Reliability Review of North American Gas/Electric System Interdependency

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Abstract

This paper summarizes reliability analyses of Gas/Electric system interdependency performed in the Northeast, as well as report on the status of North American investigations by the NERC Gas/Electric Interdependency Task Force.

The majority of new generation proposed for North America relies natural gas as its primary fuel. While adequate supplies of natural gas have been forecast, the adequacy of the existing and proposed gas pipeline infrastructure to deliver the fuel to the gas-fired generating units depends on several factors. Reliability standards for the North American interconnected electric transmission systems require that they be planned and operated to reliably respond to first contingency electrical events. The lack of similar standards for the North American gas transportation systems has prompted a regional investigation of the adequacy of the North American gas pipeline infrastructure to reliably supply gas for gas-fired generation under single pipeline contingencies, as well as reliably withstanding major electrical contingencies. Upon the sudden loss of electric generation, the response of the gas delivery system may prevent other gas-fired generation from remaining on-line or fully responding to the electrical contingency.

1. Background

The North American Electric Reliability Council (NERC) recently reported that the majority of new generation planned for the future relies on natural gas as its primary fuel, and has raised concerns about the near-term and long-term adequacy of both the availability of natural gas and the infrastructure to move it to the generating stations [1]. The following is a brief excerpt from that report summarizing the reliability concerns.

Reliability standards for the interconnected electrical transmission systems dictate that they are planned to reliably operate through first contingency electrical failures. The lack of similar reliability standards for natural gas pipelines makes it difficult to assess the adequacy of the pipeline infrastructure under single pipeline contingencies. In some areas of North America, a single gas system disturbance may result in the eventual loss of more electrical generation than traditional analysis would indicate for a similar electrical disturbance. Additionally, upon the sudden loss of electrical generating units, gas delivery limitations may prohibit gas-fired generators that remain on line from fully responding to the sudden loss unless adequate measures are taken prior to the occurrence.

Unlike the electric system, the gas system has significant storage capability with adequate line packing. This characteristic can allow an electric generating station to operate for enough time that system operators can take action even if interruptions occur elsewhere on the gas delivery system.

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1 NERC has established operating policies and planning standards to ensure that the electric system operates reliably. The standards can be found at http://www.nerc.com/standards/.
Although interconnections exist among the natural gas pipelines, the pipelines generally operate independently of one another, which may place long-term fuel supplies in jeopardy for single component failures in the gas delivery infrastructure. Also, the pipeline owners are under no legal obligation to assist one another in emergency situations, unless a contractual arrangement to do so has been previously negotiated, but in fact have cooperated in the past and are expected to do so because they are aware of their mutual dependencies.

As with electrical curtailments, the security of the gas delivery system can be maintained through the use of gas curtailments. If and when gas curtailments are necessary, electric generators will have their service cut in accordance with the order of firmness that they have contracted. If customers contracted for non-firm service, they will be the first curtailed after a predetermined notice period (typically several hours). In addition, electric generators (especially new combustion turbines and combined cycle plants) depend upon high gas pressure at their delivery point and are susceptible to pressure drops depending on their specific design.

The interconnected electric transmission systems are designed and operated to be secure against the sudden loss of any single circuit, transformer or generating unit without loss of firm customer demand. Such losses result in electrical transients that are often instantaneous and large in magnitude, requiring that the electrical system be pre-configured to handle the contingency. The amount of spinning reserves within an area is sized to reliably accommodate a reduction of import capability or loss of the local generation. With more generating stations being supplied by natural gas, interactions between the gas supply and the generating units are increasingly becoming an electrical security issue. Transients in the operation of the gas pipeline may have a significant impact on the continuity of the service of gas-fired generation being served by that pipeline.

The cursory review conducted by NERC indicated that additional coordination between the planning and operation of electrical generation and natural gas infrastructure is necessary to ensure future deliveries of natural gas to the generators. There are some areas of North America in which the single most critical contingency for the electric systems is not the loss of a generator, transmission line or transformer, but rather a natural gas pipeline or even a single compressor station. A single gas contingency such as interruption or pressure loss of a single gas pipeline may result in the loss of multiple electric generators. Although many natural gas fired electric generators have dual fuel capabilities (i.e. burn fuel oil as a backup) there are questions surrounding the ability of this capability to fully mitigate a widespread loss of natural gas deliveries. Some generators must be taken off line to switch out burners; others may not have oil supplies available when the emergency occurs since they have burned oil as a hedge against gas price spikes; still others may not be able to switch when called upon due to environmental limitations and finally, in most cases there is not enough on-site oil in storage to ride through a very long interruption of gas supplies.

