concerns, and potential issues affecting fuel for gas-fired generation.

Key Finding: Formalized communication and coordination with the gas pipeline and supply industry during extreme events is needed.

Information on daily fuel supply adequacy and less probable contingencies on the gas pipeline or compressor stations which could result in loss of multiple gas-fired units should be provided to electric system operators with as much notice as possible.

Both industries have stated that there are sufficient coordination practices at this time and enhancements planned for the future. Based on these practices, operational procedures should include formalized coordination with the gas supply and pipeline industry, as well as emergency procedures during extreme events. Timely information sharing is most important when natural gas suppliers and pipeline operators can determine that a potential shortages or interruptions may occur due to usage and transportation outages.

Recommendations:

- System operators should re-examine interindustry communication protocols that apply during periods of stress

Key Finding: System operators will need access to sufficient flexible resources to mitigate the added uncertainty associated with natural gas fuel risks, including those introduced by interruptible gas transportation service.

Operating criteria, forecasting, commitment, scheduling, dispatch and balancing practices, procedures and tools should consider fuel risks and risk mitigation measures to assist operators in maintaining bulk power system reliability. Enhanced operator training should be considered in light of the increasing need for electric and pipeline operator communication and coordination. Training crosses a number of areas, some of which are specific to each industry, while others likely represent interindustry efforts.

A projection of flexibility can also provide additional observability to the system operator in order to maintain operational reliability; however, this can only be made with enhanced coordination with gas-fired generators and the natural gas pipeline operators. In response to gas disruptions, electric system operators should be able to identify vulnerable capacity, determine if reserve capacity is available, dispatch the appropriate resources, implement any operating procedures, and minimize any impacts caused by fuel disruptions.

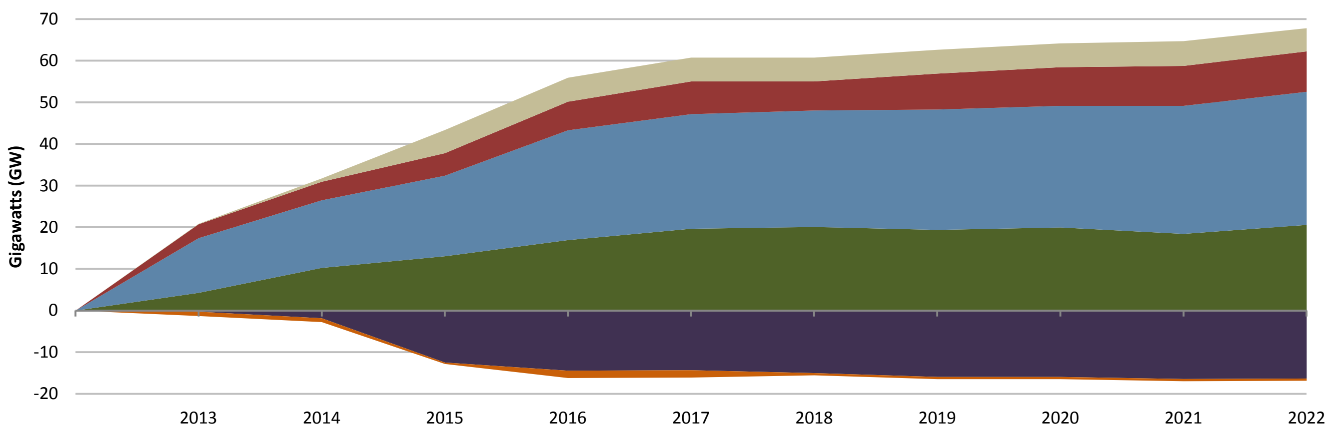
Recommendations:

- NERC should leverage its stakeholder groups to identify best practices in areas currently most vulnerable to gas dependency risks and taking immediate actions for improvement, such as New England. Such an effort could lead to insights for enhanced operator training and table-top exercises.
- Joint industry drills or table-top exercises with the key players of both gas, electric, and various state commissions would foster enhanced coordination and harmonize cross-industry issues, response plans, and mitigation measures.

Chapter 1—Introduction

For a variety of reasons, including (a) the adoption of efficient natural gas-fired combined-cycle and combustion turbine technology by the electric power industry and (b) the emergence of shale gas, both of which have altered the relative economics of gas-fired generation, the natural gas and electric power industries have become significantly more interdependent. The trends in fuel-mix changes highlighted in NERC's *2012 Long-Term Reliability Assessment* (see Figure 1) identify gas-fired generation as the primary choice for new generation capacity. Continued high levels of dependence on natural gas for electricity generation have increased the BPS's exposure to interruptions in fuel supply, transportation, and delivery. Efforts to address this dependence must be sustained and expanded in order to analyze potential risks in the future.

Figure 1: NERC-Wide Planned Capacity Additions



		Current		2022 Planned			2022 Planned & Conceptual		
		Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
Coal		307,201	29.78%	290,915	26.86%	-16,286	278,775	22.61%	-28,426
Petroleum		52,498	5.09%	51,954	4.80%	-544	51,377	4.17%	-1,121
Gas		397,464	38.53%	429,462	39.65%	31,998	529,328	42.94%	131,863
Nuclear		113,821	11.03%	123,525	11.41%	9,704	136,361	11.06%	22,540
Other/Unknown		271	0.03%	5,840	0.54%	5,569	12,683	1.03%	12,412
Renewables		160,420	15.55%	181,311	16.74%	20,891	224,235	18.19%	63,815
TOTAL		**1,031,676**	**100.00%**	**1,083,007**	**100.00%**	**51,332**	**1,232,759**	**100.00%**	**201,083**

While there are a number of positive impacts from increased natural gas use by the electricity industry, the emergence of this interdependency issue has made the power sector more vulnerable to adverse events that may occur within the natural gas industry (e.g., curtailment of gas supplies due to line breaks and well freeze-offs). Similarly, the system reliability of the gas industry can be impacted by events that occur in the electricity industry (e.g., loss of electric compression in the field, at processing plants, or for transportation systems).

This report, which builds on an earlier NERC report regarding gas use within the electric industry,[5] addresses the need to further improve coordination that will lead to enhanced electric system reliability. Coordinated approaches with collaborative interindustry activities will provide enhanced system reliability beyond independent efforts of each industry. A constant theme throughout this report is the need for interindustry coordination to be focused at the regional level due to existing significant operational differences, regulatory rules, and market structures.

[5] NERC, *2011 Special Assessment Report: A Primer of the Natural Gas and Electric Power Interdependency in the United States:* http://www.nerc.com/files/Gas_Electric_Interdependencies_Phase_I.pdf.

This report examines gas-electric interdependency as a long-term resource adequacy issue and therefore excludes specific discussions of best practices for day-to-day operation, and emergency planning between the electric and gas industries. The issue of what additional natural gas infrastructure may be needed nationally or in any given region is not addressed. Finally, this report contains no policy recommendations for changes in market design or regulation that supports any one solution. Instead, the report includes hypothetical case studies and recommendations for general analytic techniques. The report is structured as follows:

- **Chapter 1—Introduction**
  The introduction provides an overview of each chapter in this report and describes the goals and objectives, as well as the parameters of focus.
- **Chapter 2—Interface Between Two Industries**
  This chapter provides an overview of the key attributes of the natural gas loads within the power industry that are challenging for the gas industry to accommodate, as well as the major differences in the planning systems for the two industries. In addition, this chapter briefly summarizes historical efforts to both analyze and facilitate increased coordination between the two industries.
- **Chapter 3—Gas Supply Vulnerabilities**
  The power industry's recent increased reliance on gas-fired generation and the expected further growth of gas-fired capacity has elevated concerns over fuel supply and delivery. Although small in number, there have been interruptions of gas supply and delivery to both electric generators, as well as consumers within other demand sectors. This chapter highlights several of these historical incidents and potential implications for the power industry.
- **Chapter 4—Scenario Reliability Assessments**
  In this chapter, NERC analyzes hypothetical scenarios and describes the corresponding impact of rare pipeline disruptions. Calculations and estimates of the risk exposure are incorporated in these scenarios. The resource adequacy scenario assessment is intended to illustrate the impacts to planning reserve margin projections due to reduced gas-fired capacity.
- **Chapter 5—Methods for Analyzing Natural Gas Demand and Infrastructure**
  In this chapter, NERC recommends a three-layered approach to the analysis of natural gas demand and infrastructure. Layer 1 is to assess the regional capacity of the gas infrastructure under normal operating conditions, and compare that capacity to the gas load by developing daily and hourly gas load duration curves for a specific set of weather conditions. Layer 2 is to compare the same gas load duration curves to gas infrastructure capacity under assorted gas transportation contingencies, such as a compressor station outage. Layer 3 is to perform a Monte Carlo simulation analysis, which examines a wide range of weather and gas supply conditions to determine how often the existing and projected natural gas infrastructure cannot serve generation needed for power system reliability.
- **Chapter 6—Enhancing Resource Adequacy Assessments**
  This chapter describes how the fuel supply availability analysis would be factored into conventional electric system resource adequacy studies. The section is organized under three subsections. The first section provides a brief description of the resource adequacy concept within the electric power sector. The second section introduces standard resource adequacy modeling approaches. The third section introduces NERC's recommended approach for integrating fuel availability within resource adequacy modeling efforts.

- **Chapter 7—Performance Analysis of Generator Outages**
  This chapter examines the NERC Generating Availability Data System (GADS), a series of databases that tracks the performance of electric generating stations in North America. Using the information gathered in GADS, NERC performed an analysis on generator outages due to "lack of fuel." The analysis provides a means for the power industry to track and trend potential issues that may cause concern in the long term.

- **Chapter 8—Risk Assessment for Electric Reliability**
  The initial sections of this report highlight that natural gas is a reliable fuel source for electric generators; however, during high electric demand, some electric generators are subject to interruptions, which in turn have the potential to adversely impact overall system reliability. This chapter discusses, from several different perspectives, how the risk from this potential vulnerability can be addressed and managed.

- **Chapter 9—Key Findings and Recommendations**
  This chapter provides key findings and recommendations for short- and long-term electric system planning, operational planning, and operations.

- **Appendix I: Consolidation of Reports and Studies**
- **Appendix II: Regional Analysis of Generator Outages**
- **Appendix III: Terms Used in This Report**

Coordination of gas and electric service was first discussed more than a decade ago by the North American Energy Standards Board (NAESB), the Natural Gas Council, and existing and prospective shippers—including shippers that would serve generation. At that time, however, various factors in natural gas markets allowed generators to use available pipeline capacity, largely through interruptible service and released capacity. Drivers for these conditions included:

- The development of the first wave of pipeline capacity turn-back by shippers as alternative transportation paths for natural gas delivery

- Pipelines were originally constructed and paid for by Local Distribution Companies (LDCs) to serve near peak winter heating loads. Power plants were able to use underutilized capacity in the summer and shoulder months.

- A period of high gas prices that moderated gas demand within the industrial sector, thereby freeing up existing pipeline capacity available to power generators, often on an interruptible basis

- The economic recession of 2001, which created further "slack" capacity on many interstate pipelines

Over time, the market for pipeline capacity within some Regions has tightened, changing the ability of generators to reliably obtain interruptible pipeline capacity during higher electricity demand hours.

Natural gas pipeline facilities have been designed and constructed based on peak day firmly contracted capacity. Firm pipeline customers usually contract close to 100 percent of the capacity on a pipeline since capacity is not built to serve interruptible customers. This practice presents issues for gas-fired generators that prefer interruptible transportation service due to variability in volumetric requirements as well as economics.

Over the past several years, the subject of the interdependency of gas and electric service reliability has intensified in many forums. As the amount and dispatch of gas-fired generation increases, the interaction between the electric grid and the gas network can become stressed. These stresses highlight the similarities and differences in the structure, operation, business practices, and communication between the two industries.

In August 2012, the Federal Energy Regulatory Commission (FERC) recognized the need for coordination between natural gas and electricity markets and held technical conferences on coordination between natural gas and electricity markets around the United States. The conferences covered issues such as coordination and information sharing, scheduling, market structures, and reliability concerns. These issues are a reflection of a request for comment from industry participants regarding pressing issues concerning gas–electric integration. Many participants also asserted that issues differ considerably by Region. In recent years, a number of studies have attempted to assess the gas–electric reliability issues. A summary of the findings can be found in Appendix 1. FERC also hosted the Technical Conference titled *Coordination between Natural Gas and Electricity Markets* on February 13, 2013, where the Commissioners, FERC staff, and representatives of both industries shared concerns related to gas–electric coordination and the BPS reliability challenges presented by the interruptible natural gas supply and/or transportation contracts used by power generators.[6]

[6] Industry members have submitted comments to FERC related to this issue under Docket No. AD12-12-000.

Chapter 2—Interface Between Two Industries

There are many differences between the natural gas and electricity industries. The two sectors have very different structures, physical attributes, regulatory processes, and cost recovery mechanisms. The core of these differences is represented by centralized and market driven—to a point—natural gas transportation compared to the more centralized, reliability driven electric transmission development mechanisms.

There are also differences between the two industries in terms of planning and operating practices. For example, the planning process for a new natural gas pipeline and storage infrastructure is based on an underpinning of contracts for firm service entitlements for the contracting party. New or expanded pipeline capacity is only constructed with long-term (at least 10 years) contractual commitments from gas shippers; however, in some cases, suppliers will fund pipeline development to bring their product to a liquid trading hub (i.e., market push). Gas suppliers are often unable to obtain the required certificate for new capacity without these contracts. Within this model, no capacity is constructed specifically to serve interruptible service requirements.

Under average annual operating conditions, most pipelines have some level of capacity that is not used by firm customers and is therefore available for non-firm (interruptible) loads, including gas generators with non-firm contracts. If the requirements for non-firm deliveries are communicated to the pipeline within the nomination cycle timeline, the pipeline can use facilities to allow for delivery of gas requested up to the physical capabilities the system can allow. This is the normal procedure for interruptible transportation service or capacity release from firm shippers.

The structure within the electric industry is fundamentally different. Generation capacity expansions are driven by a combination of resource adequacy requirements and market forces. Planning for transmission infrastructure is triggered by reliability criteria under stressed system conditions; therefore, there is an implicit level of reserve capacity available in the transmission and generation systems to accommodate contingencies or above-normal weather conditions. Furthermore, from an operating perspective, power plant generation follows load to serve the hourly needs of the system. The generating units that are primarily required for reliability during peak conditions tend to run for a very limited number of hours and as a result, generator owners may prefer interruptible gas services. Firm gas transportation services—purchased with fixed reservation fees that do not provide a customer time-of-day use rates and do not vary based upon the volume of gas delivered—may not be cost-effective when considering the annual amount of gas required for these peaking gas facilities.

In some power markets or regions where there is excess gas pipeline capacity available, these low-capacity factor units can rely upon interruptible service with a reasonable degree of certainty that service will be available. As growth in gas system requirements in a region reaches the point where new pipeline capacity is required or when market conditions result in simultaneous peak electricity and gas demand, the differences in the structures of the two industries can result in a mismatch between the availability of gas delivery services and gas demand for electricity generation. This can be particularly challenging in areas where a significant amount of the generation capacity, or more importantly reserve capacity is susceptible to gas transportation interruptions and the resulting generator outages.

Additionally, within the electric industry, regulated utilities have cost recovery mechanisms for fuel supplies and transportation procurement. These mechanisms have incorporated overall cost into the rate case. However, in deregulated markets, accurate price signals reflecting reliability needs and incorporating acceptable risks are vital to maintaining a risk-averse resource portfolio.

Electric and Gas Integration Concerns

Regarding incorporation of natural gas availability into electric system reliability assessments and long-term resource planning, there are differences in the structure and regulation of the two industries that need to be recognized and understood. The following section will discuss specific aspects of the regulatory framework and operational protocols for natural gas interstate pipelines that affect the delivery of natural gas to electric generators.

The growing reliance on natural gas has raised concerns of the ISOs and RTOs, market participants, and national and Regional regulatory bodies regarding the ability to maintain electric system reliability. While natural gas utilities (often referred to as local gas distribution companies) contract for firm pipeline transport and storage capacity and maintain local peak shaving facilities to meet customer demand, many gas-fired electric generators have chosen to rely on interruptible gas transportation services to meet fuel needs. As gas consumption for both power and non-power uses has grown, the availability of interruptible capacity has declined, especially during periods of peak gas demand.[7] Thus, concerns about gas supply and infrastructure adequacy to satisfy future power generation needs have recently re-focused FERC's attention on gas–electric reliability, particularly in regions where generators rely heavily on interruptible gas transportation.

These difficulties are attributed to the electric customer's large point loads, high pressure requirements, significant variation in loads, and non-ratable takes. Each of these characteristics is thoroughly reviewed in Phase I of NERC's special assessment.[8] Also, straining the interface between the two industries is the significant difference in the "electric day" and "gas day" operating schemes used by the two industries. While protocols and tariffs in several Regions have been revised to better accommodate this difference in operational planning days, coordination between the two industries can be strained.

One major concern with current electric reliability assessments is that resource adequacy studies traditionally assume most fuels are always available (fuel expectations for hydro, wind, and solar are generally considered and incorporated into the analysis). These concerns have heightened the interest in studying gas–electric reliability issues and have increased the importance of questions that power market participants, regulators, and system planners have about the adequacy of natural gas to satisfy growing gas-fired generation over time. Some of the specific questions of interest to the electric power industry, regulators, and NERC regarding gas–electric integration and coordination include:

- Is there sufficient physical delivery capability to deliver gas to power plants at a time of peak demand?
- Do gas-fired power plants have contractual call options on gas supply and pipeline delivery capacity at a time of peak demand, and can the power plants be considered firm if they don't have firm gas supply and firm pipeline capacity? If not, what is the probability that interruptible gas transportation will be available?
- How can utilities, electric transmission organizations, and gas pipelines better coordinate the different scheduling and contracting practices to ensure reliable and efficient operation of the gas and electric systems?
- Is there sufficient gas supply (i.e., overall gas resources) from producers to satisfy peak demand in a given power market? Will wellhead gas supplies be affected by more stringent upstream environmental rules?
- How and why might gas supply be limited under certain circumstances (e.g., wellhead freeze-offs and LNG disruption), and how would this impact gas and electric system reliability?
- How and why might delivery capacity be limited under certain circumstances (e.g., compressor or pipeline failure), and how would this impact gas and electric system reliability?

[7] ISO-NE Study and 2012/13 Winter Operations Report: http://www.isone.com/committees/comm_wkgrps/strategic_planning_discussion/materials/winter_operations_summary_2013_feb_%2027_draft_for_discussion.pdf

[8] http://www.nerc.com/files/Gas_Electric_Interdependencies_Phase_I.pdf

- What are the costs of supporting new transmission pipeline infrastructure? What are the benefits of constructing new natural gas pipelines? Is local high-pressure natural gas storage a viable option?
- What are the costs and feasibility of on-site storage (e.g., LNG/CNG[9] storage) and dual-fuel capability as solutions to these problems? Is on-site or portable liquefaction a viable option for peaking facilities? Can LNG be delivered by truck or rail for needed peak facilities that operate a few days a year?
- What are the costs of other solutions, such as coal must-run backup, demand response, or more electric transmission?

Further, a future surge in electricity sector gas demand is expected to occur in response to recent and pending Environmental Protection Agency (EPA) regulations. The latter likely will result in more than 70 GW of coal-fired capacity being retired; much of the reduction in coal-fired generation will be replaced by additional gas-fired generation, demand response, and energy efficiency. While there will be significant variations among the Regions, a critical aspect of the power industry's further dependence on gas-fired generation is that for some electric utilities, gas generation will begin to serve baseload, intermediate load, and peaking load requirements, whereas historically gas-fired generation has been used almost exclusively for intermediate and peaking loads. This shift, which already has occurred in ERCOT, FRCC, and NPCC, is expected to cause a change in the demand for natural gas transportation services, from the historical reliance on interruptible transportation services to more firm transportation services.

Because it typically takes three to four years to build pipeline infrastructure, solution sets that call for increased pipeline capacity must be developed as quickly as possible so the electric industry is well postured to manage the challenges and emerging risks associated with increasing dependence on natural gas.

Differences in Gas and Electric Industry Structures and Coordination Issues

There are several differences in the structure and regulation of the natural gas and electric industries that need to be recognized and understood when considering the coordination and interdependencies of the two industries. These differences affect both the planning and the operating areas. Operational coordination concerns between electric systems and natural gas pipelines include:

- Coordinated business day and bidding/nomination schedules
- Notification procedures (Order 587-V)
- Coordinated emergency response procedures
- Coordinated planned outages for routine maintenance and repairs
- Market-clearing times for natural gas and electricity pricing
- Lack of flexibility in gas transportation services and scheduling
- Transparency reporting
- Gas supply disruption due to extreme weather
- Regulatory coordination between state and federal agencies regarding coal-to-gas-fired conversions, gas supply growth, and infrastructure investment
- Temperature design limits of plants (to recognize the impact of low outside temperatures on loss or duration of capacity)
- Impact of winterization of plants to limit winter-related capacity losses

[9] http://www.oscomp-systems.com/

Regulatory and Contractual Context of the Natural Gas Infrastructure

Certification of Interstate Natural Gas Pipelines

Section 7 (c) of the Natural Gas Act of 1938 grants FERC the authority to issue a certificate of public convenience and necessity to natural gas companies upon demonstrating that an interstate pipeline is in “the public” interest.[10] Interstate pipelines cannot construct facilities or provide gas transportation service without a Section 7 certificate. FERC (and FERC’s predecessor, the Federal Power Commission) grants a certificate when service is needed. The certificate is important because it grants the power of eminent domain to the pipeline.

The definition of “need” has evolved over time. Originally, a pipeline company needed to demonstrate both the market need and the presence of sufficient supply to ensure that the pipeline would be sufficiently utilized. Prior to the restructuring of the natural gas industry in the 1980s and ’90s, a pipeline company would be required to have 20-year gas purchase contracts to demonstrate that there was sufficient supply to fill the pipeline.

With restructuring, FERC regulations evolved to rely on contractual commitments by the shippers on the pipeline as a demonstration of market need—along with the co-existence of supply. The contractual commitments of pipeline customers—known as shippers—is considered a superior method to evaluating need in a competitive market setting, compared to a review of competing projects conducted by regulators.

The evaluation of need requires that the pipeline bring to FERC legally binding precedent agreements showing that the pipeline will be fully or nearly fully subscribed[11] for a minimum of 10 years. Contracts for interruptible service are not included in the demonstration of market need. Only contracts for firm service are included within that evaluation. As discussed later in this section, the rates charged for firm service, which include fixed, monthly reservation, or “demand” charges to reserve the capacity, are often higher than non-firm charges and can present challenges to any pipeline customer wishing to receive gas transportation service during a limited number of hours each month.

Firm Transportation Service and Primary and Secondary Rights

As noted above, firm service contracts with shippers underpin the economic regulation and cost recovery for natural gas pipelines. The firm service contract grants the shipper certain rights to utilize the capacity that has been contracted according to the published pipeline tariff.

Under FERC Order 636,[12] FERC created a framework to allocate capacity and property rights to the shippers on the pipeline. One of the objectives of Order 636 was to increase the economic efficiency within the pipeline network. To do that, FERC directed the pipeline industry to establish a system with primary and secondary rights under the firm service contract.

Each firm service contract specifies a primary receipt point(s) where gas can be received by the pipeline for transport on the system, and a primary delivery point(s) where the gas is removed from the pipeline and delivered to the shipper’s facility (e.g., a local distribution company, power generator, industrial plant, etc.) or to another gas pipeline for continued transport. “Primary” firm service has the highest priority for service and will not be disrupted, barring a significant force majeure event or mandatory maintenance.

In addition to the rights of primary service, Order 636 instructed pipeline contracts to include a system of secondary rights. The details of the system of secondary rights differ somewhat from one pipeline to the next. The implementation requirements were dictated by the physical configuration of each pipeline. All FERC-regulated pipelines, however, have a system that allows a shipper to deliver gas to them for transport at an alternative receipt point or remove gas at an alternative delivery point. By requiring this flexibility, FERC created a system where a shipper could generate some

[10] 15 USC 717h. “U.S. Natural Gas Act of 1938,” section 7.
[11] FERC requires that a vast majority of the capacity is under contract prior to certificating the project.
[12] Order 636 Final Rule, Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations, Issued April 8, 1992

economic value from holding a firm service contract during the time that the shipper did not require a full quantity of pipeline capacity to be reserved under the contract.

Order 636 also required each pipeline to institute a Capacity Release program whereby shippers could resell the firm contracted capacity to other shippers on the pipeline. The ability to designate alternative receipt and delivery points is a necessary element that creates economic value for a shipper buying capacity from the primary contact holder (in this case the shipper is known as a "replacement shipper"). Additionally, FERC required the pipelines to allow shippers to "segment" the capacity held under contract. For example, if a shipper holds capacity on a pipeline that runs from Louisiana to New York, the shipper could, on a single day, deliver gas to the pipeline in Louisiana for delivery in Kentucky and deliver gas to the pipeline in Pennsylvania for delivery to New York. A variation of this example would be to sell the capacity downstream of Pennsylvania in the capacity release market while still delivering the contract volume to New York with gas sourced from Pennsylvania.

Gas service provided to shippers under these secondary rights to firm service is given a lower priority than the right granted to primary firm service. The secondary rights, however, are granted a higher priority for service than those granted to interruptible service. Some pipelines have created additional levels of priority for secondary firm service rights. For example, some pipelines may have a priority category for secondary service that is "in the primary service path" that has a higher priority than secondary firm service that is "out of the primary service path."

Interruptible Transportation Service

Under "average annual operating" conditions, most pipelines have some level of capacity that is not used by firm customers and is therefore available for non-firm loads. If the requirements for non-firm deliveries are communicated to the pipeline within the nomination cycle timeline, the pipeline can use facilities to allow for delivery of gas requested up to the physical capabilities of the system. Pipelines may suspend, reduce or not schedule interruptible transportation services in accordance with the pipeline's tariff and FERC policy.

As noted earlier, the planning process for new natural gas pipeline and storage infrastructure has developed based on an underpinning of contracts for firm service entitlements for the contracting party. Pipeline owners do not construct new or expanded capacity without long-term (at least 10 years) contractual commitments from gas shippers. FERC will not grant the required certificate for new capacity without the firm service contracts discussed earlier. Within this model, capacity is not constructed to serve interruptible service demand.

Unlike firm service, which has a fixed monthly reservation fee paid to reserve capacity, interruptible service is priced solely on a volumetric basis. The shipper only pays for the volume of transportation service that it receives. This is an attribute that is often desirable for power generation customers of the pipeline, particularly those that have relatively low annual capacity factors.

Interruptible service, however, comes with the lowest service priority. As a result, interruptible service is the first to be restricted or reduced during periods where the pipeline is highly used, maintenance is occurring, or force majeure is in effect. It is not uncommon for interruptible service to be unavailable during winter peak periods, particularly in constrained gas-delivery areas such as New England.

Nomination, Confirmation and Scheduling, and the "Gas Day"

Whereas electricity control areas and utilities in North America operate on various wholesale market "electric days," every natural gas pipeline in North America operates on a common "gas day" for the transportation (flow) of gas. The gas day commences at 9:00 a.m. Central. The pipeline must offer at least four nomination opportunities as required by NAESB and FERC regulation. For each "nomination cycle," there is a schedule for the communication between the shippers and the pipeline.

The communications process is divided into three steps: nomination, confirmation, and scheduling. The nomination step involves a shipper indicating to the pipeline the amount of service being requested for the next gas day or for the next cycle. During the nomination process, all parties request service including firm, secondary firm, segmented capacity, interruptible transportation, etc. The pipeline then fills those requests based on priority of service. The confirmation process involves communication between the shipper and a producer to ensure the pipeline has gas supply and can be delivered to the pipeline at a specific receipt point. The scheduling process involves the pipeline communicating to the shippers whether it can "confirm" that the shipper's requested volume of gas can be removed at the delivery point based on the producers' confirmation of the supply point and volume.

Despite the fact that natural gas generally moves at no more than 30 miles an hour through the pipeline, a shipper removes gas at the delivery point simultaneously with the gas being delivered to the pipeline at the receipt point, which may be 1,000 miles upstream. The nomination, confirmation and scheduling process in conjunction with the gas control center ensures the operation and pressure requirements for reliable service.

Figure 2 presents the timeline for nomination, confirmation, and scheduling for the minimal level of nomination cycles that a pipeline must provide. Figure 3 compares the gas day cycle to that of the electric day.

Figure 2: Pipeline Nomination Cycles (CPT)[13]

Nomination Cycle	Nomination Deadline	Third-Party Confirmation Deadline	Pipeline Scheduled Quantity Deadline	Flow Time
Timely (Cycle 1)	11:30 a.m. (The day before the gas flows)	3:30 p.m. (The day before the gas flows)	4:30 p.m. (The day before the gas flows)	9:00 a.m. (The next day)
Evening (Cycle 2)	6:00 p.m. (The day before the gas flows)	9:00 p.m. (The day before the gas flows)	10:00 p.m. (The day before the gas flows)	9:00 a.m. (The next day)
Intraday 1 (Cycle 3)	10:00 a.m. (The Gas Day)	1:00 p.m. (The Gas Day)	2:00 p.m. (The Gas Day)	5:00 p.m. (The same day)
Intraday 2 (No Bump- Cycle 4)	5:00 p.m. (The Gas Day)	8:00 p.m. (The Gas Day)	9:00 p.m. (The Gas Day)	9:00 p.m. (The same day)

When the pipeline operator receives a request for service, the total amount of service requested must be considered, along with the priority of service requested. Primary firm service is scheduled first. Secondary firm, including any differentiation within the category, is scheduled next. Interruptible capacity, which is often used by gas generators, is scheduled at a lower priority. Other services, such as "park and loan," may have the lowest priority.

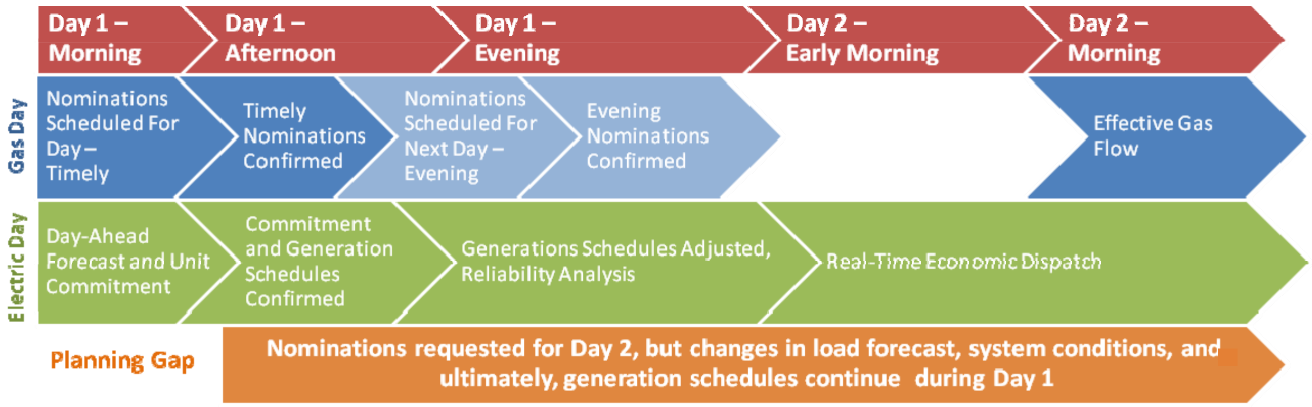
If there is insufficient capacity to meet all of the service requested within a priority category, the pipeline schedules the service on a pro-rated basis within the lowest priority category that is granted service. If all firm customers are using their full contractual entitlements, there may be insufficient capacity to meet the demands of interruptible transportation customers. Scheduling is done pursuant to the pipeline's tariff and based on specific segments of the pipeline. As a result, interruptible capacity may be available on some segments of the pipeline but not all segments.

The focal point of these differences is a multi-hour gap in the timing between the two days, which increases the difficulty of providing the needed services to gas-fired generation.[14] For example, the electric day, in essence, completes its planning for the next day by 6:00 p.m. of the current day. While the completed electric utility plan identifies which electric units will run the next day (which in turn provides the basic information to project the next day's fuel consumption), the pipeline deadlines for nominations historically have been at 10:00 a.m. of the current day. Thus, there is a six-or-more-hour gap of incompatibility between the two traditional approaches to planning and scheduling.

[13] http://www.naesb.org/

[14] See Chapter 7 of NERC's *A Primer on the Natural Gas Industry and its Interface with the Electric Power Industry*, 2011, for a complete assessment of both the electric day and the gas day.

Figure 3 : Description of the Interaction of Gas-Day and Electric-Day Planning Cycles



The net result of this scheduling gap is that electric generator nominations, with their relatively large gas loads, are based upon estimates by the individual fuel planners of each Generator Owner (GO) between 24 and 36 hours in advance. The issue could be magnified when scheduling on a Friday, since gas markets are closed for the weekend. This can result in significant differences between nominations and actual gas requirements (see Figure 3). The nominating and scheduling process provides an opportunity for each Generator Owner to manage and effectively minimize its risk exposure. However, the amount of firm pipeline capacity needed, either through firm capacity entitlements or capacity release, should reflect the best possible estimate of actual gas requirements; although, inherent risk with estimates poses additional threats.

Power producers have expressed concerns about the lack of liquidity in the gas market after the nominations are confirmed and the gas flows are scheduled. After the scheduling is completed, power generators have difficulty procuring additional gas and often are unable to move gas procured for other facilities to the facility in need due to lack of pipeline capacity.

Furthermore, sudden weather and system events can exacerbate these differences. When such differences occur, a pipeline may not be able to accommodate changes between previous nominations and actual delivery requirements depending on how other customers have nominated to use their contractual rights on the system. In addition, if a generator goes out of balance for a prolonged period or withdraws gas faster than the tariff permits, then the generator may be subject to a number of imbalance penalties required under the pipeline tariffs.

While there are regional nuances to the above portrayal of the gas day and the electric day (i.e., the electric day is not standardized across different power markets), within each Region there is basic incompatibility between the two planning days. In addition, while the example above assesses the traditional gas and electric days, over the last decade, each industry has made steps to accommodate the other—at least to a degree. For example, many, but not all, pipeline tariffs have been revised to include additional mechanisms for revising gas quantity nominations. Similarly, some GOs are refining their planning and scheduling protocols so that information becomes available a few hours earlier in the traditional electric day. The latter can facilitate the refining of intraday volume adjustments. Nevertheless, these improvements are not sufficient to close the gap between the electric and gas day and ensure that generators would be able to procure sufficient gas supplies during peak hours. This issue was most recently exposed in New England during the January through February 2013 operating period.[15]

[15] Winter Operations Summary: January – February 2013: http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/winter_operations_summary_2013_feb_%2027_draft_for_discussion.pdf

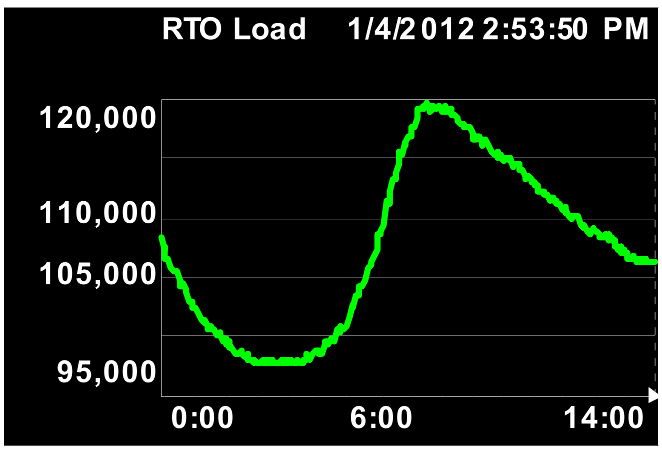
Imbalances, Penalties, and Unauthorized Overruns

All shippers experience some variability in the hourly and intra-hour rate that gas is required. Residential and commercial gas requirements, for example, generally increase in the morning hours as homeowners awake, turn up the thermostat, and increase hot water requirements. The gas load tends to peak around 8:00 or 9:00 a.m. and decline as people go to work. A second relative peak generates within the day as people return home from work.

Power generation requirements also experience similar load patterns within the day, and the rates of change can be quite dramatic. Figure 4 represents the load profile for the PJM Interconnection (PJM) on January 4, 2012. That morning, PJM demand increased 27,000 MW in 4 hours—over 100 MW/min. As electric power demand increased, the requirements for natural gas serving the regional gas-fired generation, which is well-suited to meet the variable requirements, also increased with the core gas loads.

The variability of gas demand requirements, however, is affected by other factors that can be even harder to predict. An unanticipated outage in a large, non-gas-fired generator can create a rapid increase in other gas-fired generation output from spinning or other reserve capacity. In addition, the resulting operating characteristics of variable energy resources, such as wind or solar, can also add to the gas demand uncertainty.

Figure 4 : PJM Power Requirements (January 4, 2012)[16]



Pipeline operators are required to manage load variability such that the pressure conditions on the pipeline can meet the operational needs while safe operating conditions are continuously maintained. To accomplish this, each pipeline has language in its tariff that provides guidance in terms of the hourly variability (delivery and receipt) that can be accommodated.[17] In most cases, the pipeline tariff provides for more hourly flexibility on days of normal operation. During periods of peak requirements, and in conditions where a pipeline has issued a critical notice, the hourly variability tolerances are reduced.

An imbalance is the measure of the difference between the amount of gas that a shipper removes from the pipeline at the delivery point and the amount of gas that the shipper delivers to the pipeline at the receipt point, while accounting for gas that is used for fuel or "lost or unaccounted for" (LAUF). The pipeline tariff specifies how imbalances are recovered, as well as how any penalties are incurred. In most cases, the total cost of the imbalance and penalties is designed to exceed the

[16] PJM. "Gas-Electric Coordination Issues (RTO Perspective)" presentation. PJM, January 2012: Norristown, PA.

[17] Local distribution companies (LDC) shippers have noted that the historical quality of service that the pipeline has provided with facilities that are paid for largely with firm service contracts entered into by LDCs has accommodated variability that is greater than a strict reading of the tariff. The LDCs have expressed that increases in gas pipeline variability created by increasing requirements for gas fired generation should not result in a degradation of the historical quality of serve received from the pipeline.

cost or value of the gas flowing on the pipeline. If this were not the case, there could be significant incentives to increase imbalances intentionally or to behave in a way that does not minimize the size of imbalances.

Imbalance management is accounted for each day. Although there have been discussions about the possibility of creating imbalance managements systems that operate on an hourly basis or for periods that match the nomination cycles, to date no interstate pipeline has instituted such a system. As a result, a shipper that has taken more gas off the pipeline in one nomination cycle than was delivered to the pipeline (or alternatively, took less gas off than was put on) is not penalized as long as imbalance is eliminated by the end of the gas day. Because of this, the pipeline must be prepared to operate with variation in the amount of gas being delivered to the pipeline and the gas being removed within each day.

The integrity of the pipeline is the pipeline's preeminent obligation. In some instances, a pipeline may allow a customer to take more gas off the pipeline than a pipeline's imbalance service, if it does not compromise the operational integrity of the pipeline. When the pipeline is able to allow an overrun, it generates additional transportation revenue (which is subsequently shared among "non-offending" shippers) from providing the additional service. Authorized overruns are therefore accommodated by pipelines whenever possible.

In order to protect the operational integrity of the system, pipelines install flow control valves at various locations. Increasingly, these valves have been installed at delivery points where large volumes of gas are removed from the pipeline. Using these valves, the pipeline can physically reduce the volume of gas flowing to a facility that is taking more gas than it is entitled.

Most pipelines, however, have been reluctant to take such actions. The shipper is, after all, the customer of the pipeline, and the pipeline prefers to accommodate its customers' needs so that the customer does not consider contracting their loads to a competing pipeline. As a result, shutting the valve on a customer that is taking more gas than scheduled is considered a "last resort" and rarely occurs. Rather than closing the valve, many pipelines will attempt to regulate the flow to align deliveries with the contracted volume and rate.

In markets where there is excess gas pipeline capacity available, low-capacity-factor gas-fired power plants can rely upon interruptible service with a reasonable degree of certainty that service will be available. As growth in gas system requirements in a region reaches the point where new pipeline capacity is required or when market conditions result in simultaneous peak in electricity and gas demand, the differences in the structures of the two industries can result in a mismatch between the requirements for gas delivery service and requirements for gas-fired electric generation.

Even on non-peak flow days, gas-fired generation requires high-volume, high-pressure loads with large load swings that pipelines may not have been designed to accommodate. Pipelines need to align a slow-moving product (gas) with a fast-moving product (electricity) that is subject to large variations (gas-fired generators come on- or off-line on short notice). The sudden demand swings from generators may cause pipeline pressure drops that could reduce the quality of service to all pipeline customers. The main issues are whether the requirements for the gas are predictable within the gas pipeline nomination cycle, if supplies are available and confirmed, if the pipeline is sized to handle the load variation, what the proximity to storage is, and whether volumes are taken in excess of confirmed nominations, including specified allowances for hourly swings.

If the requirements for the gas are not known within the gas pipeline nomination cycle and the available capacity for interruptible loads is factored into the pipeline operating plans, or if hourly swings are excessive, a pipeline would need to allocate, reserve, or build facilities on the pipeline to provide service for the intra-cycle requirements. This may involve the creation of pipeline services that do not exist. While pipelines are capable of adding capacity in the form of more pipe, compression, or market-area storage deliverability, they are unlikely to do so without a cost recovery mechanism, which is traditionally in the form of a contract for that service.

In a number of market locations, some gas-fired generation units rely on gas pipeline capacity above the level that has been nominated, scheduled, and confirmed with the pipeline. The gas nomination cycle is not synchronized to day-ahead or real-time operations of generation facilities, which results in a potential disconnect in usage versus nomination. While these gas volumes are ultimately replaced through balancing provisions, the timing of the replacement does not prevent pressure transients that threaten delivery pressures along the pipeline and harm to other pipeline customers.

Delivery of unscheduled volumes lowers pressure on the pipeline in proximity to the delivery point and at locations upstream and downstream of that point. This is particularly critical if it occurs at periods of peak pipeline use. Given the coincidental winter peak for gas Local Distribution Companies (LDCs) and gas-fired generation serving electric load, this is a significant risk in regions like New England that do not have excess aggregate pipeline capacity. Weather is the key variable affecting LDCs' gas loads and, subsequently, the availability of gas supply to electric generators.

In the context of unanticipated loss of a facility, the natural gas and electric systems operate in fundamentally different manners. At its most severe condition, a mechanical or other physical failure in electric infrastructure can result in the immediate loss of service from an entire generating unit or transmission line that can, under some conditions, produce cascading loss of firm load. The nature of these events and the required instantaneous response of system operators have generally served as an impetus for electric system planners to employ both resource adequacy review and reliability (system security contingency) review to assess infrastructure requirements. The result of these reviews allows the bulk power system to be operated in a manner that is resilient to disruptions.

By contrast, most mechanical or physical failures of gas pipeline or storage facilities result in reductions in the amount of pipeline capacity rather than a complete loss of service—largely do the physical attributes of electrons compared to molecules of gas. The exception is a complete failure of a pipe segment or third-party damage to a single line pipe segment through improper excavation in the pipeline right-of-way. Both of these are rare events. Even when a pipe segment is completely disrupted, some level of service in the downstream markets is usually maintained via the diversion of gas through other delivery routes. Many, but not all, pipelines have some ability to re-route gas along their main transmission backbones.

As a result, outages in the gas industry are addressed by allocating reductions in capacity that result from a contingency event, consistent with the priority of contract-based customers. Low-priority services such as interruptible and park and loan services are curtailed first, followed by firm service to secondary delivery points, and finally firm service to primary points. If the event is sufficient to require reductions in firm service rights, best efforts are made to retain service to "human needs" customers; that is, residential customers and other buildings, such as hospitals and nursing homes, where people reside. Therefore, in the event of a severe outage there is the potential that electric generators with firm transportation service could be curtailed.

FERC Orders Defining Information Posting and Exchange of Information

FERC Order 587

In 1996, FERC issued Order 587, "Standards for Business Practices of Interstate Natural Gas Pipelines."[18] It was based on natural gas pipeline standards developed by the Gas Industry Standards Board (GISB), the predecessor to NAESB. The original and subsequent orders included critical conditions (i.e., those that pertain to Transportation Service Providers (TSP) that affect scheduled gas flow) and non-critical notices (i.e., general information) that were required to be posted on the TSP's designated website and were provided to applicable parties' choices for Electronic Notice Delivery mechanisms. In

[18] 18 CFR Part 284, issued July 17, 1996.

addition, the order defined 12 notice types, several of which are listed below, that are specified in electronic correspondence:[19]

- Capacity Constraints – capacity constraints resulting from situations other than Operational Flow Order, Curtailment, or Force Majeure
- Capacity Discount – firm capacity offered at rate less than maximum tariff rate
- Customer Service Update – general customer service information
- Gas Quality – warnings of gas quality issues
- Intraday Bump – warnings of bumping scheduled interruptible transactions
- Maintenance – scheduled repairs/maintenance that may impact service
- Operational Flow Order – issued to alleviate conditions that may impact safe operation.

Since 1996, FERC Order 587[20] has undergone a series of modifications, which are listed in alphabetical order above. The most recent modification was made on July 19, 2012, and the current order is listed as FERC Order 587-V. [21] The current order incorporates the latest version (Version 2.0) of certain business practice standards adopted by the Wholesale Gas Quadrant (WGQ) of NAESB. That version of the standard includes:

- Standards to support gas–electric coordination;[22]
- Standards created for Capacity Release redesign due to the elimination of Electronic Data Interchange (EDI) for Capacity Release Upload information;
- Standards to support the Electronic Delivery Mechanism (EDM);
- Standards to support the Customer Security Administration (CSA) Process;
- Standards for pipeline postings of information regarding waste heat; and
- Minor technical maintenance revisions designed to more efficiently process wholesale natural gas transactions.

The previous order, 587-U, issued on March 24, 2010, incorporated Version 1.9 of NAESB's Standard Business Practices of the WGQ. On March 4, 2011, NAESB filed a report informing FERC that it had adopted and ratified Version 2.0 of its business practice. The filing process at FERC initiated steps to incorporate these business practice modifications to become mandatory and enforceable by FERC.

NAESB's role is limited to creating consensus for business practices, rather than making policies or policy recommendations. Thus, FERC Order 587 and its modifications reference NAESB practices, which attempt to standardize and simplify procedures for interstate natural gas pipelines. Ongoing gas–electric interdependency efforts include FERC's regional technical conference series to discuss issues with key market players (e.g., ISOs and RTOs) and NAESB's Board Committee on Gas–Electric Harmonization Committee Report, presented to the NAESB Board of Directors in September 2012. In

[19] Ibid.

[20] A similar FERC Order issued in 2007 that focuses on gas-electric interdependency issues, based on NAESB business practices. The order arose from cold weather conditions in the northeastern part of the country in the winter of 2003 which led to short-term reliability issues and high gas and electric prices.

[21] FERC Order 587-V: Final Rule: http://www.ferc.gov/whats-new/comm-meet/2012/071912/G-1.pdf

[22] A description of the roles and responsibilities under the Gas/Electric Operational Communication Standards circulated in FERC Order 698; These provisions gave more details on each notice, created 15 new notice types for use in Notices section of pipelines' websites for public utilities to more easily identify relevant pipeline system conditions and for shippers and interested parties of intraday pumps, operational flow orders, and other critical information electronically.

addition, FERC is conducting market assessments with pre- and post-seasonal reporting for ISO-NE, MISO, and other Regions, and NERC is examining gas–electric interdependencies with a viewpoint on the reliability of the BPS.

FERC Order 698

FERC Order 698 is similar to FERC Order 587 in that it addresses gas–electric interdependency issues.[23] Order 698 arose from the stressful conditions and high gas and electricity prices that resulted from a cold snap in New England in January 2004.[24] Order 698, issued in 2007, incorporated certain standards (by reference) of NAESB's WGQ and the WEQ[25] after NAESB established a gas–electric coordination subcommittee to assess the relationship between the gas and electric industries, as well as to identify areas to improve coordination through standardization. As with Order 587, NAESB provided business standards rather than policy or policy recommendations to FERC.

FERC Order 698 requires a Power Plant Operator (PPO) to coordinate natural gas deliveries with the TSP directly connected to the PPO's facility. As a result, TSPs now publish on their websites material changes that may impact hourly flow rate to their PPOs (i.e., critical notices and planned service outages).

The order requires interstate natural gas pipelines and PPOs, Transmission Owners (TOs) and Transmission Operators (TOPs), independent Balancing Authorities (BAs), and Regional Reliability Coordinators to improve communications for the coordination of gas transportation scheduling and the operations of gas-fired generators.

Critical notices and planned service outages pertain information on Transportation Service Provider conditions that affect scheduling or adversely affect scheduled gas flow. PPOs are required to sign up to receive operational flow orders and other critical notices from TSPs. TSPs communicate operational flow orders and other critical notices by posting them on their website. TSPs also publish non-critical notices, which do not adversely affect scheduled gas flow and typically include bid awards, annual or monthly meeting notices, and tariff changes.

Example:[26] Northwest will communicate material changes in its circumstances that may impact hourly flow rates for PPOs by issuing a critical notice. Critical notices can be accessed by: 1) Northwest's website; 2) Northwest's proprietary system, Northwest Passage, after completing an Access Agreement located in the download section on the Northwest Informational Posting website; or 3) email or fax after completing a Business Associate form located in the download section on the Northwest Informational Posting website.[27]

Issues for Balancing Authorities and Reliability Coordinators

At this time, it is not clear whether the electric BAs and Reliability Coordinators (RCs) have an adequate understanding of the information that was made available to them following FERC's Order 587-V. A first step is for the BAs and RCs to identify the gas-fired generators—and their pipeline sources—that affect conditions in their areas. This is done by identifying the specific pipeline or LDC "Meter ID" that is associated with delivering gas to the specific power plant or station. While the generators' fuel managers may understand the critical and non-critical notices, the information may not be readily communicated or understood well enough by the BAs or RCs. A second step would be for the electric reliability practices to include a basic understanding of the need to receive and understand the information contained in critical notices. Currently, the pipeline is considered compliant if the information is sent to BAs only if requested by the BA. If the BA does

[23] FERC. (2012) *Standards for Business Practices of Interstate Natural Gas Pipelines*. 18 CFR Part 284. Docket No. RM96-1-037; Order No. 587-V <www.ferc.gov/whats-new/comm-meet/2012/071912/G-1.pdf>

[24] North American Energy Standards Board (NAESB). "Order 698 Effort." NAESB, 10 September 2007: Houston, TX. Available at: www.naesb.org/pdf3/update091207w5.doc

[25] The standards for the Wholesale Electric Quadrant are: Gas/Electric Coordination Standards WEQ-001-0.1 through WEQ-011-0.3 and WEQ-011-1.1 through WEQ-011-1.6. The standards for the Wholesale Gas Quadrant are: Additional Standards, Definitions 0.2.1 through 0.2.3 and Standards 0.3.11 through 0.3.15.

[26] Welcome to *Northwest Pipeline:* www.northwest.williams.com/Files/Northwest/10192007WelcometoNorthwestPipelinefinal_4_.pdf Accessed 14 Nov. 2012.

[27] www.northwest.williams.com

not request notification (and therefore does not receive the information), the pipeline is still compliant. On the other hand, BAs are not required to request this information, but some of them do in order to facilitate their planning and operations process.

RCs, BAs, ISOs, and RTOs should work to increase their understanding of the information in Order 587-V and be able to incorporate it into their hourly and real-time operations. The ability to interpret the informational postings is critical for the reliability of the BPS, and the electric industry should be able to take advantage of it. During the last FERC technical conference on this issue in February 2013, some ISOs noted that they were unable to make full use of the informational postings so far. Additionally, Generator Owners and Operators should be well coordinated with pipeline operators in this information exchange. NERC is in the process of evaluating this problem and will work with industry members to address it, where necessary. NERC could leverage its stakeholder groups to identify best practices in areas that are currently most vulnerable to gas dependency risks and are taking immediate actions for improvement, such as New England. Such an effort could lead to insights for enhanced operator training and table-top exercises.

Differences of Contingency Events in the Gas and Electric Industries

Natural gas and electric infrastructures are fundamentally different in the manner in which their integrated systems operate, particularly in the context of the unanticipated loss of a facility. A mechanical or other physical failure in electric infrastructure can result in the immediate loss of service from an entire generating unit or transmission line that can, under some extreme conditions, produce cascading loss of service to electric customers.[28] The nature of these events and the required instantaneous response of system operators has generally served as an impetus for electric system planners to employ both resource adequacy review and reliability (system security contingency) review to assess infrastructure requirements—a requirement of NERC TPL Standards.[29]

By contrast, most mechanical or physical failures of gas pipeline or storage facilities result in reductions in the amount of capacity of the pipeline rather than a complete loss of service. The exception to this is a complete failure of a pipe segment or an incident of third-party damage to a pipe segment through improper excavation in the pipeline right-of-way. Even in the instances where a pipe segment is completely disrupted, some level of service in the downstream markets is usually maintained via the diversion of gas through other delivery routes and/or storage.

As a result, outages in the gas industry are addressed by allocating reductions in capacity that result from a contingency event consistent with the priority of contracts-based customers. Interruptible service is curtailed first, followed by firm service to secondary delivery points, and finally firm service to primary points.

Because of these differences, as well as the various probabilities of contingency events, the planning and operation of facilities to address unanticipated outages and other contingencies differ markedly between the two industries.

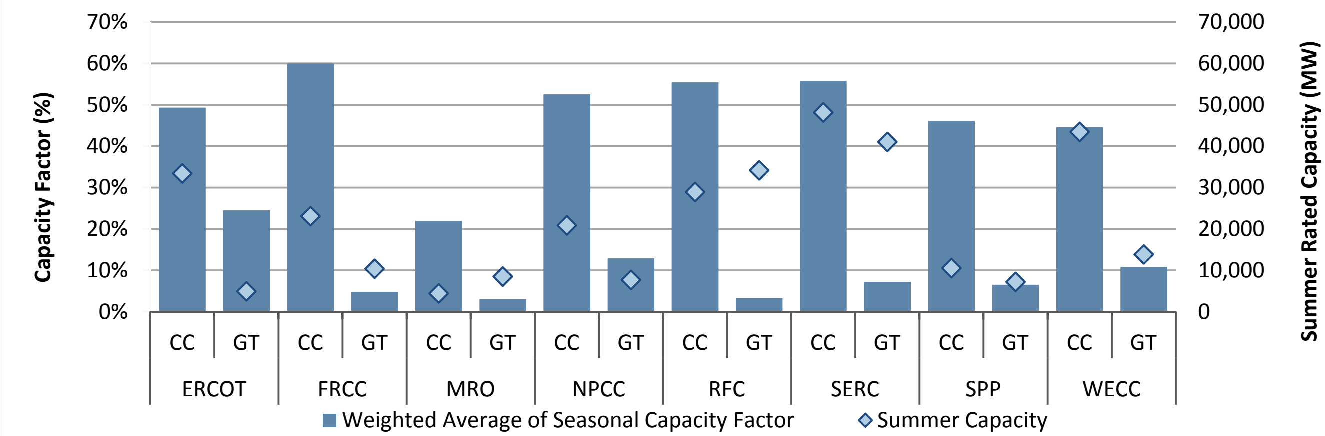
Other Factors

Historically, the average capacity factors for non-peaking gas-fired units have been about 25 percent, with peaking units having average capacity factors of five percent or less. In addition, the period of greatest use for these units was during the summer season, when electric loads peaked because of air conditioning demand. As a result, the power industry used, and continues to use, interruptible transportation in an effort to minimize production costs. The gas industry was able to adapt to this use of interruptible transportation services, because the gas used for generation loads at the time accounted for a lower percentage of the total pipeline loads, and the pipelines had economic incentive to provide these interruptible transportation services. However, more recently, many electric generator loads have shifted from being peak and intermediate load providers to being base, intermediate, and peak load providers. This shift has caused average capacity

[28] If an electric grid were operated below N-1 criteria, a loss of a single component can cause cascading failure of that grid.
[29] NERC Reliability Standard TPL-002-0b: http://www.nerc.com/files/TPL-002-0b.pdf

factors[30] of combined-cycle generation to approach 50 percent and, in some Regions, exceed 60 percent (Figure 5). However, there are significant regional differences in this evolving phenomenon, with some Regions still only utilizing their non-peaking gas-fired units only 20 percent of the time. Average gas-turbine capacity factors are generally below 12 percent across all Regions—almost 25 percent in ERCOT.

Figure 5: 2012 NERC US Actual Weighted Average Capacity Factors for Combined Cycle vs. Combustion Turbine Gas-Fired Generators[31]



Due to this shift in gas loads, interruptible transportation services may be best suited for generators with low-capacity factors, and firm transportation services may be more appropriate for generators with high-capacity factors. However, given a larger portfolio of gas-fired generation and tighter reserve margins in some cases, for reliability, more firm fuel service may be necessary to manage potential risks. Obtaining firm transportation services represents a significant challenge for the electric power industry and to consumers, due to the higher costs associated with these services. Dual-fuel and a variety of storage options can bridge the gap between the uncertainties of gas availability during extreme events and maintaining a reliable source of capacity available to meet seasonal peak demands. Ultimately, the right balance of firm pipeline capacity, dual-fuel capabilities, and a variety of storage and no-notice options will depend on the region and the individual generation facilities. Factors such as market structure, geography, fuel mix, and pipeline infrastructure will all determine the extent of gas dependency risks and the available options and solution sets for reducing this risk.

Lastly, gas quality (or gas composition) can also be a relatively important issue for the power industry, as well as for other gas consumers. Every natural gas field in the world is unique, some types of natural gas in particular (e.g., coal-bed methane, sour vs. sweet gas, and man-made LNG). This uniqueness of natural gas supplies can be problematic for some users, depending on the design of their equipment and appliances. For example, natural gas with a high British thermal unit (Btu) level (i.e., from excessive ethane, propane, and other heavier hydrocarbons) can burn too hot in low-nitrogen oxide (NO_x) burners, which could impact both the efficiency and environmental performance of these units. Also, natural gas with excessive heavy hydrocarbons under low temperature conditions can solidify and accumulate as a slug in a pipeline or other equipment, which can lead to undesirable results, including pipeline blockage, equipment failure, and fuel quality issues.

Specifically, combined-cycle gas-fired units with low NO_x burners can be sensitive to unanticipated, transient changes in natural gas heat content[32] (+/- 5 percent Btu/cu-ft), which could trigger automatic control-action to avoid unit shutdown and equipment damage.[33] In cases where a number of gas-fired units obtain their fuel from the same pipelines, changes in

[30] Regional capacity factors are weighted by summer rated capacity of each gas-fired generator.
[31] Source: EIA-860 and EIA-923, US Only
[32] See http://www.beg.utexas.edu/energyecon/lng/documents/NGC_Interchangeability_Paper.pdf and http://www.ferc.gov/industries/lng/indus-act/issues/gas-qual/lng-interchangeability-rpt.pdf for more background.
[33] FERC Docket RP08-374-000, June 11, 2008, page 5, item 12: "Casco Bay states that in 2006 it experienced a unit trip due to a "lean blow out" condition… attributed to backhauling gas from alternate supply during a Sable outage."

natural gas heat content can result in multiple unit trips at nearly the same time, which threatens BPS operating reliability.[34] LNG presents the most notable challenges due to its diverse origins and compositions; however, unconventional natural gas production can also present similar fuel quality concerns. Furthermore, units are not only susceptible to full outages, but they may experience the inability to modulate power output, since one mitigation strategy is to fix the output of units at constant power output until a fuel quality disruption subsides. This strategy may affect both operational flexibility and resource adequacy. While fuel quality and composition risks associated with the increased penetration of unconventional and liquefied natural gas remain relatively low, the potential reliability impacts should be studied further.

Over the last decade, the industry—largely through FERC proceedings—has carefully examined the issues surrounding gas interchangeability.[35] This has caused the pipelines to carefully review their specifications for pipeline quality gas and to clearly note these specifications within their pipeline tariffs. While no two pipeline tariffs for gas quality are identical because of differences in gas fields across the nation, they are all relatively similar. Largely because of prior actions taken by regulators and the industry, this issue has not been a significant problem for electric generators so far.

Critical Incidents

Historical incidents illustrate that with increasing interdependency between the natural gas and electric power industries, an event caused by either sector can affect the system reliability of both. This, in turn, has created a need for greater interindustry coordination. There already have been a number of studies on how the coordination between the two industries can be enhanced. As a first step to enhancing the coordination between the two industries and reducing the vulnerabilities of the electric industry, NERC tabulated the observations, insights, and recommendations of these reports in Appendix I.

As an aid to completing this critical first step, Appendix I identifies several of the major historical reports on the topic and summarizes their findings and recommendations. The historical reports cover nearly every aspect of the complex issue of interindustry coordination and identify the barriers against accomplishing such coordination. Limitations on fuel switching, limitations caused by environmental restrictions, the vulnerabilities of each industry to the other, the need for adequate incentives to ensure BPS reliability, and the importance of working with third parties to ensure system reliability are among the issues identified. Several of these historical assessments also cite the need for interindustry coordination at a regional level, as a universal solution to this complex issue does not exist, particularly in light of the unique characteristics of each region.

While relatively few in number and limited to specific regions, there have been interruptions to the delivery of gas supply to gas-fired units, as well as to consumers within the other demand sectors. As illustrated by the review of selected historical service interruption incidents in Chapter 3, none of the incidents directly affected overall system reliability. In some cases, the gas industry was able to either respond quickly or resort to alternatives. However, some historical incidents have contributed to the degradation of system reliability, and similar incidents that could easily threaten regional system reliability are possible.

[34] ISO-NE January 29, 2009 letter, "Summary of Events Related to the January 26, 2008 Sable Island Production Disturbance, 1,470 MW lost in New England – (No OP4 declared) but shows loss of Sable can be disruptive.

[35] Probably the most significant proceedings in the past have been (1) the Natural Gas Pipeline proceeding in 2005 (Docket No. RP01-503-002 and 003) on the appropriate permanent safe-harbor hydrocarbon dew point figure (below 15° F); and (2) the Washington Gas Light and Cove Point LNG proceeding concerning the interchangeability and LNG (i.e., Docket No. PL-04-3-000). Concerning the latter, FERC determined the issue specific to Washington Gas Light was an increase in operating pressure and the use of hot tar as a method of corrosion protection. Also, see Chapter 7 of NERC's *A Primer on the Natural Gas Industry and its Interface with the Electric Power Industry*, 2011, for a discussion of the Wobbe Index.

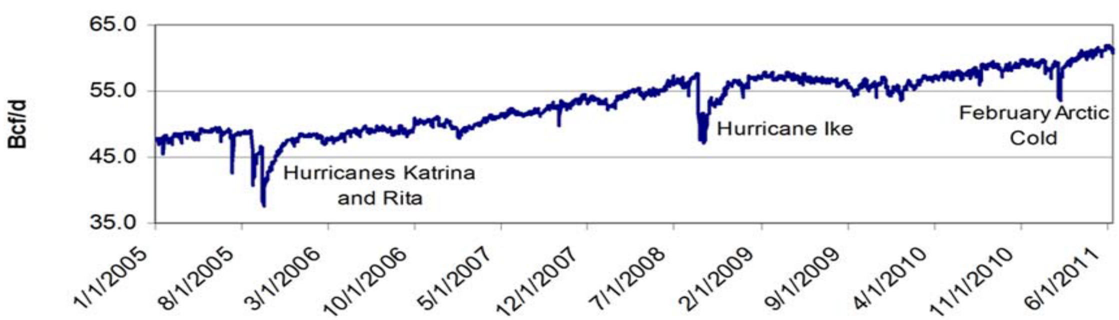
Chapter 3—Gas Supply Vulnerabilities

As shown in previous NERC assessments, reliability challenges are more likely to occur during the winter season.[36] It is important to understand that while firm gas transportation significantly decreases the likelihood that fuel delivery will be curtailed, extreme events, such as wellhead freeze-offs causing decreased gas production,[37] could potentially lead to common-mode failures of multiple gas-fired generators. Additionally, non-interstate pipeline customers with gas use designated as "human use" (typically local distribution companies and some commercial customers at the state-regulated level) always receive priority over electric generation, which during emergencies and restoration efforts can have an impact on gas-fired generation—even with pipelines that have firm capacity rights.

Extreme Winter Weather Impacts

Disruption of natural gas supplies during extreme and prolonged weather conditions identified are vulnerabilities that should be sufficiently studied and assessed. Most recently, the reductions in supply during the February 2011 Southwest cold weather event were comparable in magnitude to the production shut-ins during interruptions caused by past major hurricanes.[38]

Figure 6 : U.S. Dry Gas Production



Extreme and prolonged winter weather is clearly a high-risk period, and while weather conditions cannot be controlled, preparations and sufficient planning could help minimize the effective impact to BPS reliability. Cold weather is the primary driver for gas and electric use during winter months. While electric generation owners and operators are generally able to schedule gas during the summer to meet seasonal peak demand, this flexibility usually decreases during winter months when pipelines peak and firm transportation customers schedule their full entitlements. Cold weather can also be responsible for increased infrastructure and supply disruptions, which are generally caused by freezing.

Historical Gas Supply Disruptions

Historically, large curtailments of natural gas to both electric generation and consumers within other demand sectors are generally considered rare events. The natural gas industry is considered by most industry observers to be relatively safe and to offer a high degree of reliable service. However, incidents leading to curtailments do occur. In addition, there are instances of upstream gas supply loss. Regions that depend heavily upon gas-fired generation can be particularly sensitive to such incidents, as they can impair electric reliability and cause regional wholesale prices to increase for a short period of time.

[36] *2011 Special Assessment Report: A Primer of the Natural Gas and Electric Power Interdependency in the United States*, http://www.nerc.com/files/Gas_Electric_Interdependencies_Phase_I.pdf

[37] Force majeure clauses in fuel contracts relieve the lessee from liability for breach if the party's performance is impeded as the result of a natural cause that could not have been anticipated or prevented. Force majeure events must completely prevent performance and must be unanticipated.

[38] http://www.nerc.com/files/SW_Cold_Weather_Event_Final_Report.pdf

While several of the pipeline incidents noted below were caused by either acts of nature or third-party actions, there are other causes of pipeline interruptions.[39] In several of these incidents, the gas industry took advantage of pipeline looping, interconnects with other pipelines, storage, and other inherent redundancies, and was able to recover services relatively quickly. However, for the electric industry, which tends to operate in almost a millisecond environment, such a rapid recovery can still result in system reliability problems, particularly when significant fuel switching capability does not exist within that region or could not be operational within a sufficient time frame.

Below is a list of several interruption events and their impact on the gas and electric industries.

- **El Paso Natural Gas:** An explosion on El Paso's southern system in 2000 forced the curtailment of 500–700 MMcfd for at least two weeks. Full service was not returned for months. The outage had a significant impact on the entire region and forced some consumers to make withdrawals from storage in a period when regional storage injections were already well behind the historical benchmarks.[40]

- **Florida Gas Transmission:** A lightning strike at the Perry compressor station in 1998 melted all three of the main lines on the Florida Gas Transmission system, which forced the curtailment of 1.5 Bcfd. Regional electric utilities were able to avoid rolling blackouts by switching from gas to residual fuel oil and requesting voluntary curtailments (increasing air conditioning thermostats 10^{o}F and not using dishwashers). Electric service to a few commercial customers was interrupted (i.e., demand response) in return for compensation.

- **Algonquin Gas Transmission:** In 1995, as a result of damage to the Algonquin system caused by a bulldozer operated by a third party, Algonquin began to lose line pressure, which forced the 489 MW Manchester Street power plant in Rhode Island offline. Because of its fuel-switching capabilities, the plant was able to later come back online and burn oil, which it did for 11 hours before gas pipeline service was restored.

- **TransCanada:** During the 1995–1997 period, there were five explosions or fires on the TransCanada pipeline, which is a major transporter of gas into the New England region. The most significant of these occurred in July 1995 near Rapid City, Manitoba, where an explosion took out all six parallel pipelines that make up the TransCanada system and two electric generators at a nearby compressor station. While two lines were back online the same day as the incident, it took over a week to get three of the remaining lines online, and it was not until mid-August before the last line and one unit at the compressor station were back in service. This incident forced TransCanada to curtail 32 percent of its firm supplies, or 1.75 Bcfd. All interruptible service was interrupted.[41]

- **Sable Island:** On Saturday, January 26, 2008, a mechanical component failure at the Sable Offshore Energy Project (Sable Island) located off the Nova Scotia coast resulted in a significant loss of natural gas supply to northern New England generating resources. The ISO New England control room received direct notification of the disturbance at 10:00 a.m. By 2:00 p.m., New England had lost 1,040 MW of New England-wide gas fired generation, 808 MW of it in northern New England. By 6:00 p.m., those numbers had grown to 1,470 MW and 1,116 MW respectively. In response, 570 megawatts of oil-fired replacement generation was brought on-line for the peak. At 5:00 p.m.,

[39] According to the database provided by the U.S. Pipeline and Hazardous Materials Safety Administrator (PHMSA), which covers the period from 2005 to 2010, (1) 25 percent of the pipeline incidents were due to material, welding, or equipment failure; (2) 23 percent was due to corrosion; (3) 19 percent was due to natural causes; (4) nine percent was due to damage from outside forces (i.e., third parties); (5) 6.8 percent was due to excavation damage; and (6) approximately 14 percent was due to miscellaneous or unknown causes. About 70 incidents occurred per year over this timeframe.

[40] In addition, environmental limits in southern California, (e.g., for NO_x emission), resulted in some gas-fired generation being shifted to less efficient generating units adding additional stress to the electric system: http://docs.cpuc.ca.gov/published/comment_decision/41366-02.htm

[41] The other incidents occurred on April 15, 1996, September 30, 1996, December 11, 1996, and December 2, 1997. For the most part, these incidents only impacted one of the six lines on the TransCanada system, and since the pipeline was not at peak capacity, supplies were rerouted in order to avoid curtailing firm contracts.

resources were postured to maintain operating reserve.[42] Repairs to Sable Island were completed early on January 28, 2008 with gas production returning to normal levels later that day.[43]

The Sable Offshore Energy Project was the only source of supply for the Maritimes and Northeast (M&NE) Pipeline, prior to the commercialization of the Canaport LNG facility. In the summer of 2009, which is a period of peak power demand, there was a planned production outage at the Sable Island gas field. The resulting loss of gas supply was problematic for the New England region and, in particular, the number one consumer of regional gas supplies at that time: the power industry. Fortunately, the Canaport LNG re-gasification terminal (started in July 2009) prevented an extreme incident. However, the difficulties that materialized clearly illustrate the need for increased communication between the two industries, as well as improvements for internal coordination.

- **Pacific Gas and Electric (PG&E):** In 2010 and 2011, three incidents involved the rupture of an old section of cast iron pipe. The most significant involved the rupture of a 36" diameter section on Line 132 of the pipeline system.[44] This section of pipe was 55 years old.[45] In the case of the PG&E incident, there was a significant loss of service due to pressure reductions required by regulators following the incident. This limited the pipeline system's ability to adapt to changes in load requirements, particularly for power plants, because of the reduction in line pack. Following the accident, PG&E took many actions ordered by the California Public Utility Commission, including reducing the operating pressure on Line 132 to 20 percent below the operating pressure.[46]

- **Southwest:** In February 2011 the Southwest experienced both rolling blackouts and significant gas curtailments as the result of extreme winter weather conditions. A similar event occurred in the region in a 1989 incident.[47] While the primary cause of both the blackouts and curtailments was extreme weather conditions,[48] there have been investigations into the need for more integration within both industries. About 52 percent of the over 250 electric generating units that experienced outages and 67 percent of the approximate 1.2 TWh lost were directly weather-related. However, about 15 percent of the lost units and 12 percent of the lost energy were either due to gas supply problems or attempts to switch from gas to alternative fuels.

  With respect to these gas supply problems and the interdependency of the two industries, pipeline companies were not significantly affected by the electric outages, because they typically had gas-fired pipeline compression or backup power supplies on critical equipment. However, further upstream within the gas industry, the loss of electricity did affect the performance of gas producers, gas processing plants and storage facilities, and some electric-driven compressors. While the majority of the gas curtailments were attributed to well freeze-offs, approximately 29 percent of the gas supply in the Permian basin and 27 percent in the Fort Worth (Barnett) basin occurred as a result of shutting down electric pumping units or compressors on gathering lines. Similarly, while processing plants suffered a number of mechanical failures, loss of electricity also contributed to performance problems. Storage facilities with electric compressors were not able to provide the requested storage withdrawals during this period of unprecedented peak gas demand for the region due to the electric supply disruptions.

[42] No electric load was interrupted. Operating Procedure #4 and Master/Local Control Center Procedure #2 were not implemented.
[43] From ISO-NE correspondence dated January 29, 2008.
[44] The other two incidents involved 12" diameter distribution lines for LDCs (UGI Utilities in Allentown, PA, and Philadelphia Gas Works).
[45] Since the initial PG&E incident, there have been three other failures of legacy pipeline on the PG&E system (October 24, November 3, and November 6). All three of these additional incidents occurred during hydrostatic testing of the lines at pressures between 525 and 998 psig. The October incident occurred in a section of pipe in PG&E's Line 300B (part of the backbone of the PG&E system).
[46] Pacific Gas and Electric Company Natural Gas Transmission Pipeline Rupture and Fire San Bruno, California September 9, 2010: www.ntsb.gov/doclib/reports/2011/PAR1101.pdf
[47] See NERC's A Primer on the Natural Gas Industry and its Interface with the Electric Power Industry, 2011; see Appendix A for a discussion of the 1989 incident.
[48] Weather conditions caused frozen sensing lines, frozen equipment, frozen water lines, frozen valves, blade icing, low temperature cutoff limits, well freeze-offs, icy roads that prevented the deployment of maintenance crews, etc.

While the majority of the problems for both industries during the February 2011 events were directly related to weather conditions; rolling blackouts resulted in reduced upstream gas supplies, which in turn resulted in less gas-fired generation. As a result of this incident, there is an investigation into whether critical downstream electric loads in the gas industry should be deemed "human needs" customers and thus be exempted or given special consideration for the purposes of electric load shedding. In some local areas, critical electric loads in the gas industry are already being identified for special consideration in electric load shedding and restoration plans, ensuring that compressor stations are on protected circuits.

As described above, some of the pipeline incidents were the results of acts of nature. While it is not possible to fully protect any system against acts of nature, contingency plans can and should be prepared and constantly reviewed prior to and during the events to ensure system adequacy. When new, unforeseen incidents occur, contingency plans can be adapted as appropriate to incorporate the major lessons learned from such incidents, even if they occur in another region.

Even for incidents that are not directly caused by acts of nature, implementing a lessons learned approach to reliability is likely to reduce vulnerabilities. The following issues are based on NERC's evaluation of prior gas and electric incidents.

Pressure Reductions: While in most instances regional gas flows were restored rather quickly, in at least two cases gas flow was affected for longer periods of time. In such cases, pipeline pressures could be reduced. Gas-fired electric generation units, in particular, are very sensitive to such pressure reductions because of their unique requirements for high burner-tip pressures. In such instances, having access to on-site booster compression for certain (critical) gas-fired units within the region could enhance overall system reliability.

Cast Iron Pipe: Cast iron pipeline sections are largely confined to the distribution systems of gas LDCs and are virtually nonexistent on the interstate pipeline system.[49] While most newer gas-fired power plants are not directly connected to LDC systems, there are many exceptions (e.g., New York Facility System). A key contributing cause of ruptures in cast iron pipeline sections is steadily increased or transient pressures, which is an inherent incompatibility with gas-fired generators' high-pressure demands. While replacement of the legacy pipes continues, acceleration of these efforts could decrease the likelihood of another large disruption.

Wellheads Freeze-Offs: The natural phenomenon of freezing is a common occurrence in the operation of a natural gas pipeline system. Freezing is a potential and serious problem that starts at the production wellhead and continues through the last point in the customer delivery system. Production and gathering systems are typically laden with water vapor, which increases the likelihood of freezing problems. Gas producers use a wide variety of measures to prevent or minimize freezing impacts, such as adding chemicals and other heating systems to prevent freezing. Producers use different weatherization techniques for wells. For example, producers use methanol injection or drip in their wells, they use cold weather barriers, and they increase hauling of fluids from tanks, anti-freeze fluids, heat tracing, hot oil trucks, insulation, burial of lines, and heaters.

Pipelines are usually less likely to be affected by freezing temperatures since the gas has typically been through a treatment facility and a majority of the natural gas liquids have been subsequently removed. The water allowance for typical pipeline tariff gas quality is around 7 lbs. per million standard cubic feet (scf) (roughly 1 U.S. gallon), which is considered to be relatively dry gas and therefore less likely to lead to freezing concerns. Within the normal LDC, the problems associated with freezing should be almost nonexistent.[50]

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[49] At the beginning of 2010 there were approximately 35,600 miles of cast iron pipe and 48,100 miles of unprotected base steel pipe, which represented about three percent of the nation's pipeline infrastructure. LDCs have programs to replace legacy pipes. For example, during the 2004–2009 period, only 5,900 miles of pipe was replaced, while Atlanta Gas Light (AGL) is near the end of a program they started in the mid-1990s to replace their legacy pipe.

[50] Freeze Protection for Natural Gas Pipeline Systems and Measurement Instrumentation, David J. Fish. 2005

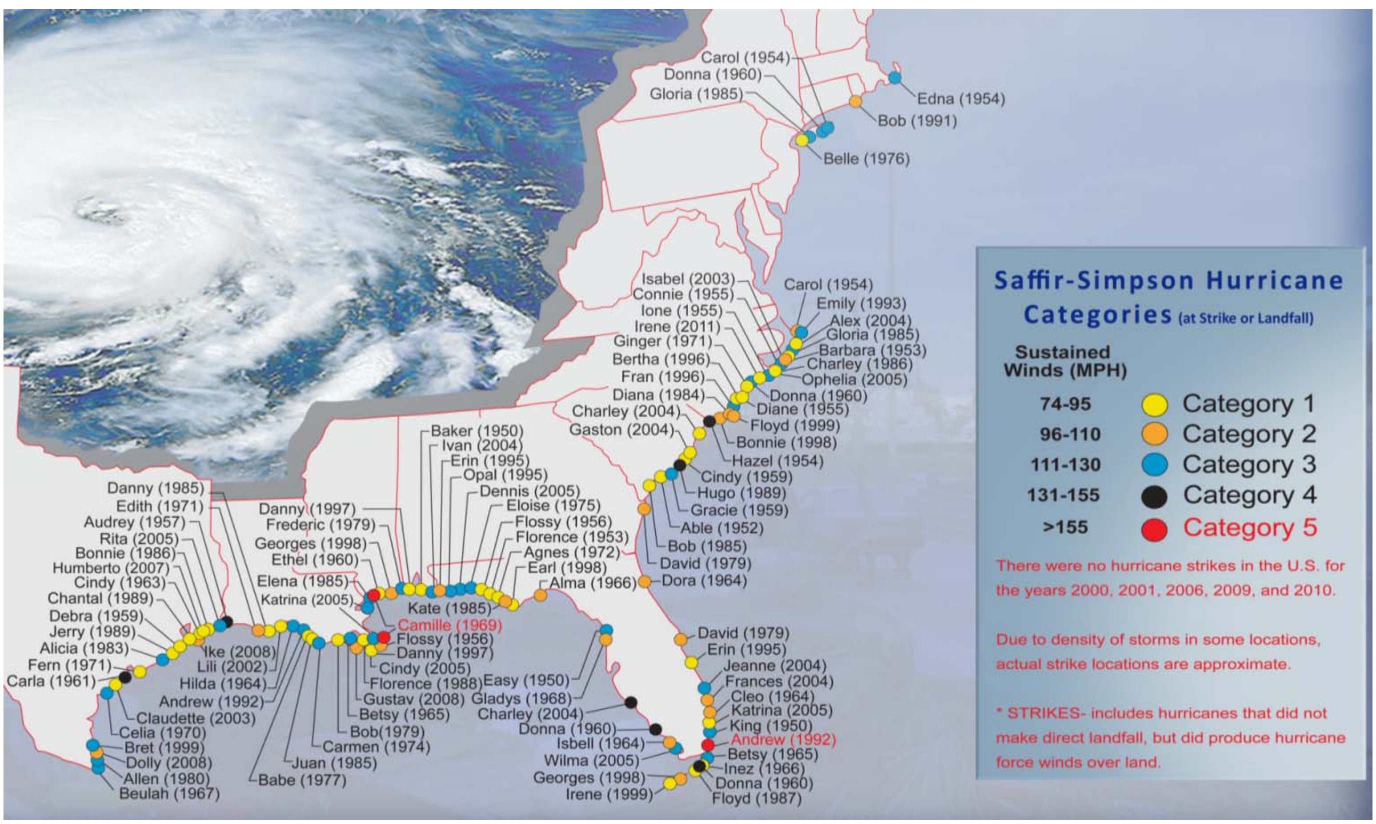
Gas Supply Source Outages and Contingencies

Gas supply sources, gas processing plants, and LNG import terminals may also be modeled using scheduled and unscheduled outage scenarios. For wellhead supplies, the most common form of significant forced outages are freeze-offs caused by extremely cold weather, and hurricanes that lead to abandonment and shut-down of offshore production platforms and damage to various kinds of onshore and offshore production facilities. As an illustration, the effect of hurricanes is discussed below.

Atlantic hurricanes have a long history of passing into the Gulf of Mexico and making landfall along the coast of the United States, as shown in Figure 7. With decreases in Gulf of Mexico production and increases in shale production in regions less impacted by hurricanes, this is less of a concern today.

When hurricanes pass into the Gulf of Mexico, they often disrupt oil and gas production from offshore platforms and in coastal areas. Disruption can be caused by production shut-ins due to the evacuation of personnel from the production area or by damages to production facilities or transmission pipelines that require replacement or repair. Table 1 lists the storms that have disrupted production since 1992 in the Gulf of Mexico. In 11 of the past 21 years, there have been hurricane-level storms that could disrupt Gulf of Mexico oil and gas production. In 6 of 21 years, two or more hurricanes have entered the Gulf. The two most recent high hurricane activity years in the Gulf of Mexico are 2005, which had hurricanes Katrina and Rita, and 2008, which had hurricanes Gustav and Ike. The impact on electric generators is somewhat difficult to assess, because some generators were flooded, and transmission was down due to winds.

Figure 7: Continental United States Hurricane Strikes 1950-2011*[51]



[51] http://www.ncdc.noaa.gov/

Table 1: Storms Causing Disrupted Production Since 1992 in the Gulf of Mexico (Gulf)				
Year	**Storms in Gulf**	**Category 3+ Storms in Gulf**	**Description**	**Estimated Gulf Gas Production Lost (Bcf)**
1992	1	1	Andrew hit S. FL as a Cat 5 and LA as a Cat 3	N/A
1995	2	1	Erin hit E. FL as a Cat 1, crossed into gulf and hit FL panhandle as a Cat 2; Opal landed as a Cat 3 on FL panhandle	19
1997	1	0	Danny came across central gulf and LA tip and landed in Mobile Bay as Cat 1	
1998	1	0	Georges hit Cuba but was down to a Cat 1 when it hit MS	
1999	1	1	Bret hit S. TX as a Cat 3, Irene hit S. FL as a Cat 1	
2002	2	0	Isidore and Lili both Cat 1	76
2003	2	0	Tropical Storm Bill, Claudette Cat 1, and Erika	8
2004	2	2	Charlie Cat 4 hit SW FL and Ivan Cat 3 hit AL/FL border	196
2005	5	3	Cindy Cat 1 hit LA, Dennis Cat 3 hit FL panhandle, Katrina Cat 3 hit LA, and Rita Cat 3 hit TX/LA border	899
2007	0	0	Dean and Felix hit southern Mexico	
2008	3	2	Dolly in late July, Gustav Cat 2 in late August, and Ike Cat 2 in early September	441
2009	1	0	Ida in early November	
2010	0	0	Alex crossed Mexico in June	

The hurricane probability curve in Figure 8 shows actual hurricane disruptions over the past 20 years that have shut in or damaged production. Based on historical events, there is a 40% chance of no hurricane disruption each year, a 29% chance of having multiple Gulf hurricanes, and only a 5% chance of having a very active storm year (like 2005 or worse).

Table 2 lists the assumptions of monthly disruptions behind each point on the probability curve shown in Figure 8. Hurricanes Gustav and Ike disrupted about 5.5 Bcfd out of 8.0 Bcfd (69%) of the Gulf of Mexico's gas production in September 2008. Hurricane damage kept some production out of service for the rest of the year, with some facilities not resuming production until April 2009. The total production loss for 2008 was about 1.0 Bcfd (13%) of the possible 8.0 Bcfd of annual Gulf gas production, and only about 1.4% of total U.S. and Canadian production in 2008. In 2012, Gulf of Mexico offshore production was about 5.2 Bcfd out of about 81 Bcfd of U.S. and Canadian gas production.

