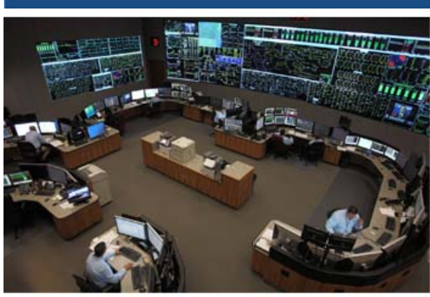
NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Generation Retirement Scenario

Special Reliability Assessment

December 18, 2018

RELIABILITY | ACCOUNTABILITY




3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

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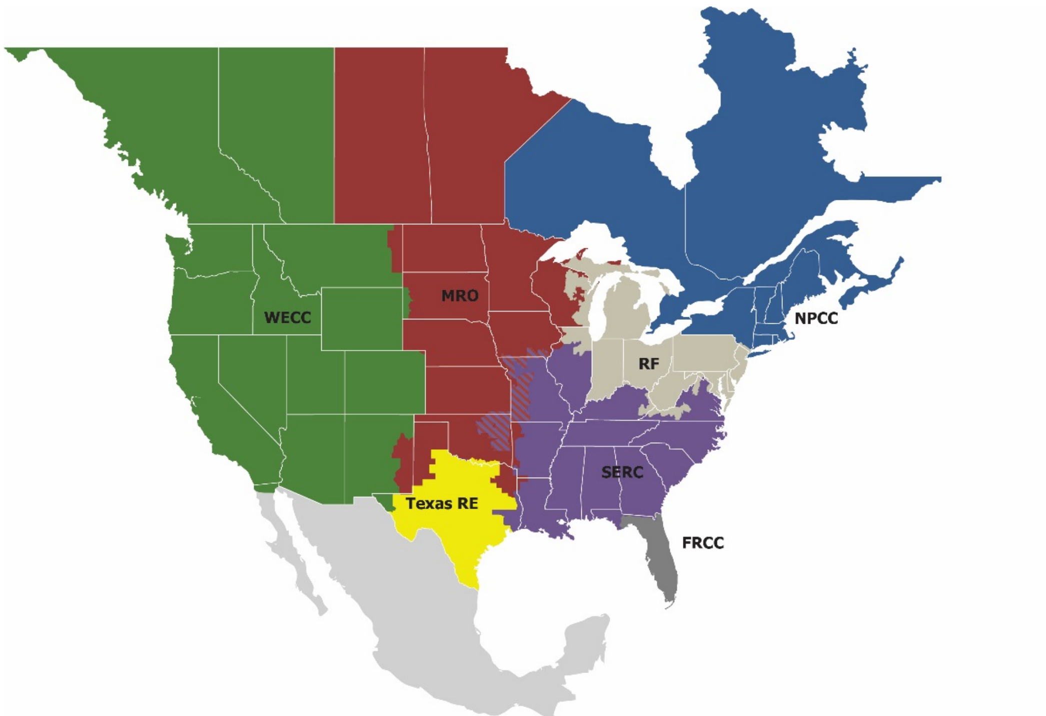
Preface

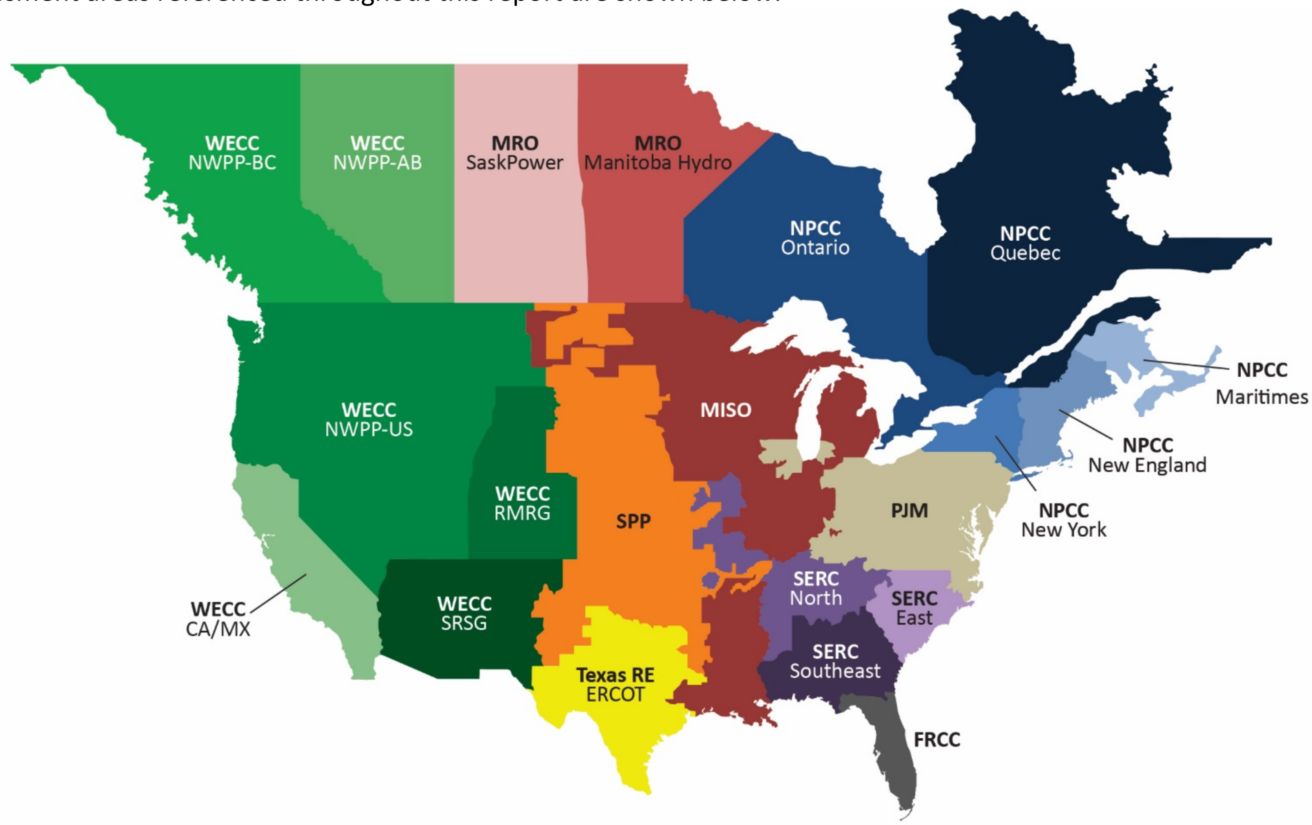
The vision for the Electric Reliability Organization (ERO) Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the seven Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

The North American BPS is divided into seven RE boundaries as shown in the map and corresponding table below. The highlighted areas denote overlap as some load-serving entities participate in one Region while associated Transmission Owners/Operators participate in another.



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

Assessment areas referenced throughout this report are shown below.



FRCC – Florida Reliability Coordinating Council
- FRCC

MRO – Midwest Reliability Organization
- MISO
- MRO-Manitoba Hydro
- MRO-SaskPower

NPCC – Northeast Power Coordinating Council
- NPCC-Maritimes
- NPCC-New England
- NPCC-New York
- NPCC-Ontario
- NPCC-Québec

RF – ReliabilityFirst
- PJM

SERC – SERC Reliability Corporation
- SERC-East
- SERC-North
- SERC-Southeast

SPP – Southwest Power Pool
- SPP

Texas RE – Texas Reliability Entity
- Texas RE-ERCOT

WECC – Western Electricity Coordinating Council
- WECC-CA/MX
- WECC-NWPP-AB
- WECC-NWPP-BC
- WECC-NWPP-US
- WECC-RMRG
- WECC-SRSG

Executive Summary

This special reliability assessment is part of NERC's ongoing efforts to assess the potential implications of the changing generation resource mix on the reliability of the North American BPS and provide actionable recommendations to address identified risks. The BPS is undergoing a significant transformation that is marked by growth in new natural gas, wind, and solar resources as older fossil-fired and nuclear generation retire. This shift is caused by several drivers, including federal, state, and provincial policies; continuing low natural gas prices; wholesale electricity market forces; customer preferences; and low and improving technology costs. The changing resource mix alters the operating characteristics and constraints of the BPS, and these changing characteristics must be well understood and incorporated into planning to assure continued reliability. This assessment affirms that risk-informed planning and existing tools can assure continued reliability of the BPS during this time of revolutionary changes to the generation resource mix.

Managing generator retirements and the transition to replacement resources is a complex process that requires close coordination between transmission and resource planners, system and market operators, and state, provincial, and federal regulators. Accelerated retirements—or retirements that occur sooner than expected and are not yet incorporated into planning—can create challenges for this coordination, particularly when multiple units request to retire over the same time period. Substantial BPS planning activity occurs in five-year and longer time horizons, involving detailed analysis and engineering studies that account for existing and projected resources, electrical demand, and transmission topology to ensure reliable operations under a range of system and environmental conditions. Accelerated generation retirements require similar analysis to ensure that the system being developed continues to meet established planning criteria and to identify system or operational changes that must be made to accommodate the retirements. In addition to assessing resource and transmission adequacy, including consideration of essential reliability services such as voltage support and frequency response, planners must increasingly look to the adequacy of the replacement fuel infrastructure to assure reliable fuel supply as well.

The key conclusion is that generator retirements are occurring, disproportionately affecting large baseload, solid-fuel generation (coal and nuclear). If these retirements happen faster than the system can respond with replacement generation, including any necessary transmission facilities or replacement fuel infrastructure, significant reliability problems could occur. Therefore, resource planners at the state and provincial level, as well as wholesale electricity market operators, should use their full suite of tools to manage the pace of retirements and ensure replacement infrastructure can be developed and placed in service. Again, ensuring reliability throughout a significant retirement transition will likely include construction of new transmission and fuel infrastructure.

The purpose of this assessment is to identify resource and transmission planning challenges that may arise or be exacerbated by an accelerated pace of conventional generator retirements. This assessment applies a scenario that incorporates significant retirements into an aggressive time frame. The scenario is intended to be a stress-test to identify risk; it is **NOT** a predictive forecast. The scenario was selected not for its predictability or probability but to illustrate unlikely, but possible, system stress. By mining recommendations from this unlikely scenario, the system can be made more resilient to unexpected or rapid changes to the generation resource mix.

In this stress-test scenario, NERC examines how the accelerated pace of generation retirements impacts resource adequacy, fuel assurance and fuel diversity, and transmission system reliability.

Stress-Test Scenario, Not Predictive Forecast

NERC's stress-test scenario is not a prediction of future generation retirements nor does it evaluate how states, provinces, or market operators are managing this transition. Instead, the scenario constitutes an extreme stress-test to allow for the analysis and understanding of potential future reliability risks that could arise from an unmanaged or poorly managed transition. The scenario focuses on ten NERC assessment areas within the North American BPS where coal-fired and nuclear generation make up a significant part of the overall generation resource mix. The assessed areas include integrated resource (regulated) states, wholesale electricity markets, and combination areas within an independent system operator/regional transmission organization (ISO/RTO). The risks and drivers related to accelerated generation retirements vary for each assessment area as do the mitigating measures available to address identified risks.

In developing the scenario, NERC used publicly available data and reliability information compiled from industry sources through NERC's *Long-Term Reliability Assessment* (LTRA) process.[1] NERC's *2017 LTRA* generation data, which includes only confirmed generation retirements, projects more than 27 GW of generator retirements through year 2022 (18 GW coal-fired and nearly 9 GW of nuclear generation capacity). Because generator retirement announcements can be made as late as 90 days prior to planned deactivation in some areas, long-range retirement projections based on confirmed retirements could be significantly understated. The stress-test scenario uses a U.S. Energy Information Administration (EIA) sensitivity case to identify potential coal-fired and nuclear generation retirement capacity through year 2025 and then accelerates those retirements to 2022. The stress-test scenario retires nearly 91 GW of generating capacity (62 GW coal-fired and 29 GW nuclear) in addition to the confirmed retirement projection from the *2017 LTRA*. The stress-test scenario provides insights that would otherwise be overlooked if perspectives are limited to confirmed retirements.

NERC's stress-test scenario evaluates resource adequacy risk in each area by comparing projected 2022 Planning Reserve Margins for the scenario with a reference scenario based on confirmed retirements. The amount of generation capacity available to replace the retiring resources is determined from planned generation (natural-gas-fired, wind, and solar generating units) in the area's interconnection queue. Using 2022 as the test year provides good insight into the upper limit of capacity additions, assuming all capacity in the interconnection queue (Tier 1 and Tier 2) gets built. Projected loads for 2022 are also obtained from the *2017 LTRA* data.[2] Resource adequacy concerns are identified when replacement generation capacity is not sufficient to make up for scenario retirements and return to Reference Margin Levels for year 2022 peak load conditions.[3] Basing assessments on a year 2022 benchmark makes good use of resource and load projections that will degrade in accuracy over longer terms.

As most of the replacement generation embedded in development queues is natural-gas-fired, essential reliability services (ERSs) were not explicitly tested for in the stress-test scenario—the assumption was that replacement generation would provide adequate ERSs.[4] However, the results of transmission planning studies performed by NERC entities are included in this report to illustrate how transmission system performance may be affected by certain retirement scenarios selected by the entities. When generators retire from one location and are replaced with resources in another location (which may occur for fuel, regulatory, business, or other reasons), power flow on the system can change in order to continue serving load. Transmission planning studies (including power flow studies) may identify upgrades, operating procedures, or generation dispatch plans that are necessary to ensure the system operates within established limits and meets performance criteria—essential attributes of a reliable electric power system.

[1] Work for this assessment began in early 2018. The assessment uses data collected for the *2017 LTRA*, which was published in December 2017. Generation retirements that were confirmed before June 2018 have also been taken into account for this assessment. Data used for the 2018 LTRA, which is expected to be published in December 2018, does not alter this report's key findings.

[2] Distributed energy resources (DERs) are accounted for in area load profiles and reflect in peak load projections. Growth in DERs could result in actual year 2022 peak load requirements that are lower than projected in the scenario.

[3] Reference Margin Levels provide a relative measure for assessing the level of planning reserves in an area and generally equate to the needed reserves required to maintain a one-day in 10 probability of a capacity resource deficit occurrence. A detailed explanation of reference margin levels and requirements by assessment area is found in the *2017 LTRA*.

[4] NERC's report titled *Essential Reliability Services Task Force Measures Framework Report* (ERS Report) describes ERSs as voltage control, ramping capability, and frequency support. The report identified ERS measures that NERC and industry use to monitor key reliability aspects associated with the changing resource mix.