Much of the growth in natural gas consumption has been met with new pipelines or extensions from new supply areas rather than expanding the infrastructure in existing areas. Additional capacity is also being developed by increasing compression on the existing system and by looping (integrating a parallel pipeline).

A special government report looked at the level of new capacity added to the natural gas pipeline network in 2002 and the current capability of that network to transport supplies from production areas to U.S. markets [2]. The report concluded that it is likely that only about 70 to 80 percent of the proposed capacity additions would be completed.

2. NERC Gas/Electricity Interdependency Task Force

As a result of these concerns, the NERC Board of Trustees approved a scope of work outlining a review of the interdependency relationship between gas pipeline operations and planning, and electric generation operations and planning.

A Task Force was formed, whose membership consists of U.S. and Canadian electric, gas, and regulatory representatives, providing a wide range of expertise in both industries. The Task Force reports to the NERC Planning Committee, and provides status reports to the NERC Planning Committee, Operating Committee, Market Committee and the NERC Board of Trustees.

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2 Approved by the NERC Board on Trustees on February 11, 2003; see http://www.nerc.com/~pc/geitf.html
2.1. Northeast Gas Supply Overview

According to [3] natural gas represents approximately 18 percent of New England’s primary energy consumption, and roughly 27 percent of New York’s, compared to the national average of 24 percent. Approximately 90 percent of New York City’s generation uses natural gas as a primary or secondary fuel.

Canadian supplies play an important role in the gas supply to the Northeast U.S. region. In the last decade, four new pipelines systems opened the region connecting New York and New England to both western and eastern Canadian supply basins. Canadian gas provides about 25 percent of the gas supply to the mid-Atlantic region, and about 43 percent of New England’s gas supply. Also contributing are liquefied natural gas (LNG) imports from Algeria and, since mid-1999, Trinidad and Tobago in the Caribbean. LNG provides almost 30 percent of New England’s peak day requirements, and 10 percent of New York’s. LNG represents about one percent of New York’s total annual gas supply, but represents 15 percent of New England’s.

2.1.1 New England. The pipeline companies serving New England (shown Figure 1) are: Algonquin Gas Transmission, Granite State Gas Transmission, Iroquois Gas Transmission System, Maritimes & Northeast Pipeline, Portland Natural Gas transmission System, and the Tennessee Gas Pipeline Company. With 35,000 miles of pipeline and mainline, total pipeline deliverability is close to 4 Bcf/day.

In addition, New England is the site of one of the four currently operating import terminals for liquefied natural gas. The terminal is owned by Tractebel LNG North America and is operated by its subsidiary, Distrigas of Massachusetts Corporation. It is delivered by tanker to the Distrigas terminal in Everett, MA. The vaporization capability of the terminal is a maximum of 1 Bcf/day, with a daily send out by truck of another 100 MMcf/day.

2.1.2. New York. The pipeline companies serving New York (also shown in Figure 1) are the Algonquin Gas Transmission, Columbia Gas Transmission, Dominion Transmission, Empire State Pipeline Company,
Gas Power Plants Added to New England Since 1999\(^3\)


In the last decade, New York has added two new pipeline systems, the Iroquois gas Transmission System and the Empire State Pipeline, both delivering gas from Canada. With over 48,000 miles of pipeline and mainline, New York’s total pipeline delivery is roughly 6 Bcf/day.

2.1.3. Planned Infrastructure Enhancements.
Several pipeline infrastructure enhancements are currently planned for New England and New York over the 2003-2008 time period to meet the growing demands for natural gas. They include:

- Columbia Gas Transmission Corporation, TransCanada, Westcoast Energy, MNC Energy Group (Millennium Pipeline\(^4\))
- Iroquois Gas Transmission System (Eastchester Extension\(^5\))


\(^4\) Approximately 425 miles in New York using existing utility corridors, proposed to transport 700 million cubic feet of gas per day from a new interconnection with the TransCanada Pipeline in Lake Erie to a termination point in Mt Vernon, New York.

