NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Guideline

Natural Gas and Electrical Operational Coordination Considerations

March 22, 2023

RELIABILITY | RESILIENCE | SECURITY

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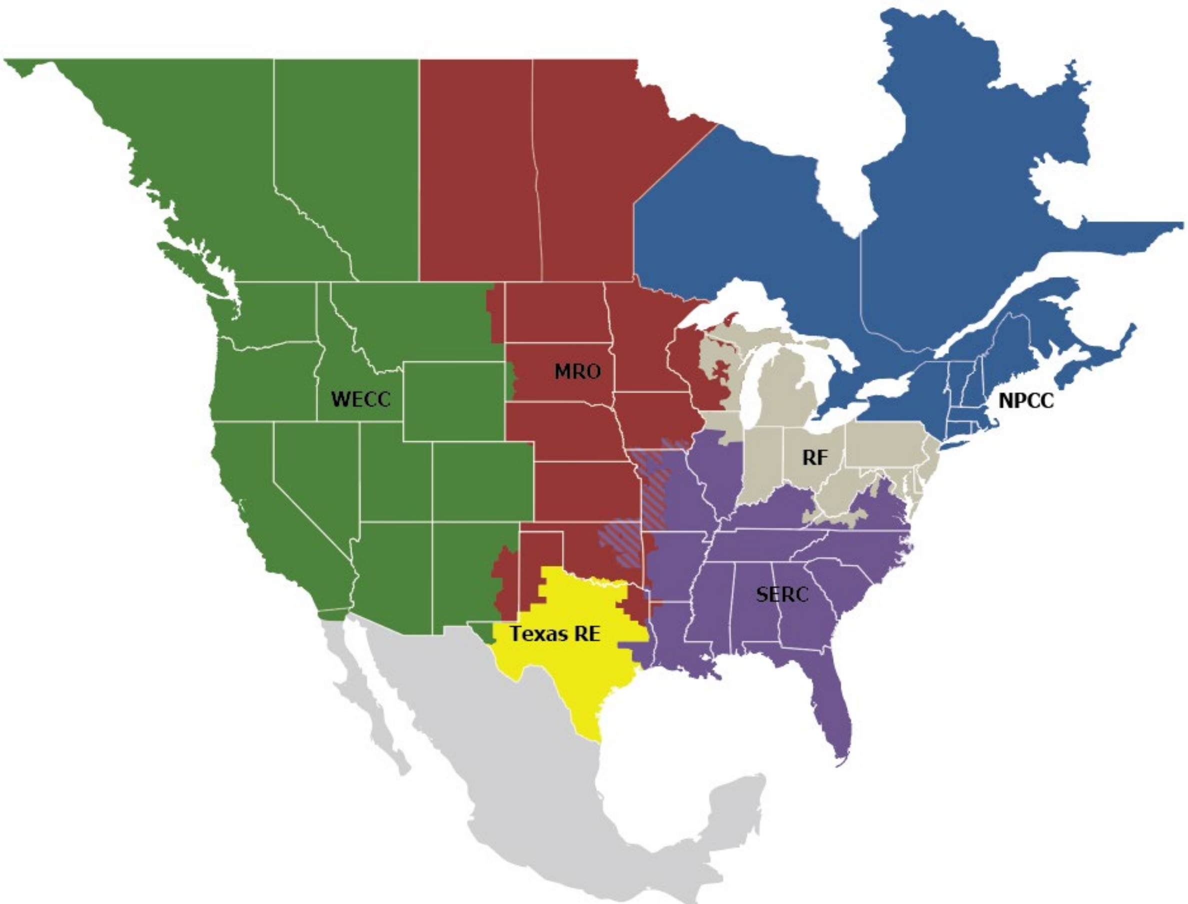
Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities, is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security
Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six Regional Entity boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators (TOPs) participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

Preamble

The NERC Reliability and Security Technical Committee (RSTC), through its subcommittees and working groups, develops and triennially reviews reliability guidelines in accordance with the procedures set forth in the RSTC Charter. Reliability guidelines include the collective experience, expertise, and judgment of the industry on matters that impact BPS operations, planning, and security. Reliability guidelines provide key practices, guidance, and information on specific issues critical to promote and maintain a highly reliable and secure BPS.

Each entity registered in the NERC compliance registry is responsible and accountable for maintaining reliability and compliance with applicable mandatory Reliability Standards. Reliability guidelines are not binding norms or parameters nor are they Reliability Standards; however, NERC encourages entities to review, validate, adjust, and/or develop a program with the practices set forth in this guideline. Entities are encouraged to review this guideline in detail and in conjunction with evaluations of their internal processes and procedures. It is suggested that reviews could highlight changes that might be needed, noting that these changes should be done with consideration of actual system design, configuration, and internal business practices.

It is in the public interest for NERC to develop guidelines that are useful for maintaining and enhancing the reliability of the Bulk Electric System (BES). The subgroups of the RSTC—in accordance with the RSTC charter[1] are authorized by the NERC Board of Trustees to develop reliability and security guidelines. These guidelines establish a voluntary code of practice on a particular topic for consideration and use by BES users, owners, and operators. These guidelines are coordinated by the technical committees and include the collective experience, expertise, and judgment of the industry. The objective of this reliability guideline is to distribute key practices and information on specific issues critical to appropriately maintaining BES reliability. Reliability guidelines are not to be used to provide binding norms or create parameters by which compliance to NERC Reliability Standards are monitored or enforced. While the incorporation of guideline practices is strictly voluntary, reviewing, revising, or developing a program using these practices is highly encouraged to promote and achieve appropriate BES reliability.