Tools Exist to Manage, Assure Reliability

Accounting for generation retirements and resource additions is a normal part of resource and transmission planning that occurs on an ongoing basis throughout North America. Planning processes and responsibilities for NERC entities, regulators, and wholesale electricity market operators vary by state or province and regulatory structure. Although these processes may be unique to specific areas, each provides a framework for stakeholders to work together to ensure projected generation resources are sufficient to meet anticipated electrical demands and that the transmission system can meet operating reliability requirements. In planning processes, each generating plant retirement is analyzed individually (and sometimes in aggregate if multiple retirements are requested) for its potential impact on resource adequacy and transmission system performance within well-defined reliability criteria. The industry has employed its processes for managing generation retirements during periods of considerable change in the generation fleet and has been successful in maintaining reliability. However, industry is entering a period of rapid resource turnover with changing risk characteristics (e.g., larger units to smaller units, solid fuel to natural gas and/or weather dependent fuel, dispatchable generation to generation that is more stochastic in its availability). During such a period of rapid change, it is particularly important that these mechanisms be proactive, timely, and capable of considering the full range of reliability criteria (e.g., resource adequacy, transmission limits, fuel assurance and diversity, system inertia).

Regulatory structures and resource planning processes are important factors in determining the timing and location of generator retirements. In the same way, these factors affect how generator retirement risks are identified and mitigated. This scenario includes an overview of the regulatory structure, processes, and features related to generator deactivation and planning across the grid. Areas with specific integrated resource planning or regulated capacity requirements may present lower risk. Similarly, regulatory provisions and requirements for regulated utilities may reduce the likelihood that utility-owned generation would retire on a short time frame.

Key Findings

NERC's analysis of the stress-test scenario resulted in the following conclusions:

- For resource adequacy, in six of the 10 assessment areas, existing and planned generation resources would be sufficient to maintain peak demand reserves at or above 2022 Reference Margin Levels. However, generation retirements on the scale of the stress-test scenario could reduce Planning Reserve Margins to levels that would be near or below Reference Margin Levels. Mandatory resource levels could act to limit the amount of generation considered for retirement in a regulatory jurisdiction. On a regional (RTO/ISO) scale, significant amounts of replacement generation capacity would be required, which could create the need for expediting development of generation resources in interconnection queues. In the event sufficient replacement resources are unavailable to make up for retirements, actions may be needed to ensure resource adequacy (e.g., delaying announced retirements, deployment of additional demand response or other demand-side resources, and/or larger-scale electricity storage).
- Replacement resources in the scenario are predominantly (but not exclusively) natural-gas-fired generation. Utility-scale wind and solar resources that are progressing through the interconnection queue are included as well. The natural-gas-fired generators are expected to provide the same, or at least adequate, levels of voltage support and frequency response as did the retiring resources. However, such a significant shift to natural-gas-fired generation could leave the BPS more vulnerable to natural gas supply and transportation disruption events or curtailments if firm service and new pipeline capacity are not procured for these replacement resources. Detailed analysis of natural gas infrastructure was not in scope for this assessment; however, additional midstream natural gas infrastructure could be required to meet the volumetric and flexibility needs of the electric sector in this scenario. Even with build out to accommodate increased pipeline capacity, policymakers should consider the potential for increased reliability risk from declining fuel diversity. This assessment assumes that all planned new generation, including wind, solar, and nuclear will be built. Fuel diversity is an inherent means of providing resilience to the system by reducing BPS vulnerability to disruptions of any individual fuel type.

- Transmission planning studies performed for this stress-test scenario found that BPS transmission system reinforcements, generation dispatch requirements, and new operating procedures would be needed to support generator retirements and replacements to maintain reliability criteria. Larger amounts of generator retirements within a short time frame could result in extensive transmission network upgrade requirements that may not currently be included in transmission expansion plans. As electric transmission is time consuming to design, site, and permit, Transmission Planners and Operators must be prepared to use various mechanisms, either in- or out-of-market, and could include steps to delay generator retirements until these transmission upgrades are completed.
- NERC's scenario assessment finds that various processes, mechanisms, and backstops are in place to manage generator retirements:
  - In many states and provinces, for example, retirements go through the same integrated resource planning processes that are used to permit new additions. The states and provinces have the ability to control the pace of transition from older generation to new.
  - Market areas are more complex but have various tools, such as forward capacity markets (FCMs), regional transmission expansion processes, market-based mechanisms and tools (e.g., demand response, conservation and efficiency initiatives), and/or temporary out-of-market actions, that can all support challenges arising from unexpected retirements in organized market areas. Reliability-must-run (RMR) agreements are an example of an out-of-market action that system operators can pursue to retain needed, but otherwise uneconomic, capacity to address identified reliability issues. Where implemented by tariff, RMRs provide ISOs and RTOs with a mechanism for providing temporary added financial incentives to generator units that are planned for retirement but needed for reliability. The key concern with the tools in market areas is that they provide economic incentives and signals to uneconomic units that are needed for reliability. The efficacy of those signals should be tested to ensure they are delivering the desired outcomes. For example, current forward capacity markets might be inadequate to secure longer term supply; similarly, RMR contracts typically only cover fuel as well as operating and maintenance costs and may not be sufficient to incent an owner to maintain operations that are needed for reliability.

Recommendations

NERC makes the following recommendations to industry, stakeholders, and policymakers:

- **Review Planning Processes and Market Mechanisms to Mitigate Reliability Risks:** In wholesale electricity market areas, market operators should assess whether existing tools are adequate to manage significant levels of generation retirements. New mechanisms should also be explored, if necessary, such as new market constructs that value resources differently or new out-of-market solutions that can control the pace of generation retirements when needed. Additionally, RTOs and ISOs should evaluate the efficacy of their existing tools to ensure that the retirement pace is managed consistently with the development of any needed supplemental transmission or fuel infrastructure. In regulated utility areas, the integrated resource planning process and mandatory resource adequacy requirements likely mitigate reliability risks, however, those processes should explicitly consider fuel diversity and fuel infrastructure adequacy to the extent they currently do not.
- **Incorporate Fuel Assurance Analysis in Generator Retirement Processes:** Transmission and resource planners should incorporate fuel assurance analysis in generator retirement assessments. Fuel supply contingency scenarios used in system planning studies should be developed or adapted for assessing the potential impact of generator retirements as part of generator retirement planning and approval processes. Fuel assurance analysis should consider specific regional fuel mixes, fuel supply infrastructure, new infrastructure requirements (for replacement resources), and contractual provisions that govern fuel delivery (i.e., firm vs. non-firm). In a previous assessment, NERC recommended industry consider the loss of key

natural gas infrastructure in their planning studies, including extreme event analysis conducted as part of NERC Reliability Standard TPL-001-4.[5] Additionally, NERC has initiated efforts with both the electric and natural gas industries to develop guidelines for NERC entities to use for analyzing fuel supply disruptions and their potential impact on the BPS; this should continue.

- **Provide Regulatory Flexibility to Respond to Changing Infrastructure Needs:** Regulators and policymakers should consider ways to expedite regulatory and environmental permitting processes for transmission upgrades and energy infrastructure. When a generator's planned retirement is delayed to allow for completion of transmission system upgrades, expedited regulatory proceedings can help minimize the delay. Where more natural gas generation is needed, more natural gas pipeline capacity will likely also be needed. As in past studies, NERC encourages regulators to support and approve the construction of new natural gas pipeline and storage capacity to meet electric generation needs as well as capabilities for back-up liquid fuels to manage extreme conditions or fuel disruptions.

Conclusion

NERC encourages consideration of these recommendations by stakeholders and policymakers. The stress-test scenario provides valuable insight about risks to the BPS that could arise if the pace of desired retirements is accelerated. From these insights, NERC developed recommendations to help address reliability concerns. While the stress-test scenario was applied to only certain areas, stakeholders in all areas should be aware of the potential consequences of generation retirements and take steps to manage the pace as dictated by local conditions. This assessment should not be interpreted to mean the BPS cannot be operated reliably given the change in the generation resource mix; rather, NERC's scenario affirms that risk-informed planning and existing tools can assure continued reliability of the BPS while managing evolutionary changes to the generation resource mix. The pace of the current change creates potential challenges to reliability that must be understood and addressed.

Successfully managed, the changing resource mix can provide positive outcomes including potential benefits to reliability and security of the BPS. Less reliance on large, centralized generation stations and greater use of dispersed networks comprised of smaller diversified generation resources can provide operating and planning flexibility. Additionally, some fuel assurance risks diminish with the changing resource mix. The effects of adverse weather on coal stockpiles or fossil fuel resupply infrastructure may be reduced when natural gas pipelines supply a greater proportion of the generating fleet. Attaining reliability enhancements associated with the changing resource mix is possible when the different challenges to fuel assurance and ERSs are addressed.

The BPS has gone through many changes over the years, and each change requires adaptation, education, and continuous learning. As required by Section 215 of the Federal Power Act, NERC as the ERO shall conduct periodic assessments of the reliability and adequacy of the BPS. These independent assessments provide insights into the possible so stakeholders and policymakers can address emerging issues. NERC takes its job of assuring the reliability of the North American BPS seriously and will continue to identify and analyze reliability trends, evaluate events and issues, and work with stakeholders to assess and reduce risks to the present and future grid.

[5] See NERC Special Reliability Assessment *Potential Bulk Power System Impacts due to Severe Disruptions on the Natural Gas System:* https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SPOD_11142017_Final.pdf

Introduction

Background

The retirement of traditional baseload generators and the rapid replacement with natural-gas-fired, wind, and solar generation is changing the characteristics of the BPS and introducing new considerations for reliability planning. High levels of traditional baseload generation, such as coal-fired and nuclear generating plants, have retired during the last decade.[6] New generation resources provide economic and environmental benefits and also have implications for grid reliability that must be better understood. As reported in NERC's *2018 State of Reliability* Report[7] and reliability assessments, the BPS continues to exhibit an adequate level of reliability;[8] however, maintaining reliability and resilience while undergoing a rapidly changing resource mix poses unique challenges.

Recent NERC reliability assessments have consistently highlighted several emerging reliability issues related to the changing resource mix.[9] Key observations are summarized below:

- As conventional resources retire, sufficient amounts of ERSs must be maintained for reliability.
- Higher reliance on natural gas as a fuel source can expose electric generation to new fuel supply and delivery vulnerabilities, particularly during high natural gas demand periods, such as those associated with some extreme weather conditions.
- Resource flexibility is needed to supplement and offset the variable characteristics of solar and wind generation. Investment and development in energy storage continues to expand, enabling greater penetration of variable generation resources in the generation resource mix.
- Increasing amounts of distributed energy resources change how the distribution system interacts with the BPS and transforms the distribution system into an active source for energy and some ERSs.
- Because the system was designed with large, central-station generation as the primary source of electricity, significant amounts of new transmission may be needed to support renewable resources located far from load centers.

Over the past decade, factors (e.g., the relatively low cost of natural gas; state, federal, and provincial government policies; low capacity and energy wholesale market prices) have led to changes in the composition of the resource mix. As identified in NERC's *2017 LTRA*,[10] this trend continues as more than 100 GW of conventional generation has retired since 2011 (see **Figure I.1**), and replacement generation includes a mix of new, more efficient natural-gas-fired generators and variable energy resources.

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[6] NERC's *2017 LTRA* reports 46.5 GW of mostly older coal-fired generation retirements since 2011 with 19 GW of confirmed retirements planned by 2027. Six nuclear units have retired since 2012 and 14 nuclear units have announced plans to retire by 2025.

[7] The 2018 State of Reliability Report is available at the following location: https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_2018_SOR_06202018_Final.pdf

[8] The definition of "adequate level of reliability" is available at the following location: http://www.nerc.com/pa/Stand/Resources/Documents/Adequate_Level_of_Reliability_Definition_(Informational_Filing).pdf

[9] NERC's long-term, seasonal, and special reliability assessments contain key findings and recommendations related to the changing resource mix and other reliability issues. All reports can be obtained from NERC's website: https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx

[10] The *2017 LTRA* is available at the following location: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_12132017_Final.pdf

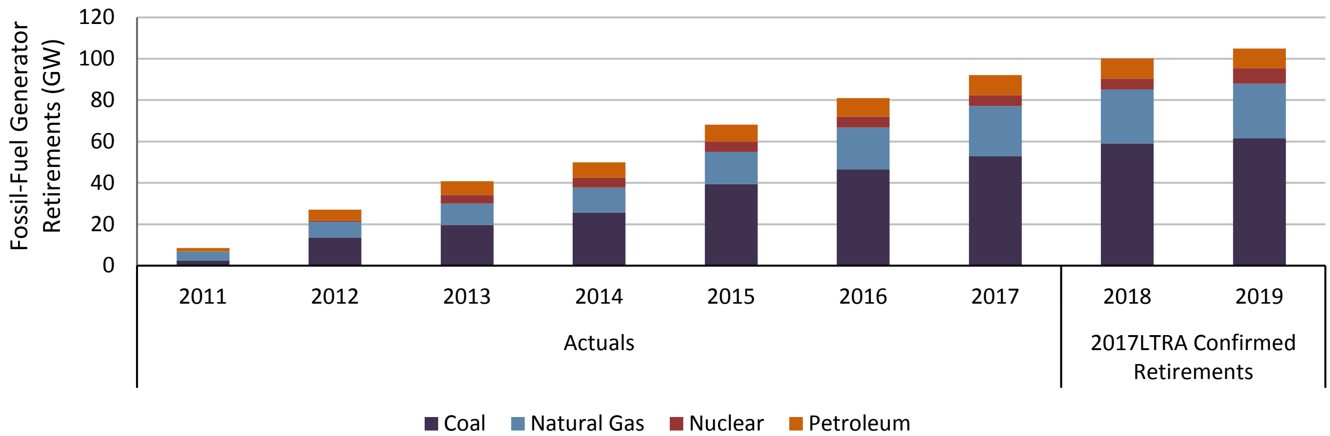


Figure I.1: Cumulative Retirements of Fossil-Fueled Generators by Fuel Type Since 2011

While parts of the North American BPS have ample reserve margins that can accommodate some level of capacity retirement through ongoing planning processes, challenges could arise when retirements are numerous and rapid. Accelerating the transition period from traditional baseload generation to newer natural-gas-fired generation and increased penetrations of variable energy resources could expose temporary periods of increased reliability risks. For example, retirements can lead to near-term reductions in Planning Reserve Margins or requirements for additional transmission to meet reliability criteria. Furthermore, the evolving generation resource mix currently is accompanied by a growing interdependence between the natural gas and electric sectors, resulting in new operational and planning challenges. The potential uncertainty in generation resources during periods of high natural-gas demand is an ongoing concern for resource planning.[11] A notional depiction of the accelerated retirements scenario and near- and long-term reliability challenges are shown in Figure I.2. This assessment continues NERC's evaluation of reliability risks associated with the changing generation resource mix by examining BPS reliability under a variety of scenarios involving accelerated generation retirements.