\(^5\) Approximately 36 miles of new pipeline from Iroquois’ mainline at Northport, Long Island into the Bronx, where it will connect with the ConEd system, and increase of 230 MMcf/day.
2.2. Northeast Gas-Fired Electrical Generation

2.2.1. New England. Approximately 3,000 MW of new gas-fired generation is expected to be in-service on the New England grid in 2003, in addition to the approximately 6,000 MW of new generation added since 1998. As a result, the projected installed capacity on ISO New England’s system is expected to outpace the summer peak demand over the next five-year period.

Of these projects, the Federal Energy Regulatory Commission (FERC) announced approvals in 2002 for the Dracut Expansion, the HubLine project, Phase II of the Maritimes and Northeast Pipeline, the Eastchester Extension, Islander East, and the Millennium Pipeline. The Eastchester project, the Maritimes and Northeast Phase II and the HubLine project are currently under construction.

2.2.2. New York. Natural gas is also projected to be the leading fuel for electric generation in New York State. Approximately 4,000 MW of new generation has been certified under New York’s Article X process. 1,000 MW of new generation is expected on-line in 2003.

2.2.3. Reliability Concerns. The original reliability studies for the Hydro-Québec Phase II interconnection [4] concluded that a large single source loss of generation in New England could have more severe effects on the Pennsylvania-New Jersey-Maryland (PJM) and New York systems than the worst internal contingency that these systems individually protect against. Accordingly, an operating philosophy in which size of the largest single generation contingency was limited to the extent necessary to ensure that the MAAC –ECAR-NPCC (MEN) system’s thermal, voltage and stability operating criteria are not violated was agreed upon.

The original study [5] indicated that the Hydro-Québec Phase II interconnection would be restricted to approximately 1,500 MW during periods of high transmission utilization in MAAC, in order to avoid unacceptable voltages in MAAC and New York following the loss of the Phase II interconnection.

The Joint Interregional Review Committee’s approval of this report was contingent upon the operating entities in MAAC, ECAR and NPCC establishing documented joint operating procedures to insure that deliveries to the U.S. on the Hydro-Québec Phase II interconnection are limited to safe levels that will not jeopardize the regional reliability of the MEN systems.

Ways to increase the size of the size of the largest single contingency that can be reliably withstood have been identified [6], but until the proposed solutions[14] are implemented, the overall limits calculated daily by the affected system operators will limit the range of the single contingency from 1,200 MW to 1,500 MW, depending on system conditions.

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[6] Approximately 30 miles of 24” pipeline primarily offshore between Beverly and Weymouth, Massachusetts and a five mile 16” lateral to Deer Island in Boston Harbor.


[9] Replace 12 miles of 16” pipeline with 24” within existing right-of-way from Dracut, Massachusetts to Burlington, Massachusetts.

[10] Approximately 950 miles of sub sea 36” pipeline from offshore Nova Scotia to New York/New Jersey, designed to carry 1 Bcf/day.


[12] Approximately 25 miles of 30” pipeline from Methuen to Beverly, Massachusetts, where it will interconnect with HubLine.

[13] Four compressor stations to be added in Maine and 31 miles of additional pipeline loop in Washington County; will nearly double the pipeline capacity to transport gas from offshore Nova Scotia.

[14] The NPCC Regional Planning Forum has investigated approaches to enhance the transmission grid from a Wide-Area, Trans-regional outlook; see: http://www.npcc.org/regionalPlanningForum.asp.
With respect to the gas-fired generation projects shown in Figure 2 for New England, there is a reliability concern that a common single gas supply contingency may result in a loss of generation or combination of generation in excess of the allowable limits calculated from considering only purely electrical contingencies.

In New York, the New York ISO dispatches the bulk electric power grid and administers the spot market for electricity. The New York ISO has two primary electric markets, the Day Ahead Market, a financial market with schedule commitment, and a Real Time balancing market where differences between schedules and actual are settled at the real time price. The day Ahead schedules are released at 11:00 a.m. for the next day – after initial gas nominations are required.