The probability assumptions for a Gulf hurricane should still be valid for reliability assessment purposes, but the size of the disruption should be scaled down to the current level of Gulf offshore production that is caused by unconventional gas production within regional shale plays. Natural gas storage also can significantly help mitigate these supply disruptions.

Figure 8: Hurricane Disruptions

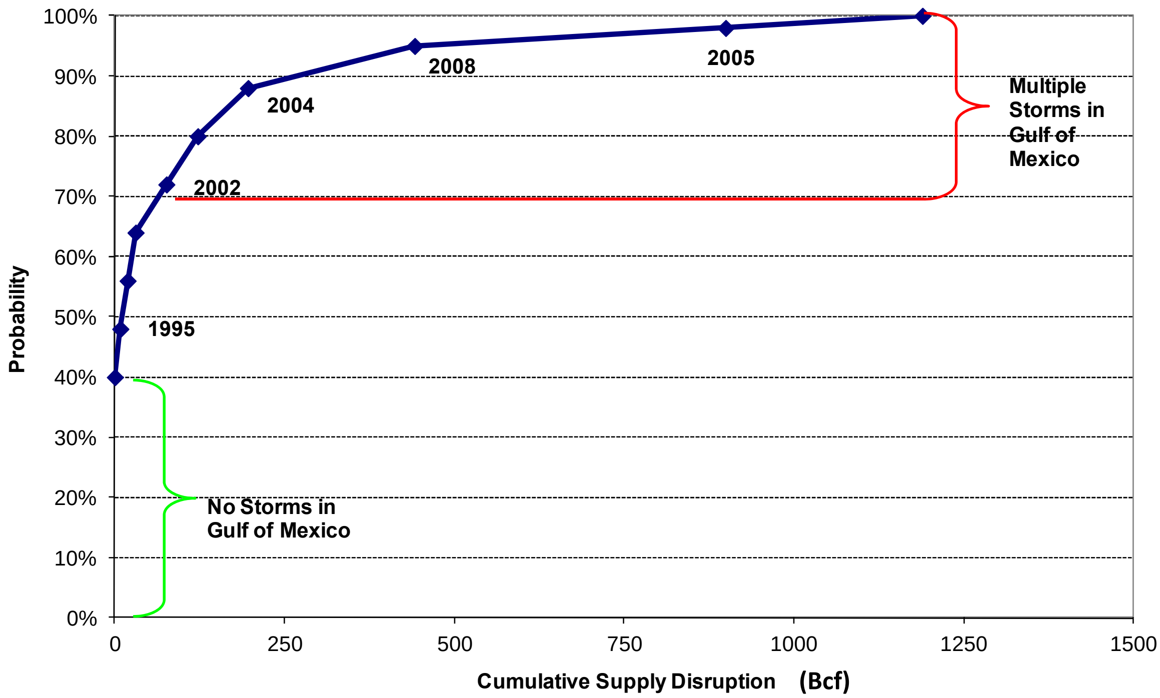


Table 2: Monthly Disruption Assumptions

Hurricane Disruption Type (Point on Curve in Figure 7)		0	1	2	3	4	5	6	7	8	9
Disruption Pattern Based on Historical Hurricanes in Year		Multiple Years	2003 Bill, Claudette, & Erica	1995 Opal	ICF Generic Outage Assumed in all forecast years	2002 Isidore & Lili	Not Historical, ICF Made up Disruption	2004 Bonnie, Charlie, Frances, & Ivan	2008 Gustav & Ike	2005 Cindy, Dennis, Emily, Katrina, & Rita	Not Historical, ICF Worst Case
Description of Disruption		No Hurricanes in Gulf	Minor storms early in the season, no damage	Minor late-season storm, no damage	One or two storms in Sep or Oct, no damage	Two strong late-season storms in Gulf. Minor damage from second storm	Two major storms: one early and one late. Minor damage in both storms	Active year. Last storm caused damage that took several months to repair	Two major storms at end of summer. Outages carried into the next year	Heavy activity through summer and fall. Extensive damage into the next year	Worst hurricane year in 100 years. Massive damage offshore and onshore
Probability of Disruption (%)		40%	8%	8%	8%	8%	8%	8%	7%	3%	2%
Cumulative Probability (%)		40%	48%	56%	64%	72%	80%	88%	95%	98%	100%
Cumulative Disruption (Bcf)		0	-8	-19	-31	-76	-122	-196	-441	-899	-1189
Offshore Disruption (%)		100%	100%	100%	100%	100%	100%	100%	100%	75%	65%
Onshore Disruption (%)		0%	0%	0%	0%	0%	0%	0%	0%	25%	35%
Offshore Disruption (Bcf)		0	-8	-19	-31	-76	-122	-196	-441	-674	-773
Onshore Disruption (Bcf)		0	0	0	0	0	0	0	0	-225	-416
Days	**Month**	**Monthly Disruption (Bcfd)**									
31	July	0.00	-0.25	0.00	0.00	0.00	-1.50	0.00	0.00	-0.85	-2.00
31	August	0.00	-0.01	0.00	0.00	0.00	-0.50	-0.13	-0.29	-1.10	-4.00
30	September	0.00	0.00	0.00	-0.50	-0.53	-2.00	-1.90	-5.45	-6.10	-7.00
31	October	0.00	0.00	-0.61	-0.50	-1.93	0.00	-1.66	-2.77	-6.20	-6.50
30	November	0.00	0.00	0.00	0.00	0.00	0.00	-1.04	-1.92	-4.00	-5.00
31	December	0.00	0.00	0.00	0.00	0.00	0.00	-0.60	-1.44	-2.70	-3.50
31	January	0.00	0.00	0.00	0.00	0.00	0.00	-0.57	-1.10	-2.00	-3.00
28	February	0.00	0.00	0.00	0.00	0.00	0.00	-0.30	-0.85	-1.70	-2.00
31	March	0.00	0.00	0.00	0.00	0.00	0.00	-0.14	-0.50	-1.60	-2.00
30	April	0.00	0.00	0.00	0.00	0.00	0.00	-0.10	-0.25	-1.30	-1.50
31	May	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-1.10	-1.50
30	June	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-0.90	-1.00

Gas Shales Reduce Risk from Weather-Related Supply Shortages

Perhaps the most important factor in assessing gas supply risks is abundance of gas shale plays across North America (Figure 9), which reduce the risk of supply shortages. As described in the previous chapter, historical gas supply shortages have been due largely to hurricane or cold weather disruptions across the Gulf of Mexico. With shale gas production spreading geographically across the continent, single points of failure in gas supply due to weather events can be somewhat mitigated by increasing production in other unaffected areas. For example, increased Marcellus shale production could aid the mitigation of supply disruptions in the Gulf of Mexico. However, without transportation, mitigation through these alternative supply sources can be limited. Additionally, a higher risk of wellhead freeze-offs should also be considered within these types of mitigation strategies.

Figure 9: North American Shale Plays Reduce Risk of Weather-Related Vulnerabilities to Gas Supply

Source: U.S. Energy Information Administration based on data from various published studies. Canada and Mexico plays from ARI.
Updated: May 9, 2011

From 2010 to 2012, hurricanes such as Irene and Sandy had minimal impact on gas supply. Despite shutting in on more than one occasion, the Gulf of Mexico region had almost no impact on the national supply because of the new sources of gas such as the Marcellus fields in western Pennsylvania. Marcellus now produces almost 6 Bcfd and greatly decreases northern regions' dependence of gas transportation from southern regions.

Chapter 4—Scenario Reliability Assessments

Resource Adequacy Scenario Assessment

Similar to other reliability studies that stress system conditions to measure a given area's resilience to BPS contingencies, resource adequacy assessments can be stressed to measure a given area's resilience to various extreme scenarios. Such efforts can reveal how dependent an area's overall resource adequacy is on gas-fired generation. They can also identify potential capacity shortfalls and determine the time frames in which issues may occur and could be resolved. As a supplement to reliability assessment (e.g., 50/50, normal case), scenarios can provide additional insight to regional diversity and sensitivity.

Scenario Methods and Assumptions

The scenario focuses on 18 assessment areas instead of NERC Regions (with the exception of WECC[52]). The results from each assessment area can be found by accessing a link on the NERC website.[53] The data was collected from each assessment area for the *2012 Long-Term Reliability Assessment*. It was used to calculate the Net Internal Demand, available capacity, and planning reserve margins that are used in this assessment. This study analyzes the assessment areas' planning reserve margins in the case of the extreme scenario when demand increases by 5 percent for the summer peak scenario and 10 percent for the winter peak scenario[54] and a portion of the gas-only capacity is assumed to be unavailable.

The winter scenario is a more important analysis since natural gas transportation interruptions and supply curtailments are more likely to occur in the winter. In the summer, the demand for residential natural gas is lower than in the winter and as such, capacity release on the secondary market is generally greater than in the winter. Furthermore, it provides additional pipeline capacity that can be reasonably relied on for interruptible service; therefore, the amount of gas-fired generation that can be reasonably assumed to be unavailable in this scenario is greater in the winter.

In the summer scenario, the total capacity from non-dual-fuel gas-fired combustion turbines is reduced by 30 percent, and a combine-cycle capacity is reduced by 10 percent. Additionally, the capacity from units with dual-fuel capability is reduced by 25 percent. In the winter scenario, non-dual-fuel gas combustion turbines will be reduced by 75 percent, and a combine-cycle capacity will be reduced by 25 percent.[55] Additionally, the capacity from units with dual-fuel capability is reduced by 50 percent. The assumptions for this scenario analysis are provided in Table 3.

Table 3: ASSUMPTIONS & METHODS FOR SCENARIO ANALYSIS

	Summer	Winter
Net Internal Demand (NID) Increase	5%	10%
Non Dual-Fuel Gas Turbine Unavailable/Derate	30%	75%
Non Dual-Fuel Combined Cycle Unavailable/Derate	10%	25%
All Gas-Fired Dual-Fuel Unavailable/Derate	25%	50%

[52] The WECC Region, for this scenario, was not assessed at the subregional due to variations in transfers that would result.
[53] Resource Adequacy Scenario Analysis & Tool: http://www.nerc.com/docs/pc/ras/2013GasScenarioRAS.xls
[54] Generally corresponds to more than one standard deviation from a normal 50/50 forecast
[55] Scenario assumptions were developed for sensitivity analysis. In a practical sense, combined cycle units are more likely to have a firm contact than a combustion turbine, due to its generally higher capacity factor. Therefore, the likelihood for combustion turbines due to a lack of fuel is larger than combined cycle units. Future analysis should identify scenario assumptions that are representative of regional differences as an enhancement to "blanket" assumptions for all areas.

Scenario Results

Based on the methods and assumptions described in the previous section, results are provided by assessment area in Figures 13 (summer peak) and 14 (winter peak). Overall results indicate that for both summer and winter peak periods, with a 5 and 10 percent increase in peak demand, respectively, most areas have sufficient resources to cover the assumed gas-fired generator outages. However, the capability to fuel gas-fired generators with alternate fuels (e.g., oil) plays an important role within this assessment. In this scenario, the assumption is that only a portion of dual-fuel generators are able to perform on their secondary fuel within appropriate timeframes to offset additional impacts. Without this dual-fuel capability, the reductions in generator availability for gas turbines and combined-cycle generators would be more significant. With the exception of ERCOT in the summer and SaskPower in the winter, scenario projections do not show significant concerns in the 2015 and 2017 seasonal peaks. The scenario points out that over the projected ten-year period, region-wide resource adequacy concerns may not be a significant risk to the BPS; however, it shows that more granular analysis is needed in areas with known operating and emerging issues as a result of increasing gas-fired generation—such as New England. The following chapters describe the type of analysis that can support a more detailed, risk-based analysis.

Figure 10: Anticipated Reserve Margin Scenario (from *2012LTRA*) with 5% Demand Increase – Summer

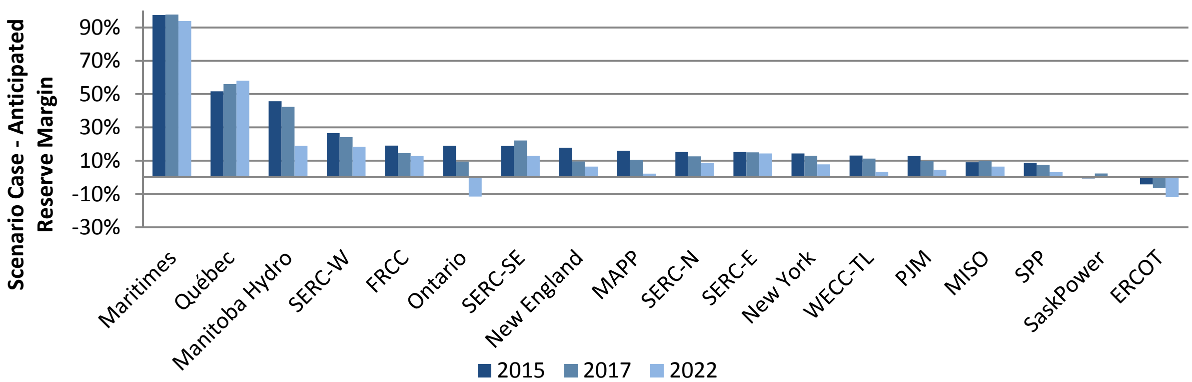
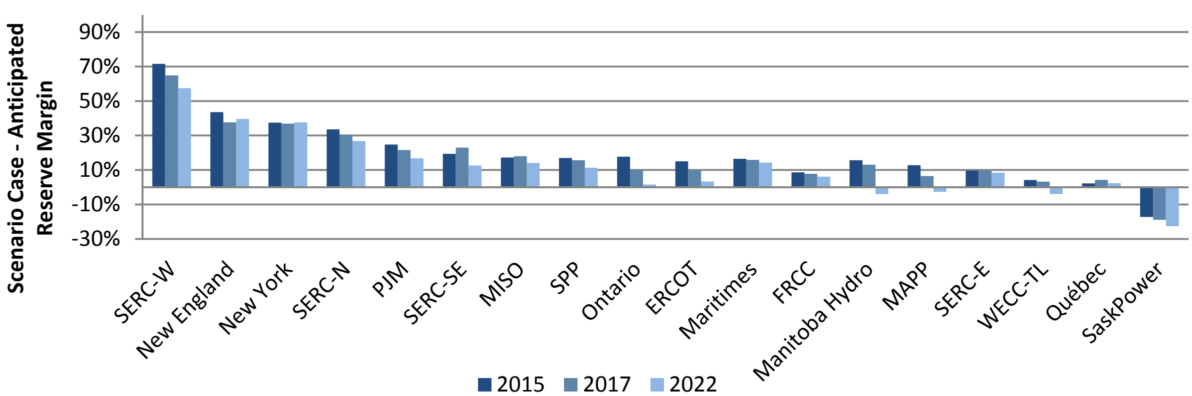


Figure 11 : Anticipated Reserve Margin Scenario (from *2012LTRA*) with 10% Demand Increase – Winter



Alternative Analysis

Because the assumptions in the scenario assessment would be most accurately applied if based on a regional risk profile—versus a more widely applicable assumption—an alternative approach to understanding the resource adequacy risk is to determine how much gas capacity could be lost in an assessment before planning reserve margins fall to zero. The analysis provided in Figure 12 identifies the amount of gas-fired capacity reduced so that the resulting planning reserve margin is equal to zero percent. This is calculated for both summer and winter peak hours in absolute terms, as a percent of non-dual-fuel gas-fired capacity, and as a percent of the total gas-fired capacity. Analysis for the forecast years of 2013, 2015, 2017, and 2022 is shown by assessment area. Areas with lower percentage values are more vulnerable to gas supply or transportation disruptions since negative values indicate a deficit from zero without the loss of any capacity.

Figure 12 : Stress Test Analysis on Extreme Demand Scenario Case (10 % Increase)

Summer Scenario Case: Amount of Gas Capacity Causing the Planning Reserve Margin to Equal 0%

Assessment	2013			2015			2017			2022		
Area	X MW	% NDF	% ∑Gas	X MW	% NDF	% ∑Gas	X MW	% NDF	% ∑Gas	X MW	% NDF	% ∑Gas
ERCOT	2,234	7%	6%	(2,856)	-9%	-7%	(4,730)	-14%	-11%	(9,891)	-29%	-23%
FRCC	7,477	-	29%	8,277	-	32%	6,467	79%	23%	6,387	47%	19%
MISO	9,660	59%	34%	8,237	51%	29%	8,903	55%	31%	5,789	36%	20%
MAPP	949	-	89%	781	-	73%	507	71%	48%	21	3%	2%
New England	5,973	49%	43%	5,084	41%	37%	2,747	22%	20%	1,876	15%	14%
New York	5,061	61%	35%	4,511	54%	31%	4,072	-	28%	2,224	27%	15%
PJM	25,103	-	48%	15,509	-	31%	11,165	85%	21%	2,857	22%	5%
SERC-E	6,285	-	39%	5,633	89%	33%	5,642	89%	33%	5,864	65%	29%
SERC-N	5,831	-	34%	5,695	-	34%	4,556	-	27%	2,746	92%	16%
SERC-SE	9,417	-	35%	8,764	-	33%	10,672	-	40%	6,067	70%	23%
SERC-W	6,819	-	31%	6,785	-	31%	6,294	-	28%	4,910	-	22%
SPP	5,664	27%	19%	5,970	28%	20%	5,370	25%	18%	2,857	13%	9%
Manitoba	1,066	-	-	1,416	-	-	1,334		-	555	-	-
SaskPower	125	9%	9%	52	4%	4%	291	16%	16%	273	13%	13%
Maritimes	3,182	-	-	3,110	-	-	3,119		-	3,056	-	-
Ontario	6,308	-	96%	4,580	73%	69%	2,219	37%	36%	(2,995)	-55%	-52%
Québec	9,680	-	-	10,440	-	-	11,658		-	12,292		-
WECC-TL	23,443	46%	26%	24,197	44%	26%	21,794	39%	23%	8,532	16%	9%

Winter Scenario Case: Amount of Gas Capacity Causing the Planning Reserve Margin to Equal 0%

Assessment	2013/2014			2015/2016			2017/2018			2022/2023		
Area	X MW	% NDF	% ∑Gas	X MW	% NDF	% ∑Gas	X MW	% NDF	% ∑Gas	X MW	% NDF	% ∑Gas
ERCOT	21,626	68%	53%	19,758	59%	47%	17,709	50%	40%	13,735	39%	31%
FRCC	10,875	-	39%	10,897	-	37%	10,911	-	33%	11,372	72%	29%
MISO	32,832	-	-	27,107	-	90%	27,890	-	93%	25,036	-	83%
MAPP	1,330	-	-	1,259	-	-	931	-	82%	371	48%	33%
New England	14,326	-	92%	14,218	-	91%	12,756	91%	82%	13,081	93%	84%
New York	15,462	-	96%	13,922	-	86%	13,812	-	85%	14,335	-	89%
PJM	51,649	-	99%	44,662	-	88%	41,723	-	78%	36,193	-	68%
SERC-E	8,466	-	52%	7,864	-	44%	7,987	-	45%	8,192	96%	39%
SERC-N	20,802	-	-	19,756	-	-	18,614	-	98%	17,488	-	92%
SERC-SE	15,332	-	53%	15,126	-	52%	17,223	-	60%	12,416	-	43%
SERC-W	21,225	-	70%	21,334	-	70%	20,549	-	67%	19,556	-	64%
SPP	16,115	82%	58%	16,625	85%	60%	16,291	81%	58%	14,788	72%	51%
Manitoba	868	-	-	911	-	-	794		-	(127)	-	-32%
SaskPower	187	12%	12%	133	7%	7%	227	11%	11%	212	9%	9%
Maritimes	1,192	-	-	1,151	-	-	1,125		-	1,048	-	-
Ontario	7,649	-	-	7,388	-	-	5,330	86%	82%	3,176	55%	52%
Québec	300	-	-	941	-	-	1,890		-	1,194		-
WECC-TL	36,665	69%	39%	38,554	68%	40%	37,628	66%	39%	25,672	46%	27%

Note: "-" for %NDF indicates that the area can lose all Non-Dual-Fuel gas and still remain above a zero percent planning reserve margin. Likewise, a "-" for % ∑Gas indicates that the area can lose all gas-fired capacity and still remain above a zero percent planning reserve margin

Key

X MW	Capacity needed to reduce an area's reserve margin to 0%
% NDF	X MW divided by the total non-dual fuel gas available in an assessment area
% ∑Gas	X MW divided by the total gas available in an assessment area (non-dual fuel + dual fuel)

Pipeline Disruption Scenario

In addition to evaluating the gas–electric interface through a series of historical disruptions, there are other factors that should be considered when assessing regional BPS reliability. As discussed in NERC's *Primer* report,[56] a key attribute of pipeline flexibility is line pack. Line pack is the amount of gas held in the pipeline at any given time and represents a localized form of short-term storage that pipeline operators can use to meet fluctuating demand of firm customers. Most pipelines use line pack as a resource to help manage the load fluctuations on their systems, building up line pack during periods of decreased demand and drawing it down during periods of increased demand. This feature of pipeline operations historically has enabled the pipeline to adapt to unexpected or abrupt changes in load requirements. However, gas-fired generator reliance on pipeline line pack to respond to unexpected events, such as weather or unplanned outages of other units, is of limited value. Pipelines use line pack to ensure nondiscriminatory service to all firm customers and is not designed or utilized to mitigate large contingency events.

Also discussed below is the possibility of expanding the detailed contingency planning studies to include extreme-case scenarios for the possible disruption of regional gas supplies; for example, a single point of failure. While the fuel supply dynamics for each electric generator and region are unique, two simplified examples (a loss of critical compressor station and pipeline break) are presented to illustrate potential extreme-case scenarios for interruptions in the delivery of gas supplies to that region.

While each pipeline's line pack dynamics are unique, NERC's *Primer* report[57] presented typical examples of the use of line pack to meet unexpected increases in electric power load requirements. For example, an unexpected weather event impacts the gas load requirements of several gas-fired power plants connected to the same pipeline. The conclusion drawn from the examples reviewed in the NERC *Primer* is that pipeline line pack at best represents a limited buffer and should not be expected to reliably mitigate gas supply or transportation disruptions.

Primarily because of the inability to store electricity, electric utilities perform extensive contingency analysis for their systems at both the local and regional levels. These assessments are conducted most often by analyzing the capability of the electric system to operate in the event that any single part of the system were suddenly to fail. For example, the single-largest contingency in New England that the ISO must be ready for is the nearly 1,900 MW that could be lost due to the failure of the Hydro Quebec Phase II transmission line. Since failures propagate nearly instantaneously throughout the electric system, grid operators must maintain power supplies that can respond instantaneously in the event of a contingency. In addition, if a contingency were to occur, the electric system operators must replenish "instantaneous" operating reserves within a short period of time, usually 10 or 30 minutes, in order to be postured for the next potential contingency.

As gas-fired generation increases, both industries may find it valuable to perform a similar set of contingency assessments on pipeline systems. Such contingency assessments would enable the power industry, if not both industries, to uncover means of being better prepared to handle a contingency event involving the loss of delivered gas supply to gas-fired units within a region and mitigate the potential resulting domino effect.

Two such possible contingency assessments are outlined below for a hypothetical gas and electric system,[58] which is highly dependent on gas generation but has limited access to gas supplies. These examples are intended to serve as an illustration of a possible contingency assessment and may not be representative of actual pipeline and gas-fired generator interconnections. Since the primary purpose of these examples is to be illustrative, steady-state or transient hydraulic flow

[56] See Chapter 7 of NERC's A Primer on the Natural Gas Industry and its Interface with the Electric Power Industry, 2011.

[57] See Chapter 7 and Appendix F of NERC's A Primer on the Natural Gas Industry and its Interface with the Electric Power Industry, 2011.

[58] A hypothetical system was developed for this analysis using hypothetical pipeline and system topological information such as pipeline diameter, pipeline lengths, generator locations, and generator pressure requirements. The total electric system capacity is 3,500 MW which is made up of generators of various sizes and capabilities.

analyses was not used to analyze these examples. When undertaking similar analyses, Planning Coordinators, in concert with the pipelines serving their region, would take the extra time to thoroughly research and identify the specifics of the region's current operating conditions and topological configurations. The end goal for these types of scenario studies is to determine credible contingencies for which the BPS should be planned and operated to withstand.

Failure of a Critical Pipeline Compressor Station

Figure 13 provides a visual representation of a hypothetical pipeline that could be affected by the sudden failure of a single compressor station (all compressors and backup compressor). In this example, a compressor station failure at a downstream location would impact gas pressures and flows over a wide dispersion of generators as the downstream gas demand draws down pressure in the pipeline. For simplicity, only those power plants that are known to be natural gas only are considered impacted (dual-fuel units were excluded). Also, the capability of using remedial pressure and flow from other pipelines is not considered, although interconnections with other pipelines, natural gas storage, and LNG could potentially provide remedial pressure and flow downstream of the affected compressor station.

Figure 13: Compressor Failure Scenario

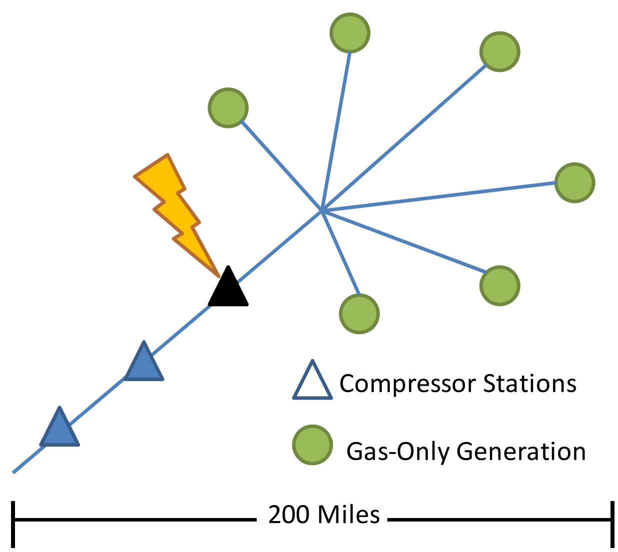


Figure 14: Time Profile of Capacity Lost Due to Loss of Compressor Station

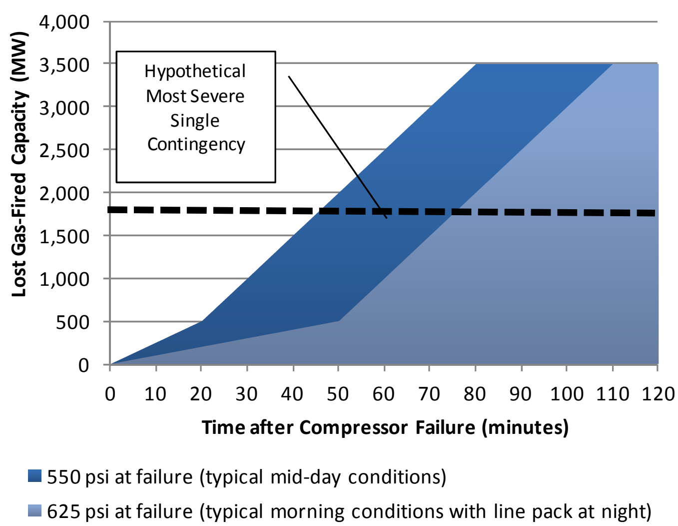


Figure 14 shows the profile of how much gas-only power plant capacity would become unavailable over time due to this particular compression station contingency. Under this scenario, approximately 3,500 MW is lost over a span of 80–110 minutes, depending on the pressure of the pipeline at the time of the contingency.

The one-to-two-hour time frame of the contingency implies that the electric system operators would have the opportunity to locate and dispatch replacement power supplies online if they are available. It may be more difficult to replace this capacity if these units had dual-fuel capability and had to switch during the allotted scenario time frame. In addition, it is possible that not all of the impacted units would be operating during the contingency. However, no rules or tools currently known to exist that dictate that the electric system operators would—or should—avoid operating all units simultaneously during any specific period.

Line Break Scenario

A more serious hypothetical contingency scenario involving a line break for the same hypothetical gas and electric system, as shown in Figure 15, would result in a rapid drop in pipeline pressure. Line break refers to a physical rupture or a break of the natural gas pipeline. Often, large interstate pipelines consist of two or more separate pipelines—sometimes within a single right-of-way. This scenario assumes a rare event where the capability to transport gas along a single corridor is completely lost. In this scenario, natural gas could not continue to flow to downstream consumers, as was the case in a compressor failure. Downstream gas pressure was lost more rapidly as natural gas was released quickly from the ruptured pipeline to the atmosphere. For this contingency, there is no benefit gained through existing interconnections with other pipelines.

Calculations of how fast and how much of the gas-only capacity would be lost under this scenario are shown in Figure 11. Figure 16 also shows that within 16 minutes, as much as 3,500 MW could be lost.

Figure 15: Line Break Scenario

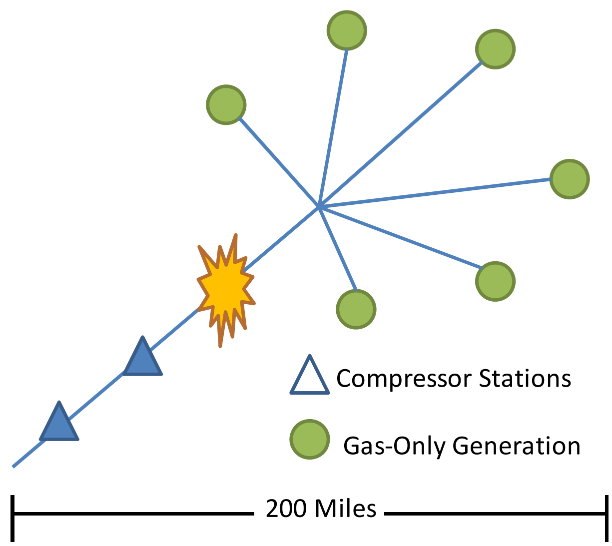
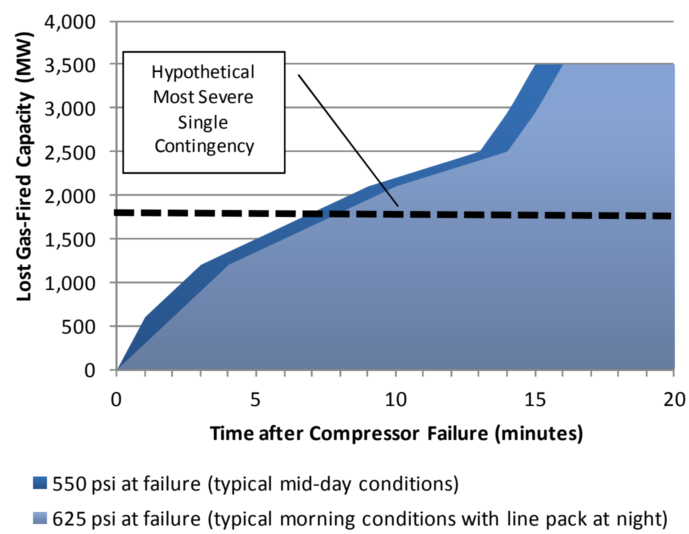


Figure 16: Time Profile of Capacity Lost Due To Line Break



The impact on the electric system is similar in magnitude to the compressor failure scenario. However, the period of time after the event during which this pipeline capacity is lost is much shorter, leaving less time for execution of emergency plans. During times of high electric and natural gas demand, flexibility of pipeline interconnections and dual-fuel capabilities could be minimal and may not provide sufficient mitigation. Joint study of these scenarios present the opportunity for gas and electric entities to develop an assessment that could help identify credible contingencies to study, determine constraints on both systems, and develop potential mitigation strategies should these events manifest.

Chapter 5—Methods for Analyzing Natural Gas Demand and Infrastructure for Electric Power Needs

The natural gas system is designed to serve its firm load customers, yet much of the electric power industry--particularly in wholesale electric markets—depends on interruptible service. This chapter describes recommended techniques for analyzing the natural gas demand characteristics in a given area and for assessing the adequacy of natural gas infrastructure to meet non-power and power demands. This study addresses how planners can estimate the number of days in which gas-fired power generators will not be able to procure natural gas supplies and thus may not be available to supply power. The results could be incorporated into the electric power resource adequacy models to more accurately estimate the key adequacy metrics, such as Loss-of-Load Expectation (LOLE), Loss-of-Load Hours (LOLH), and Expected Unserved Energy (EUE). An important feature of integrating these suggested analyses with existing tools is the ability to incorporate existing operational solutions into the planning models (e.g., demand response, voltage reduction, public appeals, etc.). By incorporating results from a natural gas fuel and infrastructure assessment into probability-based resource adequacy models, an accurate representation of risk can be quantified and then translated into risk-based planning solutions. The results of this analysis also could serve as information for generators to determine the appropriate level of natural gas service to meet their reliability needs and, upon a generator making contractual commitments, for pipelines to determine if additional infrastructure is necessary to meet that demand.

Because of the complexities and extensive data requirements involved in assessing the impact of fuel availability on electric system reliability, NERC recommends a three-layered approach to this analysis. The first step (Layer 1) is to assess the capacity of the gas infrastructure under normal operating conditions, and compare that capacity to the gas load by developing daily gas load duration curves for a specific set of weather conditions (e.g., 50/50 or 90/10 probabilities of forecast load). This provides an indication of the potential for fuel-related outages if the gas system is fully operational. The second step (Layer 2) is to compare the same gas load duration curves to gas infrastructure capacity under selected gas transportation contingencies, such as a compressor station outage or mainline capacity reduction. This provides an indication of the additional incremental fuel outages that could be caused by potential large disruptions with the regional gas system.

While Layer 1 and Layer 2 provide an initial assessment of the potential severity of fuel-related outages, they do not fully quantify the probability that demand for gas will not be met. The third step (Layer 3) is to perform a Monte Carlo analysis, which examines a wide range of weather and gas supply and/or transportation conditions to determine how often expected power sector gas demand cannot be served and the resulting threat of potentially lost electric loads. A more detailed description of each of the three layers to this approach is provided below. Figure 17 highlights how Layer 3 (Monte Carlo analysis) differs from the analysis performed in Layers 1 and 2. The key difference is that the Monte Carlo analysis would provide a probabilistic assessment of the impacts of weather and contingencies on electric system reliability.

Figure 17: Features of Each Layer of Analysis

Scenario	Layer 1: Compare Gas Infrastructure Capacity to Gas Load Duration Curves	Layer 2: Assessing the Impact of Gas Supply Contingencies	Layer 3: Monte Carlo Analysis of Gas and Electric Systems
Weather Scenarios	Limited number of scenarios examining average (50/50) and extreme (90/10) weather	Limited number of scenarios examining average (50/50) and extreme (90/10) weather	Full weather probability Monte Carlo cases with hundreds of combinations made consistent with actual weather patterns among regions
Gas System Contingencies	Not considered	Used to adjust gas supply capability, but no probabilistic analysis	Can be incorporated as probability distributions within Monte Carlo analysis and can be correlated to weather
Electric System Contingencies	Not considered	Not considered	Can be incorporated as probability distributions within Monte Carlo analysis and can be correlated to weather
Regional Detail	Limited to examining larger regions	Limited to examining larger regions	Finer level of detail to examine intraregional constraints
Time Steps for Analysis	Daily over forecast year	Daily over forecast year	Hourly over forecast year
Plant Dispatch and Interregional Electricity Flows	Static	Static	Includes dynamic plant re-dispatch to move generation among control areas based on electric and gas contingencies
Gas Flows Into and Out Of Region	Endogenously calculated based on weather case	Endogenously calculated based on weather case and contingencies	Endogenously calculated based on weather case and contingencies
Integration of Results into Electric Reliability Calculations (e.g., LOLE)	Not considered	Not considered	Provides quantification of probabilities of fuel supply interruptions. This could be directly input into electric reliability estimation processes in different ways.

Layer 1: Comparing Gas Infrastructure Capacity to Gas Load Duration Curves

There are three basic steps to this layer of the analysis:

1. Define the boundaries for the region being analyzed and assess the current and projected natural gas supply and transportation capabilities under normal operating conditions for the region.
2. Assess the current and projected power and non-power gas loads for the region based on weather conditions and seasonal diversity.
3. Compare the supply capabilities to the total projected gas load to determine the amount of unmet gas demand in the region.[58]

The first step is to define the boundaries of the region of the dispatch area being analyzed. The region could be as large as a single ISO or RTO, or could be a smaller area, such as a market zone. Within this region, the characteristics of the gas system must be quantified to assess the current supply capabilities. The current gas supply capabilities for a region include inbound pipeline capacity, less the amount of capacity firmly contracted by downstream customers, plus other supply sources within the node, such as underground storage, LNG/CNG and propane-air peak shaving storage, and LNG import capabilities. Pipeline system capacity can be determined by assessing the physical capability of the systems (number of lines, line diameter and operating pressure), as well as data posted on the pipeline's bulletin board, such as design capacity, operationally available capacity, and the pipeline's index of customers. The FERC index of customer data can be used to assess the daily volumes of firm pipeline transportation capacity contracted within a given region and the amounts contracted by customers further downstream (of the study area) to determine the net pipeline capacity available for the region under consideration.

Questions Answered in Layer 1 Analysis

- What are the characteristics of the current natural gas infrastructure? How much supply capability currently exists in different markets?
- How much pipeline capacity is contracted in different markets?
- What are the locations and the sizes of gas-fired generating units within the region? What type of gas transportation contracts do they hold?
- How does weather impact both power and non-power daily gas loads?
- How do daily load swings affect the assessment of gas supply?
- What impact does dual-fuel capacity have on power gas loads and electric system reliability?

To create scenarios for the region's future gas supply and transportation capabilities, it is necessary to account for any planned change to existing infrastructure that would have a significant impact on the region's gas market, such as:

- New pipelines or incremental capacity increases on existing systems
- Planned abandonments or conversion of existing gas pipelines that may reduce capacity
- New storage facilities or storage field abandonments
- Impact of new facilities or changes in the operation of existing facilities:
  - Local gas peak shaving facilities
  - LNG import terminals, operations, and supply contracts

[58] By design, the gas system is planned and operated to serve only its firm load customers.

- LNG export terminals
- Large, industrial gas-consuming facilities, such as ammonia and gas-to-liquids (GTL) plants.

Not all planned changes may occur. For example, two competing pipeline systems may announce plans for capacity expansions, but only one may get the firm contract commitments needed to proceed with the expansion. Therefore, it is necessary to apply a confidence factor to the chances of each of the planned infrastructure changes. Announced plans generally only extend a few years into the future. When looking 5 to 10 years ahead, it is also necessary to assess the growth of gas LDCs' firm demand within the region and to assess what type of new pipeline and storage infrastructure they are likely to require as their firm loads increase.

The next step in Layer 1 is to project the daily loads for both power and non-power (firm residential, commercial, and industrial) customers based on a discreet set of weather conditions. Gas consumption is closely correlated with weather, and therefore, projections for daily gas loads can be determined by analyzing historic load and weather (daily temperature) data. Electric load and dispatch analyses can provide the similar gas demands as projected power generation gas demand. For this type of analysis, a daily gas load model (DGLM) was created to project daily gas loads as a function of temperature. The DGLM uses regression-based equations to estimate the amount of demand by sector (residential, commercial, industrial, and power) as a function of the average daily temperature.[59]

Figure 18: Non-Power and Power Gas Demand as a Function of Temperature

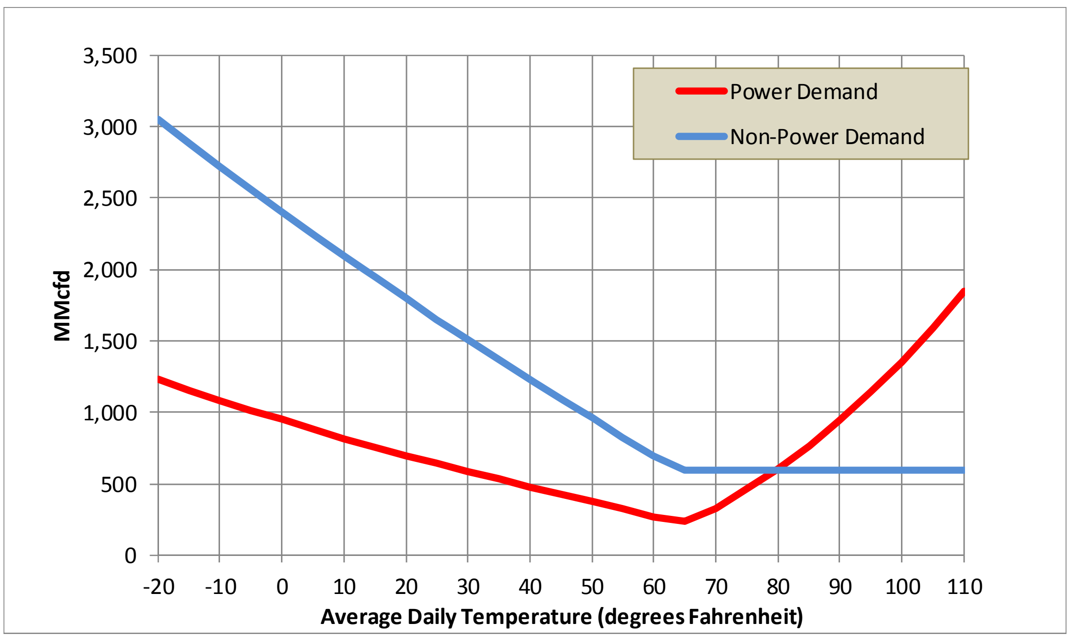
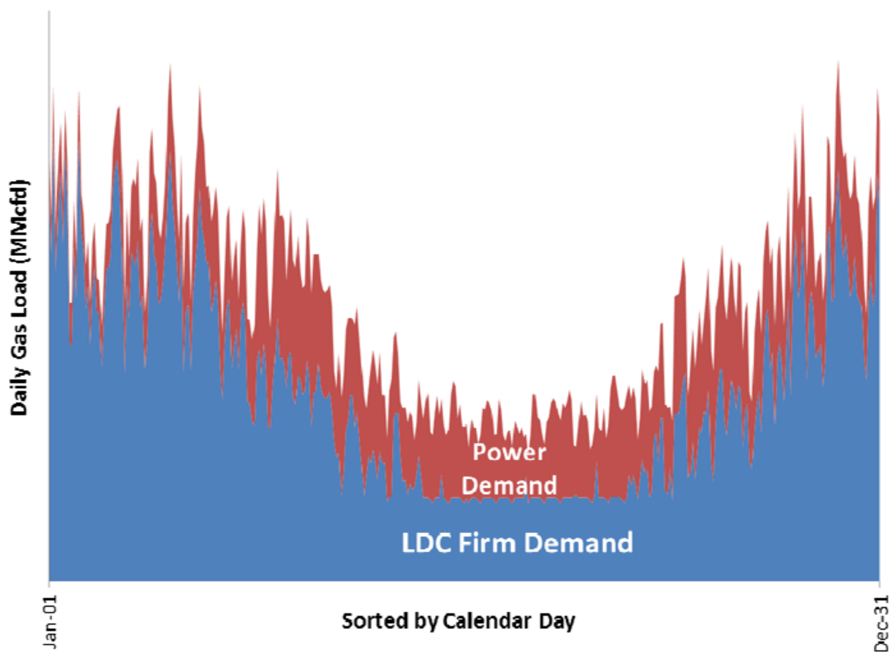


Figure 18 provides an example of how power and non-power demand for gas changes as a function of temperature. As the average daily temperature increases, non-power load decreases due to lower heating demand. At the high end of the temperature range, space-heating load is virtually zero, and all that remains is non-space-heating load, such as water heating and cooking applications. In contrast, power demand has a u-shaped curve, with high demand at both very low and very high temperatures, and lower demand at moderate temperatures. Figure 19 provides an example of one year of daily gas load ordered by calendar days (January 1 to December 31).

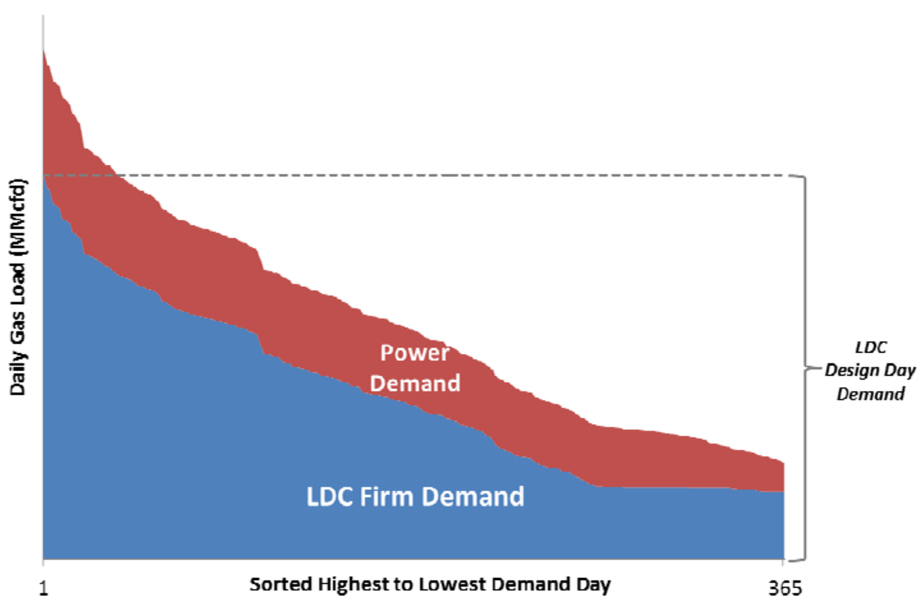
[59] The regression analysis used for the DGLM is based solely on average daily temperatures. This same type of approach could also include other weather variables that have an impact on gas and electricity demand, such as dew point, relative humidity, wind speed, cloud cover, precipitation, wind chill, and heat index.

Figure 19: Natural Gas Daily Load Profile Example



Another way to examine this data is to order the demand days from highest to lowest, as shown in Figure 20. LDCs contract for supply and interstate pipeline transporation and design their distribution systems according to firm customer demands on a very cold winter day, usually equal to the coldest day observed in the past 30 years. In the example load curve below, the peak day is based on the gas LDC "design day" specification, and the total demand over the course of the winter is based on a 90th percentile (1-in-10 probability) winter temperatures.

Figure 20: Natural Gas Load Duration Curve Example

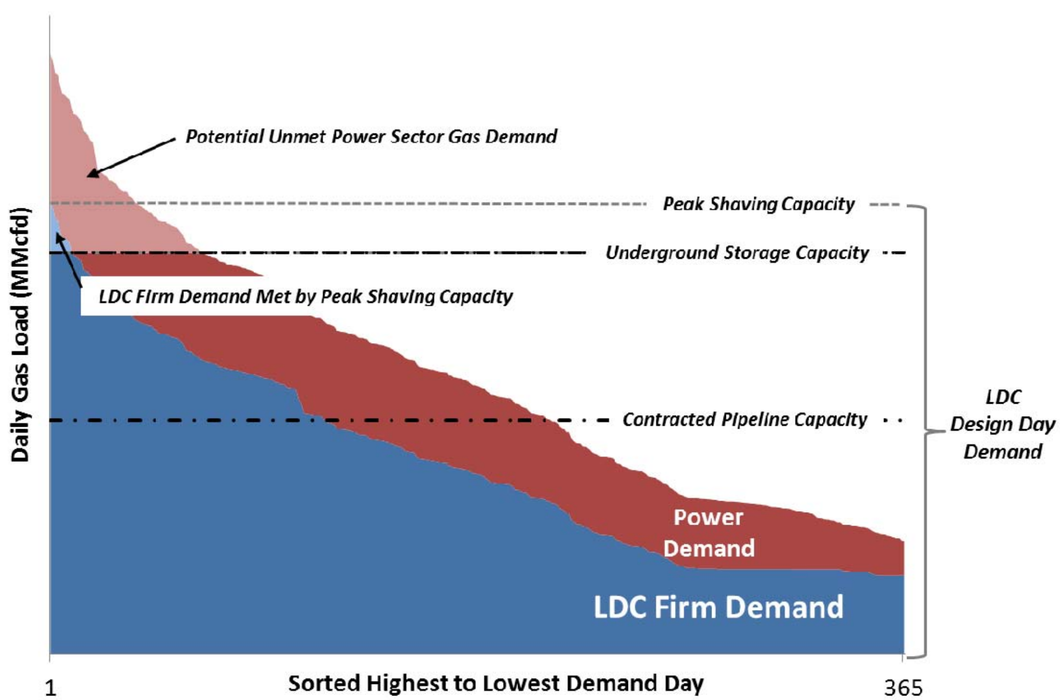


The weather conditions selected for the Layer 1 analysis should represent a range of load conditions for both the summer and winter months, for example:

- 90th percentile winter weather (90/10 winter load conditions)
- 90th percentile summer weather (90/10 summer load conditions)
- 50th percentile winter weather (50/50 load winter conditions)
- 50th percentile summer weather (50/50 load summer conditions)

The third step in Layer 1 analysis is to compare the delivered gas transportation capability to daily load duration curves and thereby determine how often the projected gas demand for electric generation cannot be served, as shown in Figure 21. For the majority of days, LDC firm load is met with a combination of firmly contracted pipeline capacity and local underground storage capacity. Interruptible transportation availability in the commercial and industrial sectors will also decrease as firm transportation customers increasingly use their full contracted entitlements and available pipeline capacity becomes constrained. On the 10 to 15 coldest winter days when gas demand is highest, a pipeline may not be able to schedule interruptible transportation and, in many cases, firm transportation customer commitments must be met with local peak shaving storage, such as satellite LNG storage or propane air facilities. If an electric generator does not contract for sufficient transportation service to meet its load, there could be a number of days when a significant portion of the gas demand for electric generation could be unmet (as represented by the light red area at the top of the curve in Figure 21) and electric sector reliability could be compromised. This type of screening analysis can indicate the number of days that demand for interstate pipeline capacity would not be met, and the quantity of demand not met can be determined for any given scenario.[60]

Figure 21: Comparison of Load Duration Curve to Delivered Gas Supply Capability

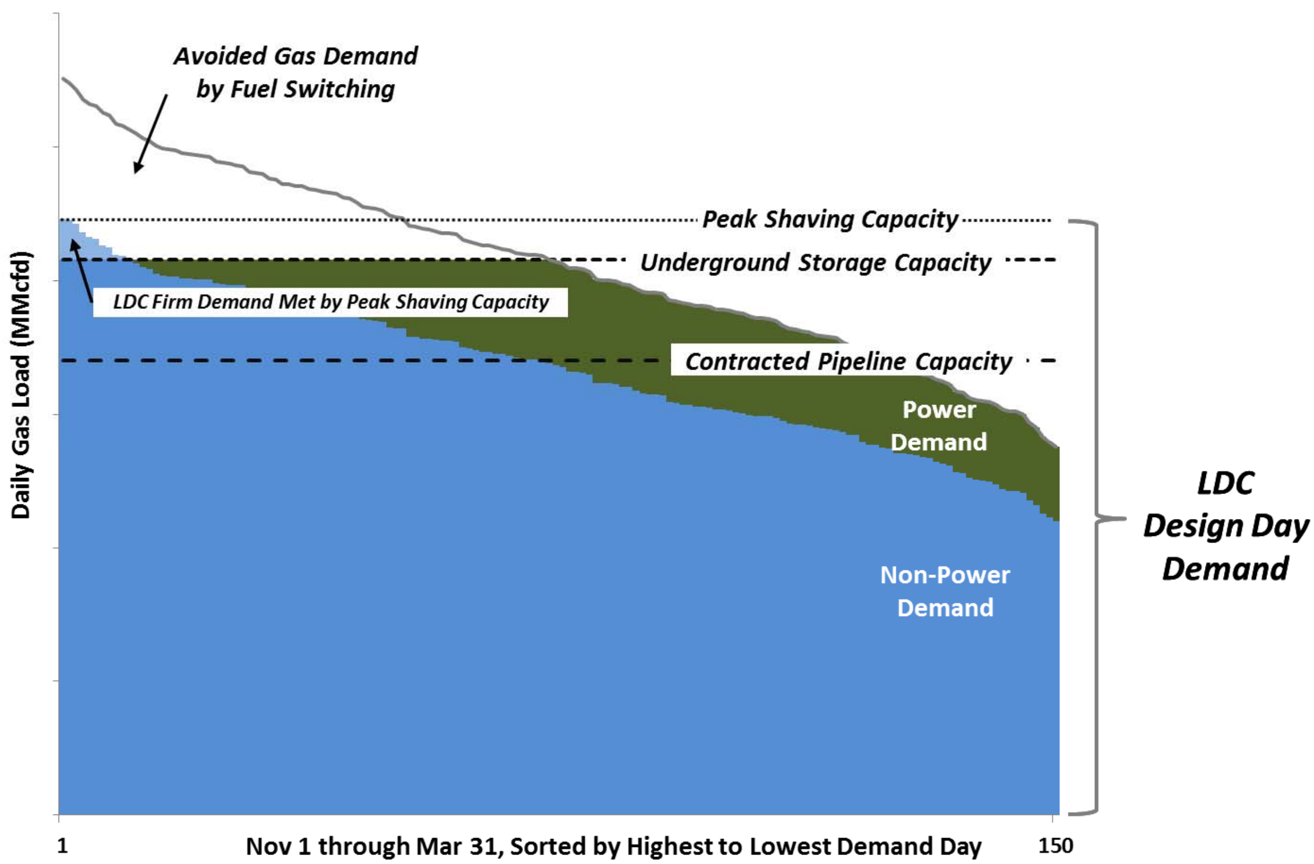


[60] While pipeline capacity and storage capacity provide increased availability of delivered natural gas, storage capacity is unique in that it generally serves local gas loads and does not increase the ability to transport natural gas on the pipeline system. Unless gas storage is at the point-of-use, pipeline capacity will be required to get it there.

The example above excludes the impact on interstate pipeline demand from fuel switching at dual-fuel units. If gas/oil switchable generating capacity is available, as shown in Figure 22, the amount of unmet interstate pipeline demand could be reduced or eliminated. This approach can be used to calculate the reduction in on-peak gas demand due to functional fuel switching, and the positive impacts on electric system reliability (temporary reduction in operable capacity).

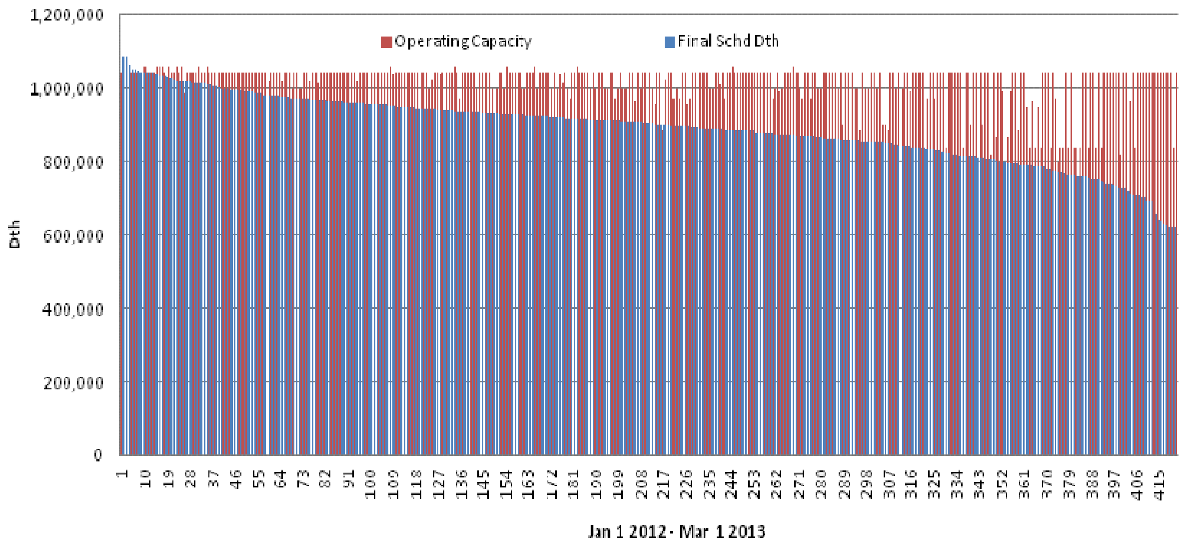
In addition to fuel-switching capabilities, some gas-fired generators hold some form of firm contracts for fuel supplies. The degree of "firmness" of a generator's gas supply depends on the type and number of contracts held. The generator may have a pipeline capacity contract securing supplies directly from the wellhead or from a liquid trading point on the regional gas system. The generator may only have firm pipeline capacity on the lateral spur that serves it off the mainline. The generator may have a contract on a single pipeline system, or contracts on multiple systems. Determining the firmness of fuel supplies, both firm gas production and firm pipeline transportation, is an important consideration in determining the non-firm demand and thus the vulnerabilities on a given electric system.

Figure 22: Daily Gas Load Curve Including Fuel Switching



The load duration curve analysis described above is based on a daily cycle. It treats the sum of 24 hours of loads as "demand" and average daily pipeline, storage, and peak shaving capacities as "supply." Layer 3, which is discussed in a later section, extends the daily analysis to hourly analysis to determine the likelihood that hourly gas loads cannot be served, even if the daily analysis shows the market to be in balance. An example of the load duration curve using actual pipeline data is shown in Figure 23.

Figure 23: Operating Capacity and Final Scheduled Volume – Example Pipeline



Layer 2: Assessing the Impact of Gas Supply Contingencies

Most areas in the United States and Canada are served by many different pipeline systems that are relied on to transport gas into and out of each area. The North American natural gas pipeline network is a highly integrated system, with many interconnects that allow for the transfer of gas between the different pipeline systems. In addition, there are numerous interconnects with gas utilities and gas-fired power plants that receive gas. In many cases, multiple interconnects from multiple pipelines create both flexibility and reliability in gas deliveries. Further, underground gas storage is connected to the pipelines, creating reliability in gas delivery. Market area gas storage makes it possible for firm peak month and peak day deliveries to be satisfied with a greater degree of certainty and reliability. Gas utilities further augment underground storage supplies with storage from above-ground facilities, most notably LNG peak shaving and propane-air facilities. In short, the gas infrastructure is extensive and diverse, making the system for serving firm loads very reliable. Nevertheless, contingencies that negatively impact gas service can and do occur. On rare occasions these contingencies threaten firm service. More often, these contingencies may reduce the capacity available for interruptible service, which the pipeline has no contractual obligation to provide and only is available when firm shippers are not using their capacity.

Questions Answered in Layer 2 Analysis

- What are the potential contingency cases in which natural gas systems lose their ability to provide their total expected service capacity?
- How much capacity loss or range of capacity losses would be expected from each of these specific contingencies?
- What causes these gas system contingences, and what data exist to help predict the frequency, severity, and duration with which they might be expected to occur?
- How do the occurrences of these gas system contingencies correlate to severe weather or other types of natural events?
- How much gas-fired electric generating capacity would be estimated to lose interruptible or firm gas service under each specific contingency?
- What are the connections between electric service reliability and natural gas end use markets and natural gas infrastructure, and to what extent could electric outages affect operational gas system capacities?

The purpose of this layer of the analysis is to identify and characterize potential contingencies on the gas system that could adversely impact gas supplies and thereby adversely impact electric reliability. The recommended approach to Layer 2 can be broken down in to three steps:

1. Identify potential gas system contingencies and their frequency of occurrence.
2. Assess the impacts for each of the identified contingencies, in terms of duration and amount of gas supply disrupted.
3. Apply the contingency disruptions to the gas supply capabilities (determined in the Layer 1 analysis) to calculate the impact on total gas supplies and, more specifically, the amount of gas available to electric generators.

First, it is necessary to identify the types of contingencies that can occur in the natural gas system's infrastructure and to compile data on their frequencies, duration, and consequences that can be used in reliability assessments. There are a wide range of events that could result in the loss of gas service, including physical/operational, technical/cyber, natural, and man-made causes. A list of some of the potential gas system vulnerabilities includes:

- Physical/Operational
    - Mechanical or operational malfunction of a specific gas system equipment, such as a compressor station
    - Pipeline leakage or burst due to stress or corrosion cracking
    - Storage well degradation or failure due to scaling, water penetration, or other factors
    - Pipeline capacity outages due to scheduled construction, maintenance, and testing
- Technical/Cyber
    - SCADA system malfunction
    - Electrical failure of supporting computer and control systems
    - Database corruption
    - Hacking or tampering with supporting software and information for control systems
    - Failure or malfunction of operational flow control systems
- Natural
    - Damage to compressor stations from flooding
    - Damage to pipelines due to flooding, erosion, river scouring
    - Damage to facilities due to hurricanes or high winds
    - Well freeze-offs in production and storage systems
    - Damage to facilities due to earthquakes
    - Other high-impact, low-frequency (HILF) events (e.g., solar storms)
- Man-made
    - Damage resulting from terrorist activities
    - Pipeline damage due to excavation
    - Damage due to negligence

Fully assessing these vulnerabilities requires a review of existing studies and historical data (e.g., pipeline bulletin board data and well-level production histories), as well as consultation with the gas industry to establish the frequencies, duration, and consequences of the types of events listed above. Specific data could be compiled on the number of occurrences of events such as:

- Large-scale wellhead disruptions (freeze-offs, hurricanes, floods)
- Gathering line/field compressor problems

- Outages of gas processing plants (scheduled outages, hurricanes or floods, loss of electricity service, physical attack)
- Pipeline outages (scheduled outages for pipeline integrity surveys, pigging, etc.; integrity failures; failures to control systems; accidents or damage from external forces; earthquakes; loss of cover by ground erosion, scouring of river beds, physical attack, cyber attack)
- Prime mover or compressor outages (scheduled outages; failures of prime mover;[61] hurricanes or floods; loss of electricity service to electric-drive compressors)

An analysis of "nominal design capacity" and "operationally available capacity" information—which pipelines routinely post to meet FERC requirements—may provide a valuable baseline to assess the availability of gas pipeline transportation services. The "operationally available capacity" information provides data on pipeline and prime mover/compressor outages. Pipelines could provide a characterization of the type of events that affect capacity to inform such an analysis.

It also may be useful to develop correlation coefficients or other scenario-building assumptions that will be used to represent how different types of events are related to each other. To accomplish this, it is necessary first to determine what variables need to be considered (temperature, wind speeds, precipitation, etc.) in an analysis of probabilities of natural gas disruptions and electricity market events. NERC and the Regions, along with industry Planning Coordinators (PCs), have already studied some of these statistical relationships for their electric reliability analysis and planning functions (e.g., how wind speeds correlate to temperatures and electric loads), and additional data will be required, such as weather data from the National Oceanic and Atmospheric Administration (NOAA), pipeline incident reports from the U.S. Department of Transportation (DOT), and infrastructure outage data from the DOE. Further statistical analysis will also be required to determine frequency and severity of events and the correlation between events and time of year. The results of the correlation analysis could ultimately be applied within the Monte Carlo analysis in Layer 3 (discussed below) or within the Layer 2 analysis to develop scenarios. As stated above, interstate pipeline service availability can be measured by analyzing the difference between interstate pipeline "nominal design capacity" and pipeline "operationally available capacity' at certain points on the pipeline system. Pipelines can then characterize or identify why capacity was reduced on the system.

The next step in the analysis would be to estimate how different contingency events would affect the normal operational capacities identified in the Layer 1 analysis. Events range from compressor failures (which would generally cause the loss of some, but not all of the capacity on a system) to a complete pipeline failure and loss of all capacity. This data would be used to create a comprehensive list of contingencies including information regarding the locations, event type, and amount of lost capacity. In prior studies of disruptions of natural gas infrastructure, estimated impacts on gas supplies using hydraulic models and simpler hydraulic calculations were completed. For example, in a recent study for ISO-New England, ICF employed a set of hypothetical gas sector contingencies, which were incorporated into various reliability calculations and analyses.[62] These contingency cases examined reductions in available gas supplies when either one or two elements of the regional gas system were not available on the peak winter and peak summer days.

Once the impact on gas supplies is identified for each of the contingency cases, these supply reductions can be applied to the gas supply capability estimates to arrive at the change in total gas supply from any individual contingency (N-1) or combination of contingencies (N-1-1). The impact of these changes in total gas supply capability could then be compared to the load duration curves (as discussed above in Layer 1) to determine the impact on gas supplies available to electric generators (i.e., how much fuel supply (in Btu), capacity (in MW) and generation (in MWh) would be reduced by the contingency).

[61] The failure of a component/station affecting output will be noted by the publically available "Critical Notice" on the pipeline's website
[62] http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2012/gas_study_public_slides.pdf

Layer 3: Monte Carlo Analysis of Gas and Electric Systems

The Layer 1 and Layer 2 analyses described above are designed to assess the impact of fuel availability on electric system reliability under a limited set of weather conditions and gas supply contingencies for the region modeled as a whole or single system. The analysis does not take into account localized constraints that may develop within the region, or how the natural gas system may respond to these changes (e.g., redirection of pipeline flows). While the first two layers quantify the potential extent of gas supply shortages to electric generators on a regional basis, they do not provide an indication of how often these fuel shortages might occur and what specific areas within the region may be affected by the shortfall.

For Layer 3, NERC recommends a Monte Carlo analysis using an integrated gas and electric system network model to quantify the probabilities and correlations among various types of gas and electric contingencies, weather events, generation, and electric loads in order to better understand how often shortfalls in gas supplies may occur. A Monte Carlo analysis would provide a robust method of analyzing how frequently various combinations of events can occur, particularly events that can be correlated to each other. In this integrated approach, gas fuel supply availability will be modeled inside the sequential Monte Carlo algorithm and tested hourly, as opposed to the daily load duration curve approach. Integrated modeling provides a more accurate representation of the gas–power infrastructure and therefore provides better understanding of impact and likelihood.

Questions Answered in Layer 3 Analysis

- What is the probability of gas supply loss? How does this probability change under different weather conditions?
- What plants within a region are most likely to be affected by gas supply shortages?
- How does the gas system respond in a contingency event? Can the gas infrastructure be used differently to reduce supply shortfalls?

Considerations of Hourly Loads and Line Pack

The gas supply and demand assessments described so far have been for average daily values. To assess hourly availability of pipeline capacity requires an estimation of the potential impact from line pack. To assess the impact of line pack on gas supplies, one could use a method similar to the approach developed by ICF as part of their "Market Clearing Engine" (MCE).

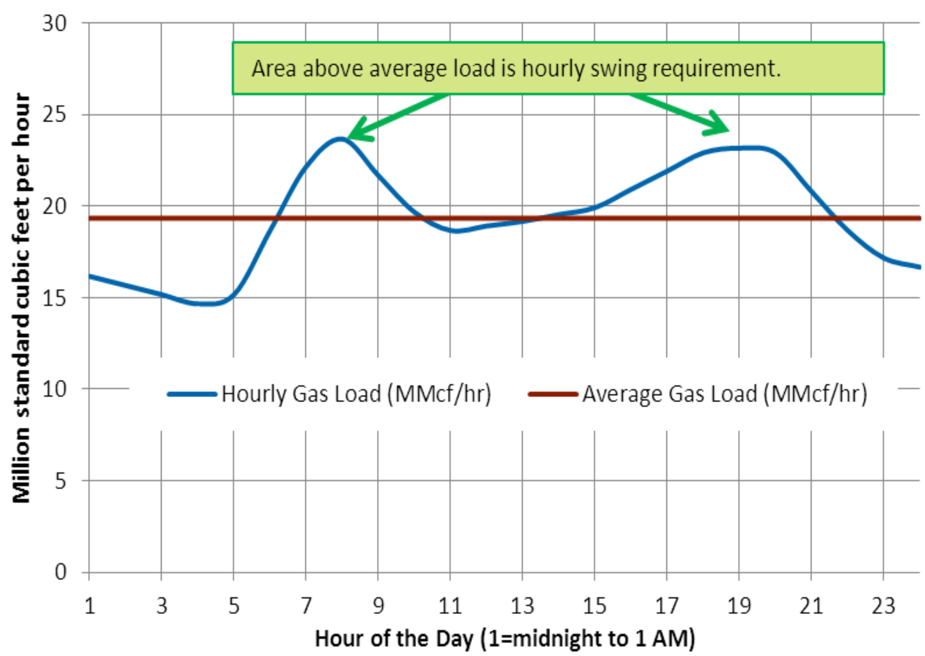
ICF has used the MCE for the last 16 years to manage Southern Australia's gas system operations, including the hourly supply scheduling of gas pipeline and storage injections and withdrawals. The MCE model estimates available line pack based on the physical dimensions of the pipeline systems and assumed variations in average pipeline pressures that could be managed throughout a day. The amount of line pack is calculated as a function of the diameter, length, and average pressure of the pipeline. When a gas pipeline is operated at the maximum allowed operating pressure (MAOP) throughput volumes at a steady state, the pressure at the compressor inlet might be around 760 pounds per square inch (psi), and the pressure at the compressor outlets might be close to 1,000 psi. This way, the pressure in the pipeline goes from 1,000 psi of the outlet of one compressor down to 760 psi at the inlet of the next compressor located about 70 miles downstream. Using this example, the average pressure would be about 880 psi. At that pressure, a 36" diameter line would hold about 2.2 million cubic square feet of gas per mile length. If the average pipeline pressures were allowed to go up during the low-demand overnight period, additional gas could be stored in the pipeline during evening hours. During a given day, the pressure could be reduced allowing for the delivery of more gas. For example, using standard hydraulic calculations, the daily swing capacity available for a 36" pipeline could be estimated at 0.3 MMcf per mile if the loads are predictable. Pipelines operating near maximum design capacity have no available linepack--it is only available when a pipeline is partially loaded and pressures are below the maximum allowable operating pressure. Pipelines that operate through significant swings must leave some linepack available to maintain pipeline operating requirements.

These estimations could be verified by consulting with pipeline companies and determining if additional hourly swing capacity is available through storage deliverability that is dedicated to maintaining system pressures and reliability. The most important factors determining hourly swing capacity available through management of line pack are:

- Physical dimension of the pipeline (diameter and length)
- Normal steady-state operating pressure profile
- MAOP
- Minimum operating pressure needed to deliver gas to customers
- Ability to fully re-pressurize the pipeline for the next day's cycle

The hourly analysis NERC suggests for the Layer 3 modeling is not a full hydraulic modeling of hourly gas flows into and out of the gas system. Rather, it represents an approximate analysis that compares the hourly patterns (specifically the hourly swing requirement, or the volume of hourly gas load above the daily average load) against the available hourly swing capacity made up mostly of pipeline line pack available to a region (see Figure 24). These values can then be converted into an hourly swing index by dividing the hourly swing requirement in MMcf by the available the hourly swing (line pack) capacity in MMcf. An hourly swing index value above 1.0 would indicate hourly gas loads that are greater than what can be provided by line pack and indicate potential problems in serving those specific loads; the higher the index, the more severe the problems would be. An estimate of the amount of potential lost hourly load can also be computed as the hourly swing requirement minus available hourly swing capacity.

Figure 24: Example of Hourly Winter Gas Load Swings



Regional Definition and Boundary Conditions

The first step in conducting the Monte Carlo analysis is to construct a network representation of the natural gas and electric infrastructure within the region under examination. The network model would consist of a series of nodes, which represent gas supply resources and demands within the region, and arcs, which represent either gas pipeline capacity or electric transmission capacity between the nodes. The division of the region into nodes would be based on an assessment of pipeline receipt and delivery points within the region, the location of interconnects between different pipeline systems or between a pipeline system and storage field, LDC services, and electricity dispatch zones within the region. The goal is to create a network representation of the region that is simple enough to solve relatively quickly, but also has sufficient detail to indicate where gas supply constraints may develop. Depending on the region's size and complexity of its gas pipeline systems, a network of between 5 and 15 nodes should be sufficient. In an aggregated nodal system, electric generators could be grouped together by type (e.g., gas-only combustion turbines, gas/distillate switchables, etc.) within each region. However, assuming sufficient information on pipeline capacities and receipt and delivery points is available, it is possible to construct a nodal network with much greater detail, and even represent gas consumption at individual power plants. Non-power demand would be represented by the same type of algorithms used in a daily gas load model (discussed in the previous section) to determine gas demand as a function of weather.

Sensitivity of Electric and Natural Gas Loads to Weather

Based on past studies and analysis on the subject and current practices of electric market participants, hourly and daily electric load models are most often a function of weather, seasonal and calendar factors, time of day factors, and other autoregressive components. It is also a common practice to generate separate models for each distinct seasonal or daily interval in order to capture unique dynamics of that period.

The most used weather variables in load models are linear and non-linear components of temperature, wind speed, humidity, cloud cover, and precipitation, with temperature having the largest impact among these variables. Seasonal and calendar factors include months, weekday or weekend distinctions, day of the week, and holiday dummy variables. Time of day factors include variables capturing specific dynamics associated with hourly load differences, which could include specific hours or simply off-peak and on-peak classifications. Finally, there are a number of variations of autoregressive components that tend to explain all other factors not captured by the above-mentioned independent variables. These factors are most often captured through autoregressive lags of different lengths but can also be captured with moving average lags, depending on specific time-series dynamics.

There are also common structural form variations among different hourly and daily electric load models. It is a common practice to build separate models for each season or month, and even each day of the week or hour in order to capture unique dynamics of these distinct periods. Alternatively, seasonally or otherwise differenced autoregressive integrated moving average (ARIMA) models can capture these dynamics in a single model. Similarly, models can oftentimes capture these distinct dynamics with dummy variables.

Twelve separate hourly load curve equations could be used to capture unique monthly electric load dynamics for each of the examined regions. The models could include level, squared, and cubed temperature variables in order to capture non-linear relationships between temperature and load. The resulting model will also include day-of-the-week-and-month variables, holiday variables, and time-of-day variables to capture other variations associated with these periods. The model will also include autoregressive components based on the unique structure of regional load lags.

The finalized monthly load curve equations will be used in the simulation process in order to generate hourly load requirements based on assumed hourly weather scenarios and aggregate monthly load level assumptions. The aggregate monthly load level assumptions will be calculated through independent load forecasts based on historical load growth and expected future economic activity levels for each examined region.

Modeling weather scenarios should be based on future weather expectations calculated by historical weather trends in the regions of interest. This is a difficult task, because historical weather patterns have not reverted around a single, long-term mean. Instead, weather tends to persist at its short-term pattern for prolonged periods of time before returning to its long-term trend. Figure 25 and Figure 26 show annual heating and cooling degree days (HDD and CDD) by year for the past 42 years, and 20-year normal degree days. Since 1980 the 20-year average of HDDs has declined 7 percent, while the 20-year average for CDDs has increased almost 12 percent.

Figure 25: U.S. Lower 48 Heating Degree Days[63]

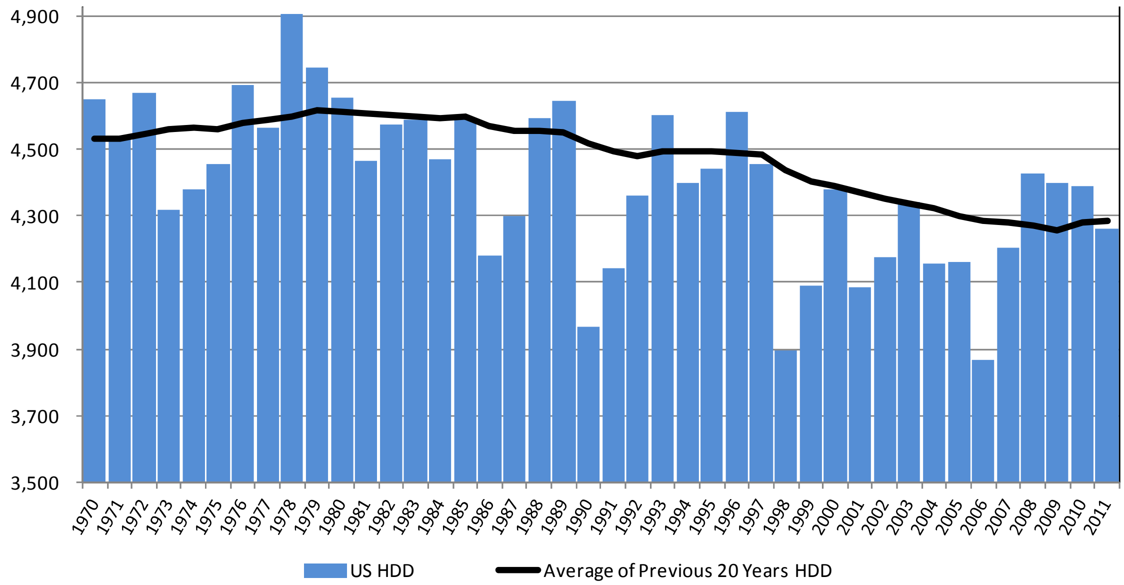
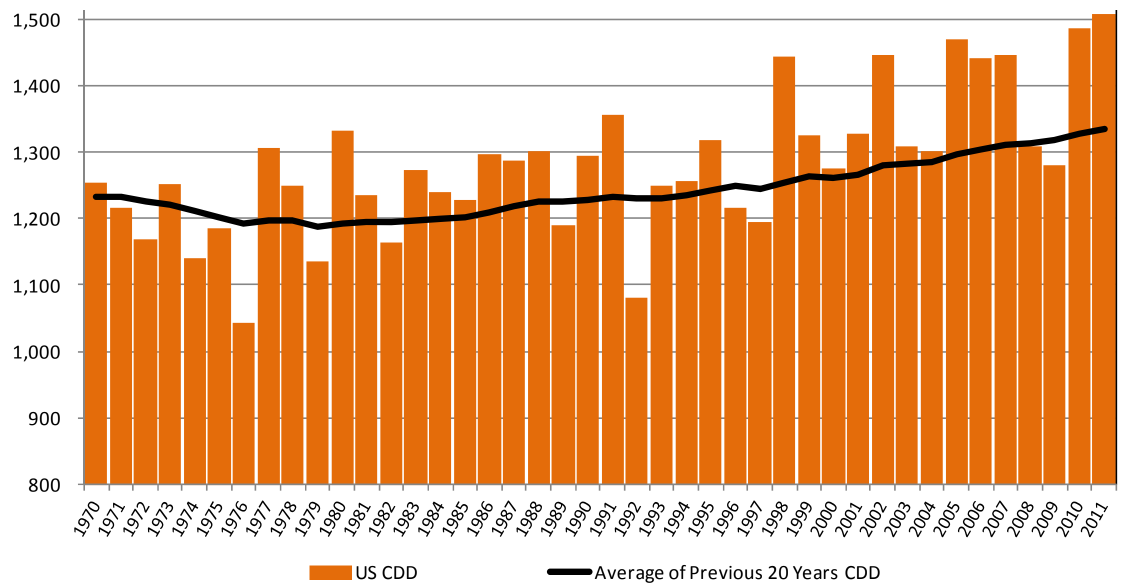


Figure 26: U.S. Lower 48 Cooling Degree Days[64]



The trend toward warmer temperatures in the summer and cooler temperatures in the winter could lead the electric industry away from considering long-term, 30-year historical periods and toward shorter, 10-year historical periods when identifying weather normal conditions. For all reliability analyses, system planners could identify "normal weather year"[65] by selecting a year for which temperatures deviate least from average temperatures over the last decade.

[63] U.S. Lower 48 heating degree days for calendar year as computed by NOAA for each census region and weighted by population using 2010 census data (excluding Alaska and Hawaii).
[64] Ibid.
[65] A normal weather year is the year with the lowest sum of squared monthly deviations from 10-year monthly averages.

Since the region is being examined independently from the rest of the North American market, it is also necessary to define the boundary conditions for each case; that is, the movement of gas supplies into and out of the region as a whole, as well as where gas supplies enter and exit the region. Under normal operations, the boundary conditions are a function of weather, which impacts demand upstream and downstream. The boundary conditions can also be considered in the Monte Carlo model, for example, by considering contingencies such as hurricanes that disrupt gas supplies available to the region.

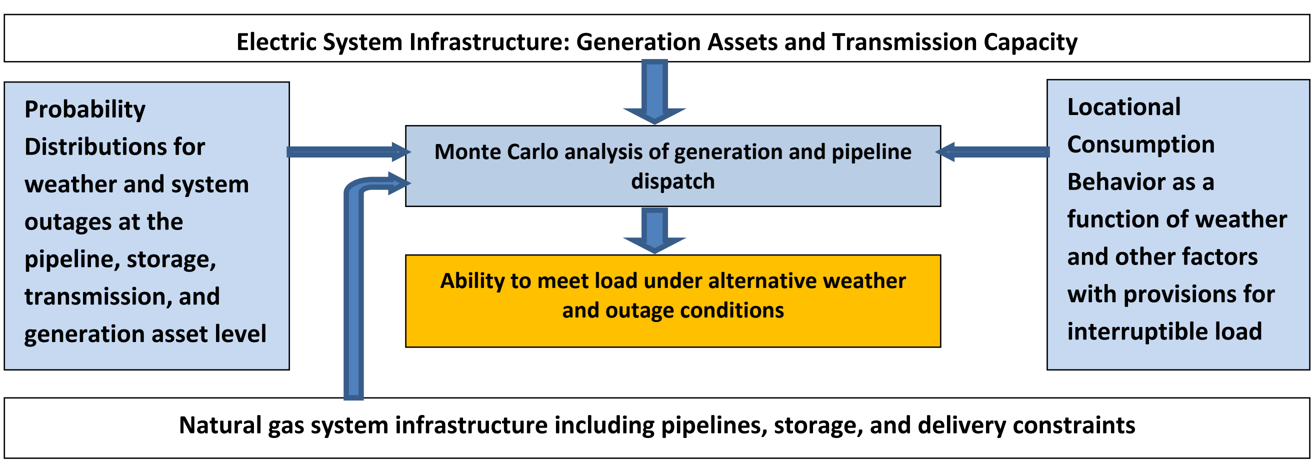
Monte Carlo Modeling

The Monte Carlo cases would be driven by probability assumptions for weather and forced outages of elements of the gas and electric systems. The weather would determine non-power demand for natural gas and demand for electricity. The probability assumptions for weather would include temperatures but could also include other variables that have an impact on demand, such as wind speed, cloud cover, humidity, and precipitation. Based on correlation analysis of historical data, weather would also affect the forced outage rates on both the gas and electric infrastructure (e.g., low temperatures increase probability of wellhead freeze-offs, while high winds increase the probability of transmission line outages). The probability of forced outages would also be a function of mean-time-between-failures for each system component and the duration of the outage based on a mean time to repair each component. Scheduled maintenance outages on the gas and electric system, such as compressor station maintenance, pipeline inspections, and power plant maintenance, would follow a fixed schedule for all cases, based on typical maintenance schedules for each system element.

For Monte Carlo analysis, several options exist, such as a resource adequacy model known as the Stochastic Resource Adequacy Model (SRAM).[66] SRAM is a probabilistic resource adequacy model used to analyze the impact of uncertainties in load forecasts, generator-forced outages, and variable energy resources on system reliability. It employs an hourly, sequential Monte Carlo algorithm to quantify the risks associated with supply-and-demand-related uncertainties. The random variables accounted for in the standard SRAM model include the forced outage rate of generators, wind turbine dispatch profiles, and load uncertainty. SRAM or similar models could be expanded to add an overlay of the natural gas infrastructure to allow the examination of gas supply availability as a separate, dynamic variable within the model.

Once the set of Monte Carlo cases is defined, SRAM (with a gas-infrastructure overlay) could be run for each case over the forecast year, and the model would solve for the network's response to weather conditions and forced outages in the gas and electric systems. Figure 27 provides a flow diagram of the Monte Carlo modeling process.

Figure 27: Flow Diagram of Monte Carlo Modeling Process



66 Developed by ICF, International

The key outputs from each of the Monte Carlo cases would be:

- Loss-of-Load Expectation (LOLE): Expected number of days (or hours) to identify that the available capacity is insufficient to serve the peak demand.
- Loss-of-Load Hours (LOLH): The number of hours in the forecast year that the available generation was incapable of meeting firm (non-interruptible) load due to lack of gas supplies.
- Expected Unserved Energy (EUE): The total MWh in a year that could not be met, as either an absolute value or as a percentage of annual Net Energy for Load (normalized EUE).

The Monte Carlo analysis described above estimates resource adequacy through metrics such as LOLE for the assumed gas and electric system infrastructure in place for the forecast year. The Monte Carlo analysis does not identify new infrastructure additions. The need for new infrastructure would have to be ascertained by examining results for those cases with significant loss of electric load and determining what new infrastructure (pipeline capacity, storage capacity, fuel-switching capability) could alleviate the problems. If multiple infrastructure solutions are possible, the options could be evaluated by comparing the cost of each option to how often they would be relied upon to avoid loss of electricity loads. For example, if a gas supply-related loss of load event is expected to occur 50 days or more per year, additional pipeline capacity may be the best solution. Adding fuel-switching capability may be the best option for short-duration loads, especially where underground gas storage is not feasible or in a scenario with relatively low oil prices. The duration of the need for additional fuel volumes (and related infrastructure needs) necessary to increase electric system reliability will be driven primarily by the growth in power and non-power demand for natural gas, but will also be greatly influenced by weather patterns and gas and electric system contingencies.