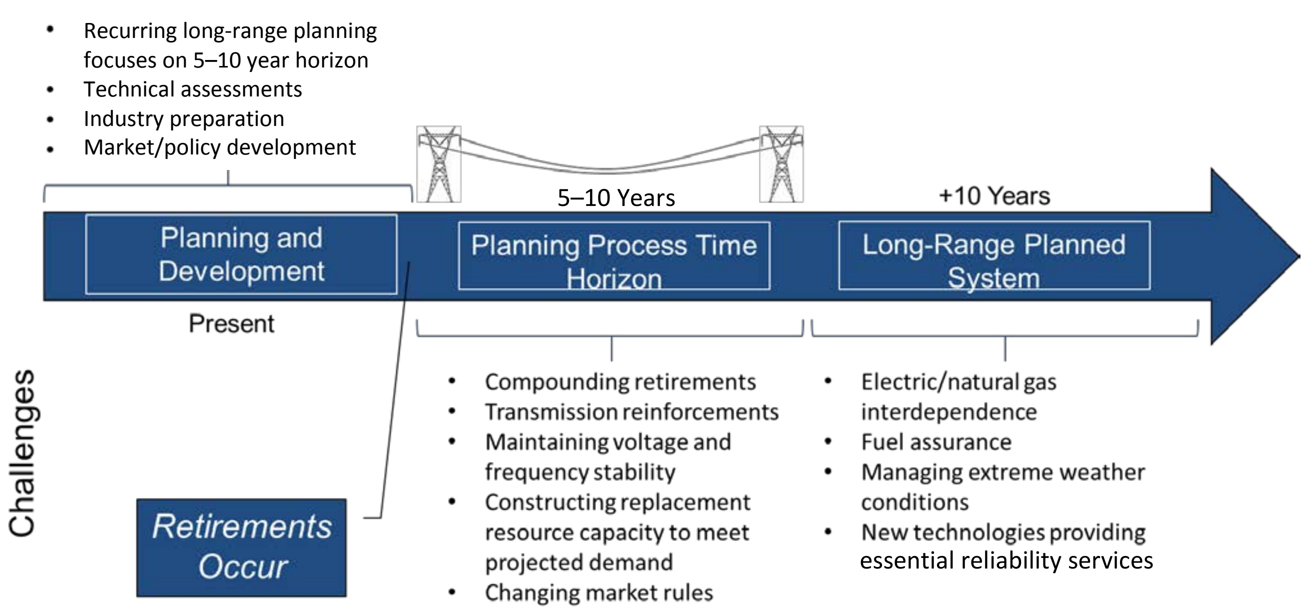


Figure I.2: Notional View of Accelerated Retirement Scenario and Reliability Challenges

[11] *NERC 2013 Special Reliability Assessment: Accommodating an Increased Dependence on Natural Gas for Electric Power* discusses this and other related risks, identifies ways to minimize vulnerabilities, and describes interindustry coordination approaches.

Scenario Objectives

The purpose of this scenario is to identify resource and transmission planning challenges that may arise or be exacerbated by an accelerated pace of conventional generator retirements. This scenario incorporates significant retirements into an aggressive time frame. The scenario is intended to be a stress-test to identify risk; it is **NOT** a predictive forecast. The following potential reliability issues associated with scenario are examined in this assessment:

- **Resource Adequacy:** the impact the stress-test scenario could have on capacity and energy supplies relative to the amount of generator resources and energy needed to meet the anticipated demand.
- **Transmission Adequacy:** the impact the stress-test scenario and resulting replacement location of generation resources could have on the ability of the transmission system to maintain voltages, operate without overload, and meet other transmission system reliability criteria.
- **BPS Reliability Planning:** the impact the stress-test scenario and the resulting changes to generation resource mix could have on the ability of the BPS to maintain reliable operation and serve all firm load during extreme events (e.g., prolonged extreme weather and fuel supply or transportation disruptions).

Additionally, the scenario includes a description of regional (i.e., ISO/RTO, regulated utility area) processes for managing generator retirements and mechanisms that regional system planners use to ensure that generator retirements do not impact reliability. Regulatory structures and resource planning processes are important factors in determining the timing and location of generator retirements. In the same way, these factors affect how generator retirement risks are identified and mitigated. This scenario includes an overview of the regulatory structure, processes, and features related to generator deactivation and planning across the grid.

Assessment Approach

The potential impact that accelerated retirement of generation could have on the BPS is examined through several reliability indicators. NERC analyzed aggregated generation resource and load projections provided by industry in selected NERC assessment areas to understand potential impacts that could result from the stress-test scenario involving accelerated retirement and replacement of generation resources. Areas where coal-fired and nuclear generation provides a significant contribution to generator resource levels were considered. A more granular examination of potential impacts was obtained by coordinating with industry planners at Electric Reliability Council of Texas (ERCOT) and Public Service Electric & Gas (PSE&G) to perform engineering studies that illustrate how transmission system performance may be affected by certain retirement scenarios.[12] NERC then reviewed information about regional processes for managing generator retirements and deactivation requests to understand how these processes might be employed to handle an accelerated pace of generator retirements.

Resource Adequacy

The first part of this assessment is based on analysis of Planning Reserve Margins under a stress-test scenario, including the following:

- Comparison with reference margin levels[13]
- Impact of extreme weather and natural gas disruption scenarios on reserves

Data and information for this chapter was provided by the Regional Entities in developing the *2017 LTRA*. The assessment looked at the following NERC assessment areas (**Figure I.3**):

- Midcontinent ISO (MISO)

[12] ERCOT is the ISO in Texas. PSE&G is a provider of electric service in New Jersey.

[13] Reference Margin Levels provide a relative measure for assessing the level of planning reserves in an area and generally equate to the needed reserves required to maintain a one-day in 10 probability of a capacity resource deficit occurrence. A detailed explanation of Reference Margin Levels and requirements by assessment area is found in the *2017 LTRA*.

- ISO New England (ISO-NE)
- New York ISO (NYISO)
- PJM Interconnection
- SERC East and Southeast Assessment Areas
- Southwest Power Pool (SPP)
- Texas-ERCOT
- Western Interconnection Rocky Mountain Reserve Sharing Group and Southwest Reserve Sharing Group

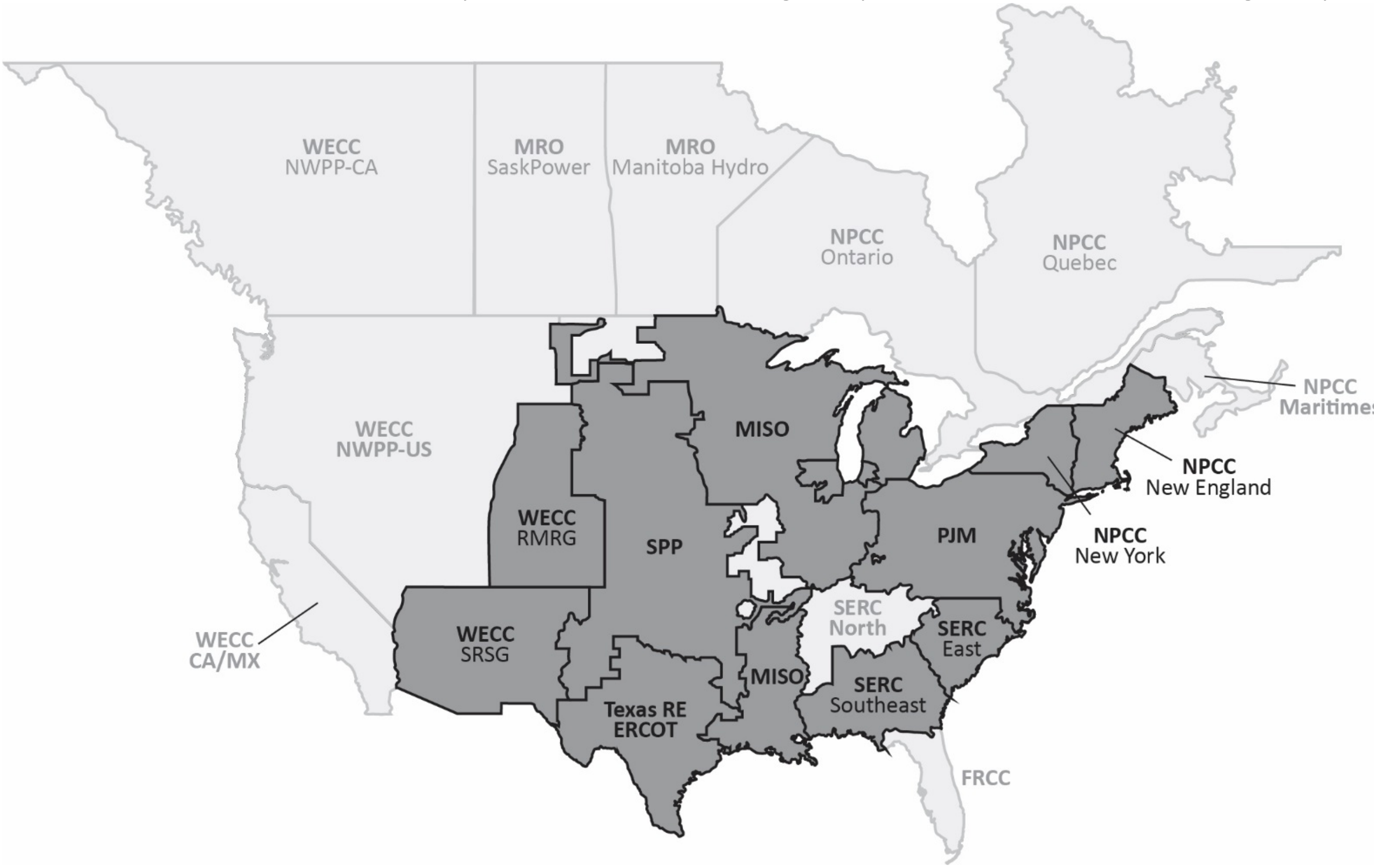
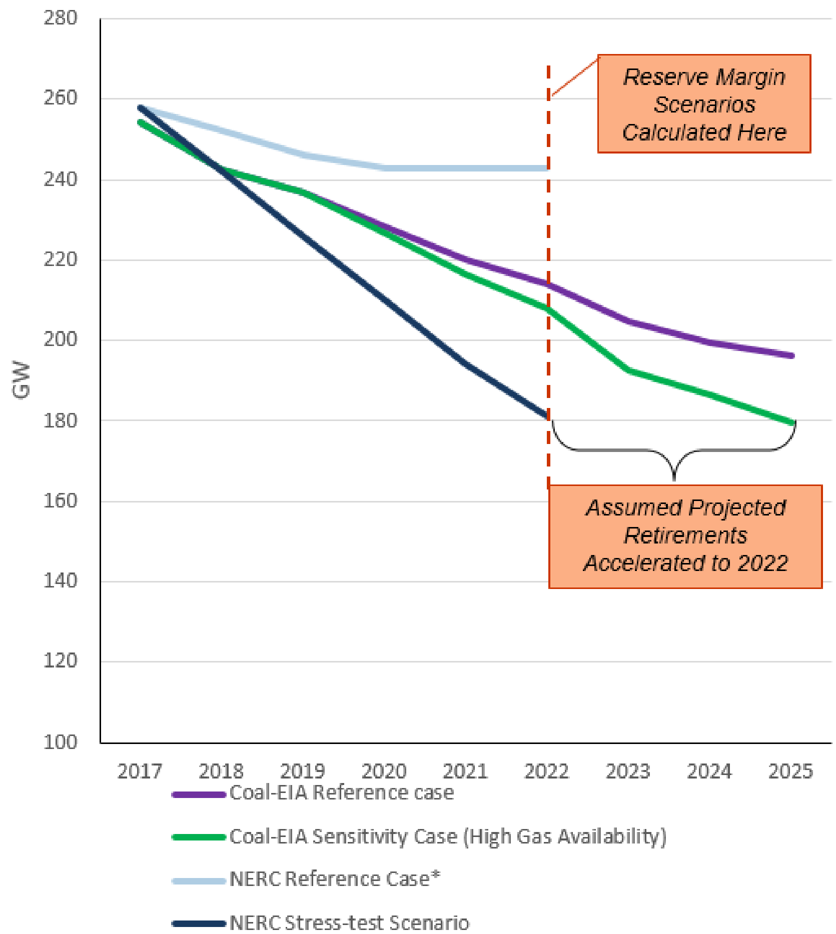


Figure I.3: NERC Assessment Areas in Resource Adequacy Analysis

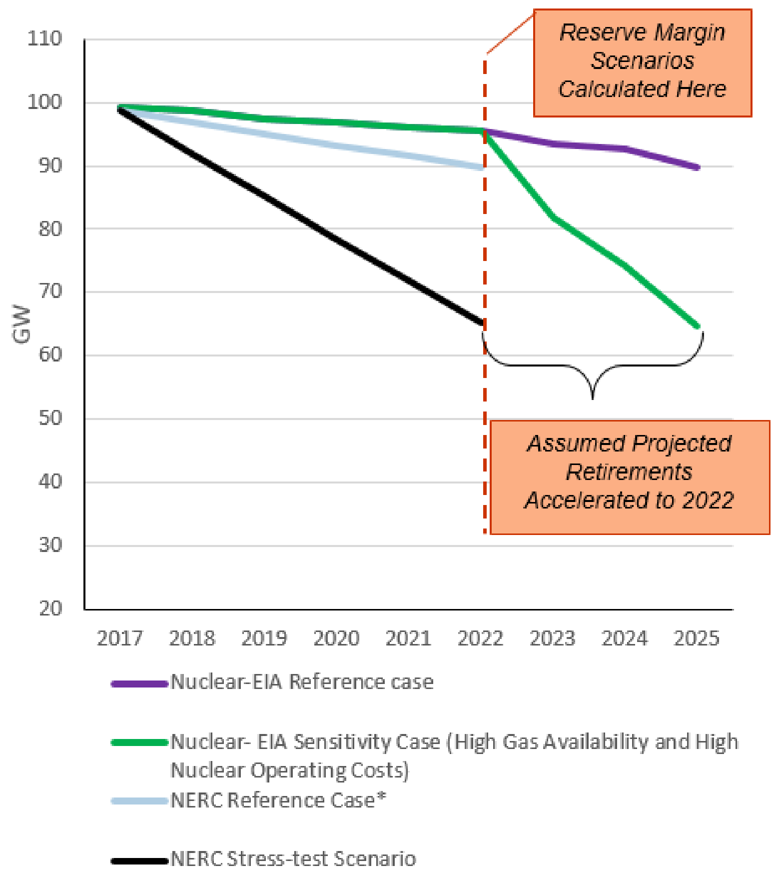
The stress-test scenario used to assess resource adequacy is based on generation capacity projections that are accelerated for the purpose of developing a stressful assessment scenario. This scenario uses an EIA sensitivity case to identify potential coal-fired and nuclear generation retirement capacity through year 2025 and then accelerates those retirements to 2022 as shown in **Figure I.4** and **Figure I.5**.

NERC's 2017 LTRA generation data, which includes only confirmed generation retirements, projects more than 27 GW of generator retirements through 2022 (18 GW coal-fired and nearly 9 GW of nuclear generation capacity). Because generator retirement announcements can be made as late as 90 days prior to planned deactivation in some areas, long-range retirement projections based on confirmed retirements could be significantly understated. The stress-test scenario retires nearly 91 GW of generating capacity (62 GW coal-fired and 29 GW nuclear) in addition to the confirmed retirement projection from the *2017 LTRA*. The stress-test scenario is **not** predictive but rather provides insights that would otherwise be overlooked if perspectives are limited to confirmed retirements.