Last winter’s prolonged cold weather posed challenges to both the electrical and gas systems. January and February saw significant gas price volatility and restrictions on gas availability that highlighted the electric grid’s reliance on natural gas. As reported at a recent Northeast Gas Association Conference15, both the New York ISO and ISO-New England operators encountered an increased number of generator outages due to lack of fuel. In New York, generators were unable to meet their Day Ahead commitments for over 800 unit-hours16 last winter due to unavailable fuel. 363 of these unit-hours affected New York City units, nearly all of which were nominally dual-fuel units. At least one instance of gas derating directly affected the reliability operations of the New York ISO.

During the winter period of 2002/03 (December 1, 2002 to February 28, 2003) ISO New England reported that its generating sector experienced approximately 3,000 Equivalent Outage Hours17 (EOH) reported as “gas-related issues.” This involved 29 different units that have an aggregate winter claimed capability of 6,875 MW.

3. Summary of Northeast Analyses
3.1.Circa 1990’s


16 A unit hour is defined a one generation unit that cannot run in an hour.

17 EOH defined as [(Unit Rating-unit Derate)*affected hours]/Unit Rating.

3.1.1. New York. The 1989 New York State Energy Plan included a Lower Emission Scenario, which required a significant increase in the use of natural gas as a fuel for electric generation during the April – October summer period to reduce emissions. The New York Power Pool and the New York Gas Group examined the use of natural gas for several assumptions [7] concerning proposed Federal environmental law changes, goals related to the New York State Energy Plan, and regulations that were likely to be promulgated by the New York Department of Environmental Conservation Department.

The study examined gas use for three specific days during the winter, spring and summer seasons to determine if the required gas for both gas and electric systems could be delivered through the interstate natural gas pipelines.

A contingency loss of gas supply through a single pipeline delivery point or a line break in a gas distribution company’s gas transmission system was studied to determine the impact on continued operation of gas-fired generation.

The studies pointed out the need for rapid communications between the gas utility, the pipeline(s), all gas fired generation and the electric system dispatchers so that appropriate action can be taken to minimize the impact of a contingency. The studies showed that there is very little time to act before serious consequences occur – electric generating units tripping off and/or low pressure on a gas transmission system which may effect service to gas customers.

3.1.2. New England. The New England Gas/Electric Discussion Group was established in 1991 to address regional coordination issues in a non-adversarial setting. At the same time, EPRI initiated research on inter-industry coordination at a national level. These activities proceeded in parallel. The resulting report [8] underscored the importance of taking a regional approach to identifying and resolving potential problems created by the characteristics of electric loads on pipeline systems.

The Group set itself three objectives: 1) to examine the operational reliability of the gas/electric infrastructure, 2) to increase coordination between the industries, and 3) to educate industry participants and observers. The first phase of the Group’s activities concentrated on defining and modeling operational worse case scenarios for regional gas supply. A hypothetical three-day period in the fall of 1995 was chosen for this analysis, which examined the
consequences of both sudden losses and sudden increases in gas demand. Pipeline physical capabilities were found to be adequate, but some of the pressure and flow conditions were beyond normal operating procedures.

The Group developed recommendations for communication channels and procedures under both normal and crisis conditions, recommending initial direct communications between the power pool and the pipelines during emergency conditions.

3.2. Circa 2000’s

3.2.1. New York. The proposed Millennium natural gas pipeline project occupies approximately 28 miles of Consolidated Edison’s Right of Way connecting the Buchanan substation through to the Sprain Brook substation. Transmission lines are located in close proximity to each other over much of these rights of way and the construction and possible explosion of the proposed pipeline represent a risk to these lines. Power flows on these lines can reach from between 4,000 MW to 5,000 MW, which represents approximately 40 to 70 percent of Consolidated Edison’s total system load, depending on system conditions.

A study conducted by the New York ISO Transmission Planning Staff [9] demonstrated the impacts that the loss of either four or six circuits in the affected rights of way can have on the New York Bulk Power system, as well as neighboring systems. While the loss of the four circuits did not result in widespread significant adverse system impacts, it did result in the loss of local load in the Westchester area, representing a peak load of 600 MW. The loss of all six circuits results in the loss of local load, voltage collapse, and first swing system instability.