Gas System Scheduled Outages and Contingencies for Layer 3 Gas Infrastructure Analyses

The Layer 3 Monte Carlo model would represent various components of the natural gas infrastructure in terms of the overall topology (what other components each component directly connects to) and the capacity of each component. Given certain assumed scheduled outages and forced outage rates for each component, the reliability of the overall system in terms of serving a single power plant or a group of power plants in an area would be computed by a Monte Carlo simulation. Because there can be several pathways for natural gas to move to any given location or region, it is important to model the exact topology of the system and to use a network flow model to determine how the outage of any given component or set of components affects the ability to serve the demand for natural gas.

The types of natural gas infrastructure components represented in the Layer 3 model could include:

- Sources of production (gas wells and oil wells, synthetic natural gas plants)
- Gas processing plants
- Gas transmission or gathering lines and compressor stations
- LNG import terminals
- Underground gas storage fields
- Gas distribution systems
- Peak shaving plants (full-cycle LNG plants or propane-air plants)

The Layer 3 Monte Carlo model would represent scheduled outages and contingencies in natural gas infrastructure in much the same way that it would represent scheduled outages and contingencies for electric generation and transmission infrastructure:

- Scheduled outages would be represented by a frequency and a duration for each type of scheduled outage, and

- Forced outages would be represented by a probability of occurrence and a probability density function for the duration of each forced outage.

Unfortunately, there is no compiled statistical data on gas system outages that would be the equivalent to NERC GADS databases. Therefore, outage data would have to be estimated from various surrogate sources, including pipeline bulletin board postings, including “nominal design capacity” and “operationally available capacity” postings, accident reports filed with government agencies, surveys of pipeline and distribution companies in the study region, and maintenance and repair information from equipment manufacturers and service companies.

As discussed in more detail below, NERC suggests that for modeling purposes these outage rates be specified separately for gas pipelines, compressor units in each station, and single-line pipeline “segments,” which are distinguished based on components of the gas infrastructure system (e.g., two adjacent compressor stations). Thus, the Layer 3 model would simulate for each Monte Carlo case the operating state and available capacity at each compressor station and for each pipeline segment.

Definition of Contingency (Forced Outage)

The NERC Glossary of Terms defines contingency as “the unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element.” Solely for the purpose of this report and associated analysis, NERC is using a parallel definition for natural gas system contingencies (i.e., forced outages):

> ***“A natural gas contingency is an unexpected failure or outage of a system component that renders some part of the natural gas infrastructure unable to produce, process, transport, or store natural gas up to its rated capacity and serve firm customers*.”**

For example, cold weather is not considered a contingency just because it increases gas demand and makes interruptible pipeline capacity less available. As long as the system is able to perform up to its rated capacity and firm customers are served, there is no contingency event under this definition.

Compressor Outages

Major gas infrastructure components in the Layer 3 Monte Carlo model would have scheduled outages specified in terms of frequency and duration. For example, a gas compressor unit (prime mover, gear box, and compressor) might have scheduled outages of:

- Eight 4-hour outages per year for offline cleaning
- Two 3.5-day outages per year for inspection and maintenance
- One 28-day outage every three years for overhaul

This is an average of 18 scheduled outage days per year, or about 5 percent of the days in a year. Stated in other terms, the single compressor unit would have 95 percent scheduled availability for the year. Given that a pipeline will schedule long maintenance outages during months of low throughput, the scheduled availability of the compressor unit would be near 100 percent during peak gas demand months.

Contingencies or forced outages for a gas compressor unit could be represented by data for:

- Mean-time-between-failures (MTBF), which might be expected to be several hundreds of days for well-maintained compressor units
- Mean-time-to-repair (MTTR), which might be expected to be on the order of several days
- Distribution of repair days, which could range from under one day to months for a major failure, such as a cracked drive shaft

For example, assumptions of MTBF=625 days and MTTR=6 days for a single compressor unit would mean that the expected number of forced outage days per year would be 3.5. Therefore, the chance that a compressor will not be available on any given day due to forced outages is about 1 percent.

The values given above refer to a single compressor unit made up of one prime mover, one gear box, and one compressor. Natural gas pipeline compressor stations typically are comprised of several individual compressor units. Table 3 below shows one such possible configuration for a compressor station on a 1 Bcf/D pipeline.

Table 4: Example Compressor Station Configuration on 36", 1 Bcf/D pipeline	
Configuration Component	**Units**
Maximum Operated Horsepower (HP)	15,000
Compressors Units (No.)	4
Compressor Size (HP)	5,000
Total Installed (HP)	20,000
Degree of Redundancy (%)	33%

In this example, there is one spare compressor unit that provides 33 percent redundancy. At any one time, all four, three, two, one, or none of the compressors could be available. If four or three compressor units are available, then the compression station can supply the full compression needed to maintain the pipeline's 1 Bcf/D capacity. When only two compressors are available, then the capacity of the pipeline will be somewhat less. Table 5 below shows the probabilities for the number of compressors available on days without scheduled outages, and the approximate portion of the pipeline's rated capacity that would be available when the number of compressor units is two or fewer. Note that the probabilities shown assume that the forced outages on the compressor units are independent of each other. This assumption holds true for most mechanical failures but may not be true if an external event, such as a severe flood, makes the entire compressor station inoperable. Contingencies on compressors at one station could also be correlated to each other if the prime movers are electric-driven and the cause of the failure is lack of electricity.

Table 5: Probabilities for Number of Available Compressors at a Station[67] *(For days without scheduled maintenance at a station with 4 units and 33% redundancy)*			
Operable Compressors	**Percent of Days**	**Days per Year**	**Available Capacity on Pipeline Segment**
0	0.00%	0.0	70.4%
1	0.00%	0.0	83.7%
2	0.06%	0.2	92.9%
3	3.88%	14.2	100.0%
4	96.06%	350.6	100.0%
Sum of All Conditions	**100.00%**	**365.0**	**100.0%**

[67] Based on all outage percent of 1.0%.

Chapter 6—Enhancing Resource Adequacy Assessments

With an advanced understanding of the electric reliability vulnerabilities, associated increased dependence on natural gas, and probabilities of significant events can be incorporated into resource and contingency planning. Probabilistic measures of resource adequacy are produced and evaluated across the electric industry. By accounting for the risks associated with increased dependence on gas-fired generation, the electric sector can be well-prepared to manage and maintain reliability, particularly during extreme conditions.

Reliability assessments are key in providing an independent view on power system reliability. It is essential that the assessments contain the most accurate assumptions and integrate only valid risks. Regulators and policymakers need this information to make risk-informed decisions on future needs.

This chapter describes how the fuel supply and transportation analysis would be factored into conventional electric system resource adequacy studies. The section is organized under three subsections. The first section provides brief a description of the resource adequacy concept within the electric power sector. The second section introduces standard resource adequacy modeling approaches within the power sector. The third section introduces a recommended approach for integrating fuel availability analysis with resource adequacy modeling efforts.

Electric Power Resource Adequacy

Resource Adequacy is defined by NERC Glossary as the ability of supply-side and demand-side resources to meet the aggregate electrical demand (including losses). Planners predominantly use LOLE as the baseline metric in resource adequacy studies. LOLE is generally defined as the expected number of days, events, or hours for which available capacity is insufficient to serve the peak demand.

Historically the electric power industry has applied the 1-in-10 (1 day in 10 year) LOLE standard for analyzing resource adequacy requirements or the adequate level of reserve margin requirements. The origins of this metric could be traced to a 1947 paper by Giuseppe Calabrese,[68] although the precise origin is not clear. The 1-in-10 standard typically refers to the resource adequacy level at which electricity demand is curtailed due to lack of installed (or available) resources for one day in a 10-year period. Although 1-in-10 is the predominant standard, some Planning Coordinators and/or states use cost minimization of the combination of the cost of EUE, reliability purchases, and capacity. The cost minimization approach typically results in maintaining reserve margins between 10% and 20%.

The 1-in-10 has been assumed to be the optimal level (i.e., inflection point for willingness to pay for reliability) of reliability for bulk power systems for several decades. There are, however, different interpretations of 1-in-10, mostly due to the utilization of different modeling techniques within resource adequacy studies. For example, some studies interpret 1-in-10 as 2.4 hours per year, and others interpret it as one event in 10 years. Hourly chronological resource adequacy models are generally capable of capturing the 2.4 hours-per-year definition, which is more granular than one event in 10 years. The power industry recently made efforts to re-identify reliability metrics and the corresponding (optimal) level of reliability. In its 2010 report, NERC's Generation and Transmission Reliability Planning Models Task Force recommended that three metrics be reported by resource adequacy studies. These metrics are Loss-of-Load Hours (LOLH), Expected Unserved Energy (EUE), and normalized EUE.

In addition to NERC efforts, FERC has performed parallel efforts to assess the economics and different interpretations of 1-in-10 LOLE.

[68] Giuseppe Calabrese, *"Generating Reserve Capacity Determined by the Probability Method"* (March 25, 1947), presented at the AIEE Midwest meeting of November 3, 1947—page 21 cites a 0.00046 probability of loss of load.

Resource Adequacy Modeling

Almost all resource adequacy metrics are probabilistic in nature, and their calculations require implementing statistical modeling techniques. Probabilistic resource adequacy models attempt to capture the full range of uncertainty by modeling demand, forced outages, and variability of renewables as probability distributions. Monte Carlo modeling has emerged as the industry standard to model the unpredictability of the bulk power systems. Monte Carlo methods are based on repeated random sampling of input parameters and are especially useful for simulating systems where there is a large set of possible scenarios. Monte Carlo-based resource adequacy models test system reliability by creating thousands of scenarios where demand and supply vary based on defined probability distributions. The most significant outcome of Monte Carlo simulation is the probability of demand being greater than the probability of supply at any given hour.

The ultimate goal of resource adequacy modeling is to calculate reserve margin requirement (i.e., installed capacity requirement or planning reserves) that would result in a target reliability level (e.g., 1-in-10). To calculate the target reserve margin requirement, a resource adequacy model is run at different capacity levels until the reliability target is met. When a new uncertainty (risk) factor is introduced to the system, the amount of reserves required to satisfy reliability goals is expected to increase. In this context, introduction of power–gas interdependence to resource adequacy modeling may result in the requirement for higher reserve margins, market tools, or other risk mitigation measures for extreme days or hours.

One purpose of this report is to recommend a conceptual approach to integrating standard resource adequacy modeling with fuel availability models or results. This section defines the basic features of a standard resource adequacy model and introduces their basic components. By doing so, the report sets a foundation for gas–power integrated modeling efforts.

Integrating Fuel Supply Availability with Electric Power Resource Adequacy Models

Standard resource adequacy models used by the electric industry generally consider generation and transmission outages as independent events. From a pure statistical and modeling perspective, increasing positive dependence between uncertain parameters is typically expected to increase overall uncertainty (risk) of the system. Therefore, resource adequacy models that do not capture power–gas interdependence may underestimate the probability of loss of load. Modeling dependencies between random variables and simultaneously capturing the probability of extreme events occurring is paramount to creating a sound probabilistic resource adequacy model; the sole purpose of a probabilistic resource adequacy model is the ability to capture the impacts from extreme events. Additionally, the results of these assessments are used by Planning Coordinators to inform resource planning, to incentivize market participants by sending accurate price and reliability signals, or for use by state/provincial/local regulators.[69]

A review of the technical literature indicates no existing resource adequacy model or study explicitly addresses this power–gas interdependence issue. While the complete understanding and quantification of power–gas interdependence is only possible by integrating the modeling of power and gas networks, recent experience with the Electric Reliability Council of Texas (ERCOT) markets shows a dependency exists and is likely to increase with the increasing penetration of gas-fired capacity. For example, a recent study[70] has shown that ERCOT may lose 24 percent of its gas-fired generation if the weather pattern of December 1983 repeats itself.[71] However, the ERCOT analysis did not assume any winterization mitigation in effect that would likely reduce the loss in electric generation capacity. A survey conducted by ERCOT revealed that the

[69] NERC 2008 Resource Issues Subcommittee Survey on Resource Adequacy Assessment Criteria: http://www.nerc.com/docs/pc/ris/Planning_Coordinator_Adequacy_Assessment_Practices-Survey_Responses_08_14_08.xls

[70] Black & Veatch, ERCOT Natural Gas Curtailment Risk Study, Prepared for ERCOT, March 2012. http://www.ercot.com/content/news/presentations/2012/BV%20ERCOT%20Gas%20Study%20Report%20March%202012.pdf

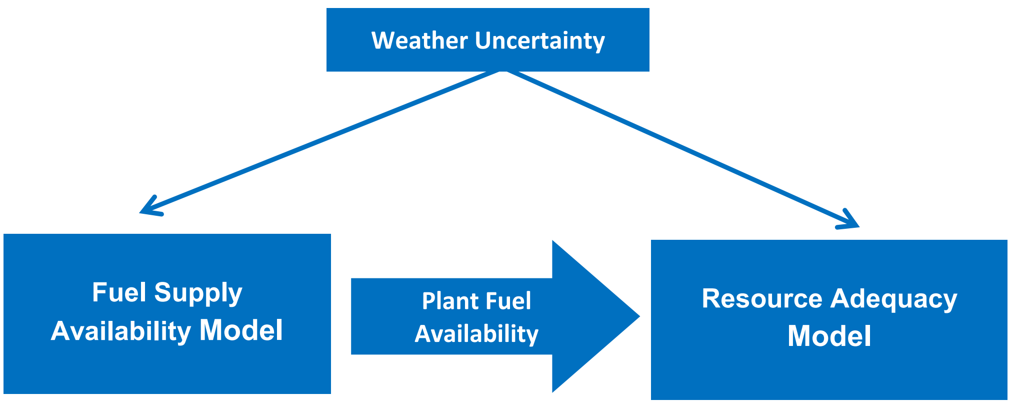
[71] In 1983, the arctic front barreled through the Dallas–Ft. Worth area on the 18th, and temperatures stayed in the deep freeze for nearly two weeks. There were 295 consecutive hours at or below freezing: 7:00 a.m. Dec 18 to 2:00 p.m. Dec 30, 1983.

majority of ERCOT generators reported interconnects with multiple pipelines and access to pipeline capacity in excess of their peak needs.

The previous section introduced basic structure and components of standard resource adequacy models. To incorporate fuel system availability into the Monte Carlo framework of the resource adequacy model, one first needs to identify common risk factors and direction of data flow.

Figure 28 provides the basic scheme of integrated gas–power resource adequacy modeling. Both gas and power demand uncertainties are mostly driven by weather uncertainty. An integrated model, therefore, needs to have the weather uncertainty as a common random variable, feeding into both fuel supply and transportation availability and resource adequacy models. Ultimate output of the fuel supply and transportation availability model would be hourly fuel availability information for every gas-fired unit within the power grid. Fuel availability will be another layer of outage information that will complete the scheduled and forced outage history created within the resource adequacy model.

Figure 28: Integrating Fuel System Availability with Resource Adequacy



Incorporation of a fuel supply availability model into a resource adequacy model will fill two gaps in standard resource adequacy models:

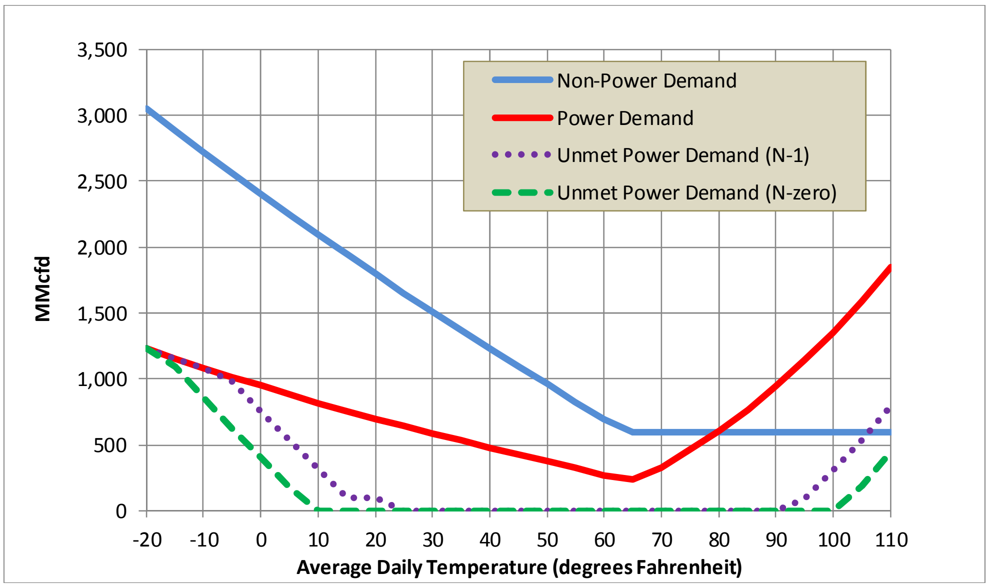
- By modeling the gas supply network, probabilistic resource adequacy models will be able to capture the dependence between gas supply risk and power outages.
- Fuel supply and transportation availability is not factored into the standard forced outage rate assumptions within standard resource adequacy models. As a result, the fact that significant numbers of gas-fired power plants do not have firm fuel supply and transportation contracts is not reflected in the current resource adequacy models. Integrated modeling will create an opportunity to examine the risks associated with non-firm fuel supply on the power grid.

In the previous sections, NERC suggested three options for capturing power generation fuel availability. Layer 1 and Layer 2 analyses use natural gas duration curves to assess fuel availability. Layer 3 includes the representation of a gas network model inside the resource adequacy models. Incorporation of all three layers into the resource adequacy modeling framework will require the establishment of a process flow similar to that shown in Figure 28. The following sections provide a description of the integration of resource adequacy models with different layers of fuel availability analysis.

Layers 1 and 2 (Load Duration Curve Approach)

The analyses from Layers 1 and 2 include a series of deterministic scenario analyses at different weather confidence levels (e.g., 50/50, 90/10, etc.) and include profile testing of the supply-and-demand balance to calculating the amount of unserved natural gas demand at different peak levels, such as 0.1 percent peak hours, 1 percent peak hours, etc. The ultimate output of the load duration curve analysis would be to calculate the functional relationship between weather temperature and amount of unserved natural gas load within the power sector. The expected nature of this functional relationship is presented in Figure 29. It is expected that the amount of unserved load will increase during extreme temperatures, reflecting the correlation created in the power sector due to increased use of natural gas.

Figure 29: Amount of Unserved Natural Gas Load in Power Sector as Function of Weather Temperature and Gas Contingencies[72]



This functional relationship between temperature and unserved load would then be modeled in a resource adequacy model. Given that weather temperature is the main driver of load uncertainty, variations in weather temperature are directly or indirectly captured by the resource adequacy models. Therefore, incorporation of such function into resource adequacy modeling would not require significant revisions to the existing models. Once the functional relationship is captured, a resource adequacy model is able to adjust the availabilities of single-fuel, gas-fired generation based on the quotient found by dividing the amount of unserved natural gas by the total demand. Note that availability adjustment should be made for all single-fuel, gas-fired plants in the region.

The load duration curve approach captures gas–power interdependency without requiring robust modeling of the gas network within the resource adequacy modeling. Note, however, that the load duration curve approach will not be able to capture the equipment reliability fully, as the contingency analysis will only provide a static view of equipment reliability. Layer 1 analysis will not have representation of the gas network system. Put another way, load duration curve modeling will generalize the impact of gas availability on the power system by allocating gas availability to all non-switchable, gas-fired plants equally. Furthermore, the load duration curve approach is not a chronological modeling approach and is therefore likely to miss the finer details of the natural gas network operations, such as storage—a location-dependent resource.

[72] **Note:** The term “N-zero” is read “N minus zero” and refers to the scenario wherein all natural gas infrastructure is operational at its full (equilibrium) capacity. The term “N-1” is read “N minus one” and refers to a scenario wherein there is loss of one large component of the natural gas infrastructure. Scenarios wherein there is a loss of two large components would be called “N-1-1,” and so on.

Layer 3 (Fully Integrated Gas–Power Resource Adequacy Modeling)

Fully integrated gas–power resource adequacy modeling includes representation of the natural gas network in a standard resource adequacy modeling. Components of the natural gas network are assigned random outage statistics, and the supply-and-demand balance changes dynamically during simulation. Infrastructure components are a board term that includes various segments of the natural gas value chain including, production, processing, transportation, distribution, storage and other elements. Rather than the cascaded modeling defined within Layer 1 and 2 analyses, the integrated Monte Carlo algorithm simultaneously tests natural gas and power systems under different weather conditions. In the case of integrated modeling, gas fuel supply availability will be modeled inside the sequential Monte Carlo algorithm and tested chronologically, as opposed to the load duration curve approach. Integrated modeling reflects more accurate representation of the gas–power infrastructure interdependencies and, therefore, provides better understanding of associated risks.

Integrated modeling would have to adhere with the minimum resource adequacy modeling requirements listed in NERC's *Probabilistic Assessment* report[73]. Furthermore, the model would need to include a simplified merit order dispatch algorithm for assessment of natural gas demand and economics of reliability.

Expected Outputs and Answers

In addition to standard outputs produced from currently available resource adequacy models, integrated resource adequacy modeling will answer the following questions:

- Do variations in available natural gas transportation create additional risk on system reliability?
- What is the impact of gas–power interdependence on electric system reliability metrics (e.g., reserve margin)?
    - What is the amount of expected unserved energy due specifically to fuel supply and transportation unavailability?
    - What is the number of LOLH and LOLE caused by fuel supply and transportation unavailability?
- Does gas–power interdependence create a need for a higher planning reserve margin?
- What can be done to "firm up" fuel supplies to meet the reliability goals?

Probabilistic resource adequacy models used by the electric industry to calculate LOLE and other metrics attempt to capture the full range of uncertainty by modeling demand, forced outages—and variability of renewables—as probability distributions. Monte Carlo modeling has emerged as the industry standard to model randomness of bulk power systems. The most significant outcome of Monte Carlo simulation is the probability of demand being greater than supply at any given hour. The Layer 3 analysis of natural gas markets and infrastructure recommended in this report is intended to mirror and enhance these existing Monte Carlo methods for electric resource adequacy assessments.

This study described how planners can estimate the numbers of days per period of time that various gas-fired power generators would not be able to procure natural gas supplies and thus may not be available to supply power. The results of such analyses should be incorporated into the electric power resource adequacy models to more accurately estimate the key adequacy metrics, such as LOLE. The results of the Layer 1 and 2 analyses could be transferred to electric resource adequacy models in the form of curves showing available gas volumes for power generation on the y-axis and temperature on the x-axis. The curves would be bounds within which Monte Carlo samples could be drawn to adjust the availability of gas-fired power plants. The results of the Layer 3 analysis could also be transferred in the form of volume versus

[73] http://www.nerc.com/files/2012_ProbA.pdf

temperature curves, or the Layer 3 model could be configured to directly output LOLE and other electric resource adequacy metrics.

The main goal of resource adequacy modeling is to calculate reserve margin requirements that would result in a target reliability level (e.g., loss of a day or less of load every 10 years). To calculate the target reserve margin requirement, a resource adequacy model is run at different generating capacity levels until the reliability target is met. When a new uncertainty (risk) factor is introduced to the system, the result is either a requirement for more reserves to satisfy reliability goals, or a requirement for other measures, such as bolstering fuel supplies or resolving another source of systemic weakness. To incorporate the reliability of natural gas supply and transportation into resource adequacy models, any finding that the lack of available natural gas during the planning horizon will significantly contribute to inadequate electric supplies may result in suggested mitigation measures to:

- Increase natural gas delivery capacity by contracting and building new gas pipeline and storage capacity.
- Add new onsite natural gas storage capacity at or near gas-fired power plants.
- Install more alternative fuel capability and onsite (liquid) gas storage at gas-fired power plants.
- Expand use of interruptible electricity contracts to reduce electric loads in periods of constrained fuel supplies.
- Expand use of non-power interruptible gas contracts to reduce gas loads in periods of constrained fuel supplies.
- Increase electric transmission capacity into areas expected to have fuel-related generating constraints.
- Build up reserve margins using non-gas fuel capacity.

Since such measures may involve higher costs, it is important to assure that the natural gas market analysis providing into to electric resource adequacy studies is accurate; all mitigation measures should be weighed against each other and against the potential cost of the averted lost load. For similar reasons, it is important to assure that all stakeholders, regulators, and policy makers understand the reasons that fuel availability would be incorporated into resource adequacy studies and that they agree with the methods and data used for fuel supply analysis.

Assessment of Regional Pipeline Infrastructure

In addition to compressor unit scheduled and forced outages, gas pipeline system operations can be affected by maintenance requirements and operational problems with other pipeline components. Most pipeline maintenance tasks to test or clean the line (such as pigging[74]) usually can be done without curtailing firm pipeline services. It is also possible to construct new connections to pipelines without stopping services (e.g., hot tapping). However, a pipeline may on occasion stop service to some customers or reduce its operationally available capacity due to scheduled construction or tie-in of new facilities, component replacement (meters, valve, controls, and line pipe), or hydrostatic testing.

Except for those related to compressor units, contingencies on gas pipelines are most often related to problems with the pipeline leaks caused by third-party excavation damage, construction contractor damage, corrosion, natural forces, or mechanical failures, for example. Some, but not all of these incidences are reported to the Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA). Through Title 49 of the Code of Federal Regulations[75], PHMSA requires pipeline operators to submit incident reports within 30 days of a pipeline incident or accident. Title 49 defines accidents and incidents, as well as criteria for submitting reports to the Office of Pipeline Safety. The following is collected:

- Key report information

[74] How Does Pipeline Pigging Work: http://www.rigzone.com/training/insight.asp?insight_id=310&c_id=19
[75] 49 CFR Parts 191, 195

- In-depth location information
- Facility information
- Operating information
- Drug and Alcohol information
- Cause of the accident/incident

Specific information includes the time and location of the incident, number of any injuries or fatalities; commodity spilled/gas released, causes of failure, and evacuation procedures. The incident reports are used for identifying long- and short-term trends at the national-, state-, and operator-specific levels. The frequency, causes, and consequences of the incidents provide insight into the safety metrics currently used by PHMSA, state regulators, and other pipeline safety stakeholders, including the pipeline industry and general public. PHMSA also uses the data for inspection planning and risk assessment.

A reportable incident under PMHSA requirements is triggered by any of the following events:

1. An event that involves a release of gas from a pipeline, or of liquefied natural gas, liquefied petroleum gas, refrigerant gas, or gas from an LNG facility, and that results in one or more of the following consequences:
    a. A death or personal injury necessitating in-patient hospitalization;
    b. Estimated property damage of $50,000 or more, including loss to the operator and others, or both, but excluding cost of gas lost; and
    c. Unintentional estimated gas loss of three million cubic feet or more.
2. An event that results in an emergency shutdown of an LNG facility. Activation of an emergency shutdown system for reasons other than an actual emergency does not constitute an incident.
3. An event that is significant in the judgment of the operator, even though it did not meet the criteria of paragraphs 1 or 2 of this definition.

Based on the definitions above, incident reports may not always result in service interruptions. However, this may be determined by analyzing the explanations given in the data, were a system shutdown to occur. It would be necessary to analyze the incidents that clearly resulted in a system shutdown to determine the cause and duration of the shutdown.

Table 6 indicates that for the United States as a whole, there were 1,848 gas pipeline incidents reported over 20 years. This comes to roughly 0.0003 incidences per mile of pipeline each year, or 0.021 incidents per year for each 70-mile pipeline segment (approximately the distance between compressor stations). The pipeline segment between two compressor stations might expect to have a reportable incident to PHMSA once in 48 years. Assuming the mean period to repair is two days, the expected forced outage rate would be 0.042 days per year for a 70-mile gas pipeline segment.

The highest probability of rupture events of all rupture events is excavation damage. Excavation damage is generally considered time independent; therefore, hard to predict. However, each rupture cause has a probability of occurrence. These have been determined and the main focus of continuous improvement within the pipeline industry.

The actual impacts of forced outages were predicted in an ICF study conducted for INGAA in studying the impacts of outages due to the PHMSA mandated Pipeline Integrity Program. The effect on the market with the multitude of installation of pigging facilities—with attendant outage times—can be compared with random outages due to pipeline failures. The correlation between the number of rupture incidents and the market impacts (2006 to present) provides a more accurate probability of a pipeline rupture affecting the market.

Table 6: Probabilities for Types of Gas Pipeline Incidents Reported to PHMSA
(Note: These data do not include all types of non-compressor problems that can lead to forced outages)

Incident Type	Incidents Over 20 Years	Incidents per 1 Year	Incidents per Mile per Year	Per 70-mile 1-line Segment			
				Incidents per Year for 70-Mile Segment	Assumed Days to Repair per Incident	Days per Year Disrupted	Daily Probability of Disruption
Serious (death or hospitalization)	126	6.3	0.00002	0.001	7.0	0.01	0.0028%
Moderate (above property damage threshold)	1,070	53.5	0.00018	0.012	2.0	0.025	0.0067%
Lowest Reportable	652	32.6	0.00011	0.007	1.0	0.007	0.0020%
All Damages to Lines	**1,848**	**92.4**	**0.00031**	**0.020**	**2.0**	**0.042**	**0.0116%**

Large interstate mainline gas pipelines are often made up of two or more individual lines running parallel. Therefore, the scheduled or forced outage of one line would not affect all the capacity on the other mainline segment. Table 7 below shows how the probability of a forced outage might be computed on a mainline segment made up of two lines (L1 and L2). Each row represents a potential state of being for that pipeline segment. For example, the first line represents the case in which both L1 and L2 are operable and the capacity of the segment is 100% of its rated capacity. The next two lines represent states of being when one of the lines is operable while the other is not, and the line segment is at 50% of rated capacity (assuming the two lines are of equal diameter and operate at the same pressures).

The next row of data (L1=0, L2=0) represents both lines as inoperable with segment capacity at zero. As in the case of simultaneous outages of individual compressors in one compressor station, it is important to consider what the causes are for outages on the different lines making up each multi-line segment. It is also important to consider whether they are correlated to each other (generally true for mechanical failures) as opposed to those causes that might affect both lines at once (severe earthquakes or erosion/river scouring). The correlation coefficients used for generating the Monte Carlo case might be derivable from historical data but are more likely to be based on reasoned judgment.

Table 7: Example Calculation of Forced Outage Probabilities on a Pipeline Segment

Two Lines on a 70-mile Pipeline Segment				
L1	L2	Sum	Daily Probability	Available Capacity
1	1	2	99.9769%	100.0000%
1	0	1	0.0115%	50.0000%
0	1	1	0.0115%	50.00000
0	0	0	0.0000%	0.0000%

Overall Gas Pipeline System Reliability (in Reference to Specific Demands or Locations)

Once the scheduled and forced outages of the compressor stations and pipeline segments are specified, it is possible to analyze the overall system reliability using the Layer 3 Monte Carlo model, which would be represented by each of the following key components:

- Location and type of component (gas sources, gas pipeline segments, compressor stations, etc.)
- Rated capacity in MMcf/D or Bcf/D
- The scheduled outage requirements (frequency and duration)
- Probability of forced outages and probability density function of times to repair
- Correlation coefficients among the different kinds of outages (including relations to severe weather events)
- Effect of each kind of outage or combination of outages on operable capacity
- System topology (what other components connect directly to each component)

In order to reach meaningful results, any measure of gas pipeline reliability has to be defined in terms of specific natural gas demands or locations. For example, one can refer to the reliability of the overall system in terms of serving a single power plant or a group of power plants in a defined area. Because there can be several pathways for natural gas to move to any given location or region, it is important to model the exact topology of the system and to use a network flow model to determine how the outage of any given component or set of components in the natural gas value chain affects the ability to service any given demand for natural gas. It is possible that a power plant located somewhere on the gas system with only one pathway from the supply source might be much closer to the source than power plants located on the system where there are multiple pathways from various supply sources.

Figure 30 shows how simple gas pipeline topologies might be specified in a Layer 3 Monte Carlo model and how the reliability of service to an area could be computed. Figure 30 represents a simple 2.0 Bcf/D linear pipeline system for which there is a single gas source and one mainline route to markets. The mainline is made up to two parallel-running lines. There are three single-line 0.7 Bcf/D laterals running off the end of the mainline, each of which serves a market area. A gas pipeline's reliability is computed by estimating how often and for how long outages exist on each pipeline segment and at each compressor station and what the "operationally available capacity" is for those components. In this example, reduced capacity at a compressor station or pipeline segment would cause the gas to move only in one direction along the mainline, therefore reducing capacity at all downstream points.

Figure 30: Example of Overall Gas Pipeline System for Reliability Analysis (Linear System with No Interconnects)

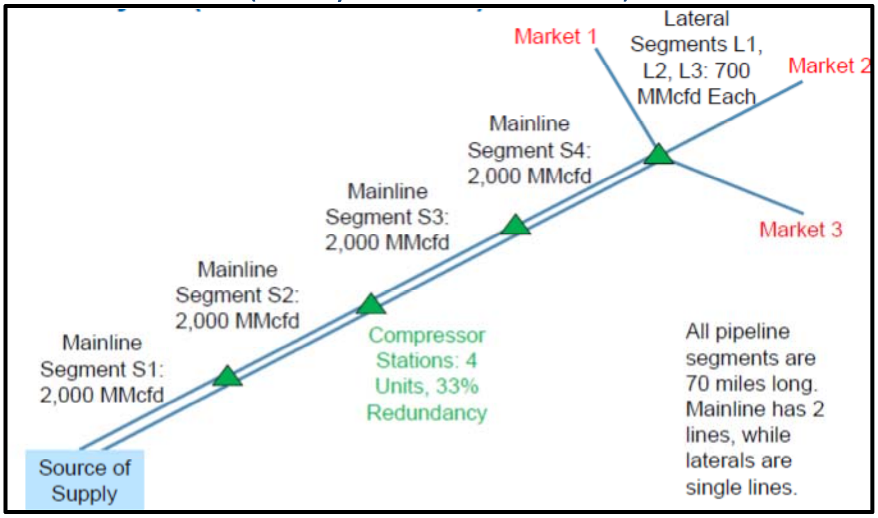
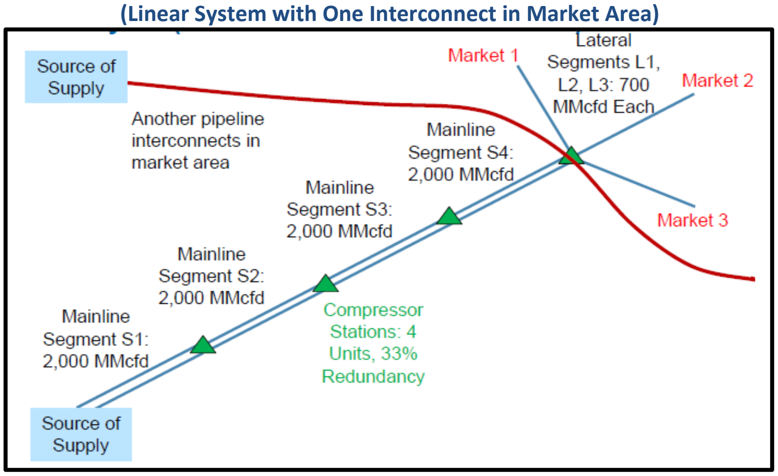


Figure 31 is another example of a simple gas pipeline topology. This topology is the same as the previous one except a second pipeline of 1.0 Bcf/D capacity has been introduced to connect to the three market area laterals to a second source of supply.

Figure 31: Example of Overall Gas Pipeline System for Reliability Analysis (Linear System with One Interconnect in Market Area)

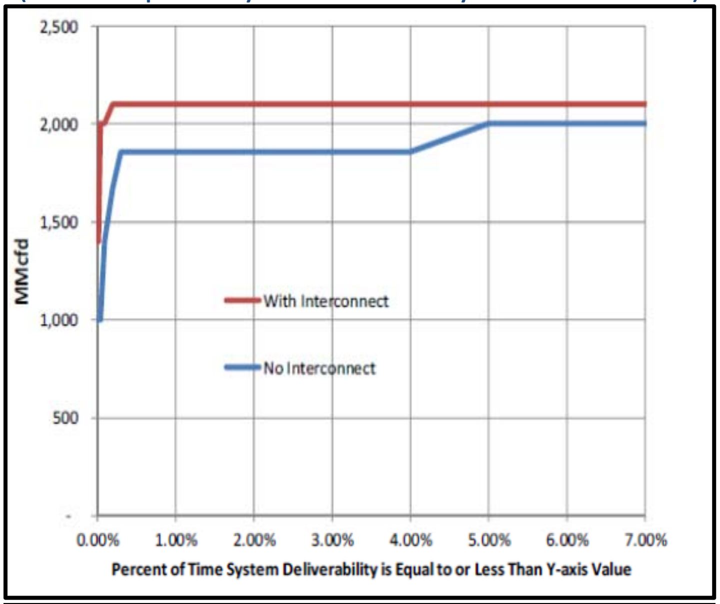


A Monte Carlo simulation was used to produce 2,000 cases of each topology. In each case, the operable status of each pipeline component (that is, each pipeline segment and each compressor station) is specified based on the frequency and duration of scheduled outages, the probability of forced outages, and the probability density function of the time to repair a forced outage.

The results of this Monte Carlo simulation are shown in Figure 32 with respect to the sum of deliverability into the three market areas. The x-axis represents the percent of time that the total deliverability is equal to or less than the capacity (in MMcf/D) value on the y-axis. For the first topology with just one pipeline, the maximum deliverability is maintained 95 percent of the time. As expected, the second case with a second pipeline serving the three market areas shows greater reliability with maximum deliverability being maintained over 99.8 percent of the time.

It is important to keep in mind that these examples only illustrate how the physical capacity of a gas pipeline system to deliver gas can be estimated stochastically. This does not take into account non-power demand for those transportation services and the entities that have the contractual rights to those services.

Figure 32: Gas Pipeline System Reliability Chart
(Cumulative probability of total deliverability to three market areas)



Data Sources for Pipeline Information

Pipelines post a list of firm transportation and storage customers the first business day of each quarter. BPS operators and planners could access these postings to identify which generators have contracted for firm transportation service, at what receipt and delivery and points, and the quantity (volume) of transportations service associated with the contract. However, sometimes this does not reflect the actual firm assets of a particular Generator Owner—firm supply can be used with firm transportation for segmentation opportunities. Pipelines also post additional firm transportation service, interruptible transportation service, and capacity release information no later than the first nomination for service under a transaction.

Pipeline postings typically show the energy value of natural gas capacity in Maximum Daily Quantity (MDQ) or Dekatherm (Dth). These informational postings do not list pipeline capacity in megawatts, because power capability is a function of the efficiency (heat rate) of the generating unit. Converting pipeline capacity from Dth, for example, to megawatt capacity will depend on the efficiency of a generator and whether the generator uses its gas at ratable or non-ratable takes.

BPS operators and planners should be aware of the natural gas capacity needed to run generators within their territories. A comparison could also be done between the expected pipeline capacity and generators' contracted capacity with the pipeline (which is available on the pipeline's website). Advancements in cross-industry communication and coordination could aid in accounting for daily firm service market changes and secondary firm point of receipt/delivery changes.

Another potential source of data are the pipeline Electronic Bulletin Board (EBB) notices, which could be analyzed to develop useful statistics. FERC Order 698 requires a Power Plant Operator (PPO) to coordinate natural gas deliveries with the Transportation Service Provider (TSP) directly connected to the PPO's facility. In compliance with the order, TSPs publish material changes that may impact hourly flow rates to their PPOs (i.e., critical notices and planned service outages).

The June 25, 2007 FERC Order No. 698 require interstate natural gas pipelines, PPOs, TOs, TOPs, independent BAs, and Regional RCs to establish communication procedures to improve communications for the coordination of gas transportation scheduling and the operations of gas-fired generators. Critical notices and planned service outages pertain to information on TSP conditions that affect scheduling or adversely affect scheduled gas flow. TSPs communicate Operational Flow Orders (OFO) and other critical notices by posting them on their websites. TSPs will also publish non-critical notices that don't adversely affect scheduled gas flow and that typically include bid awards, annual or monthly meeting notices, and tariff changes.

In many cases, a historical record of such notices is available on the pipeline website, although the data provided will vary from system to system. This information typically is removed from these websites within a three-to-six-month time frame. Prior notices may also be found in the archived Department of Energy's Office of Energy Assurance daily reports.[76] Such data may be useful in estimating the frequency of various outage types and (where data exists) the degree of the outages (i.e., how many MMcfd of capacity were lost).

[76] http://www.oe.netl.doe.gov/ead.aspx

Chapter 7—Performance Analysis of Generator Outages

The NERC Generating Availability Data System (GADS) is a series of databases used to track the performance of electric generating stations in North America. This reporting system was initiated by the electric utility industry in 1982 as a way to expand and extend the data collection procedures established by the industry in 1963. GADS was a voluntary industry program, open to all members of the Regional Entities and any other organization (domestic or international) that operate electric generating facilities—GADS became mandatory in 2012. The voluntary GADS database covered 72% of the installed generating capacity in the United States.

GADS information is used to support reliability and availability analyses and decision-making processes developed by GADS subscribers. GADS subscribers can use the data to calculate important performance statistics; they can also support bulk power trend analysis by referencing GADS information for forced outages, maintenance outages, planned outages, and deratings.[77] The PC, Regional Entity, industry stakeholders, and other GADS users (e.g., World Energy Council) use GADS data for conducting assessments of generation resource adequacy.

The NERC Board of Trustees approved mandatory GADS reporting criteria in 2011,[78] with data collection for conventional units above 50 MW beginning in 2012. GADS data is collected on a mandatory basis from all Generator Owners (GOs) on the NERC Compliance Registry under NERC's Rules of Procedure Section 1600, Requests for Data or Information.[79] Mandatory reporting requirements apply to generators with a nameplate generating capacity greater than the specified threshold of 50 MW. This was extended January 1, 2013, to include conventional generating units of 20 MW and above. Generating units with less than 20 MW of nameplate capacity are invited to report to GADS on a voluntary basis. These mandatory reporting requirements do not apply to non-conventional generation technologies such as wind and solar.[80] Additionally, many generators that do not meet the mandatory requirements provide information and data to GADS on a voluntary basis for benchmarking purposes.

GADS data are compiled and published annually by NERC in the Generating Availability Report (GAR).[81] GADS also produces a Historical Availability Statistics (HAS) report. HAS provides annual performance information from 1982 through the most current year for each of 63 generator unit groups in the GAR reports.

Generators report fuel unavailability-related outages to GADS under two different outage (cause) codes:

- 9130 Lack of fuel (water from rivers or lakes, coal mines, gas lines, etc.) where the operator is not in control of contracts, supply lines, or delivery of fuels
- 9131 Lack of fuel (interruptible supply of fuel part of fuel contract)

Outages related to lack of fuel are recorded regardless of a unit's dispatch. If the unit becomes unavailable due to fuel unavailability, the event is recorded as an outage in GADS even if the unit is not dispatched. GADS records outage start and end days and hours by Region, unit type, and utility.

The GADS database is one of the most complete sources of outage data utilized in resource adequacy models. For future efforts in overlaying an integrated gas–power resource adequacy model, forced outage statistics of gas-fired generators will

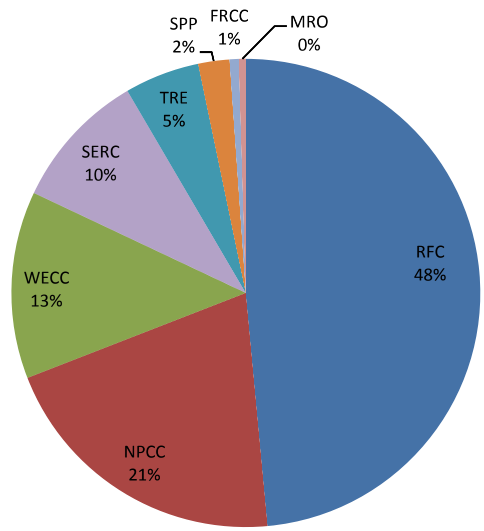
[77] NERC GADS website: http://www.nerc.com/page.php?cid=4|43|401
[78] NERC Board of Trustees minutes for August 4, 2011 meeting: http://www.nerc.com/docs/docs/bot/BOT_08-11m_complete.pdf
[79] North American Electric Reliability Corporation Rules of Procedure Section 1600—REQUESTS FOR DATA OR INFORMATION, Page 88, March 2012 http://www.nerc.com/files/NERC_ROP_Effective_20120315.pdf
[80] Non-conventional generating units are not subject to these mandatory reporting requirements, but they are tracked on a voluntary basis and governed by a separate set of reporting instructions, e.g., http://www.nerc.com/files/GADS_Wind_Turbine_Generation_DRI_042611_FINAL.pdf
[81] Generating Availability Data System (GADS): Reports http://www.nerc.com/page.php?cid=4|43|47

need to be recalculated to exclude outages related to lack of fuel that are currently masked in the final outage statistics to avoid double counting of fuel unavailability-related outages.

Lack of Fuel Cause Code Analysis

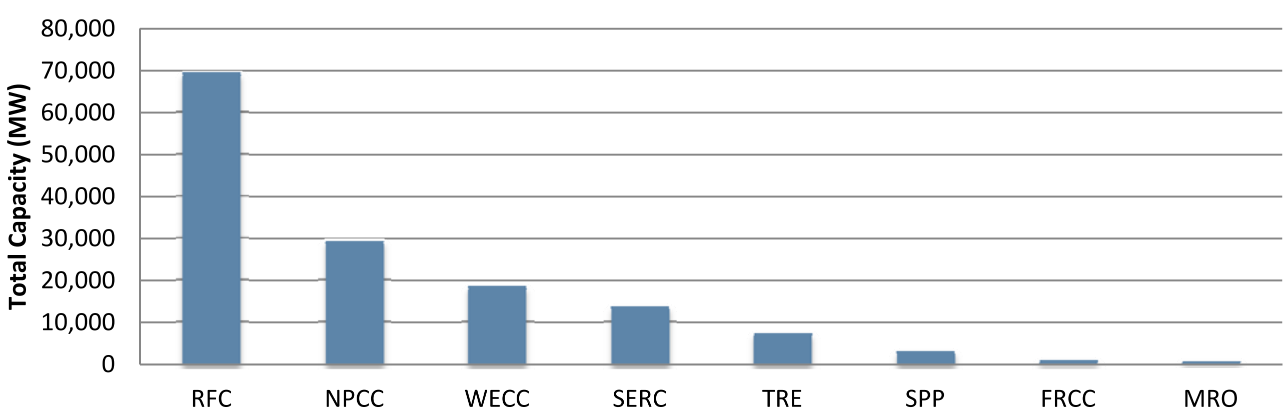
For the lack of fuel cause code analysis, NERC used 10 years of historical performance data for gas-fired generators and analyzed a total of 1,240 events. Statistical data are displayed in the charts below for the number of forced outages due to lack of fuel for the eight reliability Regions. The importance of analyzing the GADS database is to form a foundation for future analysis and trend generator outages due to fuel loss.

Figure 33: Number of Forced Outages due to Lack of Fuel by Region



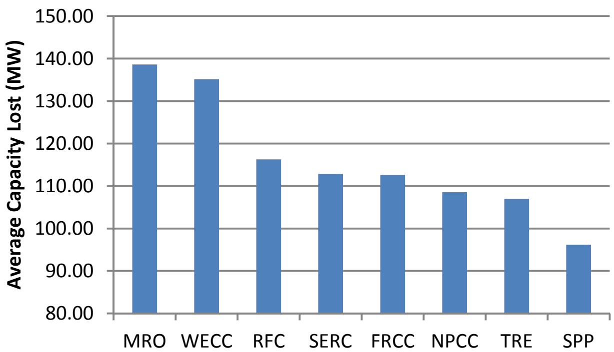
The summary statistics for NERC-wide Regions shows that the majority of outages due to lack of fuel occurred in RFC. In RFC alone, there were 597 reported outages due to lack of fuel, accounting for 48 percent of all outages due to lack of fuel in NERC since 2001 (Figure 33). NPCC has the second-highest number of gas outages due to lack of fuel.

Figure 34: Cumulative Capacity Outages between 2001 and 2011 due to Lack of Fuel



The average amount of capacity lost for outages ranges from 96 MW to 140 MW (Figure 35). The minimum average time that a unit is out in FRCC is 5 hours and 36 minutes. By contrast, the longest average time for an outage is approximately 47 hours (RFC). The second-longest average time for an outage occurred in SPP, with an average duration of over 31 hours per outage. From an energy perspective, loss in energy (Figure 36) NERC-wide is largely due to energy losses in RFC.

Figure 35: 2001–2011 Average Amount of Capacity Lost (left) and Average Outage Duration per Event due to Lack of Fuel (right)



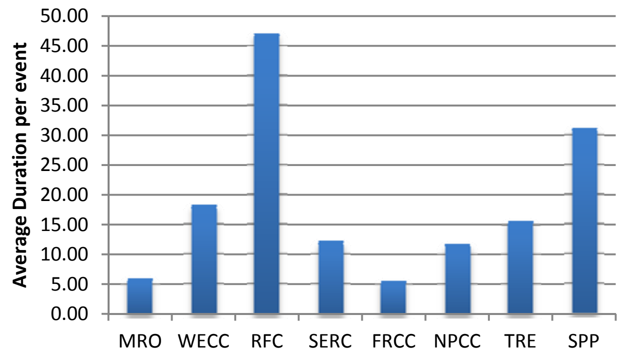


Figure 36: Total Annual Energy Loss per Year by Region

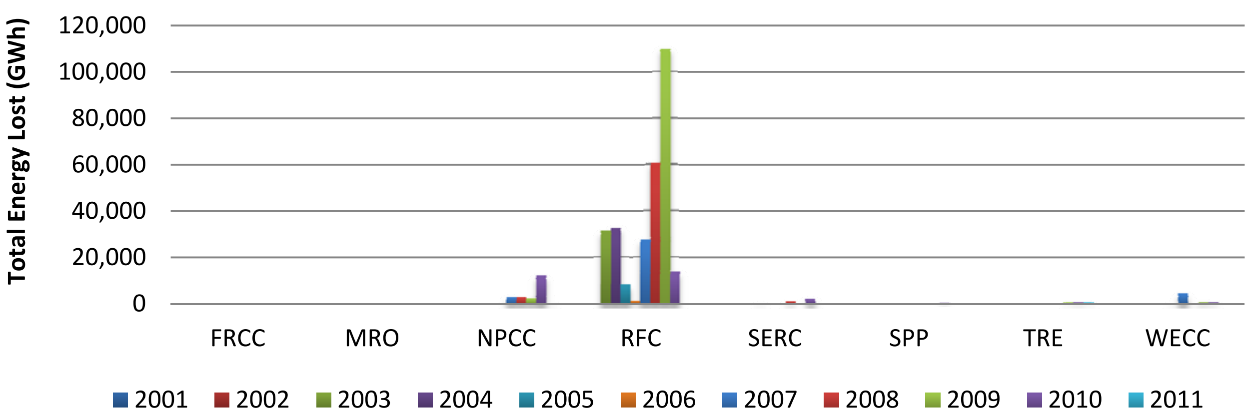
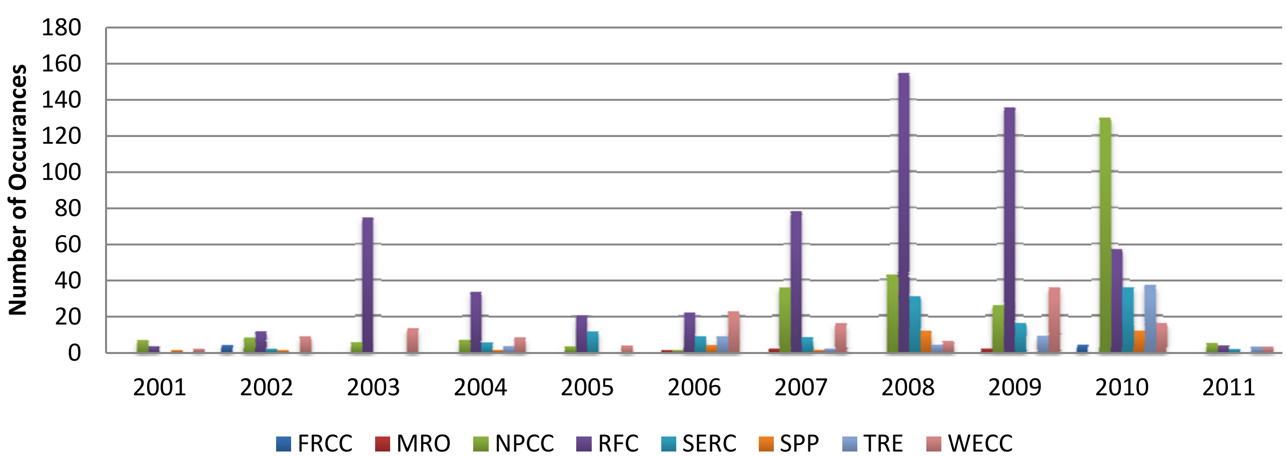


Figure 37: Number of Outages due to Lack of Fuel Supply from 2001 to 2011



By linearly trending the aggregated GADS data for all Regions, gas interruptions trends may increase in terms of capacity, duration, and occurrences. There have been more occurrences throughout the years, but there were fewer in 2011, which can be explained by 2011's mild temperatures. The number of occurrences for total capacity lost and outage duration are shown below. The trend lines for the two graphs follow a similar projected path as Figure 38, which indicates increased occurrences, total capacity loss, and duration.

Figure 38 : NERC-Wide Number of Annual Occurrences

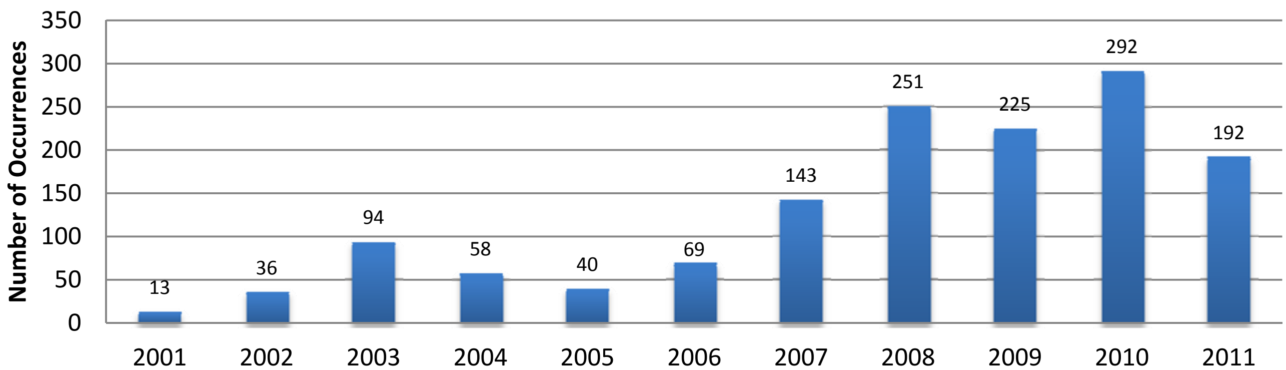


Figure 39 : NERC-Wide Total Annual Capacity Lost

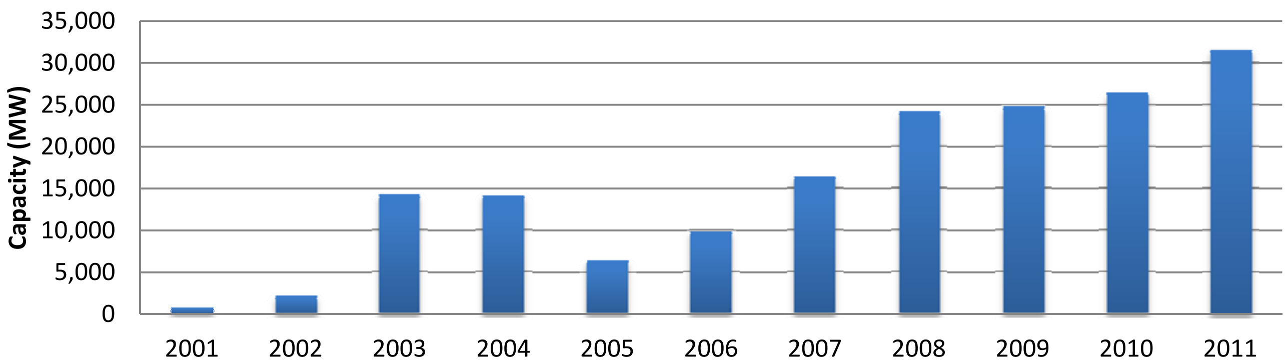


Figure 40 : NERC-Wide Total Annual Outage Duration

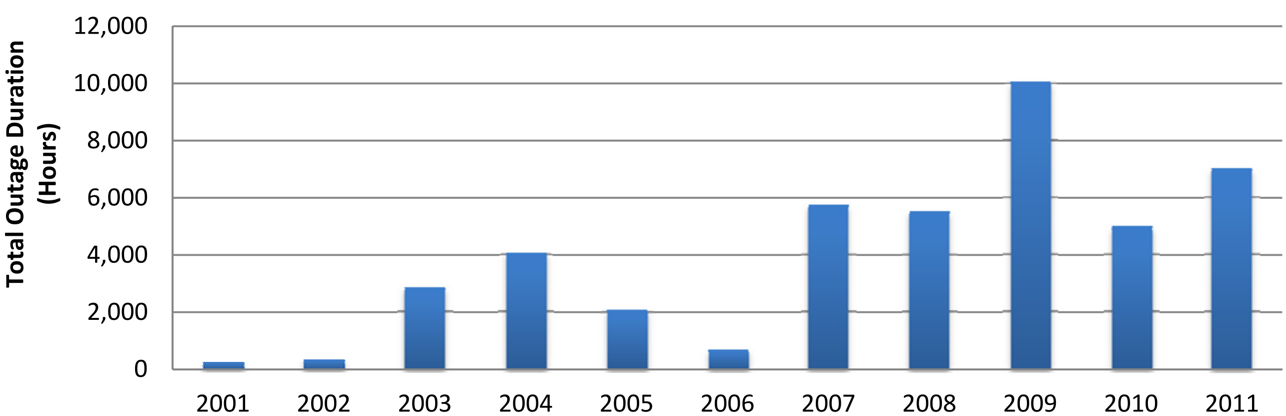
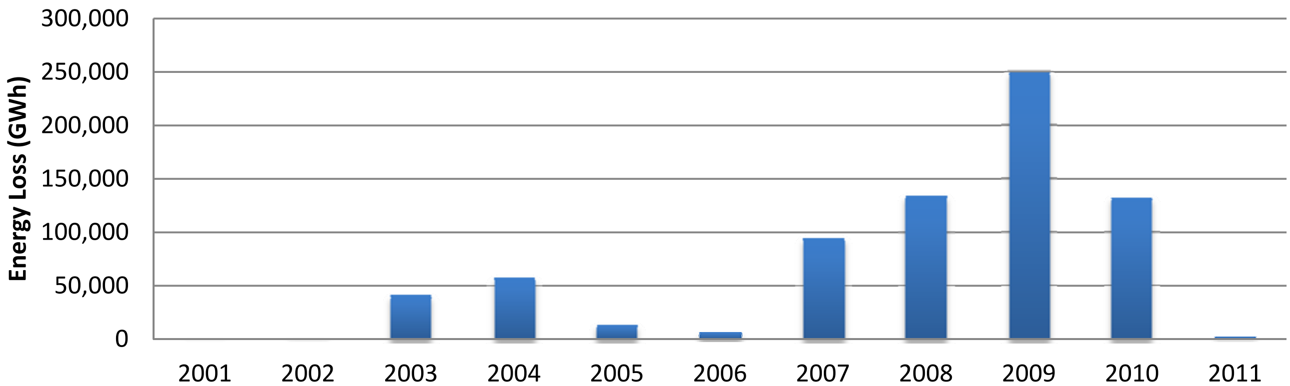


Figure 41 : NERC-Wide Total Annual Energy Loss



Recommendations for Future GADS Analysis

Upon finalizing the analysis of GADS data, NERC has identified recommended improvements to GADS cause code definitions and analysis. NERC suggests that future GADS analysis and trending capabilities focus on the following enhancements:

- Perform "deeper dive" analysis to a sample of individual generator outages to determine the cause of the outage. GADS should be able to identify if generator outages were the result of either fuel contract interruptions or uncontrolled gas curtailment events.
- Overlay GADS outage data on pipeline capacity trends to determine if there is a correlation and identify potential leading indicators.
- Determine natural gas pipeline and supply conditions during times of gas generator outages.
- Perform a study to determine approaches where dispatch trends and load duration curves can provide insights to future generator performance.
- Use GADS data for probabilistic adequacy models and develop scenarios around increased forced outage rates

Chapter 8—Risk Assessment for Electric Reliability

Prior sections of this report highlighted that for a variety of reasons, including acts of nature, gas supplies to electric generators are subject to temporary disruptions, and such disruptions can impact overall electric system reliability. Furthermore, as the dependence of the power sector on the natural gas industry is expected to increase, exposure to this vulnerability could result in significant gas-fired generation losses.

This chapter discusses different perspectives on how risks can be identified and vulnerabilities can be addressed and managed. NERC assessed the benefits of using more firm transportation, as well as where using firm transportation does not resolve all reliability issues. NERC also offered examples of enhanced transportation services that the two industries might consider to better support electric generation needs. In addition, a key theme in this chapter is the need to analyze and address options for improved reliability on this interface at the regional level due to the unique characteristics of each Region.

As shown in previous chapters, significant improvements in system reliability can be realized from having sufficient backup, dual-fuel switching capabilities. Obstacles to achieving such benefits usually include state, federal, and provincial environmental regulations (which effectively limit the amount of oil that can be burned), and operational preparedness.[82] Current policies and rules that regulate backup oil use and emissions for electric generation may need to be re-evaluated to ensure dual-fuel capability can be maintained during emergencies or other extreme conditions.

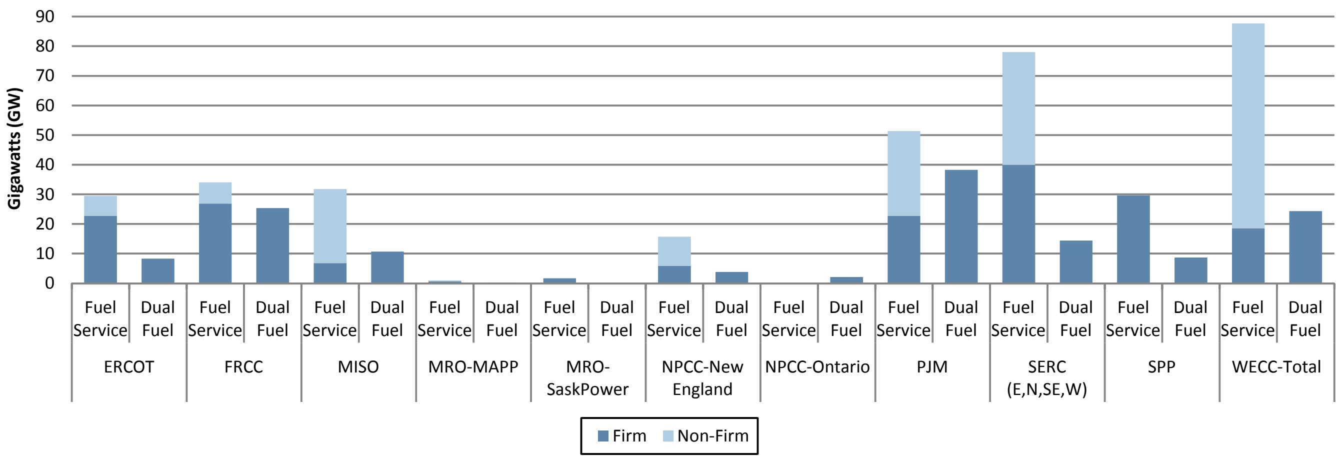
Economics, however, will drive decision making as solutions are developed and proposed. Additionally, it is important to recognize that maintaining the reliability of the evolving BPS comes at a cost. The most reliable and cost-effective solutions will ultimately be supported by an appropriate risk profile—a desired level of risk that the system is planned to withstand. Within the competitive wholesale market environments, a significant challenge will be to enhance market incentives and penalties needed to absorb the increased cost of maintaining system reliability. For regulated utilities, cost recovery of fuel supplies and transportation procurement is incorporated into the rate case. However, in deregulated markets, accurate price signals reflecting reliability needs and incorporating acceptable risks are vital to maintaining a risk-averse resource portfolio.

Dual-fuel capabilities and a variety of storage options may help bridge the gap between the uncertainties of gas availability during extreme events and maintaining a reliable source of operable capacity available to meet seasonal peak demands. Ultimately, the right balance of firm pipeline capacity, dual-fuel capabilities, and a variety of storage options will be regionally dependent. Factors such as market structure, geography, fuel mix, electric transmission, and pipeline infrastructure will determine the extent of gas dependency risks, as well as what solutions are available.

Improvements in system reliability may be realized from having sufficient back-up, dual-fuel switching capabilities. Obstacles to achieving such benefits include operational preparedness and state, federal, and provincial environmental regulations, which effectively limit the amount of oil that can be burned. Current policies and rules that regulate backup oil use and emissions for electric generation may need to be re-evaluated to ensure that truly functional dual-fuel capability can be maintained during emergencies or other extreme conditions. Additionally, planning processes should consider backup fuel inventories, changes in ramp and unit power capabilities, and the time requirements for fuel switch-over. Without considering this information, the amount of available dual-fuel generation projected to be available may be overstated. NERC-wide, 125 GW of gas-fired generation has dual-fuel capabilities (approximately 35 percent of gas-fired capacity). Of the Regions able to report and determine portfolio-wide firm contracts, approximately 58 percent of gas-fired capacity is tied to firm supply, transportation, and delivery (Figure 42).[83]

[82] The physical plant site and the siting and permitting process is also an important factor of whether liquid fuels can be stored on-site.
[83] Data gathered in supplemental request: http://www.nerc.com/docs/pc/ras/2012LTRA_Supplemental_Request-Instructions_v2.pdf

Figure 42: 2012 Gas-Fired Generation Fuel Services and Dual-Fuel Capabilities by Assessment Area[84]



Risk Assessment

To fully understand the implications of increasing gas-fired generation on the BPS, a risk assessment is needed to determine where the power industry should focus its attention. The risk assessment shown in Figure 43 provides a framework for developing a risk profile. A high-level risk profile may need to be adjusted for region-specific considerations; however, given a common risk of "loss of generation when needed," a clear path to assessing vulnerabilities and the likelihood of an associated impact can be ascertained.

The risk assessment in Figure 43 shows that the loss of generation of any magnitude is a resource adequacy concern—not an operating reliability concern. As such, it is not likely that this risk could lead to an uncontrollable, cascading, or unstable BPS. Rather, with a high magnitude of generator outages, a capacity deficiency would be the most probable outcome. The threat of such a risk is directly correlated to conditions on regional pipelines. A disruption to fuel delivery to a gas-fired generator, whether it is an interruption or a curtailment—again, depending on the magnitude of generators affected and time to respond—would likely result in system operators implementing emergency operating procedures (EOPs), firm load shedding, or rotating outages.

In terms of timing, a significant amount of redundancy and flexibility is already available during off-peak periods for both gas and electric systems. The most vulnerable periods to expose these risks happen during electric peak periods and when firm customers on the pipeline have nominated their full entitlements (i.e., pipeline peak). As the electric system peaks closer to the pipeline peak and both systems are stressed, the likelihood of a larger impact increases—typically during extreme winter weather. For many generators, this risk is mitigated through sufficient preparation and planning, which includes dual-fuel backup, adequate capacity release on the secondary market, and LNG shipments to injection points or generator sites.

[84] This analysis shows results of where fuel service is known. Areas that did not provide results, and may have unknown fuel service, are not shown.

Figure 43: Risk Assessment and Decomposition

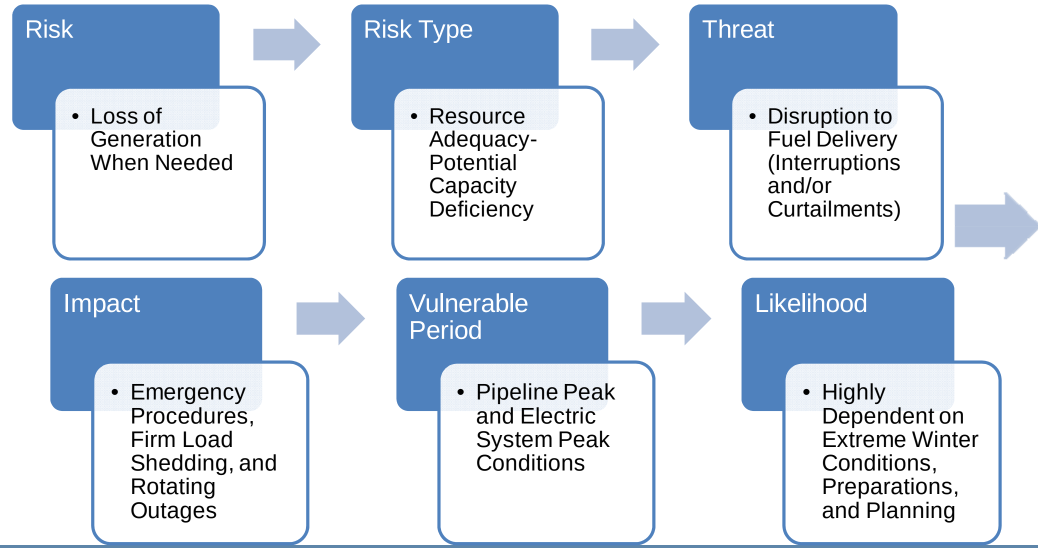


Figure 44 shows the risk assessment of two distinct vulnerabilities. Vulnerabilities and associated impacts of curtailments (pipeline or supply disruption) and interruptions (cold weather-related) are separate and distinct. Curtailments of fuel supply and transportation occurs because of a disruption either on the pipeline or at the supply source. Interruptions, on the other hand, generally occur because there is insufficient pipeline capacity. While both of these vulnerabilities can lead to common-mode outages, the causes of these occurrences are very different, and so are the risks associated with them.

Figure 44: Risk Assessment of Impacts and Mitigation

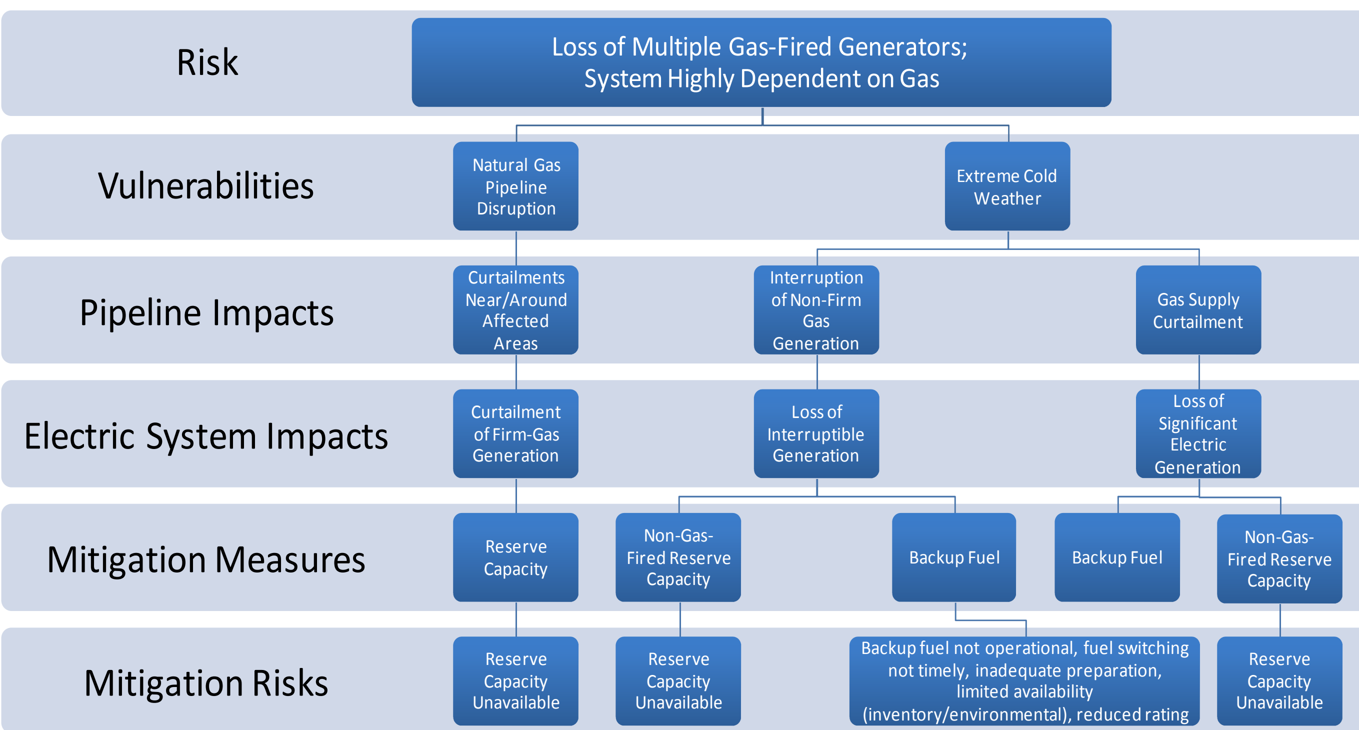
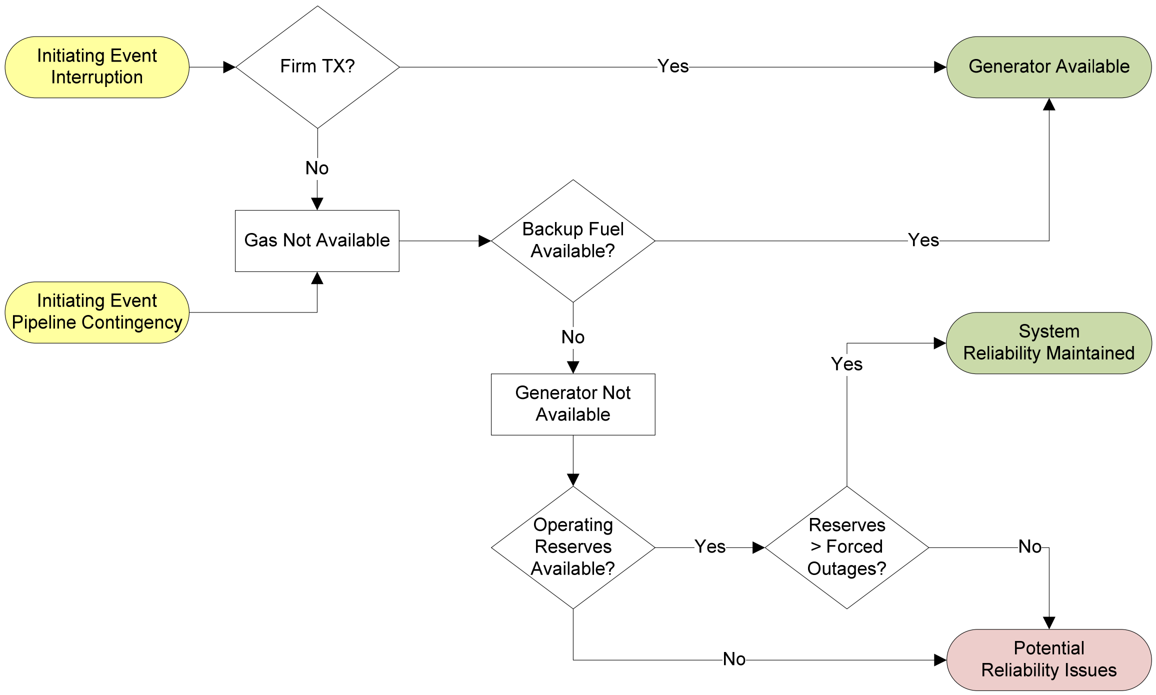


Figure 45 helps visualize the differences between natural gas interruption and curtailment risks. Along the flow chart, each step will have an associated risk value. Developing a risk profile for a Balancing Authority using this framework can aid in understanding the impact of each risk.

Figure 45: Operations Flow Chart and Risk Tree for Supply/Transportation Contingency versus Interruption (Initiating Events)



Pipelines are able to operate with temporary supply disruptions, provided the gas pressures are maintained within acceptable limits. However, within a relatively short time, a major failure along an interstate gas pipeline could result in a loss of electric generating capacity that could exceed the electric reserves available to compensate for these losses. The likelihood of pipeline failures occurring during electric peak periods, however, is extremely low. Therefore, efforts should be focused on preventative maintenance and recovery from these events.

Pipeline Services

Historically, the power industry has relied largely upon interruptible transportation services in order to balance costs and reliability. Because of the relatively low capacity factors of gas-fired units[85] and available secondary transportation capacity during the summer months, interruptible service is widely used by electric generators. However, reliance on interruptible service presents an increased risk of fuel interruption, particularly during periods of peak electric and gas demand.

As gas demand for electric generation grows, available pipeline capacity will likely decrease. On high-demand days, if the pipeline's firm customers schedule all of their contracted pipeline capacity, gas loads that have not contracted for firm capacity may not be able to procure the pipeline capacity necessary to provide delivery of gas supply.

Firm Transportation Services

Firm transportation is service offered to customers under schedules or contracts that anticipate no interruptions. While these services could significantly reduce the generator availability risks, the cost of such services can be economically prohibitive for generators with low capacity factors or generators within competitive wholesale markets.

[85] The average annual capacity factors for gas-fired generation vary by region as shown in Chapter 2.

However, firm transportation may not alleviate all reliability issues. For example, it does not resolve reliability problems arising from:

- Significant electric load variations that occur from unexpected weather events. Generator gas demand can be significantly different from the nominated gas volumes (only under traditional firm contracts with non-ratable takes).
- Reductions in gas pipeline pressures that occur due to an anomalous or man-made event and cause the high-pressure combined-cycle gas turbine units to trip offline.
- Gas curtailments as a common-mode failure.
- The problems that arise from the differences between the ”gas day” and the ”electric day.”

Based on current rules and tariffs, firm transportation services for the gas-fired peaking units—that have average annual capacity factors of 10 percent or less—are presently not economical. Peaking units, of which almost all are gas-fired, are an integral part of overall system reliability and usually represent the difference between being resource adequate and not. Proposed enhancements to overall system reliability must extend beyond the focus of any one solution (i.e., requirements for procuring firm natural gas transportation service is not a guaranteed solution).

In the future, it is likely that more gas-fired units, particularly combined-cycle units, will procure firm transportation services, as these units serve baseload generation requirements at higher capacity factors. With gas-fired generation providing more baseload generation, tensions between costs and improved reliability may be reduced.

Similarly, gas transportation strategies may become more complex and require a portfolio of transportation alternatives, with firm transportation being used for baseload requirements and interruptible transportation used for peaking contracts. With respect to the potential range of intermediate load requirements, this likely will require intense analysis and result in a relatively complex set of congestion-based, option-based, and derivative-based transportation contracts. Asset managers (also referred to as marketers, fuel suppliers, or portfolio managers) will play a much larger role in managing a portfolio of flexible and diverse transportation contracts for GOs.

Lastly, the power industry’s gas supply contracting practices are likely to change in order to meet this new challenge. Greater emphasis will be placed on either baseload supply contracts or supply contracts with complex swing capabilities or options. Potential integration of storage could—at a cost—reduce the complexity of such swing requirements. In addition, the power industry is likely to place greater emphasis on where gas supplies are sourced in an effort to manage transportation complexities, supply chain issues, and overall costs.

New Services

In addition to the above, the pipeline industry could assist in reducing the potential for system reliability issues that arise as a result of the growing interdependency of the two industries. Among other things, this could include the development of new or modified transportation services tailored to the needs of generation customers. Many pipelines have created such services or have attempted to market these services to their customers, particularly generation customers. Since these services may be more expensive than firm transportation service (they may require pipelines to reserve capacity for the subscribed customers in order to provide the service), many generators do no subscribe to such services.

As a result of the location and drilling of shale gas closer to traditional end-use markets, the industry (in some regions) is starting to source its gas supplies closer to local production. This, in turn, has initiated a trend in many Regions for a reduction in long-haul transportation requirements. While the latter phenomenon reduced the overall cost of firm transportation for affected customers, it also resulted in a reduction in the capacity factors for sections of the overall gas pipeline network. A careful evaluation of both phenomena shows it is possible to develop new transportation services that focus on the reliability needs of the power sector. However, since the ability to offer new services tailored to generators is contingent upon underutilized capacity being available, new pipeline infrastructure may also be needed.

One example is Texas Gas's recent adoption of the Enhanced Nominations Service.[86] This new service, which is structured primarily for the needs of the power industry, adds 11 new nomination and confirmation cycles during the gas day. While this new service does not affect the rights of firm customers, it does provide gas generators priority in interruptible nominations. With this service, GOs can adapt better to changing gas-fired generation requirements due to changes in the weather or variable generation.

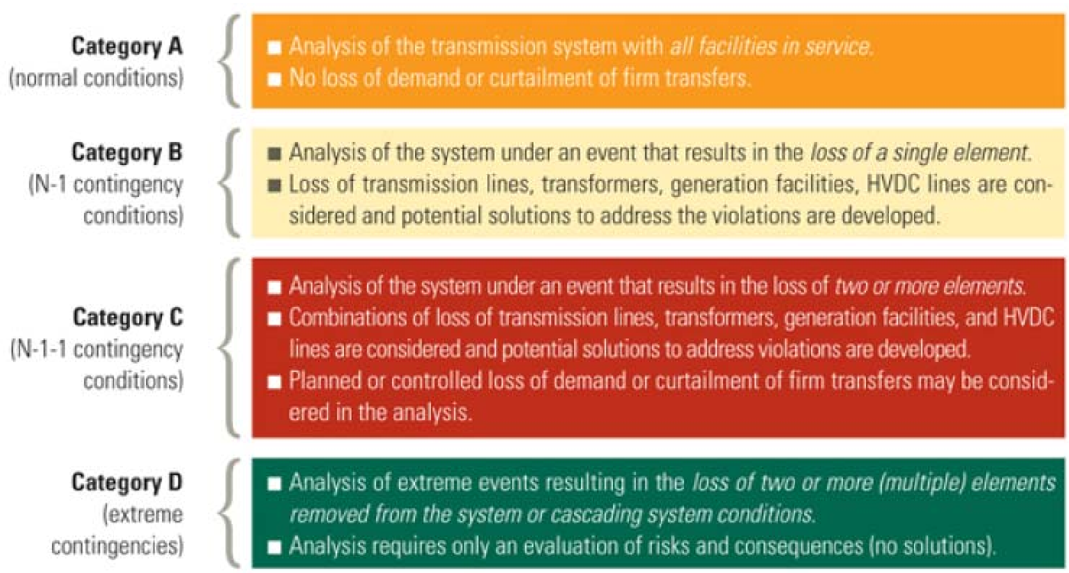
However, the gas industry likely cannot proceed down this path entirely by itself, and the power industry would have to create incentives for GOs to subscribe to these tailored delivery services. Without a joint effort from both industries, the development of such new services by the gas industry would not be effective or sustainable.

Regional Planning

As discussed throughout this report and stressed in previous NERC assessments, there are significant regional differences within the electric industry, as well as the gas industry. These regional differences include, among other things, differing degrees of dependency on gas-fired generation; number and types of pipelines serving the Region; access to storage within the region; geography; climate; electric infrastructure; and demand. As a result, analysis, reliability assessment, and associated planning are best done at the regional level.

NERC Reliability Standards provide a layer of protection for transmission planning—utility planners must consider system backup, or robustness, to cover a scenario called a "single-contingency situation," such as the failure of a transformer or other significant event that causes the outage of a transmission line or large generator (Figure 46).

Figure 46: Four Primary Categories for Normal and Emergency Conditions



Credible contingencies on pipeline systems could be integrated into a similar process designed to study and perform scenario analysis on the electric system. The assessment is intended to be basic and high-level. A screen test will be helpful for prioritizing the various scenarios to help identify credible contingencies and provide a better understanding of risks and consequences.

[86] "TransCanada files new application to expand Eastern Mainline system," *Inside FERC's Gas Market Report*, November 11, 2011, p. 23.

This assessment would then become a basis for contingency planning for a loss of major gas supplies within the Region, which might be similar to the pipeline break scenario, the key compressor station failure, or the cascading domino effect as discussed in Chapter 4.

Chapter 4 describes one element of this Region-specific planning effort that requires an assessment of all the pipelines in the Region. That assessment includes gas loads being provided by each system to supply gas-fired generators, as well as the most vulnerable points for an unplanned interruption or curtailment of supply.