*NERC Reference Case is based on generation retirements and planned (Tier 1) generation additions for Year 2022 from 2017 LTRA projections. It also accounts for generation retirements that were confirmed before June 2018.

Figure I.4: NERC Assessment Scenario Coal-fired Generation Capacity and EIA Projection Coal-fired Generation Capacity (2017 LTRA data and EIA 2018 Annual Energy Outlook)



*NERC Reference Case is based on generation retirements and planned (Tier 1) generation additions for Year 2022 from 2017 LTRA projections. It also accounts for generation retirements that were confirmed before June 2018.

Figure I.5: NERC Assessment Scenario Nuclear Generation Capacity and EIA Projection Nuclear Generation Capacity (2017 LTRA data and EIA 2018 Annual Energy Outlook)

When scenario retirements result in resource adequacy issues, replacement generation capacity is added based on the available generation resources (natural-gas-fired, wind, and solar generating units) currently in planning in the interconnection queue. The five-year time frame was selected to provide a distant future target while making use of currently held BPS data and projections. The data was collected from industry through NERC's *Long-Term Reliability Assessment* process and includes projected electricity demand, replacement generation resources in planning queues, and other anticipated resources. Using 2022 as the assessed year provides good insight into the upper limit of capacity additions—as all capacity in the interconnection queue (Tier 1 and Tier 2) is assumed to be built. Resource adequacy concerns are identified when replacement generation capacity is not sufficient to make up for scenario retirements and return to Reference Margin Levels for 2022 peak load conditions. Basing assessments on a 2022 benchmark makes good use of resource and load projections that will degrade in accuracy over longer terms.

Although the stress-test scenario may be unprecedented, it provides insights into boundary conditions and the nature of the changing resource mix. These insights are useful in considering the reliability of a potential state of the BPS using established reliability criteria. Various factors (including wholesale electricity market response to generator retirements, government incentives, load projections and the expansion of distributed energy resources, and technology development) affect generation resource additions and retirements. Because these factors and affects are unpredictable, it is useful to perform stressful scenario analysis to understand potential future reliability risks.

Transmission Planning Studies

Two power flow studies are included in this scenario to illustrate how transmission system planning accounts for generator retirement scenarios and the impact that retirements can have on transmission system needs. Power flow studies, and other advanced studies, are typically performed by system planners to prepare for generator retirements and other changes to the BPS. These studies are included in the scenario because they reveal important information about system reliability that is not contained in a typical reserve margin analysis.

Power flow studies are used by BPS planners to ensure that the transmission system is capable of delivering electric power to where the load is and that there are sufficient generation resources available to serve the expected load. For example, a reserve margin analysis does not take into account the reactive power requirements needed to maintain sufficient control of voltages. As generators retire in certain locations, power flow on the system may change in order to continue serving load with resources from other locations. Transmission planning studies, including power flow studies, may identify upgrades, operating procedures, or generation dispatch plans that are necessary to ensure the system operates within established limits and meets performance criteria—essential attributes of a reliable electric power system.

Regional Processes for Managing Generator Retirements

Accounting for generation retirements and resource additions is a normal part of resource and transmission planning that occurs on an ongoing basis throughout North America. Planning processes and responsibilities for NERC entities, regulators, and wholesale electricity market operators vary by state or province and regulatory structure. Although these processes may be unique to specific areas, each provides a framework for stakeholders to work together to ensure projected generation resources are sufficient to meet anticipated electrical demands and that the transmission system can meet operating reliability requirements. The industry has employed its processes for managing generation retirements during periods of considerable change in the generation fleet and has been successful in maintaining reliability.

In this scenario, NERC provides an overview of regional processes for managing generator retirements and deactivation requests that might be employed to handle an accelerated pace of generator retirements. There are many and diverse entities responsible for planning the reliable operation of the North American BPS. In some parts of the grid, ISOs and RTOs are responsible for planning and coordinate among merchant generator owners (GOs), private transmission owners, and regulated utilities (in some cases). Processes among RTOs and ISOs vary in their approaches to managing the introduction of new generation, the deactivation of existing generation, and changes that are needed to ensure the reliability of the grid and successful operation of wholesale markets. Elsewhere, vertically integrated utilities are responsible for generation and transmission planning within their jurisdiction, which is largely overseen by individual state public utility commissions in the United States or provincial authorities in Canada.

Regulatory structures and resource planning processes are important factors in determining the timing and location of generator retirements. Areas with specific integrated resource planning or regulated capacity requirements may present lower reliability risk from accelerated retirements. This section of the report provides insights into the various mechanisms that may be employed to address identified reliability risks associated with the accelerated pace of generator retirements.

Role of NERC Reliability Standards

Although the system planning processes and precise roles of utilities, ISOs, RTOs, and merchant generators are highly varied throughout North America, NERC's Reliability Standards provide consistent criteria for BPS planning that is applicable across the interconnected transmission system. Among other things, NERC Reliability Standards require owners and operators to perform annual long-term planning studies based on existing and planned generator resources and loads and to correct issues if needed to ensure that the BPS can maintain reliable operation under both normal conditions and anticipated contingencies. The standards also require entities to evaluate extreme events, identify mitigating actions, and have emergency operating procedures to respond and recover from severe system disturbances. However, requirements for construction of additional generation or transmission facilities are not within NERC's authority.[14]

[14] Details about NERC's regulatory authorities can be found at the following location: https://www.nerc.com/AboutNERC/keyplayers/Pages/Reliability-Legislation.aspx

Chapter 1: Resource Adequacy Scenarios

Resource adequacy refers to the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times while taking into account scheduled and reasonably expected unscheduled outages of system components. NERC uses Planning Reserve Margins, a percentage value of expected generation levels above anticipated peak loads, as a metric to measure resource adequacy. A Reference Margin Level is established for each assessment area that depends on reliability criteria (e.g., deterministic resource adequacy thresholds, probabilistic loss-of-load expectation), regulatory decisions, and applicable market-based principles.[15] Monitoring the impact that potential generation retirements have on Planning Reserve Margins and comparing results with Reference Margin Levels provides an indication of potential reliability issues.

Areas Identified for Scenario

The resource adequacy portion of this scenario focuses on areas where coal-fired and nuclear generation provide a significant contribution to generator resource levels. For example, in the MISO area, coal-fired and nuclear generation make up 51 percent of the 2018 generation capacity. Texas RE-ERCOT is another area that could be impacted by accelerated retirement of traditional baseload generation. Although natural-gas-fired generation is the leading resource type in this area, the Planning Reserve Margins are relatively low, making the contribution of coal-fired and nuclear generation significant in maintaining reliability. Areas where coal-fired and nuclear generation provide limited contribution to the overall generation resource mix were omitted from the scenario. **Table 1.1** shows the capacity contributions of coal-fired and nuclear generation in each area included in this portion of the assessment along with Planning Reserve Margins.

Table 1.1: 2018 Generation Resources and Reserve Margins[16]

Area	Coal and Nuclear Generation (MW)	Coal and Nuclear Generation (%)	Planning Reserve Margin (%) at Peak Load
MISO	72,691	51.4%	19.2%
NPCC New England	4,918	16.1%	23.7%
NPCC New York	6,386	16.1%	22.5%
PJM	90,494	48.3%	32.5%
SERC-E	25,162	50.1%	16.5%
SERC-SE	24,797	38.2%	33.7%
SPP	26,326	38.1%	32.4%
Texas RE-ERCOT	19,677	26.5%	18.2%
WECC-RMRG	8,994	49.8%	23.7%
WECC-SRSG	12,901	40.1%	23.7%

As generators retire, Planning Reserve Margins could decrease unless resources, such as new generators, demand response, or firm import transfers, are added to replace the retiring capacity. Potential new generation is reported to NERC by NERC Regions in tiers defined as follows:[17]

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[15] Expressed as a percentage, Planning Reserve Margin are the difference between resources and demand, divided by the demand. NERC's annual Long-term Reliability Assessments (LTRA), available at the following link, provide a full description of Planning Reserve Margin, NERC assessment areas, and other reliability indicators.
https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx

[16] Data source: *2017 LTRA*

[17] See LTRA Data Concepts and Assumptions Section

- **Tier 1:** generation capacity that is either under construction or has received approved planning requirements
- **Tier 2:** generation capacity that has been requested but not received approval for planning

Reserve Margin Scenario Analysis

The 2022 Planning Reserve Margins in assessment areas of interest were calculated and compared for the stress-test scenario and the NERC reference case.[18] The scenario affects generation resources for the 2022 peak by removing 30 percent of coal-fired generation capacity and up to 45 percent of nuclear generation capacity. The reference case includes only confirmed retirements.[19] **Figure 1.1** shows the capacity of combined coal-fired and nuclear generation relative to total capacity that is retired in the 2022 reference case and the generation retirement scenario. Resource levels are shown as percentage of total 2022 generation capacity.

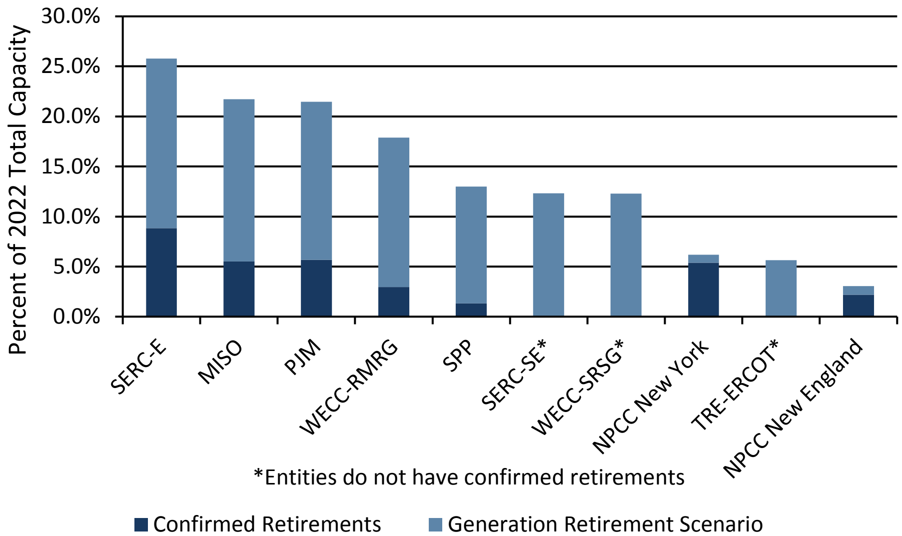


Figure 1.1: Capacity of Combined Coal-fired and Nuclear Generation in the 2022 Reference Case and Stress—Test Scenario

Generation resource capacity to replace the scenario retirements is determined by analyzing the prospective new generation resources reported in the *2017 LTRA* data. Natural-gas-fired generation, as well as solar and wind generation, were considered in the analysis. If the retiring capacity in the stress-test scenario results in Planning Reserve Margins that are below the Reference Margin Levels, Tier 2 generation resources within the assessment area are added.[20] **Table 1.2** lists the retirement and replacement generation capacities for the 2022 reference case and the stress-test scenario. For purposes of this assessment, the quantity of Tier 2 generation resources in current planning (i.e., in the interconnection queue) can provide an upper bound estimate of the potential near-term resources available for reliability.

[18] See NERC's 2017 LTRA for supply and margin definitions.

[19] Confirmed retirements in the reference case are those reported in the 2017 LTRA and any additional retirements confirmed before June 2018.

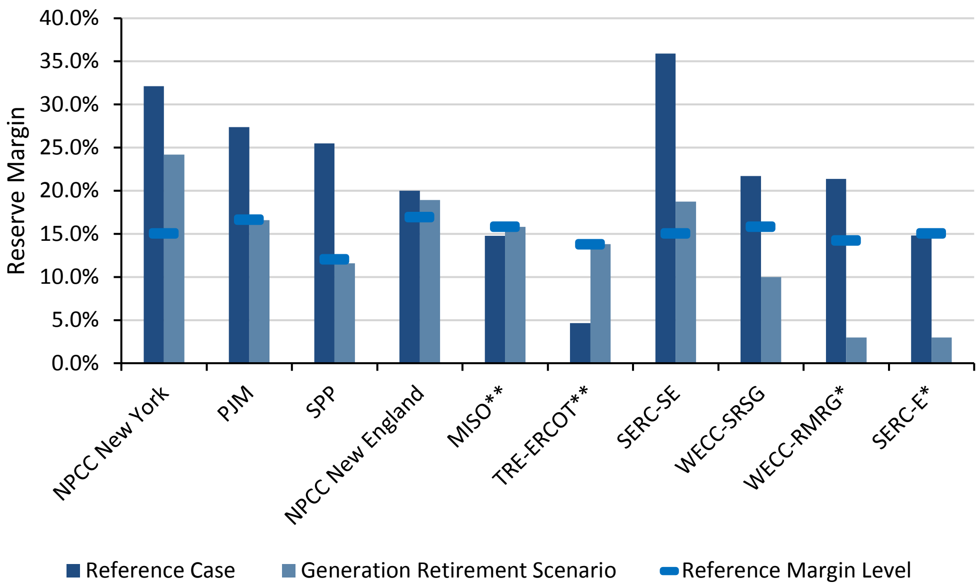
[20] The addition of Tier 2 resources represents potential generation that could be added to the system within the planning horizon to provide for resource adequacy. However, Tier 2 resources may include generators that are never realized for variety of reasons, including merchant owner business decisions, technical issues, and siting or permitting constraints.

Table 1.2: Retirement and Replacement Generation Capacities for the 2022 Reference Case and Stress-Test Scenario				
	Reference Case (Confirmed Retirements)		Scenario (30% Coal and 45% Nuclear Retired)	
Area	Confirmed Retirements (MW)	Anticipated Tier 1 Gas Generation (MW)	Total Retired Capacity in Scenario (MW)	Replacement (Tier 2) Generation (MW)
MISO	7,746	3,622	22,717	34,429
NPCC New England	671	2,617	273	0
NPCC New York	2,042	784	303	0
PJM	10,560	14,128	29,348	13,484
SERC-E	4,753	2,254	9,109	0
SERC-SE	0	100	7,891	0
SPP	880	404	7,802	403
Texas RE-ERCOT	0	3,883	4,409	11,259
WECC-RMRG	536	352	2,698	0
WECC-SRSG	0	510	4,002	1,058

NERC's stress-test scenario considers high levels of generator retirements occurring in a five-year horizon. Although such a scenario is not a prediction and may be unparalleled, it provides insight into boundary conditions and the nature of the changing resource mix. These insights can be useful in considering the reliability of a potential state of the BPS using established reliability criteria. Various factors, including wholesale electricity market response to generator retirements, government incentives, and technology development affect generation resource additions and retirements. Because these factors and effects are unpredictable, it is useful to perform stressful scenario analysis to understand potential future reliability risks.

Analysis Results

Despite the high levels of generation retirements in the stress-test scenario, six of the 10 NERC assessment areas would have sufficient generation resource capacity (existing and Tier 1 and 2 generation from the interconnection queue) to maintain peak demand planning reserves at or above 2022 Reference Margin Levels as shown in **Figure 1.2**. Detailed results of the resource adequacy analysis are shown in **Appendix A**.