[1] https://www.nerc.com/comm/RSTC/RelatedFiles/RSTC_Charter_Board_Approved_Nov_4_2021.pdf

Executive Summary

The goal of this reliability guideline is to provide key practices and information to responsible entities that depend on natural gas for the Reliable operation of their portion of the electric grid during normal and emergency conditions. This guideline provides a set of principles and strategies that could be adopted by Regional Entities who depend on the reliable distribution of natural gas. This guideline does not apply universally, and an evaluation of each area's unique needs is essential to determine which principles and strategies may be useful. The guideline principles and strategies may be applied by Reliability Coordinators (RCs), Balancing Authorities (BAs), TOPs, Generator Owners (GOs), and Generator Operators (GOPs) in order to ensure reliable coordination with the natural gas industry. Finally, the document focuses on the areas of preparation, coordination, communication, and gathering and sharing information that may be applied in order to coordinate natural-gas-electric utility operations and minimize reliability-related risk.

Introduction

Purpose

The purpose of this reliability guideline is to provide key practices and information that could assist grid operators and owners in the reliable coordination of electric operations with natural gas providers. The electric power sector's use of natural gas, specifically natural-gas-fired generation, has grown exponentially in many areas of North America and effective coordination with natural gas providers is important to maintaining electric grid reliability. With this increased growth in natural gas usage comes greater reliance and associated risk due to the dependency that each industry now has on the other. To minimize the operational impact of the interdependencies electric system operators and owners should consider the guidance provided in the guideline.

Applicability

RCs, BAs, and TOPs. While not included in the NERC glossary definition of System Operator, this guideline is also relevant for GOs, GOPs, and Distribution Providers (DP).

Chapter 1: Establish Industry Coordination Mechanisms

Establish Natural Gas and Electric Industry Coordination Mechanisms

Establish Contacts

Once contacts among these participants are established, additional coordination activities can begin. Natural gas industry trade organizations, such as the Interstate Natural Gas Association of America, Natural Gas Supply Association, American Gas Association, or a Regional Entity may be able to aid in development of operational contacts and the establishment of coordination protocols. The reliability of the grid would benefit from responsible entities developing contacts that coordinated and aligned with long- and short-term planning, including resource and transmission outage coordination as well as consideration of near-term and real-time operations through proactive engagement with organizations, including (but not limited to) RCs, BAs, TOPs, GOs, GOPs, and natural gas control operators. Additionally, where possible, consideration should be given to coordinating contacts with both control room operating staff as well as management. Establishing and maintaining these contacts is the most important aspect of natural gas and electric coordination; however, communications during normal operations is an effective way to deve[2]lop relationships rather than making the first call during emergency conditions.

Key Takeaway

An essential part of any coordination activity is the identification of participants. For natural gas and electric coordination, this could involve the identification of the natural gas interstate/intrastate pipelines, natural gas suppliers, and Local Distribution Companies (LDC) as well as natural gas industry operations staff within the electric footprint boundaries and in some instances beyond those boundaries.

Communication Protocols

Once counterparts are identified in the natural gas industry, communications protocols could be established within the regulatory framework of both energy sectors looking to coordinate and share information. The Federal Energy Regulatory Commission (FERC) issued a final rule under Order No. 787 that allowed interstate natural gas pipelines and electric transmission operators to share non-public operational information to promote the reliability and integrity of their systems. Since the inception of this rule and the subsequent incorporation of those rules into the associated tariffs followed by the appropriate confidentiality agreements, natural gas and electric entities have been able to freely share operational data. Data that could be shared to improve operational coordination may include (but is not necessarily limited to) the following:

- Electric entities could share detailed operational reports with natural gas pipeline operators by specific generating assets operating on specific pipelines that specify expected fuel burn by asset and by hour over the dispatch period under review. It is important to convert dispatch plans from electric power (MWh) to natural gas demand (in terms of natural gas units/time like dekatherms/day or MMcf/hour) when conveying that information to natural gas system operators. In real-time electric system demands may change from the planned dispatch period under review, resulting in deviations in actual fuel usage by asset and hour.
- Electric entities could provide expected fuel consumption values in aggregate so that natural gas entities associated with relevant pipelines have an hourly and daily basis for demand.
- Entities could exchange real-time operating information in both verbal and electronic forms (e.g., pipeline company informational postings) of actual operating conditions on specific assets on specific pipelines. They could also consider the electronic communication of real-time system information between affected parties, such as real-time natural gas meter readings and generator dispatch instructions.
- Entities of both industries could share outage planning for elements of significance, including sharing detailed electric and natural gas asset scheduling information on all time horizons and coordinating outages of those

[2] www.ferc.gov/sites/default/files/2020-04/order-787_0.pdf

assets to ensure reliability on both the natural gas and electric systems. Examples include, but are not limited to, must-run requirements, in-line inspection operations, the risk of disruption to electric compression, and pipeline outages that potentially cause the need for pressure reductions.