In addition, the tabulation of pipelines serving a Region could be used to establish a Region-specific coordination and notification of pipeline maintenance requirements with Regional PCs. Once this initial assessment of the Region's pipelines is complete, the electric industry should attempt to work with each of the pipelines within their Regions to structure a joint assessment of the most vulnerable areas and the best set of contingency plans. One result of that effort might be the ability to provide the electric coordinators with a better understanding of the capabilities and limitations of the transportation systems that provide fuel services to their Regions, particularly during periods of stress. The latter could result in a limitation of the amount of scheduled gas-fired generation within a Region during periods likely to be of significant stress (i.e., peak demand periods) or, alternatively, limitations on the amount of standby generation capacity that is gas-fired.

Lastly, such a joint effort might be dependent on the disclosure of some proprietary information, which would inhibit the overall process. However, if the overall process were developed only with a small, core group of electrical industry representatives, this dilemma likely could be resolved. Another option would allow protected sharing of information with nondisclosure agreements and FERC Standards of Conduct protections that the electric industry has experience with in protecting proprietary information for the unregulated generation business.

Electric Transmission

Electric transmission increases the BPS's flexibility and resilience. If there is sufficient bulk power transmission, risks can be managed by obtaining ancillary services and flexible resources from a larger generation base, such as through participation in wider area balancing management. Transmission planning and operations techniques, including economic interarea planning methods, should be used for such interarea transmission development to provide access to and sharing of flexible resources.

When attempting to manage gas supply and transportation disruptions, entities should consider the benefits of electric transmission. Common-mode impacts to generators related to a single pipeline may be able to be managed by importing more power to load pockets.

Flexibility Requirements

The need for flexibility is a common theme among technical studies that address electric system impacts due to resource mix changes. The strong growth in wind power and the lack of cost-effective electric storage solutions indicates that power systems will rely heavily on more flexible resources, such as gas turbines, to compensate for wind power variability. Even in Regions with significant amounts of hydroelectric power (a better technology to compensate for wind power variability), gas turbines will be required to back up wind power, because environmental regulations limit the minimum and maximum amount of water a hydroelectric facility can release (termed "run-of-river" environmental constraints).

Power systems have many sources of flexibility that are currently needed to maintain the balance of supply and demand in anticipation of potential changes in system conditions. These changes can be expected and planned. For example, when morning load increases, it can require a dramatic and prompt increase in generation to follow load. The loss of a large generating unit that requires fast-ramping generation or load response to return the system to equilibrium can result in an unexpected change in the supply-and-demand balance. These flexibility needs are known and are anticipated during the planning process.

While gas-fired generation has typically been thought of as providing flexibility to the electric grid, absorbing the impacts from gas interruptions and curtailments may also require flexibility. A number of characteristics must be considered when identifying system needs for flexible resources. These can be grouped into three main areas:

- **Magnitude** refers to the size of ramp events and their direction. Traditional reserve calculations sometimes measure the requirements as the size of the first and second contingencies. Incremental flexibility is required at times of facility outages and net load increases while decremental flexibility is required when net load decreases. On the supply side, the magnitude is an indicator of the resources needed to respond to the ramp event**.**
- **Ramp Response** refers to the rate of change of the net load or unit output and the predictability of net load or unit output. The ramp rate of the resources must be sufficiently large to be available to respond to system ramping needs. Large ramping events, which happen quickly, will require fast-acting responsive resources, the simultaneous movement of a larger number of slower acting resources, or both to meet the ramping needs of the system. Slower acting ramps, such as seasonal variations, require less responsive resources. Resources that can respond quickly would be labeled "highly responsive ramping resources," while resources with slower response times would be labeled "lower responsive ramping resources."
- **Frequency** refers to the number of times events of various magnitudes and responsiveness occur. Variable resources generally increase the number of times flexible resources must be used in response to small or medium-sized events. This is usually a cost issue as resources incur an operating cost each time they are used to balance supply and demand.

During extreme winter weather, electric system operators should maximize the availability of flexible resources and understand how much flexibility is available at any given time. This can provide the system operator additional observability of the system to maintain operational reliability. In response to gas disruptions, the electric system operator should be able to identify vulnerable capacity, determine if reserve capacity is available, dispatch the appropriate resources, implement any operating procedures, and minimize any impacts by maintaining the integrity of the system.

Confidential Information

As discussed in the NERC *Primer*, the gas and electric industries in some Regions have historically shared significant information; however, deregulation has resulted in almost every piece of information concerning operations now being considered proprietary and confidential.[87] Most of the industry has adopted this philosophy, and it presents a challenge for coordinating between the two industries.

While it is a challenge to overcome the treatment of most confidential operating information, these challenges should not be insurmountable. For example, a recent NERC-wide effort to request how much electric capacity is backed by firm transportation led to questions of market-proprietary information. However, all pipelines post a list of firm transportation and storage customers the first business day of each quarter. This posting, which is called an Index of Customers and is required by the Natural Gas Act (NGA),[88] includes the name of the shipper, the applicable rate schedule, the effective and expiration dates of the contract, the maximum daily contract quantity (MDCQ), the receipt and delivery points, and other information about whether the contract is arranged by an asset manager, whether there are any affiliate relationships, and whether the contact is a negotiated rate.[89]

Costs

There is no doubt that some gas transportation services are less expensive than others and that the most reliable gas transportation services are usually the most expensive (e.g., no-notice firm transportation). This basic relationship creates a

[87] ISO-NE Information Policy located at: http://www.iso-ne.com/regulatory/tariff/attach_d/index.html
[88] 18 C.F.R. 284.13.
[89]This information is publicly available and you can download this information. For example, see Southern Natural Gas Company's index of customers on its Informational Postings website: http://ixsnp.sonetpremier.com/EbbMasterPage/ebb.aspx

significant tension between two almost equally important objectives within the power industry: (1) minimizing the overall cost of electricity, and (2) providing the most reliable service possible in an industry that has very limited tolerances for interruption.

Nevertheless, industries, regulators, and policymakers should work together to minimize this tension and accommodate the unique services needed for BPS reliability. For peakers and low-capacity-factor gas-fired units, firm transportation services are not the only solution, but developing alternative forms of interruptible transportation services that can accommodate the need for added reliability during periods of stress can effectively minimize the risk exposure to the BPS. Short-haul transportation alternatives that are starting to evolve within the industry may be part of the solution set. However, it is important to recognize that while more flexible interruptible transportation services may provide some benefits, the service is still interruptible. Consequently, it may not be available when firm capacity customers fully utilize their entitlement to pipeline transportation. Most importantly, PCs and state regulators must understand the risk a generator is taking and whether that risk is transferred with a compounding effect from multiple generators to the BPS. These risks must be made clear to regulators and policy makers through assessments and planning studies (i.e., planning assumptions that do not take into account potential fuel supply and transportation issues, may underestimate potential impacts and reserve requirements).

With respect to the natural gas industry, it is likely that it will respond to these new challenges for the power industry and develop new services tailored to meet generation requirements, load profiles, and reliability needs. Such adaptations are likely to vary significantly between Regions. However, currently, the gas industry has seen low demand for tailored services from the power industry due to the higher costs associated with them. The demand for tailored gas supply and transportation contracts is likely to increase as the share of gas baseload generation increases.

Fossil-Fired Capacity Retirements

An added perspective to this assessment is that about 70 GW of coal-fired and oil-fired capacity are projected to retire within the next several years, with gas-fired generation replacing much of this retired capacity. This change of fuel mix is a key factor behind the growing dependence on natural gas.[90] With respect to environmental regulations, an added layer of uncertainty to future reliability results in regions where future pipeline capacity is expected to be constrained.[91]

Accommodating High Levels of Variable Generation

Renewable generation—and, in particular, wind generation—has increased significantly over the last decade and will continue to increase in the future. In order to reliably accomodate wind and other variable generation, it is necessary for an electric system to have adequate backup sources of generation that can come on-line quickly. While there are several different methods of providing backup power that comes online rapidly, by far the dominant method is the gas-fired combustion turbine. As a result of gas-fired generation's ability to provide flexibility to the BPS, gas-fired generation has inherited an additional role within the power industry, and this role, which likely will be highly regional, will continue to increase as wind generation continues to grow.

This added backup requirement to wind generation for gas power plants increases the complexity of gas supply and transportation strategies for the power industry. In addition, it could have a significant impact on the pipeline segment of the natural gas industry, as there is the potential for a domino effect. This domino effect is demonstrated by the following example: (1) a sudden loss of wind generation as a result of a weather event could result in (2) the loss of an electric system (i.e., rolling blackouts), which could result in (3) electric compressors for both pipelines and field gas compression being forced offline, which could result in (4) a reduction in pipeline pressure, which could result in (5) gas-fired units being forced

[90] 2012 Long-Term Reliability Assessment: http://www.nerc.com/files/2012_LTRA_FINAL.pdf

[91] Extraction from *2011 Long-Term Reliability Assessment: Potential Impacts of Future Environmental Regulations*: http://www.nerc.com/files/EPA%20Section.pdf

offline. The possibility of both regional electric and gas industry reliability being dependent on sudden changes in wind generation represents an evolving challenge for both industries.

Fuel Switching

Historically switching from gas to oil was the most significant means of ensuring system reliability during periods when gas supplies were either uneconomic or under stress; this capability, for the most part, was stripped when the power industry transitioned from the less efficient steam generator technology to the more efficient combined-cycle technology. One attribute of the older steam generator technology was that many of them were designed to be dual-fuel units, which could switch to oil during periods of stress. However, when the industry converted to the combined-cycle units, the vast majority of them were built to be gas-only units,[92] as they could not secure permits at the time to be dual-fuel capable because of environmental pressure to minimize air emissions.

Economic gas-to-oil fuel switching likely is a phenomenon of the past. However, due to the price parity relationship between natural gas and fuel oil, gas-to-oil fuel switching to enhance overall system reliability likely represents the preeminent means of maintaining system reliability when gas supplies to gas-fired power units are constrained or interrupted. One of the key attributes of the gas-to-oil fuel switching is that it can be done rather quickly for a properly designed dual-fuel unit. Fast fuel switching is associated with some additional costs, including the installation of dual-fuel burners, on-site liquid storage tanks, testing, and monitoring and maintaining viable fuel oil supplies.

However, as a result of the country's de facto zero tolerance policy for incremental air emissions, the power industry, for the most part, has been stripped of this capability to fuel switch. The limited number of combined-cycle units with permits that allow dual-fuel capability could affect system reliability in certain situations.

Because of the concern to preserve the reliability of the electric system during periods of significant stress, it could be beneficial if the electric industry approached both federal and state regulators with a plan that would allow or increase fuel switching. Such a plan should contain key elements that include the following:

- **Fuel Switching:** an explanation of how gas-to-oil fuel switching works, how long it takes to switch a unit's fuel (some Regions are capable of doing so in minutes), and the added costs and inherent risks.
- **Dual-Fuel Capabilities:** GOs should be responsible for the data and information sharing related to each generator's functional dual-fuel capabilities.
- **Mitigation:** RCs and PCs should be responsible for establishing the system-wide reliability plans for minimizing BPS impacts due to lack of fuel-related forced outages. A detailed description and plan is needed, along with examples of how fuel switching can be used to maintain system reliability and how the added time provided by fuel switching to allow electric system operators to take other actions (e.g., bring online other units).
- **Identification of Gas Supply and Transportation Risks:** An assessment of regional pipeline infrastructure and the potential risks of both gas interruptions and curtailments should be performed. For a variety of reasons (including acts of nature, gas supply and transportation arrangements, and other extreme conditions), outages of gas-fired generation due to lack of fuel do occur. Statistic probabilities can be evaluated to determine what the true risks (likelihood and impact) of gas supply and transportation interruption and curtailments are to electric system reliability (three-layer approach).
- **Resource and Contingency Analysis:** RCs and PCs should be responsible for the risk analysis as well as integrating these risks into resource and contingency planning. These entities should study the effects of different gas supply and pipeline contingencies and dual-fuel requirements that may provide system operators the needed flexibility to maintain reliability during extreme events.

[92] From 1998 to 2005 there was a building boom for new gas-fired combined-cycle capacity, as approximately 150 GW were brought online during this period. In addition, another 75 GW of simple-cycle capacity (i.e., peakers) was brought online. See Chapter 4 of NERC's *A Primer on the Natural Gas Industry and its Interface with the Electric Power Industry*, 2011.

Case examples that illustrate how the system reliability of both industries can be affected in periods of stress and the joint advancement of such plans could result in a new regulatory framework that would resolve many of the key issues assessed in this report. In wholesale market areas, consideration should be given to the development of a market product that offers incentives for peaking units with dual-fuel capability. This product could include requirements around fuel reserves and fuel switch testing.

Lastly, if successful, the power industry would need to take extra steps to ensure sufficient dual-fuel capability within a given system, and formal procedures are in place to demonstrate that dual-fuel capability is fully functional (through audits) even under severe weather conditions. GOs should provide dual-fuel considerations to RCs and PCs that may include:

- **Inventory Assessment**: Hours of fuel burned kept on site. This may also include contracts with suppliers to deliver fuel to the generator site.
- **Mitigation Plans**: Detailed plans on how the generator expects to run (or not) in the event of a fuel supply disruption.
- **Response Capability:** Description of the unit's ability to switch over in a timely period, as well as results from tests performed within an appropriate time period (e.g., capability audits within the past year).
- **Ratings:** Unit rating when fired by an alternate fuel source.
- **Limitations:** A description of other limitations that may affect the performance of the unit, including but not limited to local, state, and federal environmental regulations, (inter)dependencies on other units located at the same power plant facility, etc. GOs should also provide any difference in performance characteristics and the unit's ability to provide real and reactive power to the transmission that differs from the unit's performance when fired by its primary fuel source under normal conditions.

Chapter 9—Key Findings and Recommendations

The combination of growth in natural gas demand within the electricity sector and its changing status among the gas-consuming sectors has significantly increased the interdependencies between the gas and electric industries. As a result, the interface between the two industries has become the focus of industry discussions and policy considerations. In its effort to maintain and improve the reliability of North America's BPS, NERC examined this issue in detail, as outlined in the report, and has developed several recommendations for the power industry. These recommendations could improve the existing coordination between the gas and electricity sector and foster enhancements in planning and operations. NERC has approached this issue solely from a reliability point of view and has not examined the potential solutions available through various market mechanisms.

Regionality

In light of the unique characteristics of each region, which significantly impacts the interdependency between the two industries, integrated assessments should be fine-tuned to what is applicable to each region. For example, some regions have adequate levels of natural gas storage that can be relied on during emergency conditions, while others, such as parts of the Southwest and the Northeast, do not. As a result, more regional gas storage could be developed.

Also, each region may develop different approaches for interacting with critical third parties (e.g., regulatory bodies) on endorsing new procedures and approaches in order to preclude the loss of system reliability during periods of extreme stress. These new procedures and approaches might include new definitions of essential gas loads (e.g., beyond human needs) and greater discretion on granting emissions waivers during emergency conditions (e.g., the use of fuel switching to preclude rolling blackouts), among other things.

For regions with limited gas-fired generation, such an effort at present may require long-term planning solutions to manage future conditions that could result in the loss of system reliability. Other regions might focus on historical events and, based on these events, develop specific action plans to minimize the potential loss of system reliability in the future.

Key Findings and Recommendations

NERC's key findings in this report are categorized into two planning and operating timeframes: Long- and Short-Term Planning and Operational Planning and Operations. The recommendations presented below are intended to provide a platform for further technical and policy input.

Long- and Short-Term Planning Findings

- Reliability assessment and resource adequacy studies
- Gas supply and fuel security
- Transportation expectations
- Generator availability
- Back-up fuel and fuel-switching capabilities

Operational Planning and Operations Findings

- Seasonal and day-ahead observability
- Coordinated operational procedures
- Coordinated outage schedules
- Increasing flexibility
- Information sharing and situation awareness
- Emergency operating procedures

Long- and Short-Term Planning Summary

Key Finding: Risk-based approaches are needed to study the impact and regional challenges associated with an increasing dependence on natural gas.

The power sector's growing reliance on natural gas has raised concerns by ISOs, RTOs, market participants, national and regional regulatory bodies and other government officials regarding the ability to maintain electric system reliability when natural gas supplies to power generators are constrained. The extent of these concerns varies from region to region; however, concerns are most acute in areas where power generators rely on interruptible gas pipeline transportation and where the growth in gas use for power generation is growing the fastest. Because it typically takes three to four years to build pipeline infrastructure, solution sets that call for increased pipeline capacity must be developed as quickly as possible so the electric industry is well postured to manage the regional challenges and emerging risks associated with an increasing dependence on natural gas.

Recommendations:

- Implement advanced modeling and analysis approaches. NERC recommends the Three-Layer approach or similar advanced probabilistic techniques.
- Enhance the NERC Generator Availability Data System (GADS) to increase the effectiveness of trending gas-fired generator outages and causes related to fuel issues.

Key Finding: Enhancements to reliability and resource assessments should reflect risks to gas-fired generation as a result of various fuel disruptions.

Natural gas is a reliable fuel source that is expected to fire electric generation serving more than 50 percent of the electric peak demand in North America by 2015. However, because natural gas is largely delivered on a just-in-time basis, vulnerabilities in gas supply and transportation from a planning perspective must be sufficiently evaluated to inform BPS operators about credible contingencies and flexibility options. Resource planning and adequacy assessments in some areas do not fully account for the risk of disruptions in the natural gas and other fuel supply chains.

For example, electric system impacts due to a single point of failure within the natural gas fuel supply chain can impact electric generators downstream from the disruption. Impacts of potential wide-spread common-mode failure events, such as a major failure along an interstate gas pipeline or major supply source, although rare, must be well understood to foster enhanced planning and design insights.

Pipelines are able to operate with temporary supply disruptions, provided the gas pressures are maintained within acceptable limits. However, within a relatively short time, a major failure could result in a loss of electric generating capacity that could exceed the electric reserves available to compensate for these losses. The likelihood of pipeline failures occurring during electric peak periods, however, is extremely low.

By integrating these risks into planning studies, potential generator outages due to natural gas interruptions and curtailments can be better understood. Through rigorous analysis, vulnerabilities can be identified in the planning stages (1 to 10 years) and risks can effectively be minimized. These studies provide the foundation for state, federal, and provincial regulators, policymakers, and system planners to implement changes and send accurate signals to the electricity market for future needs of the bulk power system. Additionally, these studies allow for solution sets to be measurable and achievable.

Recommendations:

- Incorporate natural gas fuel availability or natural gas-fired generation availability into the NERC Long-Term Reliability Assessment and Seasonal Reliability Assessments.

- Identify how risk assessments are performed in different regions and use this information to develop recommendations for a uniform seasonal and long-term reliability assessment process for consideration by NERC Planning Committee.
- Improve Generator Owner procedures and methods to maintain fuel switching capabilities.
- Enhancements to market products supporting higher levels of fuel certainty should be considered (i.e., adequate level of fuel inventories and functional capability testing and/or firm natural gas transportation).
- NERC should support further studies for enhancing planning processes that relate to fuel availability and resource adequacy.

Key Finding: Regional solutions will likely include a mix of mitigating strategies, increased gas and/or electric infrastructure, and dual or back-up fuel capability.

Dual-fuel capabilities and a variety of storage options may help bridge the gap between the uncertainties of gas availability during extreme events and maintaining a reliable source of operable capacity available to meet seasonal peak demands.

Based on the reserve margin scenario assessments performed as part of this report's efforts, many of the NERC assessment areas have sufficient reserve margins to mitigate the loss of a significant portion of their gas-fired generation.

Electric transmission increases the bulk power system's flexibility and resilience to various disruptions. Efforts to manage gas supply and transportation disruptions should consider the benefits of electric transmission.

Although generators may have contractual obligations to perform, performance incentives, particularly in competitive wholesale electricity markets, may not be strong enough to incentivize generators to procure firm or otherwise reliable fuel supplies (natural gas supply and transportation, oil, or other mitigating strategies).

Risks to gas supply shortages can largely be mitigated or reduced with the abundance and geographic diversification of shale plays across North America. With unconventional shale gas production spread across the continent, vulnerabilities in gas supply due to weather events can be mitigated or reduced by increasing production in unaffected areas.

Recommendations:

- Policymakers and regulators should consider developing solutions that provide the right balance between electric reliability and the increased costs associated with it.

Key Finding: Enhancements to data sharing and planning coordination can provide insights through additional studies and scenario analysis.

There is no compiled statistical data on gas system outages that would be the equivalent to NERC GADS databases. Therefore, outage data would have to be estimated from various surrogate sources, including pipeline bulletin board notices, accident reports filed with government agencies, surveys of pipeline and distribution companies in the study region, and maintenance and repair information from equipment manufacturers and service companies. This type of information is important for complex analyses that rely on past performance to achieve an acceptable level of prediction and certainty. Increased coordination and information exchange for planning purposes could aid in developing confidence around a distribution of potential scenarios.

Recommendations:

- Work jointly with the natural gas industry to identify data requirements that can be used for electric reliability analysis.
- Planning Coordinators and/or Reliability Coordinators should identify critical gas-fired electric generation to ensure "critical generators" have the ability to mitigate or reduce the risks associated with fuel disruptions and curtailments.

Operations and Operational Planning

Key Finding: Sharing information for operational planning purposes is essential to fully understanding generator availability risks in the season ahead.

While Generator Owners are generally able to schedule and secure gas during the summer to meet seasonal peak demand, this flexibility decreases during winter months when pipeline use tend to peak and firm transportation customers have scheduled their full entitlements. Cold weather can also be responsible for increased infrastructure and supply disruptions, which are generally caused by freezing. Risks to gas wellheads, generators, and pipeline infrastructure due to freezing can expose the electric industry to significant capacity shortages. While firm gas transportation significantly decreases the likelihood that fuel delivery will be curtailed, extreme events, such as wellhead freeze-offs causing decreased gas production (a force majeure event), could potentially lead to common-mode failures of a significant amount of gas-fired generators. The expected increases in gas-fired generation on the BPS will increase the amount of operational uncertainty that the system operator must factor into operating decisions.

Recommendations:

- Increased situation awareness of the natural gas supply and pipeline system enhances the electric system operator's ability to make risk-informed decisions.
- In preparation for summer and winter extreme conditions, electric system operators need enhanced observability of pipeline conditions, capacity availability, supply concerns, and potential issues affecting fuel for gas-fired generation.

Key Finding: Formalized communication and coordination with the gas pipeline and supply industry during extreme events is needed.

Information on daily fuel supply adequacy and less probable contingencies on the gas pipeline or compressor stations which could result in loss of multiple gas-fired units should be provided to electric system operators with as much notice as possible.

Both industries have stated that there are sufficient coordination practices at this time and enhancements planned for the future. Based on these practices, operational procedures should include formalized coordination with the gas supply and pipeline industry, as well as emergency procedures during extreme events. Timely information sharing is most important when natural gas suppliers and pipeline operators can determine that a potential shortages or interruptions may occur due to usage and transportation outages.

Recommendations:

- System operators should re-examine interindustry communication protocols that apply during periods of stress

Key Finding: System operators will need access to sufficient flexible resources to mitigate the added uncertainty associated with natural gas fuel risks, including those introduced by interruptible gas transportation service.

Operating criteria, forecasting, commitment, scheduling, dispatch and balancing practices, procedures and tools should consider fuel risks and risk mitigation measures to assist operators in maintaining bulk power system reliability. Enhanced operator training should be considered in light of the increasing need for electric and pipeline operator communication and coordination. Training crosses a number of areas, some of which are specific to each industry, while others likely represent interindustry efforts.

A projection of flexibility can also provide additional observability to the system operator in order to maintain operational reliability; however, this can only be made with enhanced coordination with gas-fired generators and the natural gas pipeline operators. In response to gas disruptions, electric system operators should be able to identify vulnerable capacity, determine if reserve capacity is available, dispatch the appropriate resources, implement any operating procedures, and minimize any impacts caused by fuel disruptions.

Recommendations:

- NERC should leverage its stakeholder groups to identify best practices in areas currently most vulnerable to gas dependency risks and taking immediate actions for improvement, such as New England. Such an effort could lead to insights for enhanced operator training and table-top exercises.
- Joint industry drills or table-top exercises with the key players of both gas, electric, and various state commissions would foster enhanced coordination and harmonize cross-industry issues, response plans, and mitigation measures.

Further Detail on Recommendations

Recommendations to Address Long- and Short-Term Planning Risks	
Lead	**Recommendation**
NERC GADS Working Group	Review the fuel supply-related outage data gathered in the GADS system and determine whether the adequacy and usefulness of the data could be improved to better serve the purposes of fuel supply analyses. The primary need would be to develop an estimate of generating unit rates excluding fuel availability issues (to avoid double counting). The second purpose would be to estimate the degree to which lack of fuel has added to generating unit unavailability in the recent past. Clear definitions for fuel related outages should include a distinction between those outages caused by supply or transportation interruptions and those caused by curtailment events.
NERC RAS	Incorporate natural gas fuel availability or natural gas-fired generation availability into the Long-Term Reliability Assessment and Seasonal Reliability Assessments. The RAS should develop a framework and method to integrate these considerations into future long-term reliability resource adequacy projections.
NERC and Planning Coordinators	Modify the recommended Three-Layer methodology framework—based on feedback from NERC stakeholders. NERC can leverage stakeholder groups to identify how risk assessments are performed in different regions and use this information to support an overall strategy for incorporating these methods into a consistent assessment process. This could be done by supporting data gathering efforts with gas industry, developing modeling algorithms (e.g., synthetic weather probability generators), cosponsoring regional case studies, holding workshops, and collaborating on reliability assessment enhancements.
Generator Owners	Improvements to procedures and methods to maintain fuel switching capabilities and improving the reliability of such capability are needed. In wholesale market areas, enhancements to market products could be considered to support higher levels of fuel certainty (i.e., adequate level of fuel inventories and functional capability testing and/or firm natural gas transportation).
Generator Owners and State, Federal, and Provincial Regulators	Discretionary emission waivers may be needed to obtain authorization and endorsement from third-parties to allow some discretion for dual-fuel gas-fired generators during periods of stress. Coordination between Generator Owners and state and federal environmental and electricity regulators may be needed to facilitate these waiver provisions if necessary.

Electric and Gas Industry **State, Federal, and Provincial Regulators**	Consider developing a new category of "essential [natural gas] loads" for "critical generators" and appropriate cross industry procedures. Planning Coordinators and/or Reliability Coordinators should identify critical gas-fired electric generation to ensure "critical generators" have the ability to mitigate or reduce the risks associated with fuel disruptions and curtailments. These "critical generators" could be identified and shared with regulators and the gas pipeline industry to be considered as part of emergency operating procedures.
NERC	Support further studies for enhancing planning processes that relate to fuel availability and resource adequacy. This effort could help identify enhancements to current practices. NERC should also evaluate best practices that are already offered through existing market practices and generator mitigation strategies. Furthermore, an evaluation of the reliability assessment process is needed to capture industry progress.
NERC Planning Committee and Reliability Issues Steering Committee (RISC)	NERC should take the lead in tabulating an overall set of observations, insights and recommendations on this topic and prioritize actions that should be taken by the electricity sector. Further, the advisory committee could identify where interaction and coordination with natural gas associations as well as with federal, state, and provincial regulators to foster and implement steps to maintain bulk power system reliability. Once completed with this initial effort, the same NERC advisory committee could then actively facilitate the formation of a series of regional subcommittees that revise and tailor the points outlined in the initial national level committee to the unique attributes of individual regions. Some of these regional groups already exist. In these cases, a liaison should be identified to coordinate regional and NERC-wide initiatives.

Recommendations to Address Operational Planning and Operations Risks	
Lead	**Recommendations**
Joint Gas and Electric Industry	While FERC Order 698 establishes the communication protocols between the interstate pipelines and the power industry (i.e., system operators, transmission owners and transmission operators), it would be useful for each region to re-examine their interindustry communication protocols that apply during periods of stress and during normal operations within either industry to (1) ensure these protocols are functioning properly; (2) assess whether they need to be updated in light of more recent incidents and (3) decide whether the same protocols should be used for both emergency and normal operations to ensure consistency and reliability. Undoubtedly this re-examination of the best means of achieving interindustry communication, particularly during periods of stress, will result in an assessment of the proper means, if any, of transferring proprietary information.
Joint Gas and Electric Industry	RCs, BAs, TOPs, and PCs should work to increase their understanding of the Order 587-V information and be able to incorporate it into their hourly and real-time operations. The ability to interpret the informational postings is critical for the reliability of the BPS and the electric industry should be able to take advantage of the information made available.

Joint Gas and Electric Industry	The electric industry should assess essential loads, which would allow for maintaining critical components for both gas and electric loads in the event of rotating outages. These critical components (e.g., electric compressors and/or gas-fired generator units), in most instances, represent the core of the interdependency of the two industries, and would need to be identified at the regional level. In addition to manual load shed plans, electric system planners and operators should avoid critical gas component loads in UVLS/UFLS schemes and identify them as priority loads in restoration plans.
Electric System Operators	System operators will need access to sufficient flexible resources to mitigate the added uncertainty associated with natural gas fuel risks, including those introduced by interruptible gas transportation service. NERC recommends that operating criteria, forecasting, commitment, scheduling, dispatch and balancing practices, procedures and tools must be enhanced to assist operators in maintaining bulk power system reliability.
NERC and Gas and Electric System Operators	Enhanced operator training should be considered in light of the increasing need for electric and pipeline operator communication and coordination. Training crosses a number of areas, some of which are specific to each industry, while others likely represent interindustry efforts. Additionally, NERC should leverage its stakeholder groups to identify best practices in areas currently most vulnerable to gas dependency risks and taking immediate actions for improvement, such as New England. Such an effort could lead to insights for enhanced operator training and table-top exercises. Joint industry drills or table-top exercises with the key players of both gas, electric, and various state commissions would foster enhanced coordination and harmonize cross-industry issues, response plans, and mitigation measures.
Balancing Authorities and Reliability Coordinators	During extreme winter weather, electric system operators should maximize the availability of flexible resources and understand how much flexibility is available at any given time—particularly gas-fired generation as it relates to potential fuel interruptions and oil-fired backup capability. A projection of flexibility can also provide additional observability to the system operator in order to maintain operational reliability; however, this can only be made with enhanced coordination with gas-fired generators and the natural gas pipeline operators. In response to gas disruptions, electric system operators should be able to identify vulnerable capacity, determine if reserve capacity is available, dispatch the appropriate resources, implement any operating procedures, and minimize any impacts caused by fuel disruptions.

Next Steps

NERC suggests that an action plan be developed by a joint NERC Planning and Operating Committee subgroup to determine what activities should be pursued by NERC and the technical committees and identify a timeline for its completion. Observations and action plans for both the North American-wide and ongoing regional efforts could identify approaches where coordinated interindustry activities could provide enhanced system reliability and improved efficiency beyond that attainable by each industry and Region as a separate entity. This report will be submitted to the Reliability Issues Steering Committee (RISC) to provide additional guidance and prioritization of future technical committee work plans.

Appendix I: Consolidation of Reports and Studies

With the steady growth in the interdependency of the electric and natural gas industries, there have been a number of studies and reports published on how the coordination between the two industries can be enhanced. As a first step to (1) further enhancing the coordination between the two industries and (2) reducing the vulnerabilities of the electric industry to this growing interdependency, a thorough review and tabulation of the observations, insights, and recommendations of these historical reports should be completed.

As an aid to completing this critical first step, this chapter identifies several of the major historical reports on the topic and briefly summarizes their major findings and recommendations. This diverse group of historical reports covers nearly every aspect of the complex issue of interindustry coordination and barriers to accomplishing such coordination. Among the issues identified are (a) limitations on fuel switching, (b) limitations caused by environmental restrictions, (c) the vulnerabilities of each industry to the other, (d) the need for adequate incentives to preclude the loss of system reliability, (e) the importance of working with third parties to ensure system reliability, and (f) other elements. Also cited in several historical assessments is the need for interindustry coordination at the regional level, as there is no universal solution to this complex issue, particularly in light of the unique characteristics of each region. Additionally, considering the great changes that shale gas is having on both the gas and electric sector, many older reports need to be reexamined through the lens of the new gas paradigm—particulary as they relate to natural gas supply and disruptions of supply in the Gulf of Mexico.

NERC, along with representatives of the various segments of the natural gas industry, should take the lead on developing an integrated assessment of the observations, insights, and recommendations of prior reports and expected reports on the topic. Specific areas of concern for this integrated assessment are highlighted. Finally, it is suggested that a series of regional groups be formed to fine-tune this initial integrated, or composite, assessment to the specific characteristics of the region, as the composite observation will not be universally applicable to each region. It is likely that this regional mechanism will result in identifying approaches where coordinated interindustry activities could provide enhanced system reliability and improved efficiency beyond that attainable by each industry as a separate entity.

Past Coordination Efforts

In light of this increasing interdependence of the two industries, there is a heightened need to increase coordination between the two industries in order to facilitate the various interface issues between gas and power and thus, minimize the risks of significant problems within either industry.

In large part this increased level of coordination can build upon historical efforts to facilitate coordination between the industries. The following points are included in past coordination efforts:

Ad Hoc Industry Groups: A few ad hoc industry groups were among the earlier efforts to focus on the need for coordination between the two industries. These groups explored and made recommendations for increased coordination between the two industries, primarily at the regional level, and some of these recommendations were implemented. Probably the most notable of these was the regional effort within New England to promote increased gas–electric coordination.[93] At least one other regional group and a national group were functional for a period of time.

Reports: Over the last decade a number of reports have highlighted the need for increased coordination between the two industries, particularly at this regional level. While it is not practical to note all of these reports, the themes contained within them are relatively similar, and the reports usually highlighted periods when either or both industries were under

[93] See EPRI, *Natural Gas and Electric Industry Coordination in New England (TR-102948)*, November 1993 for a summary of the two year effort by this New England coordination group and New England's Electric-Gas Operations Committee (EGOC) of which information can be found at: http://www.iso-ne.com/committees/comm_wkgrps/othr/egoc/index.html

stress. Also, New England and ERCOT tend to be referenced most often. The combination of New England's (1) distance from the main source of U.S. gas supplies (i.e., the Gulf), (2) potential for severe winter weather, (3) rapid growth in regional gas demand (which has taxed its regional infrastructure), and (4) lack of regional gas storage has contributed to increasing risks. With respect to ERCOT, the concern historically has been the curtailment of gas supplies due to well freeze-offs.[94] ERCOT has its own regional Emergency Electric Curtailment Plan to maintain reliability in the event of natural gas curtailments. Both of these regions have been highlighted in NERC's Winter Assessment Reports.[95]

Within New England, the January 14–16, 2004 severe cold snap (coldest in 20 years) significantly stressed both the region's gas and electric industries. While there were neither curtailments of firm transportation service nor regional loss of electric power, some power plants (i.e., in particular merchant suppliers)lost interruptible gas supplies (by design) and gas prices were both high (> $50.00 per MMBtu) and very volatile. More importantly, the incident highlighted the vulnerability of the gas-electric interface within the region and resulted in an extensive assessment of the incident and the regional interface between the two industries.[96] Recommendations and observations contained in the report of this incident noted (1) a lack of understanding of and coordination with the gas industry; (2) the need to coordinate timing to allow maximum utilization of gas infrastructure; (3) the need to provide incentives and signals to ensure electric unit availability; and (4) the need to establish a regional dialogue about barriers to dual-fuel capability. Subsequent reports have highlighted how the gas and electric infrastructure within the region can be stressed under unusual weather conditions and the need for both industries to continually monitor the adequacy of regional infrastructure.[97]

Within the power industry, NERC's 2004 NERC Gas/Electric Interdependencies and Recommendations report[98] formalized the need to improve the gas–electric interface. Among the observations in this report was (1) that either industry can impact the reliability of the other, (2) a lack of understanding of each other's businesses by pipeline and system operators and lack of communications between them, (3) substantial differences in planning and system expansion between the two industries, (4) the stringent fuel delivery and fuel requirements for combustion turbines can be a challenge for the gas industry, and (5) firm transportation service is not a viable alternative for peaking facilities.

These observations became the basis for a series of recommendations to increase the joint reliability of the two industries. Included in these were recommendations for individual NERC regions to increase their awareness and monitoring of gas transportation infrastructures, including planned and unplanned pipeline outages, contingency planning related to gas infrastructure, and the establishment of electric unit reliability standards for gas transportation. NERC also recommended increased communications between pipeline(s) and system operators, as well as at other levels within the two industries.

FERC Order 698: Historical reports and other industry examinations of the critical interface between the two industries were important precursors to FERC Order 698, which was issued in 2007. Included in other industry examinations were (1) the DOE Primer, (2) the NRRI Primer, and (3) a report by the NAESB. The latter, in particular, presented detailed recommendations and analyses concerning natural gas transmission tariffs and services that affected the day-to-day interface between the gas and power industries, as well as other gas consumers. While a complete summary of FERC Order 698 is beyond the scope of this report, this FERC order set out a number of standards that facilitated and clarified the interaction between the two industries in an effort to improve the communications, operations, and reliability of both.

The most significant element of FERC Order 698 was the establishment of communication protocols between interstate pipelines and power operators and TOs and TOPs. Included in these protocols were the rapid notifications by the gas

[94] See Appendix A of NERC's *A Primer on the Natural Gas Industry and its Interface with the Electric Power Industry*, 2011 for a discussion of historical incidents within ERCOT.
[95] See NERC 2003/04, 2004/05, and 2012/13 Winter Reliability Assessments
[96] See ISO New England, Interim Report on Electricity Supply Conditions in New England During the January 14-16, 2004 "Cold Snap", May 10, 2004.
[97] See Analysis Group, New England Energy Infrastructure-Adequacy Assessment and Policy Review, November 2005.
[98] See NERC Gas/Electric Interdependencies and Recommendations, June 15, 2004.

industry to the power industry of Operational Flow Orders (OFOs) and Critical Balancing Alerts for their transportation systems and, similarly, the power industry's rapid notification to the gas industry of Energy Emergency Alerts.

Other standards included in the FERC order were (1) a requirement to establish new transportation services, such as load-following services, (2) a requirement for pipelines to establish formulas for ratable takes, (3) reaffirmation of within-the-path scheduling adopted by FERC Order 637, (4) a requirement to increase the certainty of interruptible transportation, particularly with respect to eliminating bumping by firm last intraday nominations, and (5) a requirement for increased communications in changes to hourly flow rates and efforts to resolve such changes. A key result of FERC Order 698 was the eventual revision to individual pipeline tariffs to incorporate the improved requirements, which took some time to fully implement.

FERC Order 698, as well as all the assessments preceding it, represents a significant effort to define and clarify many of the communications, procedures, and standards for gas transportation services. As a result of this order, the interface between the two industries is more clearly defined, as are the boundaries and operating parameters for both industries. This increased communication and definition of parameters, while resulting in increased costs in some cases,[99] boosts the reliability of both industries. Nevertheless, the two industries need to continue to strive to increase their coordination, particularly in times of stress, as each industry can still impact the reliability of the other.

Recent Reports, Studies, and Industry Activities

Over the past couple of years, the subject of the interdependency of gas and electric service reliability has intensified in many forums. As the amount and dispatch of gas-fired generation increases, the interaction between the electric grid and the gas network can be stressed. These stresses have highlighted both the similarities and differences in the structure, operation, business practices, and communications between the two industries.

Recognizing the need for sound integration of natural gas and electricity markets, FERC held technical conferences on coordination between natural gas and electricity markets around the United States in August 2012. The conferences covered issues such as coordination and information sharing, scheduling, market structures, and reliability concerns. These issues are a reflection of a request for comment from industry participants on pressing issues that concern gas and power integration. Many participants also asserted that issues differ considerably by region. In recent years, a number of studies have attempted to assess the gas–electric reliability issues.

Other entities also have published reports concerning the interface between the natural gas and electric industries. These more recent reports by FERC, NERC, ISO New England Inc., and the Interstate Natural Gas Association of America (INGAA) Foundation, in general, also focus on the need for increased coordination between the two industries. They make similar observations to those made in the earlier EPRI reports. Key observations, recommendations, and conclusions from these reports are noted below.

[99] A significant area of increased costs for the power industry was the eventual implementation of significant penalties in the event the strict provisions for some transmission services were not followed (e.g., exceeding nominated loads or contracted capacity).

Table 8: Summary of Major Gas–Electric Integration and Disruption Contingency Studies	
Study	**Study Summary**
ERCOT – Black & Veatch[100]	Black & Veatch consulting group conducted a study on behalf of the Energy Reliability Council of Texas (ERCOT) that included a number of gas curtailment scenarios to assess areas of improvement in gas interruption for power generation. The study found that freezing weather is the most common gas curtailment incident. It follows that gas curtailment would not be primarily caused by normal load requirements in the winter season since ERCOT is a summer peaking region. An important study observation is that the majority of ERCOT generators reported interconnects with multiple pipelines allowing them access to pipeline capacity in excess of their peak needs and thus reducing the probability of gas supply shortages to those generators.
FERC and NERC[101]	FERC and NERC collaborated on a report summarizing the outages/curtailments that occurred during the cold weather event in early February 2011 in the U.S. Southwest. The study found that ERCOT's fast actions initiating rolling blackouts prevented more widespread and unanticipated blackouts, transmission operations generally did not identify natural gas facilities as critical loads, and reliability coordinators did not understand the temperature design limits of plants (and thus did not recognize the loss in generation when temperatures dropped). The study also found that the lack of winterization of power plants impacted loss of load, while generators were generally reactive in making such preparations.
INGAA/U.S. DOE – ICF[102]	ICF International conducted a series of studies for both INGAA and DOE focused on quantifying: 1) the amount of pipeline capacity loss that can be absorbed by "economic reallocation" of remaining gas supplies in the gas market; and 2) the amount of additional capacity outage that can be accommodated by shedding all but "essential human needs" gas load under emergency conditions. To address the first item, ICF used the GMM and DGLM to look at pipeline outages under a variety of weather scenarios. To address the second item, ICF surveyed LDCs to determine the amount of nonessential gas load that could be shed. Regions studied include New England, Mid-Atlantic, South Atlantic, Midwest,

[100] Black & Veatch. "Gas Curtailment Risk Study." The Electric Reliability Council of Texas (ERCOT), March 2012: Dallas, TX. Available at: http://www.ercot.com/content/news/presentations/2012/BV%20ERCOT%20Gas%20Study%20Report%20March%202012.pdf

[101] Federal Energy Regulatory Commission (FERC) and North American Electric Reliability Corporation (NERC). "Report on Outages and Curtailments during the Southwest Cold Weather Event of February 1-5, 2011." FERC and NERC, August 2011: Washington, D.C. Available at: http://www.ferc.gov/legal/staff-reports/08-16-11-report.pdf

[102] ICF International. "Natural Gas Pipeline Security Study for the Northeast U.S." The Interstate Natural Gas Association of America (INGAA) Foundation, February 2003: Washington, D.C.

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Table 8: Summary of Major Gas–Electric Integration and Disruption Contingency Studies	
Study	**Study Summary**
	Gulf Coast, and the Western United States.
ISO-NE – ICF[103]	This ICF International analysis focused on the availability of gas supplies to New England electric generators with interruptible service on peak winter and summer days through 2020 for four alternate generation forecasts. The analysis included 16 contingency scenarios in which pipeline capacity or other gas supplies (e.g., LNG imports) are disrupted, and then quantified the impacts in terms of reduced gas supplies to generators and the resulting available generating capacity.
MISO – EnVision Energy Solutions[104]	The Midwest Independent System Operator (MISO) commissioned EnVision Energy Solutions to conduct a gas and electric interdependency analysis in early 2012. The study found that nearly all pipelines in the MISO area will have to improve flexibility to be able to provide delivery service to MISO power generators. Out of 25 pipelines, three do not have sufficient capacity, and three others do not have enough capacity to support a gas-fired combustion turbine plant or combined-cycle plant. The cost to accommodate increased supplies could exceed $3 billion. In addition to physical infrastructure expansions needed, the study found that improving the collaborative process between gas pipelines, power generators, and regulators is also necessary. The study was later updated. The pipelines reviewing the study, after the fact, noted backhaul capacities were not considered. For example, reversing the REX pipeline enabling it to deliver Marcellus gas to the MISO region could have a net effect of adding billions of cubic feet of gas to the region at a cost estimated to be much less than $1 billion.
NYS DHSES – ICF[105]	NYS DHSES commissioned ICF to conduct a supply-based criticality and vulnerability analysis of the interstate natural gas and petroleum pipelines supplying New York State. The natural gas pipelines study consisted of a two-part modeling effort. The first part involved a macro criticality assessment of major interstate pipelines relevant to New York. The macro analysis included roughly 20 different cases of natural gas supply reduction based on simulated disruptions of each of the major interstate natural gas pipelines entering New York State using ICF's GMM. The microanalysis involved simulation of 25 different cases of natural gas supply reduction based on simulated disruptions of specific natural gas facilities relevant to New York State. The second part of the analysis relied on ICF's Regional Infrastructure Assessment Modeling System (RIAMS) to assess the flow and demand impacts on each day during a peak winter month.

[103] ICF International. "Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short- and Near-term Power Generation Needs" presentation. New England Independent System Operator (ISO-NE), 21 June 2012: Holyoke, MA. Available at: http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2012/gas_study_public_slides.pdf

[104] EnVision Energy Solutions. "Gas and Electric Infrastructure Interdependency Analysis." Midwest Independent System Operator (MISO), February 2012: St. Paul, MN. Available at: https://www.midwestiso.org/Library/Repository/Tariff/FERC%20Filings/MISO%20Supp.%20Resp.%20to%20Evid.%20Requests_AD12-1-000.pdf

[105] New York State Division of Homeland Security and Emergency Services (NYS DHSES). "Interstate Pipeline Supply-Based Criticality and Vulnerability Analysis Project: Natural Gas and Petroleum Pipelines." Prepared by ICF International for NYSDHSES, 22 December 2011.

Table 8: Summary of Major Gas–Electric Integration and Disruption Contingency Studies	
Study	**Study Summary**
NAESB[106]	NAESB surveyed industry participants on the development of industry standards. NAESB then recommended a number of industry standards in June 2012 based on those surveys. Recommendations include greater flexibility in scheduling gas transportation services and related requirements, inclusion of market-clearing times for natural gas and electricity pricing, transparency reporting, review of NAESB communications protocol standards, and review of nuclear power plant communications.
Interim Report on Electricity Supply Conditions in New England During the January 14–16, 2004 "Cold Snap" (2004)[107]	While electric system reliability was not compromised during this cold snap, the extreme circumstances (coldest period in 20 years) did stress test both regional gas and electric reliability, with electric system reliability pushed to its limits. The detailed assessment of this period highlighted the vulnerability of electric system reliability to the dynamics of the region's natural gas industry, which also was incurring peak demand requirements. Among the most critical vulnerabilities was the power industry's lack of access to adequate gas pipeline capacity, as gas requirements for the other sectors taxed the region's pipeline capacity. The report also highlighted that, during this period, some members of the electric industry sold both their gas supplies and pipeline capacity rights to LDCs, which enabled them to meet heightened levels of demand for home heating. The electric utilities that sold their gas supplies then fuel switched to distillate in their dual-fuel units. This particular aspect of the cold snap illustrates how enlightened coordination between the two industries during periods of stress can result in limited regional gas supplies being allocated to achieve the optimum results for all consumers in the region. With respect to the dual-fuel electric units, they functioned very well during this stressful period. Recommendations in the report focused on the need for better understanding of the interface between the two industries and how the two industries could better coordinate to allow maximum utilization of the region's gas infrastructure. The report also cited the need for adequate incentives to obtain the optimum performance from both merchant and non-merchant electric units during critical periods. Lastly, the report recommended a regional dialogue with regulators and others to remove the regulatory (environmental) barriers to installing and using dual-fuel capability.
Gas/Electricity Interdependencies and Recommendations (2004)[108]	This NERC report summarized the findings of its Gas/Electricity Interdependency Task Force (GEITF). Chief among the GEITF findings was that while the pipelines communicate with the LDCs serving a generator or with the generator itself, they do not communicate with a regional reliability coordinator, primarily because of confidentiality restrictions. As a result, it was recommended that NERC, in concert with other energy industry organizations, formalize communications between the electric industry and the gas transportation

[106] North American Energy Standards Board (NAESB). "Gas-Electric Harmonization Committee Report." NAESB, September 2012: Washington, D.C.
[107] http://www.iso-ne.com/pubs/spcl_rpts/2004/interim_report_jan2004_cold_snap.pdf
[108] http://www.nerc.com/docs/docs/pubs/Gas_Electricity_Interdependencies_and_Recommendations.pdf

Table 8: Summary of Major Gas–Electric Integration and Disruption Contingency Studies	
Study	**Study Summary**
	industry for the purposes of education, planning and, most importantly, emergency response.
Natural Gas Pipeline and Storage Infrastructure Projections through 2030 (2009)[109]	This nationally oriented report by the Interstate Natural Gas Association of America (INGAA) Foundation, along with another similar report that focused on a single region,[110] highlights the importance of adequate gas infrastructure to ensure the delivery of adequate gas supplies to consumers. This observation is particularly acute for the electricity sector because of increasing interdependence of the two industries. Also, both reports note that there is a need to routinely assess the infrastructure capability and future plans to expand it because of the likely growth in both industries.
Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011 (2011)[111]	This report, which was jointly authored by FERC and NERC, examined in detail the factors that contributed to the loss of regional system reliability for both industries during this February incident, which was summarized briefly in Chapter 3. The report included recommendations for both industries in a number of areas, including planning, interindustry coordination, communications, load shedding and, in particular, winterization.

There have also been a number of resource adequacy studies done on behalf of the electricity sector that have attempted to identify and remedy current electricity reliability issues. Prominent studies include those listed below.

Table 9: Summary of Probabilistic Electric Reliability Studies	
Study	**Study Summary**
Carden et al[112]	The study discussed the use of the 1-in-10 reliability standard frequently used in reliability planning and highlighted its different interpretations. Typically it is defined as one reliability event occurring within 10 years and is measured by calculating the LOLE in "events per year," or 0.1 LOLE per year. Others, however, define it as in one day (24 hours) of load loss during a 10-year period, meaning an LOLE of 2.4. The cost of reliability events rises as reserve margins decline, meaning the 1-in-10 standard interpretations could mean a difference of over 4% in target reserve margins. The paper asserts that reliability assessments must include economic reliability modeling of the full range and uncertainty of outcomes, supplementing physical reliability standards (e.g., 1-in-10) and target reserve margins with other considerations. Other considerations include analysis of both production and scarcity costs of power above the variable cost of the marginal capacity resource, realistic distribution of weather, unit performance, economic growth, analysis of

[109] http://www.ingaa.org/Foundation/Foundation-Reports/Studies/7828/9115.aspx
[110] Analysis Group, New England Infrastructure – Adequacy Assessment and Policy Review, November 2005.
[111] http://www.ferc.gov/legal/staff-reports/08-16-11-report.pdf
[112] Carden, Kevin; Johannes Pfeifenberger; and Nick Wintermantel. "The Value of Resource Adequacy: Why Reserve Margins aren't just about Keeping the Lights On." Public Utilities Fortnightly, March 2011: Reston, VA. Available at: http://www.acciongroup.com/file_upload/03012011_ValueResourceAdequacy.pdf

Table 9: Summary of Probabilistic Electric Reliability Studies	
Study	**Study Summary**
	transmission capabilities, and neighboring systems to assess potential constraints.
NRRI – Astrape Consulting and the Brattle Group[113]	The National Regulatory Research Institute (NRRI) commissioned Astrape Consulting and the Brattle Group to conduct resource adequacy modeling of the power market. The analysis asserts that supplemental measures, in addition to the historical 1-in-10 standard, must also be included in physical resource adequacy planning. Including economic simulation of bulk power reliability in resource adequacy planning allows for economically efficient target reserve margins.
NERC – G&T RPM[114]	In September 2010, the Generation & Transmission Reliability Planning Models (G&T RPM) Task Force conducted a reliability report for the NERC Planning Committee. In terms of probabilistic resource adequacy metrics, the study recommended that each designated reporting area assess the annual loss-of-load-hours, assess the annual expected unserved energy, and define its meaning of loss-of-load event (e.g., voltage reductions, reduction in spinning reserves below minimum requirement).

A series of Electric Power Research Institute (EPRI) reports were prepared for the power industry in the early 1990s that addressed potential natural gas and electric power interdependencies. One of these reports addressed the topic on a national scale, while the other was more regional in nature. Highlights and major points of emphasis in each report are noted below.

Table 10: Summary of Major Electric Reliability Studies	
Study	**Study Summary**
Natural Gas for Electric Generation: The Challenge of Gas and Electric Industry Coordination (1992)	In addition to highlighting in some detail the unique load characteristics of the power industry, the report emphasized the following points as a result of the transition to modern turbine technology: • The growth in power sector demand represented a challenge for both industries. • This growth in demand would result in increased interdependence between the two industries that would require a much higher level of coordination. • There is no universal solution to interface problems between the two industries; instead, regional solutions should be sought, as each region has its own unique

[113] Carden, Kevin; Johannes Pfeifenberger; and Nick Wintermantel. "The Economics of Resource Adequacy Planning." The National Regulatory Research Institute (NRRI), April 2011: Silver Spring, MD.

[114] Generation & Transmission Reliability Planning Models Task Force for the NERC Planning Committee. "G&T RPM Task Force Final Report on Methodology and Metrics." North American Electric Reliability Corporation (NERC), September 2010: Princeton, NJ.

Table 10: Summary of Major Electric Reliability Studies	
Study	**Study Summary**
	characteristics. In addition, the report highlighted that the gas industry transition to open-access transportation likely would increase the challenge for optimum industry coordination. Lastly, the report provided a checklist for gas-fired units within the electric utility industry to follow in order to minimize interface problems. This checklist started at the initial point of planning a gas-fired unit with suggestions concerning siting and equipment selection—all of which were focused on minimizing interface problems. The checklist was extended to include items concerning daily operations, as well as contracting terms. Finally, the checklist noted that environmental restraints increased coordination challenges between the two industries, as they limited or eliminated fuel switching options.
Natural Gas and Electric Industry Coordination in New England (1993)	This report documents efforts of the New England Gas/Electric Discussion Group, which consisted of representatives from approximately 30 firms from various segments of both industries, to critically examine the interface between the two industries for their region. At the time, power sector gas demand in the region was increasing 30 fold. The group's primary focus was to examine and uncover ways that coordinated interindustry activities could provide enhanced system reliability and improved efficiency beyond that attainable by each industry separately. With respect to the focus on reliability and maintaining system integrity, the group used detailed simulation models to analyze several worst-case scenarios for the region. This analytical effort highlighted the need for quick communications between the two industries and resulted in a series of recommendations for communications between the two industries under both normal and crisis conditions. The recommendation for direct communication between power pool and pipeline operators was included. This and other facets of the report in essence became a template for other regions seeking to improve coordination and overall system reliability.

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Federal Energy Regulatory Commission (FERC). "Order 636 Final Rule, Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations." FERC, 8 April 1992: Washington, D.C.

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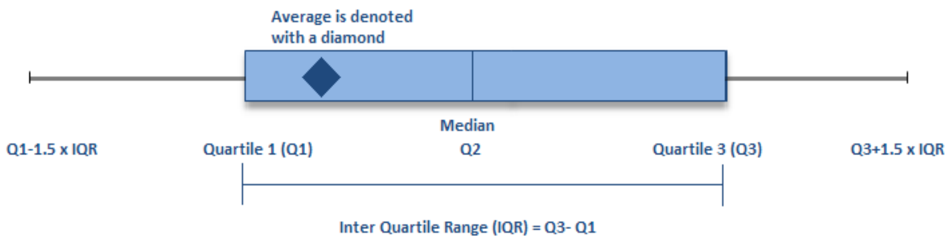
U.S. Congress. "U.S. Natural Gas Act of 1938," section 7. 15 USC 717h.

Williams Companies. "WECC Presentation." Williams, 12 November 2012.

Appendix II: Regional Analysis of Generator Outages

The follow series of Regional data represents a statistical analysis of gas-fired generator outages (reported in the NERC GADS) between 2001 and 2011 caused by a lack of fuel.



- **First quartile** (Q_1) = **lower quartile** = splits lowest 25% of data = *25th* percentile
- **Second quartile** (Q_2) = **median** = cuts data set in half = *50th percentile*
- **Third quartile** (Q_3) = **upper quartile** = splits highest 25% of data, or lowest 75% = *75th percentile*

The following charts show the distribution for all reported outages from 2001 to 2011. The two different graphs show the capacity loss and duration of each event reported. The distribution shows the variation over time for each Region. If an event falls outside the tail (Q1 - 1.5 x IQR, Q3 + 1.5 x IQR), the event would be considered an outlier or extreme event. Continued trending and tracking of this data may uncover leading indicators of system stress and better understand future risks.

The above "box and whisker" legend applies to all charts in Appendix II

FRCC

Figure 47: FRCC Gas Outage

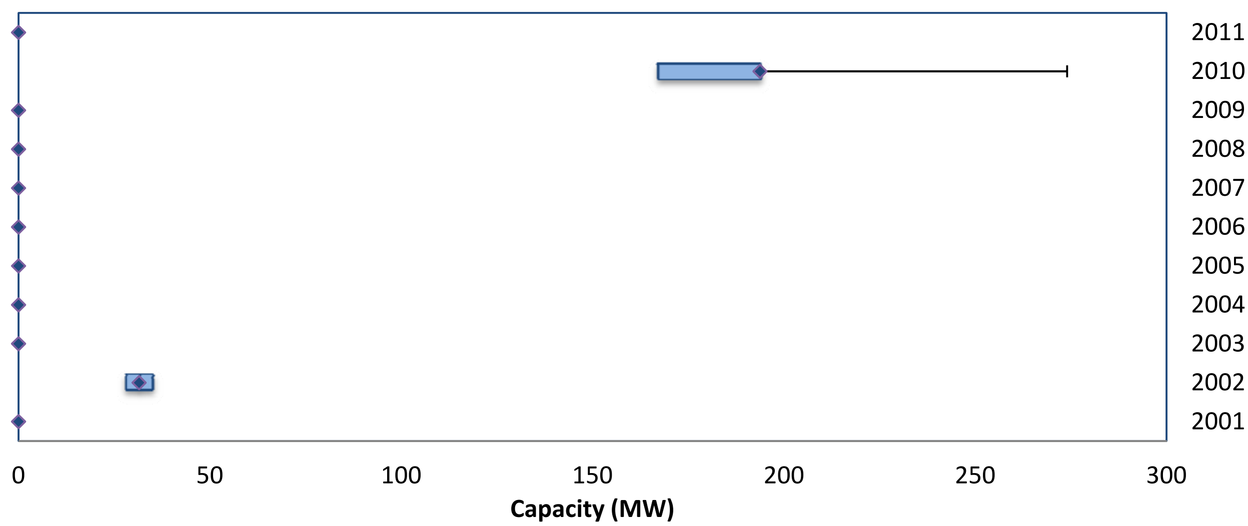
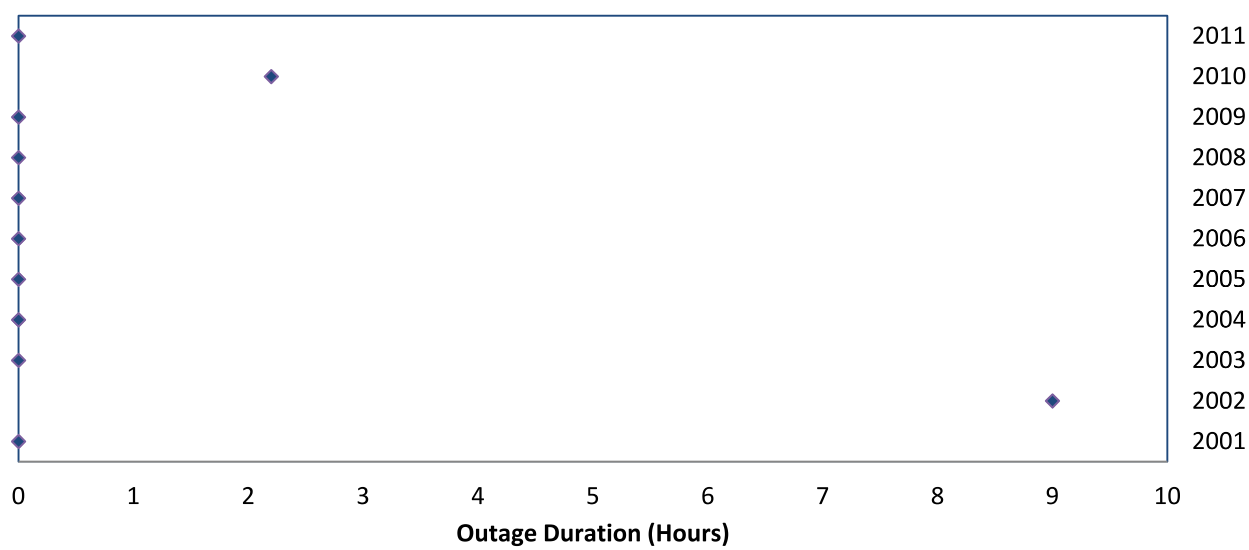


Figure 48: FRCC Gas Outage Duration



MRO

Figure 49: MRO Gas Outage

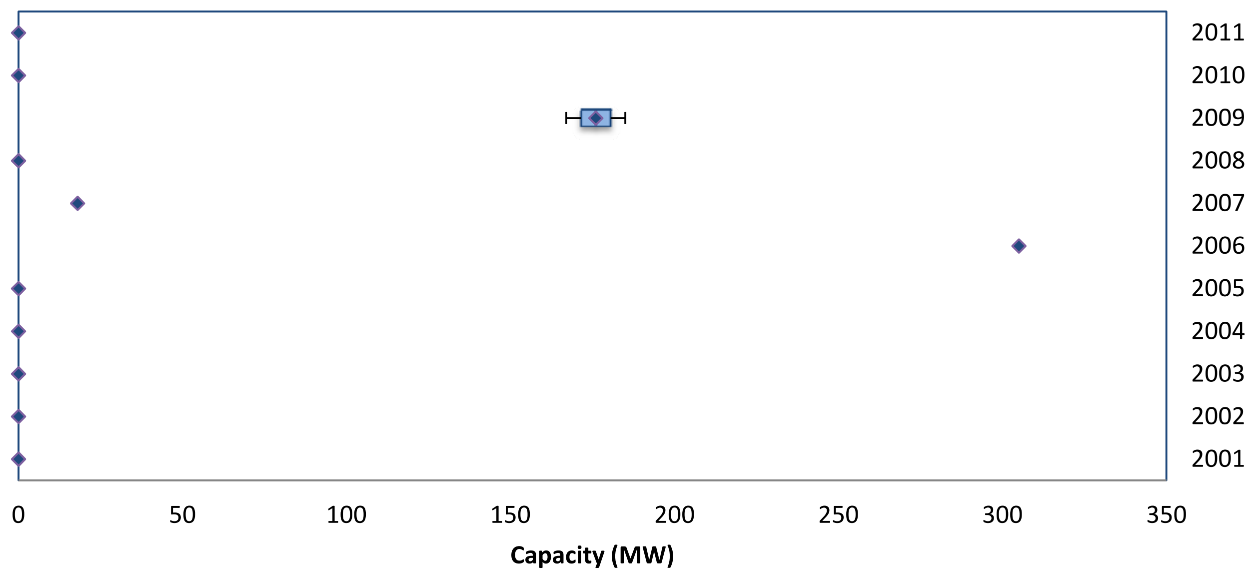
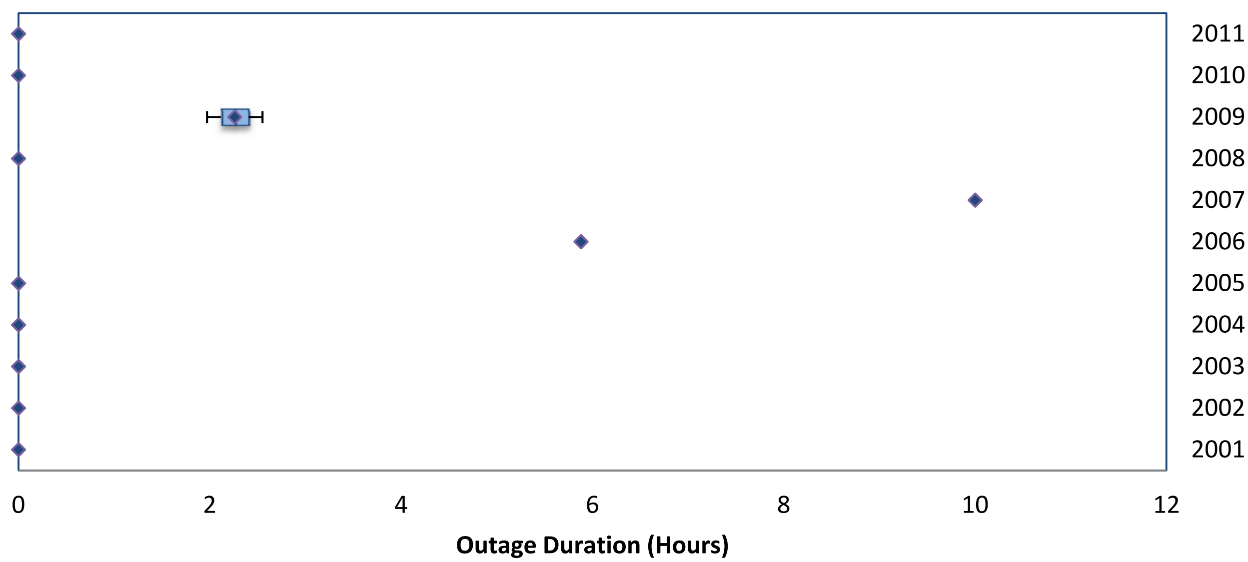


Figure 50: MRO Gas Outage Duration



NPCC

Figure 51: NPCC Gas Outage

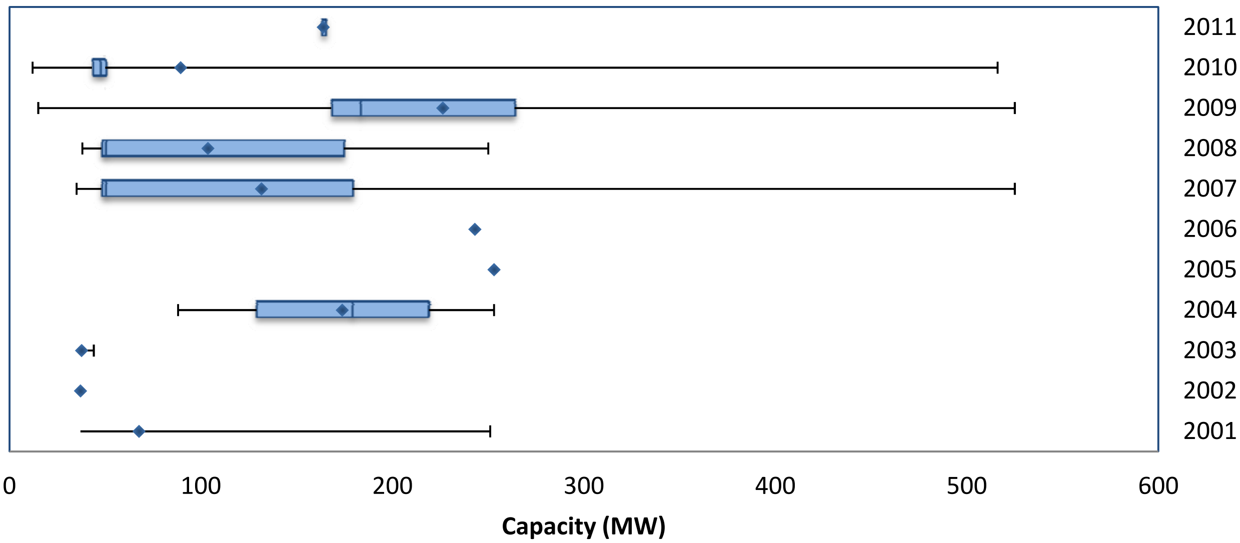
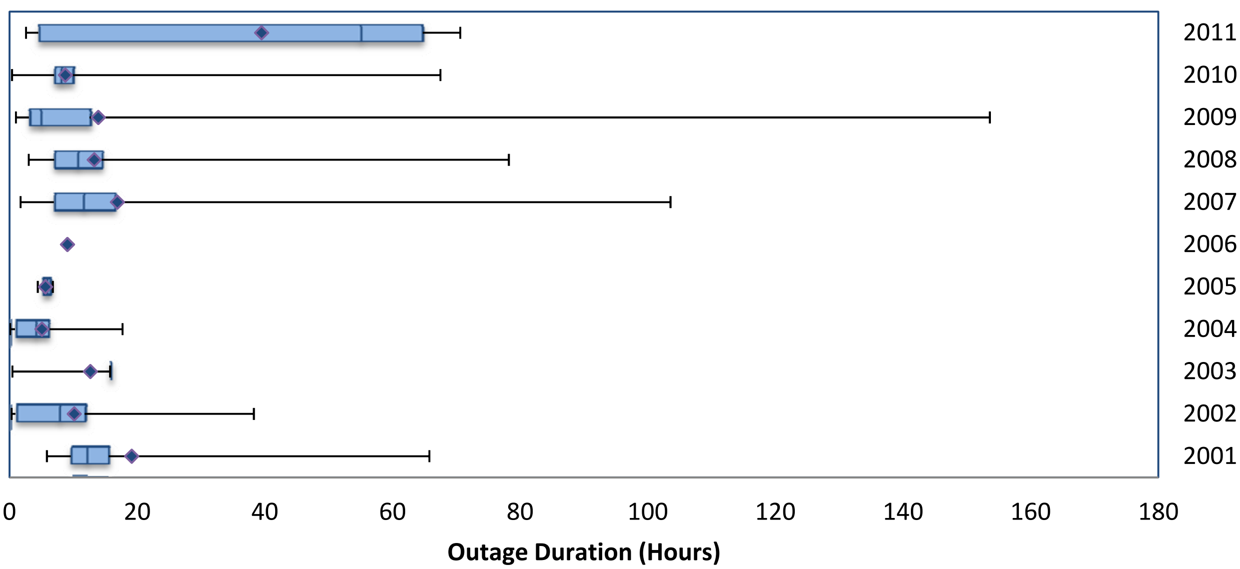


Figure 52: NPCC Gas Outage Duration



RFC

Figure 53: RFC Gas Outage

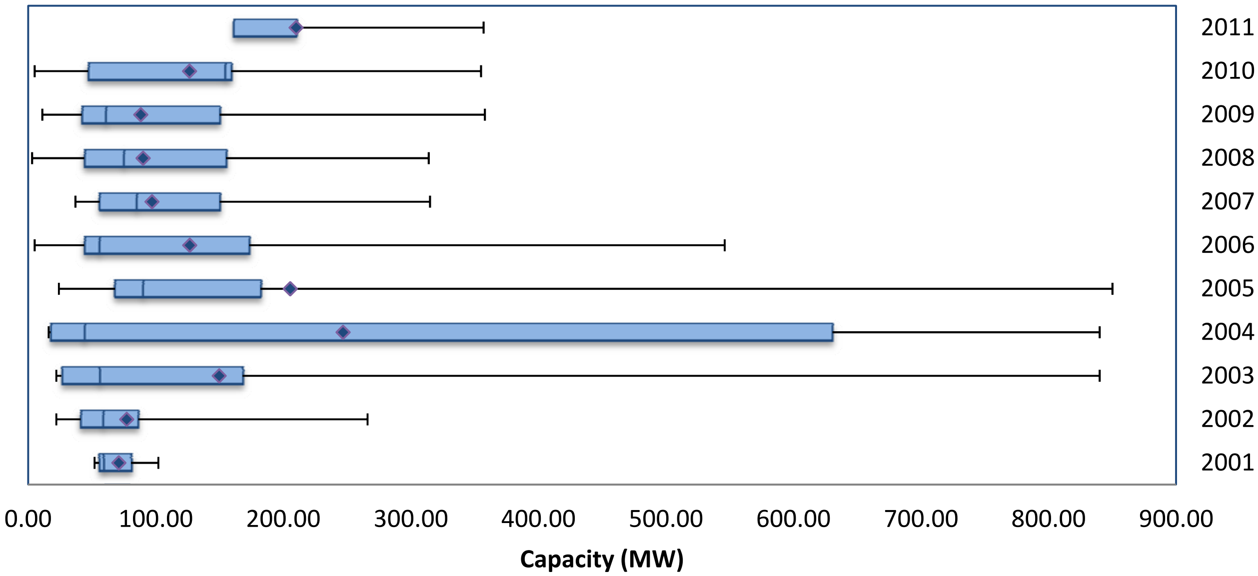
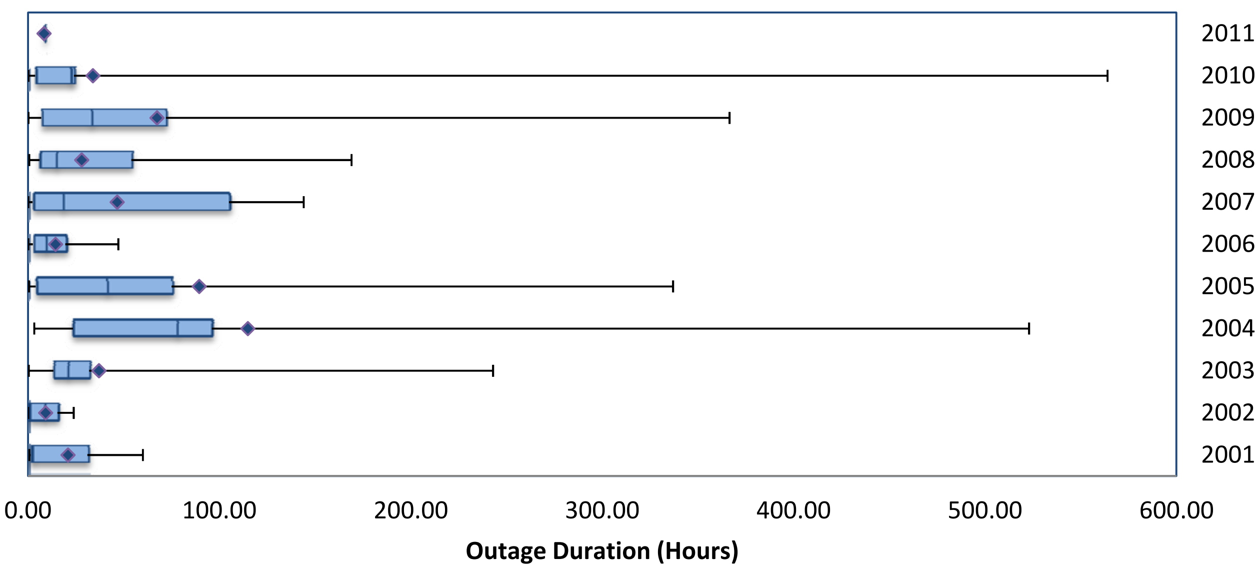


Figure 54: RFC Gas Outage Duration



SERC

Figure 55: SERC Gas Outage

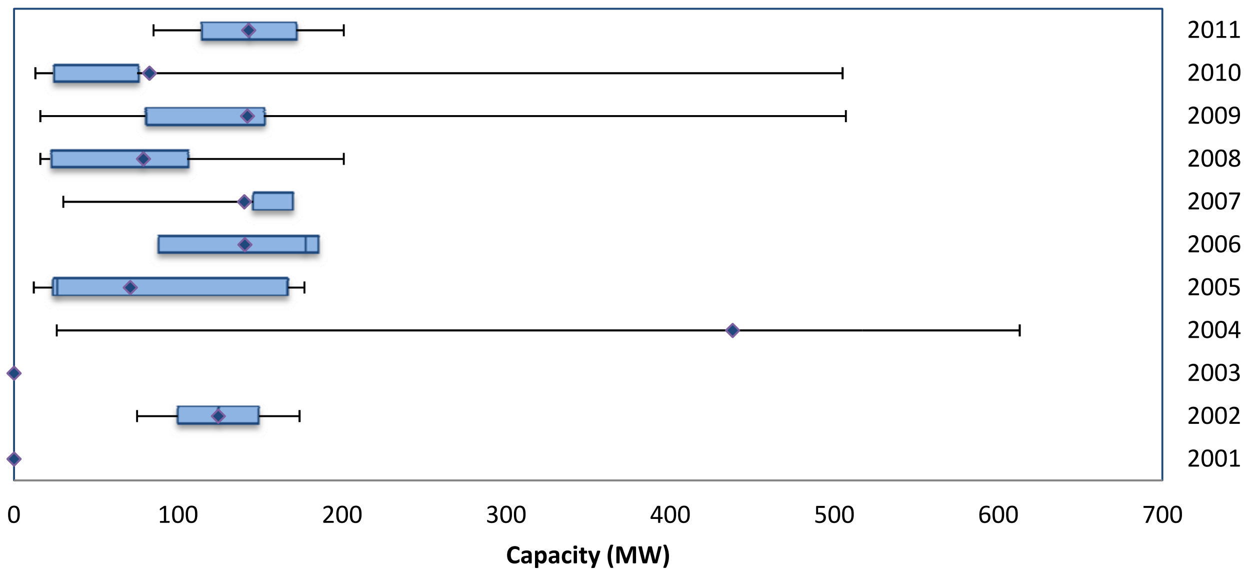
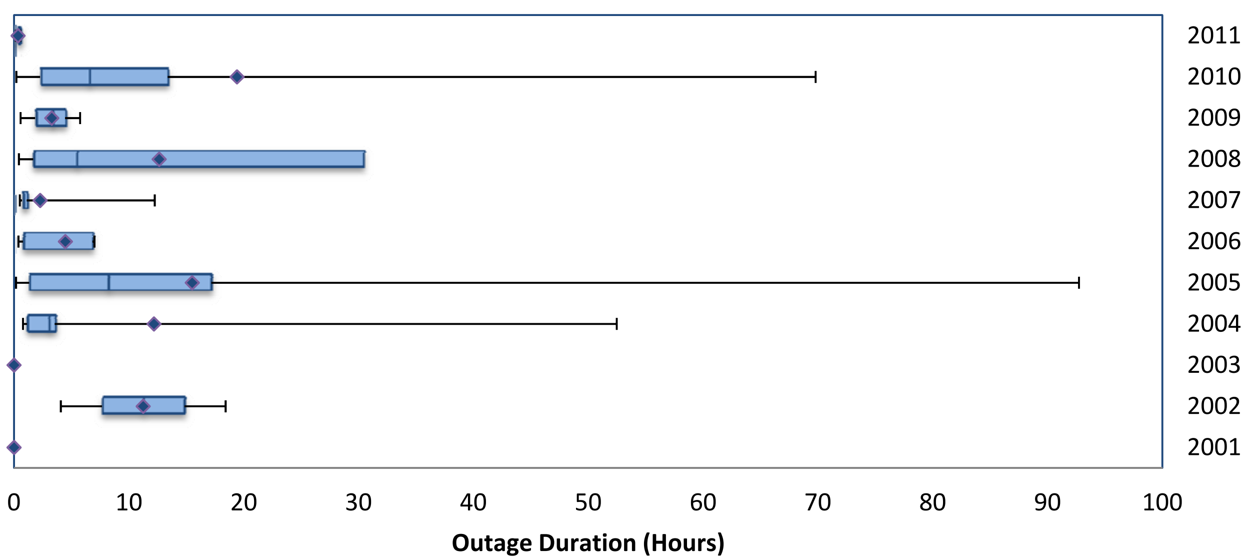


Figure 56: SERC Gas Outage Duration



SPP

Figure 57: SPP Gas Outage

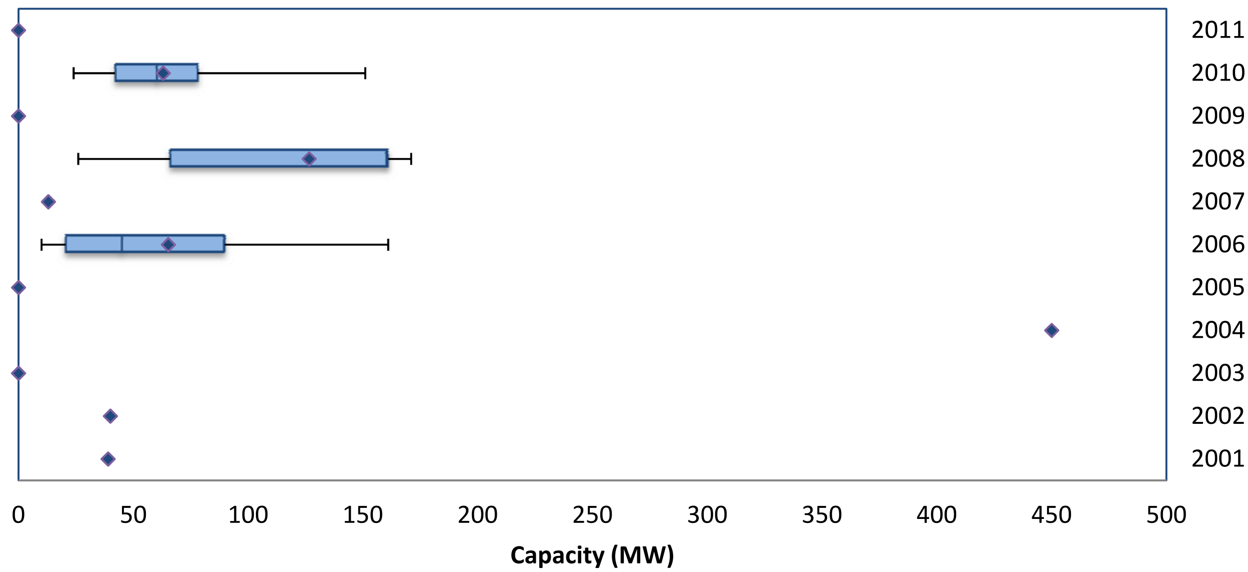
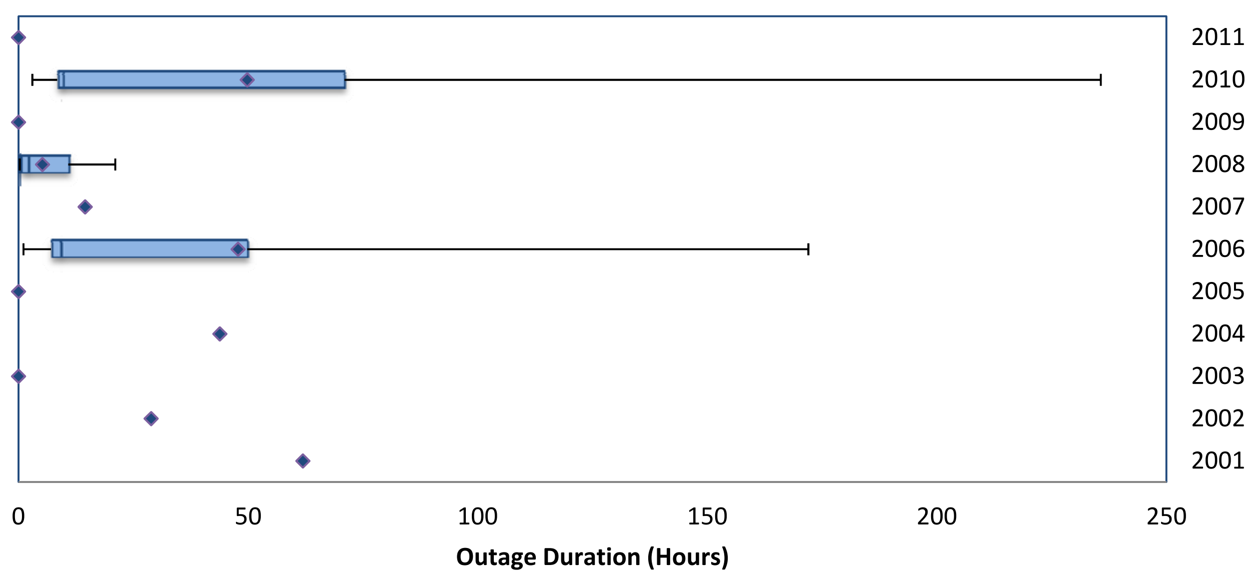


Figure 58: SPP Gas Outage Duration



TRE

Figure 59: TRE Gas Outage

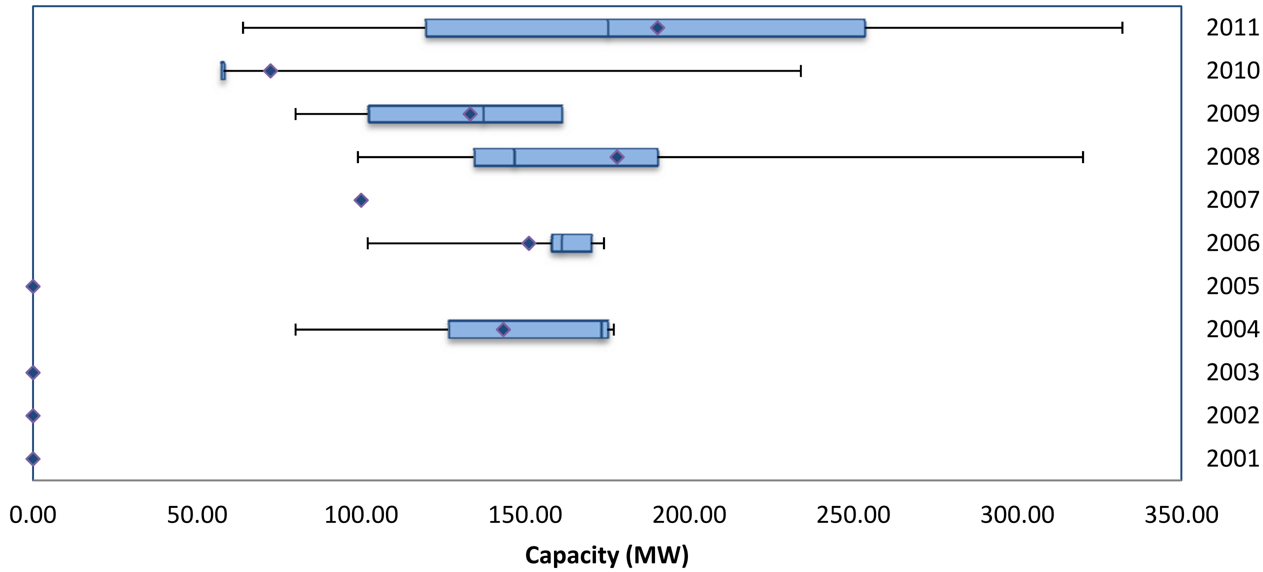
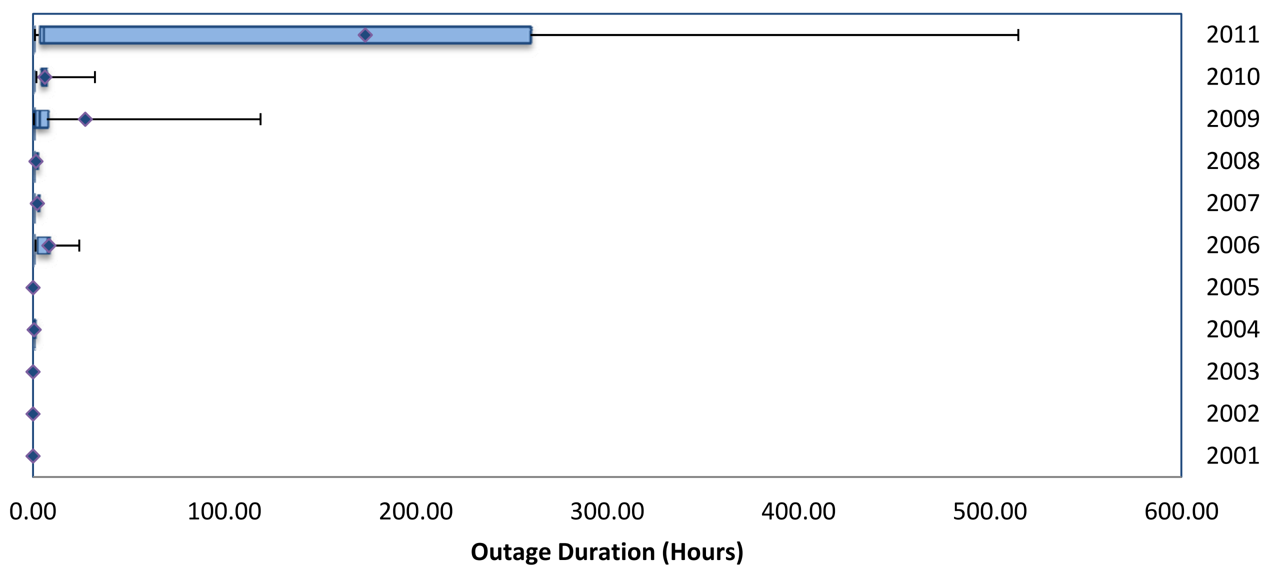


Figure 60: TRE Gas Outage Duration



WECC

Figure 61: WECC Gas Outage

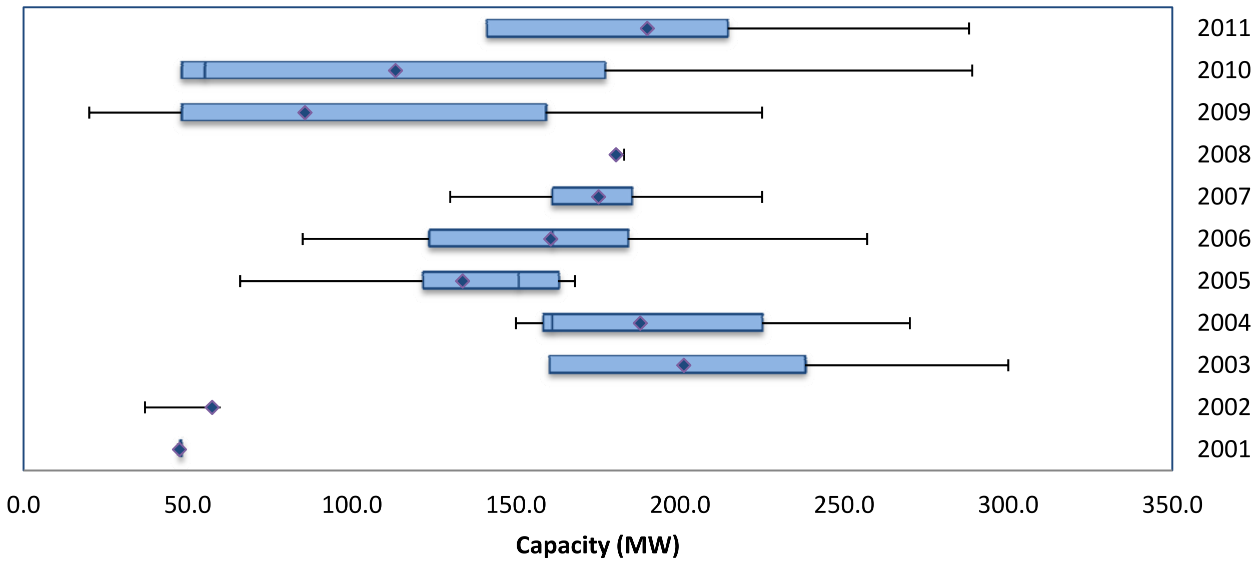
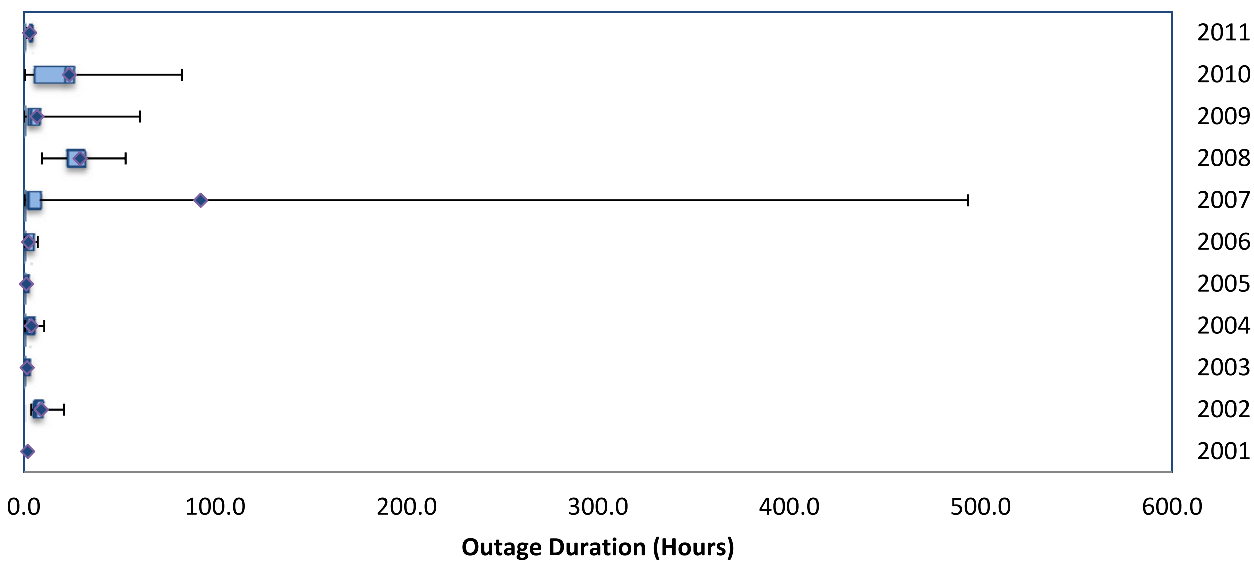


Figure 62: WECC Gas Outage Duration



Appendix III: Terms Used in This Report

Acronyms	Definition	Acronyms	Definition
AIC	Akaike information criterion	IESO	Independent Electricity System Operator (Ontario)
Bcfd	billion cubic per day	ISO-NE	New England Independent System Operator
Btu	British thermal unit	ISO	Independent system operators
CDD	cooling degree days	IT	interruptible transportation
CSA	Customer Security Administration	LAUF	lost or unaccounted for
CSAPR	Cross-State Air Pollution Rule	LDC	local distribution company
DGLM	Daily Gas Load Model	LNG	liquefied natural gas
DOE	U.S. Department of Energy	LOLE	Loss-of-Load Expectation
DOT	U.S. Department of Transportation	LOLH	Loss-of-Load Hours
Dth	Dekatherm	MCE	Market Clearing Engine
EDI	Electronic Data Interchange	MDQ	Maximum Daily Quantity
EDM	Electronic Delivery Mechanism	MISO	Midwest Independent System Operator
EPA	Environmental Protection Agency	MMcfd	millions of cubic feet per day
ERCOT	Electric Reliability Council of Texas	MTBF	Mean time between failures
EUE	Expected Unserved Energy	MTTR	Mean time to repair
FERC	Federal Energy Regulatory Commission	MW	Megawatt
G&T RPM	Generation & Transmission Reliability Planning Models	MWh	Megawatt hour
GADS	Generating Availability Data System	NAESB	North American Energy Standards Board
GAR	Generating Availability Report	NERC	North American Electric Reliability Corporation
GISB	Gas Industry Standards Board	NOAA	National Oceanic and Atmospheric Administration
GTL	gas-to-liquid	NRRI	National Regulatory Research Institute
HAPS	Hazardous Air Pollution Standard	NYISO	New York Independent System Operator
HAS	Historical Availability Statistics	OFO	Operational Flow Orders
HDD	heating degree days	PHMSA	Department of Transportation's Pipeline and Hazardous Materials Safety Administration

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Appendix 2:

Natural Gas Electricity Interface Review

VT INCEPIT FIDELIS SIC PERMANET
Ontario

Natural Gas Electricity Interface Review

A Report by Ontario Energy Board Staff

EB-2005-0306

November 21, 2005

Table of Contents

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.