*Actual Planning Reserve Margin is near or below 0%

**Chart depicts the projected 2022 Planning Reserve Margin Reference Case below Reference Margin Level based on 2017 LTRA data and confirmed retirements. Generation Retirement Scenario Planning Reserve Margins assume new generation is installed to make up for confirmed and accelerated retirements.

Figure 1.2: Planning Reserve Margins for the 2022 Reference Case and Stress-Test Scenario

In PJM, MISO, and Texas RE-ERCOT, the stress-test scenario retirements could be made up to reach current Reference Margin Levels using some combination of natural gas, wind, and solar resource capacity from the interconnection planning queue (Tier 2). Similarly, scenario retirements do not result in a reserve margin shortfall in NPCC-New York (NYISO), NPCC New England (ISO-NE), and SERC Southeast. In these areas, the stress-test retirements would not reduce planning reserves to the point where capacity additions were required from the interconnection planning queue to meet Reference Margin Levels. Of the 10 assessed areas, SERC East, SPP, WECC-RMRG, and WECC-SRSG could anticipate resource adequacy issues resulting from generation retirements that were similar to those assessed in this scenario. In these areas, Planning Reserve Margins could fall below Reference Margin Levels if retirements proceeded because the capacity of generation in the planning queue is not sufficient to replace needed capacity from retiring coal-fired and nuclear generation.

While most areas are able to maintain resource levels for this stress-test scenario, the analysis shows a range of potential issues that BPS planners may need to address to maintain reliability. As shown by this scenario, large-scale generation retirements can potentially reduce Planning Reserve Margins to levels that are near or below Reference Margin Levels. Mandatory resource levels can act to limit the amount of generation considered for retirement in a regulatory jurisdiction. On a regional (RTO/ISO) scale, significant amounts of replacement generation capacity may be required, which could create the need for expediting development of generation resources in interconnection queues. In the event that sufficient replacement resources are unavailable to make up for planned retirements, actions may be needed to ensure resource adequacy (e.g., delaying planned retirements, deployment of additional demand response or other demand-side resources, and/or larger-scale electricity storage).

Maintaining adequate Planned Reserve Margins directly impacts the reliability of the BPS. Planning reserves are necessary for reliability because they provide a measure of electrical energy on the system that may be called upon to overcome electrical system contingencies, unplanned generation and transmission outages, and extreme environmental conditions. Planning reserves also provide a margin that is needed to account for uncertainty that is inherent with variable generation resources. Reduction in Planning Reserve Margins below reference margin levels could increase the potential for loss of load during unplanned or extreme events.[21]

Key Finding
For resource adequacy, in six of the 10 assessment areas, existing and planned generation resources would be sufficient to maintain peak demand reserves at or above 2022 Reference Margin Levels. However, generation retirements on the scale of the stress-test scenario could reduce Planning Reserve Margins to levels that are near or below Reference Margin Levels. Mandatory resource levels could act to limit the amount of generation considered for retirement in a regulatory jurisdiction. On a regional (RTO/ISO) scale, significant amounts of replacement generation capacity would be required, which could create the need for expediting development of generation resources in interconnection queues. In the event sufficient replacement resources are unavailable to make up for retirements, actions may be needed to ensure resource adequacy (e.g., delaying announced retirements, deployment of additional demand response or other demand-side resources, and/or larger-scale electricity storage).

Resource Mix and Fuel Assurance

Generator resource mix—the collection of generator fuels and power sources producing electricity—is evolving as traditional coal-fired, oil, and nuclear generators are replaced by smaller natural-gas-fired units as well as wind and solar resources. In some ways, the changing resource mix can benefit reliability and security of the BPS. For example, replacing a large baseload generator with a mix of smaller natural-gas-fired generators and variable generation from renewables can provide operating and planning flexibility. However, the changing resource mix also presents known challenges to reliability that owners and operators must address, such as the need to ensure the new mix of fuel can be supplied at all times to meet the load and operating reserves.

Natural-Gas-Fired Generation Increases in the Scenario

In the preceding reserve margin analysis, the replacement generation resource mix includes natural-gas-fired units, as well as variable generation from wind and solar. Natural-gas-fired generation continues to grow in interconnection planning queues and has the potential to provide several attributes for selection as a replacement resource for retiring generation. Like the traditional baseload generators being replaced, natural-gas-fired generators can provide certain ERSs necessary to balance and maintain the electric grid under a variety of system conditions. Additionally, in many areas, natural-gas-fired generation can be sited and brought online relatively quickly—often in less than three years. Even in states or provinces with energy policy goals designed to boost the share of renewable generation in the resource mix, analysts predict that the levels of baseload retirements will require increased reliance on natural gas for electricity generation.[22] **Figure 1.3** compares the contributions of natural-gas-fired generation in the overall resource mix for the scenario, reference cases, and current mix. Variable generation resources in the replacement generation resource mix include all planned (Tier 1) additions for 2022, as well as wind and solar resources in earlier planning stages (Tier 2) as needed to meet Reference Margin Levels.

[21] A detailed explanation of Reference Margin Levels and requirements by assessment area is found in the *2017 LTRA*.

[22] See Western Interconnection Gas-Electric Interface Study, Wood Mackenzie, June 2018, pp. 6-7.

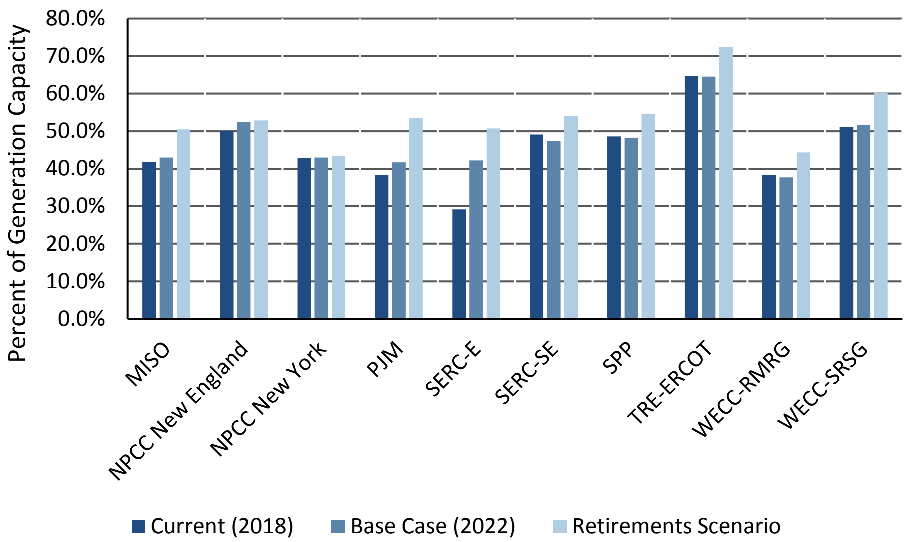


Figure 1.3: Natural-Gas-Fired Generator Contribution to Resource Mix

The addition of natural-gas-fired generation resources can be challenging in areas where natural gas supply and transportation infrastructure is operating near capacity and where growth in natural gas sector infrastructure is constrained. For example, natural-gas-fired generators in the Northeast can experience natural gas supply shortfalls as a result of upstream pipeline constraints. Approvals for new pipeline projects in the Northeast face challenges.[23] Other parts of North America can be susceptible to disruptions in natural gas supply, such as portions of southwestern United States, which are dependent on a limited number of long-haul natural gas transmission pipelines.[24]

In order for natural-gas-fired resources to provide reliability benefits of traditional baseload generation that they replace, the new resources need fuel assurance. When natural gas fuel supplies to generators are uncertain (i.e., not obtained through firm contracting or supported by sufficiently redundant natural gas delivery infrastructure), Reference Margin Levels may need to be increased in order to provide the same level of BPS reliability that is being provided by retiring generation. Accelerated retirements of coal-fired and nuclear generation could place additional demand on the regional natural gas infrastructure network for assured delivery as natural-gas-fired generation increases.

Maintaining Adequate Reserves under Extreme Conditions

Generation retirements that result in declining Planning Reserve Margins and reduced fuel assurance can challenge the reliable operation of the BPS in extreme conditions. Reliability may be at risk from extreme events and conditions that result in elevated electrical and natural gas load, stressful environmental conditions for grid equipment, or reduced generator fuel availability. Often the extreme conditions that NERC and industry consider in evaluating resource adequacy and BPS reliability are regional in nature, reflecting unique challenges associated with geography, weather variations, or constrained energy infrastructure. Examples of such extreme conditions include the following:

- The 2014 Polar Vortex and 2017–18 Northeast cold snap
- Prolonged heat or drought conditions in the Southwest
- Natural gas supply risks in areas with limited pipeline redundancy or natural gas storage capacity

[23] See *Gas-Electric System Interface Study* conducted by the Eastern Interconnection Planning Collaborative (EIPC Study), July, 2015. Specifically, *Gas-Electric System Interface Study Target 2: Evaluate the Capability of the Natural Gas Systems to Satisfy the Needs of the Electric System*: http://www.eipconline.com/phase-ii-documents.html

[24] See Western Interconnection Gas-Electric Interface Study.

The following sections examine the impact that retirement scenarios could have on resource needs for withstanding extreme risks that are applicable to each area of interest (**Table 1.3**).

Table 1.3: Summary of Regional Extreme Event Risks for Scenario Analysis

Area	Extreme Event Risk	Scenario Analyzed
MISO	**Winter Reliability:** Insufficient resources during periods of prolonged cold temperatures that result in high generator forced outage rates and electrical demand exceeding forecast winter peak demand	Polar Vortex
NPCC New England	**Winter Fuel Assurance:** Insufficient resource availability resulting from generator fuel curtailments, or deliverability issues, or as a result of high-impact infrastructure disruption	ISO-NE's Operational Fuel-Security Assessment (OFSA)
PJM	**Winter Reliability:** Insufficient resources during periods of prolonged cold temperatures that result in high generator forced outage rates and electrical demand exceeding forecast winter peak demand	Polar Vortex
SERC-E	**Winter Reliability:** Insufficient resources during periods of prolonged cold temperatures that result in electrical demand exceeding forecast winter peak demand	Polar Vortex
WECC	**Fuel Assurance:** Insufficient resources resulting from generator fuel curtailments or as a result of high-impact infrastructure disruption	Western Interconnection Gas-Electric Interface Study

Polar Vortex Scenario

The 2014 Polar Vortex, which impacted a majority of the midwestern and northeastern United States and southern Canada, tested the resilience of the North American BPS. This event served as an example of how extended periods of cold temperatures have direct impacts on generator resource availability. Higher than expected forced outages were observed during the 2014 Polar Vortex (particularly for natural-gas-fired generators) as well as higher-than-forecast peak demand (See **Figure 1.4**).[25] The following impacts were caused by fuel delivery challenges and extended periods of low temperatures:

Fuel Delivery

- Natural gas interruptions (supply injection, compressor outages, and one pipeline explosion)
- Oil delivery problems
- Inability to procure natural gas
- Fuel oil gelling

Low Temperatures

- Low temperature limits for wind turbines

[25] Detailed analysis is available in NERC's *January 2014 Polar Vortex Review* and the *2014 LTRA*:
https://www.nerc.com/pa/rrm/Pages/January-2014-Polar-Vortex-Review.aspx
https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2014LTRA_ERATTA.pdf

- Icing on hydro units
- Failed auxiliary equipment
- Stress of extended run times
- Frozen instrumentation (drum level sensors, control valves, and flow and pressure sensors)

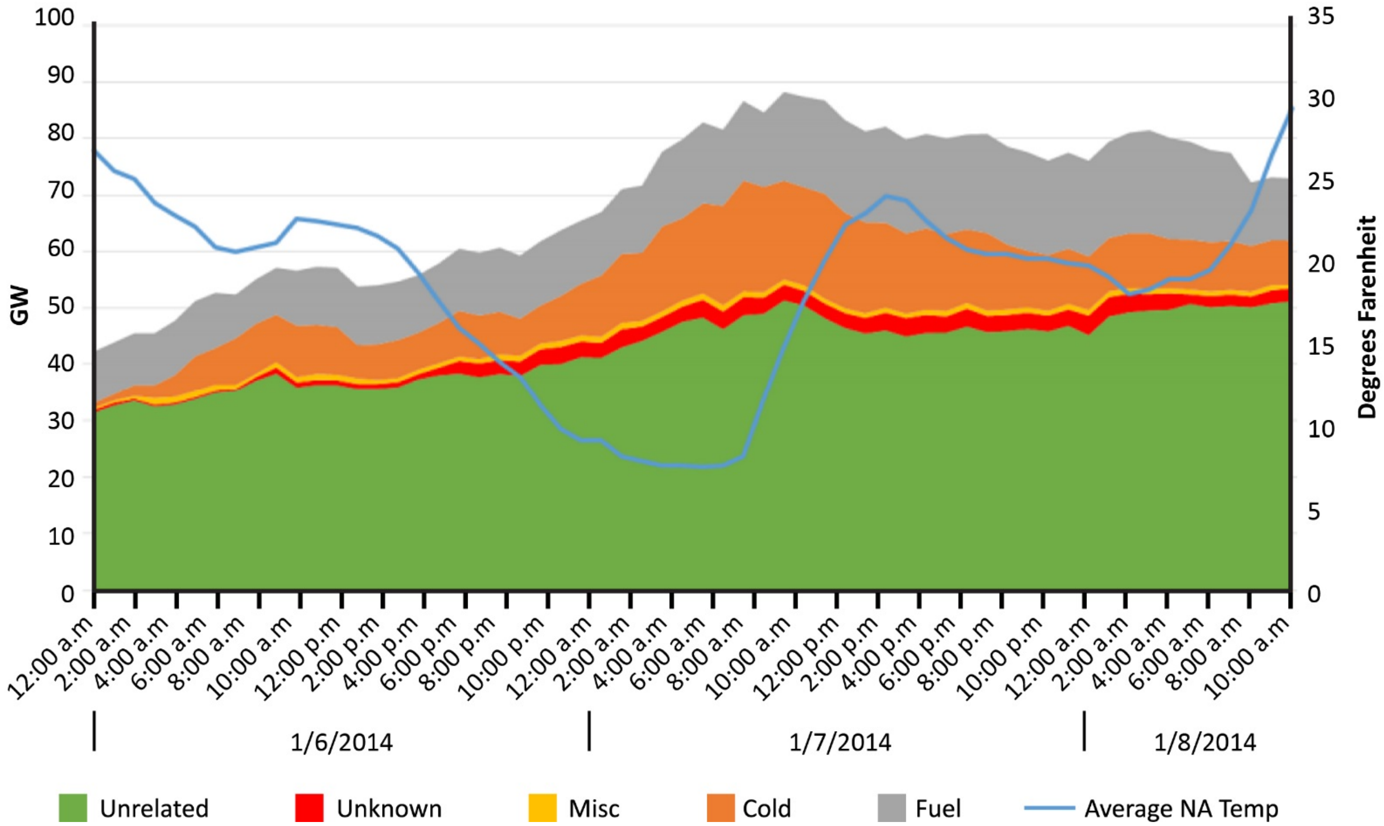


Figure 1.4. Polar Vortex 2014 Cumulative Impact of Outage Type vs. Temperature in NERC Regions (excluding WECC)[26]

Analysis of Generator Retirement Impacts on Resource Adequacy for a Polar Vortex Scenario

A polar vortex analysis of the generator retirement scenario was performed by NERC for the PJM (**Figure 1.5**), MISO (**Figure 1.6**), and SERC (**Figure 1.7**) assessment areas in the 2022–2023 winter case. These assessment areas experienced significant loss of generation during the 2014 Polar Vortex. Forced outage data from the 2014 Polar Vortex were applied as derates to the new generation mix in the generation retirement scenario, and load projections (scenario peak demand) for the 2014 Polar Vortex analysis were based on the increases to forecast net internal demand (**Table 1.4**).