- Entities could schedule coordination meetings, face-to-face whenever possible, on a periodic basis (e.g., annual, bi-annual, quarterly) to discuss a range of topics, including (but not limited to) outage coordination, proposed electric/natural gas market rule changes, upcoming natural gas generator additions, pending electric retirements/repowers, enhancements/modifications to natural gas/electric coordination tools, natural gas pipeline infrastructure changes, near/long-term seasonal forecasts, and load shape changes.
- Entities of both industries could share normal and emergency conditions in real-time and ensure that each entity understands the implications to their respective systems. This could include natural gas and electric entities proactively reaching out to the operators of stressed natural gas systems to discuss the impacts, adverse or otherwise, of their expected or available actions. Entities could understand the direct impacts to electric generation assets when natural gas pipelines are directed under more extreme natural gas system operating conditions and/or force majeure conditions.

The sharing of non-public operating information between the electric operating entity and the LDC, intrastate pipelines, and gathering pipelines is not covered under FERC Order 787[3]. For this reason, individual communication and coordination protocols could be considered with each LDC and intrastate pipelines within the footprint of the operating entity. These protocols might be set up to specifically allow natural gas dispatchers or dispatch departments at intrastate, LDC, and gathering pipelines to communicate directly with generator operators and may include (but is not necessarily limited to) the following:

- Understand the conditions under which an LDC or intrastate pipeline would interrupt natural-gas-fired generation is of particular importance and incorporate this information into operational procedures and planning to assist in identification of potential at-risk generation.
- Set up electronic/email alerts from each LDC or intrastate pipeline as to the potential declaration of interruptions is one key means of real-time identification of potential loss of generation behind the LDC city gate or meter station on an intrastate pipeline.
- Address the identification of electricity sources for electric compression stations and protocols for protecting these sources during periods of high demand or system stress with plans to mitigate such risk when possible.

Coordinating Procurement Time Lines

Operating entities may want to consider changing next day operating plan scheduling practices to align more efficiently with natural gas day procurement cycles. The natural gas and electric industries operate on differing time lines for day-ahead planning processes and in real-time with the electric day on a local midnight to midnight cycle. The natural gas industry process operates on a differing time line with the operating day beginning at 9:00 a.m. central time and uniform throughout North America. This difference in operating days can lead to inefficient scheduling of natural gas to meet the electric day demands. In many instances throughout North America, the electric industry has moved the development and publishing of unit commitments and next day operating plans in order to ensure that generation resources have the ability to procure and nominate natural gas more efficiently to better meet the scheduling time lines of the natural gas industry. In addition, the natural gas

> **Key Takeaway**
>
> Entities could coordinate and modify scheduling practices with more effective time periods to allow for a higher level of pipeline utilization and, more importantly, provide the early identification of constraints that could require starting natural gas generation with alternate fuels if available or use non-natural-gas-fired facilities for fuel diversity to meet the energy and reserve needs of the electric system

[3] www.ferc.gov/sites/default/files/2020-04/order-787_0.pdf

industry has adjusted some of its nomination and scheduling practices to allow for more efficient scheduling that meets the needs of the electric system.

- Recently, the fast-ramping capability of natural-gas-fired units has been used in some places to bolster grid flexibility in areas trending toward more renewable energy, primarily with variable and intermittent supplies of fuel (e.g., sunshine, wind, and water). Maintaining a balanced power system will likely require a more flexible approach to energy and capacity adequacy in order to sustain operational awareness.

Identification of Critical Natural Gas System Components and Dual-fuel Supplier Components

Electric transmission and distribution owners are capable of interrupting electrical load either automatically through under frequency load shedding relays installed in substations throughout North America or via manual load shedding ordered by RCs, BAs, and/or TOPs via SCADA. These manual and automatic load shedding protocols are part of every entity's emergency procedures.

Entities could try to ensure critical natural gas sector infrastructure is not located on electrical circuits that are subject to the load shedding as described above. Electric operators' could establish contact with the natural gas companies operating within their jurisdictions to compile a list of critical natural gas and other fuel facilities that are dependent upon electric service for operations. This list could also consider the availability of backup generation at critical natural gas facilities.

Key Takeaway

It is essential that natural gas and electric operating entities coordinate to ensure that critical natural gas pipelines, compressor stations, Liquefied Natural Gas (LNG) and other natural gas storage, natural gas processing plants, and other critical natural gas system components identified by the owners and/or operators should not be subject to electric utility load shedding in general but more specifically under frequency and/or manual load shedding programs.

Once the list is compiled, a comprehensive review of load shedding procedures/schemas/circuits could be done to verify that critical infrastructure is not connected to or located on any of those predefined circuits. This review could be considered for evaluation at least annually. The best practice in this area is to try and ensure that these facilities are not included in the initial under frequency or manual load shedding protocols at the outset. In the event that critical natural gas system components are subject to load shedding or even uncontrolled loss of load, consideration could be given to the priority or restoration in the restoration plan for that equipment. Fuel delivery infrastructure restoration may be necessary to fully utilize all aspects of a full restoration plan.

In a similar manner, it may be appropriate to coordinate with secondary fuel (e.g., diesel or fuel oil, onsite LNG) suppliers to ensure that any necessary critical terminals, pump stations, and other critical components identified by the owners and/or operators are not subject to electric utility load shedding programs in general and, more specifically, under frequency and/or manual load shedding programs. This is especially appropriate if adequate on-site fuel reserves are not guaranteed and just-in-time fuel delivery practices are required.