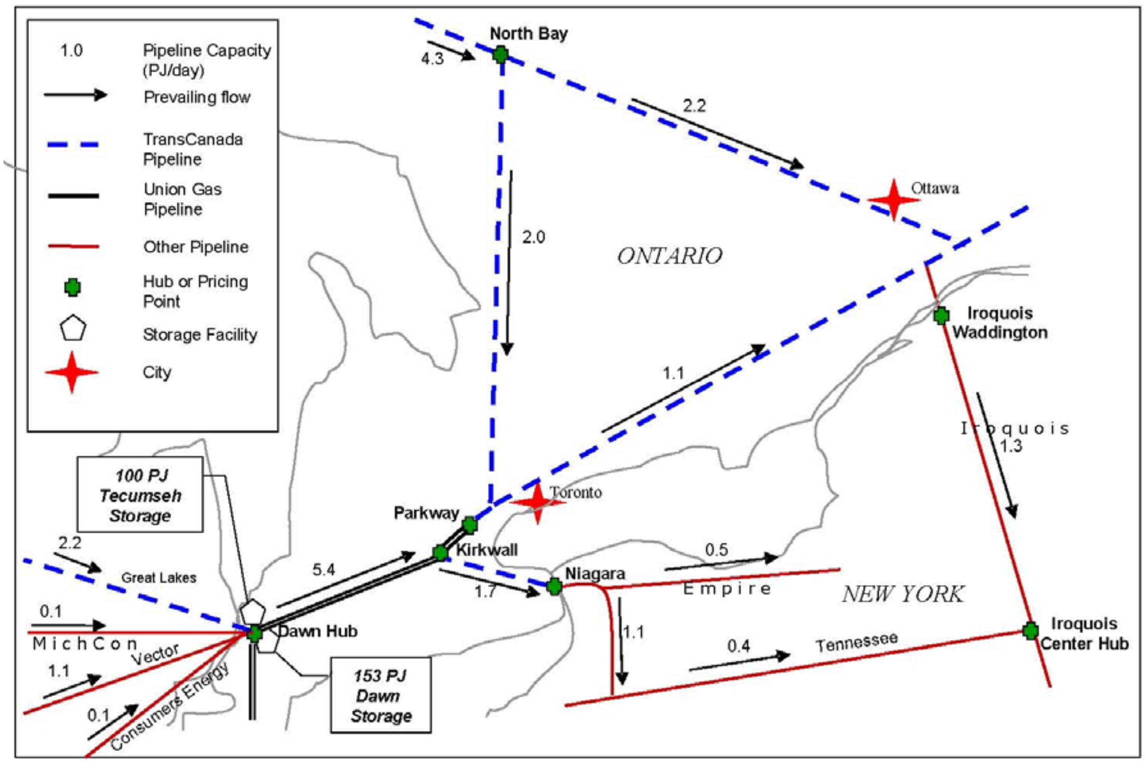
Because the Phase I work suggested a need for major gas infrastructure investment, Board staff asked stakeholders to outline their concerns about the draft set of issues on the regulatory treatment of new facilities. The Board received 12 final written submissions and two responses to support Phase I 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.

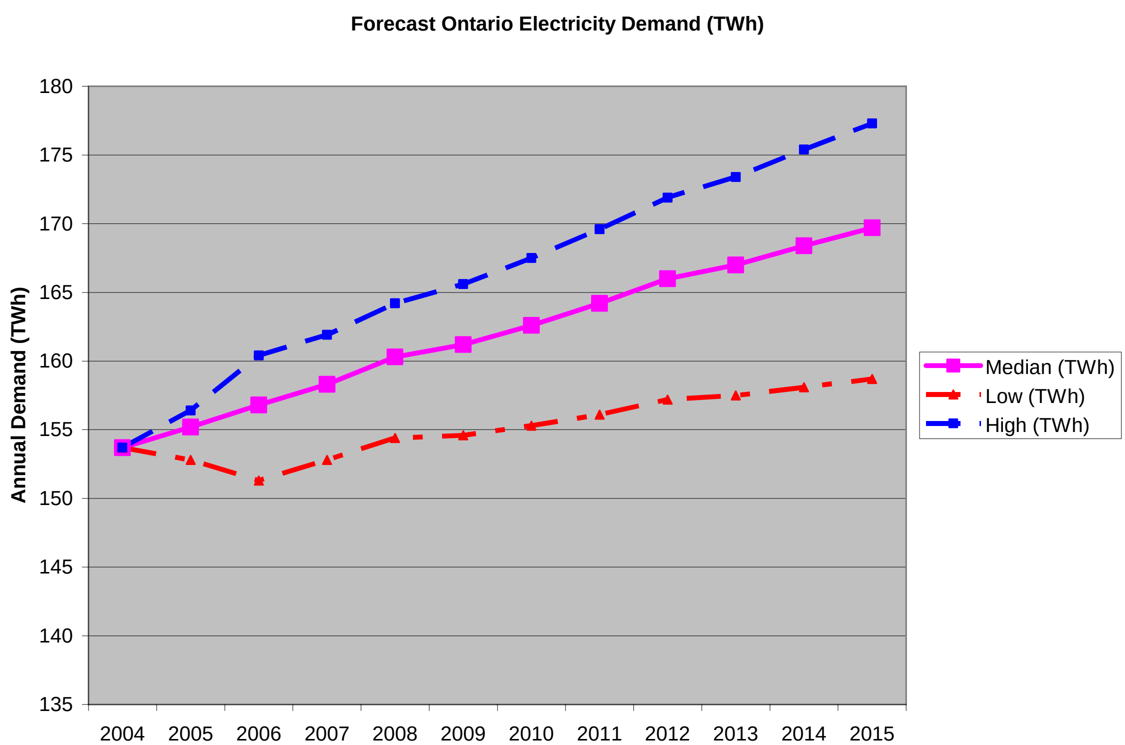
5 Scenario Analysis

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



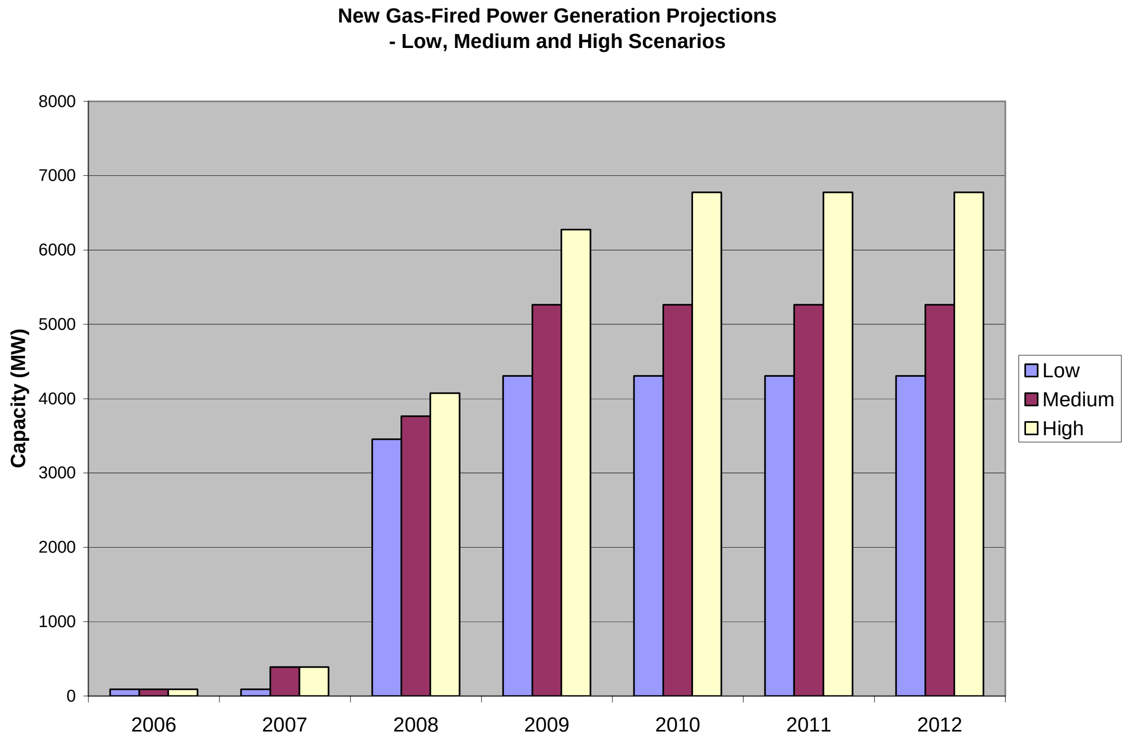
The capacity assumptions for the three scenarios were the following:

- 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.

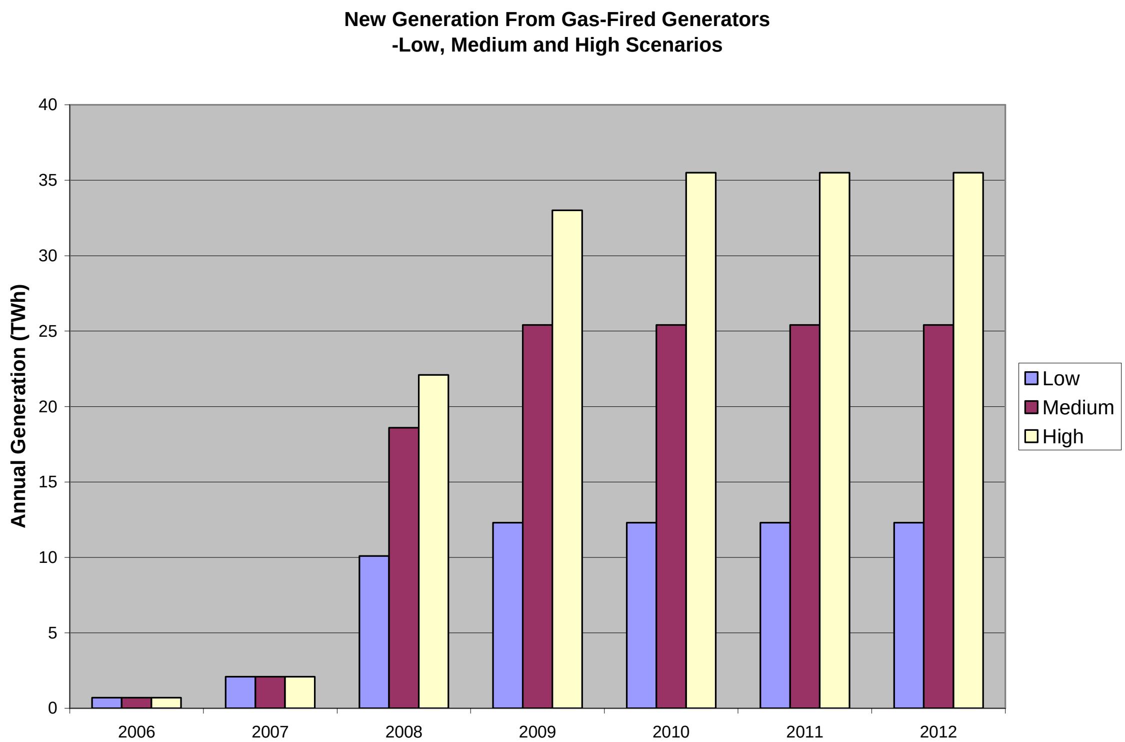
Based on these capacity numbers, the annual new gas-fired power generation capacity for each of the three scenarios is shown in Figure 3.

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.

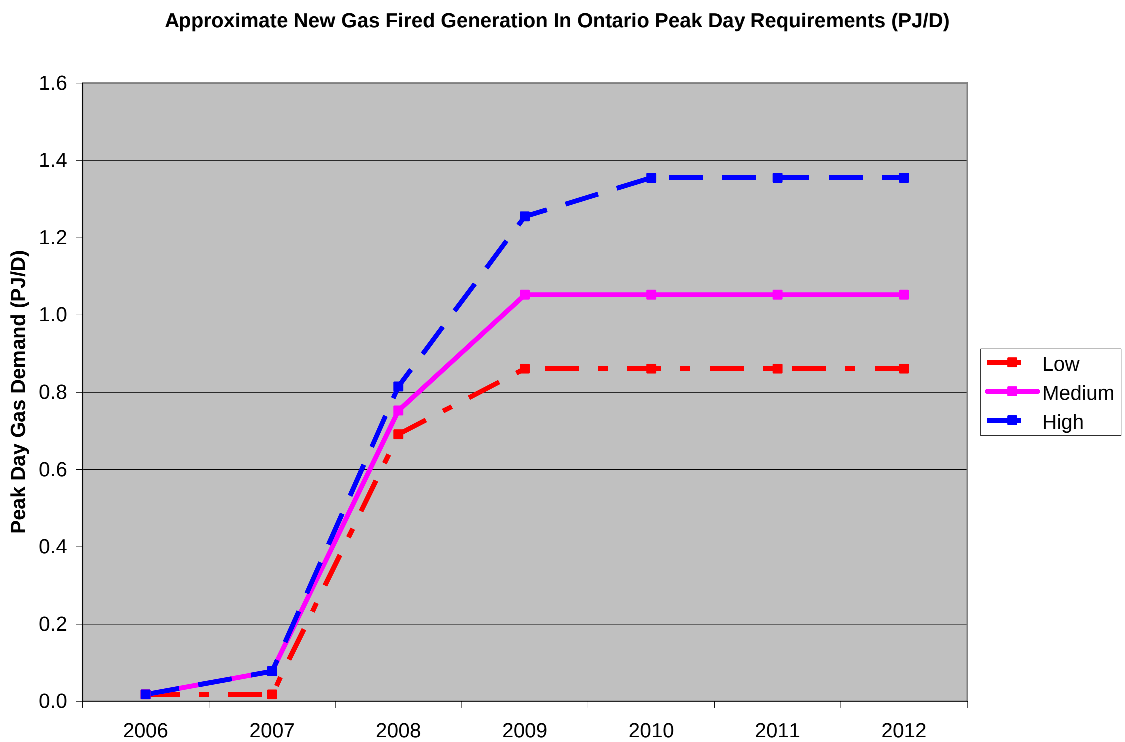
Table 1 illustrates the utilization rates that ERA used to assess the facilities and gas requirements for the three scenarios. In the medium scenario, ERA provided a mix of generation to match as reasonably as possible the following: announced cogeneration plans, annual coal replacement requirements,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

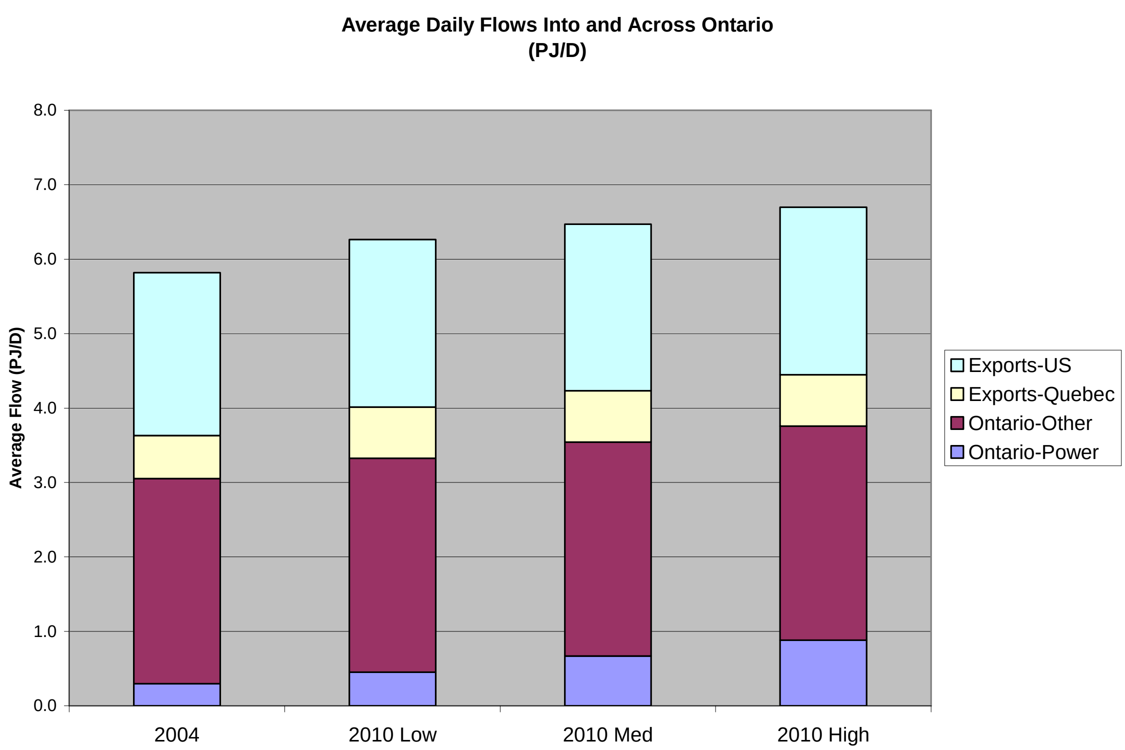
Because not all of the TCPL mainline capacity is contracted for long-term, it is possible that some of the existing capacity could be made available. It is not possible, however, to predict the quantity available over the period 2007-2012 with any certainty. For purposes of this report, ERA has assumed 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".

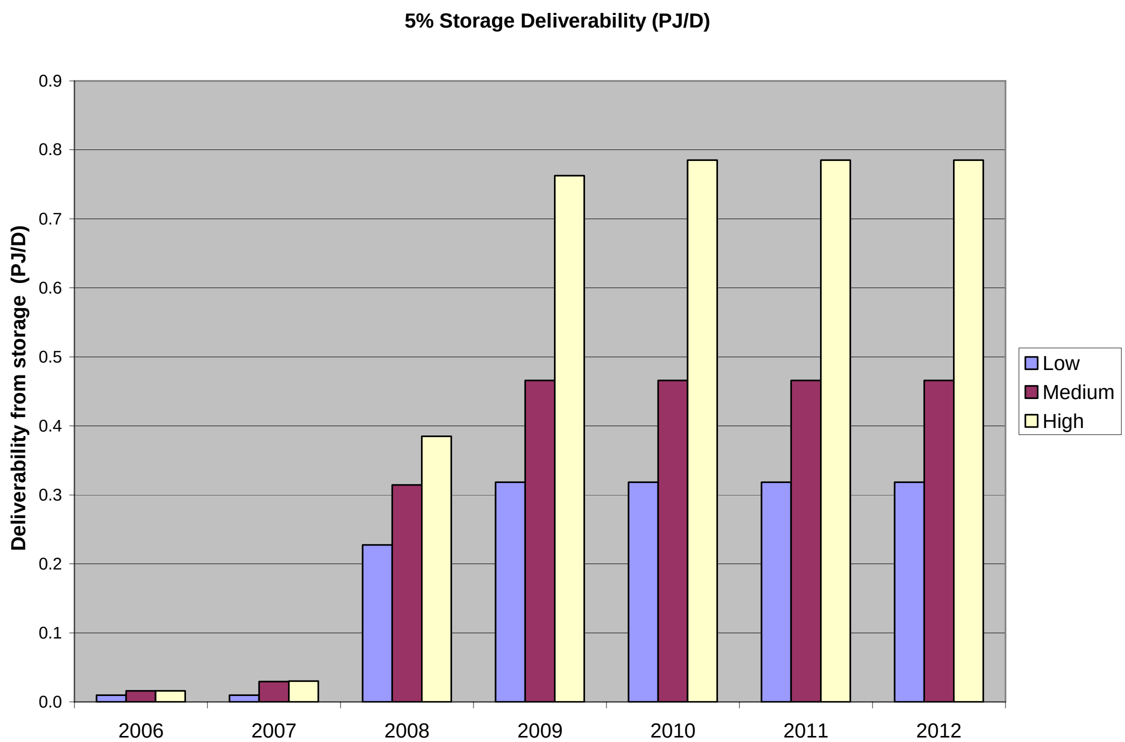
ERA also assumed that the demand for Ontario storage from ex-franchise storage customers would continue to be significant, even though these customers could turn to storage developments elsewhere (for example, in Michigan). As a result, ERA estimated

[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

Stakeholder Views

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?

Recommendation

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

<u>Stakeholder Views</u>

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.

<u>Recommendation</u>

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

<u>Stakeholder views</u>

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.

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[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.

Appendix 3:

18-Month Outlook

From June 2013 to November 2014

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18-MONTH OUTLOOK

From June 2013 to November 2014

Power to Ontario. On Demand.

An Assessment of the Reliability and Operability of the Ontario Electricity System

Executive Summary

Ontario is expected to continue to have adequate generation and transmission capability in the provincial power system. During the next 18 months, approximately 3,300 megawatts (MW) of wind, solar, hydro and biomass capacity are expected to be connected to the transmission grid, with a number of the operational changes needed to support this supply coming into force.

By the end of this outlook period, these new projects are anticipated to provide approximately 8.7 terawatt-hours (TWh) in energy output on an annual basis. By November 2014, the total wind and solar generation connected both to the transmission and distribution networks in Ontario are expected to exceed 6,800 MW and provide approximately 14.9 TWh of annual energy.

This summer, about 450 MW of renewable capacity is slated to come into service. However, more than 1,100 MW of new wind projects are expected to connect to the grid in the summer of 2014, which will be the largest influx of renewable capacity in a single season. By November 2014, total grid-connected annual wind output is expected to reach 10.9 TWh.

Solar generation – which up until now has only been embedded within distribution networks – will soon include nine new projects connected to the transmission grid, amounting to a total capacity of 180 MW. This capacity will complement the anticipated 1,700 MW of embedded solar capacity that will be in service during the outlook period.

To support these levels of new supply, the IESO's Renewable Integration Initiative (RII), continues to move forward to address three key elements – forecast, visibility and dispatch of renewable resources. RII initiatives have already yielded results, including the integration of the hourly centralized forecast into the IESO scheduling tools and enhanced visibility of renewable output within the IESO Control Room which will provide greater levels of awareness of system conditions.

The dispatch of grid-connected renewable resources is planned to be in place by this fall. This initiative will provide increased flexibility from available variable generation resources and will allow the IESO to operate the system more efficiently. Although, solar dispatch will be enabled at the same time as wind, it is not expected until early 2014 as grid connected solar resources come on line.

Coal-fired generation in Ontario is in the final stages of the shutdown process. The remaining generating units at Lambton and Nanticoke are scheduled to stop burning coal by the end of 2013, in line with government policy. The conversion of Atikokan generating station from a coal-fired unit to biomass is underway, with the unit expected to be back in service by the third quarter of 2014. The loss of these facilities results in a considerable but acceptable reduction in resources as seen in the summer 2014 resource scenarios depicted within the report.

Energy demand is forecast to decrease by 0.4% in 2013. The increase in electricity demand from modest economic and population growth will be more than offset by growth in embedded generation capacity, which reduces bulk power system demand, along with on-going conservation initiatives.

Peak demands are also impacted by these same factors plus a few more. The projected growth in embedded solar capacity will have a significant impact on the apparent summer peak. Contributions from distribution-connected solar resources will effectively reduce demand for grid-supplied energy. Additionally, price impacts like time-of-use rates and the Global Adjustment Allocation will continue to have an effect on peak demands, leading to a decline in summer peaks and a slight increase in winter peaks. The following table summarizes the forecasted seasonal peak demand numbers.

Season	Normal Weather Peak (MW)	Extreme Weather Peak (MW)
Summer 2013	23,213	25,368
Winter 2013-14	22,239	23,297
Summer 2014	22,937	24,954

Ontario will continue to experience an increase in volume, frequency and duration of surplus baseload generation (SBG) conditions with declining wholesale demand for electricity and significant quantities of baseload generation on the system. A vast majority of SBG is being managed via IESO tools and processes such as managing exports and nuclear maneuvering. In the first three weeks of May, nuclear units were shut down on three occasions in response to surplus conditions. The IESO will gain another tool to help manage SBG in September 2013 as wind becomes a dispatchable resource, which will help manage this increase in SBG.

Conclusions & Observations

The following conclusions and observations are based on the results of this assessment.

Demand Forecast

- Ontario's energy demand is expected to decline in 2013 by 0.4%. Increased demand due to economic expansion and population growth will be offset by growth in embedded generation capacity and on-going conservation initiatives. These factors reduce bulk power system demand. Since, 2012 was a leap year, the additional day bumped energy demand growth by 0.3% in 2012 and thus, 2013 shows a corresponding 0.3% reduction in energy demand.
- The growth in embedded solar and wind capacity will put significant downward pressure on overall energy demand and summer peak demands from the bulk electric system. Combined with conservation, Global Adjustment impacts and time-of-use rates, summer peaks are expected to decline and winter peaks are expected to show a slight increase over the 18-month time horizon.
- Although high peak demands are likely under extreme weather conditions, they are not expected to pose any province-wide reliability concerns.

Resource Adequacy

- Reserve requirements are expected to be met for all weeks in all the weather scenarios.
- Lambton and Nanticoke coal generating units will be removed from the grid by the end of 2013.
- The Lower Mattagami expansion project is underway which is expected to add more than 400 MW of hydro generation in Northeast Ontario. The first phase of this project is the addition of a third unit at Little Long Generating Station, with 70 MW capacity, which is expected to be in service by end of Q2 2014.
- Approximately 3,300 megawatts (MW) of grid-connected renewable capacity will be added to the grid throughout this outlook period, which includes about 180 MW of grid-connected solar capacity in Ontario.
- During the summer months of 2013, about 450 MW of renewable capacity is expected to be added to Ontario's supply. However, the largest influx of new wind generation capacity in a single season will take place the following summer, with more than 1,100 MW of new wind projects connecting to the grid.
- Decisions around the possible Pickering unit retirements and associated transmission upgrades are required within the timeframe of this Outlook to ensure supply adequacy continues beyond 2014.

	Normal Weather Scenario	Extreme Weather Scenario
Planned Scenario	• There are no weeks when reserve is lower than required	• There are no weeks when reserve is lower than required
Firm Scenario	• There are no weeks when reserve is lower than required	• There are no weeks when reserve is lower than required

Transmission Adequacy

- Ontario's transmission system is expected to reliably supply the demand under the normal and extreme weather conditions forecast for this Outlook period**.**
- The IESO, OPA, Transmitters and affected distributors are reviewing system needs and considering solutions under the Regional Planning Process established by the Ontario Energy Board (OEB).
- Several local area supply improvement projects are underway and will be placed in service during the timeframe of this Outlook. These projects, shown in Appendix B, will help relieve loadings of existing transmission stations and provide additional supply capacity for future load growth.
- To help control voltages in northwestern Ontario, Hydro One will be installing new reactors. Reactors at Marathon are scheduled to be installed and in service by Q4 2013 and reactors at Dryden are scheduled for Q4 2014.
- The IESO, Hydro One and OPA are also considering long term solutions to help control high voltages in southern Ontario during low demand periods.
- To improve the transmission capability into the Guelph area, Hydro One will be proceeding with the Guelph Area Transmission Refurbishment project to reinforce the supply into Guelph-Cedar TS, with an expected completion date in the second quarter of 2016.
- In the Cambridge area, to help meet the IESO's load restoration criteria following a contingency, a second 230/115 kV autotransformer is expected to be installed at Preston TS. Longer-term solutions to fully address meeting restoration criteria are being developed.
- Transmission enhancements at Manby TS, which include 230kV switchyard reconfiguration and breaker upgrades are planned for Q4 2014. Hydro One has also planned to upgrade 115kV breakers at Hearn and Leaside by Q4 2014. These upgrades will help manage long-term load supply in the south-western GTA.
- In the eastern portion of the GTA, a new Clarington TS that provides 500/230 kV transformation and 230 kV switching facilities is scheduled to be in-service as soon as spring 2015 to maintain supply reliability beyond Pickering end-of-life. Clarington TS will also improve restoration capability to the loads in the Pickering, Ajax, Whitby, Oshawa and

Clarington areas so that IESO's load restoration criteria following transmission outages will be satisfied.

Operability

- The IESO continues to approach the completion of its RII. RII initiatives have already yielded results, including the integration of the hourly centralized forecast into the IESO scheduling tools and enhanced visibility of renewable output within the IESO Control Room which will provide greater levels of awareness of system conditions. The dispatch of grid-connected renewable resources is planned to be in place within the forecast period.

- By the end of 2013, a 5-minute forecast for variable generation, wind and solar, is expected to be introduced into the real-time scheduling process and variable resources themselves will become fully dispatchable.

- The conditions for surplus baseload generation are likely to continue to grow in 2013 and 2014, following the recent nuclear unit restarts and with the expected increased penetration of renewable generation, combined with lower off-peak demand for electricity. A vast majority of SBG is being managed via IESO tools and processes such as nuclear maneuvering and managing exports. The IESO will gain another tool to help manage SBG by fall of 2013 as wind becomes a dispatchable resource, and helps to maintain operational efficiency.

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1 Introduction

This Outlook covers the 18-month period from June 2013 to November 2014 and supersedes the last Outlook released in February 2013.

The purpose of the 18-Month Outlook is:

- To advise market participants of the resource and transmission reliability of the Ontario electricity system;
- To assess potentially adverse conditions that might be avoided through adjustment or coordination of maintenance plans for generation and transmission equipment; and
- To report on initiatives being put in place to improve reliability within the 18-month timeframe of this Outlook.

The contents of this Outlook focus on the assessment of resource and transmission adequacy. Additional supporting documents are located on the IESO website at http://www.ieso.ca/imoweb/monthsYears/monthsAhead.asp

This Outlook presents an assessment of resource and transmission adequacy based on the stated assumptions, using the described methodology. Readers may envision other possible scenarios, recognizing the uncertainties associated with various input assumptions, and are encouraged to use their own judgment in considering possible future scenarios.

Security and Adequacy Assessments are published on the IESO website on a weekly and daily basis, and progressively supersede information presented in this report.

Readers are invited to provide comments on this Outlook report or to give suggestions as to the content of future reports. To do so, please contact us at:

- Toll Free: 1-888-448-7777
- Tel: 905-403-6900
- Fax: 905-403-6921
- E-mail: customer.relations@ieso.ca.

- End of Section -

2 Updates to This Outlook

2.1 Updates to Demand Forecast

The demand forecast is based on actual demand, weather and economic data through to the end of February 2013. The demand forecast has been updated to reflect the most recent economic projections and data. Actual weather and demand data for March 2013 and April 2013 have been included in the tables.

2.2 Updates to Resources

Lambton and Nanticoke Generating Stations will be shut down by the end of 2013.

Point Aux Roches Wind Energy Centre is in service and its generating capacity of 48.6 MW has been added to the resources. The new Niagara Tunnel is in-service producing more renewable electricity at the Sir Adam Beck generating complex.

Nine grid-connected solar projects are expected to come in-service during the outlook period, adding a total of 180 MW to Ontario's supply mix. Monthly solar capacity contribution values are used to forecast the capacity contributions at the time of weekday peak for these solar projects. The value used in the summer months is 34% and in winter months is 0%. In summer, the peak demand hour mostly coincides with the higher production from the solar panels, whereas in winter the peak demand hour occurs after sunset.

The assessment uses planned generator outages as submitted by market participants to the IESO's Integrated Outage Management System (IOMS). This Outlook is based on submitted generation outage plans as of April 15, 2013.

2.3 Updates to Transmission Outlook

The list of transmission projects, planned transmission outages and actual experience with forced transmission outages have been updated from the previous 18-Month Outlook. For this Outlook, transmission outage plans submitted to the IOMS as of April 1, 2013 were used.

2.4 Updates to Operability Outlook

The outlook for surplus baseload generation (SBG) conditions over the next 18 months uses planned generator outages as submitted by market participants to the IESO's IOMS. This Outlook is based on submitted generation outage plans as of April 15, 2013.

- End of Section -

3 Demand Forecast

The IESO is responsible for forecasting electricity demand on the IESO-controlled grid. This demand forecast covers the period June 2013 to November 2014 and supersedes the previous forecast released in March 2013. Tables of supporting information are contained in the 2013 Q2 Outlook Tables spreadsheet.

Energy demand is forecast to decrease by 0.4% in 2013. This reduction is the combination of a number of effects. Increased embedded generation production, conservation initiatives and the impact of the loss of a day compared to last year being a leap year, all act to reduce the growth rate of grid supplied electricity. Increased demand is generally driven by economic expansion and population growth. Though population growth remains steady, economic expansion has been quite modest. Additionally, economic growth has and will continue to be centered in areas of the economy which have low levels of electric intensity. The traditionally electricity intense industries have seen mixed results since the 2009 recession.

Summer peak demands will face downward pressure from a number of factors. The projected growth in embedded solar capacity, conservation, time of use rates and the Global Adjustment Allocation will have a significant impact on the grid supplied summer peak. Contributions from distribution-connected solar resources will supplant grid-supplied electricity. Conservation reduces the overall need for electricity and price impacts lead electricity customers to shift their usage to non-peak periods. Combined these impacts will act to reduce summer peaks going forward. Conversely, these factors are weaker or absent during the winter peak periods. The winter peak occurs after sundown so it not impacted by embedded solar. Unlike the summer peak which is primarily electric air conditioner load and impacted by changes to air conditioner efficiency, the winter peak load is a mix of end-uses, with the greatest conservation impacts coming from lighting efficiency gains. The price impacts are also muted as the Global Adjustment Allocation has only applied to summer peaks so far. Winter peaks will show a slight increase over the forecast.

The following tables show the seasonal peaks and annual energy demand over the forecast horizon of the Outlook.

Table 3.1 Forecast Summary

Season	Normal Weather Peak (MW)	Extreme Weather Peak (MW)
Summer 2013	23,213	25,368
Winter 2013-14	22,239	23,297
Summer 2014	22,937	24,954
Year	**Normal Weather Energy (TWh)**	**% Growth in Energy**
2006 Energy	152.3	-1.9%
2007 Energy	151.6	-0.5%
2008 Energy	148.9	-1.8%
2009 Energy	140.4	-5.7%
2010 Energy	142.1	1.2%
2011 Energy	141.2	-0.6%
2012 Energy	141.8	0.4%
2013 Energy (Forecast)	141.2	-0.4%

Table 3.2 Weekly Energy and Peak Demand

Week Ending	Normal Peak (MW)	Extreme Peak (MW)	Load Forecast Uncertainty (MW)	Normal Energy Demand (GWh)	Week Ending	Normal Peak (MW)	Extreme Peak (MW)	Load Forecast Uncertainty (MW)	Normal Energy Demand (GWh)
09-Jun-13	19,461	23,068	1,298	2,598	09-Mar-14	20,045	21,401	531	2,872
16-Jun-13	20,482	24,060	1,298	2,670	16-Mar-14	19,030	20,569	649	2,781
23-Jun-13	21,127	24,561	749	2,690	23-Mar-14	18,433	19,751	611	2,674
30-Jun-13	22,499	24,533	876	2,807	30-Mar-14	18,513	20,271	569	2,702
07-Jul-13	22,567	24,247	770	2,708	06-Apr-14	17,855	19,780	567	2,641
14-Jul-13	23,213	25,368	1,003	2,842	13-Apr-14	17,586	19,157	471	2,563
21-Jul-13	23,006	24,554	889	2,847	20-Apr-14	17,132	17,901	496	2,471
28-Jul-13	22,561	24,240	926	2,790	27-Apr-14	16,999	17,778	531	2,469
04-Aug-13	22,534	24,750	1,050	2,810	04-May-14	17,513	19,637	721	2,473
11-Aug-13	22,360	25,165	930	2,794	11-May-14	17,654	19,953	849	2,451
18-Aug-13	21,641	24,340	954	2,751	18-May-14	18,526	21,974	845	2,479
25-Aug-13	21,521	23,939	817	2,737	25-May-14	18,922	22,094	1,175	2,431
01-Sep-13	21,457	23,697	1,233	2,748	01-Jun-14	18,943	22,327	1,330	2,511
08-Sep-13	20,405	22,878	1,464	2,619	08-Jun-14	19,865	23,383	1,292	2,627
15-Sep-13	19,460	22,340	1,243	2,530	15-Jun-14	20,711	23,796	1,055	2,670
22-Sep-13	19,237	21,075	622	2,555	22-Jun-14	21,565	24,048	835	2,754
29-Sep-13	18,751	19,768	784	2,553	29-Jun-14	22,318	24,315	754	2,758
06-Oct-13	17,754	18,293	537	2,508	06-Jul-14	22,513	24,075	1,016	2,703
13-Oct-13	17,548	17,809	733	2,494	13-Jul-14	22,937	24,954	814	2,787
20-Oct-13	17,473	17,938	839	2,495	20-Jul-14	22,776	23,905	838	2,736
27-Oct-13	18,347	18,558	585	2,582	27-Jul-14	22,140	24,128	1,035	2,819
03-Nov-13	18,294	18,602	487	2,577	03-Aug-14	22,120	24,378	841	2,795
10-Nov-13	19,283	19,340	437	2,635	10-Aug-14	21,582	24,573	958	2,661
17-Nov-13	19,384	20,021	532	2,690	17-Aug-14	21,488	23,656	985	2,671
24-Nov-13	19,906	20,427	708	2,758	24-Aug-14	21,465	23,320	1,362	2,709
01-Dec-13	20,278	20,939	550	2,793	31-Aug-14	20,461	22,675	1,413	2,614
08-Dec-13	20,718	22,027	677	2,871	07-Sep-14	18,975	22,355	1,370	2,453
15-Dec-13	21,281	22,120	496	2,912	14-Sep-14	18,755	21,002	680	2,454
22-Dec-13	21,392	22,298	585	2,938	21-Sep-14	18,600	19,717	781	2,515
29-Dec-13	19,304	20,524	755	2,697	28-Sep-14	17,727	17,777	420	2,464
05-Jan-14	20,739	21,438	353	2,854	05-Oct-14	17,099	17,422	554	2,481
12-Jan-14	22,239	23,297	570	3,068	12-Oct-14	17,357	17,649	786	2,524
19-Jan-14	21,699	22,649	547	3,014	19-Oct-14	18,079	18,265	507	2,509
26-Jan-14	21,826	22,649	483	3,026	26-Oct-14	18,064	18,281	392	2,576
02-Feb-14	21,902	22,579	404	3,062	02-Nov-14	18,652	18,842	318	2,621
09-Feb-14	21,077	22,364	734	3,012	09-Nov-14	18,898	19,437	416	2,638
16-Feb-14	20,666	22,167	635	2,927	16-Nov-14	19,465	19,914	601	2,703
23-Feb-14	20,438	22,028	581	2,892	23-Nov-14	19,944	20,496	342	2,754
02-Mar-14	20,999	21,954	501	2,961	30-Nov-14	20,456	21,401	607	2,805

3.1 Actual Weather and Demand

Since the last forecast the actual demand and weather data for February, March and April have been recorded.

February

- The weather for February was very close to normal. Demand for the month was 11.7 TWh (11.7 TWh weather-corrected). This is a decrease compared to the previous February but after adjusting for the extra day in 2012 demand would have been higher this February. The monthly peak was 21,426 MW and occurred on February 4th, which wasn't the coldest day, but was during a cold snap starting the month before. This weather corrected peak was an almost identical 21,451 MW.

- Despite having one less day, wholesale customers' consumption increased by 7.1% over the previous February. Wholesale customers' consumption has shown strong year over year increases since September.

March

- March's weather was near normal. The average temperature was normal, though the peak temperatures were milder than normal. Energy demand for the month was 12.0 TWh (11.8 TWh weather-corrected). The peak day did not occur on the coldest day as those days occurred on a weekend. The peak was on the Monday following. The 19,825 MW peak was lower than the previous March.
- Wholesale customers' consumption growth weakened in March growing by just 1.8% over the previous March. Over the previous five months year over year growth had averaged 6.7%.

April

- The weather for April was fairly close to normal. Actual energy demand for the month was 10.9 TWh (11.0 TWh weather-corrected) which is an increase over the previous April. The actual peak for the month was 18,854 MW and occurred on April 3rd which makes the peak a cold weather peak. The peak was lower than the previous April's.
- Wholesale customers' consumption growth was much weaker for the second consecutive month. Their consumption growth had been strong for five months, averaging 6.7%. However year over year growth for April was just 0.1%.

Weather-corrected demand was down 0.3% for the first four months of 2013 compared to the previous year. However, after adjusting for the impact of the additional leap year day demand would have risen 0.6%. Unfortunately, recent economic data and forecast points to lower expansion throughout the remainder of 2013 meaning lower demand growth later in the year.

The 2013 Q2 Outlook Tables spreadsheet has several tables with historical data. They are:

- Table 3.3.1 Weekly Weather and Demand History Since Market Opening
- Table 3.3.2 Monthly Weather and Demand History Since Market Opening
- Table 3.3.3 Monthly Demand Data by Market Participant Role.

3.2 Forecast Drivers

Economic Outlook

The economic outlook has not changed appreciably since the recession. High debt loads, high unemployment rates and weak economic growth are the stories for most of the western economies. Low borrowing costs and stimulus spending has not given traction to the recovery. Canada's economy had fared much better than other nations due to lower debt levels, high commodity prices and a fairly robust real estate market. However, as a trade based nation, Canada is not insulated from global economic events and signs are pointing for weaker growth.

- Table 3.3.4 of the 2013 Q2 Outlook Tables has the economic assumptions for the demand forecast.

Weather Scenarios

The IESO uses weather scenarios to produce demand forecasts. These scenarios include Normal and Extreme weather, along with a measure of uncertainty in demand due to weather volatility. This measure is called Load Forecast Uncertainty.

- Table 3.3.5 of the 2013 Q2 Outlook Tables has the weekly weather data for the forecast period.

Conservation, Demand Management and Pricing

Conservation will continue to grow throughout the forecast. The demand forecast is decremented for the impacts of conservation and embedded generation.

Other demand measures such as dispatchable loads, demand response programs, and contracted loads are not decremented from the demand forecast but instead are treated as resources in the assessment. Therefore the effects of demand measures are added back into the demand history and the forecast is produced prior to these impacts. That total demand measure capacity is discounted – based on historical and contract data – to reflect the reliably available capacity.

The impact of time of use rates and the Global Adjustment allocation are factored into the demand forecasts.

- End of Section -

4 Resource Adequacy Assessment

This section provides an assessment of the adequacy of resources to meet the forecast demand. When reserves are below required levels, with potentially adverse effects on the reliability of the grid, the IESO has the authority to reject outages based on their order of precedence. Conversely, an opportunity exists for additional outages when reserves are above required levels. These actions address shortages and may help to reduce surpluses of reserves.

The existing installed generating capacity is summarized in Table 4.1. This excludes capacity that is commissioning.

Table 4.1 Existing Generation Resources as of April 15, 2013

Fuel Type	Total Installed Capacity (MW)	Forecast Capability at Summer Peak* (MW)	Number of Stations	Change in Installed Capacity (MW)	Change in Stations
Nuclear	12,998	12,844**	5	0	0
Hydroelectric	7,939	5,718	70	0	0
Coal	3,293	3,018	3	0	0
Oil / Gas	9,987	8,925	29	0	0
Wind	1,560	213	13	49	1
Biomass / Landfill Gas	122	90	6	0	0
Total	35,899	30,808	126	49	1

* Actual Capability may be less as a result of transmission constraints

** Output of certain nuclear units may be limited due to environmental variances

4.1 Committed and Contracted Generation Resources

All generation projects that are scheduled to come into service, be upgraded, or be shut down within the Outlook period are summarized in Table 4.2. This includes both the generation projects in the IESO's Connection Assessment and Approval Process (CAA) that are under construction and the projects contracted by the OPA. Details regarding the IESO's CAA process and the status of these projects can be found on the IESO's website at http://www.ieso.ca/imoweb/connassess/ca.asp under Application Status.

The estimated effective date in Table 4.2 indicates the date on which additional capacity is assumed to be available to meet Ontario demand or when existing capacity will be shut down. For projects that are under contract, the estimated effective date is the best estimate of the date when the contract requires the additional capacity to be available. If a project is delayed the estimated effective date will be the best estimate of the commercial in-service date for the project.

Table 4.2 Committed and Contracted Generation Resources

Project Name	Zone	Fuel Type	Estimated Effective Date	Change	Project Status	Capacity Considered Firm (MW)	Capacity Considered Planned (MW)
Comber Wind Limited Partnership	West	Wind			Commercial Operation	166	166
Thunder Bay Condensing Turbine Project	Northwest	Biomass	2013-Q2		Commissioning	40	40
Summerhaven Wind Energy Centre	Southwest	Wind	2013-Q2		Construction	125	125
Conestogo Wind Energy Centre 1	Southwest	Wind	2013-Q2		Pre-NTP	69	69
McLean's Mountain Wind Farm	Northeast	Wind	2013-Q2		NTP	60	60
Becker Cogeneration Plant	Northwest	Biomass	2013-Q4		Construction		8
Lambton Coal Shutdown	West	Coal	2013-Q4			-1,016	-1,016
Nanticoke Coal Shutdown	Southwest	Coal	2013-Q4			-1,985	-1,985
Leamington Pollution Control Plant	West	Oil	2014-Q1		Construction		2
Bow Lake Phase 1	Northeast	Wind	2014-Q1		pre-NTP		20
Dufferin Wind Farm	Southwest	Wind	2014-Q1		Pre-NTP		100
Twin Falls	Northeast	Water	2014-Q1		Construction		5
Niagara Region Wind Farm	Southwest	Wind	2014-Q1		Pre-NTP		230
Nigig Power Corporation	Essa	Wind	2014-Q1		Pre-NTP		300
Port Dover and Nanticoke Wind Project	Southwest	Wind	2014-Q1		Pre-NTP		104
Haldimand Solar Project	Southwest	Solar	2014-Q1		Pre-NTP		100
Haldimand Wind Project	Southwest	Wind	2014-Q1		Pre-NTP		150
South Kent Wind Project	West	Wind	2014-Q1		Construction		270
New Third Unit at Little Long	Northeast	Water	2014-Q2		Pre-NTP		71
Amherst Island Wind Project	East	Wind	2014-Q2		Pre-NTP		75
Goulais Wind Farm	Northeast	Wind	2014-Q2		pre-NTP		25
Bow Lake Phase 2	Northeast	Wind	2014-Q2		pre-NTP		40
Adelaide Wind Power Project	West	Wind	2014-Q3		Pre-NTP		40
Bornish Wind Energy Centre	Southwest	Wind	2014-Q3		Pre-NTP		74
Grand Bend Wind Farm	Southwest	Wind	2014-Q3		Pre-NTP		100
Grand Valley Wind Farms (Phase 3)	Southwest	Wind	2014-Q3		Pre-NTP		40
East Lake St. Clair Wind	West	Wind	2014-Q3		Commissioning		99
Erieau Wind	West	Wind	2014-Q3		Commissioning		99
Gunn's Hill Wind Farm	West	Wind	2014-Q3		Pre-NTP		25
Silvercreek Solar Park	West	Solar	2014-Q3		Pre-NTP		10
Cedar Point Wind Power Project Phase II	Southwest	Wind	2014-Q3		Pre-NTP		100
Adelaide Wind Energy Centre	Southwest	Wind	2014-Q3		Pre-NTP		60
Bluewater Wind Energy Centre	Southwest	Wind	2014-Q3		Pre-NTP		60
Goshen Wind Energy Centre	Southwest	Wind	2014-Q3		Pre-NTP		102
Jericho Wind Energy Centre	Southwest	Wind	2014-Q3		Pre-NTP		150
Gitchi Animki Bezhig Generating Station	Northwest	Water	2014-Q3		NTP		9
Gitchi Animki Niizh Generating Station	Northwest	Water	2014-Q3		NTP		10
Atikokan conversion to biomass	Northwest	Biomass	2014-Q3		Construction		205
White Pines Wind Farm	East	Wind	2014-Q3		Pre-NTP		60
Liskeard 1	Northeast	Solar	2014-Q3		NTP		10
Liskeard 3	Northeast	Solar	2014-Q3		NTP		10
Liskeard 4	Northeast	Solar	2014-Q3		NTP		10
Northland Power Solar Abitibi	Northeast	Solar	2014-Q3		Pre-NTP		10
Northland Power Solar Empire	Northeast	Solar	2014-Q3		Pre-NTP		10
Northland Power Solar Long Lake	Northeast	Solar	2014-Q3		Pre-NTP		10
Northland Power Solar Martin's Meadows	Northeast	Solar	2014-Q3		Pre-NTP		10
Total						**-2,541**	**271**

Notes on Table 4.2:

1. The total may not add up due to rounding. Total does not include in-service facilities.
2. Project status provides an indication of the project progress. The milestones used are:
    a. Connection Assessment - the project is undergoing an IESO system impact assessment
    b. Approvals & Permits - the proponent is acquiring major approvals and permits required to start construction (e.g. environmental assessment, municipal approvals etc.)
    c. Construction - the project is under construction
    d. Commissioning - the project is undergoing commissioning tests with the IESO
    e. Pre-NTP/NTP - Feed-in Tariff (FIT) projects are categorized as Notice to Proceed (NTP) or pre-NTP. OPA issues NTP when the project proponent provides necessary approvals and permits, finance plan, Domestic Content Plan and documentation on impact assessment required by the Transmission System Code or the Distribution System Code.
    f. Commercial Operation – the project has achieved commercial operation under OPA criteria.

4.2 Summary of Scenario Assumptions

In order to assess future resource adequacy, the IESO must make assumptions on the amount of available resources. The Outlook considers two scenarios: a Firm Scenario and a Planned Scenario as compared in Tables 4.3 and 4.4.

Both scenarios' starting point is the existing installed resources shown in Table 4.1. The Planned Scenario assumes that all resources that are scheduled to come into service are available over the study period while the Firm Scenario only assumes those scheduled to come into service over the first three months and generators that have started commissioning. Both scenarios recognize that resources that are in service are not available during times for which the generator has submitted planned outages. Also considered for both scenarios are generator-planned shutdowns or retirements which have high certainty of happening in the future. The Firm and Planned Scenarios also differ in their assumptions regarding the amount of demand measures.

The generation capability assumptions are as follows:

- The hydroelectric capability (including energy and operating reserve) for the duration of this outlook is typically based on median historical values during weekday peak demand hours from May 2002 to March 2013. Adjustments may be made, periodically, when outage or water conditions drive expectations of higher or lower output that varies from median values by more than 500 MW. Manual adjustments to affected months have been made during this outlook period to account for specific scheduled hydroelectric outages and low water conditions.
- Thermal generators' capacity and energy contributions are based on market participant submissions, including planned outages, expected forced outage rates and seasonal deratings.
- For wind generation the monthly Wind Capacity Contribution (WCC) values are used at the time of weekday peak, while annual energy contribution is assumed to be 29% of installed wind capacity. For solar generation, the monthly Solar Capacity Contribution (SCC) values are used at the time of weekday peak. For annual solar energy contribution however, 14% output of installed capacity is assumed. The specifics on wind and solar values can be found in the Methodology to Perform Long Term Assessments.

Table 4.3 Summary of Scenario Assumptions for Resources

<table>
<tr><th></th><th></th><th>Planned Scenario</th><th>Firm Scenario</th></tr>
<tr><td rowspan="3">Over the 18-Month Period</td><td>Total Existing Installed Resource Capacity (MW)</td><td colspan="2">35,899</td></tr>
<tr><td rowspan="2">New Generation and Capacity Changes (MW)</td><td>All Projects</td><td>Generator shutdowns or retirements, Commissioning Generators and Generators starting in the first 3 months</td></tr>
<tr><td>271</td><td>-2,541</td></tr>
</table>

The Firm and Planned Scenarios also differ in their assumptions regarding the amount of demand measures.

Table 4.4 Summary of Scenario Assumptions for Normal Weather Demand

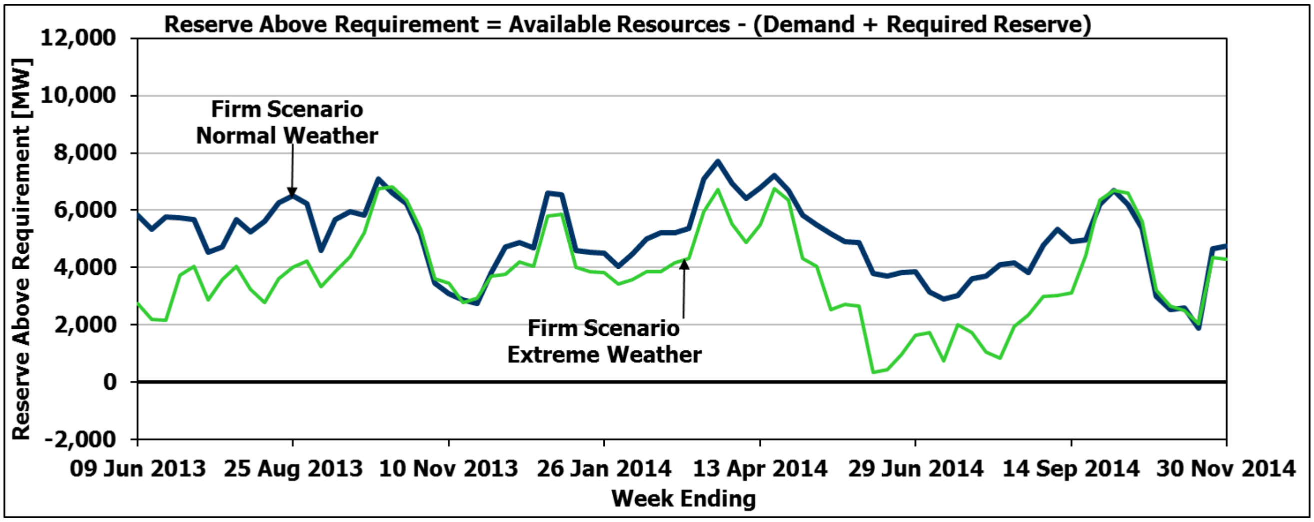
<table>
<tr><th></th><th></th><th>Planned Scenario</th><th>Firm Scenario</th></tr>
<tr><td rowspan="5">2013 Summer Peak vs. 2012 Summer Peak</td><td>Growth in Conservation at Peak (MW)</td><td colspan="2">57</td></tr>
<tr><td>Growth in Embedded Generation Capacity at Peak (MW)</td><td colspan="2">530</td></tr>
<tr><td rowspan="2">Demand Measures Effective Capacity at Peak (MW)</td><td>Exisiting + Incremental</td><td>Existing</td></tr>
<tr><td>549</td><td>549</td></tr>
<tr><td>Ontario Demand at Peak (MW)</td><td colspan="2">23,213</td></tr>
</table>

4.3 Firm Scenario with Normal and Extreme Weather

The firm scenario incorporates capacity coming in service in the first three months of the Outlook period and generation being removed from service during the 18 months. This will include the addition of 420 MW of wind and 40 MW of biomass capacity.

Reserve Above Requirement levels, which represent the difference between Available Resources and Required Resources, are shown in Figure 4.1.

Figure 4.1 Reserve Above Requirement: Firm Scenario with Normal vs. Extreme Weather

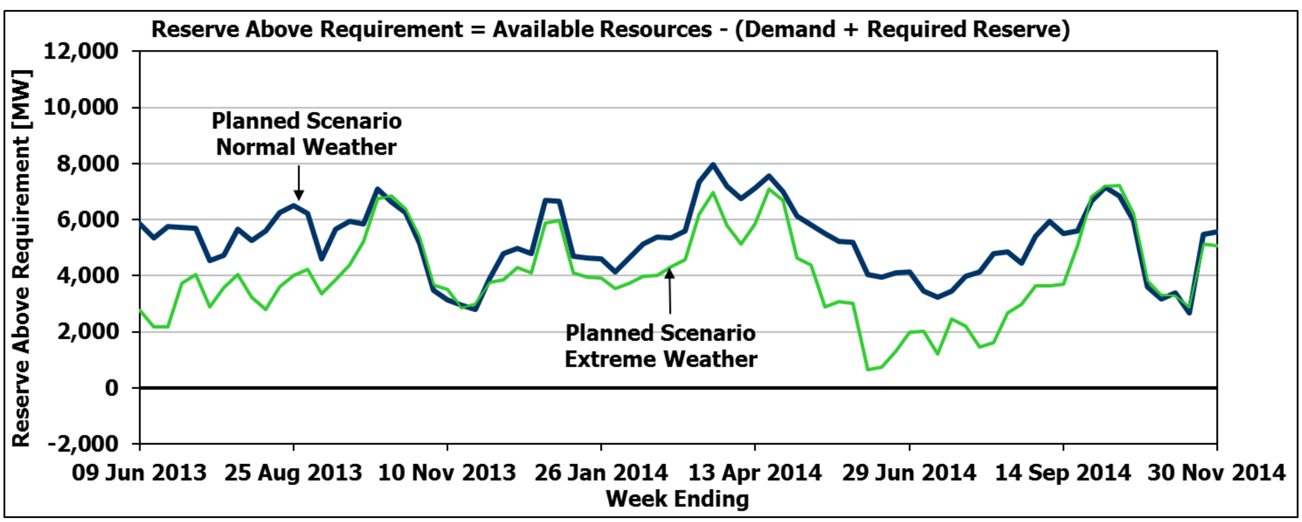


4.4 Planned Scenario with Normal and Extreme Weather

The planned scenario incorporates all capacity coming in service and being removed from service over the Outlook period. This will include the capacity changes in the firm scenario as well as approximately 3,300 MW of grid-connected renewables added to the system. The loss of coal-fired facilities results in a considerable but acceptable reduction in resources.

Reserve Above Requirement levels, which represent the difference between Available Resources and Required Resources, are shown in Figure 4.2.

Figure 4.2 Reserve Above Requirement: Planned Scenario with Normal vs. Extreme Weather



4.5 Comparison of Resource Scenarios

Table 4.5 shows a snapshot of the forecast available resources, under the two scenarios, at the time of the summer and winter peak demands during the Outlook. The monthly forecast of energy production capability, as provided by market participants, is included in the 2013 Q2 Outlook Tables Appendix A, Table A7.

Table 4.5 Summary of Available Resources

Notes	Description	Summer Peak 2013		Winter Peak 2014		Summer Peak 2014	
		Firm Scenario	Planned Scenario	Firm Scenario	Planned Scenario	Firm Scenario	Planned Scenario
1	Installed Resources (MW)	36,359	36,359	33,358	33,368	33,358	35,444
2	Total Reductions in Resources (MW)	5,785	5,785	4,110	4,036	5,369	7,157
3	Demand Measures (MW)	549	549	529	547	549	598
4	Available Resources (MW)	31,122	31,122	29,777	29,878	28,537	28,886

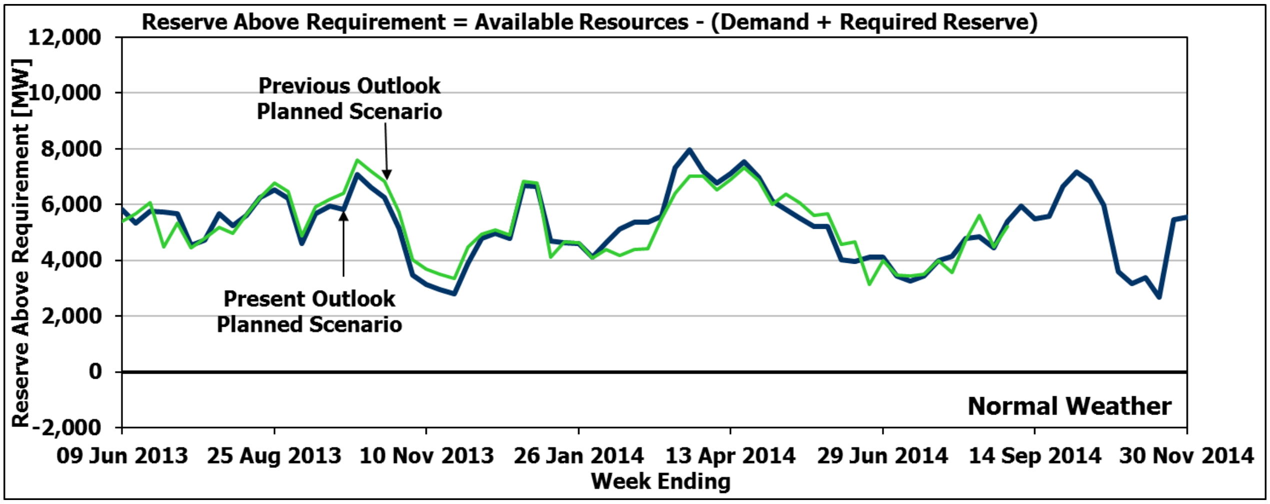
Notes on Table 4.5:

1. Installed Resources: This is the total generation capacity assumed to be installed at the time of the summer and winter peaks.
2. Total Reductions in Resources: Represent the sum of deratings, planned outages, limitations due to transmission constraints, generation constraints due to transmission outages/limitations and allowance for capability levels below rated installed capacity.
3. Demand Measures: The amount of demand available to be reduced.
4. Available Resources: Equals Installed Resources (line 1) minus Total Reductions in Resources (line 2) plus Demand Measures (line 3).

Comparison of the Current and Previous Weekly Adequacy Assessments for the Planned Normal Weather Scenario

Figure 4.3 provides a comparison between the forecast Reserve Above Requirement values in the present Outlook and the forecast Reserve Above Requirement values in the previous Outlook published on February 28, 2013. The difference is mainly due to the changes to outages and changes in the demand forecast.

Figure 4.3 Reserve Above Requirement: Planned Scenario with Present Outlook vs. Previous Outlook



Resource adequacy assumptions and risks are discussed in detail in the "Methodology to Perform Long Term Assessments" (IESO_REP_0266).

- End of Section -

5 Transmission Reliability Assessment

This section provides an assessment of the reliability of the Ontario transmission system for the Outlook period. The transmission reliability assessment has three key objectives:

- Identify all major transmission and load supply projects that are planned for completion during the Outlook period and identify their reliability benefits;
- Forecast any reduction in transmission capacity brought about by specific transmission outages. For a major transmission interface or interconnection, the reduction in transmission capacity due to an outage condition can be expressed as a change in its base flow limit;
- Identify equipment outages that could require contingency planning by market participants and/or by the IESO. Planned transmission outages are reviewed in conjunction with major planned resource outages and the scheduled completion of new generation and transmission projects to identify reliability risks.

5.1 Transmission and Load Supply Projects

The IESO requires transmitters to provide information on the transmission projects that are planned for completion within the 18-month period. Construction of several transmission reinforcements is expected to be completed during this Outlook period. Major transmission and load supply projects planned to be in service are shown in Appendix B. Projects that are already in service or whose completion is planned beyond the period of this Outlook are not shown. The list includes only the transmission projects that represent major modifications or are considered to significantly improve system reliability. Minor transmission equipment replacements or refurbishments are not shown.

Some area loads have experienced modest growth requiring additional investments in new load supply stations and reinforcements of local area transmission. Several local area supply improvement projects are underway and will be placed in service during the timeframe of this Outlook. These projects help relieve loadings on existing transmission infrastructure and provide additional supply capacity for future load growth.

5.2 Transmission Outages

The IESO's assessment of the transmission outage plans is shown in Appendix C, Tables C1 to C10. The methodology used to assess the transmission outage plans is described in the IESO document titled "Methodology to Perform Long Term Assessments" (IESO_REP_0266).

This Outlook contains transmission outage plans submitted to the IESO as of April 9, 2013.

5.3 Transmission System Adequacy

The IESO assesses transmission adequacy using the methodology described in IESO_REP_0266 on the basis of conformance to established criteria, planned system enhancements and known transmission outages. Zonal assessments are presented in the following sections. Overall, the Ontario transmission system is expected to supply the demand under the normal weather conditions forecast for the Outlook period.

As a result of localized load increases, several areas in the province have been identified as having limited capability of existing transmission infrastructure to meet the IESO's load restoration criteria following a permanent transmission outage. The IESO, OPA and Hydro One are considering long-term options to address these situations under the Regional Planning Process established by the OEB.

5.3.1 Toronto and Surrounding Area

The Greater Toronto Area (GTA) electricity supply is expected to be adequate to meet the normal weather-forecasted demand. Hydro One is working to change the configuration of the 230 kV switchyard at Manby TS by the end of the second quarter in 2014. This transmission enhancement solution will help manage the long-term load supply in the southwestern GTA. For the short term, day-to-day operating procedures are available to manage the forecasted transmission loading during periods of high demand.

Clarington TS is scheduled to be in service as soon as spring 2015. This new station will increase the 500 to 230 kV autotransformer capacity in the eastern part of the GTA. This increased capacity will be required in advance of the shutdown of Pickering NGS, to maintain a reliable supply to the loads in the Pickering, Ajax, Whitby, Oshawa and Clarington areas.

These loads are currently supplied from four very long 230kV circuits that extend from Cherrywood TS through to eastern Ontario. Since there is only a very limited capability to supply these loads from the remote eastern terminal stations of these circuits, restoration of the supply is not expected to be possible within the times specified in the IESO's criteria. These circuits are planned to be connected into Clarington TS and once in service, it will able to provide a full, alternative source of supply to these loads and significantly reduce restoration times.

Hydro One is continuing with the work of replacing 115 kV breakers at Hearn TS, Manby TS and Leaside TS. The new equipment is expected to be in service by the end of 2014 and will allow for more flexibility during day-to-day operation.

High voltages in southern Ontario are being experienced more frequently during periods of light load. High voltages become more acute during these periods if shunt reactors are also unavailable due to either repair or maintenance activities. The IESO is working with Hydro One and the OPA to develop options for managing this situation.

Transmission transfer capability in Toronto and its vicinity is expected to be sufficient to supply load in this area with a margin to allow for planned outages.

5.3.2 Bruce and Southwest Zones

In the Guelph area, the existing 115 kV transmission facilities are operating close to capacity and have limited margin to accommodate additional load. To improve the transmission capability into the Guelph area, Hydro One will be proceeding with the Guelph Area Transmission Refurbishment project to reinforce the supply into Guelph-Cedar TS, with an expected completion date in the second quarter of 2016. As part of this project two in-line breakers will be installed at Inverhaugh SS that will allow the 230 kV system between Detweiler TS and

Orangeville TS to be sectionalized. This will improve the restoration capability and reduce restoration times to the loads in the Waterloo, Guelph and Fergus areas.

The capability to restore loads in the Cambridge area remains very limited and does not satisfy the IESO's criteria. The OPA is working on longer-term solutions to fully address compliance with the restoration criteria for this area. A second 230/115 kV autotransformer to be installed at Preston TS, is an option that is being considered in order to improve the capability of existing transmission infrastructure in the Cambridge area to meet the IESO's load restoration criteria following a contingency. Longer-term solutions to fully address compliance with restoration criteria are being developed.

Two new 500kV switching stations, Evergreen and Ashfield, are planned to be in service by the end of 2014, to accommodate 384 MW and 270 MW of wind generation respectively.

Transmission transfer capability in the Southwest zone and its vicinity is expected to be sufficient to supply load in this area with a margin to allow for planned outages.

5.3.3 Niagara Zone

The completion date for transmission reinforcements from the Niagara region into the Hamilton-Burlington area continues to be delayed. Completion of this project will increase the transfer capability from the Niagara region to the rest of the Ontario system. Until the project is in service, the supply needs in Southern Ontario will continue to be met through the existing system.

Hydro One is working to replace existing 115 kV breakers at Allanburg TS. The new equipment is expected to be in service by the end of the third quarter of 2014 and will allow for the incorporation of additional generation in the area.

Transmission transfer capability in Niagara and its vicinity is expected to be sufficient to supply load in this area with a margin to allow for planned outages.

5.3.4 East Zone and Ottawa Zone

Hydro One is working to replace existing 115 kV breakers at Hawthorne TS. The new equipment is expected to be in service by the end of the second quarter of 2014 and will improve the reliability of the 115 kV system supplying the Ottawa area, while enabling the incorporation of generation in the Ottawa area. A new load supply transformer station, Terry Fox TS is expected to be in service by the end of 2013 to address load growth in the area.

Transmission transfer capability in the East and Ottawa zones is expected to be sufficient to supply load in this area with a margin to allow for planned outages.

5.3.5 West Zone

Transmission constraints in this zone may restrict resources in southwestern Ontario. This is evident in the constrained generation amounts shown for the Bruce and West zones in Tables A3 and A6.

Hydro One is planning to uprate two 230 kV circuits from Lambton TS to Longwood TS. This is expected to be in service by the end of 2014 and will increase the transfer capability into the London area.

Transmission transfer capability in the West zone is expected to be sufficient to supply load in this area with a margin to allow for planned outages.

5.3.6 Northeast and Northwest Zones

Hydro One is expected to finish transmission work related to the Lower Mattagami generation expansion project by the end of the second quarter of 2013.

Managing grid voltages in the Northwest has always required special attention. With significantly lower demand in the past few years, it has become increasingly difficult to maintain an acceptable voltage profile without compromising the reliability of supply, in particular during times of low northeast-northwest transfers.

There were occasions in the Northwest area when normal dispatch actions have been exhausted, and exceptional voltage control measures, including the temporary removal of one or more transmission circuits from service, were implemented to maintain grid voltages within acceptable ranges. These operational measures reduced the grid’s ability to withstand disturbances and impacted customers’ supply reliability.

To reduce and eventually eliminate the dependence on the operational measures described above, additional reactive compensation is required for voltage control in this zone. Hydro One is working on the installation of new shunt reactors at Marathon by the end of 2013 and new shunt reactors at Dryden by the end of 2014 in an effort to resolve this problem.

Some loads in the north of Dryden to Pickle Lake area experienced significant growth over the last few years and recently indicated their intention to expand operations. The transmission circuits in the area are currently operating close to their capability and the IESO, OPA, Hydro One, local distributors, customers and First Nations are developing a regional planning study that will account for elements of the Ontario Long-Term Energy Plan and recent expansion plans of customers in the area.

The IESO is also working with Hydro One and OPG to accommodate the Atikokan conversion from coal to biomass project currently underway. Work includes completion of planned maintenance on other critical equipment to support the outage, and ensuring plans to manage high voltage situations are sufficient to cover the duration of the Atikokan outage.

Reduced load in the Northeast has resulted in voltages in the Timmins area that are higher than normally permitted. To help reduce the increasing dependence on the generating facilities in the Northeast to maintain voltages, Hydro One is allowing selected portions of the transmission system to operate at higher voltage levels.

Transmission transfer capability in the Northeast and Northwest zones is expected to be sufficient to supply load in this area with a margin to allow for planned outages.

- End of Section

6 Operability Assessment

This section highlights any existing or emerging operability issues that could potentially impact system reliability of Ontario's power system.

Over the next 18 months, Ontario continues to expand its renewable resource capacity. During the next 18 months, approximately 3,300 MW of wind, solar and biomass capacity are expected be connected to the transmission grid. By November 2014, the total wind and solar generation connected both to the transmission and distribution networks in Ontario are expected to exceed 6,800 MW.

Solar generation – which up until now has only been embedded within distribution networks – will soon include nine new projects connected to the transmission grid, amounting to a total capacity of 180 MW. This capacity will complement the anticipated 1,700 MW of embedded solar capacity that will be in service during the outlook period.

A number of the operational changes are needed to support these levels of new supply. IESO's Renewable Integration Initiative (RII) continues to move forward towards completion and will address three key elements – forecast, visibility and dispatch of renewable resources. RII initiatives have already yielded results, including the integration of the hourly centralized forecast into the IESO scheduling tools, enhanced visibility of renewable operations within the IESO Control Room which will provide greater levels of visibility and awareness of system conditions.

The dispatch of grid-connected renewable resources is planned to be in place within the forecast period. This initiative will provide the system operator with increased flexibility from available variable generation resources, contribute to increased reliability, and will allow the IESO to operate the system more efficiently.

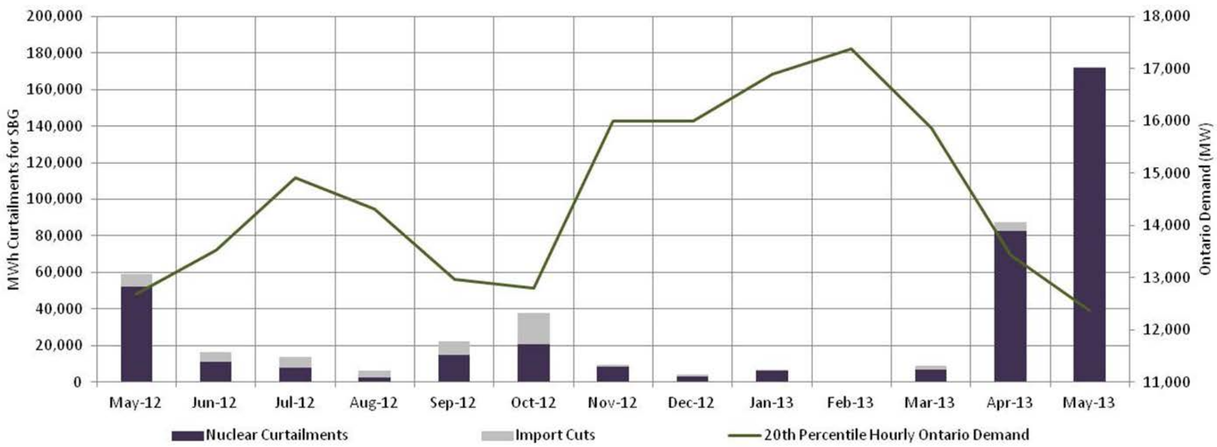
6.1 Surplus Baseload Generarion (SBG)

Baseload generation is made up of nuclear, run of the river hydroelectric and variable generation such as wind. SBG conditions occur when the amount of baseload generation exceeds Ontario demand and is typically mitigated through exports. However, when the baseload fleet is expected to top Ontario demand plus scheduled exports, nuclear curtailments and managing exports are often needed to eliminate the excess. When variable generation becomes dispatchable, additional flexibility will be available to diminish the frequency of out of market control actions for SBG. These actions usually occur in the spring and fall, when the Ontario demand is lowest, and seldom occurs in extreme heat or extreme cold conditions when air conditioning or heating keeps the demand high. The correlation between Ontario demand and surplus baseload curtailments is negative, that is, when Ontario demand is low, curtailments for SBG are typically high.