[26] See NERC's 2014 *Polar Vortex Review*, Figure 5, September 29, 2014, at the following link: https://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf
Forced outages in the category of "Cold" include frozen equipment and/or sensors under the control of the generating plant and on-site fuel issues, such as frozen coal piles and gelled fuel. Forced outages in the category of "Fuel" refer to those that are directly related to the inability of the plant to receive fuel from their provider. Temperature represents an average of seven selected cities in the approximate geographic centers of the studied areas.

Table 1.4: Polar Vortex Scenario Fuel-type Derates and Net Internal Demand Increase				
Assessment Area	Assumed Net Internal Demand[27]	Derated Capacity by Fuel Type		
		Coal	Natural Gas	Wind and Solar
MISO	107%	15%	30%	100%
PJM	107%	21%	34%	100%
SERC-E	118%	0%	0%	0%

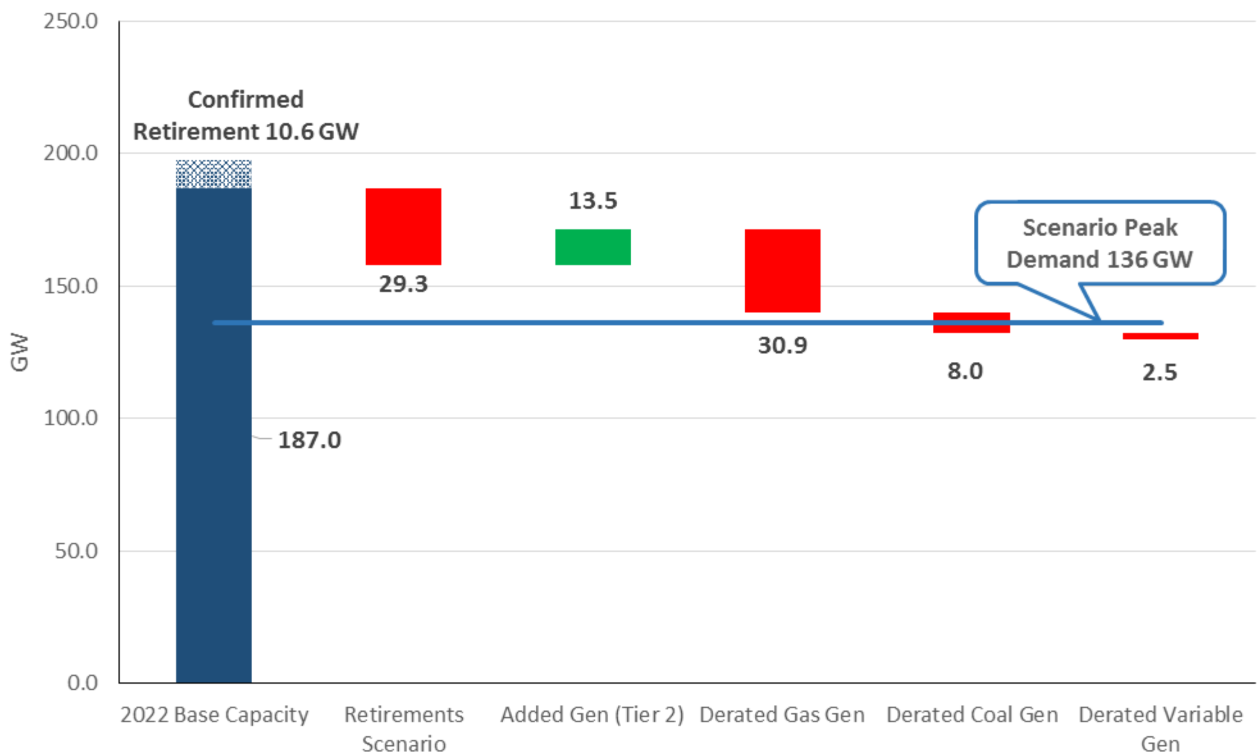


Figure 1.5: Polar Vortex Capacity and Assumed Electrical Loads for PJM Area (Normal Winter Peak and Polar Vortex Peak) [28]

[27] Load projections for the polar vortex scenario are based on 2022 winter forecasted net internal demand. This demand value is the forecasted total internal demand reduced by the amount of controllable and dispatchable demand response projected to be available.

[28]This figure depicts NERC's analysis. Separately, PJM performed polar vortex analysis of potential future resource portfolios and identified reliability concerns when high amounts of coal-fired and nuclear generation resources are replaced by natural-gas-fired generation. See *PJM's Evolving Resource Mix and System Reliability*, PJM Interconnection, March 2017: "The share of natural gas in the resilient portfolios ranges from a minimum of 33 percent to a maximum of 66 percent" (Appendix, p. 41): https://www.pjm.com/~/media/library/reports-notices/special-reports/20170330-pjms-evolving-resource-mix-and-system-reliability.ashx
Furthermore, a separate study by Quanta Technology of the PJM area included polar vortex-type analysis and probabilistic modeling of natural gas facility interruptions. In the Quanta Technology study, coal-fired generation retirements ranging from 15 GW to 30 GW result in increased LOLE between 0.421 to 0.575 day/year (Established LOLE is 0.1 day/year or one-day in 10 years). See *Ensuring Reliability and Resiliency – A Case Study of the PJM Power Grid*, Quanta Technology, April 2018: http://www.americaspower.org/issue/ensuring-reliability-and-resilience-a-case-study-of-the-pjm-power-grid/

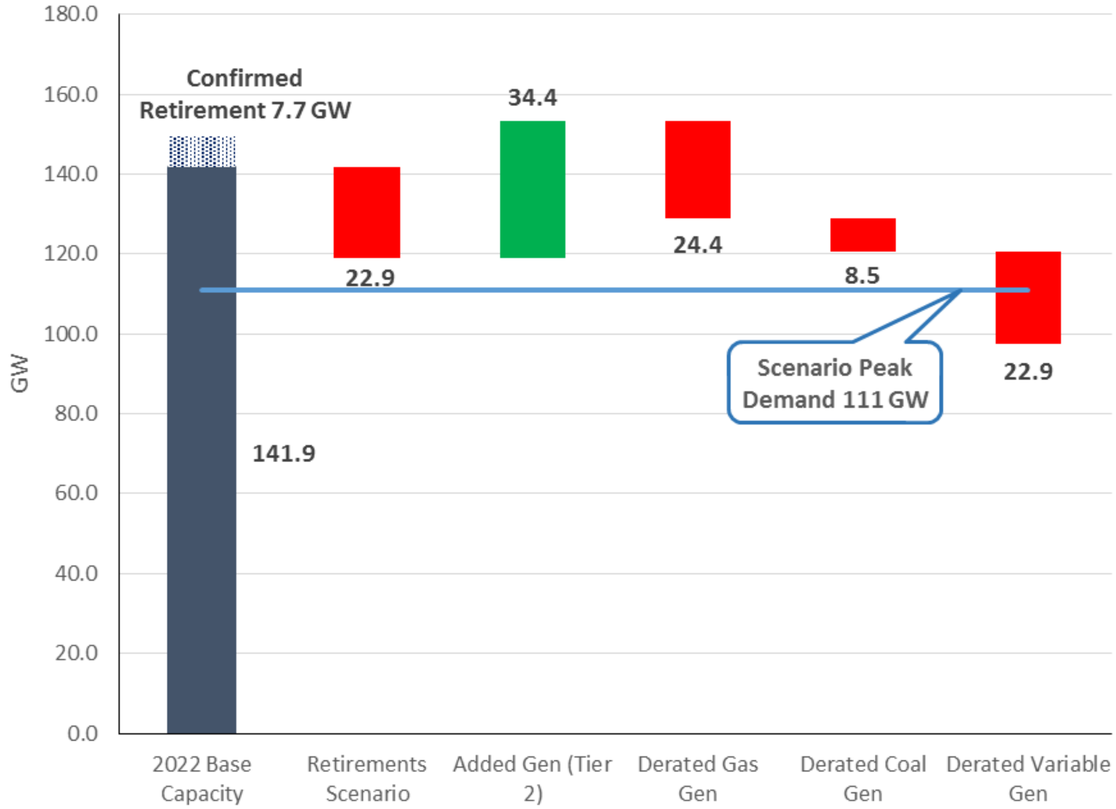


Figure 1.6: Polar Vortex Capacity and Assumed Electrical Loads for MISO Area (Normal Winter Peak and Polar Vortex Peak)

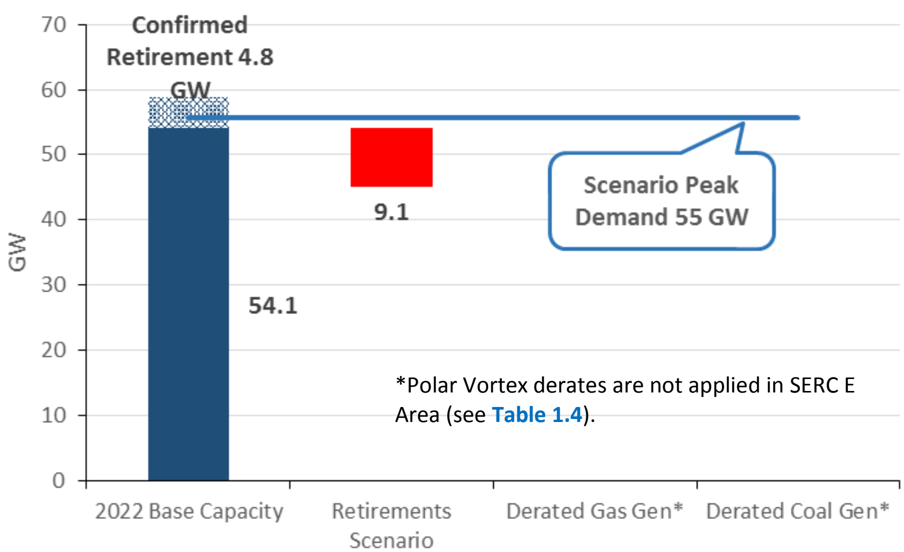


Figure 1.7: Polar Vortex Capacity and Assumed Electrical Loads for SERC-E Area (Polar Vortex Peak)

Based on the NERC analysis in these three assessment areas, projected reserve margins combined with the projected increased dependence on natural gas and variable generation (associated with the retirement scenarios) could increase the adverse impacts to BPS reliability if similar facility outages, peak electric loads, and high natural gas demand (due to extreme weather events) were to occur.

The 2014 Polar Vortex scenario is a useful approach for assessing resource adequacy to a known extreme event that resulted in high levels of generator outages. Since the 2014 Polar Vortex, there have been significant efforts to improve generator performance during severe cold weather, and marked improvements in forced outage rates have been observed during subsequent winter periods. Nonetheless, the 2014 Polar Vortex is informative for understanding extreme event risk associated with the changing resource mix.

Other Winter Scenarios Highlight Fuel Assurance Concerns

Operational assessment of the BPS in New England highlights concerns with securing sufficient quantities of fuel in the future to serve electrical load over the course of an entire winter. As the area shifts away from having generation resources with on-site fuel storage and is not home to natural resource fossil fuels or underground storage, fuel supply logistics are integral to BPS reliability planning. ISO-NE's study of hypothetical scenarios examined the extent of generator fuel supply shortages projected for the 90-day duration of the 2024/2025 winter.[29]

The reference case in the ISO-NE study provides an expectation of key input variables based on trends, including generation retirements, fuel resources, renewable generation, and electricity imports. One of several scenarios in the study examines the impact of increased retirements of fossil-fueled generators (3,000 MW above the reference case) for comparison. In both the reference case and the increased retirements scenario, adequate levels of fuel would not be available to meet the anticipated electrical load throughout the entire winter, resulting in periods of insufficient reserves, need for emergency purchases from neighboring systems, and other emergency operation procedures (EOPs)—including load shedding (see **Figure 1.8**). High retirements of heavy fuel oil resources (or dual fueled resources) exacerbate fuel availability issues and could result in up to 105 hours of load shedding over 16 days in the projected winter period.

						TOTAL WINTER IMPACT					
	Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil Tank Fills)	Imports (MW)	Renewables (MW)	Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6-11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
Reference Case	–1,500	1.00	2	2,500	6,600	35	165	76	53	14	6
More Retirements	–4,500	1.00	2	2,500	6,600	35	455	316	258	105	16

Figure 1.8 Assumptions and Results for Scenarios (Reference and More Retirements) Examining Generator Fuel Supply Impacts in ISO New England[30]

Impacts of Generator Fuel Supply Disruption

The increasing proportion of electricity that is generated by natural gas results in a need to consider the unique fuel supply characteristics associated with this fuel type. In most cases, electricity generation with natural gas does not involve on-site storage of fuel. Instead, natural gas infrastructure (e.g., pipelines, underground storage, and above ground liquefied natural gas (LNG) storage, compressor stations, metering and control equipment) support "just-in-time" delivery of fuel to meet the electric generator's production signal from the power grid. Because natural-gas-

[29] See *Operational Fuel-Security Analysis*, ISO-NE, January 2018: https://www.iso-ne.com/static-assets/documents/2018/01/20180117_operational_fuel-security_analysis.pdf

[30] See *Operational Fuel-Security Analysis*, ISO-NE, January 2018

fired generators typically lack on-site natural gas storage capability, fuel supply disruptions to the natural-gas-fired generator could produce near-immediate degradation in electricity generation and potentially impact BPS reliability.

Regional Assessments of Fuel Assurance

The level that the BPS is vulnerable to natural gas disruption is subject to many factors, including the redundancy of pipeline infrastructure, the availability of natural gas storage facilities, generator natural gas supply contracting arrangements (firm vs. interruptible), generator dual-fuel capability, and the level of electric and natural gas industry coordination. Several in-depth regional assessments of the potential impacts to natural-gas-fired generation resulting from natural gas infrastructure events have been conducted.[31]

Western Interconnection Gas-Electric Interface Study

In a recent study of the Western Interconnection, various natural gas disruption scenarios described in **Table 1.5** and **Figure 1.9** were modeled to determine their effect on natural-gas-fired generation and the resultant BPS impact.