Operating Reserves

The electric industry may want to consider adjustments to operating reserve or capacity requirements to better reflect the increased reliance on natural gas for the generation fleet. For instance, In addition, some electric operators are considering the implementation of a risk-based operating reserve protocol that increases or decreases the amount of operating reserve procured based upon the risks identified to both the natural gas and electric system.

Chapter 2: Preparation, Supply Rights, Training and Testing

Assessments

Preparing the natural gas and electric systems for coordinated operations benefits from up front assessments and activities to ensure that system operators are prepared and can effectively react when real-time events occur. Preparation activities that may be considered include the following:

- Develop a detailed understanding of where and how natural gas infrastructure interfaces with the electric industry, including:
  - Identifying each pipeline (interstate and intrastate) that operates within the electric footprint and mapping the associated electric resources that are dependent upon those pipelines.
  - Identifying the level and quantity of pipeline capacity service (firm or interruptible; primary/secondary) and any additional pipeline services (storage, no-notice, etc.) being utilized by each natural-gas-fired generator.
  - Developing a model of and understanding the non-electric generation load that those pipelines and LDCs serve and will protect when natural gas curtailments are needed.
  - Identifying natural gas single element contingencies (i.e., single points of disruption) and how those contingencies will impact the electric infrastructure.
    - For instance, although most natural-gas-side contingencies will not impact the electric grid instantaneously, they can be far more severe than electric side contingencies over time because natural-gas-side contingencies may impact several generation facilities. When identifying natural gas system contingencies, the electric entity should consider what the natural gas operator will do to secure its firm customers. This could include the potential that the natural gas system will invoke mutual aid agreements with other interconnected pipelines, possibly leading to the curtailment of non-firm electrical generation from the non-impacted pipeline to aid the other. Consideration could also be given to electric system impacts across adjacent BAs and/or RCs.
  - Understanding how natural gas contingencies may interact with electric contingencies during a system restoration effort

Emergency Procedure Testing and Training

- When possible, training should include lessons learned from past events, such as actual pipeline disruptions or compressor station lightning strikes. Particular attention could be focused on any natural-gas-related contingency that may result in an instantaneous generation loss.
- Consider the addition of electric and natural gas coordination and interdependency training to educate and exercise RCs, BAs, TOPs, GOs, and GOPs during potentially adverse natural gas supply disruptions.
- If voltage reduction capability exists within the area, practical testing and training could be considered as part of seasonal or annual work plans.

Key Takeaway

Consider the development of testing and training activities to recognize abnormal natural gas system operating conditions and support extreme natural gas contingencies (e.g., loss of compressor stations, pipelines, pipeline interconnections, or large LNG facilities) that can result in multiple generator losses over time.

- The use of manual firm load shedding may be required for extreme natural gas and/or electric contingencies. Consideration could be given to practicing the use of manual load-shedding in a simulated environment. These simulations could also be used as part of recurring system operator training at a minimum. The use of tabletop exercises can be a valuable training aid, but consideration could be given to using an advanced training simulator that employs the same tools the operators would use to accomplish the load shedding tasks wherever possible.

- Consider conducting periodic operational drills and tabletop exercises between ISO/RTO's, RCs, BAs, TOPs, GOs, GOPs, local emergency management entities, and applicable natural gas industry providers (interstate and intrastate pipelines as well as local distribution companies that serve natural gas generators) where possible.
- Consider the development of, and drill on, internal communication protocols specific to potential natural gas interruptions.
- Consider the development of training programs for generator personnel on the typical form (electronic or telephonic), message and circumstances that characterize information exchange between natural gas pipeline operators and the generator. This training should detail the relevant information for normal operations as well as emergency situations.

Generator Testing

Consideration could be given to adopting generator testing requirements for dual-fuel auditing. Some items to consider when establishing a dual-fuel audit program are as follows:

- The frequency that audits should be conducted and under what weather and temperature conditions.
- The verification of sufficient alternate fuel (e.g., fuel oil) inventory to ensure required generation response and output with seasonal (i.e., winter vs summer) consideration.
- As part of this assessment, evaluate if the stored fuel is fully burnable as well since the full volume of the tank may not be able to pump at very low inventories.
- Capacity, ramping capability, or other reductions related to alternate fuels.
- Understanding of metrics like the capability and expected time it takes to startup, switch to alternate fuel, ramp to and operate at full capacity, ramp down, and resource shut down.
- Additional consideration should be given to assets that require a shutdown in order to swap to an alternate fuel source.
- Consideration of any environmental constraints the generator must meet in order to swap to and operate on the alternate fuel.

Capacity and Energy Assessments

Consideration should be given to the development of forward-looking capacity analyses with which the electric industry is familiar but applying the impacts of fuel restrictions that may occur due to pipeline constraints or other fuel delivery constraints, such as LNG shipments or liquid fuel delivery considerations. In order to conduct these types of assessments, the analysis needs to consider the LDC loads within the Regional Entity while acknowledging the potential impact of LDC loads outside the Regional Entity. The weather component of the assessment could consider normal and extreme conditions (i.e., Gas Design Day, which is the equivalent to the highest peak that the pipeline was designed for and potential impacts of ambient temperatures increasing gas volume consumption). This capacity assessment can be on several time horizons, including real-time, day ahead, month ahead, and years into the future. These assessments could consider pipeline maintenance, known future outages, construction and expansion activities as well as all electric and natural gas industry considerations, such as potential or anticipated regulatory changes.