Figure 6.1.1 shows the volume of nuclear and import curtailments due to surplus baseload conditions versus the bottom 20% hourly Ontario demand up till May 15, 2013. The amount of nuclear and import curtailments for SBG in Q1 of 2013 was lower than Q1 of 2012 by 6 GWh.

However, there have been three nuclear shutdowns in 2013 year to date due to SBG events as opposed to one shutdown in 2012. The total loss in nuclear energy due to SBG as of May 15, 2013 is 310 GWh compared to 106 GWh for the same timeframe in 2012.

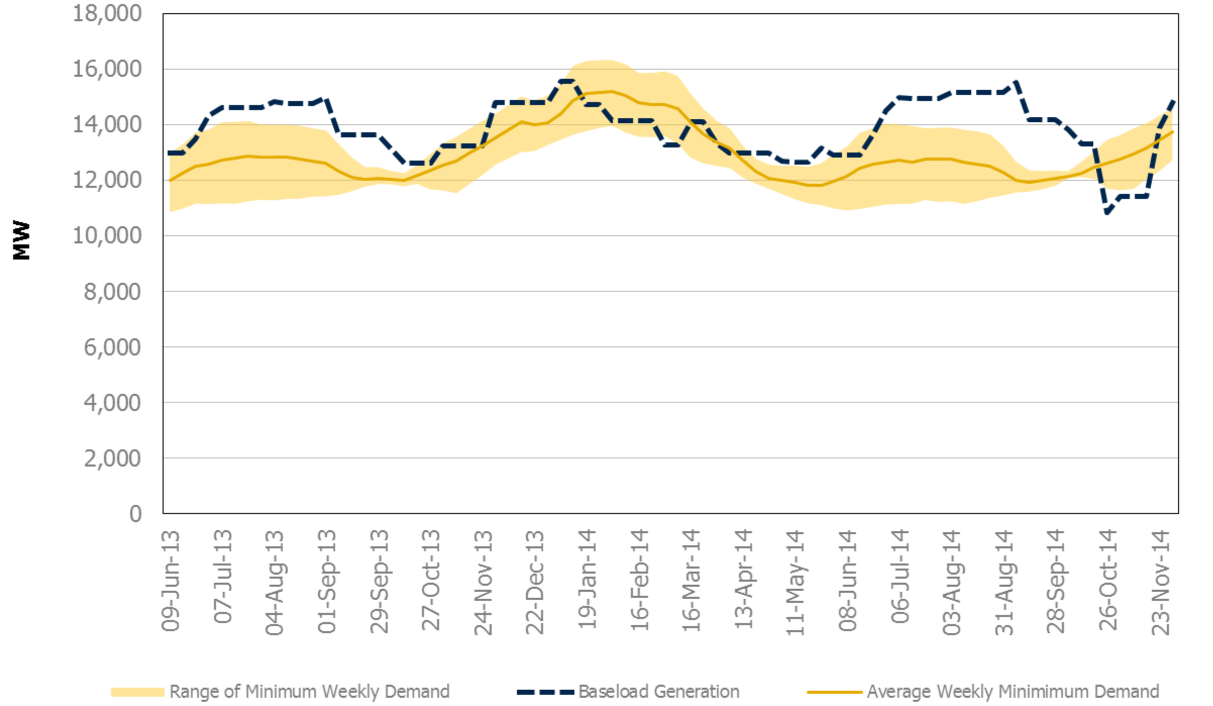
Figure 6.1.1 MWh Curtailments for SBG versus Ontario Demand



There were no significant changes in transmission or generation that would result in significant variations. The main variation between winter 2013 and winter 2012 is the increase in our baseload generation number. 2013 saw two additional nuclear facilities commissioned into service.

The expected SBG for the next 18 months can be seen in Figure 6.1.2. The baseload generation assumptions include market participant-submitted minimum production data, the latest planned outage information, projected forced outage rates, in-service dates for new or refurbished generation, and reliable export capability. The expected contribution from self-scheduling and intermittent generation has also been updated to reflect the latest data. Output from commissioning units is explicitly excluded from this analysis due to uncertainty and the highly variable nature of commissioning schedules.

Figure 6.1.2 Minimum Ontario Demand and Baseload Generation (includes Net Export assumption)



Ontario will continue to experience an increase in volume, frequency and duration of SBG conditions with declining wholesale demand for electricity and significant quantities of baseload generation on the system. A vast majority of SBG is being managed via IESO tools and processes such as nuclear maneuvering and managing exports. The IESO will gain another tool to help manage SBG in September 2013 as wind becomes a dispatchable resource, and helps to maintain operational efficiency.

- End of Section

7 Historical Review

This section provides a review of past power system operation, including the most recent months of operation, to identify noteworthy observations, emerging problems and variations from forecast.

7.1 Weather and Demand Historic Review

Since the last Ontario Demand Forecast document was published, actual demand and weather data have been reported for the six months of November through April.

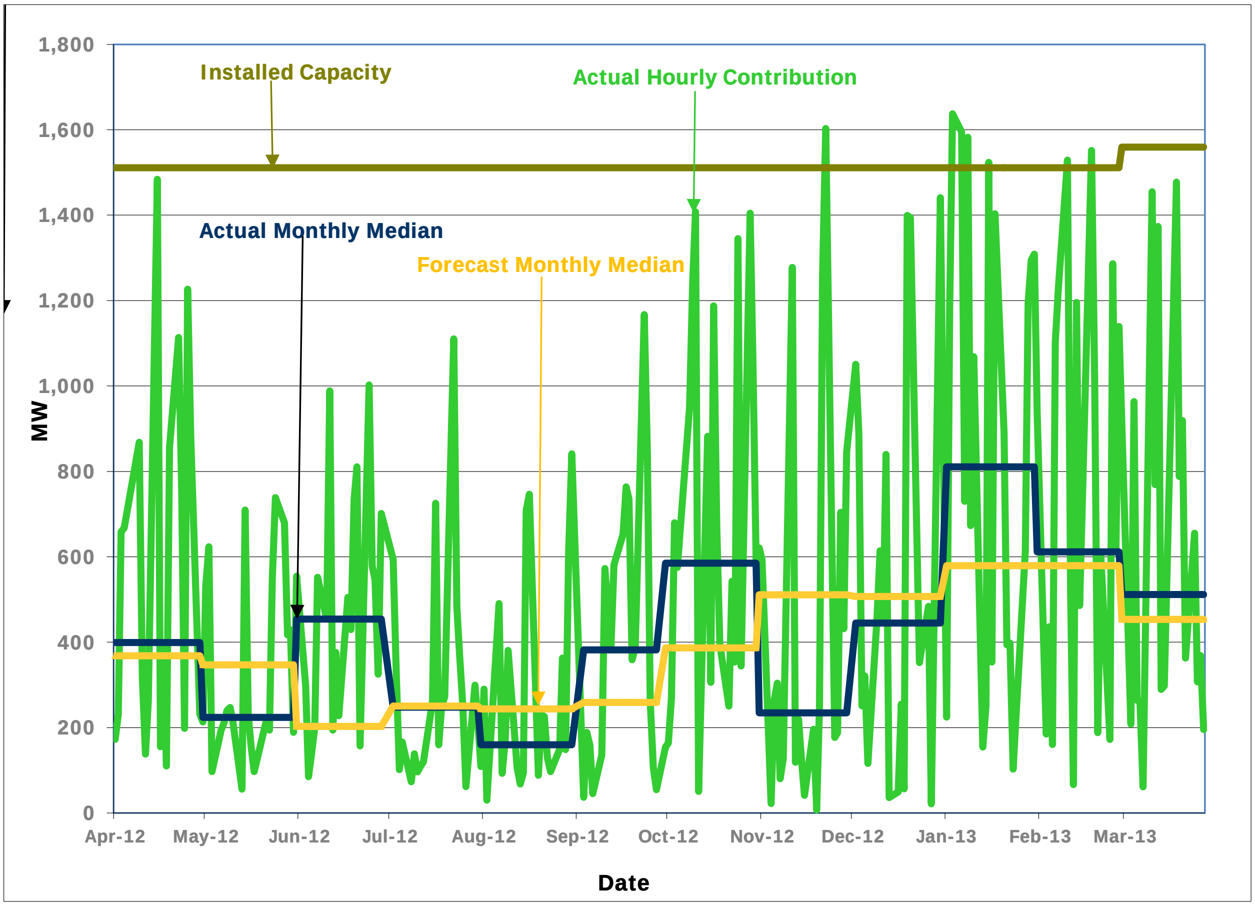
Overall, energy demand for the six months was up a robust 2.3% compared to the same months a year earlier. After adjusting for the leap year affects, demand would have been up by 3.2% over the same six month period a year earlier. However, the weather had much to do with the growth. After adjusting for weather the growth rate was a much lower 0.3% decline and 0.6% growth after the leap year adjustment. Still, demand has shown some strength heading into 2013. The growth has not been consistent fluctuating month to month.

7.2 Hourly Resource Contributions at Time of Weekday Peak

The figures from 7.2.1 to 7.2.4 show the contributions made by wind generators, hydro generators, imports, and net interchange into Ontario at the time of weekday peak. The period analyzed is from April 2012 to March 2013. Holiday and weekend data were not considered in the analysis since hydro peaking generation and interchange transactions during this timeframe are not typical of time periods when Ontario's supply adequacy may be challenged.

Figure 7.2.1 indicates the amount of wind contribution to the wholesale market at the time of weekday peak, compared to the forecast values. The forecast methodology takes into account seasonal variances in wind patterns, among other factors. Installed wind capacity is expected to continue to grow with wind generation procured under the FIT programs.

Figure 7.2.1 Wind Contributions at the Time of Weekday Peak



Note: Commercially operable capacity does not include commissioning units. Therefore actual hourly contribution may exceed commercial capability.

Figure 7.2.2 indicates the amount of hydroelectric contributions to energy and operating reserve markets at the time of weekday peak, excluding weekends and holidays, compared to the forecasted contributions. The forecasted monthly is typically the median contribution of hydroelectric energy at the time of weekday peak since 2002. However, if low water persists, the forecast is adjusted accordingly to reflect the observed trend. The hydroelectric production at the hour of weekday peak summer months were lower than forecasted. The lower summer values are due to a decrease in precipitation levels from previous years and project related outages scheduled for hydroelectric generating stations. As in previous reports, we expect the impact of these outages to continue at varying degrees over the next 18 months. We have made adjustments to the forecast in this Outlook to account for these outages.

Figure 7.2.2 Hydro Contributions (Energy and Operating Reserve) at the Time of Weekday Peak

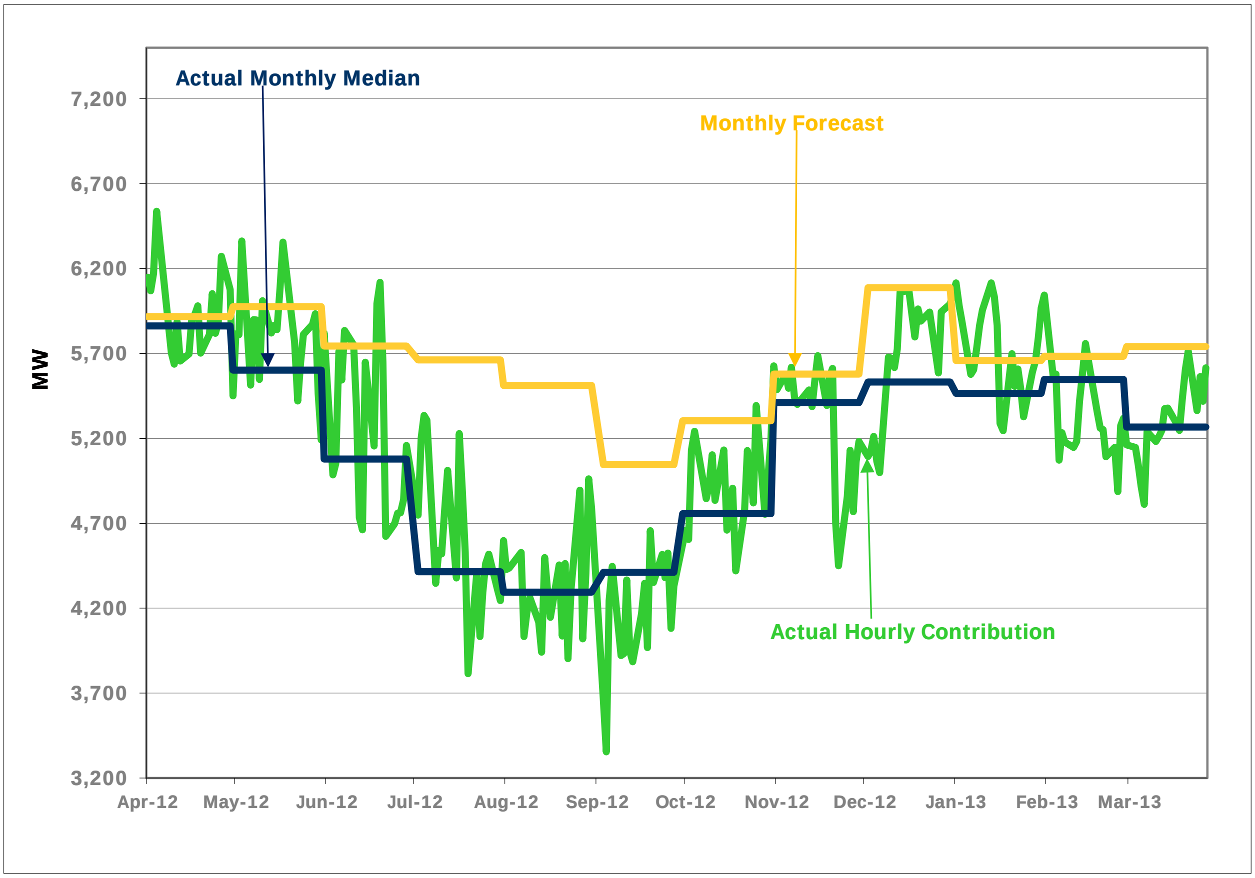


Figure 7.2.3 shows imports into Ontario at the time of weekday peak. Summer 2012 imports were noticeably higher than the rest of the reporting period. The extremely high temperatures in July and August contributed to high demands, high prices and consequently an increase in imports. In contrast, the mild fall of 2012 contributed to low demand and an increase in our baseload nuclear fleet in the early winter of 2013 contributed to low prices and therefore lower imports.

Figure 7.2.3 Imports into Ontario at the Time of Weekday Peak

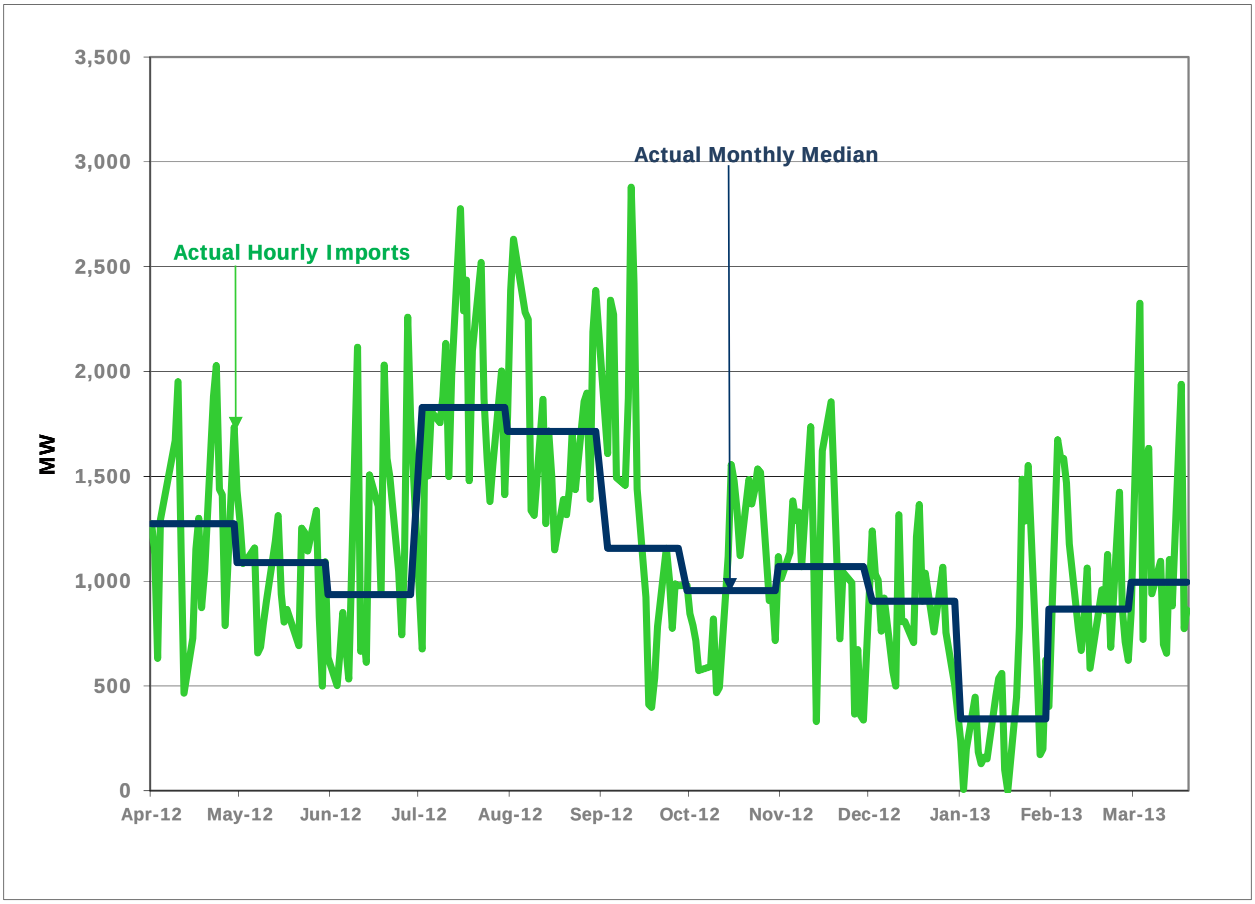
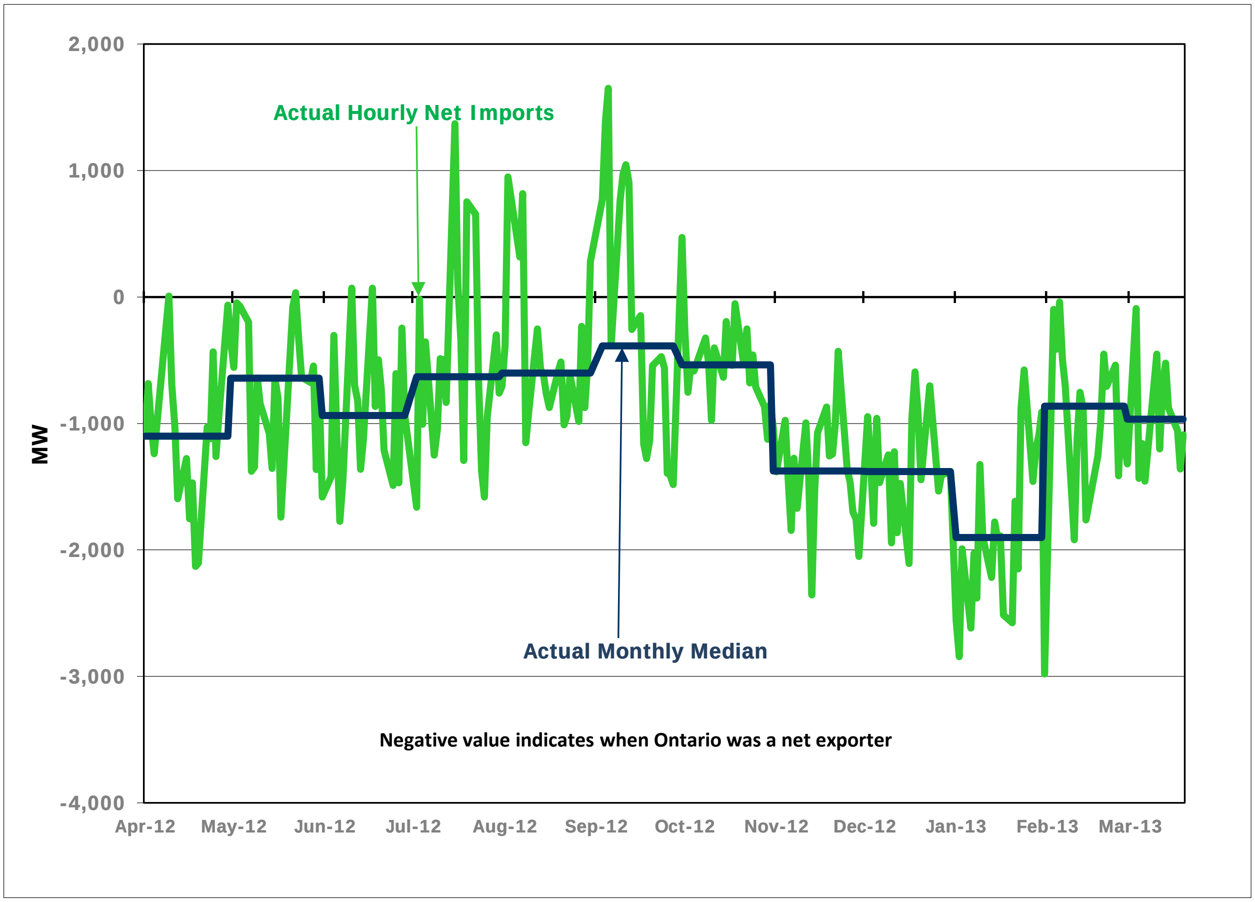


Figure 7.2.4 shows the amount of net interchange at the time of weekday peak, excluding weekends and holidays. Net Interchange is the difference between total imports into Ontario and total exports out of Ontario. An average net export situation prevailed, which can be in part attributed to the continued export capability with Quebec. Additionally, surplus baseload generation conditions caused by ample generation and lower demands further contributed to Ontario being a net exporter for most of the reporting period.

Figure 7.2.4 Net Interchange into Ontario at the Time of Weekday Peak



7.3 Report on Initiatives

Centralized forecasting for variable resources is an initiative which provides better forecasting of energy production in order to ensure that more accurate unit commitment and intertie scheduling occurs. A centralized forecast was implemented and integrated into IESO day-ahead and hourly scheduling processes in November 2012. Forecasting for embedded variable resources will be developed by Q3 2013. Additionally, RII will facilitate the dispatching of variable generation, with implementation set for September 2013.

Variable generation dispatch will allow for greater flexibility and help alleviate surplus baseload generation concerns.

- End of Document -

Appendix 4:

18-Month Outlook

From January 2006 to June 2007

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18-MONTH OUTLOOK:

An Assessment of the Reliability of the Ontario Electricity System

From January 2006 to June 2007

ieso
Power to Ontario. On Demand.

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Executive Summary

Recent additions to Ontario's generating capacity and planned market enhancements in the first half of 2006 contribute to a more positive outlook for Ontario's overall supply adequacy picture over the next 18 months. The overall Outlook for resource availability continues to indicate that for most weeks during the 18-Month Outlook timeframe, there are sufficient resources to meet the present resource requirements, under the normal weather demand scenario. Under extreme weather conditions, the Outlook results continue to identify significant reliance on imports in many weeks, to meet resource requirements.

While the overall supply situation appears adequate concerns remain in a number of areas within Ontario, particularly in the Greater Toronto Area (GTA) where the need for new supply and transmission facilities is particularly urgent. It is also critical that more efficient regulatory approvals processes be developed in order to enable timely implementation of the required new generation and transmission facilities.

The Independent Electricity System Operator (IESO) regularly assesses the adequacy and reliability of Ontario's power system. This 18-month Outlook provides our assessment of the reliability of the Ontario electricity system from January 2006 to June 2007. The assessment uses the most up to date forecast information and considers experience gained from past operations.

A number of changes are forecast for the Ontario electricity sector to address the risks in the GTA and to implement the provincial government's plan for coal replacement and a transition to cleaner forms of generation. The IESO is monitoring the progress of the inter-related generation, transmission and demand management projects underway and planned and the resulting impact on reliability.

Experience Gained from Past Operations

There were a number of challenges to maintain reliability of Ontario's bulk power system during the summer of 2005. Soaring temperatures brought significant demand and drought-like conditions limited hydroelectric generation, resulting in a continued strain on the power system. The IESO relied on extensive use of Emergency Control Actions in order to maintain reliability and avoid power interruptions. Public appeals urging customers to cut back on electricity consumption were issued on 12 separate days, five per cent voltage reductions were implemented across the province on two days in August with two additional voltage reductions implemented in the GTA. This occurred despite good performance and availability of the Ontario generation and transmission facilities and the support from neighbouring markets.

Increased supply brought into service in the fourth quarter of 2005 (515 megawatts from Pickering Unit 1), as well as changes proposed by the IESO to put imports into Ontario on a more secure footing during times of need, should improve the supply-demand situation and help reduce the likelihood of a repeat of the events of the past summer.

A Reliability Demand Response Program similar to those of neighbouring markets is being developed for the summer of 2006 to give more certainty that an IESO request for demand response will be followed and to allow for activation earlier in the list of control actions.

To increase the certainty of capacity and energy availability through day-ahead arrangements, the IESO is working with stakeholders to implement a Day Ahead Commitment Process for the summer of 2006.

In the western GTA, and in central Toronto, transformer load levels were near, and in some cases exceeded their capability in summer 2005. The need for transmission enhancements and new supply to unload these transformers continues to be a priority requirement for the IESO.

Outside the GTA, the transmission system is expected to be adequate to supply demand under the forecast conditions studied in this Outlook, with some exceptions. Limitations experienced over the summer of 2005 in the Windsor area, northward into the Hamilton-Burlington area, and westward from the St. Lawrence transformer station limited the use of available Ontario generation and/or limited imports into the province during hot weather, high-demand periods. Changes and upgrades are underway, and will improve but not completely relieve the situation for summer 2006.

Other Concerns

There are a number of growing reliability risks that need to be addressed during this assessment period in order to have timely solutions available.

Toronto currently relies on supply generated outside the city to meet demand. The main transmission paths and related facilities carrying this power into the city are already nearing capacity.

New generation must be installed by the summer of 2008 to address the risk of rotating power cuts to areas of central Toronto during periods of high demand. Increased demand response and conservation efforts will reduce but not eliminate the need for new supply. The IESO is working with the Ontario Power Authority to address the need for new supply in Toronto. But in the absence of a viable, approved plan, timely resolution is at risk. The IESO will continue to work with stakeholders to assess the needs and develop options.

Even with new generation installed by 2008, the risk will again grow to unacceptable levels without new transmission, requiring a third transmission path into Toronto early in the next decade to maintain reliability under extremely hot summer weather conditions.

New supply and transmission is also required in the western GTA to address overloading of transmission facilities supplying the GTA, to meet the forecast growth in demand and to control voltages in the area.

The recently announced Goreway natural gas units in Brampton will substantially reduce the reliability risks in the area but not completely remove them. Transmission facilities and lines serving the area exceeded their long-term emergency capability and the IESO's supply deliverability guidelines in summer 2005. A combination of new generation and transmission enhancements are required to address this. Necessary transmission solutions under discussion are likely to be required to provide time for the development of additional supply projects.

More Efficient Regulatory Processes Required

The current regulatory approvals process is complex and will impede the installation of new facilities in time to address projected reliability concerns. Given the amount of new supply and transmission enhancements required in such a short period of time, timely regulatory approvals processes are required. Serious consideration needs to be given to developing expedited, but thorough, approvals processes to ensure timely implementation of the new facilities.

Demand

Energy demand is expected to be 157.0 terawatt hours (TWh) for 2006, a 1.3 per cent increase over the projected energy demand for 2005 (154.9 TWh). The expected seasonal peak demand for the winter of 2006 is 24,899 MW. The expected seasonal peak for the summer 2006 is forecast to be 25,917 MW.

The following table shows the peak demand forecasts for the seasons covered in the Outlook period.

Season	Normal Weather Peak (MW)	Expected Seasonal Peak (MW)	Extreme Weather Peak (MW)
Winter 2006	24,285	24,899	25,802
Summer 2006	24,232	25,917	27,407
Winter 2007	24,547	25,161	26,088

While extreme weather conditions have a lower probability of occurring, history shows that even seasons with average weather will include periods of extreme weather Prudent planning dictates that the system be capable of operating reliably during extreme weather periods without significant use of emergency control actions.

- End of Section -

Caution and Disclaimer

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1.0 Introduction

This Outlook covers the 18 month period from January 1, 2006 to June 30, 2007. It supersedes the report titled "An Assessment of the Reliability of the Ontario Electricity System from October 2005 to March 2006", dated October 24, 2005. Its purpose is to advise market participants of the resource and transmission reliability of the Ontario electricity system, and to assess potentially adverse conditions that might be avoided through adjustment or coordination of maintenance plans for generation and transmission equipment.

This Outlook presents an assessment of resource and transmission adequacy based on the stated assumptions, and using the described methodology. Readers may envision other possible scenarios, recognizing the uncertainties associated with various input assumptions, and are encouraged to use their own judgement in considering possible future scenarios. This Outlook provides a base upon which updates in assumptions can be considered. The tables contained in the document can be downloaded from the Independent Electricity System Operator (IESO) web site in MS Excel format.

In addition to the comprehensive Outlook, the IESO generally publishes Interim Updates to the 18-Month Outlook during each month for which a full Outlook is not issued. These updates include a spreadsheet which reflects changes to Total Resources, Total Reductions to Resources, and Reserve Above Requirement values for the Planned Resource Scenario. The updates also include a summary of actual demand and forecast demand data. Similar to the full Outlooks, the Interim Updates are posted on the IESO web site. These updates provide Outlook information on a more frequent basis to allow market participants to better adjust their operational plans and outage schedules.

The reader should be aware that Security and Adequacy Assessments are published on the IESO web site on a weekly and daily basis that progressively supersede information presented in this report.

The contents of this Outlook focus on the assessment of resource and transmission adequacy. Other supporting information and forecasts are contained in separate documents. These documents will be updated as required.

- The document entitled "Ontario Demand Forecast from January 1, 2006 to June 30, 2007" (IESO_REP_0254) (found on the IESO web site at http://www.ieso.ca/imoweb/pubs/marketReports/18Month_ODF_2005dec.pdf describes in detail the 18 month forecast of electricity demand for the Ontario Market used in this Outlook. The demand forecast document identifies the assumptions used to determine the forecast and identifies the details regarding peak and energy demand forecasts for the Ontario market and parts thereof. It also contains information regarding variations in demand due to weather, economic growth and calendar day types. Data from the demand forecast document can be downloaded in MS Excel format from the IESO web site.
- The document entitled "Methodology to Perform Long Term Assessments" (IESO_REP_0266) (found on the IESO web site at http://www.ieso.ca/imoweb/pubs/marketReports/Methodology_RTAA_2005dec.pdf) contains information regarding the methodology used to perform the demand forecasts, resource adequacy assessments and transmission reliability assessments in this Outlook.

- The document entitled "Ontario Transmission System" (IESO_REP_0265) (found on the IESO web site at www.ieso.ca/imoweb/pubs/marketReports/OntTxSystem_2005jun.pdf) provides specific details on the transmission system, including the major internal transmission interfaces and interconnections with neighbouring jurisdictions.

Readers are invited to provide comments on this Outlook report or to give suggestions as to the content of future reports. To do so, please contact us at:

- Toll Free: 1-888-448-7777
- Tel: 905-403-6900
- Fax: 905-403-6921
- E-mail: customer.relations@ieso.ca.

- End of Section -

2.0 Changes from Previous Outlook

Updates to Resources

One of the three shutdown Pickering A nuclear units was returned to service in the fourth quarter of 2005 which resulted in a capacity increase of 515 MW. The Greater Toronto Airports Authority's new 117 megawatt co-generation power plant at Pearson International Airport is being commissioned and is scheduled for commercial operation in the first quarter of 2006. This new generator is not considered to be part of the Existing Installed Generation Resources shown in Table 5.1.

One of the 10 new projects announced in November 2004 from the Request for Proposals for Renewable generation is already in-service. Seven more generation projects with the installed capacity of about 360 MW are expected to be available within the 18 month timeframe of this Outlook.

There are changes to the scheduled dates and the capacity increases to nuclear unit upratings that are scheduled to occur in the 18 month timeframe. A total of 32 MW is now expected within the next 18 months.

The Existing Resource Scenario includes a higher quantity of forecast price-responsive demand than the previous Outlook. However, the price-responsive demand reduces by 30 MW from April 2007 when the Transitional Demand Response Program (TDRP) is scheduled to end. In the Planned Resource Scenario, the price-responsive demand is forecast to reach about 430 MW by end of March 2007 and then drops to about 400 MW thereafter. This capability to reduce demand, based on dispatch signals sent from the IESO, represents an additional resource that may be deployed to maintain the balance between supply and demand.

There have been updates to the generator outages submitted by market participants.

Updates to Transmission Outlook

The list of transmission projects and planned and forced transmission outages has been updated from the previous 18-Month Outlook.

This outlook also presents a discussion of some of the transmission enhancements that are forecast to be required within the outlook period and just beyond.

- **End of Section –**

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3.0 Historic Review and Preparations for Future Operation

This section provides a review of past power systems operations, including the most recent months of operation, to identify noteworthy observations, emerging problems and variations from forecast.

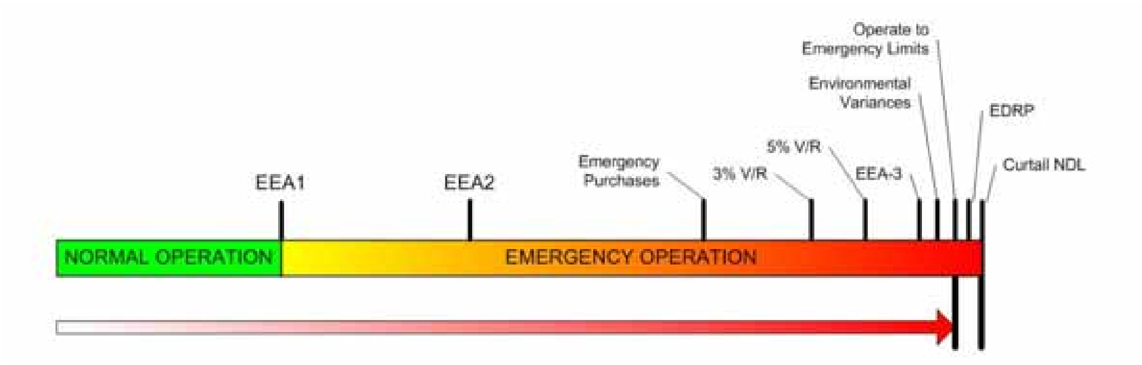
3.1 Emergency Control Actions

When the IESO runs out of market mechanisms to maintain the supply/demand balance, it turns to one or more of the following emergency control actions to maintain reliability. The control actions are listed in the order they are applied and represent actions with increasing impact on customers, the environment and risk to interconnected system reliability.

Emergency Control Actions
- public appeals
- emergency power purchases
- voltage reductions
- environmental variances
- operation of transmission to emergency condition limits
- activation of the Emergency Demand Response Program (EDRP)
- load shedding (also referred to as curtailing Non-Dispatchable Load (NDL))

Figure 3.1 illustrates the typical steps that IESO may take to maintain the supply/demand balance in Ontario. The figure also indicates the timing of several Energy Emergency Alerts (EEA1, EEA2 and EEA3) which provide notification to Ontario's neighbours to make them aware of the status of reliability in Ontario.

Figure 3.1 Emergency Control Actions

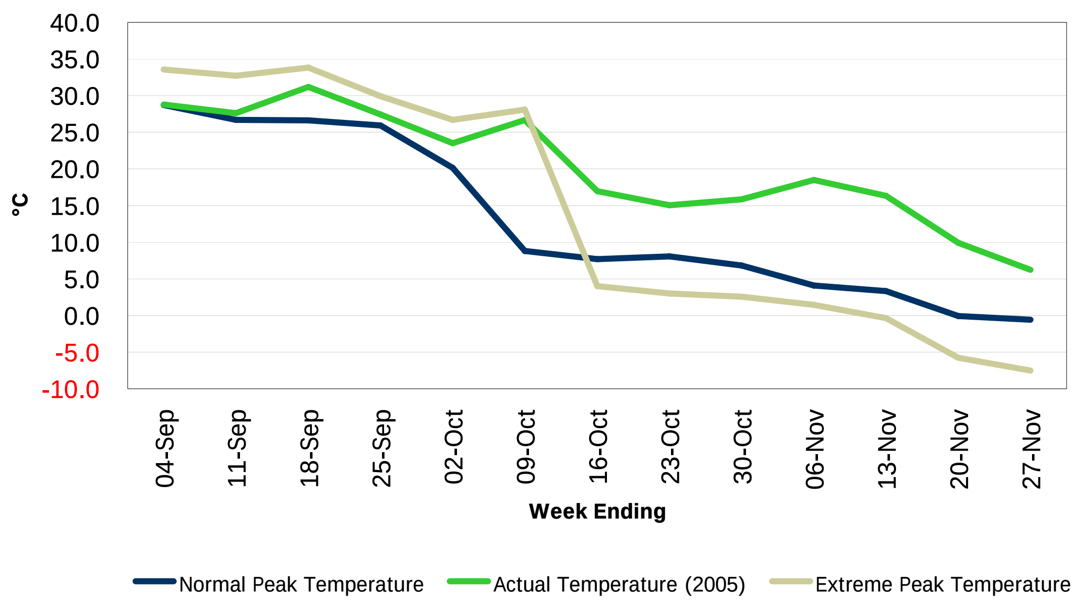


Use of these control actions was a very frequent occurrence this past summer. When emergency control actions must be initiated there is almost no room left to manoeuvre and the impact on customers, the environment and additional risk to interconnected system operation can escalate rapidly. The repeated use of these emergency actions this past summer represented a sustained challenge to Ontario's reliability.

3.2 Weather and Demand Historical Review

The actual weather for September to November 2005 was consistently warmer than Normal. The daily high (temperature) for September, October and November averaged just less than 15 °C, the 3rd warmest average for these months since 1970. Figure 3.2 compares the weekly temperatures from 2005 with the Normal and Extreme weather scenarios. The graph depicts the peak temperature for each week of the period. It is clear that it was warm – particularly in the latter half.

Figure 3.2 Weather Impact – 2005 Actuals Versus Normal and Extreme Weather



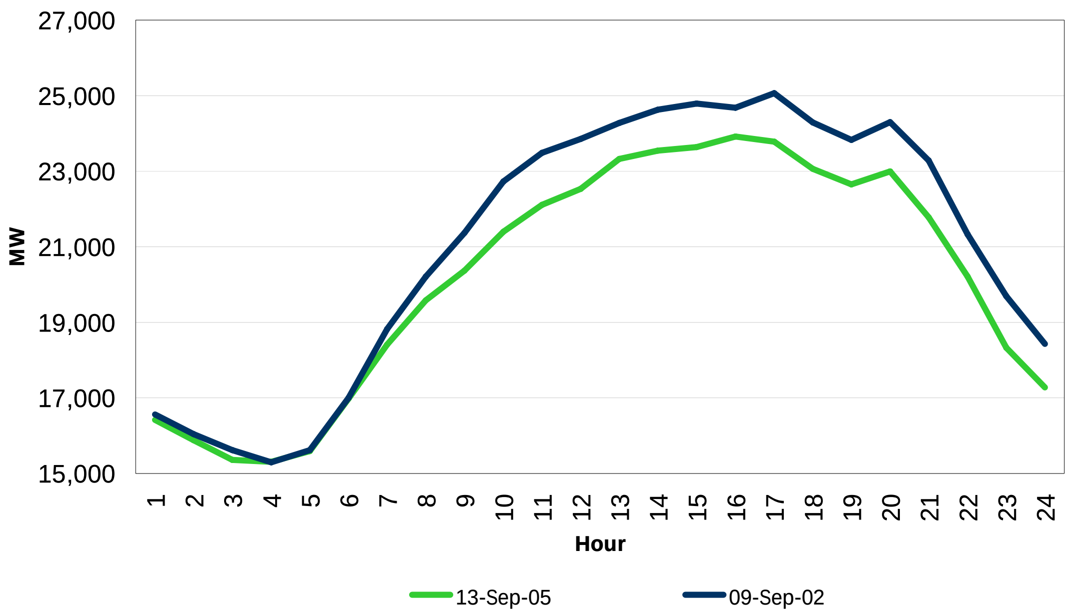
September is a "cooling load" month, while October and November are "heating load" months. With higher than average temperatures, demand was higher in September and lower in October and November. Table 3.1 compares actual weather and demand for these months of 2005 with Normal weather and the forecast of demand. Since any given month is covered by several forecasts, the forecast presented in the table is the average of all forecasts for that month.

Table 3.1 Fall 2005 Weather and Demand

Weather and Demand		November	October	September
Weather - Actual	Average Temperature (°C) Minimum Temperature (°C) Maximum Temperature (°C)	7.8 -6.3 18.9	14.5 6.2 25.8	23.8 13.1 31.6
Weather - Normal	Normal Average Temperature (°C) Normal Minimum Temperature (°C) Normal Maximum Temperature (°C)	6.5 -2.0 16.4	13.6 6.8 23.3	21.6 13.1 29.8
Demand - Actual	Peak Demand (MW) Energy Demand (GWh)	22,564 12,441	20,752 12,187	23,914 12,553
Demand - Weather Corrected	Peak Demand (MW) Energy Demand (GWh)	22,475 12,525	21,307 12,140	21,901 12,284
Demand - Blended Forecast	Peak Demand (MW) Energy Demand (GWh)	22,726 12,808	20,822 12,412	22,171 12,179

Figure 3.3 shows the hourly profile for the all-time fall peak (September 9th, 2002) and the 2005 fall peak (September 13th, 2005). Both the all-time and 2005 peak are driven by cooling load.

Figure 3.3 Fall Peak Day Hourly Profile



3.3 Resource and Transmission Adequacy Review of Past Season

In considering the historic review of resource adequacy, we examine the amount of generation that is made available from various generating resources. Of particular interest is the amount of self-scheduling generation in the Ontario market and the amount of generation made available from hydro generation.

The hot weather this fall resulted in numerous restrictions to thermal plant production in order to manage heat related environmental restrictions. These restrictions limited the amount of energy that could be produced from one large facility, further aggravating energy management on several days. An algae bloom in Lake Ontario forced three large thermal units from service on one occasion. Fortunately this occurred early in the morning and did not result in immediate need for emergency control actions. IESO is working with the appropriate market participants to understand the extent of the risk and to manage mitigate these risks.

Resource Additions

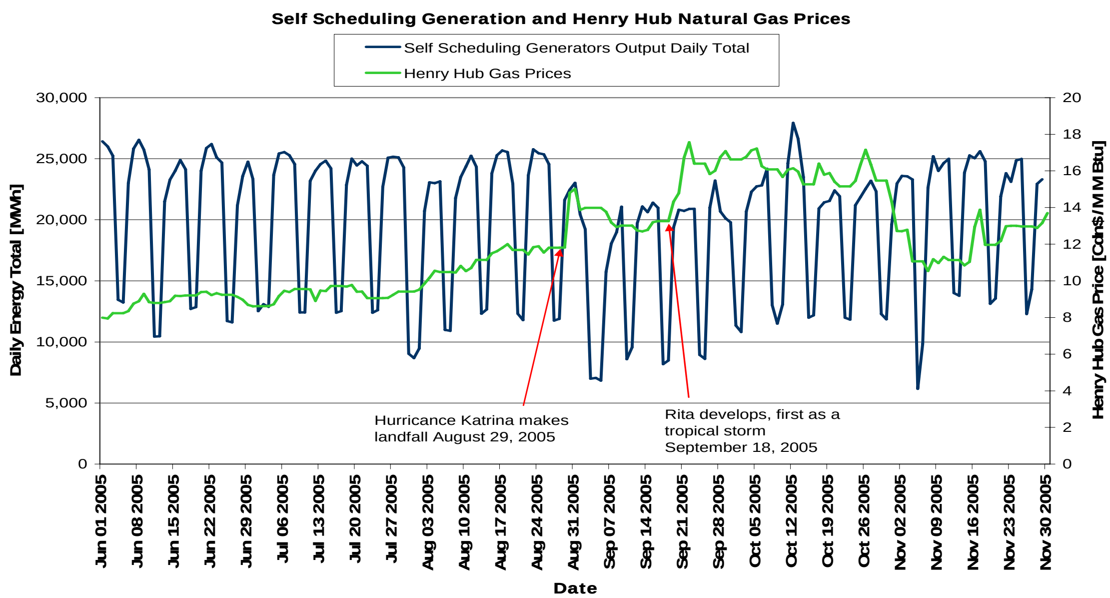
Since the last Outlook was published, Pickering Unit 1 (515 MW) came into service.

Self-Scheduled Generation

We have observed a correlation between the price for natural gas and the energy output from certain gas-fired generators operating in Ontario. We believe there could be more risk to reliability in the future, due to increased uncertainty regarding the amount of generating capacity that will be made available from some gas-fired generators. These risks are expected to be higher during periods of time when natural gas prices are expected to be volatile or high. At these times for some gas-fired generators, it is more profitable for them not to generate electricity. These conditions predominantly exist for generators that have specific fixed structures to their natural gas and electricity contracts. Fortunately, the latest Clean Energy Supply generator contracts do not have structures that are as likely to result in these conditions. The gas-fired generators that may be subject to these conditions fall into the self-scheduling generation category of resources that are operating in the IESO wholesale markets.

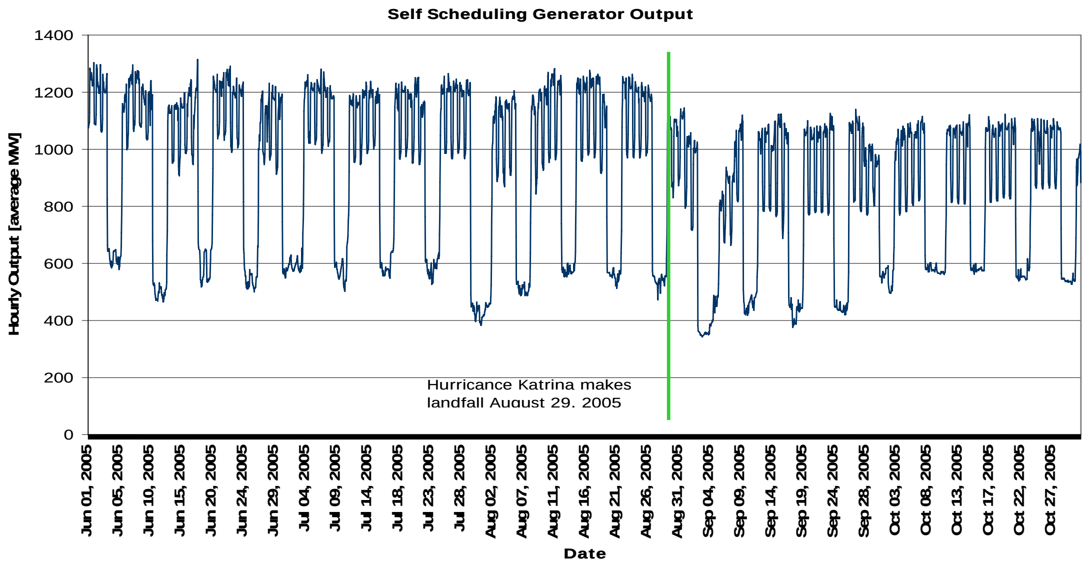
Figure 3.4 indicates the daily closing price of natural gas at the Henry Hub, and the daily energy produced from all self-scheduled generators in Ontario. For the week after hurricane Katrina made landfall, the amount of energy produced by all self scheduled generators decreased by about 4,000 MWh per day. Daily energy production quantities seemed to be restored to pre-Katrina levels once the price of natural gas reached pre-Katrina prices.

Figure 3.4 Daily Energy from Self Scheduling Generation and Gas Prices



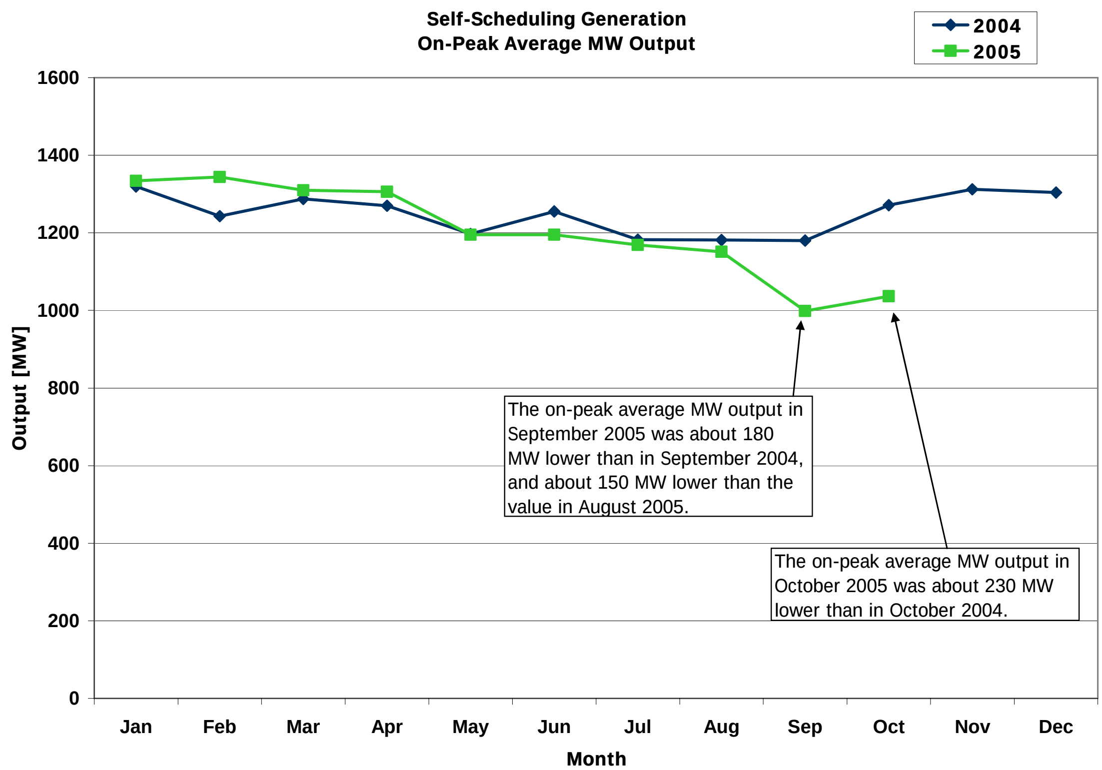
The peak MW contribution of self-scheduled generators at the time of the daily peak is correlated to the price of natural gas at the Henry Hub. This is shown in Figure 3.5 below. There appears to be a decrease of about 150 MW in the amount of production during the peak periods of each workday following Hurricane Katrina.

Figure 3.5 Hourly Output from Self Scheduling Generators



The output from self-scheduling generators is also dependent on the ambient temperature of the operating month, with higher temperatures causing some decreases to the maximum amount of output from some gas-fired self-scheduling generators. This typical monthly pattern was observed in 2004. However, in 2005, a deviation from the usual pattern is observed, as shown in Figure 3.6. The output from self-scheduling generators appears to be about 180 MW lower in September 2005, compared to September 2004,

Figure 3.6 Self-Scheduling Generation On-peak Average MW Output



Hydro Generation

Figure 3.7 illustrates that the actual monthly hydro energy produced has been lower than the forecast energy capability provided by market participants for the 18-Month Outlooks. For the 2005 summer period of June, July and August, the total hydro energy output was about 15 % less than the forecast energy capability for that time period. From a different perspective, the hydro energy production for the three summer months of June, July and August of 2005 was about 20 % lower than the hydro production in the same period in 2004.

The high demands early in the summer season also meant that water available for hydroelectric use was used up early in the summer and was never fully replaced by rainfall. For the fall time period of September, October and November the total hydro energy output was about 10 % less than the forecast energy capability for that time period. For September and October, the actual hydro energy output was about 15 % less than the forecast energy capability and for November, the actual hydro energy output was only 1 % less than the forecast energy capability.

It should be recognized that the forecast monthly energy capability is based on inputs from market participants that are submitted for 18-Month Outlooks anywhere from one to four months prior to the actual month of operation. For example, the forecast monthly energy capability for September, October and November of 2005, is based on the market participant input submissions provided on or before August 1, 2005.

Figure 3.7 Monthly Hydro Energy

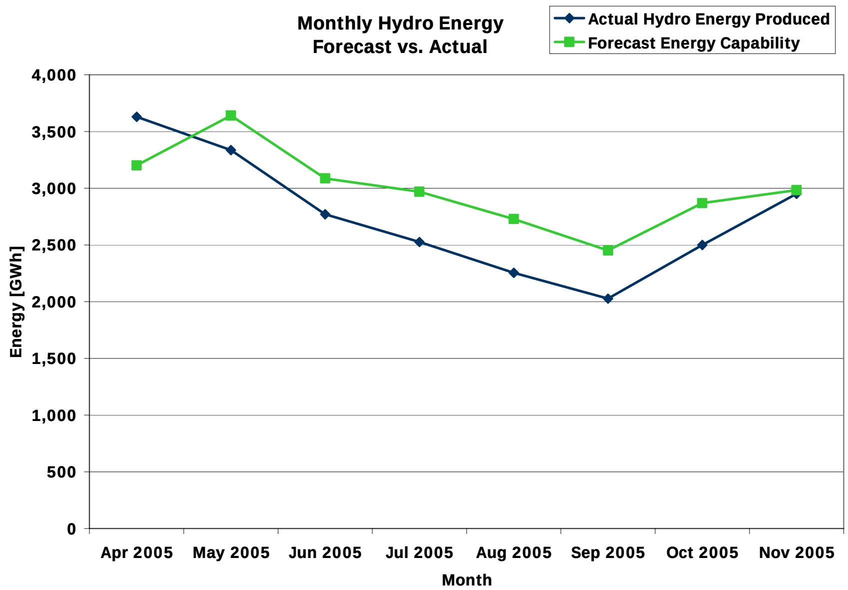
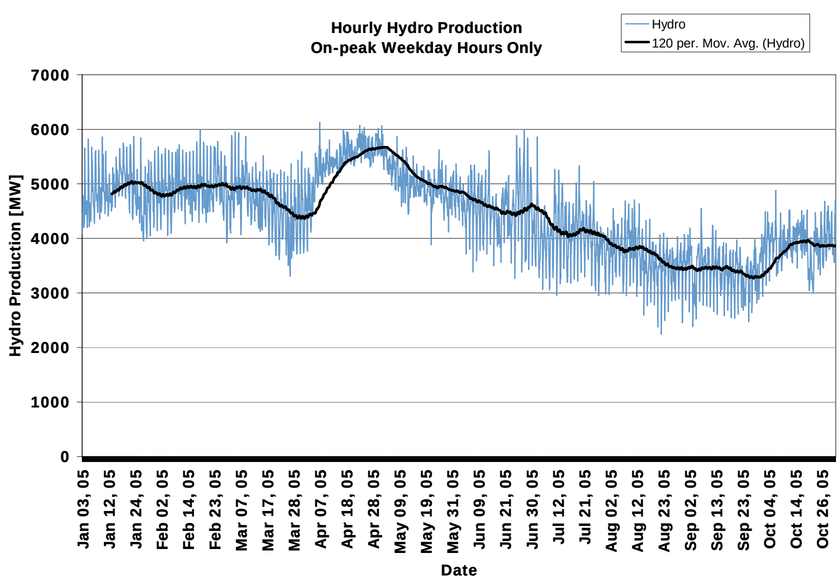


Figure 3.8 shows the hourly hydro production for the timeframe from January to October 2005, for the on-peak hours only. The moving average output for 120 on-peak hours is also shown on the graph to help illustrate the general decline in the amount of hydro production for the period from May to September of 2005.

Figure 3.8 Hourly Hydro Production



Niagara Area 25Hz System

There were several reliability concerns related to the 25Hz system in the Niagara area, which resulted in varying degrees of load curtailments and interruptions through October, November and December. These problems proved to be difficult to resolve in a timely manner, due to the number of different equipment failures on this aging section of the power system. These problems illustrate the growing concerns related to maintaining the reliability of the 25Hz system.

Transmission

The transmission system in Ontario operated very reliably in spite of the need to cancel or defer maintenance to avoid restrictions. However, the system was operated at the limit of capability on many occasions. There were a number of transmission limitations within the province that became more severe as a result of the hot weather:

- Phase shifters at interconnections with New York and Michigan
- The Niagara corridor (QFW)
- The flow into Burlington corridor
- Eastern Ontario circuits
- East-west tie

These restrictions limited the ability to move generation or imports within the province to areas of need.

In addition, throughout the summer, flows over Ontario's transmission system from transactions between parties outside Ontario limited the capability to import energy for use within the province by using up valuable transfer capability within Ontario. These flows are called parallel flow and routinely were in the range of 800 to 1000 MW.

Transmission restrictions also occurred within the west GTA. The majority of power in the GTA is supplied through a series of large transformers across the top of the GTA. During periods of high load, or during outages to equipment, these transformers are loaded very close to the maximum allowed. On two separate occasions this summer emergency voltage reductions were required in order to reduce the loading of these transformers to acceptable levels. Additional analysis of the transmission in the GTA is presented in section 7.0

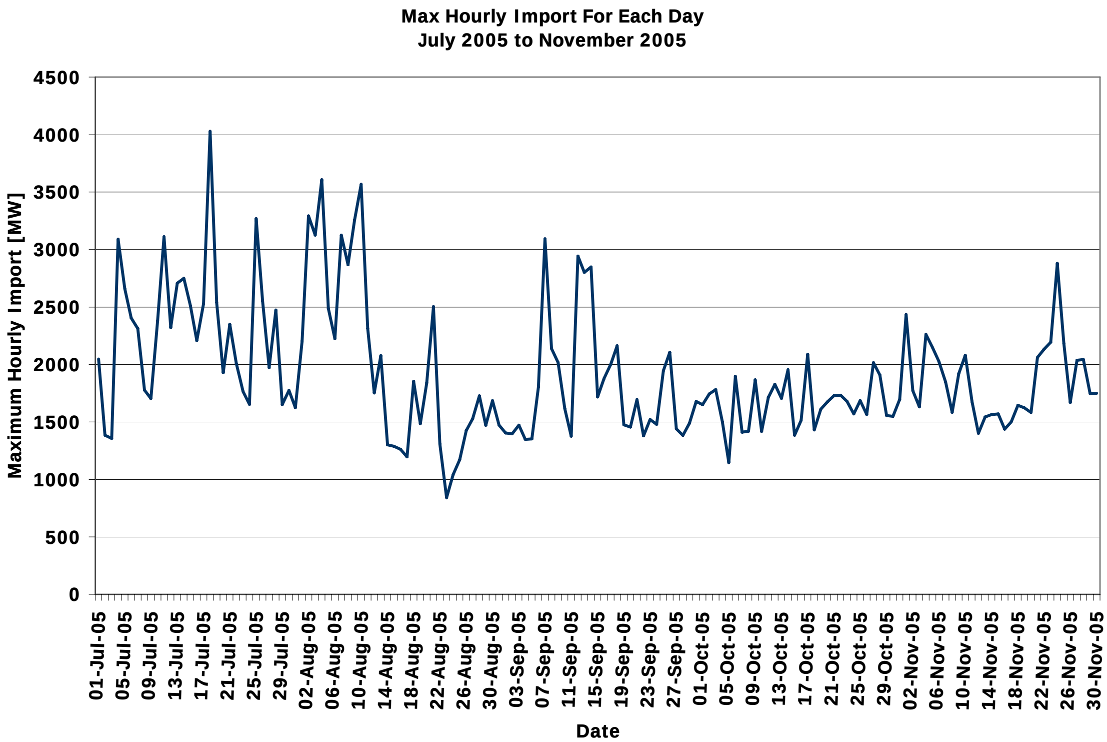
Imports

Throughout the summer period, Ontario relied extensively on imports from neighbouring markets. On many days the imports reached the maximum of our import capability. Due to transmission restrictions within the province, this capability was often less than the physical capability of the interties. The level of imports decreased during the fall period.

Figure 3.7 indicates the maximum hourly import for each day, for the summer and fall periods. The import levels indicated for the fall months of October and November are, on average lower than the levels for the months of July to September.

As reported in the Market Surveillance Panel report titled, "Monitoring Report on the IESO-Administered Electricity Markets for the period from May 2005 – October 2005" published in December 13, 2005, the relatively high prices in September 2005 were driven essentially by increases in natural gas prices that raised the cost of available energy, rather than by problems of relative supply.

Figure 3.9 Imports



An analysis of historical power flows on Ontario's interconnections for the five years prior to 2002 shows that, outside of summer peak demand periods, up to 1,800 MW of external generation resources has typically been imported into Ontario. During Ontario's summer peak demand periods of July and August imports are expected to be required and imports are expected to be available despite the fact that many neighbouring systems are often experiencing their peak demand. This is mainly due to the availability of spare capacity from systems that are not summer peaking. From the same analysis, up to 1,400 MW would be expected to be available based on observations during summer peak months in recent years prior to 2002.

The actual hourly import levels experienced from market opening indicates an average import level of about 1,167 MW for all hours. During the hours when Ontario demand exceeded 20,000 MW the average import level was about 1,479 MW. During the hours when Ontario demand exceeded 23,000 MW the average import level was around 2,193 MW, and occasionally reached the Ontario coincident import capability of approximately 4,000 MW.

Future levels of imports into Ontario will vary depending on several factors, including the availability and willingness of resources in external jurisdictions to supply the Ontario market, and the availability of required transmission capacity either within or outside of Ontario.

<u>Inter-tie Import Failures</u>

Given our demand for imported energy, a critical concern with supply this past summer was the frequent failure of large numbers of intertie transactions. These failures represent expected supply that is suddenly not available in real-time. The failures are especially problematic due to the timing and size of the failures.

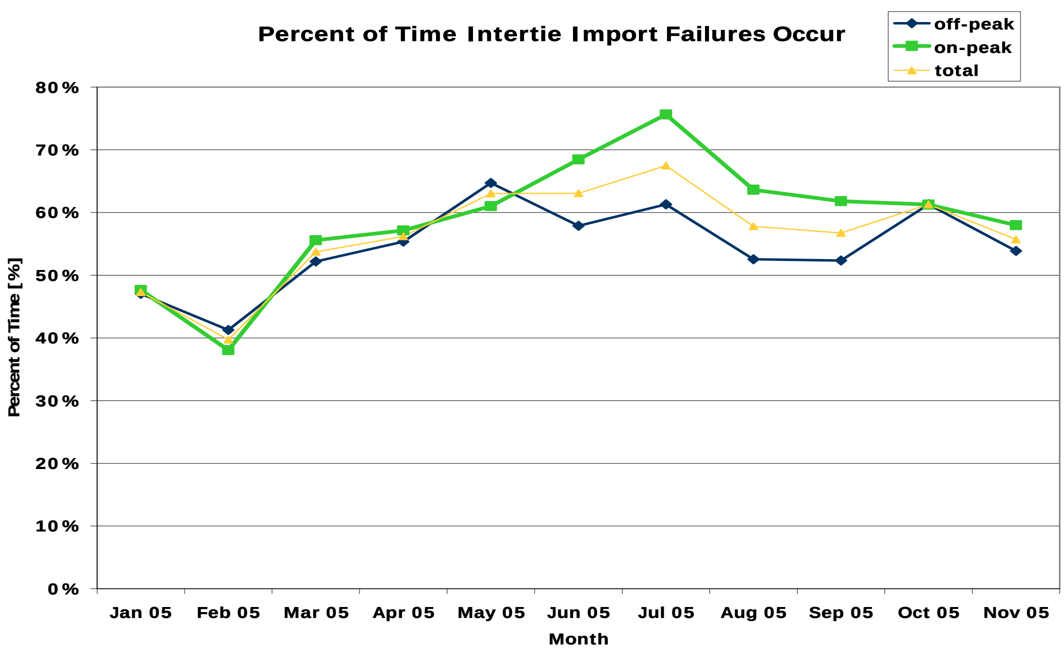
Transaction failures are equivalent to losing a generator, in their adverse impact on reliability for real-time operations. Typically, operators have about 30 minutes advance warning that a scheduled transaction has failed and that the energy must be replaced by other resources within that timeframe. Import failures can aggravate any potential energy shortage in Ontario, and can contribute to the need to use emergency control actions.

The larger the import failures are, and the more frequent the import failures are, the greater potential they have to cause reliability concerns.

The challenge to reliability that the import intertie failures present also depends on the resources that are available when the import failures occur. In the summer of 2005, when most generation was running, hydro and some thermal production was energy limited, and it was a constant challenge to balance supply and demand following these intertie failures. For the fall 2005 period, import failures were less frequent, and generally smaller in magnitude compared with summer 2005. The availability of more hydroelectric energy improved our ability to respond to the intertie failures.

During the fall months, the percent of time that intertie import failures occurred decreased compared with the summer months, but appear to be higher than the spring months of 2005. The on-peak hours of the day are the most challenging to deal with from a reliability viewpoint, and these hours, for the months of June to November, happen to have the highest percentage of import failures. For the fall months, about 60% of the time, intertie import failures occurred.

Figure 3.10: Percent of Time Import Failures Occurred



Further details on the issues regarding Intertie Import Failures can be found on the IESO web-site at: http://www.ieso.ca/imoweb/consult/intertieTrading_sub.asp

<u>Use of Emergency Actions</u>

An Emergency Operating State was declared on 5 occasions during the summer months of 2005. In the fall, there was one emergency operating state declared in December and the IESO purchased up to 500 MW of emergency energy.

Generators were asked to seek approval for environmental variances from the Ministry of Environment and were granted environmental variances on several occasions. These variances allowed greater amounts of energy to be used from thermal and hydroelectric facilities and were critical in ensuring there was sufficient energy to meet the demand.

In summary, there were a number of factors that contributed to the need for repeated use of emergency control actions, many of them temperature related:

- Load growth
- Extended periods of hot humid weather
- Low hydroelectric energy available
- Environmental limitations to thermal plant production
- Transmission system at its' limit
- Failure of import transactions to Ontario

3.4 Plans to Manage Reliability Risks

<u>Reliance on Imports</u>

The 18-Month Outlook study assumes no imports into Ontario in the available resources, or in the determination of the Reserve Above Requirement values that are presented in tabular format. However, in making an assessment of the extent to which Ontario can maintain reliability, it is recognized that Ontario may need to rely on imports to help maintain reliability. The coincident interconnection capability is normally in the range of 3,000 to 4,000 MW. Data from market opening through November 2005 reveals that, whenever demand exceeded 23,000 MW, imports averaged about 2,193 MW, and occasionally reached the 4,000 MW import capability level. In the event that Ontario experiences extreme weather conditions, or higher than expected generator forced outages, or other conditions that result in a more challenging supply-demand situation than modeled, Ontario will rely on imports to improve reliability. There are various risks to reliability listed in Section 6.3 of this document, some of which may be mitigated by imports into Ontario.

<u>Emergency Demand Response Program</u>

The IESO implemented an Emergency Demand Response Program (EDRP) in 2002. Approximately 400 MW of load is contracted under this program. The relief from the EDRP is not modeled in the reserve above requirement values presented in the 18-Month Outlook. Load under this program is cut as the last step before rotating load cuts. From a practical perspective, since reduction of this program load is voluntary, use of this program would likely occur at the same time as rotational load shedding. No EDRP load or rotational load shedding was required during this past summer or fall period.

<u>Outage Planning</u>

Every quarter, the IESO assesses the integrated generator and transmission outage plans of market participants. Periods where outages result in inadequate resource levels are identified to generators and transmitters. If market participants fail to proactively reschedule outages to mitigate concerns, the IESO may veto outages in the near-term to ensure sufficient capacity is available to meet non-dispatchable demand.

Progress on Other Action Plans

The following actions are planned to improve the capability of existing resources:

- resolution of generation dispatch issues (e.g. aggregation, frequency of dispatch)
- reaching agreement full use of phase shifters with Michigan to control parallel flows
- review of the use of environmental variances within the list of emergency control actions
- development of incremental additions to the transmission system to increase capabilities as described in the transmission adequacy section of this report

Additional actions are planned to increase the certainty of market mechanisms:

- mechanisms for imports to be scheduled day ahead similar to markets around Ontario
- mechanisms for committing generating units day ahead, similar to markets surrounding Ontario
- Implement a Demand Response Program like the markets around Ontario

In addition, we are reviewing IESO's operations and planning processes and criteria to ensure forecast risks are adequately recognized and that appropriate standards are in place.

Generation Dispatch Issues

In response to participant concerns, the IESO is addressing generation dispatch volatility issues that arise due to the number of dispatch instructions and dispatch reversals. The ability to manage plant operational requirements is also being addressed. Improving the reliability and capability of existing resources by resolving ongoing dispatch issues is also one of the areas that the IESO is addressing as part of its goal of enhancing the reliability of the power system in advance of the summer 2006. Initially, the IESO will work with affected and interested stakeholders to identify measures to address dispatch issues that can be implemented by June 2006. After implementing these measures, the IESO will continue to work with stakeholders in addressing dispatch issues requiring solutions with longer term implementation periods, such as those requiring significant tool changes.

Additional information can be found on the IESO web-site at:
http://www.ieso.ca/imoweb/consult/consult_dispatch-issues.asp

Phase Shifters between Michigan and Ontario

The Ontario-Michigan phase shifters can be used to control loop flows around Lake Erie, provided the necessary equipment and operating agreements are in place. High loop flows have often contributed to heavy loading on the QFW interface, and in doing so can limit the amount of imports into Ontario. Agreement of the involved transmission owners, Hydro One and International Transmission Company, is critical in achieving full control on the Ontario-Michigan interconnections. Until the remainder of the necessary agreements are in place, PS4 and PS51 will only be operated off neutral tap to prevent 5% voltage reduction in Ontario or Michigan, to prevent shedding firm load, or for testing. Hydro One and the International Transmission Company in Michigan must resolve outstanding issues and complete their agreements before the IESO market can use the Michigan-Ontario phase shifters to control loop flows through Ontario.

Reliability Demand Response Program

The creation of a new demand response reliability program is underway as a way of addressing measures to enhance the reliability of the power system in advance of summer 2006. The current Emergency Demand Response Program (EDRP) described earlier in this Section forms part of the IESO control action list for responding to emergency situations and is the last control action available to the IESO before the shedding of non-dispatchable load.

An additional and separate demand response program is referred to as the Reliability Demand Response Program (RDRP), which is similar to those of neighbouring markets. This program is being developed to give more certainty that an IESO request for response will be followed and to allow activation earlier than the EDRP in the list of control actions. A proposed program design was developed in November and an IESO open stakeholder workshop reviewed the proposed program. Further details on this proposal can be found on the IESO web-site at:

http://www.ieso.ca/imoweb/consult/consult_drrp.asp

Day-Ahead Commitment Processes

The IESO has initiated development of day-ahead commitment processes that are intended to allow imports to be scheduled day-ahead in order to address chronic transaction failures near real time that leave insufficient time to respond reliably; and to commit generation units day ahead to increase reliability in the operational time frame.

The design of the day-ahead commitment processes will take into consideration the following context:

- The need to design and implement these measures with a view to minimizing costs and changes to market participant business processes and systems;
- The need to design and implement these measures with consideration to the impacts on market clearing prices and uplift; and
- The need to design and implement these measures by the summer of 2006.

Further details on this initiative can be found on the IESO web-site at:

http://www.ieso.ca/imoweb/consult/consult_isr.asp and at

http://www.ieso.ca/imoweb/pubs/consult/dayAhead/da_20051125_stakeholder_plans.pdf

- End of Section -

4.0 Demand Forecast

The forecast of demand has been updated to reflect the most recent information. As part of the regular updating process, the forecasting models' equations are re-estimated based on recent economic, weather and demand data. We have also updated the Weather scenarios for the most recent weather data.

The economic outlook has been updated but does not differ significantly from the previous forecast. High oil prices and a high dollar will continue to negatively impact Ontario's exporters. Low interest rates will continue to fuel consumption, business investment and construction. Combined, the province will experience moderate growth over the forecast.

The government has set targets for energy conservation to reduce peak electricity consumption by 5 per cent by 2007. Since we have few details on how these conservation targets are to be met, they are not reflected in the demand forecast.

With no significant changes, the forecast results are very similar to the last forecast. Annual energy demand is expected to grow by 0.9% and 1.3% in 2005 and 2006. The weekly peak demands are, on average, 35 MW higher than in the previous forecast. The growth in energy and peak demands varies across the zones due to local demographic and economic factors that influence demand.

- End of Section -

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5.0 Resources

This section describes the generation resources that were considered in this Outlook based on information available to the IESO.

5.1 Existing Generation Resources Included in this Assessment

The existing installed generating capacity within Ontario is summarized in Table 5.1. This includes nuclear, coal, oil, gas, hydroelectric, wood, land fill gas and waste-fuelled generation, and results in a total capacity of 30,631 MW.

The capacity of installed generation resources in Table 5.1 does not include Bruce Units 1 and 2 and the Greater Toronto Airports Authority's new co-generation power plant.

Table 5.1 Existing Installed Generation Resources

Fuel Type	Total Capacity (MW)	Number of Stations
Nuclear	11,397	5
Coal	6,434	4
Oil / Gas	4,976	20
Hydroelectric	7,756	67
Miscellaneous	68	3
Total	30,631	99

The number of stations is unchanged from the last Outlook. However, the total capacity from nuclear generation has increased by 515 MW with the addition of Pickering A Unit 1 in the last quarter of 2005.

For purposes of determining a station count by fuel type, each generating station has been assigned a single fuel type based on the primary fuel consumed at the station. The category "Miscellaneous" includes land-fill gas, wood and waste-fuelled generating stations.

5.2 Potential Generation Resource Additions

Table 5.2 summarizes the significant new generation facilities that are scheduled to come into service within the 18 month study period. This includes projects in the IESO's Connection Assessment and Approval (CAA) process that are under construction, embedded generators that are registered to participate in the market and projects selected under the RFP process which are scheduled to be placed in-service within the 18 month study period. Generator owners or operators have provided the information regarding the status of their projects and the in-service dates listed in Table 5.2.

Table 5.2 Committed and Contracted Generation Resources and Demand Side Projects

Proponent/Project Name	Zone	Fuel Type	Capacity MW	Connection Applicant's Estimated I/S Date
Essex Power	West	Oil	3	2006-Q1
Greater Toronto Airports Authority	Toronto	Gas	117	2006-Q1
Melancthon Grey Wind Project	Southwest	Wind	68	2006-Q1
Kingsbridge Wind Power Project	Southwest	Wind	40	2006-Q1
Erie Shores Wind Farm	Southwest	Wind	99	2006-Q2
Loblaws Properties	distributed	Demand	10	2006-Q2
Nuclear Uprate	N/A	Nuclear	16	2006-Q3
Prince Wind Farm	Northeast	Wind	99	2006-Q3
Nuclear Uprate	N/A	Nuclear	16	2006-Q4
Blue Highlands Wind Farm	Southwest	Wind	50	2007-Q1
Total			**518**	

The Ontario Government's RFP for 300 MW of renewable resources resulted in a total of 10 successful projects that add up to 395 MW of installed capacity. One of these 10 new projects is already in-service. Of the rest, seven projects with a total installed capacity of about 360 MW comprised of wind and biomass projects are expected to be available within the 18 month timeframe of this Outlook. Wind capacity is intermittent and may not be fully available to meet demand when capacity is needed. For each of the renewable generation projects, the amount of dependable capacity that can be relied on to meet peak demand will need to be determined.

A study with several members of the Canadian Wind Energy Association, CanWEA, released in the spring of 2005 concluded that the median capacity contribution which can be expected from wind generation would range from about 47% in the winter to 19% in the summer. Other areas in North America typically rely on 2% to 30% of the installed capacity of intermittent wind powered generation, but this amount varies depending on the prevailing wind patterns, and how the resulting generation pattern coincides with peak demand. Until actual wind generation information from provincial resources is available, the capacity and energy contributions from these projects are assumed to be 10% and 30% respectively.

Four of the 10 renewable generators that are embedded in the distribution network or are displacing a wholesale market load have the option of participating directly in the wholesale market, or of reducing the wholesale market load of the consumer that is directly participating in the wholesale market. The one renewable generator already in-service chose to participate directly in the wholesale market.

Details regarding the IESO's CAA process and the status of all projects in the CAA queue, including copies of available Preliminary Assessment and System Impact Assessment Reports, can be found on the IESO's web site www.ieso.ca under the "Services - Connection Assessments" link. There are also a number of smaller generation capacity changes that may occur during the forecast timeframe. For this Outlook timeframe, the combined result of these generator capacity changes is about 30 MW. Some of the smaller capacity changes may not be significant enough to require the formal CAA process, and therefore not all of the capacity additions may have a project listed on the CAA Web-site.

5.3 Summary of Resource Scenarios

In assessing future resource adequacy, it is necessary to make a number of assumptions regarding the magnitude of resources expected to be available for operation. Two resource scenarios were considered in this Outlook: an Existing Resource Scenario and a Planned Resource Scenario. Both resource scenarios were established starting from the existing installed resources shown in Table 5.1.

Under the **Existing Resource Scenario,** Ontario generation resources identified in Table 5.1 were assumed to be in-service for the entire duration of the study period, except for periods of time that the generator owner/operator has submitted planned outages for their generating units. In addition, this resource scenario assumed 32 MW of generation capacity increases to existing nuclear generation facilities, as listed in Table 5.2. The existing resource scenario includes 372 MW of price-responsive demand capability up until April 1, 2007 and 347 MW thereafter. This value is based on the existing capability of price-responsive demands to reduce consumption based on signals from the IESO. Such decreases to demand are not factored into the published demand forecast values.

Under the **Planned Resource Scenario** existing Ontario generation resources were assumed to be in-service for the entire duration of the study period, except for periods of time that the generator owner/operator has submitted planned outages for their generating units. Additionally, all potential resource changes listed in Table 5.2 were included in this scenario. Price-responsive demand capability is forecast to be higher than under the Existing Resource Scenario. The price-responsive demand is forecast to reach 427 MW by end of March 2007, due to continuing increases in the amount expected to be offered into the IESO-administered markets. It drops to 398 MW for the rest of the Outlook period when the Transitional Demand Response Program (TDRP) is scheduled to end.

Forecasts of available resources were derived for each of the two resource scenarios described above, using information regarding generator output capabilities, planned outages, allowances for hydroelectric generation production below rated capacity, assumptions for the amount of price-responsive demand, and major transmission interface limitations.

Table 5.3 shows a snapshot of the forecast available resources, under the two scenarios, at the time of the seasonal peak demands over the study period. The installed resources in Table 5.3 start with the values listed in Table 5.1. The installed resources in Table 5.3 increase over the study timeframe, due to some increases in the forecast net installed capacity of existing generation facilities. For the Planned Resource Scenario only, resources are also increased by the generation additions listed in Table 5.2. The total reductions to resources include generator deratings, generator planned outages under each resource scenario, capacity limitations due to transmission interface constraints and allowances for hydroelectric generation production below rated capacity. The total reductions were subtracted and the price-responsive demand was added to the total resources, to obtain the available resources. In this Outlook, price- responsive demand ranges from 376 MW to a maximum of 427 MW under the Planned Resource Scenario, as shown in Table 5.3.

Table 5.3 Summary of Available Resources

Notes	Description \ Year	Winter Peak 2006		Summer Peak 2006		Winter Peak 2007	
		Existing Resource Scenario	Planned Resource Scenario	Existing Resource Scenario	Planned Resource Scenario	Existing Resource Scenario	Planned Resource Scenario
1	Installed Resources (MW)	30,631	30,751	30,631	30,957	30,663	31,088
2	Imports (MW)	0	0	0	0	0	0
3	Total Resources (MW)	30,631	30,751	30,631	30,957	30,663	31,088
4	Total Reductions in Resources (MW)	2,852	2,855	1,617	1,826	1,383	1,701
5	Price-responsive Demand (MW)	372	376	372	427	372	427
6	Available Resources (MW)	28,151	28,272	29,386	29,558	29,652	29,814

Notes to Table 5.3:

1. Installed Resources (MW): This is the total capacity of the generation resources in Ontario assumed to be installed at the time of the summer and winter peaks in the 18 month time span. Initially, this value includes all generators registered to participate in the IESO-administered markets at the beginning of the 18 month study period. It also reflects any minor unit re-ratings resulting from equipment changes that may have been completed prior to the publication of this Outlook. Two of the four Pickering A nuclear units are included in the existing installed generation resources. Additional generation capacity that was assumed under the applicable resource scenario is progressively included, according to the estimated in-service dates.

2. Imports (MW): Represents the amount of external capacity considered to be delivered to Ontario.

3. Total Resources (MW): This is the sum of Installed Resources (line 1) and Imports (line 2).

4. Total Reductions in Resources (MW): These reductions represent, under each of the two scenarios, the sum of generator deratings, generator planned outages under each resource scenario, generation limitations due to transmission interface constraints and allowances for hydroelectric generation production below rated capacity.

5. Price-responsive Demand: This is the amount of demand which is assumed to respond to changes in the market clearing price by reducing consumption, under each resource scenario.

6. Available Resources (MW): This equals Total Resources (line 3) minus Total Reductions in Resources (line 4) plus Price-responsive Demand (line 5).

5.4 Monthly Energy Production Capability Forecast

The monthly forecast of energy production capability, as provided by market participants, is included in Appendix A, Table A6.

- End of Section -

6.0 Resource Adequacy Assessment

This section provides an assessment of the adequacy of the resources described in Section 5 to meet the forecast demand. The purpose of the two resource scenarios described in Section 5.3 is to present a range of possible outcomes, in recognition of the uncertainty which exists regarding the future availability of resources. The Existing Resource Scenario, which assumes capacity increases to the existing generation facilities and a base amount of price-responsive demand, represents the lower boundary of the range, considering the potential for delays to the in-service dates of additional generation capacity, and additional price responsive demand capability. The Planned Resource Scenario assumes additional quantities of price-responsive demand and generation capacity additions based on project status and in-service date estimates. This scenario represents the higher boundary of the outcome range.

Results of the adequacy assessment, as well as an analysis of risk factors, are described in Sections 6.1 through 6.5. Observations, findings and conclusions are provided in Section 8, and detailed tables of results can be found in Appendix A of this document.

6.1 Weekly Adequacy Assessment

The assessment of weekly adequacy takes into consideration a range of forecast demands based on a probability distribution of historical weather data. Reserve Above Requirement levels have been calculated assuming both normal weather (with an allowance for the probability of experiencing extreme weather) and assuming extreme weather (with no further allowance for weather uncertainty). Figure 6.1 shows the normal and extreme weather demands assumed for each week in the study period.

Figure 6.1 Demand Forecast Range

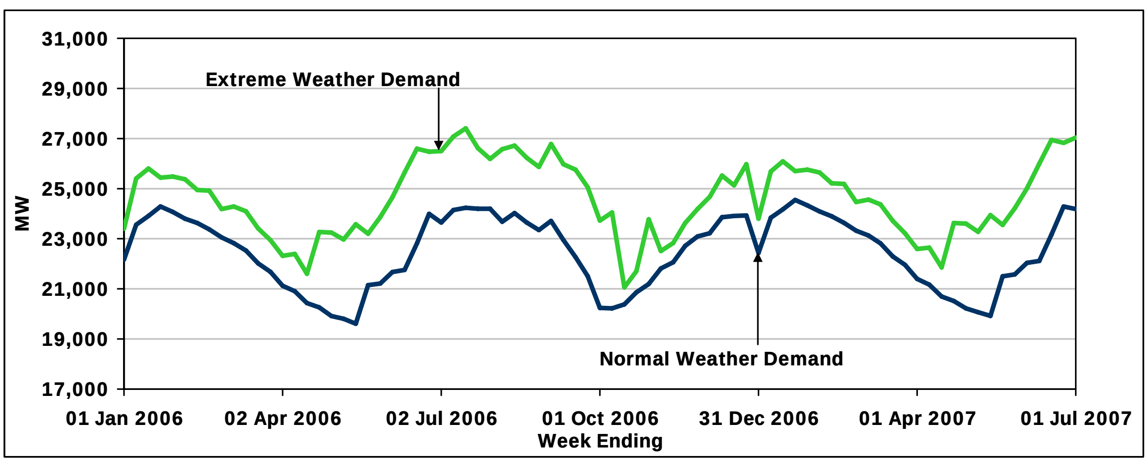


Figure 6.2 shows the Total Reductions in Resources used in the calculation of the Available Resources (as described in Section 5.3).