The analysis generated three principal findings. First, with the additions of pipeline capacity assumed to be in-place by November 2003, New York will have sufficient gas delivery capacity to supply the amounts of gas required for generation under all scenarios studied, provided the existing ability to burn oil is maintained.

Second, the ability to burn oil for electric generation has been and continues to be an important substitute for natural gas in the operation of the electric system in New York. The ability to burn oil requires having oil-capable units available, along with sufficient local storage capacity and environmental/operating permits (that allow units to run on oil).

Finally, for the scenarios analyzed, there is enough proposed new pipeline capacity with provisional FERC approval to allow the maximum potential gas demands of generators to be delivered. However, the amount of this new pipeline capacity that will be needed for electric generation depends on the amount of gas-fired generating capacity that is actually built and the extent to which the ability to burn oil is maintained.


Among the key findings: despite the many new pipeline facility enhancements into and within New England, the results of the updated gas simulation analyses show that the new pipeline facilities assumed do not materially mitigate the size of the expected gas transportation shortfall to the electric generation sector during the winter peak through the year 2005.

On extremely cold winter days when there is insufficient operational flexibility for New England’s pipelines to satisfy the coincident demands of both gas utilities and gas-fired generators, New England’s gas utilities are not expected to experience any denigration in the value of their respective capacity entitlements. The impact would be borne predominately by those gas-fired merchant generators whose gas transportation arrangements are not firm from the wellhead or storage centers to the burner-tip.

The report contains a number of recommendations for ISO New England to mitigate the resulting impact on electric system reliability, including implementing formalized communication procedures with pipeline operators to facilitate a proactive response capability when and if contingency measures are needed.

In a recent White Paper [12], ISO New England reviewed the outlook for natural gas supply, pipeline capacity, and the availability of liquefied natural gas (“LNG”) to serve power plants throughout New England. The Boston area is critically dependent on LNG to fuel Exelon’s 1,700MW new Mystic Station Units 8 & 9.
In 1999, gas-fired generation accounted for 16 percent of New England’s total electric consumption; it is expected to rise to 41 percent in 2003 and account for almost 50 percent by the year 2110. New England is one of the most dependent regions in North America for use of natural gas in electric power generation.

Natural gas reliance in the metropolitan Boston sub-area is forecast to reach 80 percent by the year 2010. The Boston area is critically dependent on the availability of LNG from Distrigas. A loss of LNG supply from Distrigas during the winter heating season would jeopardize regional energy security. Existing pipeline capacity during the winter season on the Algonquin and Tennessee pipelines, the two primary pipelines serving metropolitan Boston are not adequate to replace LNG deliveries necessary to operate the Mystic Units.

ISO New England studies indicate that approximately 2,800 MW to 3,900 MW of gas-fired generation would be unserved by pipelines during a peak winter day by the winter of 2004/05. Bulk electric power security during the winter heating season becomes increasingly dependent on the availability of residual or distillate fuel oil, as well as the ability of generators to switch to liquid fuel on short notice.

Natural gas is required year-round for electricity generation in New England, especially in Boston where the Mystic units operate as baseload units. Mystic units 8 and 9 are solely dependent on LNG from Distrigas for its fuel requirements. No other power plant in the U.S. or Canada is currently dependent on LNG for all of its fuel supply. While Distrigas has demonstrated a successful track record of maintaining LNG deliveries at its Everett, MA terminal, if, for whatever reason, LNG were not available from Distrigas, other pipelines serving the region would not have sufficient deliverability during the winter to transport fuel for the Mystic units.

Duke Energy’s proposed Everett Extension would provide another pathway to the Mystic Units, but until additional gas from Atlantic Canada flows regularly through the Maritimes and Northeast pipeline, conceivable diversions to the Mystic units would likely result in curtailments or interruptions in gas supply to other gas-fired generators in New England.