Key Takeaway

In addition to a capacity assessment that represents only a single point in time, consideration should be given to the development of a seasonal, annual, or multiannual energy analysis that uses fuel delivery capability/limitations as a component.

Such assessments can be scenario based, simulate varied weather conditions over the course of months, seasons, and/or years, and consider the same elements as discussed in the capacity analysis. The output of the assessments could determine whether there is the potential for unserved energy and/or determine the ability to provide reserves over the period in question.

Seasonal Readiness Reviews

Seasonal readiness training for winter weather could include reviews and training associated with dual fuel testing, emergency capacity and energy plans, and weather forecasts over the seasonal period, fuel survey protocols, and fuel storage readiness. Other areas that require attention in winter readiness reviews include reviewing and setting specific operational expectations on communications protocols. Finally, any winter readiness seminars could include individual generator readiness as outlined in the reliability guideline: *Generating Unit Winter Weather Readiness Current Industry Practices*,[4] such as ensuring adequate fuel arrangements are in place for unit availability, adequate freeze protection guidelines are in place, understanding access to primary and secondary fuels and testing to switch to alternate fuels, ensuring all environmental permitting is in place for the fuel options available to the asset, and making sure that the BAs and TOPs are kept apprised of the unit availability. Many of the same benefits as winter readiness exercises can be realized with the added benefit of exercises under summer operating conditions when electric loads are higher than winter loads.

Key Takeaway

Winter events, such as the 2014 Polar Vortex and the 2021 Winter Storm Uri, have magnified the need to ensure that seasonal awareness and readiness training is completed within the electric industry, including system operators, GOPs, and TOPs.

Extreme Event Readiness Reviews

Seasonal readiness reviews for extreme events (e.g., hurricane, earthquakes, and wildfires) could include responses to potential natural gas supply limitations and corresponding decreases in natural gas deliveries that may impact electric generation.

4 https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_Generating_Unit_Winter_Weather_Readiness_v3_Final.pdf

Chapter 3: Establish Communication Channels

Establish and Maintain Open Communication Channels

Industry Coordination

- In the long- and short-term planning horizons, regularly scheduled (e.g., monthly or quarterly or at a frequency deemed effective as decided by the coordinating organizations) meetings between the natural gas and electric industries could be held to discuss upcoming operations, including outage coordination, industry updates, project updates, and exchanges of contact information.
- Operating entities could consider the development of a coordinated and annually updated set of operational and planning contact information for both the natural gas and electric industries. This information could include access to emergency phone numbers for management contacts as well as all control center real-time and forecaster desks for use in normal, and emergency conditions.
- Natural gas and electric emergency communication conference call capability could be considered between the industries such that operating personnel can be made available from both industries immediately, including off hours and within the confines of the individual confidentiality provisions of each entity. Electric sector personnel could periodically monitor pipeline posted information and notices.
- In coordinating and modifying scheduling practices between natural gas and electric entities, the impact of the variability of intermittent resources could be considered in order to provide a more accurate assessment of available resources and to maintain BPS reliability.

Emergency Notifications to Stakeholders

- Operating entities may want to consider proactive notifications to stakeholders of abnormal and/or emergency conditions on natural gas infrastructure to ensure widespread situational awareness and obligations associated with dispatch relationships in the electric sector. An example of a notification used for generators in New England appears in **Figure 1**.

1. Notices Indicating Abnormal and/or Emergency Conditions on the Pipeline Infrastructure Serving Generators

NOTE

Notices indicating abnormal and/or emergency conditions on the pipeline infrastructure serving a Generator in the ISO RCA/BAA could come in the form of, but **not** limited to, Operational Flow Orders, Imbalance Warnings or even a verbal notification.

A) When electronic and or verbal notices indicating abnormal and or emergency conditions on the pipeline infrastructure serving a Generator in the ISO RCA/BAA are received, the Forecaster notifies the Operations Forecast and Scheduling Supervisor (or designee)

(1) The Forecaster reviews this information and depending upon the severity of the condition may pass the publicly available information along by drafting an email and submitting it to Customer Service for dissemination to each applicable Generator Designated Entity (DE) management contact(s) and/or Lead Market Participant (MP) contact(s).

NOTE

The following guideline or one tailored to the current situation can be used as a template for drafting this notification;

"ISO-NE has received the following information via the publicly available notices published by the gas pipelines:

(Insert Notice, such as Operational Flow Order or Force Majeure, etc.)