Table 1.5: Natural Gas Supply Disruption Scenarios Modeled in the 2018 Western Interconnection Gas-Electric Interface Study[32]

Disruption Scenario	WECC Area Focus	Base Case (N-1)	N-2 Case
Disruption of a Pacific Northwest (PNW) pipeline	PNW	Disruption at the United States/Canada border (or upstream) receipt point on the system	Low hydro conditions
Seismic event disrupting Alberta supply	PNW	Major earthquake in the Rocky Mountain House area that disrupts natural gas production in Alberta	Low hydro conditions
Disruption on a basin pipeline	Basin/California	Disruption on the critical mainline section downstream of the supply basin and upstream of the demand centers	Low hydro conditions
Disruption of a Desert Southwest (DSW) pipeline	DSW/Southern California	Disruption of critical southern New Mexico section of DSW pipeline	NA
Winter supply freeze-off in the Permian and San Juan basins	DSW	Week-long winter supply freeze-off in the Permian and San Juan basins reducing supply by 1.5 bcfd, accompanied by higher residential natural gas demand. A total of 15 percent of generation in Arizona and New Mexico unavailable due to freezing conditions.	Low hydro conditions and transmission outage from California wildfire

[31] In addition to the two reports described herein, the Nuclear Energy Institute commissioned ICF, a consulting service, to perform an analysis of how a natural gas infrastructure event affecting generation resources in PJM might impact the BPS. The report is available here: https://www.nei.org/CorporateSite/media/filefolder/resources/reports-and-briefs/icf-study-fuel-security-grid-resilience-201806.pdf

[32] See *Western Interconnection Gas-Electric Interface Study*. The scenarios were defined by a WECC project team using input from natural gas and electric industry representatives. The scenarios were selected to highlight BPS reliability concerns and capture a representative spectrum of circumstances: https://www.wecc.biz/Administrative/WECC%20Gas-Electric%20Study%20Public%20Report.pdf

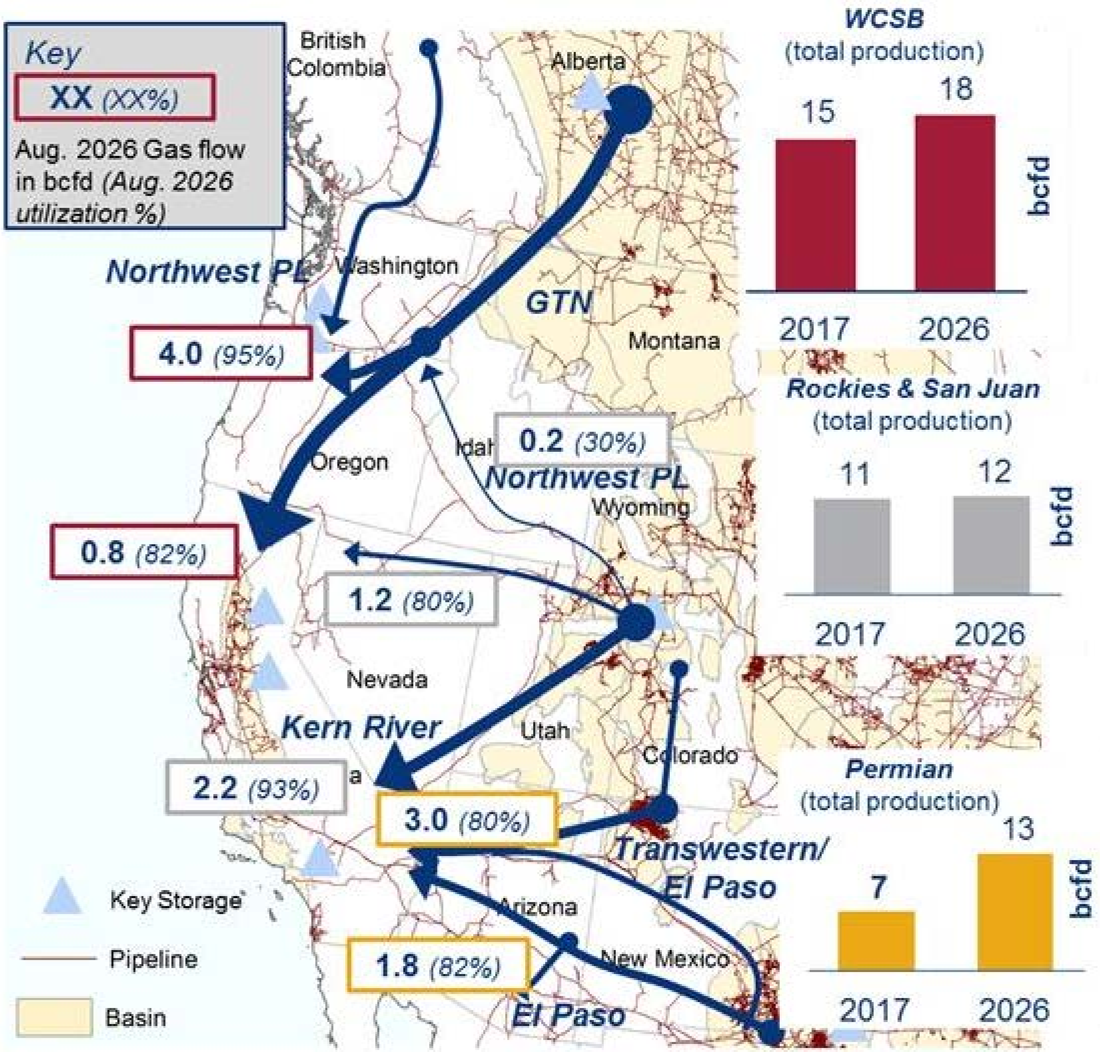


Figure 1.9. Western United States and Canada Major Gas Pipelines and Gas Basins (from 2018 Western Interconnection Gas-Electric Interface Study Report)

Figure 1.10 depicts the impacts on electrical capacity resulting from each disruption scenario. Scenarios that cause greater concern impact the desert southwest area, including the Phoenix metro area and Southern California. Here, the gas infrastructure configuration has limited pipeline redundancy and storage such that a major disruption will result in significant unserved energy. BPS reliability in this sub-area is also at risk should freezing temperatures at natural gas production well-heads reduce the flow of natural gas into the area, impacting generation and resulting in challenging balancing conditions on the transmission system. Other areas in WECC are more resilient to natural gas supply issues and pipeline contingencies due to natural gas storage availability, alternate electricity generation resources, and transmission system configuration.[33] Additional generation retirements are expected to aggravate reliability concerns in the WECC Region as regional demand on the existing gas supply infrastructure is further stressed.

[33] See *Western Interconnection Gas-Electric Interface Study*, p. 15: https://www.wecc.biz/Administrative/WECC%20Gas-Electric%20Study%20Public%20Report.pdf

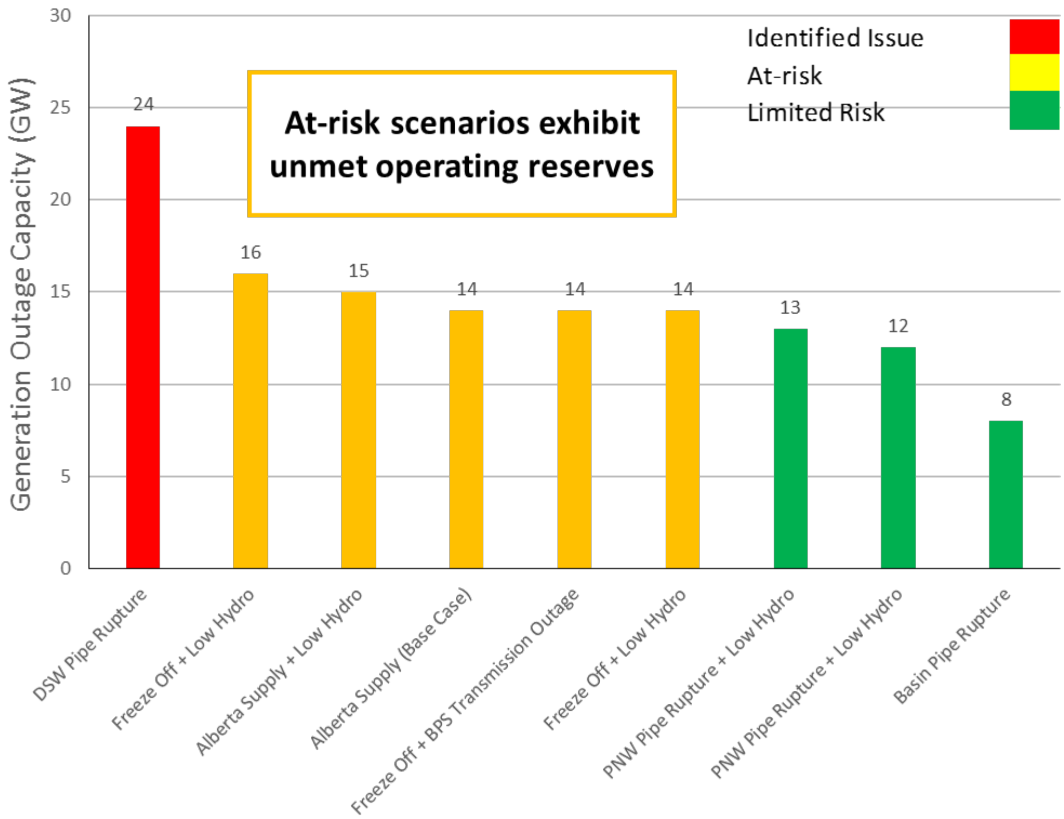


Figure 1.10 Outage Nameplate Capacity in Western Interconnection from Modeled Contingencies[34]

New England Operational Fuel-Security Analysis

Prolonged outages in energy infrastructure could potentially require emergency operating actions and impact winter BPS reliability in the New England area.[35] The effects would be exacerbated by high levels of generation retirements in most outage scenarios as analyzed by ISO-NE in its *Operational Fuel-Security Analysis*. The study examined BPS reliability in scenarios with high-impact events affecting energy facilities—some of which include disruption at key fuel supply infrastructure (e.g., outages of an interstate natural gas pipeline compressor stations or LNG import and regasification facilities). The impact on the BPS from season-long facility outages was assessed for a reference generation mix and for a case involving retirement of all fossil-fueled generation and replacement with additional renewable generation and area imports. The projected hours of load shedding for the 2024/2025 winter season due to prolonged outage scenarios is shown in **Figure 1.11**. Lengthy outages of LNG facilities that directly fuel nearby generators or inject into New England's pipeline system would reduce generation output and require electrical load shedding during the projected 2024/2025 winter season, and this load shedding would increase under higher retirement scenarios. Season-long outage of a natural gas pipeline compressor station could potentially cause the highest impact on BPS reliability—potentially up to 138 load-shedding hours over 17 days for the reference scenario.

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[34] See the *Western Interconnection Gas-Electric Interface Study*: https://www.wecc.biz/Administrative/WECC%20Gas-Electric%20Study%20Public%20Report.pdf

[35] See *Operational Fuel-Security Analysis*, ISO-NE, January 2018: https://www.iso-ne.com/static-assets/documents/2018/01/20180117_operational_fuel-security_analysis.pdf

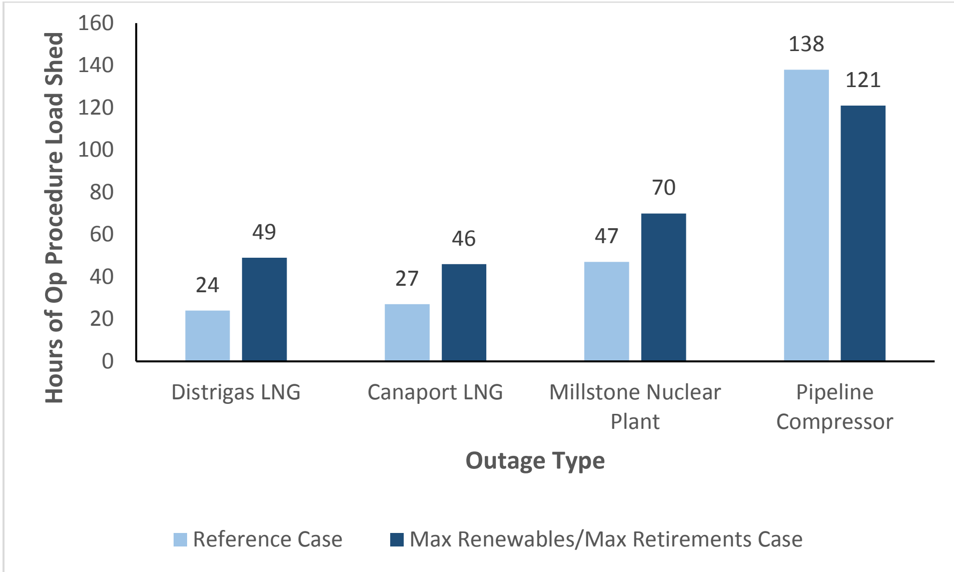

Figure 1.11 Projected Hours of Load Shedding in New England due to Season-Long Outages of Major Fuel and Energy Sources.[36]

Fuel assurance scenario analysis provides an important input into planning processes. Regional factors, such as natural gas infrastructure topology, load factors, and redundancy are a key consideration in determining the size of disruption that should be studied in resource planning. Previously, NERC recommended that industry consider the loss of key natural gas infrastructure in their planning studies, including extreme event analysis conducted as part of NERC Reliability Standard TPL-001-4.[37] Additionally, NERC initiated efforts with the electric and natural gas industries to develop guidelines for NERC entities to use for analyzing fuel supply disruptions and their potential impact on the BPS. Several fuel assurance assessments have already been completed by industry, or are underway, that help inform the development of industry guidance, practices, and potential future standards requirements. NERC and industry should continue to support these efforts to promote consistent criteria and effective practices for assessing fuel assurance and mitigating risks to the BPS from fuel supply impacts.