3.3. Summary of Studies In Progress

The Independent Market Operator of Ontario (the IMO) announced a Request For Proposals February 1, 2002 on the IMO website for a “Multi-Region Assessment of the Adequacy of the Northeast Natural Gas Infrastructure to Serve the Electric Power Generating Sector.” The contract was awarded to Levitan and Associates, Inc.

The study built on the previous New England and New York studies to the extent possible. A gas hydraulic model was developed for each area, resulting in an integrated regional model for use by the study participants to pursue additional analyses.

The report provides the details on the infrastructure characteristics, including evaluation of gas demand forecasts, an infrastructure adequacy assessment, and steady state contingency analysis with a focus on regional or inter-area impacts.

All pipelines in the study area provided information under strict non-disclosures agreements. These agreements restrict the amount of public disclosure of results but are not expected to affect the ability for the areas to implement recommendations.

ISO New England has recently formed a Fuel Diversity Working Group as part of its Transmission Expansion Advisory Group’s development of their Regional Transmission Expansion planning process.

The Working Group first met on August 5, 2003; their primary intent is to address the reliability concerns associated with fuel diversity issues. The Working Group membership includes representatives from NEPOOL, ISO New England, pipeline and gas companies as well as New England state and regulatory officials.

3.4. Gas System Response to the August 14th Blackout

A preliminary Interstate Natural Gas Association of America (INGAA) Blackout Survey18 reviewed the gas pipeline facilities in the affected area, including 12 companies, over 1,000 gas meters, and more than 50 compressor stations. The gas market responded well within operating limits during the day of the event. The response seen by the gas system following the event included reduced industrial demand and increased gas demand for electrical generation.

At gas control centers in the affected area, the UPS power supplies and backup generation facilities worked as designed. At gas compressor stations, all safety systems remained active. The electric powered units that lost power were not needed to maintain the

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18 Presented at the NERC Gas/Electric Interdependency Task Force meeting, September 10-11, Folsom, CA.
particular flow conditions. Gas powered compressor units utilized UPS and backup generation; only one unit shutdown was reported because of loss of power. Employees were called out as a precaution.

At measurement stations all regulators and meters remained operational with all safety systems active. SCADA systems lost commercial power; UPS power supplies took over the power requirements of SCADA until exhausted. Employees were called out to double check certain facilities.

In response to additional requests for natural gas by generators for start-up, the pipelines provided flexible service.

In summary, the gas system operated as designed and reliably absorbed the gas pressure transients experienced. However, it was pointed out that the event occurred during the summer period, historically a non-peak time period for the gas industry when planned maintenance occurs and gas storage areas are filled in preparation for the next winter peak period.

4. Initial Recommendations

In response to these Northeast reliability concerns and similar concerns expressed in other parts of North America, the NERC Gas/Electric Interdependency Task Force is initially considering several recommendations to address the reliability issues raised. They include:

- Requiring a review of regional gas supply and transportation as part of NERC’s annual reliability assessments, including developing standards for resources to qualify for inclusion in reserve margin calculations;
- Coordinating gas/electric system maintenance schedules and outages between the operators responsible for the reliability of electric system and gas system; these 6-12 month schedules would include compressor/pipeline outages, and electric facilities outages, for example;
- Developing an inter-industry strategy for common education, planning, and emergency response, including the establishment of an emergency communication protocol between Security Coordinators and the Gas Control Centers of the pipelines;
- Establishment of a monitoring system to report any gas/electric events that have reliability impacts;
- Development of appropriate confidentiality agreements (use and non-disclosure agreements) to facilitate data sharing, reports and reliability studies;

- Reviewing State, Federal, and Provincial gas curtailment policies and corresponding emergency tariffs;
- Preparing White Papers on fuel delivery and quality requirements for modern gas combined cycle generating units; and,
- Expanding NERC standards to include gas pipeline contingencies to the list of considerations included in the NERC Planning Criteria.

The Task Force anticipates finalization of their recommendations by the first quarter of 2004, for consideration by the NERC Board of Trustees.

5. References


6. Acknowledgements

The efforts of the NERC Gas/Electricity Interdependency Task Force, chaired by Mr. Ken Wiley of the Florida Reliability Coordinating Council and Mr. Steve Leahy of the Northeast Gas Association is greatly appreciated and acknowledged.

7. Biography

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