"Because of this situation, it is critical that each applicable Generator DE or Lead MP provide ISO-NE with up to date and reliable estimates of each Generator current and future capabilities including the ability to have fuel for a Generator under their control. This includes immediately reporting any information that may prevent a Generator from operating in accordance with submitted offer data, including, but **not** limited the following:

- Planned, Maintenance and or Forced outages of the Generator facilities as soon as that information is available
- Immediate reporting of any updates to outages including overruns and or early returns to service of the Generator facilities
- Any high risk activities at a Generator location that may reduce its capability or place the capability at risk
- Any fuel reductions or outages that may limit a Generator's ability to perform in any way
- Any changes to any operating limits of a Generator which must reflect the most accurate and up to date information available
- Any changes at all in a Generator ability to follow dispatch instructions including manual response rates, ability to provide reserve, ability to provide energy, and/or ability to provide capacity
- Any changes in projected Generator self schedules

Figure 1: Example of New England Emergency Notification

- Depending upon the level of severity and risk exposure, these written notifications and a means to communicate them may need to be followed up with direct verbal communications.
- Emergency communication protocols in the public and regulatory community
  - Most every electric operating entity has longstanding capacity and energy emergency plans in place that focus on public awareness, emergency communications, and appeals for conservation and load management; however, as the natural gas and electric industry become further dependent, considerations could be made for both industries to coordinate for extreme circumstances. Natural gas and electric operators, in coordination with public officials (including relevant regulatory communities), may find situations where the energy of both the natural gas and electric sector must be reduced in order to preserve the reliability of both. While these types of efforts are still in their infancy, they could be explored depending upon the particular circumstances of each area's Regional Entity.

Chapter 4: Information and Situational Awareness

Gathering, Sharing Information, and Situational Awareness

Fuel Surveys and Energy Emergency Protocols

Energy emergency procedures and fuel surveys are important tools in understanding the energy situation in a Region. The surveys can be used to determine energy adequacy for the region's electric power needs and for the communications and associated actions in anticipation or declaration of an energy emergency. The fuel surveys could focus on the availability of other types of fuels if the natural gas infrastructure is the constrained resource. (Examples of fuel surveys and procedures used in operational planning and real-time are referenced in the footnotes. [5][6][7])

Fuel Procurement

- Electric operating entities could consider evaluating each electric generator's natural gas procurement and commitment to determine fuel security for the operational planning period of concern, including up to the operating day. Over longer operational planning periods there will typically exist an increased level of uncertainty on the accuracy of the data and assumptions that are used in these evaluations. As day-ahead and real-time operational horizons are approached there will typically be increased certainty on the accuracy of the data and assumptions. The more lead time an electric operating entity has on a potential occurrence of an energy emergency it will allow greater flexibility for it to prepare for and develop alternative plans to mitigate this exposure.
  - The electric operating entity can collect publicly available interstate pipeline bulletin board data and compare the natural gas schedules for individual generators against the expected electric operations of the same facility in the current or next day's operating plan. An example of this type of data collection appears in **Figure 2** with the data helping to determine if enough fuel is available to meet an individual plant or in aggregate an entire natural gas fleet's expected operation for the current or future day. The report can indicate whether a fuel surplus or deficit exists by asset or for an entire pipeline.

Key Takeaways

If sufficient natural gas has not been nominated and scheduled to the generator meter, assessments can be done to determine the impact on system operations, and the operating staff may call the generator to inquire as to whether the intention is to secure the requisite natural gas supply to match its expected dispatch plus operating reserve designations.

[5] Energy emergency example: https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op21/op21_rto_final.pdf
[6] Seasonal survey example – See section 7.3.5 in Manual 14: https://www.pjm.com/directory/manuals/m14d/index.html#about.html
[7] Real-time survey example – See section 6.4 of Manual 13: https://www.pjm.com/directory/manuals/m13/index.html#about.html

Plant	MWh Burned So Far	MWh Before Midnight	MWh After Midnight	MWh Scheduled	MWh Surplus	Gas Scheduled
1	2201	169	1932	4493	191	34600
2	777	0	663	0	(1440)	0
3	1910	0	901	2849	38	20700
4	2131	0	0	2736	605	20028
5	5903	403	0	7706	1400	53800
6	2369	0	798	3097	(70)	22500
7	1253	0	350	93	(1510)	1000
8	2402	185	1850	5129	692	45500
9	0	0	0	28	28	300
10	3	0	525	0	(528)	0
11	0	0	0	0	0	0
12	1	0	0	0	(1)	0
13	4	0	0	0	(4)	0
14	5077	389	2864	9591	1261	65621
15	3394	215	0	3347	(262)	25048
16	3554	550	6017	221	(9900)	1500
17	10639	797	4157	17418	1825	126540
18	7249	545	3892	11096	(590)	80813
19	972	45	1066	9	(2074)	100
20	0	0	0	0	0	0
21	0	0	0	0	0	0
22	6294	0	2476	1643	(7127)	17471
23	2758	0	1209	3944	(23)	30000
24	2400	250	1250	579	(3321)	5000
25	4998	0	2317	6917	(398)	52595
26	3208	250	1189	0	(4647)	0
27	2434	0	0	2747	313	23512
28	4222	0	0	5634	1412	42963
29	2121	0	0	2343	222	20000
30	0	0	0	0	0	0
31	1141	86	860	2344	257	27000
32	0	0	0	0	0	0
33	1071	0	3490	5037	476	38325

Figure 2: Interstate Pipeline Bulletin Board Data Collection

Varying configurations of generator natural gas supplies can quickly complicate reports. Efforts could be made prior to the development of such reporting tools to ensure that all facets of natural gas scheduling can be displayed. Not all scheduled natural gas data will be publicly available, especially when dealing with LDC and intrastate-connected generators. Generators are occasionally supplied by multiple interstate pipelines simultaneously and may change supply sources based on daily natural gas prices. If possible, the electric operating entity should list its range of contractual arrangements with the natural gas sector, such as firm capacity and supply, no-notice storage, etc.