Figure 6.2 Total Reductions in Resources

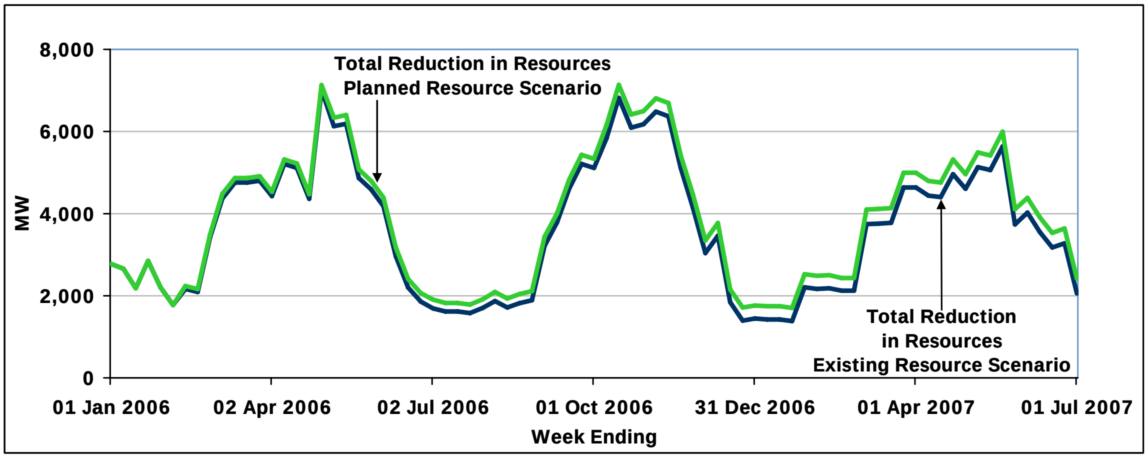


Figure 6.3 provides a comparison between Available Resources, and Required Resources for each week, for the Existing Resource Scenario. The latter quantity is the sum of Demand and Required Reserve, and is based on a probabilistic calculation, which takes into account load forecast uncertainty due to weather and random generator forced outages. Figure 6.4 provides a similar comparison for the Planned Resource Scenario.

Figure 6.3 Available vs. Required Resources: Existing Resource Scenario

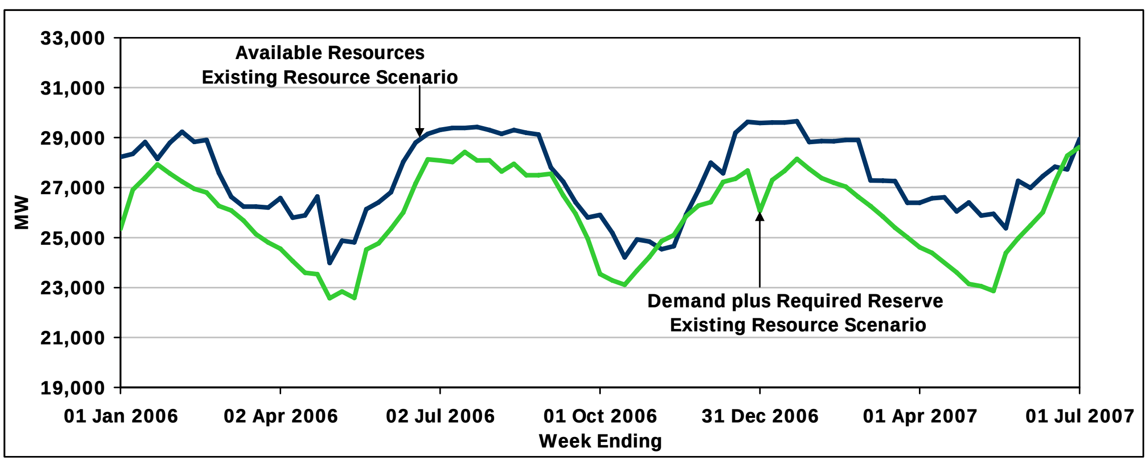
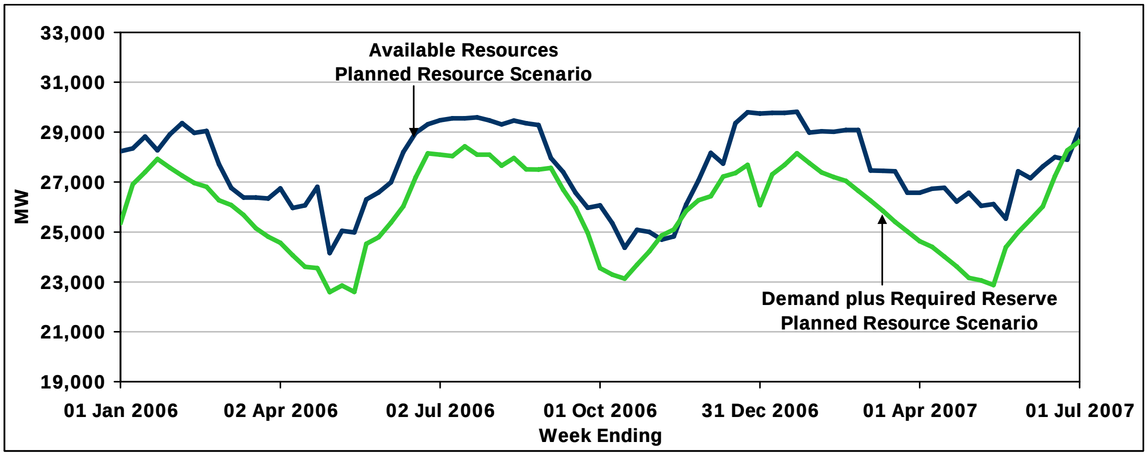
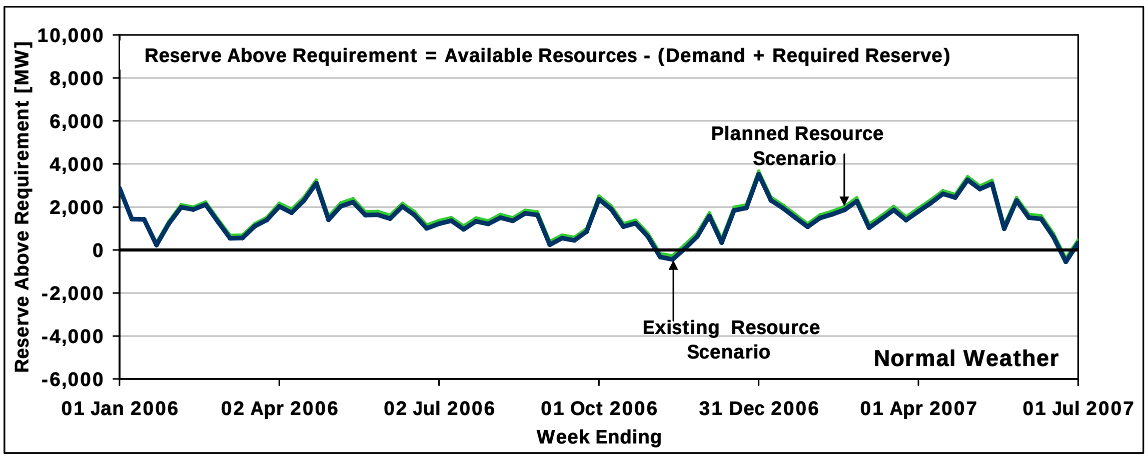


Figure 6.4 Available vs. Required Resources: Planned Resource Scenario



Reserve Above Requirement levels, which represent the difference between Available Resources and Required Resources, are shown in Figure 6.5 for each resource scenario studied.

Figure 6.5 Reserve Above Requirement: Existing Resource Scenario and Planned Resource Scenario



Under the **Existing Resource Scenario**, the forecast reserves are generally adequate for the study period. Reserves are forecast to be below requirements for three weeks of the 18 month study period. During these weeks some planned generator outages are at risk of cancellation or deferral by the IESO for reliability purposes depending on their priority and the resource adequacy situation at the time outage approval is being sought. Opportunities will exist for additional planned generator maintenance and exports in the other weeks of this Outlook period.

The results above must be assessed considering the risk factors described in Section 6.3 and the probability of this scenario occurring. During most of the study period, a combination of high demand levels under extreme weather conditions and lower than forecast levels of available resources would lead to reliance on imports and upward pressure on the wholesale market prices.

Under the **Planned Resource Scenario**, the resource adequacy situation is similar to the Existing Resource Scenario with an average improvement of only about 150 MW in the Reserve Above Requirement. For all but three weeks of the Outlook timeframe, the forecast available resources exceed the planning requirements. If we look ahead to next summer, we appear to be slightly better off than we forecast in December 2004 for the summer of 2005.

Figures 6.6 and 6.7 provide a comparison between the forecast Reserve Above Requirement values in the present Outlook and the forecast reserve above requirement values in the previous Outlook published on October 24, 2005. Under both the Existing Resource Scenario and the Planned Resource Scenario, the combined changes in forecast demands, price-responsive demand and generator planned outages yield generally the same resource outlook for the overlapping period when compared to the previous 18-Month Outlook.

Figure 6.6 Reserve Above Requirement: Existing Resource Scenario vs. Previous Existing Resource Scenario

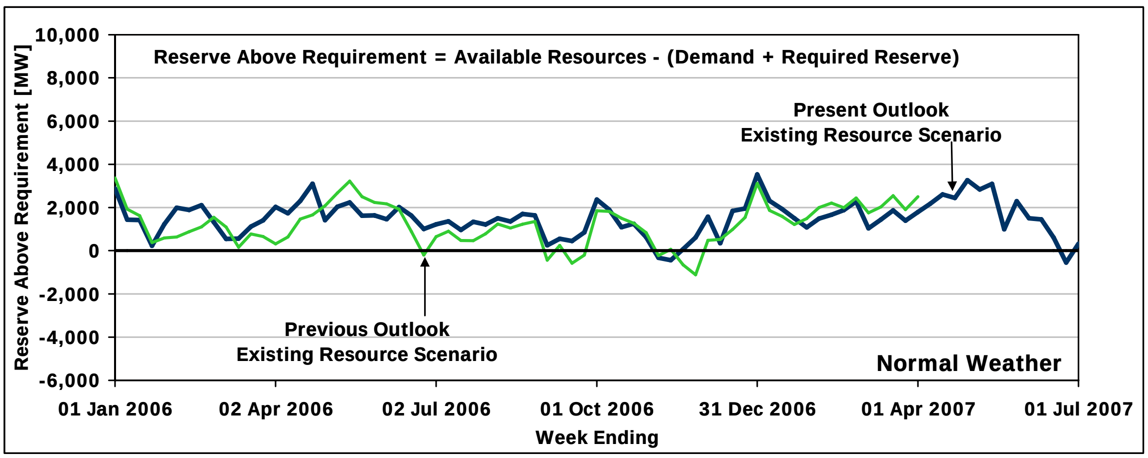
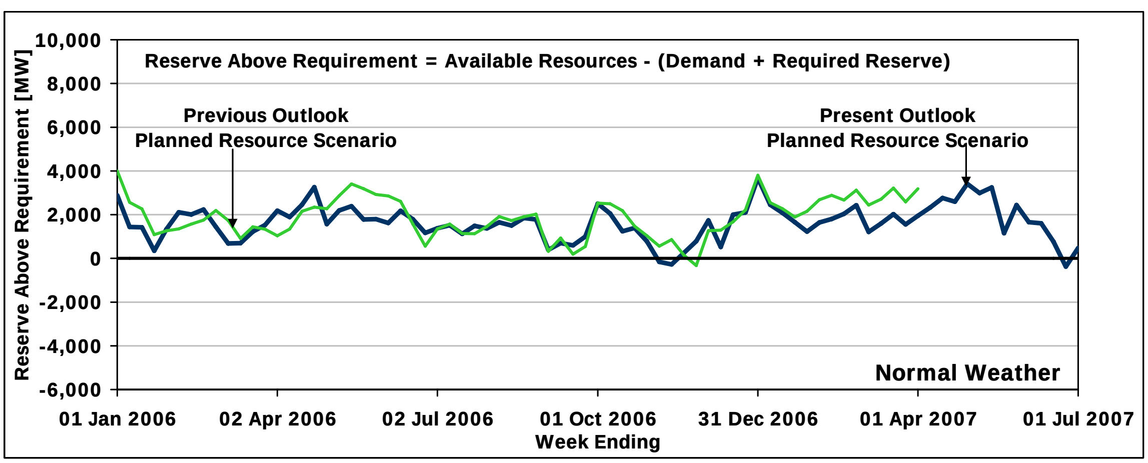


Figure 6.7 Reserve Above Requirement: Planned Resource Scenario vs. Previous Planned Resource Scenario



6.2 Loss of Load Expectation

Loss of Load Expectation (LOLE) simulation results indicate that, in order to achieve the NPCC target LOLE, additional resources would be required, sufficient to offset the reserve deficiencies under the existing resource scenario shown in Table A1 in Appendix A.

6.3 Resource Adequacy Risks

The forecast reserve levels for both the Existing Resource Scenario and the Planned Resource Scenario should be assessed bearing in mind the risks discussed below. Each of these risks, whether considered alone or in combination with the others, could result in lower than forecast reserve levels and the need for higher levels of imports or curtailment of planned outages.

6.3.1 Extreme Weather

The Existing Resource Scenario and the Planned Resource Scenario are based on the assumption of normal (average) weather. However, peak demands in both summer and winter typically occur during periods of extreme weather. Unfortunately, the occurrence and timing of extreme weather is impossible to accurately forecast far in advance. As a result, the impact of extreme weather is modeled probabilistically in the calculation of the required resources for each week of the study period. The impact of extreme weather was demonstrated in July 2005, when Ontario established an all-time record demand of 26,160 MW. Approximately 1,600 MW of this demand was due to the higher than average heat and humidity.

In order to illustrate the impact of extreme weather on forecast reserve levels during the Outlook period, both the Existing Resource Scenario and the Planned Resource Scenario were re-calculated assuming extreme weather in each week instead of normal weather. The probability of this occurring in every week is very small; however the probability of an occurrence in any given week is greater (about 2.5 percent). Over the course of the Outlook period (18-Months) you will observe at least one day of extreme weather. When one looks at the entire summer or winter periods, the expectation of at least one period of extreme weather becomes very likely. Results for extreme weather are shown in Figures 6.8, 6.9, and 6.10.

The magnitude of resource deficiencies, under extreme weather, clearly illustrates there are circumstances under which reliance on interconnected supply is likely. This emphasizes the continued need for reliable supply and demand response within Ontario.

Figure 6.8 Available vs. Required Resources: Existing Resource Scenario <u>Extreme Weather Demand</u>

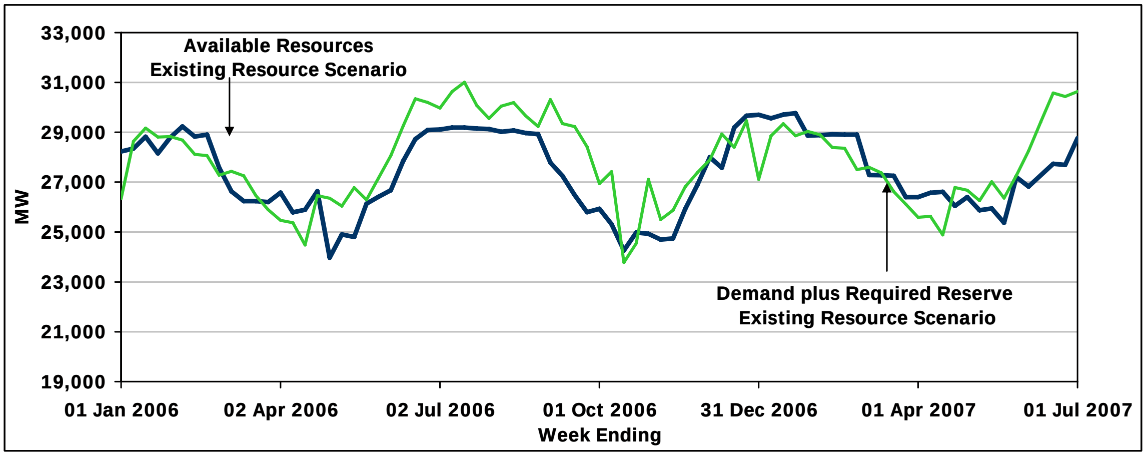


Figure 6.9 Available vs. Required Resources: Planned Resource Scenario <u>Extreme Weather Demand</u>

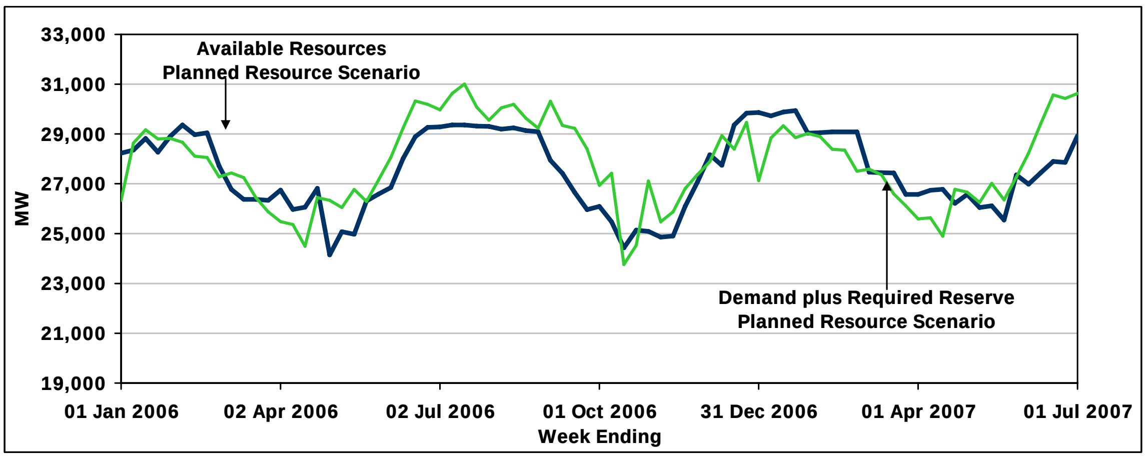
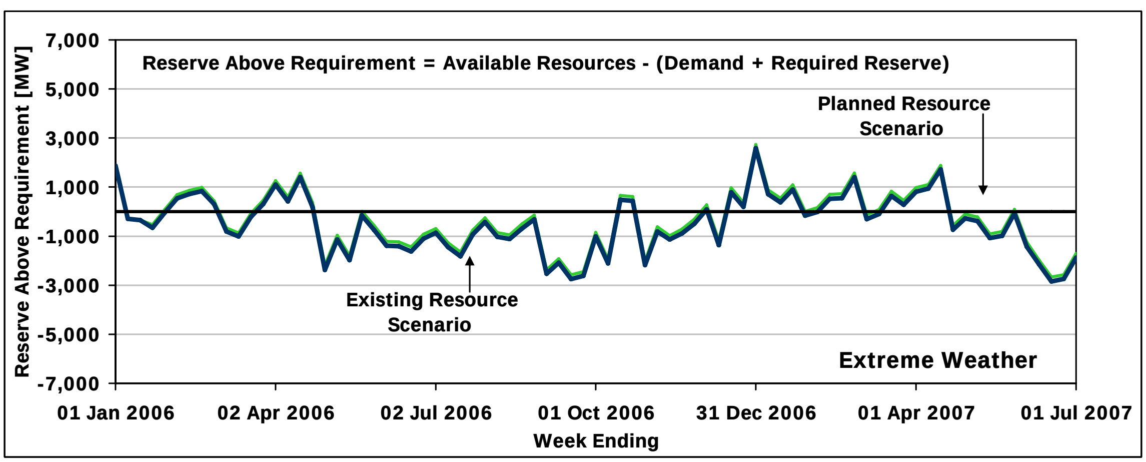


Figure 6.10 Reserve Above Requirement: Existing Resource Scenario and Planned Resource Scenario, <u>Extreme Weather Demand</u>



6.3.2 New Resource Risks

For the 18 month period under study, the improved demand-supply situation for the Planned Resource Scenario is dependent on the additional generation and price-responsive demand coming into service as forecast. Given the amount of new supply and transmission enhancements required in such a short period of time, timely regulatory approvals processes are required. Serious consideration needs to be given to developing expedited, but thorough, approvals processes to ensure timely implementation of the new facilities.

6.3.3 Extensions to Generator Planned Outages

A number of large generating units are scheduled to return to service from outage prior to winter 2006/2007 and summer 2006. Meeting these schedules is critical to maintaining adequate reserve levels. Delays in returning generators to service from maintenance outages could lead to reliance on imports and/or cancellation of planned generator outages.

In the event that generator outages must be delayed due to reliability concerns, it will be necessary for outages to be rescheduled to a more suitable time period. However outage rescheduling could stretch the ability of generator owners/operators to accommodate larger amounts of outages over shorter time periods and may increase forced outage occurrences. Operational experience so far indicates generator owners are usually able to adapt their outage plans. However, the dual peaking nature of the Ontario system (roughly equivalent peaks in winter and summer) means that outages must be scheduled in shorter spring and fall periods. Inevitably this means that some long duration outages have to be scheduled into the start of the peak seasons, creating the potential that any extensions of these outages occur when the generation is most needed.

6.3.4 Higher than Forecast Generator Unavailability

IESO resource adequacy assessments include a probabilistic allowance for random generator forced outages based on generator reliability information provided by market participants, or on industry-wide data for similar facilities. Along with weather-related demand impacts, the impact of generator forced outages is included in the determination of required resources.

6.3.5 Lower than Forecast Hydroelectric Resources

IESO resource adequacy assessments include forecast amounts of hydroelectric generation provided by market participants. The amount of available hydroelectric generation is greatly influenced both by water-flow conditions on the respective river systems and by the way in which water is utilized.

Water-flow conditions are primarily influenced by the amount of precipitation received. To accurately forecast precipitation amounts far in advance is little better than chance. Drought conditions over some or all of the study period would lower the amount of generation available from hydroelectric resources.

6.3.6 Capacity Limitations

There is a risk that any given generator may not be capable of producing the maximum capacity that the market participant has forecast to be available at the time of peak demand. There may be several reasons for these differences.

Forecast models include an equivalent forced outage rate, that is intended to capture the random nature of generator capacity limitations, deratings, and forced outages. There is a risk that actual outages and deratings may be higher than forecast, and there is also a risk that certain types of deratings or outages may not be completely random. Some outages and deratings, such as environmental limitations, may be more likely to occur at roughly the same time as the extreme weather conditions which drive peaks in demand.

In addition, the forecast models assume that the maximum capacity of any given generator may be utilized fully at the time of the Ontario peak demand, although there are risks that the maximum capability of all generating resources may not be available in the same peak hour, due to interrelationships between generating resource fuel availability. We have already discussed the risk of gas arbitrage for some generation facilities in Section 3.3. Similarly, there is uncertainty in the amount of capacity that may be available from intermittent generating sources due to their uncertain fuel supply. As the penetration of wind generation grows the range of fluctuations will change. The potential change will increase, offset somewhat by geographic diversity.

6.3.7 Transmission Constraining Resource Utilization

There is a risk, as experienced this past summer, that transmission constraints occur more often than expected, or have greater impact than expected on the ability to deliver generation to load centres. A limited number of transmission limitations are modeled without all probabilities of failure included. There is a risk that certain transmission limitations, which are not modeled, may have a greater impact than forecast and/or failures could occur to significantly impact the utilization of resources, until such equipment is repaired or replaced. This can affect the utilization of internal generation and imports from neighbouring systems.

6.3.8 Failure of Import Transactions

There is a risk, as experienced this past summer, that import transactions scheduled with neighbouring markets frequently fail to be delivered. These failures represent expected supply that is suddenly not available in real-time. The failures are especially problematic due to the timing and size of the failures.

6.4 Energy Conservation and Peak Reduction through Demand Response

The IESO has been identifying the suitability of demand-side initiatives as part of the supply picture for several years and believes demand reductions and demand shifting should be vigorously pursued in Ontario, as clean and potentially less expensive ways to reduce future supply requirements. The application of such conservation measures is virtually unrestricted in location.

Programs would improve the supply-demand balance in two main ways:

- Demand reduction through technological or process efficiency improvements would have beneficial effects on the environment and reduce the need for generation capacity additions.
- Shifting the time of use from peak to off-peak periods through demand-response programs would achieve peak demand reductions, influencing electricity prices downward and improving utilization rates of generation resources.

6.5 Hourly Resource Allocation Analysis

The 18-Month Outlook assessment of reliable electrical supply has routinely included a weekly adequacy assessment which provides an analysis of the peak hour of each week of the Outlook timeframe. Under this peak hour analysis, a range of possible demand levels are considered. This includes demands which result from very mild to extreme weather, and several steps in between. Each demand level is considered with an appropriate probability of occurrence. A peak hour analysis is also completed assuming the most extreme weather is experienced. It is noted that Ontario does not expect to experience the most extreme weather of all time for any extended period of time, but each year we average ten days of extreme weather conditions.

Based on the actual experiences during the summer of 2005 it has become apparent that only performing an assessment of a one hour peak period, with the established methods of accounting for peak hour capability of generators may not reveal energy constraints that can impact reliable electricity supply.

To better assess potential future energy constraints, an approximate hour by hour resource allocation analysis is performed for this Outlook assessment. To undertake this hour by hour analysis, consideration is given to the demand that should be used. For any given weekly period, Ontario would not typically have a reliability challenge in meeting overall weekly or daily energy demand if Ontario were to experience only normal weather conditions for each hour of the entire week. On the other hand, it is not realistic to expect that Ontario would experience the most extreme weather conditions of all time in each hour of the entire weekly period.

To determine an hour by hour demand profile, a challenging week of weather from history was identified, and then that challenging week of weather was used as the input to the latest demand forecast model. The demand forecast model will consider the appropriate future load shape and include the appropriate load growth rates, together with the historic weather pattern. This process reveals an hourly Ontario demand forecast, for a weekly period, assuming that Ontario experiences a repeat of the challenging weather pattern from history.

Historic weather was examined for each one week period in the winter, from the years 1970 to 2005, and a week was selected which had very challenging weather, from the perspective of soliciting relatively high electricity demand. IESO uses the concept of a weather factor, measured in MWs, to provide a measure of how much the weather influences the electricity demand. In selecting the challenging week, consideration was given to the combination of a high rank for the one hour peak demand impact, and a high rank for the overall weekly energy impact. The process was also repeated for each one week period in the summer, from the years 1970 to 2005.

To create a forecast of a challenging winter week, the actual weather factors for the second week of January, 1982 was assumed to occur in the second week of January 2006.

To create the forecast of a challenging summer week, the actual weather factors for the week from August 1973 was assumed to occur in the second week of August 2006.

An allocation of resources to meet the hour by hour demand is estimated based on a combination of actual hourly historic patterns, and any appropriate adjustments.

The allocation process provides a rough estimate of the extent to which the future challenging demand profiles present resource adequacy concerns.

The winter analysis indicates that if Ontario were to experience the challenging weather of 1982 in the second week in January 2006, the resulting demand would likely be met with the expected level of resources that are forecast to be available. Actual reliability could be impacted if gas-fired self scheduled generators choose to contribute less towards meeting the energy demand.

The summer analysis indicates that if Ontario were to experience the challenging weather of 1973, in the second week of August 2006, the resulting demand would be even harder to meet than in the summer of 2005. The outcome depends on the amount of hydroelectric energy that is available and the allocation profile of hydroelectric resources that are assumed and will also depend on the extent to which imports are available and utilized. We expect reliability will also be impacted by the available mechanisms that may be used to manage the challenging periods, including the extent to which initiatives that are underway now to improve reliability, can be implemented and be effective before the summer of 2006.

- End of Section -

7.0 Transmission Reliability Assessment

This section provides an assessment of the reliability of the Ontario transmission system.

7.1 Transmission Projects

Planned transmission projects, that are identified by transmitters and that have a significant impact and that have an estimated in-service date within the 18 month period under study are listed in Appendix B by transmission zone. These transmission projects do not include all transmission projects submitted to the IESO for Connection Assessments and Approval. Only those projects that are considered significant are included. To make cross referencing easier, the CAA-ID number of each project has been included where available. In general, the work listed represents some or all of the work associated with the CAA-ID.

There is also a list of transmission projects that are listed in Table 7.3, in Section 7.12, which identifies the projects that are required to maintain reliability. However, only the projects that have been identified by transmitters to the IESO via submissions to the 18-Month Outlook process are listed in Appendix B.

Additional information regarding each of the transmission projects in the CAA queue can be found at the IESO's Connection Assessments web-page, at the following location:

http://www.ieso.ca/imoweb/connAssess/ca.asp.

7.2 Adequacy of the Existing Transmission System

Recent IESO Outlooks (2005-Q3 18-Month Outlook and the 2005 10-Year Outlook) identified various areas of the IESO-controlled grid where the projected loading is expected to approach or exceed the capability of the transmission facilities in the planning period. In some cases this is expected to result in congestion of low-priced resources that must be replaced by higher priced resources, and will increase costs to market loads. In other, more critical cases, where the loading is projected to exceed the capability of the transmission facilities, there is an increased risk of load interruptions.

IESO has been working with Hydro One, to identify the highest priority transmission needs, and to ensure that those projects whose in-service dates are at risk are given as much priority as is practical, especially those addressing reliability needs for summer 2006. IESO has also been working closely with the Ontario Power Authority to specify the locations, timing and minimum generation requirements to satisfy reliability standards.

Previous outlooks included a discussion of the reliability issue and a proposed transmission or generation enhancement to address the issues in the following areas:

- Western GTA
- Downtown Toronto
- Windsor Area
- Beck-Middleport-Hamilton/Burlington circuits (QFW)
- St. Lawrence to Hinchinbrooke

- Burlington Autotransformers
- Additional Low Voltage Capacitors in the GTA
- Porcupine TS Shunt Reactors
- Great Lakes Power

7.3 City of Toronto and Western GTA

The transmission capability to supply the city of Toronto and the western GTA is provided by several transformer stations that deliver power from the 500 kV transmission system to the 230 kV local transmission and eventually to the distribution stations in and around the city of Toronto. Except for Parkway, these transformer stations operated above their post-contingency continuous capability, and in the case of Trafalgar, above its post-contingency long-term emergency (LTE) capability in summer 2005. The need for transmission enhancements and new supply to unload these transformers continues to be a priority requirement for this part of the IESO-controlled grid.

The actual summer 2005 loading for the 500 kV transformer stations in the GTA and central Ontario, and their respective transfer capabilities, are summarized in the table below:

Table 7.1 Loading of GTA 500/230 kV autotransformers

Station, # transformers, Continuous, 10-day, 15 min. rating	Maximum Summer 2005 Loading MVA	Planned 2006 Post-Contingency Continuous[1] Capability MVA	Planned 2006 Post-Contingency LTE[2] Capability MVA	Projected 2006 Loadings[3] MVA
Claireville (4) 774, 1019, 1440	3160	2566	3376	3211
Trafalgar (2) 837, 986, 1500	1458	1166	1372	1497
Parkway (2) 953, 1141, 1500	602	1320	1581	989
Cherrywood (4) 750, 1016, 1362	3089	2306	3124	3063
Middleport (2) 713, 840, 1107	1176	1054	1242	1236

Summer 2005 demands were high as a result of the hot, humid weather, but not "extreme". Statistically extreme weather could have increased demands by an additional 3%. The last column estimates the loading for 2006 by adjusting the 2005 loading by 3% for extreme weather and an additional 2% (typical) for load growth, and then for the effect of adding the 2nd Parkway transformer, which will tend to unload the other stations. An additional unit at Pickering, returned to service after the 2005 summer peak demand, will further reduce the loadings at these stations, particularly Cherrywood and Parkway; the effect on Claireville and Trafalgar will be much less, and is expected to be offset by the expected operation of 6 units at Bruce for summer 2006—there were 5 units operating during summer 2005.

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[1] The Post-Contingency Continuous Capability of the station is the maximum pre-contingency loading that can be planned to be supplied by the station such that, following a permanent failure of one transformer, load can continue to be supplied continuously without exceeding the continuous ratings of the remaining transformers. For network stations this number will be larger than the sum of the continuous ratings, as some of the initial loading of the station will redistribute on the remaining transformers at the station, and also onto other stations, according to the configuration of the grid and the laws of physics. The transformer distribution factors can be found in Appendix D.

[2] The Post-Contingency LTE is the Long-Term Emergency capability of the station. It is the maximum pre-contingency loading that can be planned to be supplied by the station such that, following a permanent failure of one transformer, load can continue to be supplied for an extended period, without interruption. This relies on the long-term limited time rating of the remaining transformers, generally their 10-day rating, and also recognizes that, following a contingency, the initial loading of the station will redistribute on the remaining transformers at the station, and also onto other stations, according to the configuration of the grid and the laws of physics. The transformer distribution factors can be found in Appendix D.

[3] Assumes a 3% increase for extreme weather, a 2% (typical) increase for load growth, and includes the effect of the second Parkway transformer.

Table 7.1 above compares the loading on these transformer stations to their expected capability for summer 2006. Except for Parkway, these transformer stations operated above their post-contingency continuous capability, and in the case of Trafalgar, above its post-contingency long-term emergency (LTE) capability in summer 2005. The post-contingency continuous capability is the pre-contingency loading level that could be sustained continuously, even following the failure of one transformer. This would allow time for a failed transformer to be replaced. If the loading of the station increases above its post-contingency continuous capability, the transformers can be operated, for a limited time, up to their long-time emergency ratings, generally a 10-day rating. Operation above the continuous rating cannot be sustained beyond the time a 10-day rating will afford, without loss of life to the transformers. Past experience has shown that a transformer replacement generally may take about a month. Where the loading exceeds the post-contingency continuous capability for a significant number of hours, there is an increased risk of transformer ageing, and a risk that load interruptions would be required before a transformer can be replaced.

Table 7.1, and figures 7.1, 7.2, and 7.3 below, show that Trafalgar, Claireville, and Cherrywood loading was very high in summer 2005, and exceeded the post-contingency continuous capability for approximately 400 hours, far in excess of the time afforded by the 10-day ratings. To avoid load interruptions following a transformer contingency would require a transformer replacement to be completed within the time allotted by the 10-day ratings.

Figure 7.1 Trafalgar TS Loading for 2005 and Capability for 2006

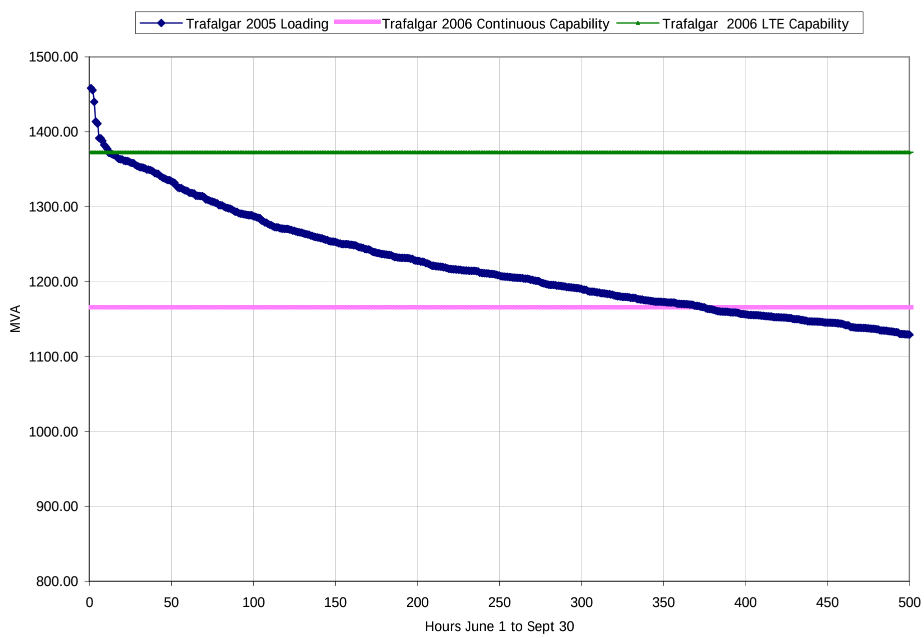
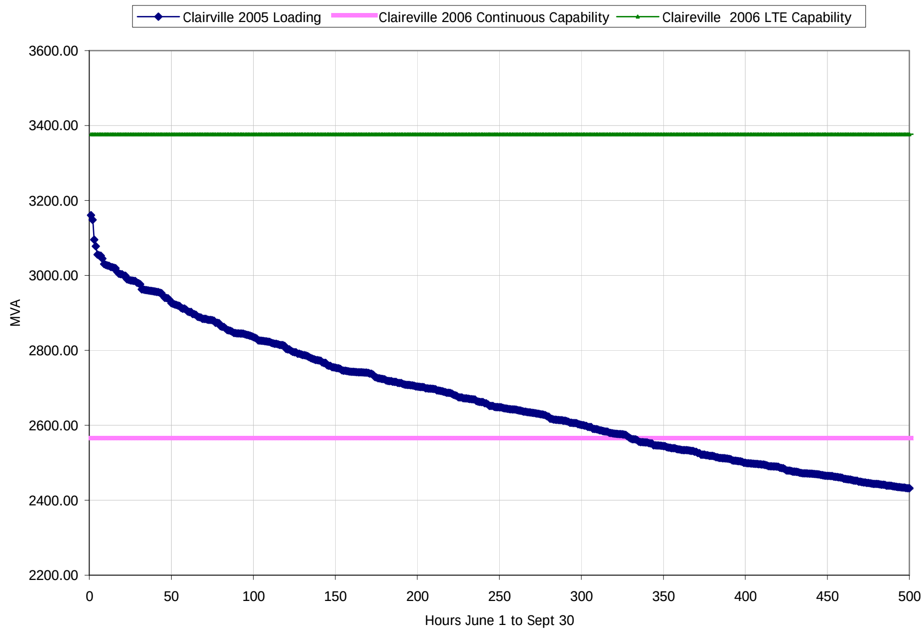


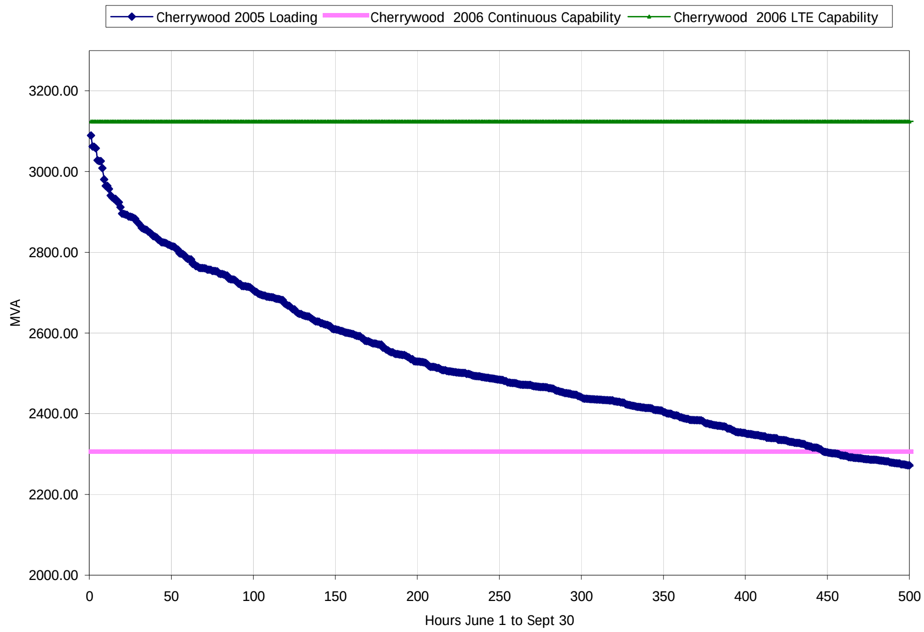
Figure 7.2 Claireville TS Loading for 2005 and Capability for 2006



For summer 2006, IESO has identified several critical short-term requirements to reduce the risk of load interruptions in the Toronto area. The most important of these is the completion of the Parkway transformer station. Hydro One has reported that the Parkway work is on schedule to be completed before summer 2006. Also included in IESO's priority items for summer 2006 is the completion of Cooksville TS, and the availability of a spare 500/230 kV autotransformer, to reduce the potential replacement time in the event of a transformer failure. Hydro One has reported that these will also be ready before summer 2006.

Transmission enhancements or new resources will be critical to an uninterrupted supply to the GTA loads in the future. There is a significant risk that new transmission and generation facilities will not be available for the earliest required in-service date, due to the expected time required for regulatory approvals and construction.

Figure 7.3 Cherrywood TS Loading for 2005 and Capability for 2006



The IESO's specific capacity requirements for new supply in the western GTA are described in the documents linked below. Many of these requirements fall into the period of this outlook.

http://www.ieso.ca/imoweb/pubs/rfp/IESO_Requirements-Western_GTA_Supply.pdf

http://www.ieso.ca/imoweb/pubs/rfp/IESO_Requirements-Western_GTA_addendum.pdf

To address the issues in the western GTA and central Toronto, the IESO will continue to work with stakeholders to assess needs and develop options.

For additional detail, IESO's 2005 10 year outlook provides the rationale and statement of need. Section 4.1 and the Greater Toronto Area section of the Conclusions address these areas specifically: http://www.ieso.ca/imoweb/pubs/marketReports/10YearOutlook_2005jul.pdf

Additional information can also be found in the 2005-Q3 18-month outlook at

http://www.ieso.ca/imoweb/pubs/marketReports/18MonthOutlook_2005sep.pdf

7.4 Toronto and Central Ontario 230/115 kV transformer stations

Table 7.2 Loading of Toronto and Central Ontario 230/115 kV autotransformers

Station, # transformers, Continuous, 10-day, 15 min. rating	Maximum Summer 2005 Loading MVA	Planned 2006 Post-Contingency Continuous[4] Capability MVA	Planned 2006 Post-Contingency LTE Capability MVA[5]	Projected 2006 Loadings[6] MVA
Leaside (6) 281, 332, 332	1289	1405	1660	1354
Manby E (3) 250, 307, 386	697	500	614	732
Manby W (3) 250, 296, 353	395	500	593	415
Burlington (4) 215, 256, 275	744	645	769	781
Beach (3) 250, 291, 348	440	500	583	462
Detweiler (3) 226, 283, 377	443	453	567	466
Allanburg (4) 225, 229, 303	770	677	688	809
Buchanan (3) 245, 300, 389	483	491	601	508

Table 7.2 shows that the autotransformers in the Toronto area and south-central Ontario were highly loaded in summer 2005, and at Manby East, Burlington, and Allanburg, exceeded both their post-contingency continuous capability, and their post-contingency long-term emergency (LTE) capability in summer 2005

Manby East loading was highest in September, when some load transfer took place. When all the available loads are transferred from Leaside, (Bridgman and Dufferin TS, approximately 250 MVA) the Manby East capability can be exceeded (Figure 7.4). As load continues to grow, it may not be possible to continue to transfer these specific loads to Manby East, while maintaining the existing level of reliability to these loads. This would reduce the flexibility to control loading at

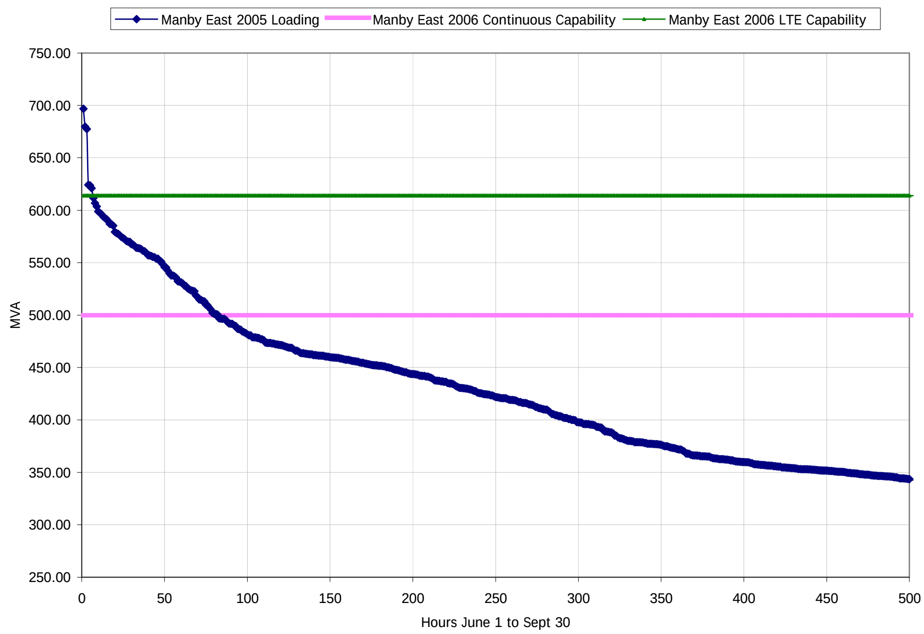
[4] The Post-Contingency Continuous Capability of the station is the maximum pre-contingency loading that can be planned to be supplied by the station such that, following a permanent failure of one transformer, load can continue to be supplied continuously without exceeding the continuous ratings of the remaining transformers. For these stations this number will be the sum of the continuous ratings of the remaining transformers at the station.

[5] The Post-Contingency LTE is the Long-Term Emergency capability of the station. It is the maximum pre-contingency loading that can be planned to be supplied by the station such that, following a permanent failure of one transformer, load can continue to be supplied for an extended period, without interruption. This relies on the long-term limited time rating of the remaining transformers, generally their 10-day rating, and also recognized that, following a contingency, the initial loading of the station will redistribute on the remaining transformers at the station.

[6] Assumes a 3% increase for extreme weather, and a 2% (typical)increase for load growth

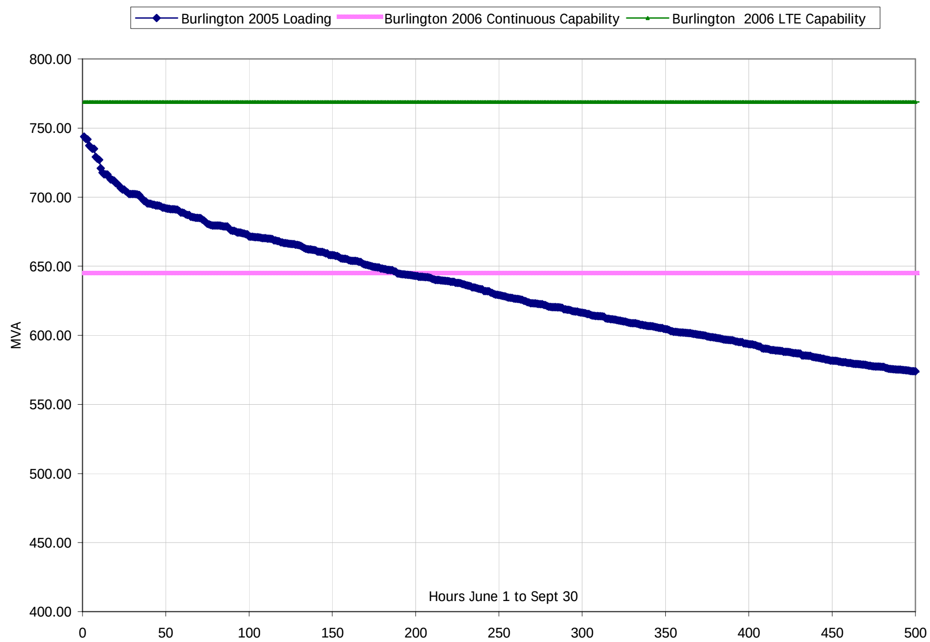
Leaside TS, although there is still spare capability at Leaside. Manby West appears to have sufficient spare capability to allow for load growth and to transfer loads from Leaside when the John-to-Esplanade link becomes available.

Figure 7.4 Manby East TS Loading for 2005 and Capability for 2006



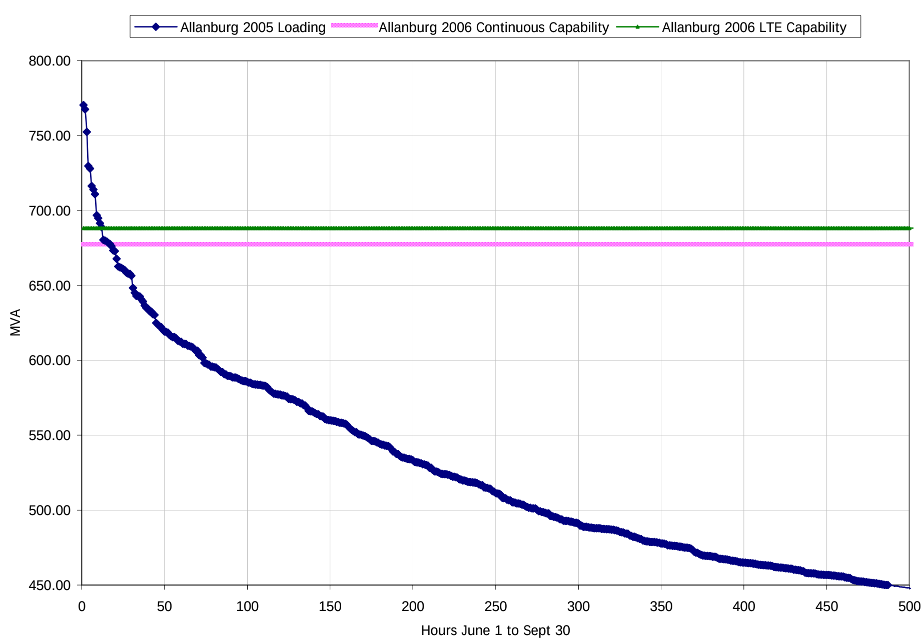
Burlington TS exceeded its post-contingency continuous capability, was very close to its LTE capability in 2005 (Figure. 7.5), and could exceed it in 2006. The IESO has asked Hydro One to ensure that overload protection is installed on these transformers, to avoid a multiple failure. IESO has also requested Hydro One to review the rating of these transformers to correct or remove any restrictions that can be accomplished before summer 2006.

Figure 7.5 Burlington TS Loading for 2005 and Capability for 2006



The loading at Allanburg TS also exceeded its LTE capability in summer 2005 (Figure 7.6) although only for less than 20 hours. In a post-contingency state it may be possible to re-dispatch Niagara area generation to control flows for a short period of time. The ratings of these transformers are unusually low for their size and IESO has requested Hydro One to review the rating of these transformers to correct or remove any restrictions that can be accomplished before summer 2006.

Figure 7.6 Allanburg TS Loading for 2005 and Capability for 2006



7.5 Significant Transmission Circuit Loadings in the GTA

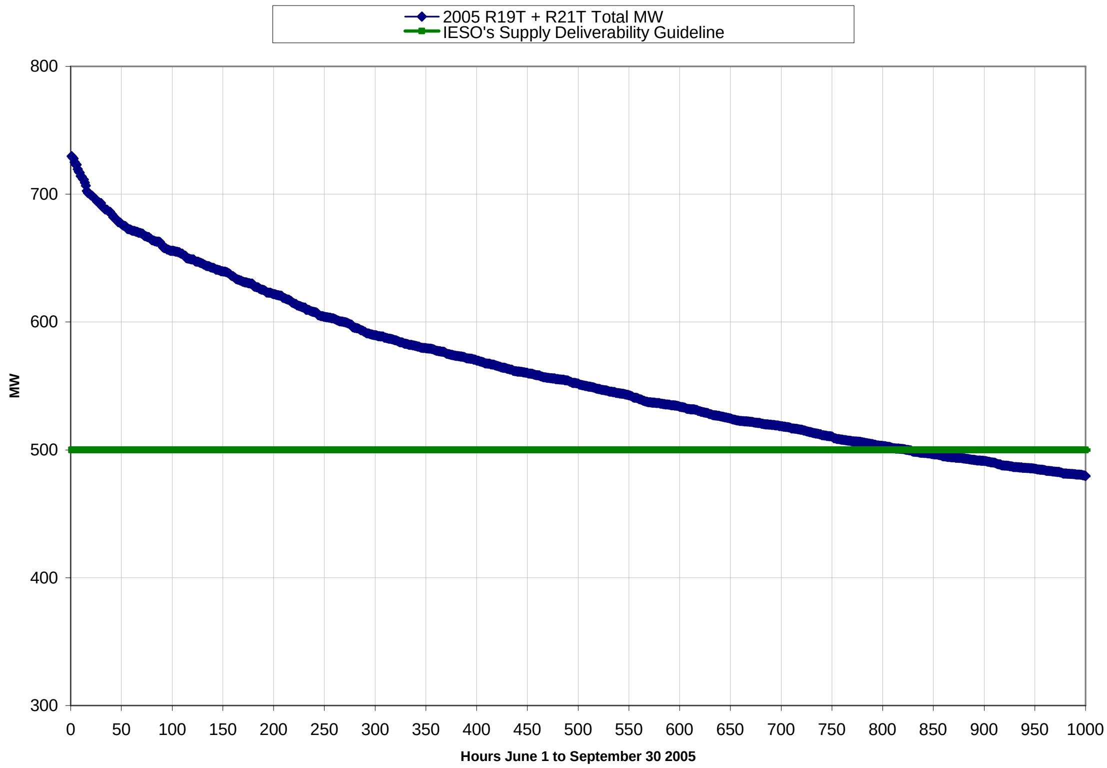
In addition to the critical loading level of the transformer stations in the GTA, there is one notable area where transmission circuits are heavily loaded and are a reliability issue that requires urgent attention.

The loading on the 230 kV double-circuit line between Trafalgar and Richview (circuits R19T and R21T) currently violates the IESO Supply Deliverability guideline for double-circuit lines (Figure 7.7). The guideline states that "for loads greater than 500 MW: with all transmission elements in service, any single element or double-circuit contingency should not result in an interruption of supply to a load level of 500 MW or more."

In summer 2005 the total load supplied by this double-circuit line was greater than 700 MW, and exceeded the IESO deliverability guideline for more than 800 hours. There is also an increased risk that load would need to be interrupted if one of the circuits were to be permanently faulted, as the load supplied exceeds the continuous rating of a single circuit (approx 650 MVA).

This has been identified as a part of the grid that requires transmission enhancements and new supply. The IESO's 2005 10-Year Outlook, and previous outlooks, have proposed transmission enhancements, including new 500/230 kV autotransformers at Milton SS or Trafalgar TS, a re-termination of connections to Halton TS and Meadowvale TS onto the new 230 kV busbar at Milton, and an extension of the connection eastward to Cardiff TS and Bramalea TS. This would allow the loads at Pleasant TS and Jim Yarrow TS (about 360 MW total) to be transferred off circuits R19T and R21T. IESO will continue to work with Hydro One and the OPA to assess available options and to advance a transmission option, in conjunction with new supply, to address this violation of guidelines. There is a significant risk that these transmission enhancements, or new supply, will not be available for the earliest required in-service date, due to the expected time for regulatory approvals and construction.

Figure 7.7 Richview to Trafalgar R19T and R21T Loading for 2005 and IESO's Deliverability Guideline Level



7.6 Windsor Area

The Windsor area is expected to continue to require the full use of operational procedures and special protection systems to reduce congestion and to mitigate the risk of interruptions to loads in the area. Thermal ratings of the 115 kV circuits and the two 230/115 kV autotransformers at Keith TS often restricted local generation, limited imports from Michigan and relied on the arming of local special protection systems for extended periods of time. For summer 2005 operation, the loading on 115 kV circuit J4E exceeded the summer design rating for about 150 hours, requiring extensive arming of the local special protection system, and restricting imports over J5D.

Upgrades for the area have been identified as a priority requirement by the IESO and IESO is working with Hydro One to advance the work to reconfigure the 115 kV circuits at Essex and to modify the Windsor Area SPS for summer 2006. Additional new transmission will require more time, and is at risk of delays due to the time required for regulatory approvals and construction.

7.7 Beck-Middleport-Hamilton/Burlington circuits (QFW)

Hydro One has completed the work to bring the rating of the circuit sections into Burlington and Hamilton up to their design capability, and for conditions similar to summer 2005, this should provide at least 200 MW of increased transfer capability into the Hamilton and Burlington area from the southwest and Niagara area.

The Niagara expansion project will also expand the thermal capability of the QFW transmission path out of Beck by adding two 230kV circuits from Allanburg to Middleport, effectively adding two circuits to the QFW interface, and increasing the transfer capability by up to 800 MW. This work is planned to be completed in the third quarter of 2006.

7.8 St. Lawrence to Hinchinbrooke

Summer 2005 operation exhibited very heavy loading on the 230 kV circuits westward from St. Lawrence TS to Hinchinbrooke TS. As two of the circuits share common towers, a tower fault would leave only one circuit to carry most of the power, and overload it beyond its limited time rating. These conditions prevailed during the heaviest demand days, and limited imports into Ontario from Quebec and New York, and required the use of emergency control actions including emergency transfer limits for some of these days.

IESO has proposed enhancements to an existing special protection system to reduce generation in the event of a tower contingency, thereby relieving the limitation in the short-term. IESO has asked Hydro One to make this available before summer 2006.

7.9 Additional Low Voltage Capacitors in the GTA

The high and growing demands experienced in summer 2005 continued to exhibit poor power factor, tending to lower voltage and increasing the need for reactive power from the generators in southern Ontario. Such a trend, if not corrected will require increasing amounts of reactive injection from the generating units, and leave insufficient spare reactive capability to control voltages following contingencies. Such a situation is unreliable and cannot be permitted to occur on the grid.

To correct this, and maintain sufficient spare reactive capability on the generators, IESO is reviewing the actual summer 2005 power factor at various stations in the Toronto area, and will be exploring, with Hydro One and the applicable distributors, options to install low voltage capacitor banks or to take equivalent power factor corrective actions, before summer 2006 where possible, at Halton TS, Meadowvale TS, Palermo TS, Jim Yarrow TS, Cambridge-Preston TS, Whitby TS, and Otonabee TS.

7.10 Porcupine TS Shunt Reactors

The recent 10-Year Outlook identified various enhancements for northeastern Ontario. Summer 2005 operation also reinforced the potential for high voltages at Porcupine and Pinard TS following 500 kV circuit contingencies. These voltages could exceed equipment capability and expose transmission customers to damaging high voltages. To reduce the risk to equipment, and reduce the exposure to customer interruptions, additional shunt reactors at Porcupine and/or Pinard TS may be required. These reactors must be included in the post-contingency switching capability of the north-east LGR scheme to effectively control voltages. Hydro One has scheduled this work to be completed before the end of 2006.

7.11 Great Lakes Power

Great Lakes Power will be completing a 230 kV transmission line between the northern part of their system near Wawa and the southern part near Sault St. Marie. The circuit will improve reliability to loads in the Sault St. Marie area and reduce restrictions to generation in the Great Lakes Power system.

7.12 Summary of Transmission Requirements for the Outlook Period

The following table summarizes the projects described above and various others that IESO has previously identified to maintain the reliability of the IESO controlled grid, and that fall into this outlook period. Most of these projects have been identified in the IESO's recent 10-Year Outlook; additional details are available in that report. Others have been identified as a result of the summer 2005 operation, or from analysis since the publishing of the 10-year outlook, and their dates modified as a result.

Of all the transmission projects listed in table 7.3, only some of these projects that have been identified by transmitters to the IESO via submissions to the 18-Month Outlook process. Those projects that have been identified by the transmitter are listed in Appendix B.

Table 7.3 Transmission Projects Priorities

Priority Transmission Project - Description of Facilities	*Comments, Expected Completion Date*	*Required Completion Date*
1. Complete the on-going work at Cooksville TS to eliminate the need for a 230kV busbar at Lakeview SS		Spring-2006
2. Complete the 2nd Phase of the development of Parkway TS including the installation of a 2nd 500/230kV auto-transformer		
3. Complete the replacement of the 500kV and 115kV breakers at Porcupine TS, including the reconfiguration of the 500kV terminations and the related changes to the North-east SPS.	October 2006	
4. Reconfigure the 115kV circuit terminations at Essex TS; Modify the Windsor Area SPS; & Re-conductor 115kV circuits J3E & J4E. Confirm OEB S92 not required.	October 2006 for reconfiguring. Need for re-conductoring under review. Not before Q2 2007.	
5. Replace the two 215MVA 230/115kV auto-transformers at Burlington TS with higher-rated units. Install 2 pu over-current protection before 2006.	Need for transformers under review. Not before 2007.	
6. Install LV capacitor banks at, Hydro One: Halton TS, Meadowvale Customers: TS, Palermo TS, Jim Yarrow TS, Cambridge-Preston TS, Whitby TS & Otonabee TS and Oakville TS.	Need for capacitors under review. Target spring 2007.	
7. Uprate existing 230kV circuits into Burlington TS. All rated to operate up to 131'C.	Done.	
8. Install additional shunt reactors at Porcupine TS (& possibly at Pinard TS) and incorporate a post-contingency switching capability into the North-east LGR Scheme.	Earliest by October 2006	
9. Enhance the Beauharnois-Saunders G/R Scheme to respond to double-circuit contingencies.	Needed by spring 2006. October 2006	
10. Uprate 115kV circuits H9A & A2 between Hawthorne TS & Bilberry Creek TS.	Rely on operating measures in the short-term. Since the long-term solution is a subset of the 1250 MW interconnection with Quebec, it can not be implemented independently.	

Priority Transmission Project - Description of Facilities	*Comments, Expected Completion Date*	*Required Completion Date*
11. Maintain a minimum of one 750MVA 500/230kV auto-transformer available as a system spare.	First-planned end May 2006. Second-after summer 2006. Third-on order, as early as Q2 2006.	
12. Reinforce the 230kV system between Allanburg TS & Middleport TS	End of July 2006	Summer-2006
13. Replace the 230/115kV auto-transformers at Keith TS with higher-rated units	Under review. Co-ordinate with item 4, re-conductoring J3E, J4E.	Fall-2006
14. Install two 250MVA 230/115kV auto-transformers at Cambridge-Preston TS	Possibly installed in phases, one transformer initially. First transformer target date spring 2007.	
15. Install shunt capacitors at Fort Frances TS or Mackenzie TS.	Review need for Mackenzie, and in light of Manitoba contract plans. Fort Frances as early as Spring 2006.	
16. Transfer Tilbury load to a dedicated circuit from Lauzon. Delete - install a 230/115kV auto-transformer at Kent TS.	late 2007, early 2008	Spring-2007
17. Install a 245MVA 250kV capacitor bank at Detweiler TS		
18. Install a 245MVA 250kV capacitor bank at Orangeville TS		
19. Install a 245MVA 250kV capacitor bank at Beach	As early as spring 2006	
20. Install two 412MVAr 250kV shunt capacitor banks at Middleport TS	Earliest spring 2007.	Spring-2007

7.13 Planned Transmission Outages

A principal purpose of the transmission reliability assessment is to forecast any reduction in transmission capacity brought about by specific transmission outages. For a major transmission interface or interconnection, the reduction in transmission capacity due to an outage condition can be expressed as a change in the base flow limit associated with the interface or interconnection. Another purpose of the transmission reliability assessment is to identify the possibility of any security-related events on the IESO-controlled grid that could require contingency planning by market participants or by the IESO. As a result, the transmission outages are reviewed to identify transmission system reliability concerns and to highlight those outages that should be rescheduled or changed. As an example, a change to an outage may include reducing the scheduled duration or recall time.

The assessment of transmission outages will also identify any resources that are forecast to be constrained due to transmission outage conditions. The identification of a constrained resource is generally not reflected in the assessment of weekly resource adequacy, which is detailed in Section 6.1, since there is typically sufficient outage scheduling flexibility to avoid constraining off resources when such resources are needed for reliability. Transmitters and generators are expected to have a mutual interest in developing an ongoing arrangement to coordinate their outage planning activities. Transmission outages that may affect generation access to the IESO-controlled grid should be coordinated with the generator operators involved, especially at times when the forecast of reserve is deficient. Under the Market Rules, where the scheduling of planned outages by different market participant's conflicts such that both or all outages cannot be approved by the IESO, the IESO will inform the affected market participants and request that they resolve the conflict. If the conflict remains unresolved, the IESO shall determine which of the planned outages can be approved according to the priority of each planned outage as determined by the Market Rules detailed in Chapter 5, Sections 6.4.13 to 6.4.18.

For this Outlook, transmission outage plans submitted to the IESO's Integrated Outage Management System (IOMS) as of November 2005 were used.

The IESO's assessment of the impact of the transmission outage plans is shown in Appendix C, Tables C1 to C10. In these tables, each element is assessed individually by indicating the possible impacts and the reduction in transmission interface and/or interconnection limits. The methodology used to assess the transmission outage plans is described in the IESO document titled "Methodology to Perform Long Term Assessments" (IESO_REP_0266).

A few of the transmission outages planned within the timeframe of this Outlook are judged to have a material impact on the overall reliability of the IESO-controlled grid.

The assessment of transmission outages for this Outlook has been limited to those outages with a scheduled duration of greater than five days or to those outages associated with a project where at least one outage has a scheduled duration of greater than five days. The IESO recognizes that there are expected to be additional outage requirements and/or changes as time approaches the Outlook study period and that transmission capacity will be impacted by outages with a scheduled duration of five days or less. Prior to approving and releasing an outage, the IESO will reassess the outage for potential system impacts, taking into account all current and forecasted conditions.

The large number of system changes identified to be completed in the 10-Year Outlook and this 18-Month assessment will require a substantial number of planned outages to incorporate the new facilities. It is too early in the development of most of these plans to identify specific outage requirements. These will be identified in future Outlooks.

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8.0 Overall Observations, Findings and Conclusions

The following findings and conclusions are based on the results of the assessment carried out for this Outlook.

Resource Adequacy

- Under the Existing Resource-Normal Weather Scenario, forecast reserves are generally adequate for the study period. Reserves are forecast to be above requirements for all but three weeks of the Outlook timeframe. During these weeks some planned generator outages are at risk of cancellation by the IESO for reliability purposes depending on their priority and the resource adequacy situation at the time their approval is being sought. Opportunities will exist for additional planned generator maintenance and exports in the other weeks of the Outlook period.
- Under the Planned Resource-Normal Weather Scenario, the resource adequacy situation is somewhat similar to the Existing Resource Scenario, with an improvement of about 150 MW on average in the Reserve Above Requirement.
- Extreme weather during the peak periods will result in significantly increased reliance on imports to supplement Ontario generation and higher potential for emergency operating procedures.
- Results of the resource adequacy assessment are summarized in the matrix below. The different shadings are intended to suggest the degree of concern regarding the supply/demand situation under each resource-weather scenario combination.

	Normal Weather Scenario	Extreme Weather Scenario
Existing Resource Scenario	- opportunities for additional outages/exports exist in most weeks - there are three weeks when reserves are lower than required (planned outages at risk or imports potentially required)	- many planned outages at risk - imports required during some peak periods - higher risk of requiring emergency operating procedures up to and including rotational load shedding
Planned Resource Scenario	- opportunities for additional outages/exports exist in most weeks - there are three weeks when reserves are lower than required (planned outages at risk or imports potentially required)	- many planned outages at risk - imports required during some peak periods - higher risk of requiring emergency operating procedures up to and including rotational load shedding

- The magnitude of resource deficiencies under extreme weather emphasizes the continued need for reliable supply and demand response within Ontario.

- For the 18 month period under study, the improved demand-supply situation for the Planned Resource Scenario is dependent on the additional generation and price-responsive demand coming into the market as forecast. Seven of the ten new projects from the recent Request for Proposals for Renewable generation are expected to be available within the 18 month timeframe of this Outlook. One of the ten is already in service.
- A number of large generating units are scheduled to return to service from outage prior to the winter 2006/2007 and summer 2006. Meeting these planned outage schedules is critical to maintaining adequate reserve levels over the peak seasons.
- High generator unavailability, whether caused by higher forced outage rates or delays in returning generators to service, could lead to reliance on imports. Under these circumstances, opportunities for planned outages, especially during the peak summer period, would be limited.
- Over the 18 month period under study, the Northeast Power Coordinating Council resource adequacy criterion is expected to be met.
- Extreme weather during peak periods places increased emphasis on reliable Ontario resources and energy imported from neighbouring systems. To maximize the ability to respond to these peak period requirements the following actions are planned:

  <u>Maximize the capability of existing resources:</u>

  - Resolve generation dispatch issues (e.g. aggregation, frequency of dispatch)
  - Review the use of environmental variances within the list of emergency control actions

  <u>Increase the certainty of market mechanisms:</u>

  - Allow imports to be scheduled day ahead like the markets surrounding Ontario
  - Commit units day ahead like the markets surrounding Ontario
  - Implement an Emergency Demand Response Program like the markets surrounding Ontario

  <u>IESO operations and planning:</u>

  - Processes and criteria are under review to ensure forecast risks are adequately recognized and that appropriate standards are in place.

Transmission Adequacy

- The transmission capability to supply the city of Toronto and the western GTA is provided by several transformer stations that deliver power from the 500 kV transmission system to the 230 kV local transmission and eventually to the distribution stations in and around the city of Toronto. Except for Parkway, these transformer stations operated above their post-contingency continuous capability, and in the case of Trafalgar, above its post-contingency long-term emergency (LTE) capability in summer 2005. The need for transmission enhancements and new supply to unload these transformers continues to be a priority requirement for this part of the IESO-controlled grid.
- For summer 2006, IESO has identified several critical short-term requirements to reduce the risk of load interruptions in the Toronto area. The most important of these is the completion

of the Parkway transformer station. Hydro One has reported that the Parkway work is on schedule to be completed before summer 2006. Also included in IESO's priority items for summer 2006 is the completion of Cooksville TS, and the availability of a spare 500/230 kV autotransformer, to reduce the potential replacement time in the event of a transformer failure. Hydro One has reported that these will also be ready before summer 2006.

- The loading on the 230 kV double-circuit line between Trafalgar and Richview (circuits R19T and R21T) currently violates the IESO Supply Deliverability guideline for double-circuit lines (Figure 7.7). The guideline states that "for loads greater than 500MW: with all transmission elements in service, any single element or double-circuit contingency should not result in an interruption of supply to a load level of 500MW or more." In summer 2005 the loading on this double-circuit line exceeded 700 MW, and exceeded the IESO deliverability guideline for more than 800 hours. IESO is working with Hydro One to advance transmission options to solve this issue.
- Upgrades for the Windsor area have been identified as a priority requirement by the IESO and IESO is working with Hydro One to advance the work to reconfigure the 115 kV circuits at Essex and to modify the Windsor Area SPS for summer 2006. Additional new transmission will require more time, and is at risk of delays due to the time required for regulatory approvals and construction
- Hydro One has completed the work to bring the rating of the circuit sections into Burlington and Hamilton up to their design capability, and for conditions similar to summer 2005, this should provide at least 200 MW of increased transfer capability into the Hamilton and Burlington are from the southwest and Niagara.
- The Niagara expansion project will also expand the thermal capability of the QFW transmission path out of Beck by adding two 230kV circuits from Allanburg to Middleport, effectively adding two circuits to the QFW interface, and increasing the transfer capability by up to 800 MW. This work is planned to be completed in the third quarter of 2006
- Burlington TS was very close to its LTE capability in 2005 (Figure. 7.5), and could exceed it in 2006. The IESO has asked Hydro One to ensure that overload protection is installed on these transformers, to avoid a multiple failure. IESO has also requested Hydro One to review the rating of these transformers to correct or remove any restrictions that can be accomplished before summer 2006.
- Summer 2005 operation exhibited very heavy loading on the 230 kV circuits westward from St. Lawrence TS to Hinchinbrooke TS. As two of the circuits share common towers, a tower fault would leave only one circuit to carry most of the power, and overload it beyond its limited time rating. These conditions prevailed during the heaviest demand days, and limited imports into Ontario from Quebec and New York, and required the use of emergency control actions including emergency transfer limits for some of these days

  IESO has proposed enhancements to an existing special protection system to reduce generation in the event of a tower contingency, thereby relieving the limitation in the short-term. IESO has asked Hydro One to make this available before summer 2006.

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Appendix A Resource Adequacy Assessment Details

Table A1 Assessment of Resource Adequacy: Existing Resource Scenario

Week Ending Day	Total Resources MW	Total Reductions in Resources MW	Price-responsive Demand MW	Available Resources MW	Required Resources MW	Available Reserve %	Available Reserve MW	Required Reserve %	Required Reserve MW	Reserve Above Requirement MW
01-Jan-06	30,631	2,776	372	28,227	25,345	27.4	6,063	14.4	3,181	2,882
08-Jan-06	30,631	2,655	372	28,348	26,914	20.3	4,790	14.3	3,356	1,434
15-Jan-06	30,631	2,180	372	28,823	27,402	20.5	4,909	14.6	3,488	1,421
22-Jan-06	30,631	2,852	372	28,151	27,926	15.9	3,866	15.0	3,641	225
29-Jan-06	30,631	2,212	372	28,791	27,567	19.6	4,718	14.5	3,494	1,224
05-Feb-06	30,631	1,772	372	29,231	27,244	22.8	5,430	14.5	3,443	1,987
12-Feb-06	30,631	2,167	372	28,836	26,953	22.0	5,206	14.1	3,323	1,883
19-Feb-06	30,631	2,093	372	28,910	26,801	23.7	5,537	14.7	3,428	2,109
26-Feb-06	30,631	3,417	372	27,586	26,263	19.7	4,531	13.9	3,208	1,323
05-Mar-06	30,631	4,371	372	26,632	26,087	16.7	3,811	14.3	3,266	545
12-Mar-06	30,631	4,760	372	26,243	25,683	16.5	3,707	14.0	3,147	560
19-Mar-06	30,631	4,760	372	26,243	25,135	19.2	4,224	14.2	3,116	1,108
26-Mar-06	30,631	4,800	372	26,203	24,801	20.9	4,521	14.4	3,119	1,402
02-Apr-06	30,631	4,426	372	26,577	24,551	25.8	5,451	16.2	3,425	2,026
09-Apr-06	30,631	5,209	372	25,794	24,058	23.4	4,884	15.1	3,148	1,736
16-Apr-06	30,631	5,111	372	25,892	23,592	26.7	5,456	15.4	3,156	2,300
23-Apr-06	30,631	4,361	372	26,642	23,537	31.5	6,387	16.2	3,282	3,105
30-Apr-06	30,631	7,019	372	23,984	22,574	20.4	4,070	13.4	2,660	1,410
07-May-06	30,631	6,127	372	24,876	22,842	25.6	5,074	15.4	3,040	2,034
14-May-06	30,631	6,191	372	24,812	22,584	26.6	5,207	15.2	2,979	2,228
21-May-06	30,631	4,869	372	26,134	24,517	23.6	4,991	16.0	3,374	1,617
28-May-06	30,631	4,589	372	26,414	24,776	24.5	5,202	16.8	3,564	1,638
04-Jun-06	30,631	4,183	372	26,820	25,360	23.7	5,142	17.0	3,682	1,460
11-Jun-06	30,631	2,970	372	28,033	26,015	28.9	6,276	19.6	4,258	2,018
18-Jun-06	30,631	2,201	372	28,802	27,176	26.3	5,996	19.2	4,370	1,626
25-Jun-06	30,631	1,858	372	29,145	28,136	21.4	5,146	17.2	4,137	1,009
02-Jul-06	30,631	1,695	372	29,308	28,091	23.9	5,654	18.8	4,437	1,217
09-Jul-06	30,631	1,617	372	29,386	28,028	21.7	5,237	16.1	3,879	1,358
16-Jul-06	30,631	1,617	372	29,386	28,425	21.3	5,154	17.3	4,193	961
23-Jul-06	30,631	1,579	372	29,424	28,091	21.6	5,227	16.1	3,894	1,333
30-Jul-06	30,631	1,704	372	29,299	28,092	21.1	5,105	16.1	3,898	1,207
06-Aug-06	30,647	1,873	372	29,146	27,642	23.1	5,461	16.7	3,957	1,504
13-Aug-06	30,647	1,716	372	29,303	27,952	22.0	5,276	16.3	3,925	1,351
20-Aug-06	30,647	1,822	372	29,197	27,498	23.5	5,546	16.3	3,847	1,699
27-Aug-06	30,647	1,893	372	29,126	27,493	24.8	5,782	17.8	4,149	1,633
03-Sep-06	30,647	3,217	372	27,802	27,554	17.3	4,093	16.2	3,845	248
10-Sep-06	30,647	3,781	372	27,238	26,685	18.7	4,286	16.3	3,733	553
17-Sep-06	30,647	4,611	372	26,408	25,961	18.6	4,141	16.6	3,694	447
24-Sep-06	30,647	5,212	372	25,807	24,958	20.0	4,304	16.1	3,455	849

Note: The reader should be aware that Security and Adequacy Assessments are published on the IESO web site on a weekly and daily basis that progressively supersede information presented in this report.

(Table A1 continued)

Week Ending Day	Total Resources MW	Total Reductions in Resources MW	Price-responsive Demand MW	Available Resources MW	Required Resources MW	Available Reserve %	Available Reserve MW	Required Reserve %	Required Reserve MW	Reserve Above Requirement MW
01-Oct-06	30,647	5,113	372	25,906	23,544	28.0	5,668	16.3	3,306	2,362
08-Oct-06	30,647	5,833	372	25,186	23,280	24.6	4,968	15.1	3,062	1,906
15-Oct-06	30,647	6,818	372	24,201	23,113	18.8	3,823	13.4	2,735	1,088
22-Oct-06	30,647	6,095	372	24,924	23,681	19.5	4,064	13.5	2,821	1,243
29-Oct-06	30,647	6,176	372	24,843	24,223	17.2	3,649	14.3	3,029	620
05-Nov-06	30,647	6,486	372	24,533	24,858	12.5	2,723	14.0	3,048	-325
12-Nov-06	30,663	6,375	372	24,660	25,098	11.8	2,596	13.8	3,034	-438
19-Nov-06	30,663	5,110	372	25,925	25,856	14.1	3,211	13.8	3,142	69
26-Nov-06	30,663	4,135	372	26,900	26,283	16.5	3,806	13.8	3,189	617
03-Dec-06	30,663	3,039	372	27,996	26,418	20.6	4,774	13.8	3,196	1,578
10-Dec-06	30,663	3,463	372	27,572	27,226	15.6	3,714	14.1	3,368	346
17-Dec-06	30,663	1,844	372	29,191	27,355	22.1	5,279	14.4	3,443	1,836
24-Dec-06	30,663	1,399	372	29,636	27,679	23.9	5,712	15.7	3,755	1,957
31-Dec-06	30,663	1,448	372	29,587	26,063	31.9	7,153	16.2	3,629	3,524
07-Jan-07	30,663	1,427	372	29,608	27,300	24.2	5,764	14.5	3,456	2,308
14-Jan-07	30,663	1,427	372	29,608	27,676	22.5	5,433	14.5	3,501	1,932
21-Jan-07	30,663	1,383	372	29,652	28,146	20.8	5,105	14.7	3,599	1,506
28-Jan-07	30,663	2,207	372	28,828	27,752	18.5	4,493	14.0	3,417	1,076
04-Feb-07	30,663	2,168	372	28,867	27,378	19.8	4,778	13.7	3,289	1,489
11-Feb-07	30,663	2,182	372	28,853	27,193	20.7	4,953	13.8	3,293	1,660
18-Feb-07	30,663	2,124	372	28,911	27,037	22.3	5,272	14.4	3,398	1,874
25-Feb-07	30,663	2,124	372	28,911	26,637	24.0	5,586	14.2	3,312	2,274
04-Mar-07	30,663	3,744	372	27,291	26,256	18.0	4,159	13.5	3,124	1,035
11-Mar-07	30,663	3,756	372	27,279	25,841	19.6	4,466	13.3	3,028	1,438
18-Mar-07	30,663	3,776	372	27,259	25,393	22.3	4,964	13.9	3,098	1,866
25-Mar-07	30,663	4,637	372	26,398	25,009	20.2	4,440	13.9	3,051	1,389
01-Apr-07	30,663	4,637	372	26,398	24,612	23.3	4,996	15.0	3,210	1,786
08-Apr-07	30,663	4,440	347	26,570	24,389	25.5	5,404	15.2	3,223	2,181
15-Apr-07	30,663	4,401	347	26,609	24,001	28.6	5,916	16.0	3,308	2,608
22-Apr-07	30,663	4,960	347	26,050	23,609	27.0	5,531	15.1	3,090	2,441
29-Apr-07	30,663	4,605	347	26,405	23,144	30.6	6,185	14.5	2,924	3,261
06-May-07	30,663	5,130	347	25,880	23,048	29.0	5,814	14.9	2,982	2,832
13-May-07	30,663	5,061	347	25,949	22,861	30.3	6,031	14.8	2,943	3,088
20-May-07	30,663	5,640	347	25,370	24,383	18.0	3,870	13.4	2,883	987
27-May-07	30,663	3,737	347	27,273	24,977	26.4	5,702	15.8	3,406	2,296
03-Jun-07	30,663	4,025	347	26,985	25,484	22.5	4,948	15.6	3,447	1,501
10-Jun-07	30,663	3,555	347	27,455	26,009	24.2	5,345	17.6	3,899	1,446
17-Jun-07	30,663	3,176	347	27,834	27,229	20.2	4,675	17.6	4,070	605
24-Jun-07	30,663	3,280	347	27,730	28,276	14.2	3,444	16.4	3,990	-546
01-Jul-07	30,663	2,061	347	28,949	28,625	19.7	4,761	18.3	4,437	324

Table A2 Assessment of Resource Adequacy: Planned Resource Scenario

Week Ending Day	Total Resources MW	Total Reductions in Resources MW	Price-responsive Demand MW	Available Resources MW	Required Resources MW	Available Reserve %	Available Reserve MW	Required Reserve %	Required Reserve MW	Reserve Above Requirement MW
01-Jan-06	30,631	2,776	376	28,231	25,345	27.4	6,067	14.4	3,181	2,886
08-Jan-06	30,634	2,658	376	28,352	26,914	20.4	4,794	14.3	3,356	1,438
15-Jan-06	30,634	2,183	376	28,827	27,402	20.5	4,913	14.6	3,488	1,425
22-Jan-06	30,751	2,855	376	28,272	27,924	16.4	3,987	15.0	3,639	348
29-Jan-06	30,751	2,215	376	28,912	27,579	20.1	4,839	14.6	3,506	1,333
05-Feb-06	30,751	1,775	391	29,367	27,256	23.4	5,566	14.5	3,455	2,111
12-Feb-06	30,819	2,238	391	28,972	26,965	22.6	5,342	14.1	3,335	2,007
19-Feb-06	30,819	2,164	391	29,046	26,813	24.3	5,673	14.7	3,440	2,233
26-Feb-06	30,819	3,488	391	27,722	26,275	20.2	4,667	14.0	3,220	1,447
05-Mar-06	30,858	4,481	391	26,768	26,083	17.3	3,947	14.3	3,262	685
12-Mar-06	30,858	4,870	391	26,379	25,679	17.1	3,843	14.0	3,143	700
19-Mar-06	30,858	4,870	391	26,379	25,148	19.8	4,360	14.2	3,129	1,231
26-Mar-06	30,858	4,910	391	26,339	24,813	21.5	4,657	14.4	3,131	1,526
02-Apr-06	30,858	4,536	427	26,749	24,563	26.6	5,623	16.3	3,437	2,186
09-Apr-06	30,858	5,320	427	25,965	24,070	24.2	5,055	15.1	3,160	1,895
16-Apr-06	30,858	5,221	427	26,064	23,604	27.5	5,628	15.5	3,168	2,460
23-Apr-06	30,858	4,471	427	26,814	23,549	32.4	6,559	16.3	3,294	3,265
30-Apr-06	30,858	7,129	427	24,156	22,587	21.3	4,242	13.4	2,673	1,569
07-May-06	30,957	6,336	427	25,048	22,853	26.5	5,246	15.4	3,051	2,195
14-May-06	30,957	6,400	427	24,984	22,596	27.4	5,379	15.3	2,991	2,388
21-May-06	30,957	5,078	427	26,306	24,529	24.4	5,163	16.0	3,386	1,777
28-May-06	30,957	4,798	427	26,586	24,789	25.3	5,374	16.9	3,577	1,797
04-Jun-06	30,957	4,393	427	26,991	25,372	24.5	5,313	17.0	3,694	1,619
11-Jun-06	30,957	3,179	427	28,205	26,027	29.6	6,448	19.6	4,270	2,178
18-Jun-06	30,957	2,410	427	28,974	27,188	27.1	6,168	19.2	4,382	1,786
25-Jun-06	30,957	2,067	427	29,317	28,148	22.2	5,318	17.3	4,149	1,169
02-Jul-06	30,957	1,904	427	29,480	28,104	24.6	5,826	18.8	4,450	1,376
09-Jul-06	30,957	1,826	427	29,558	28,041	22.4	5,409	16.1	3,892	1,517
16-Jul-06	30,957	1,826	427	29,558	28,435	22.0	5,326	17.3	4,203	1,123
23-Jul-06	30,957	1,788	427	29,596	28,103	22.3	5,399	16.1	3,906	1,493
30-Jul-06	30,957	1,914	427	29,470	28,104	21.8	5,276	16.2	3,910	1,366
06-Aug-06	30,973	2,092	427	29,308	27,656	23.7	5,623	16.8	3,971	1,652
13-Aug-06	30,973	1,935	427	29,465	27,964	22.6	5,438	16.4	3,937	1,501
20-Aug-06	30,973	2,041	427	29,359	27,509	24.1	5,708	16.3	3,858	1,850
27-Aug-06	30,973	2,112	427	29,288	27,505	25.5	5,944	17.8	4,161	1,783
03-Sep-06	30,973	3,436	427	27,964	27,566	18.0	4,255	16.3	3,857	398
10-Sep-06	30,973	4,000	427	27,400	26,697	19.4	4,448	16.3	3,745	703
17-Sep-06	30,973	4,830	427	26,570	25,973	19.3	4,303	16.6	3,706	597
24-Sep-06	30,973	5,431	427	25,969	24,969	20.8	4,466	16.1	3,466	1,000

Note: The reader should be aware that [Security and Adequacy Assessments] are published on the IESO web site on a weekly and daily basis that progressively supersede information presented in this report.