Natural Gas System Visualization

Several RCs, such as ISO New England and PJM, have developed visualization tools to provide scheduling and real-time operations staff with situational awareness that ties the natural gas and electric infrastructure together at their common point of operation. Commercially available, and custom developed, software are available to meet these objectives. What follows in **Figure 3** is an example of one such custom developed tool that has been made generic for the purposes of the illustration. In this example the primary objective is to identify potential gas supply issues to specific generators, typically in the operating day and before real-time conditions arise. The specific pipeline operational capacities and schedules are displayed by location. The generators and critical pipeline facilities, such as compressors, are also displayed by location as well. This enables enhanced situational awareness to which specific generators may be impacted by specific points of congestion on the gas pipelines. This may enable increased lead time to identify potential reliability issues and additional time to mitigate or resolve the issues before they impact real-time operations. The bubbles in the tool indicate the functionality available to the user with notes that follow.

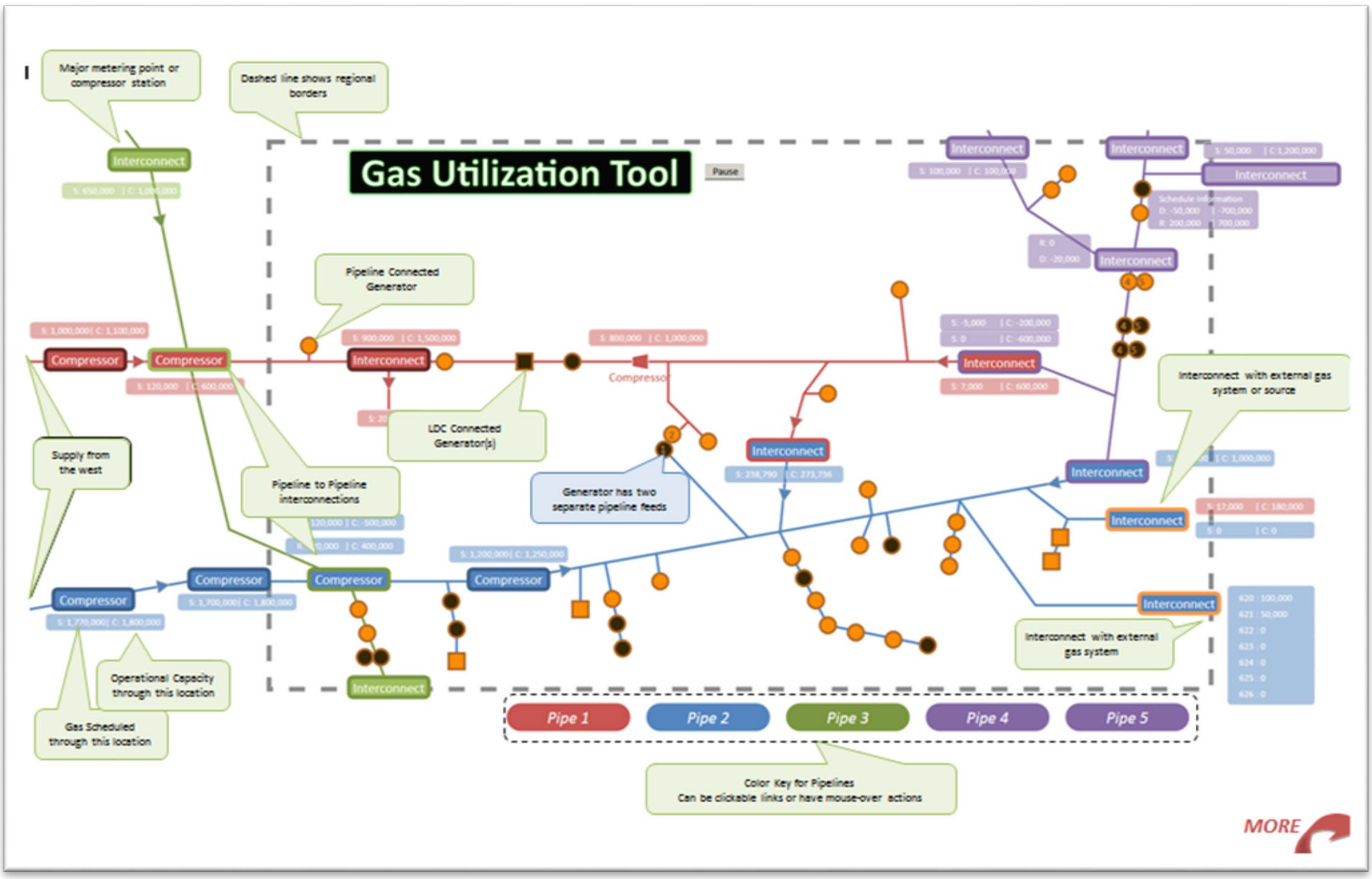


Figure 3: Natural Gas System Visualization

Natural Gas System Visualization Tool Notes:

- The display is updated automatically or on demand. Historical data is available for 30 days in the past. Can be expanded to more days or specific days.
- Generators are clickable and additional information is provided via popup message.
- Pipeline Color Key is clickable and navigates to the specific pipeline Electronic Bulletin Board (EBB).
- All of the values are in MMBtu for the gas day. When operational capacity changes, the display automatically updates based on EBB posted capacity and schedule values.

- Schedules are for the Gas Day, rolling over at 10:00 a.m. Eastern. (E.g. Gas Day 4/15/2015 starts at 10:00 a.m. Eastern on 4/15 and ends on 4/16 at 10:00 a.m. Eastern.)
- These are schedules and may not reflect the physical flow of gas. Schedules may not match due to differences in scheduling cycles or accounting methods used by different companies.
- Just because there’s room for gas to flow at a throughput meter or cross connect, doesn’t mean there’s gas there to move through.
- *Delivery* is gas leaving the pipeline. *Receipt* is gas entering the pipeline.
- Schedule badges show *delivery* and *receipt* where there can be bi-directional scheduling and *schedule* where there is not bi-directional scheduling. Most of the schedule badges show a *capacity* value as well.
  - You have to net multiple schedules to derive an estimated final schedule at a location.
- Some generators have a single meter to their facility with shared ownership. Through that meter, gas can be scheduled via pipe 4 or pipe 5.
- Many generators have multiple connections to separate pipelines and that can be displayed as well.
- Meters with zero gas scheduled have darkened icons on this display.

Possibilities:

- Overlaying critical electric system transmission system elements that are critical to the reliable operation of gas system infrastructure.
- Coordinate adjacent BAs and/or RCs to enable identification of gas supply issues at seams, potentially through adaptation of a common platform.
- Real-time power information for the generators as well as how much gas has been consumed and how much remains.
- OFO display information based on EBB postings.
- Graphical trending of any value you can select.

Chapter 5: Summary

The transformation in the mix of fuel sources used to power electric generation throughout North America and the increased penetration of renewable resources in particular as well as the continued increase in the use of natural gas highlights the continued need for the coordination processes discussed in this guideline. This guideline should serve as a reference document that NERC functional entities may use as needed to improve and ensure BES reliability. It is based upon actual lessons learned over the last several years as natural gas has developed into the fuel of choice due to its availability and economic competitiveness. The document focuses on the areas of preparation, coordination, communication, and intelligence that may be applied to improve natural gas and electric coordinated operations and minimize interdependent risks. Each entity could assess the risks associated with this transformation and apply a set of appropriate processes and practices across its system to mitigate those risks. The guidance is not a "one size fits all" set of measures but rather a list of principles and strategies that can be applied according to the circumstances encountered in a particular system, BA, generator fleet, or even an individual GOP.

Contributors

NERC gratefully acknowledges the contributions and assistance of the following industry experts in the preparation of this guideline.

This reliability guideline was originally published December 2017. The final revised product from a full review of industry feedback was completed in 2021 as planned by the RSTC. This work was a collaboration by the members of the NERC Electric Gas Working Group and the NERC Real Time Operating Subcommittee.

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Guideline Information and Revision History

Guideline Information	
Category/Topic: Energy Assurance	**Reliability Guideline/Security Guideline/Hybrid:** Reliability Guideline
Identification Number: RG-ENA-0322-3	**Subgroup:** RTOS

Revision History		
Version	**Comments**	**Approval Date**
1	Approved by the NERC Operating Committee	12/13/2017
2	Three year review by the RTOS Approved by the Reliability and Security Technical Committee	6/28/2021
3	Placed on updated template; added metrics section and link to effectiveness survey Approved by the Reliability and Security Technical Committee	3/22/2023

Metrics

Pursuant to the Commission's Order on January 19, 2021, *North American Electric Reliability Corporation*, 174 FERC ¶ 61,030 (2021), reliability guidelines shall now include metrics to support evaluation during triennial review consistent with the RSTC Charter[8].

Baseline Metrics

All NERC reliability guidelines include the following baseline metrics:

- BPS performance prior to and after a reliability guideline as reflected in NERC's State of Reliability Report and Long Term Reliability Assessments (e.g., Long Term Reliability Assessment and seasonal assessments)
- Use and effectiveness of a reliability guideline as reported by industry via survey
- Industry assessment of the extent to which a reliability guideline is addressing risk as reported via survey

Specific Metrics

The RSTC or any of its subcommittees can modify and propose metrics specific to the guideline in order to measure and evaluate its effectiveness, listed as follows:

- RTOS will conduct periodic evaluations of the gas system supply constraints that have resulted in derates to generators. These will be categorized and tracked for trend analyses. This information is available to NERC in GADS[7].

Effectiveness Survey

On January 19, 2021, FERC accepted the NERC proposed approach for evaluating reliability guidelines. This evaluation process takes place under the leadership of the RSTC and includes:

- industry survey on effectiveness of reliability guidelines;
- triennial review with a recommendation to NERC on the effectiveness of a reliability guideline and/or whether risks warrant additional measures; and
- NERC's determination whether additional action might be appropriate to address potential risks to reliability in light of the RSTC's recommendation and all other data within NERC's possession pertaining to the relevant issue.

NERC is asking entities who are users of reliability and security Guidelines to respond to the short survey provided in the link below.

[Guideline Effectiveness Survey]

[8] https://www.nerc.com/comm/RSTC/Pages/default.aspx

[7] NERC GADS Cause Codes 9130 – Lack of fuel: Physical failures of fuel supply or delivery/transportation of fuel, and Cause Code 9131 – Lack of fuel: Contract of Tariff allows for interruption may be appropriate to screen for these conditions.

Errata

Date: N/A