(Table A2 continued)

Week Ending Day	Total Resources MW	Total Reductions in Resources MW	Price-responsive Demand MW	Available Resources MW	Required Resources MW	Available Reserve %	Available Reserve MW	Required Reserve %	Required Reserve MW	Reserve Above Requirement MW
01-Oct-06	30,973	5,332	427	26,068	23,555	28.8	5,830	16.4	3,317	2,513
08-Oct-06	31,072	6,151	427	25,348	23,292	25.4	5,130	15.2	3,074	2,056
15-Oct-06	31,072	7,136	427	24,363	23,126	19.6	3,985	13.5	2,748	1,237
22-Oct-06	31,072	6,413	427	25,086	23,693	20.3	4,226	13.6	2,833	1,393
29-Oct-06	31,072	6,494	427	25,005	24,222	18.0	3,811	14.3	3,028	783
05-Nov-06	31,072	6,804	427	24,695	24,855	13.2	2,885	14.0	3,045	-160
12-Nov-06	31,088	6,693	427	24,822	25,094	12.5	2,758	13.7	3,030	-272
19-Nov-06	31,088	5,418	427	26,097	25,842	14.9	3,383	13.8	3,128	255
26-Nov-06	31,088	4,452	427	27,063	26,276	17.2	3,969	13.8	3,182	787
03-Dec-06	31,088	3,347	427	28,168	26,431	21.3	4,946	13.8	3,209	1,737
10-Dec-06	31,088	3,771	427	27,744	27,217	16.3	3,886	14.1	3,359	527
17-Dec-06	31,088	2,152	427	29,363	27,366	22.8	5,451	14.4	3,454	1,997
24-Dec-06	31,088	1,717	427	29,798	27,691	24.6	5,874	15.8	3,767	2,107
31-Dec-06	31,088	1,766	427	29,749	26,075	32.6	7,315	16.2	3,641	3,674
07-Jan-07	31,088	1,745	427	29,770	27,313	24.9	5,926	14.6	3,469	2,457
14-Jan-07	31,088	1,745	427	29,770	27,688	23.1	5,595	14.5	3,513	2,082
21-Jan-07	31,088	1,701	427	29,814	28,158	21.5	5,267	14.7	3,611	1,656
28-Jan-07	31,088	2,525	427	28,990	27,764	19.1	4,655	14.1	3,429	1,226
04-Feb-07	31,088	2,486	427	29,029	27,390	20.5	4,940	13.7	3,301	1,639
11-Feb-07	31,088	2,500	427	29,015	27,205	21.4	5,115	13.8	3,305	1,810
18-Feb-07	31,088	2,432	427	29,083	27,050	23.0	5,444	14.4	3,411	2,033
25-Feb-07	31,088	2,432	427	29,083	26,649	24.7	5,758	14.3	3,324	2,434
04-Mar-07	31,138	4,101	427	27,464	26,256	18.7	4,332	13.5	3,124	1,208
11-Mar-07	31,138	4,113	427	27,452	25,853	20.3	4,639	13.3	3,040	1,599
18-Mar-07	31,138	4,133	427	27,432	25,405	23.0	5,137	14.0	3,110	2,027
25-Mar-07	31,138	4,994	427	26,571	25,021	21.0	4,613	14.0	3,063	1,550
01-Apr-07	31,138	4,994	427	26,571	24,624	24.2	5,169	15.1	3,222	1,947
08-Apr-07	31,138	4,798	398	26,737	24,402	26.3	5,571	15.3	3,236	2,335
15-Apr-07	31,138	4,759	398	26,776	24,013	29.4	6,083	16.0	3,320	2,763
22-Apr-07	31,138	5,318	398	26,217	23,621	27.8	5,698	15.1	3,102	2,596
29-Apr-07	31,138	4,963	398	26,572	23,157	31.4	6,352	14.5	2,937	3,415
06-May-07	31,138	5,487	398	26,048	23,060	29.8	5,982	14.9	2,994	2,988
13-May-07	31,138	5,418	398	26,117	22,874	31.1	6,199	14.8	2,956	3,243
20-May-07	31,138	5,998	398	25,537	24,387	18.8	4,037	13.4	2,887	1,150
27-May-07	31,138	4,104	398	27,431	24,990	27.2	5,860	15.9	3,419	2,441
03-Jun-07	31,138	4,382	398	27,153	25,497	23.2	5,116	15.7	3,460	1,656
10-Jun-07	31,138	3,912	398	27,623	26,021	24.9	5,513	17.7	3,911	1,602
17-Jun-07	31,138	3,533	398	28,002	27,242	20.9	4,843	17.6	4,083	760
24-Jun-07	31,138	3,638	398	27,897	28,272	14.9	3,611	16.4	3,986	-375
01-Jul-07	31,138	2,418	398	29,117	28,637	20.4	4,929	18.4	4,449	480

Table A3 Demand Forecast Range For Required Resources Calculation

Week Ending Day	Ontario Demand Normal Weather MW	Ontario Demand Extreme Weather MW
01-Jan-06	22164	23401
08-Jan-06	23558	25403
15-Jan-06	23914	25802
22-Jan-06	24285	25438
29-Jan-06	24073	25486
05-Feb-06	23801	25376
12-Feb-06	23630	24949
19-Feb-06	23373	24924
26-Feb-06	23055	24191
05-Mar-06	22821	24288
12-Mar-06	22536	24099
19-Mar-06	22019	23417
26-Mar-06	21682	22943
02-Apr-06	21126	22320
09-Apr-06	20910	22394
16-Apr-06	20436	21603
23-Apr-06	20255	23267
30-Apr-06	19914	23249
07-May-06	19802	22973
14-May-06	19605	23574
21-May-06	21143	23196
28-May-06	21212	23863
04-Jun-06	21678	24653
11-Jun-06	21757	25643
18-Jun-06	22806	26596
25-Jun-06	23999	26470
02-Jul-06	23654	26504
09-Jul-06	24149	27083
16-Jul-06	24232	27407
23-Jul-06	24197	26615
30-Jul-06	24194	26187
06-Aug-06	23685	26581
13-Aug-06	24027	26713
20-Aug-06	23651	26236
27-Aug-06	23344	25865
03-Sep-06	23709	26779
10-Sep-06	22952	25972
17-Sep-06	22267	25762
24-Sep-06	21503	25054

(Table A3 continued)

Week Ending Day	Ontario Demand Normal Weather MW	Ontario Demand Extreme Weather MW
01-Oct-06	20238	23729
08-Oct-06	20218	24046
15-Oct-06	20378	21058
22-Oct-06	20860	21707
29-Oct-06	21194	23771
05-Nov-06	21810	22506
12-Nov-06	22064	22835
19-Nov-06	22714	23630
26-Nov-06	23094	24184
03-Dec-06	23222	24672
10-Dec-06	23858	25522
17-Dec-06	23912	25131
24-Dec-06	23924	25977
31-Dec-06	22434	23806
07-Jan-07	23844	25689
14-Jan-07	24175	26088
21-Jan-07	24547	25700
28-Jan-07	24335	25756
04-Feb-07	24089	25642
11-Feb-07	23900	25218
18-Feb-07	23639	25190
25-Feb-07	23325	24464
04-Mar-07	23132	24565
11-Mar-07	22813	24375
18-Mar-07	22295	23712
25-Mar-07	21958	23220
01-Apr-07	21402	22597
08-Apr-07	21166	22651
15-Apr-07	20693	21861
22-Apr-07	20519	23627
29-Apr-07	20220	23608
06-May-07	20066	23275
13-May-07	19918	23940
20-May-07	21500	23553
27-May-07	21571	24220
03-Jun-07	22037	25010
10-Jun-07	22110	26000
17-Jun-07	23159	26950
24-Jun-07	24286	26824
01-Jul-07	24188	27037

Table A4 Assessment of Resource Adequacy: Extreme Weather, Existing Resource Scenario

Week Ending Day	Total Resources MW	Total Reductions in Resources MW	Price-responsive Demand MW	Available Resources MW	Required Resources MW	Available Reserve %	Available Reserve MW	Required Reserve %	Required Reserve MW	Reserve Above Requirement MW
01-Jan-06	30,631	2,776	372	28,227	26,342	20.6	4,826	12.6	2,941	1,885
08-Jan-06	30,631	2,655	372	28,348	28,640	11.6	2,945	12.7	3,237	-292
15-Jan-06	30,631	2,180	372	28,823	29,170	11.7	3,021	13.1	3,368	-347
22-Jan-06	30,631	2,852	372	28,151	28,808	10.7	2,713	13.3	3,370	-657
29-Jan-06	30,631	2,212	372	28,791	28,833	13.0	3,305	13.1	3,347	-42
05-Feb-06	30,631	1,772	372	29,231	28,689	15.2	3,855	13.1	3,313	542
12-Feb-06	30,631	2,167	372	28,836	28,114	15.6	3,887	12.7	3,165	722
19-Feb-06	30,631	2,093	372	28,910	28,069	16.0	3,986	12.6	3,145	841
26-Feb-06	30,631	3,417	372	27,586	27,282	14.0	3,395	12.8	3,091	304
05-Mar-06	30,631	4,371	372	26,632	27,436	9.7	2,344	13.0	3,148	-804
12-Mar-06	30,631	4,760	372	26,243	27,255	8.9	2,144	13.1	3,156	-1,012
19-Mar-06	30,631	4,760	372	26,243	26,456	12.1	2,826	13.0	3,039	-213
26-Mar-06	30,631	4,800	372	26,203	25,892	14.2	3,260	12.9	2,949	311
02-Apr-06	30,631	4,426	372	26,577	25,471	19.1	4,257	14.1	3,151	1,106
09-Apr-06	30,631	5,209	372	25,794	25,377	15.2	3,400	13.3	2,983	417
16-Apr-06	30,631	5,111	372	25,892	24,480	19.9	4,289	13.3	2,877	1,412
23-Apr-06	30,631	4,361	372	26,642	26,458	14.5	3,375	13.7	3,191	184
30-Apr-06	30,631	7,029	372	23,974	26,353	3.1	725	13.4	3,104	-2,379
07-May-06	30,631	6,098	372	24,905	26,042	8.4	1,932	13.4	3,069	-1,137
14-May-06	30,631	6,201	372	24,802	26,779	5.2	1,228	13.6	3,205	-1,977
21-May-06	30,631	4,863	372	26,140	26,297	12.7	2,944	13.4	3,101	-157
28-May-06	30,631	4,589	372	26,414	27,166	10.7	2,551	13.8	3,303	-752
04-Jun-06	30,631	4,327	372	26,676	28,066	8.2	2,023	13.8	3,413	-1,390
11-Jun-06	30,631	3,156	372	27,847	29,256	8.6	2,204	14.1	3,613	-1,409
18-Jun-06	30,631	2,279	372	28,724	30,345	8.0	2,128	14.1	3,749	-1,621
25-Jun-06	30,631	1,909	372	29,094	30,197	9.9	2,624	14.1	3,727	-1,103
02-Jul-06	30,631	1,891	372	29,112	29,971	9.8	2,608	13.1	3,467	-859
09-Jul-06	30,631	1,813	372	29,190	30,638	7.8	2,107	13.1	3,555	-1,448
16-Jul-06	30,631	1,813	372	29,190	31,012	6.5	1,783	13.2	3,605	-1,822
23-Jul-06	30,631	1,853	372	29,150	30,074	9.5	2,535	13.0	3,459	-924
30-Jul-06	30,631	1,869	372	29,134	29,560	11.3	2,947	12.9	3,373	-426
06-Aug-06	30,647	1,995	372	29,024	30,049	9.2	2,443	13.1	3,468	-1,025
13-Aug-06	30,647	1,946	372	29,073	30,190	8.8	2,360	13.0	3,477	-1,117
20-Aug-06	30,647	2,047	372	28,972	29,661	10.4	2,736	13.1	3,425	-689
27-Aug-06	30,647	2,097	372	28,922	29,237	11.8	3,057	13.0	3,372	-315
03-Sep-06	30,647	3,235	372	27,784	30,315	3.8	1,005	13.2	3,536	-2,531
10-Sep-06	30,647	3,759	372	27,260	29,347	5.0	1,288	13.0	3,375	-2,087
17-Sep-06	30,647	4,540	372	26,479	29,227	2.8	717	13.5	3,465	-2,748
24-Sep-06	30,647	5,220	372	25,799	28,418	3.0	745	13.4	3,364	-2,619

(Table A4 continued)

Week Ending Day	Total Resources MW	Total Reductions in Resources MW	Price-responsive Demand MW	Available Resources MW	Required Resources MW	Available Reserve %	Available Reserve MW	Required Reserve %	Required Reserve MW	Reserve Above Requirement MW
01-Oct-06	30,647	5,087	372	25,932	26,941	9.3	2,203	13.5	3,212	-1,009
08-Oct-06	30,647	5,708	372	25,311	27,418	5.3	1,265	14.0	3,372	-2,107
15-Oct-06	30,647	6,759	372	24,260	23,776	15.2	3,202	12.9	2,718	484
22-Oct-06	30,647	6,038	372	24,981	24,543	15.1	3,274	13.1	2,836	438
29-Oct-06	30,647	6,090	372	24,929	27,112	4.9	1,158	14.1	3,341	-2,183
05-Nov-06	30,647	6,325	372	24,694	25,499	9.7	2,188	13.3	2,993	-805
12-Nov-06	30,663	6,295	372	24,740	25,876	8.3	1,905	13.3	3,041	-1,136
19-Nov-06	30,663	5,110	372	25,925	26,813	9.7	2,295	13.5	3,183	-888
26-Nov-06	30,663	4,135	372	26,900	27,393	11.2	2,716	13.3	3,209	-493
03-Dec-06	30,663	3,039	372	27,996	27,901	13.5	3,324	13.1	3,229	95
10-Dec-06	30,663	3,463	372	27,572	28,933	8.0	2,050	13.4	3,411	-1,361
17-Dec-06	30,663	1,844	372	29,191	28,399	16.2	4,060	13.0	3,268	792
24-Dec-06	30,663	1,369	372	29,666	29,468	14.2	3,689	13.4	3,491	198
31-Dec-06	30,663	1,334	372	29,701	27,115	24.8	5,895	13.9	3,309	2,586
07-Jan-07	30,663	1,467	372	29,568	28,853	15.1	3,879	12.3	3,164	715
14-Jan-07	30,663	1,319	372	29,716	29,338	13.9	3,628	12.5	3,250	378
21-Jan-07	30,663	1,266	372	29,769	28,867	15.8	4,069	12.3	3,167	902
28-Jan-07	30,663	2,166	372	28,869	29,030	12.1	3,113	12.7	3,274	-161
04-Feb-07	30,663	2,150	372	28,885	28,901	12.7	3,243	12.7	3,259	-16
11-Feb-07	30,663	2,118	372	28,917	28,395	14.7	3,699	12.6	3,177	522
18-Feb-07	30,663	2,124	372	28,911	28,362	14.8	3,721	12.6	3,172	549
25-Feb-07	30,663	2,124	372	28,911	27,506	18.2	4,447	12.4	3,042	1,405
04-Mar-07	30,663	3,744	372	27,291	27,596	11.1	2,726	12.3	3,031	-305
11-Mar-07	30,663	3,756	372	27,279	27,375	11.9	2,904	12.3	3,000	-96
18-Mar-07	30,663	3,776	372	27,259	26,616	15.0	3,547	12.3	2,904	643
25-Mar-07	30,663	4,637	372	26,398	26,113	13.7	3,178	12.5	2,893	285
01-Apr-07	30,663	4,637	372	26,398	25,594	16.8	3,801	13.3	2,997	804
08-Apr-07	30,663	4,440	347	26,570	25,633	17.3	3,919	13.2	2,982	937
15-Apr-07	30,663	4,401	347	26,609	24,883	21.7	4,748	13.8	3,022	1,726
22-Apr-07	30,663	4,960	347	26,050	26,786	10.3	2,423	13.4	3,159	-736
29-Apr-07	30,663	4,610	347	26,400	26,676	11.8	2,792	13.0	3,068	-276
06-May-07	30,663	5,135	347	25,875	26,259	11.2	2,600	12.8	2,984	-384
13-May-07	30,663	5,066	347	25,944	27,016	8.4	2,004	12.9	3,076	-1,072
20-May-07	30,663	5,635	347	25,375	26,360	7.7	1,822	11.9	2,807	-985
27-May-07	30,663	3,807	347	27,203	27,268	12.3	2,983	12.6	3,048	-65
03-Jun-07	30,663	4,187	347	26,823	28,252	7.3	1,813	13.0	3,242	-1,429
10-Jun-07	30,663	3,727	347	27,283	29,429	4.9	1,283	13.2	3,429	-2,146
17-Jun-07	30,663	3,276	347	27,734	30,577	2.9	784	13.5	3,627	-2,843
24-Jun-07	30,663	3,320	347	27,690	30,434	3.2	866	13.5	3,610	-2,744
01-Jul-07	30,663	2,245	347	28,765	30,636	6.4	1,728	13.3	3,599	-1,871

Table A5 Assessment of Resource Adequacy: Extreme Weather, Planned Resource Scenario

Week Ending Day	Total Resources MW	Total Reductions in Resources MW	Price-responsive Demand MW	Available Resources MW	Required Resources MW	Available Reserve %	Available Reserve MW	Required Reserve %	Required Reserve MW	Reserve Above Requirement MW
01-Jan-06	30,631	2,776	376	28,231	26,342	20.6	4,830	12.6	2,941	1,889
08-Jan-06	30,634	2,658	376	28,352	28,640	11.6	2,949	12.7	3,237	-288
15-Jan-06	30,634	2,183	376	28,827	29,170	11.7	3,025	13.1	3,368	-343
22-Jan-06	30,751	2,855	376	28,272	28,801	11.1	2,834	13.2	3,363	-529
29-Jan-06	30,751	2,215	376	28,912	28,827	13.4	3,426	13.1	3,341	85
05-Feb-06	30,751	1,775	391	29,367	28,674	15.7	3,991	13.0	3,298	693
12-Feb-06	30,819	2,238	391	28,972	28,104	16.1	4,023	12.7	3,155	868
19-Feb-06	30,819	2,164	391	29,046	28,058	16.5	4,122	12.6	3,134	988
26-Feb-06	30,819	3,488	391	27,722	27,282	14.6	3,531	12.8	3,091	440
05-Mar-06	30,858	4,481	391	26,768	27,432	10.2	2,480	12.9	3,144	-664
12-Mar-06	30,858	4,870	391	26,379	27,252	9.5	2,280	13.1	3,153	-873
19-Mar-06	30,858	4,870	391	26,379	26,448	12.7	2,962	12.9	3,031	-69
26-Mar-06	30,858	4,910	391	26,339	25,873	14.8	3,396	12.8	2,930	466
02-Apr-06	30,858	4,536	427	26,749	25,484	19.8	4,429	14.2	3,164	1,265
09-Apr-06	30,858	5,320	427	25,965	25,371	16.0	3,571	13.3	2,977	594
16-Apr-06	30,858	5,221	427	26,064	24,493	20.7	4,461	13.4	2,890	1,571
23-Apr-06	30,858	4,471	427	26,814	26,444	15.2	3,547	13.7	3,177	370
30-Apr-06	30,858	7,139	427	24,146	26,343	3.9	897	13.3	3,094	-2,197
07-May-06	30,957	6,307	427	25,077	26,045	9.2	2,104	13.4	3,072	-968
14-May-06	30,957	6,410	427	24,974	26,773	5.9	1,400	13.6	3,199	-1,799
21-May-06	30,957	5,072	427	26,312	26,297	13.4	3,116	13.4	3,101	15
28-May-06	30,957	4,798	427	26,586	27,147	11.4	2,723	13.8	3,284	-561
04-Jun-06	30,957	4,537	427	26,847	28,060	8.9	2,194	13.8	3,407	-1,213
11-Jun-06	30,957	3,365	427	28,019	29,247	9.3	2,376	14.1	3,604	-1,228
18-Jun-06	30,957	2,488	427	28,896	30,327	8.7	2,300	14.0	3,731	-1,431
25-Jun-06	30,957	2,118	427	29,266	30,187	10.6	2,796	14.0	3,717	-921
02-Jul-06	30,957	2,100	427	29,284	29,971	10.5	2,780	13.1	3,467	-687
09-Jul-06	30,957	2,022	427	29,362	30,630	8.4	2,279	13.1	3,547	-1,268
16-Jul-06	30,957	2,022	427	29,362	31,011	7.1	1,955	13.2	3,604	-1,649
23-Jul-06	30,957	2,062	427	29,322	30,075	10.2	2,707	13.0	3,460	-753
30-Jul-06	30,957	2,078	427	29,306	29,555	11.9	3,119	12.9	3,368	-249
06-Aug-06	30,973	2,204	427	29,196	30,050	9.8	2,615	13.1	3,469	-854
13-Aug-06	30,973	2,155	427	29,245	30,190	9.5	2,532	13.0	3,477	-945
20-Aug-06	30,973	2,256	427	29,144	29,643	11.1	2,908	13.0	3,407	-499
27-Aug-06	30,973	2,306	427	29,094	29,232	12.5	3,229	13.0	3,367	-138
03-Sep-06	30,973	3,454	427	27,946	30,311	4.4	1,167	13.2	3,532	-2,365
10-Sep-06	30,973	3,978	427	27,422	29,339	5.6	1,450	13.0	3,367	-1,917
17-Sep-06	30,973	4,749	427	26,651	29,226	3.5	889	13.5	3,464	-2,575
24-Sep-06	30,973	5,439	427	25,961	28,403	3.6	907	13.4	3,349	-2,442

(Table A5 continued)

Week Ending Day	Total Resources MW	Total Reductions in Resources MW	Price-responsive Demand MW	Available Resources MW	Required Resources MW	Available Reserve %	Available Reserve MW	Required Reserve %	Required Reserve MW	Reserve Above Requirement MW
01-Oct-06	30,973	5,306	427	26,094	26,939	10.0	2,365	13.5	3,210	-845
08-Oct-06	31,072	6,026	427	25,473	27,417	5.9	1,427	14.0	3,371	-1,944
15-Oct-06	31,072	7,077	427	24,422	23,765	16.0	3,364	12.9	2,707	657
22-Oct-06	31,072	6,356	427	25,143	24,531	15.8	3,436	13.0	2,824	612
29-Oct-06	31,072	6,408	427	25,091	27,108	5.6	1,320	14.0	3,337	-2,017
05-Nov-06	31,072	6,643	427	24,856	25,479	10.4	2,350	13.2	2,973	-623
12-Nov-06	31,088	6,613	427	24,902	25,878	9.1	2,067	13.3	3,043	-976
19-Nov-06	31,088	5,418	427	26,097	26,810	10.4	2,467	13.5	3,180	-713
26-Nov-06	31,088	4,443	427	27,072	27,377	11.9	2,888	13.2	3,193	-305
03-Dec-06	31,088	3,347	427	28,168	27,894	14.2	3,496	13.1	3,222	274
10-Dec-06	31,088	3,771	427	27,744	28,929	8.7	2,222	13.4	3,407	-1,185
17-Dec-06	31,088	2,152	427	29,363	28,390	16.8	4,232	13.0	3,259	973
24-Dec-06	31,088	1,677	427	29,838	29,468	14.9	3,861	13.4	3,491	370
31-Dec-06	31,088	1,652	427	29,863	27,127	25.4	6,057	14.0	3,321	2,736
07-Jan-07	31,088	1,785	427	29,730	28,841	15.7	4,041	12.3	3,152	889
14-Jan-07	31,088	1,637	427	29,878	29,332	14.5	3,790	12.4	3,244	546
21-Jan-07	31,088	1,574	427	29,941	28,855	16.5	4,241	12.3	3,155	1,086
28-Jan-07	31,088	2,484	427	29,031	29,022	12.7	3,275	12.7	3,266	9
04-Feb-07	31,088	2,458	427	29,057	28,895	13.3	3,415	12.7	3,253	162
11-Feb-07	31,088	2,426	427	29,089	28,384	15.4	3,871	12.6	3,166	705
18-Feb-07	31,088	2,432	427	29,083	28,351	15.5	3,893	12.6	3,161	732
25-Feb-07	31,088	2,432	427	29,083	27,506	18.9	4,619	12.4	3,042	1,577
04-Mar-07	31,138	4,101	427	27,464	27,591	11.8	2,899	12.3	3,026	-127
11-Mar-07	31,138	4,113	427	27,452	27,369	12.6	3,077	12.3	2,994	83
18-Mar-07	31,138	4,133	427	27,432	26,598	15.7	3,720	12.2	2,886	834
25-Mar-07	31,138	4,994	427	26,571	26,114	14.4	3,351	12.5	2,894	457
01-Apr-07	31,138	4,994	427	26,571	25,594	17.6	3,974	13.3	2,997	977
08-Apr-07	31,138	4,798	398	26,737	25,634	18.0	4,086	13.2	2,983	1,103
15-Apr-07	31,138	4,759	398	26,776	24,895	22.5	4,915	13.9	3,034	1,881
22-Apr-07	31,138	5,318	398	26,217	26,778	11.0	2,590	13.3	3,151	-561
29-Apr-07	31,138	4,968	398	26,567	26,667	12.5	2,959	13.0	3,059	-100
06-May-07	31,138	5,492	398	26,043	26,252	11.9	2,768	12.8	2,977	-209
13-May-07	31,138	5,423	398	26,112	27,018	9.1	2,172	12.9	3,078	-906
20-May-07	31,138	5,993	398	25,542	26,353	8.4	1,989	11.9	2,800	-811
27-May-07	31,138	4,175	398	27,360	27,269	13.0	3,140	12.6	3,049	91
03-Jun-07	31,138	4,544	398	26,991	28,230	7.9	1,981	12.9	3,220	-1,239
10-Jun-07	31,138	4,084	398	27,451	29,423	5.6	1,451	13.2	3,423	-1,972
17-Jun-07	31,138	3,633	398	27,902	30,571	3.5	952	13.4	3,621	-2,669
24-Jun-07	31,138	3,678	398	27,857	30,430	3.9	1,033	13.4	3,606	-2,573
01-Jul-07	31,138	2,602	398	28,933	30,634	7.0	1,896	13.3	3,597	-1,701

Table A6 Energy Production Capability Forecast

Month	Existing Resource Scenario Forecast Energy Production Capability (GWh)	Planned Resource Scenario Forecast Energy Production Capability (GWh)
Jan 2006	17,181	17,345
Feb 2006	15,054	15,406
Mar 2006	15,284	15,648
Apr 2006	14,299	14,652
May 2006	14,872	15,190
Jun 2006	16,002	16,355
Jul 2006	17,123	17,465
Aug 2006	16,927	17,279
Sep 2006	14,510	14,851
Oct 2006	14,030	14,382
Nov 2006	14,526	14,879
Dec 2006	17,279	17,620
Jan 2007	17,251	17,603
Feb 2007	14,892	15,233
Mar 2007	15,495	15,848
Apr 2007	14,661	15,028
May 2007	16,099	16,431
Jun 2007	16,258	16,626

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Appendix B Transmission Projects

Zone	CAA-ID#	Description	Proposed I/S Date
East	2005-194	Belle River TS	2006-Q2
East	2004-161	Cornwall 115KV Transmission	2006-Q2
Essa	2004-135	Essa Shunt Capacitor	2006-Q2
Niagara	2002-085	Queenston Flow West	2006-Q3
Northeast	2004-EX211	Patrick St. TS - 8 oil circuit breakers replaced with SF6 breakers	2006-Q3
Northeast	2003-Ex173	New Gartshore TS - 5x115 kV breaker ring-bus to replace existing Gartshore TS	2006-Q4
Northeast	2002-070	P21G 230 kV cct Upgraded to 374 MVA continuous rating	2006-Q4
Northeast	N/A	Additional 132 kv Breaker and new customer connection to Attawapsikat TS	2006-Q3
Northeast	N/A	Energize 2nd 6/8/10 MVA transformer at Attawapiskat TS	2007-Q1
Northeast	N/A	Energize 2nd 6/8/10 MVA transformer at Albany TS	2007-Q2
Northwest	2005-195	Fort France TS reactive compensation	2006-Q4
Toronto	2004-113	Cooksville TS reconfigure connections from Applewood Junction	2005-Q4
Toronto	2003-099	Parkway TS - Completion of second auto-transformer and the remaining work for project 2003-099	2005-Q4
Toronto	2005-198	Whitby TS new transformer station	2007-Q2
West	N/A	L25/27N inline breakers	2006-Q4

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Appendix C Planned Transmission Outages

The following tables list the planned transmission outages by transmission zone, for transmission outages with an expected duration greater than five days, and/or for those transmission outages associated with a major project.

Table C1 Bruce Zone

No Outages to assess.

Table C2 East Zone

Start Date/Time	End Date/Time	Equipment	Outage Type	Recall	Impact	Reduction in Limit
Jul 06 2006 10:00 PM	Jul 31 2006 9:59 PM	Cardinal Power CGS: T1, T2H, T1H, G2B, T2	CWW	10 Hour	None	
Dec 20 2006 3:00 PM	Dec 25 2006 3:15 PM	Bowmanville SS: L27L43, X527B::LENNOX_TS::BOWMANVILLE_SS, PL527, EL527,::LENNOX_TS::BOWMANVILLE_SS, L22L27	CWW	5 Minute	None	
Apr 21 2006 10:45 PM	May 13 2006 10:59 PM	Cardinal Power CGS: T1H, T1H-H, T1	CWW	Non-Recallable	None	
Apr 21 2006 10:30 PM	May 14 2006 1:59 AM	Cardinal Power CGS: 52-S	DWW	Non-Recallable	None	
May 01 2006 6:00 AM	May 11 2006 4:00 PM	Barrett Chute JCT: W3B::BARRETT_CHUTE_JCT::MOUNTAIN_CHUTE_DS, W3B::BARRETT_CHUTE_JCT::STEWARTVILLE_TS, W3B::BARRETT_CHUTE_SS::BARRETT_CHUTE_JCT, T1-L, 10-W3B, 14-W3B, W3B::BARRETT_CHUTE_SS::BARRETT_CHUTE_JCT	CNW	4 Hour	None	
Jul 03 2006 6:00 AM	Aug 04 2006 4:00 PM	Haley Industries JCT: 3501-X2Y-4, X2Y-LL01	CNW	4 Hour	None	
Jul 10 2006 6:00 AM	Aug 10 2006 4:00 PM	Cobden TS: X2Y::HALEY_JCT::COBDEN_TS, 69X2Y-23, 23X2Y-MSS1, X2Y	CNW	4 Hour	None	
Jan 23 2006 6:00 AM	Mar 02 2006 4:00 PM	Chats Falls TS: 2W6CS, 61W6CS-LC1, 58W6CS-MSO	CNW	4 Hour	None	

Table C3 Essa Zone

Jan 23 2006 7:00 AM	Feb 09 2006 6:00 PM	Minden TS: D3M::DES_JOACHIMS_TS::MINDEN_TS, L3L80, AL3, T3L3, AL3, D3M	CWW	4 Hour	None	

Table C4 Niagara Zone

No Outages to assess.

Table C5 Northeast Zone

Start Date/Time	End Date/Time	Equipment	Outage Type	Recall	Impact	Reduction in Limit
Aug 22 2006 7:00 AM	Sep 29 2006 6:00 PM	Porcupine TS: H1L502	CWW	8 Hour	None	
Jul 04 2006 7:00 AM	Aug 11 2006 6:00 PM	Porcupine TS: L01L02	CWW	8 Hour	None	
Jul 11 2006 9:00 AM	Jul 22 2006 3:00 PM	Porcupine TS: K2K3	CWW	8 Hour	None	
Oct 10 2006 7:00 AM	Nov 10 2006 6:00 PM	Porcupine TS: H2L501	CWW	8 Hour	None	
Apr 10 2006 8:00 AM	Apr 17 2006 6:00 PM	Mississagi TS: 34-P22G, P22G::ECHO_RIVER_CTS::MISSISSAGI_TS, P22G::ECHO_RIVER_CTS	CWW	Non-Recallable	None	
Apr 24 2006 7:00 AM	May 01 2006 1:00 PM	Mississagi TS: AL23, 34-P21G, 34-T27P, AL25	CWW	4 Hour	None	
Apr 10 2006 7:00 AM	Apr 17 2006 5:00 PM	Mississagi TS: 34-T28P, KL24, KL74, 34-P22G	CWW	4 Hour	None	
Apr 24 2006 8:00 AM	May 01 2006 6:00 PM	P21G P8 JCT: P21G::P21G_P8_JCT::THIRD_LINE_CTS, P21G::MISSISSAGI_TS::P21G_P8_JCT, P21G::MISSISSAGI_TS::P21G_P8_JCT, 34-P21G, P21G::P21G_P8_JCT::THIRD_LINE_CTS	CWW	4 Day	None	
Jan 16 2006 9:00 AM	Mar 03 2006 4:00 PM	Porcupine TS: 30T8-T, 30T8-H, T8	CNW	1 Hour	None	
May 03 2005 8:00 AM	Feb 07 2006 3:01 PM	Inco #4 CTS: T1	CWW	Non-Recallable	None	
Apr 10 2006 5:30 PM	Apr 17 2006 4:00 PM	Mississagi TS: 34-P22G, P22G::ECHO_RIVER_CTS::MISSISSAGI_TS, P22G::ECHO_RIVER_CTS::MISSISSAGI_TS	CWW	Non-Recallable	None	
Apr 24 2006 5:30 PM	May 01 2006 5:00 PM	Third Line CTS: P21G::P21G_P8_JCT::THIRD_LINE_CTS, 34-P21G, P21G::MISSISSAGI_TS::P21G_P8_JCT, P21G::MISSISSAGI_TS::P21G_P8_JCT, P21G::P21G_P8_JCT::THIRD_LINE_CTS	CWW	Non-Recallable	None	
Nov 22 2005 12:00 AM	Jun 14 2030 11:59 PM	Mackay TS: ANJIGAMI LINE #1, ANJIGAMI LINE #1	CWW	Non-Recallable	None	
Nov 13 2005 8:01 AM	Nov 13 2006 7:01 PM	Scott GS: 902	CWW	1 Hour	None	

Table C6 Northwest Zone

Start Date/Time	End Date/Time	Equipment	Outage Type	Recall	Impact	Reduction in Limit
Oct 29 2006 9:00 AM	Nov 19 2006 9:00 AM	Ignace JCT: M2D-D, M2D::DRYDEN_TS::IGNACE_JCT, M2D::DRYDEN_TS::IGNACE_JCT, M2D-1	CWW	4 Hour	None	
Jan 23 2006 8:00 AM	Feb 24 2006 6:00 PM	Fort Frances TS: K24F::KENORA_TS::FORT_FRANCES_TS, K24F::KENORA_TS::FORT_FRANCES_TS, 22-K24F, 34-K24F	CNW	4 Hour	OMTE, OMTW, EWTE, MPFN, MPFS	OMTE - 50 MW OMTW - 250 MW EWTE - 75 MW MPFN - 50 MW MPFS - 140 MW
Mar 13 2006 8:30 AM	May 12 2006 4:00 PM	Dryden TS: K23D::DRYDEN_TS::VERMILION_JCT, 25-K23D, 3411-25, K23D::DRYDEN_TS::VERMILION_JCT	CWW	4 Hour	OMTE, OMTW, EWTE, MPFN	OMTE - 50 MW OMTW - 250 MW EWTE - 75 MW MPFN - 25 MW
Sep 11 2006 8:30 AM	Oct 20 2006 4:00 PM	Vermilion JCT: K23D::DRYDEN_TS::VERMILION_JCT, K23D::DRYDEN_TS::VERMILION_JCT, 25-K23D, 3411-25	CWW	4 Hour	OMTE, OMTW, EWTE, MPFN	OMTE - 50 MW OMTW - 250 MW EWTE - 75 MW MPFN - 25 MW

Table C7 Ottawa Zone

Jan 30 2006 6:00 AM	Feb 09 2006 4:00 PM	Orleans JCT: 42H9A-77, T2-A, H9A::BILBERRY_CREEK_TS::BILBERRY_CREEK_JCT, A1-A2	CNW	4 Hour	None	

Table C8 Southwest Zone

Start Date/Time	End Date/Time	Equipment	Outage Type	Recall	Impact	Reduction in Limit
Nov 26 2004 8:00 AM	Dec 25 2006 3:00 PM	Campbell TS: SC4Q, SC4	CWW	30 Minute	None	
Jun 03 2005 7:01 AM	Jun 03 2006 3:00 PM	Kitchener MTS#8: K8T16-M20D, T16B, T16	DWW	4 Hour	None	
Jan 03 2006 7:01 AM	Jan 27 2006 4:01 PM	Kitchener MTS#1: 52-1B2, T1, K1T1-D12K, 52-T1B	CWW	4 Hour	None	
Mar 01 2006 5:00 AM	Mar 31 2006 6:00 PM	Bronte TS: T2-B8, M24, M23, T2-B7, M26, T2, M25, SS2-X	CWW	1 Minute	None	

Table C9 Toronto Zone

Start Date/Time	End Date/Time	Equipment	Outage Type	Recall	Impact	Reduction in Limit
Mar 06 2006 5:00 AM	Apr 14 2006 6:00 PM	Manby East TS: TR5-S, T5, T5-H2, TR5-T	CWW	4 Week	None	
Dec 25 2005 7:00 AM	Jan 20 2006 2:30 PM	Bermondsey TS: T4Y, T4, T4B, T4-C14L	CWW	36 Hour	None	
Dec 25 2006 7:00 AM	Jan 20 2007 6:00 PM	Pickering B SS: T5L27, P27C::CHERRYWOOD_TS::PICKERING_B_SS,L27R, L26L27, KL27	CWW	2 Day	None	
Jan 02 2007 7:00 AM	Jan 23 2007 6:00 PM	Cherrywood TS: KL8, L8D, P8C::PICKERING_A_SS::CHERRYWOOD_TS, L8L24, T2L8	CWW	2 Day	None	
Oct 30 2006 6:00 AM	Dec 01 2006 5:00 PM	Bridgman TS: T14, T14Y-B, T14X-H, T14-L14W	CWW	10 Day	None	
Dec 25 2006 7:00 AM	Dec 30 2006 6:00 PM	Pickering A SS: T1L6, L3L6, L6K, P6C::CHERRYWOOD_TS::PICKERING_A_SS, DL6	CWW	2 Day	None	
Jan 02 2007 7:00 AM	Jan 17 2007 6:00 PM	Pickering A SS: T3L7, P7C::PICKERING_A_SS::CHERRYWOOD_TS, L7H, DL7, L7L11	CWW	2 Day	None	
Oct 31 2005 5:00 PM	Nov 17 2006 5:00 PM	Markham MTS #1 JCT: C12R::MARKHAM_MTS_#1_JCT::PARKWAY_JCT	CWW	4 Hour	FETT	200 MW
Nov 01 2005 5:00 AM	Nov 01 2006 5:00 PM	Bathurst JCT: C12R::BATHURST_JCT::FINCH_JCT, C12R::FINCH_JCT::RICHVIEW_TS, C12R::BATHURST_JCT::LEASIDE_JCT, 12R::IBM_MARKHAM_JCT::MARKHAM_MTS_#1_JCT, C12R::IBM_MARKHAM_JCT::LEASIDE_JCT	CWW	30 Minute	FETT	200 MW
Oct 12 2005 1:29 PM	Apr 17 2006 6:00 PM	Claireville TS: T13-HT13, T13, T13-A		Non-Recallable	FETT	150 MW

Table C10 West Zone

Start Date/Time	End Date/Time	Equipment	Outage Type	Recall	Impact	Reduction in Limit
Jun 28 2005 7:00 AM	Jun 29 2006 3:00 PM	Sarnia Scott TS: KL1	CWW	2 Hour	None	
May 15 2006 5:00 AM	May 23 2006 6:00 PM	Aylmer TS: SC1, M1, SC1B	CWW	1 Hour	None	
Apr 18 2006 6:00 AM	May 19 2006 4:00 PM	Strathroy TS: 29-W2S, 19-W2S, W2S::BUCHANAN_TS::SYDENHAM_JCT, W2S::BUCHANAN_TS::SYDENHAM_JCT, W2S::SYDENHAM_JCT::STRATHROY_TS, W2S::SYDENHAM_JCT::STRATHROY_TS	CWW	4 Hour	None	

Appendix D Transformer Distribution Factors

The following table lists the distribution factors used to determine the planned 2006 LTE capability of the 500/230 kV autotransformers shown in Table 7.1.

Table D1 Transformer Distribution Factors

		1	2	3	4	5	6	7	8
	Contingency	TRAF-T14	TRAF-T15	CLAIRT13	CLAIRT14	CLAIRT15	CLAIRT16	PARKWT12	PARKWT13
	Monitored								
1	TRAF-T14	-1	0.267	0.063	0.063	0.063	0.062	0.034	0.034
2	TRAF-T15	0.269	-1	0.064	0.064	0.064	0.063	0.034	0.034
3	CLAIRT13	0.072	0.073	-1	0.176	0.176	0.174	0.053	0.053
4	CLAIRT14	0.073	0.074	0.178	-1	0.178	0.176	0.054	0.054
5	CLAIRT15	0.073	0.073	0.177	0.178	-1	0.175	0.054	0.054
6	CLAIRT16	0.068	0.068	0.165	0.165	0.165	-1	0.05	0.05
7	PARKWT12	0.035	0.035	0.048	0.048	0.048	0.047	-1	0.279
8	PARKWT13	0.035	0.035	0.048	0.048	0.048	0.047	0.279	-1
9	CHERY-14	0.027	0.027	0.037	0.037	0.037	0.037	0.092	0.092
10	CHERY-15	0.028	0.028	0.038	0.038	0.038	0.038	0.092	0.092
11	CHERY-16	0.028	0.028	0.038	0.038	0.038	0.038	0.093	0.093
12	CHERY-17	0.027	0.027	0.037	0.037	0.037	0.037	0.092	0.092
13	MIDD-T3	0.062	0.062	0.021	0.021	0.021	0.021	0.011	0.011
14	MIDD-T6	0.072	0.072	0.017	0.017	0.017	0.017	0.009	0.009
15	NANT-11	0.029	0.029	0.008	0.008	0.008	0.008	0.004	0.004
16	NANT-12	0.03	0.03	0.008	0.008	0.008	0.008	0.004	0.004

		9	10	11	12	13	14	15	16
	Contingency	CHERY-14	CHERY-15	CHERY-16	CHERY-17	MIDD-T3	MIDD-T6	NANT-11	NANT-12
	Monitored								
1	TRAF-T14	0.026	0.026	0.026	0.026	0.076	0.089	0.033	0.033
2	TRAF-T15	0.026	0.027	0.027	0.026	0.077	0.089	0.033	0.033
3	CLAIRT13	0.041	0.042	0.042	0.041	0.03	0.024	0.011	0.011
4	CLAIRT14	0.042	0.042	0.042	0.042	0.03	0.024	0.011	0.011
5	CLAIRT15	0.042	0.042	0.042	0.042	0.03	0.024	0.011	0.011
6	CLAIRT16	0.039	0.039	0.039	0.039	0.028	0.022	0.01	0.01
7	PARKWT12	0.091	0.09	0.09	0.091	0.014	0.011	0.005	0.005
8	PARKWT13	0.091	0.09	0.09	0.091	0.014	0.011	0.005	0.005
9	CHERY-14	-1	0.105	0.105	0.297	0.011	0.009	0.004	0.004
10	CHERY-15	0.106	-1	0.297	0.106	0.011	0.009	0.004	0.004
11	CHERY-16	0.107	0.298	-1	0.106	0.011	0.009	0.004	0.004
12	CHERY-17	0.296	0.104	0.104	-1	0.011	0.009	0.004	0.004
13	MIDD-T3	0.009	0.009	0.009	0.009	-1	0.147	0.146	0.147
14	MIDD-T6	0.007	0.007	0.007	0.007	0.147	-1	0.142	0.143
15	NANT-11	0.003	0.003	0.003	0.003	0.16	0.155	-1	0.478
16	NANT-12	0.003	0.004	0.004	0.003	0.164	0.159	0.484	-1

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Appendix 5:

The Ontario Reliability Outlook

February 2006

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THE ONTARIO RELIABILITY OUTLOOK

FEBRUARY

2006

VOLUME 1 ISSUE 1

ieso

Power to Ontario. On Demand.

IESO control room

“In fifteen years or so, Ontario will need in the order of 15,000 MW of new – or to some extent refurbished – generation as current generators approach the end of their planned life.”

Dave Goulding, IESO President and CEO, Toronto Board of Trade Speech – March 2003

EXECUTIVE SUMMARY

George St., Peterborough

The Independent Electricity System Operator (IESO) regularly assesses the adequacy and reliability of Ontario's power system. For the near term, the information is reported quarterly through the 18-Month Outlook. Over the period covered by the 18-Month Outlook, reliability is largely governed by the availability of existing facilities and those already under construction and expected to come into service.

Through the semi-annual release of the Ontario Reliability Outlook, of which this is the first issue, the IESO will report on progress of the inter-related generation, transmission and demand-management projects underway to meet future reliability requirements. The overall approval, construction and implementation times for these projects typically extend well beyond the scope of the 18-Month Outlook. As projects flow from the longer-term integrated system planning being conducted by the Ontario Power Authority (OPA), the Ontario Reliability Outlook will monitor progress of infrastructure developments and their impact on reliability at least three to five years into the future and further, if appropriate.

As discussed in this report, timely resolution of the challenges facing Ontario's power system is needed to maintain reliability over the next three to five years.

Aging generating units, transmission constraints, under-investment in the electricity sector over the past decade, continued demand growth and potential weather-related impacts on the system, all contribute to the need for new generation and transmission facilities as well as increased conservation and demand-management activities. As noted in the IESO's 10-Year Outlook, released in July 2005, the provincial plan to phase out coal-fired generation in favour of cleaner forms represents one of the most significant undertakings in the Ontario electricity sector's 100-year history.

The 10-Year Outlook outlined the system changes needed to meet the supply requirements for various areas in Ontario and the provincial government's coal replacement objectives. Given the amount of change required, it is critical that more efficient regulatory approvals processes are developed to enable timely implementation of the required new generation and transmission facilities.

The current regulatory approvals process is complex, unnecessarily adding to the costs and time required for decision making. The IESO has been working with other entities including the Ontario Energy Board, the OPA and Hydro One to develop a more efficient process.

Toronto's needs

The IESO's 18-Month Outlook, issued on December 22, 2005, highlighted the need for new supply and transmission facilities in the Greater Toronto Area (GTA).

The transmission system serving central Toronto was at or near capacity during peak periods in the summer of 2005. The loading of this system is reaching the point at which there is no longer the necessary redundancy available to reliably meet demand under all conditions. According to present forecasts, transmission equipment failures during peak demand periods could result in rotating load cuts as early as the summer of 2008 to avoid exceeding the load-meeting capability of the remaining transmission facilities.

Central Toronto's electricity requirements are met through supply generated outside the city and delivered through two main transmission paths. Secure supply to Canada's largest city requires local generation supply as well as new transmission facilities. As a result, 250 megawatts (MW) of generation is required within the central Toronto area by the summer of 2008 to adequately address the risk to reliability of an aging transmission infrastructure.

Longer term, additional generation within the city, together with a third transmission path into Toronto, will be necessary early in the next decade to maintain reliability under hot summer weather conditions and to provide a diversity of supply paths into the city.

Western GTA

Reliability risks in the western part of the GTA, previously identified in the 10-Year Outlook, will be substantially reduced as the Goreway natural gas plant in Brampton is brought into service over the next three years.

However, additional measures will still be needed to prevent overloading of the transmission facilities supplying the GTA, meet the forecast growth in demand and control voltages in the area. Accordingly, a combination of additional generation and transmission enhancements are required, given the risk that transmission facilities and lines serving the area could be overloaded during summer peak loads as early as the summer of 2007.

Regional needs

Plans are underway or identified for transmission reinforcements and new generation in a number of other areas of the province to maintain local reliability. These include the Newmarket-Aurora area, the Kitchener-Waterloo-Cambridge-Guelph-Orangeville area, Burlington, Sarnia-Windsor, Niagara and portions of Eastern and Northeastern Ontario. The IESO will continue to monitor these projects and identify other actions or adjustments that may be required.

Coal Replacement

The provincial government's planned transition from coal-fired generation is a challenging and complex task. Completing the move to cleaner forms of supply requires the replacement of up to 6,500 MW of generating capacity in a short period of time, and major restructuring of facilities across Ontario's power system.

Considerable steps have been taken and are planned to enable retirement of Ontario's coal-fired units. In executing these changes, flexibility is essential to accommodate the large amounts of new generation required, the tight timelines involved and the impact of each change on the entire system. Careful and continuous coordination and adjustment of plans will be required to successfully implement the coal replacement program while maintaining reliability.

Although significant progress has been made in arranging for the new supply, this Reliability Outlook reinforces the need identified in the 10-Year Outlook to have the coal units available for a period of time beyond the announced shutdown dates. This will allow for continued reliability by providing insurance to accommodate schedule delays for the replacement generation or reduced production from existing or new facilities.

While earlier retirements can be accommodated if circumstances permit, it is problematic to extend the period of reliable operation if the necessary fuel, staffing and maintenance plans have not been put in place ahead of time. Without timely preparations, the insurance afforded by maintaining the capability for reliable operation of those plants will be lost.

Several projects face a number of challenges – including the projects required to facilitate the shutdown of the Lambton Generating Station. Addressing local concerns and obtaining necessary approvals is taking longer than originally anticipated. As a result, prudence requires that provisions be made to ensure the availability of the Lambton units beyond the announced shutdown date. The 10-Year Outlook identified the need for them to be held available to operate if necessary to maintain reliability. This report confirms that fuel, staffing and maintenance plans are needed to ensure that Lambton units are capable of operation beyond currently specified dates. The IESO will continue to monitor developments and recommend timely adjustments.

Other characteristics of the coal-fired generation must also be maintained to support the overall adequacy and reliability of the power system. For example, units at the Nanticoke Generating Station are required either as generating sources or as non-coal burning synchronous condensers in order to meet the system's reactive power needs to maintain adequate voltage levels. The need for Nanticoke reactive power support intensifies with the return to service of two additional Bruce nuclear units and the additional wind generation being installed in southwest Ontario. Several Nanticoke generators must be converted to synchronous condensers to ensure that the system has sufficient reactive capability to allow for the introduction of this additional supply in the area, and as other new generation capacity becomes available, to allow the retirement of the remaining Nanticoke units.

Transmission enhancements are required to deliver the additional power from restored Bruce nuclear units and the new wind generation in the area, while reducing the need for synchronous condensers at Nanticoke.

Over this transition, staffing, fuel and maintenance provisions should also be undertaken to ensure that the Nanticoke units are capable of operating until the IESO confirms that reliability will not be impaired by station shutdown. As the Nanticoke units will be required primarily to provide reactive capability (provided replacement capacity is constructed on time), energy production and associated coal burn from these units would be minimized.

The IESO focus throughout this transition period will continue to be on the reliability of the power system. The IESO will monitor the progress of the coal replacement program and advise when circumstances are such that the units can be removed from service while maintaining reliability.

SUPPLY TO CENTRAL TORONTO

Toronto is one of the largest cities in North America without generation within its own vicinity to meet local demands. As a result, supply to the central area of Toronto (the area bounded by Highway 427, Lake Ontario, Eglinton Avenue and Victoria Park Avenue) is delivered through two main transmission paths and transformer stations (TS) – Manby TS in the west and Leaside TS in the east.

Manby TS is fed from Richview TS by five 230 kilovolt (kV) circuits. Leaside is fed by six 230 kV circuits from Cherrywood TS. These two stations and the circuits in and out of them are operating at or near maximum capacity during periods of high demand.

The supply to central Toronto will be exposed to the potential overload of the:

- 230 kV circuits from Cherrywood TS to Leaside TS;
- 230/115 kV auto-transformers at Leaside TS;
- 115 kV circuits from Leaside TS to Hearn TS;
- 230 kV circuits from Richview TS to Manby TS;
- 230/115 kV auto-transformers at Manby TS; and
- 115 kV circuits from Manby TS to downtown Toronto

Because the paths into central Toronto are forecast to be near their capacity, additional generation located outside the area cannot meet the need for power within Toronto during peak load periods. As a result, 250 MW of generation must be in service by June 1, 2008 to help meet local demand for electricity (particularly in the summer) without overloading equipment and prompting the need for rotating load shedding. Present forecasts indicate that 500 MW of total capacity should be planned for summer, 2010.

The IESO, the OPA, Toronto Hydro and Hydro One have considered alternatives and supplemental activities to the minimum generation requirements, including increased conservation and demand management, distributed generation, cogeneration and renewable energy. While all of the above alternatives should be part of the solution to address Toronto's needs, they are needed in addition to the minimum generation requirements in order to achieve an appropriate level of reliability.

This generation is necessary to provide needed flexibility to adequately address the risk to reliability of an aging transmission infrastructure within the city, and to allow for the incorporation of a new transmission supply to restore the assurance of long-term reliable electricity supplies for Toronto. This third transmission supply could bring about 1,000 MW of power to Toronto and should be in service early in the next decade, such that together with local generation within the city, a continued reliable and diverse supply for the city under hot summer weather conditions can be assured.

TORONTO

Population
2,629,030*

Central Toronto
System Peak
2,350 MW

Ontario System Peak
26,160 MW

Installed Generation
0 MW

*Statistics Canada estimates, 2004, and Ontario Ministry of Finance projections

The transmission system serving central Toronto was at or near capacity during peak periods in the summer of 2005.

WESTERN GREATER TORONTO AREA

The OPA is implementing a directive from the provincial government for a new 860 MW gas project in the Goreway area in Brampton to address overloading concerns in the western GTA.

Stage One of the project, involving almost 485 MW of new generation, is forecast to be available by July 2007. Based on initial estimates of forecast loading on the Claireville auto-transformers, Stage One of the Goreway project meets most of the requirement for 2007, significantly reducing the risk of load interruptions in that time period. Stage Two of the project adds another 375 MW of new generation to the project and is forecast to be available by July 2008.

Elsewhere in the western GTA, the 117 MW GTAA project is now in service and the 280 MW Greenfield South project is targeted to be in service in the first quarter of 2008.

The IESO has also identified concerns regarding potential overloading of the auto-transformers at Trafalgar TS during summer peak loads as early as 2007. In addition, two 230 kV Trafalgar to Richview circuits were loaded above the IESO Supply Deliverability Guidelines in summer 2005 and required load interruption during a circuit outage. Resolving these loading problems requires a combination of generation and transmission solutions near Milton or Trafalgar, and 230 kV transmission enhancements between Meadowvale TS, Cardiff TS and Pleasant TS.

The supply projects that may result from the OPA's Western GTA Request For Qualifications are not predicted to be in service by the summer of 2007 deadline to reduce the risk of load interruptions. A transmission solution is also under discussion which, if implemented, could ameliorate this situation and allow for generation to be procured on a more achievable timeline.

While reliability risks will be reduced with planned new generation facilities, additional measures are still needed.

WEST GTA*

Population
1,683,060**

Local System Peak
3,190 MW

Ontario System Peak
26,160 MW

Installed Generation
117 MW

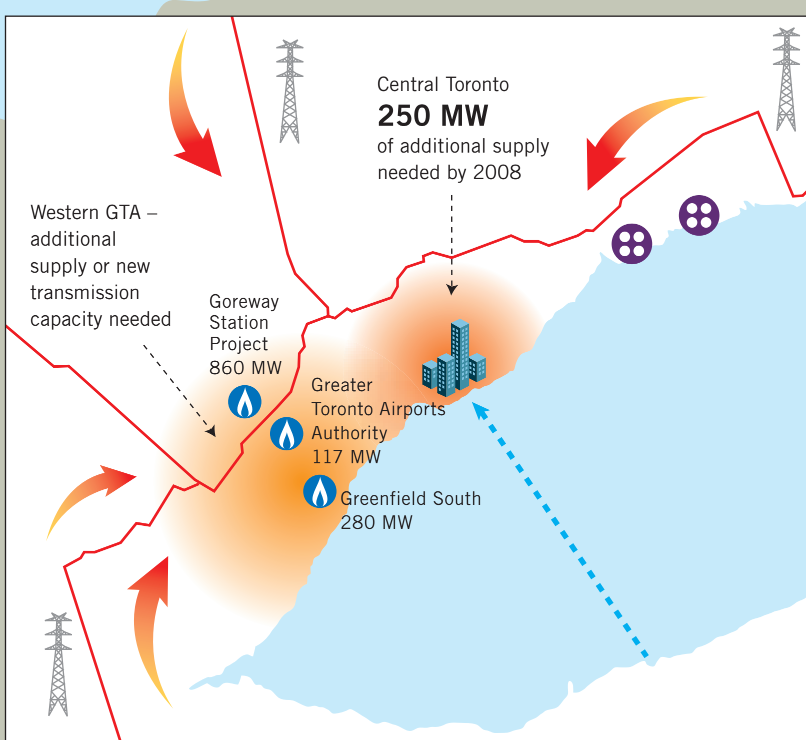
*West GTA has been defined as Halton Region (Burlington, Halton Hills, Milton and Oakville) and Peel Region (Brampton, Caledon and Mississauga).

**Statistics Canada estimates, 2004, and Ontario Ministry of Finance projections

ONTARIO ELECTRICITY PROJECTS AT A GLANCE

This map highlights both the major challenges facing the system – such as a lack of local generation or transmission constraints – and the new projects in the form of natural gas-fired facilities and renewable energies already underway to address them. The majority of these projects are proceeding through the Ontario Power Authority's procurement program; more will be added as they are confirmed.

The IESO works with the proponents of each project to assess their connections to the system, ensuring that the facilities are reliably connected to the grid. The IESO also analyses the impact of the new flows of power on the system, to ensure that electricity will be able to travel to where it is needed within safety requirements.



Legend

- New Projects – Wind
- New Projects – Gas
- New Projects – Hydroelectric
- New Projects – Biomass
- Nuclear Plants (existing)
- Coal Plants (to be phased out)
- Power Flows
- Generation Deficiencies
- Transmission Lines
- Transmission Deficiencies
- Proposed Transmission Line (3rd supply)

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THE OFF-COAL TRANSITION

Photo: Canadian Hydro/Chinodin Wind Power

The phase out of coal-fired generation and the integration of cleaner forms of supply into the Ontario system is a major and complex undertaking. To illustrate, the 6,500 MW of coal-fired supply to be replaced is greater than the load served in the four Maritime provinces. In 2005, 19 per cent of the electricity generated in Ontario originated from coal-fired units.

The move to cleaner forms of generation is not simply about replacing 6,500 MW of supply. Given the inter-dependency of the system, any significant change will affect other parts of the system. Close coordination is essential and all plans have to be continuously evaluated to determine the system impacts and make the changes necessary to maintain reliable operation.

Extensive changes and realignment of the transmission infrastructure are also necessary to integrate the new supply. More than 10 large transmission infrastructure projects will need to be completed to facilitate the replacement of coal supply and to meet growing demand over the period of the coal replacement program.

In making the above provisions for coal replacement, it is also important to be able to accommodate potential delays in obtaining the regulatory approvals associated with new generation and transmission facilities. The regulatory approvals necessary for construction are often critical-path items for the overall schedule, but can be time-consuming, particularly given the complexity and constraints associated with the current approvals process.

Finally, this transition to cleaner supply must be achieved on a very aggressive timeline and at a time when the overall supply-demand balance in the province is tight.

There have been a number of recent developments to address the need for the additional supply required to enable the shutdown of coal fired generation in Ontario.

SYNCHRONOUS CONDENSERS


(CP PHOTO/Toronto Star/Ron Bull)

Produced by generators and consumed by most loads, reactive power is an inherent part of transmitting power over long distances. The longer the distance and the greater the amount of power traveling over that distance, the more reactive power must be produced to support those power flows.

Currently the Nanticoke Generating Station produces reactive power that stabilizes the power flows into the GTA, including those from the Bruce Nuclear Station. Planned projects for new generation will not be adequate to replace the reactive power capability of Nanticoke.

To help replace the reactive power capability being lost when Nanticoke shuts down, the IESO is proposing that several Nanticoke units be converted to operate as synchronous condensers. A synchronous condenser produces reactive power and no coal burn would be required for units operating as such.

Synchronous condensers have been used in North American power systems, including Ontario.

These include:

- Renewables I RFP (395 MW)
- Renewables II RFP (1,000 MW)
- Renewables III RFP (200 MW)
- Combined Heat and Power Projects RFP (1,000 MW)
- Bruce Power return to service of Units 1 & 2 (1,540 MW)
- Goreway gas generation project Stage 1 and 2 (860 MW)
- Clean Energy Supply RFP (2,000 MW)

In assessing system adequacy, the IESO has taken into account the above projects as well as the predicted in-service dates of the supply projects that have already been contracted through the RFP process, including the Clean Energy Supply RFP.

Prudence requires that staffing, fuel and maintenance provisions be made to ensure the Lambton units are capable of operation beyond currently specified dates. This is needed to address both risks to the current schedules for replacement generation as a result of increased local concerns and potential delays to the approvals process; and any unexpected circumstances including reduced production from existing and new facilities.

To address the voltage support needs once the Nanticoke units are retired, there is a requirement to convert some of these units to operate as synchronous condensers (see sidebar). Depending on the time needed for the conversions and the ability to carry them out in parallel, adjustments to the Nanticoke shutdown schedule may be necessary. Once sufficient capacity to replace Nanticoke production is in service and operating reliably, these units are only required to provide reactive capability without the need to burn coal.

As with Lambton, provisions are also recommended to ensure the availability of Nanticoke units, given their importance across the entire network, the need for additional synchronous condensers, and a better definition of the time required to convert the Nanticoke units to synchronous condensers.

Consistent with the provincial government's commitment to maintain reliability throughout the transition period, the IESO will monitor the progress of the coal replacement program, recommend adjustments as necessary and advise when circumstances are such that the units can be removed from service while retaining the necessary level of reliability.

The new supply projects and transmission enhancements required for coal replacement must provide the power system with the necessary operational capabilities currently being provided by the coal-fired units. The government has made significant progress and additional steps are planned to implement the new facilities. The projects listed in Table 1 (page 12), expected to provide additional generation or demand response between now and 2012, are designed to address various power system issues, such as overall adequacy, local adequacy and voltage control, while also enabling the retirement of the coal-fired units.

TABLE 1: GENERATION AND DEMAND RESPONSE PROJECTS PLANNED OR UNDERWAY IN ONTARIO

Source of Project	Generation and Demand Response Projects Planned or Underway	Capacity (MW)
Wind Generation projects resulting from Renewables I RFP	Melancthon Grey Wind Project	67.5*
	Kingsbridge Wind Power Project	39.6*
	Erie Shores Wind Farm	99*
	Prince Wind Farm	99*
	Blue Highlands Wind Farm	49.5*
Biomass Generation projects resulting from Renewables I RFP[1]	Woodward Avenue Plant	1.6
	Trail Road Landfill Gas Generating Station	5
Hydroelectric Generation project resulting from Renewables I RFP[2]	Umbata Falls Hydroelectric Project	22.8
Generation project resulting from government directive for Western GTA	Goreway Gas-fired Generation Project – Phase 1	485
	Goreway Gas-fired Generation Project – Phase 2	375
Projects resulting from Clean Energy Supply RFP	Greater Toronto Airports Authority	117
	Loblaws Properties (Demand Response)	10
	Greenfield Energy Centre Gas-fired Generation Project	1,005
	Greenfield South Gas-fired Generation Project	280
	St. Clair Gas-fired Generation Project	570
Wind Generation projects resulting from RES II RFP	Wolfe Island Wind Project	197.8*
	Leader Wind Power Project A	99*
	Leader Wind Power Project B	100.7*
	Prince II Wind Power Project	90*
	Kingsbridge II Wind Power Project	158.7*
	Ripley Wind Power Project	76*
	Kruger Energy Port Alma Project	101.2*
	Melancthon II Wind Project	132*
Hydroelectric Generation project resulting from RES II RFP	Island Falls Hydroelectric Project	20
Nuclear Generation projects underway with Bruce Power	Bruce Power Unit 1 Refurbishment	770
	Bruce Power Unit 2 Refurbishment	770
Hydroelectric Generation project under development with Ontario Power Generation	Mattagami Hydroelectric Generation	Up to 360
RFP Processes underway with the Ontario Power Authority	Northern York Region Demand Response RFP	20
	Western GTA Generation RFQ	1,000
	Combined Heat and Power RFP	1,000
Generation and Demand Response Procurement Processes under development	Renewables III RFP (facilities between 0.25 MW and 19.9 MW)	200
	Central Toronto Generation	250/500
	Demand Response RFP	250

* For capacity planning purposes, wind generation has a dependable capacity contribution of 10% of the listed figures.

[1] Eastview Landfill Gas facility, which resulted from the Renewables I RFP, is currently in-service.

[2] Glenn Miller Hydroelectric facility, which resulted from the Renewables I RFP, is currently in-service.

Each of the coal-fired generating units can be retired once their respective requirements, as described in Table 2, are met. Where additional supply has been identified as a requirement the projects identified in Table 1 are expected to provide that supply. To ensure that the overall adequacy requirement is met, there must be sufficient replacement supply to meet the forecast demand before each coal-fired unit can be retired.

TABLE 2: RELIABILITY REQUIREMENTS FOR RETIRING COAL-FIRED GENERATION

Retirement Project	Capacity (MW)	Requirements to Maintain Reliability and Retire Each of the Coal-fired Generation Units
Thunder Bay Units 2 and 3	306	Conversion of Unit 2 to gas-fired generation to be completed before conversion of Unit 3 is started
Atikokan	211	Conversion of Thunder Bay Units 2 and 3 to gas-fired generation Shunt capacitors in northwest Ontario (transmission enhancement required to replace voltage control provided by Atikokan) Retain each unit on reserve pending demonstrated reliable operation of replacement generation
Lambton Units 1 – 4	1,972	Lambton switchyard re-configuration (transmission enhancement required to enable replacement generation to be introduced in the Sarnia area prior to shutdown of Lambton) Additional supply is required to meet overall adequacy requirements (see Table 1 for a list of supply projects that may be able to contribute to meeting this requirement) Retain each unit on reserve pending demonstrated reliable operation of replacement generation
Nanticoke Units 1 – 8	3,927	Additional supply is required to meet overall adequacy requirements (See Table 1 for a list of supply projects) Retain each unit on reserve pending demonstrated reliable operation of replacement generation Sufficient new supply located in the Western GTA and Central Toronto areas to alleviate transformer overloading in these areas and to reduce the need for voltage control from Nanticoke Staged conversion of several of the Nanticoke units to synchronous condenser operation is required to ensure the system has sufficient reactive capability. This is required to enable the return-to-service of Bruce Power Units 1 and 2 and to retire the Nanticoke units as coal fired generators (exact number of synchronous condensers required is dependent on amount of generation in the area and other technical factors).

REGIONAL REQUIREMENTS

There are a number of areas in Ontario that will require additional local supply and/or transmission enhancements to ensure reliability. There is currently sufficient time to address these issues but continued attention will be required to keep these plans on track.

Some of these local requirements may also contribute to overall adequacy and/or the requirements for retirement of the coal-fired units. The projects listed below are under study or have been proposed as options to address reliability needs.

Area	Reliability Needs in the Area	Required by	Project(s) Proposed to Fulfill Requirement
Newmarket – Aurora Area	Load growth taxing capability of existing circuits and local transformer station	2006-2011	York Region DR RFP (20 MW) and additional local generation and/or demand response
		2007-2008	New Holland Junction Transformer Station
		2011 or later	Additional transformer station at Aurora or Gormley, depending on the procurement of generation
Kitchener-Waterloo-Cambridge-Guelph and Orangeville Area	Local transmission enhancements required to relieve overloads and improve voltages	Spring 2007	Single 230/115 kV auto-transformer at Cambridge-Preston TS
		Fall 2008 – 2011	New 500/230 kV auto-transformer on the right-of-way of the 500 kV circuits between Middleport TS and the Milton/Claireville transformer stations
			New 230 kV double-circuit line into Cambridge-Preston TS
Burlington TS	Loading on the auto-transformers near the maximum ratings	Spring 2006	Enhance the 230/115 kV auto-transformers at Burlington TS
Bruce Complex	Ensure system has sufficient reactive capability to enable return-to-service of Bruce Power Units 1 and 2 and retire the Nanticoke units	Dependent on the timetable for new generation	Staged conversion of several of the generating units at Nanticoke GS to synchronous condenser operation (exact number of synchronous condensers required is dependent on amount of generation in the area and other technical factors)
	Transmission enhancements required to allow increased power transfers to enable return-to-service of Bruce Power Units 1 and 2	Spring 2007	Shunt capacitors in southwest Ontario
		May 2009	Series capacitors on the 500 kV circuits associated with the Bruce Complex
	Transmission enhancements required to enable operation of 8 units at the Bruce complex	January 2012	Transmission enhancements
Eastern Ontario	Loading on St. Lawrence to Hinchinbrook circuits limits Quebec and New York imports into Ontario	Summer 2006	Enhance existing Special Protection System to reduce generation in the event of a tower contingency to provide short-term relief
		Under review	Uprate the circuits as a long-term solution
	Ottawa area load growth	Under review	Add shunt capacitors as required
			1,250 MW Ontario-Quebec high voltage direct current (HVdc) connection is under review and would affect the solution or alter requirements
	Supply to the loads in the Oshawa and Belleville areas	Under review	New 500/230 kV connection be established in the Bowmanville area or that the existing 230 kV connection from Cherrywood TS into the Oshawa area be reinforced with a new 230 kV double-circuit line

Area	Reliability Needs in the Area	Required by	Project(s) Proposed to Fulfill Requirement
Niagara Area	Increase import capability on Queenston Flow West (QFW)	Scheduled September 2006	Install two new 230 kV circuits between Allanburg TS and Middleport TS and reinforce the 230 kV transmission facilities into Burlington TS
Sarnia-Windsor Area	Enhancements to enable additional generation in the area resulting from CES contracts	Fall 2007	Reconfigure the terminations at Lambton SS to accommodate split operation
	Windsor area enhancements to address restrictions during high load conditions	Summer 2006 – Fall 2007	Re-terminate two of the connections at Essex TS and expand the exisiting Special Protection System so that additional post-contingency responses can be initiated
		Spring 2007	Transfer the Tilbury load to a dedicated circuit from Lauzon TS
		Under Review	Uprate the 115 kV circuits J3E and J4E and replace the 230/115 kV auto-transformers at Keith with larger units or enhance the 230 kV connection between Keith TS and Lauzon TS
	Enable additional power transfer over the J5D Interconnection with Michigan	Fall 2007	Assess the feasibility of uprating the 230 kV line to allow transfers from Michigan to Ontario over the J5D Interconnection to be increased by at least 200 MW
Northeastern Ontario	To reduce the use of load rejection and more effectively use the Special Protection Systems	October 2006	Enhancements to existing generation rejection scheme in the northeast and additional shunt reactors at Porcupine and/or Pinard TS
	To expand the north to south transfer capability and reduce restrictions on northern resources	Spring 2007/2009	Install series capacitors at Nobel SS to increase north to south transfer capability
	Transmission enhancements to enable Mattagami expansion	June 2009	Install series capacitors in the 500 kV circuits north of Sudbury together with shunt capacitors at Little Long GS and Hanmer TS to accommodate the increased capacity
	Existing 115 kV switchgear at Abitibi Canyon GS at end-of-life	Under Review	New switchgear should be consolidated at a new 115 kV busbar at Pinard TS
			Arrangement would also provide a suitable location for a future 230/115 kV auto-transformer to reinforce the existing connection between the local 230 kV and 115 kV systems

ONTARIO APPROVALS PROCESS

The current regulatory approvals process is highly complex. Overlapping and uncoordinated requirements create unacceptably high risks to the timely implementation of the planned generation and transmission projects required to maintain reliability of Ontario's power system.

Proponents are required to obtain numerous approvals from a variety of agencies, resulting in many of the same issues having to be repeatedly addressed. This can unnecessarily add to costs and extend the time required for decision-making and approval processes, putting in-service dates at risk.

For example, the IESO has identified the need for a third transmission path to Central Toronto by early in the next decade. However, under the current approvals process, the in-service date could be as late as 2016.

Changes can and should be made to reduce unnecessary complexity and duplication, providing a more efficient process while maintaining necessary public and stakeholder participation and environmental protection.

The IESO has been working with other entities including the Ontario Energy Board, the OPA and Hydro One to identify necessary changes to the current regulatory approvals process.

CONCLUSIONS AND RECOMMENDATIONS

- Ontario's electricity sector is entering a period where aging generating units combined with the complex needs related to the coal replacement transition and the continued growth in demand, present significant challenges and require ongoing management and adjustments to maintain reliability.
- Conservation and demand-response initiatives should be aggressively pursued to help reduce the need for new supply.
- The current regulatory approvals process is complex and the requirements to comply present unacceptably high risks to the timely implementation of planned generation and transmission projects. Expedited, but thorough, approvals processes must be in place to ensure that timelines are met.
- The need for new supply, transmission and conservation initiatives remains particularly urgent in the GTA. There is a need for 250 MW of generation by 2008 to serve the central Toronto area.
- Given the reliability risks, prudence requires that provisions be made to ensure the capability of Lambton and Nanticoke Generating units to operate beyond the announced shutdown dates to accommodate circumstances such as schedule delays, extreme weather, outages or reduced performance of existing or new facilities.
- Actions are required from a number of market participants and organizations to achieve reliable supply over the next decade. These actions must be carefully coordinated and it is recognized that plans will need to be adjusted to address emerging issues and changes in schedules. The IESO will continue to monitor progress, identify risks and indicate additional actions that may be needed. The IESO observations and analysis will be reported through the Ontario Reliability Outlook, which the IESO plans to release semi-annually in conjunction with the June and December 18-Month Outlooks. As with the 18-Month Outlooks, interim updates may also be required.

Greater Toronto Airports Authority cogeneration facility

Actions are required from a number of market participants and organizations to achieve reliable supply over the next decade. The IESO will continue to monitor progress, identify risks and indicate additional actions that may be needed.

Power to Ontario. On Demand.

The Independent Electricity System Operator
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The Independent Electricity System Operator (IESO) manages the province's power system so that Ontarians receive power when and where they need it. It does this by balancing demand for electricity against available supply through the wholesale market and directing the flow of electricity across the transmission system.

Appendix 6:

IESO Letter to OPA

Re. IESO Requirements for Downtown Supply

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Power to Ontario.
On Demand.

Independent Electricity System Operator
Station A, Box 4474
Toronto, Ontario M5W 4E5
t 905 855 6100
www.ieso.ca

July 19, 2005

Mr. Paul Bradley
Vice President – Generation Development
Ontario Power Authority
175 Bloor Street East
North Tower, Suite 606
Toronto, Ontario M4W 3R8

Dear Mr. Bradley:

Re: IESO Requirements for Downtown Supply

The requirements for new downtown supply are described below.

1. Based on forecast load growth, new supply is required as early as summer 2006. However, with the scheduled completion of the John-to-Esplanade link in the fall of 2007, the need date for additional generation supply to downtown Toronto may be deferred until the summer of 2008.

2. New generation must be sited so that it can be connected to the 115 kV bus at Hearn SS. The new capacity must be limited to approximately 720 MVA so that the ratings of the existing switchgear at Leaside TS are not exceeded. This will also require that the generator step-up transformers be suitable to be equipped with neutral reactors.

   With all of the new generation capacity incorporated, the existing transmission system in the Toronto area must be operated split into two discrete halves from Cherrywood TS through to Hearn TS. The new capacity is therefore required to comprise individual generating units that will allow between 300 MW and 400 MW to be connected to the western half of the split system and with any remaining capacity connected to the eastern half. In addition, the connection should be configured such that at least 50% of the generation capacity connected to the western half of the Hearn bus is available after allowing for a single generation outage.

3. The minimum supply requirement is 500 MW. This new supply should be configured as multiple units (or unit-trains). If combined cycle, the gas turbines must be able to operate without the steam turbine (i.e. exhaust bypass). We have assessment experience with the 2+1 combined cycle configuration (Portlands Energy Centre) which we know can work effectively.

4. A secure fuel supply is required. In the case of combined cycle gas, this could be dual fuel capability (gas plus distillate). If cogeneration, firm gas transportation may suffice.

5. Black-start should be considered for this station given its critical location. This does not need to be part of the RFP as the IESO contracts for Black-start. However, the procurement process and contract structure should accommodate it.

6. When needed, the generation would be expected to run for 8 to 16 hours per day. The need is based on a number of factors including, forced outage to transmission equipment and high demand (summer and winter). The need could be met by peaking or intermediate resources. Intermediate could be combined cycle, cogeneration or a combination. Technical requirements for a gas facility are as per the 2500 MW RFP (eg. Ramp rate etc). I can provide these separately.

7. The type of facility to procure (whether peaking or intermediate) is likely related more to the broader off coal program needs and consideration of time constraints to in service than to meet Toronto needs in isolation.

For additional detail, the recent 10 year outlook provides the most up to date rationale and statement of need. Section 4.2 and Toronto section of the Conclusions address these areas specifically.

http://www.ieso.ca/imoweb/pubs/marketReports/10YearOutlook_2005jul.pdf

The following information was provided to the public in support of the 2500 MW RFP. The background it provides is still largely correct. However, some in service dates have been revised slightly. The recent 10 year outlook should be relied upon for this information.

http://www.ieso.ca/imoweb/pubs/rfp/rfp_priorityZones-2004Aug03.pdf
http://www.ieso.ca/imoweb/pubs/rfp/TransmissionMap-Zone-1-2.pdf
http://www.ieso.ca/imoweb/pubs/rfp/TransmissionMap-Zone-1.pdf

We have a considerable amount of experience with proposals for new supply in this area. We would be happy to discuss these needs further in order to ensure a timely and effective resolution to the areas problems.

As you are aware, additional supply is urgently needed. However, there is also a need for focused CDM initiatives in downtown Toronto.

Yours truly,

Don Tench
Director – Planning & Assessments
Market & System Operations
Independent Electricity Market Operator

cc: J. Carr
D. Goulding
P. Murphy
D. Cowbourne

Appendix 7:

Minister`s Directive to OPA

Re. Toronto Reliability Supply and Conservation Initiative

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Minister of Energy

Hearst Block, 4TH Floor
900 Bay Street
Toronto ON M7A 2E1
Tel: (416) 327-6175
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Ministre de l'Énergie

Édifice Hearst, 4e étage
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Télé: (416) 327-6574

Ontario

February 10, 2005

Jan Carr
Chief Executive Officer
Ontario Power Authority
Suite 1600
120 Adelaide Street West
Toronto, Ontario
M5H 1T1

Dear Dr. Carr:

Re: Toronto Reliability Supply and Conservation Initiative

I write in connection with my authority as the Minister of Energy in order to exercise the statutory power of ministerial direction that I have in respect of the Ontario Power Authority (the "OPA") under section 25.32 of the *Electricity Act, 1998* (the "Act").

On January 20, 2004, the former Minister of Energy, the Honourable Dwight Duncan, announced that the Ministry of Energy would be instituting a procurement process to secure approximately 2,500 MW of electricity capacity from Clean Energy Sources, Demand Management and Demand Response. On June 25, 2004, the Ministry of Energy released the 2,500 MW Request for Proposals document. The Request for Proposals document specifically referenced two priority zones in the province which were identified by the Independent Electricity Market Operator (now the Independent Electricity System Operator (the "IESO")) as having critical local and regional supply, reliability and voltage support needs. One of these identified priority zones was downtown Toronto. – Leaside Sector. The results of the Request for Proposals process did not, however, meet the need for new supply or demand response and conservation in this sector.

<u>New Supply</u>

In its 18-month Outlook report of December 22, 2005 and in its Electricity Reliability Report of February 2, 2006, the IESO emphasized the necessity for a decision to be made early in 2006 to address the need for new supply for downtown Toronto. More specifically, the IESO has informed the Ministry that, despite increased demand response and conservation efforts in the Toronto area, at least 250 MW of new supply is required in the downtown Toronto sector by the Summer of 2008, and at least a further 250 MW by 2010. In a joint letter to the Minister of Energy, dated January 11, 2006, Hydro One, Toronto Hydro Corporation and the OPA, joined with the IESO to re-iterate the need for this new supply with the connection point to be at the Hearn Switching Station.

Members of Ministry of Energy staff have reviewed the results of the Request for Proposals process and identified proponents with projects for supply in the downtown Toronto – Leaside Sector. Since late 2005, Ministry of Energy staff members have had discussions and solicited information from proponents regarding available options for new supply in the downtown Toronto – Leaside Sector. One of those proponents, the Portlands Energy Centre ("PEC") project, located adjacent to the retired Hearn plant, has submitted a proposal on January 27, 2006, and engaged in detailed discussions with Ministry staff for the purpose of determining mutually satisfactory terms and conditions under which the proposal could be accepted. It is the opinion of the Ministry that this proposal is the most advanced option, and the one most likely to meet the 2008 supply requirement.

Specifically, the PEC project is a proposed combined cycle natural gas-fired, co-generation-capable power plant that has a nameplate capacity of approximately 550 MW. PEC has developed a plan to achieve completion of the proposed facility in two stages: the delivery of a simple cycle operation with a capacity of 330 MW in June 2008, followed by the delivery of the combined cycle operation in early 2009. The Environmental Assessment for the combined cycle operation has been completed. None of the other potential options has started the environmental approvals process for its respective proposed project. Unlike other potential projects, the proposed PEC project was developed in accordance with the requirements of Request for Proposals and is advanced with respect to project design and costing.

Therefore, in light of the reliability requirement for new supply for the downtown Toronto – Leaside Sector by the summer of 2008, under subsection 25.32(4) of the Act, I hereby direct the OPA to proceed with the next stages of negotiations with PEC, based on the process proposed by PEC and the OPA on February 9, 2006, for the purpose of executing and delivering a definitive contract with PEC by May 2006. As part of these negotiations, it is expected that the OPA may need to provide PEC with certain interim financial guarantees or recoverable assistance to allow PEC to proceed with preparatory work on the project during the course of the negotiations, but before the contract is executed, with the purpose of expediting the project so that PEC will be able to generate electricity supply in time to meet the above critical timetable identified by the IESO. It is understood that, in the event that PEC and the OPA are unable to execute and deliver a definitive contract, the OPA may seek to recover its costs, if any, relating to the interim financial guarantees or assistance by using its statutory authority for cost recovery.

Conservation

In addition to the above supply initiative, the Ministry has, for the past two years, been engaged in various conservation outreach and education initiatives through its Conservation Partnerships program. Through this program, the Ministry has funded a number of initiatives specifically focused on the Toronto area with the intent of reducing electricity demand. These initiatives included:

- 20/20 – The Way to Clean Air, a program to provide residents with tools to build an energy conservation program at home.
- Diversity Outreach Initiative, a conservation outreach program targeting non-English speaking communities in the GTA.
- TRCA Greening Health Care – Development of energy performance benchmarks for the Greening Health Care program of the Toronto and Region Conservation Authority.
- EcoSchools – An innovative conservation outreach initiative targeted at Toronto area schools with a focus on operational improvements and teaching materials.

The IESO, in its February 2, 2006 Electricity Reliability Report and in the January 11, 2006 joint letter with Hydro One, Toronto Hydro Corporation and the OPA, to the Ministry of Energy, indicated that, in addition to generation, alternative and supplemental activities, including conservation and demand management initiatives, should be part of the solution to address Toronto's needs. In response, the Ministry began the process of expanding its Toronto-focused conservation initiatives begun under the Conservation Partnerships program. The expansion seeks up to 300 MW of demand side management and/or demand response initiatives in the Toronto area by 2010. The subject matter of this expansion is the basis for this direction to the OPA.

Therefore, pursuant to the authority granted me under subsection 25.32(4) of the Act, I hereby direct the OPA to assume, effective as of the date of this letter of direction, responsibility for seeking up to 300 MW of demand side management and/or demand response initiatives in the Toronto area by 2010. In recognition of Toronto Hydro's existing and planned conservation initiatives funded through to September 2007, it is expected that the OPA will work co-operatively with Toronto Hydro and the community in the Toronto area in order to avoid duplication of initiatives prior to that date.

This Directive shall be effective and binding as of the date hereof.

Dated: February 10, 2006

Donna Cansfield

Donna Cansfield,
Minister of Energy