[36] See *Operational Fuel-Security Analysis*, ISO-NE, January 2018. Outage scenarios model the following facilities:

- A compressor station on a major natural gas pipeline, eliminating 1.2 Bcf/d and restricting fuel to about 7,000 MW of generation for the entire winter
- The loss of Millstone Nuclear Power Station in Connecticut, one of the area's remaining two nuclear stations, eliminating 2,100 MW of baseload power
- The loss of the Canaport LNG import and regasification facility in New Brunswick, eliminating as much as 1.2 Bcf/d that could be injected into the New England and Maritimes pipeline systems
- A disruption to the Distrigas LNG import facility in Massachusetts, eliminating all the natural gas that can fuel the nearby 1,700 MW Mystic 8 and 9 natural-gas-fired generators as well as 0.435 Bcf/d that can be injected by Distrigas into the Algonquin and Tennessee interstate natural gas pipeline systems and the local natural gas utility's distribution system

The reference case assume 1,500 MW of fossil-fuel generation retirements, 2,500 MW of area imports, and 6,600 MW of added renewable generation. In the high retirements case, fossil-fuel generation retirements increase to 5,400 MW (representing all area fossil-fuel generation resources). Imports increase to 3,500 MW, and renewable generation increases to 9,500 MW: https://www.iso-ne.com/static-assets/documents/2018/01/20180117_operational_fuel-security_analysis.pdf

[37] See NERC special reliability assessment *Potential Bulk Power System Impacts due to Severe Disruptions on the Natural Gas System*: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SPOD_11142017_Final.pdf

Key Finding
Replacement resources in the scenario are predominantly, but not exclusively, natural-gas-fired generation. Utility-scale wind and solar resources that are progressing through the interconnection queue are included as well. The natural-gas-fired generators are expected to provide the same, or at least adequate, levels of voltage support and frequency response as provided by the retiring resources. However, such a significant shift to natural-gas-fired generation could leave the BPS more vulnerable to natural gas supply and transportation disruption events or curtailments. If firm service and new pipeline capacity are not procured for these replacement resources, pipeline interruptions could impact fuel delivery to generators. Detailed analysis of natural gas infrastructure was not in scope for this assessment; however, additional midstream natural gas infrastructure could be required to meet the volumetric and flexibility needs of the electric sector in this scenario. Even with build out to accommodate increased pipeline capacity, policymakers should consider the potential for increased reliability risk from declining fuel diversity. This assessment assumes all planned new generation, including wind, solar, and nuclear will be built. Fuel diversity is an inherent means of providing resilience to the system by reducing BPS vulnerability to disruptions of any individual fuel type.

Chapter 2: Transmission Planning Studies

Two power flow studies performed by NERC entities are included in this chapter to illustrate how transmission system planning accounts for an accelerated generator retirement scenario and the impact that retirements can have on transmission system needs. Transmission planning studies reveal important information about system reliability that are not contained in reserve margin analysis. As generators retire in one location, power flow on the system may change in order to continue serving load with resources from other areas. In some cases, system planners need to accommodate power flow changes by upgrading the transmission system or by developing new procedures for generation dispatch that can avoid exceeding transmission system thermal or voltage constraints. The two studies in this chapter give an indication of potential transmission system needs that planners would address in order to prepare for generator retirements and still provide reliable system operation.

ERCOT Study of Texas Transmission System

ERCOT's 2016 Regional Transmission Plan included a transmission planning study of the potential impact of unplanned retirements of coal-fired generation.[38] ERCOT updated this study at NERC's request for the generator retirements assessment, removing 9,599 MW of coal-fired units (49.6 percent of ERCOT's 19,350 MW installed coal capacity). All generators depicted in **Figure 2.1** were deactivated for system study. Replacement generation was added to the case at locations shown in **Figure 2.2**.

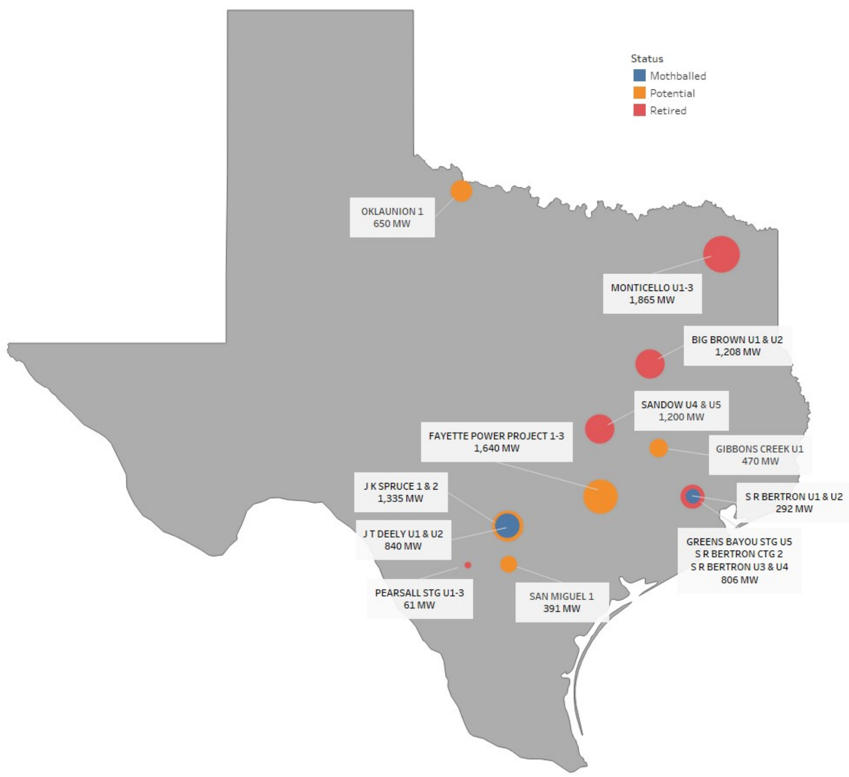

Figure 2.1 ERCOT Special Assessment Generation Retirement Map.

[38] See the 2016 Regional Transmission Plan and Long-Term System Assessment for ERCOT available here: http://www.ercot.com/news/presentations/2016

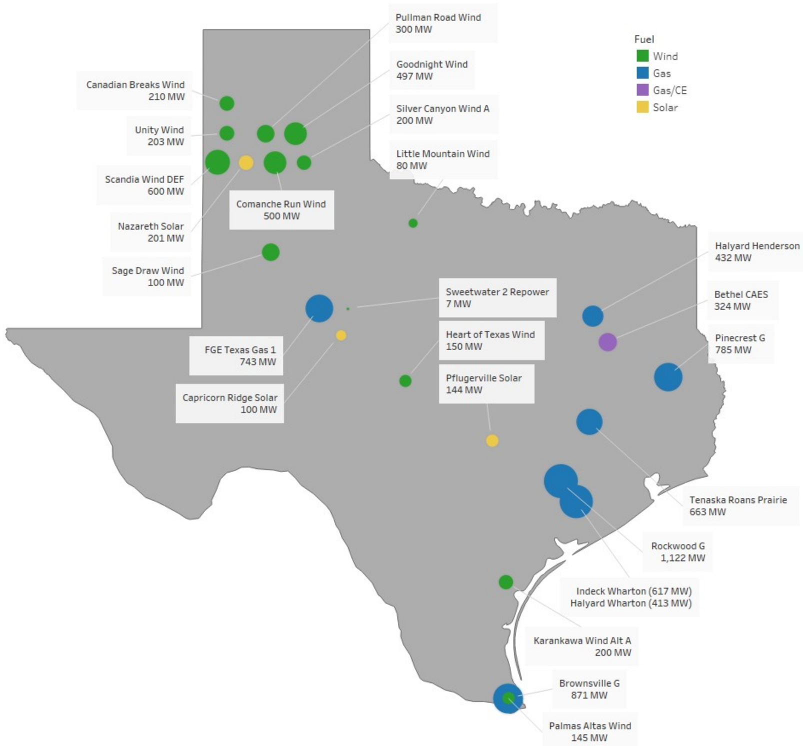

Figure 2.2 ERCOT Generation Addition Map

The ERCOT study examined transmission system performance under expected load conditions and normal transmission planning contingencies (e.g., the loss of a generator or a transmission line as a result of protective relay tripping). See **Appendix B** for a detailed discussion of the ERCOT study, including approach, assumptions, and methods. NERC entities are required to perform transmission planning studies annually at least, and more frequently when system configuration or conditions are changing, to ensure the system meets an established level of reliability. The study results are depicted in **Figure 2.3** and show that, with the retirement of the generators in consideration by the study, more than 124 circuit-miles of 345-kV transmission lines would experience thermal overloads as a result of the transmission planning contingencies. Additionally, 12 circuit miles of 138-kV transmission lines would experience thermal overload during studied electrical system contingencies.

Thermal overloads, such as those identified in the ERCOT generator retirement study, must be addressed prior to generator retirements to ensure the BPS can be operated within established performance criteria for normal and contingency conditions. A thermal overload is a condition where electrical currents exceed facility design criteria, resulting in the potential for tripping, disruption of electrical service, and potential equipment damage. In order to retire the proposed generators, entities could be required to upgrade identified circuits with higher capacity equipment (e.g., lines, breakers, switches) or new system configurations can be developed with added circuits that alleviate overloads. Other transmission system configuration changes or operating measures may be available to plan the system so that it can be operated within established thermal transmission limits.

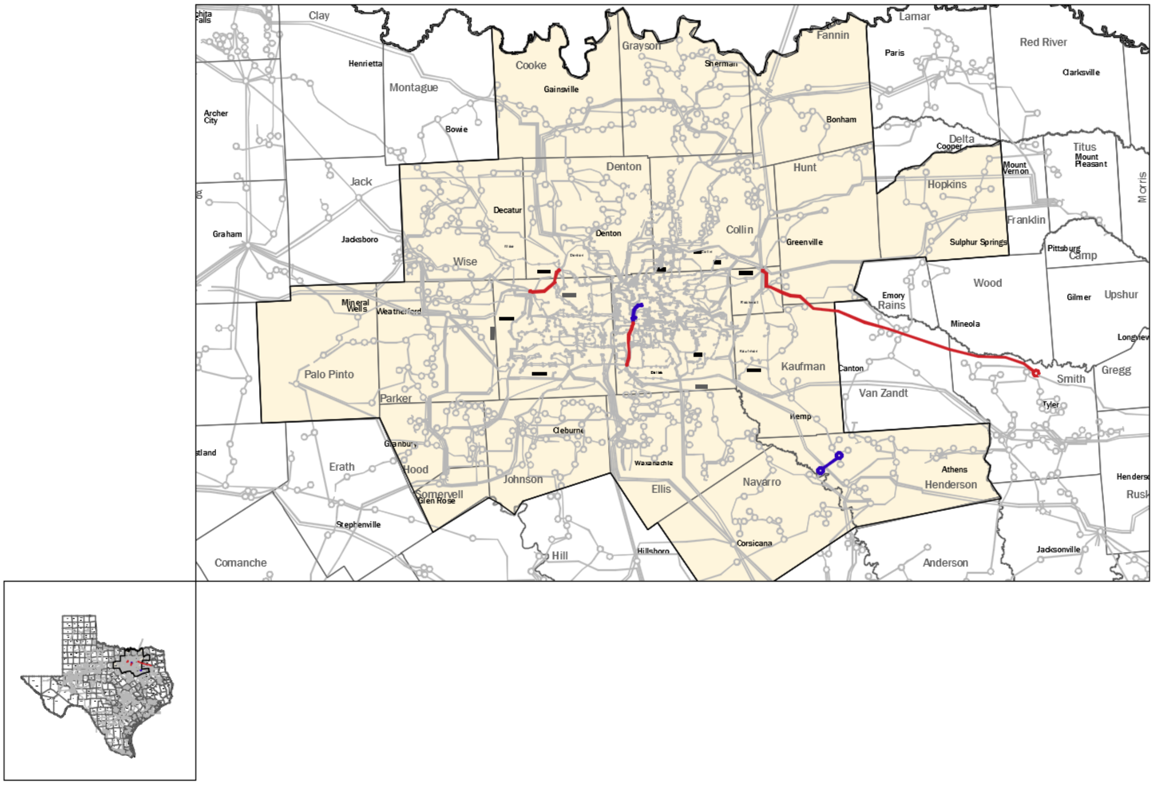

Figure 2.3: ERCOT Study—Thermal Violation Map

These results are representative of transmission system upgrades that may be needed in order for the proposed generator retirements to move forward.

PJM Area Transmission System Study

Transmission planning analysis was performed on the PJM area transmission system by PSE&G with extreme generator retirement scenario conditions. The study involved the proposed deactivation of all coal-fired and nuclear generators within the 13-state regional footprint of the system. Generation retirement locations for the PJM system study are shown in **Figure 2.4**. These retiring generators were replaced with natural-gas-fired generation from PJM's interconnection queue as shown in **Figure 2.5**. Because a sufficient quantity of resources was not available within the interconnection queue to replace all of the deactivated generation in the scenario, some additional natural-gas-fired generation was required to be added. These additions represent additional generating capacity expansion beyond what is currently being planned that would be required to maintain resource adequacy. See **Appendix C** for a detailed discussion of the PSE&G study, including approach, assumptions, and methods. The PJM transmission system study can be considered more extreme than the ERCOT study due to the significant capacity of retirements.

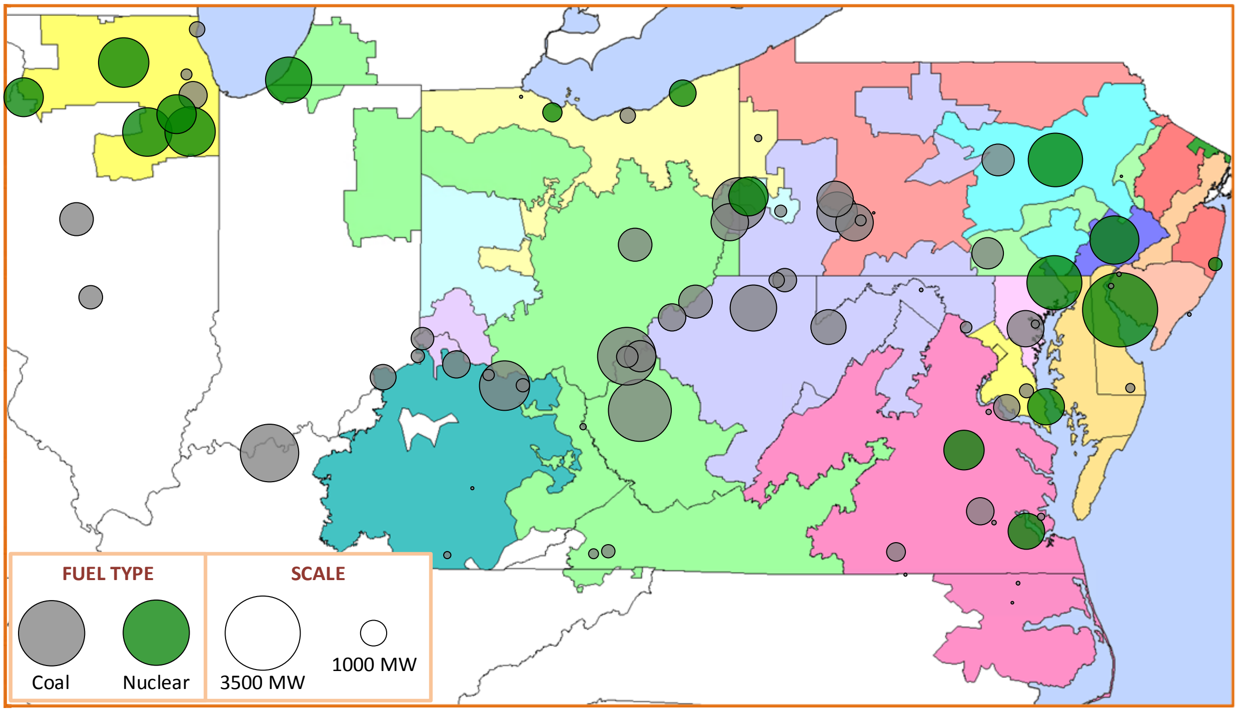

Figure 2.4: Coal-fired and Nuclear Generation in PJM Area

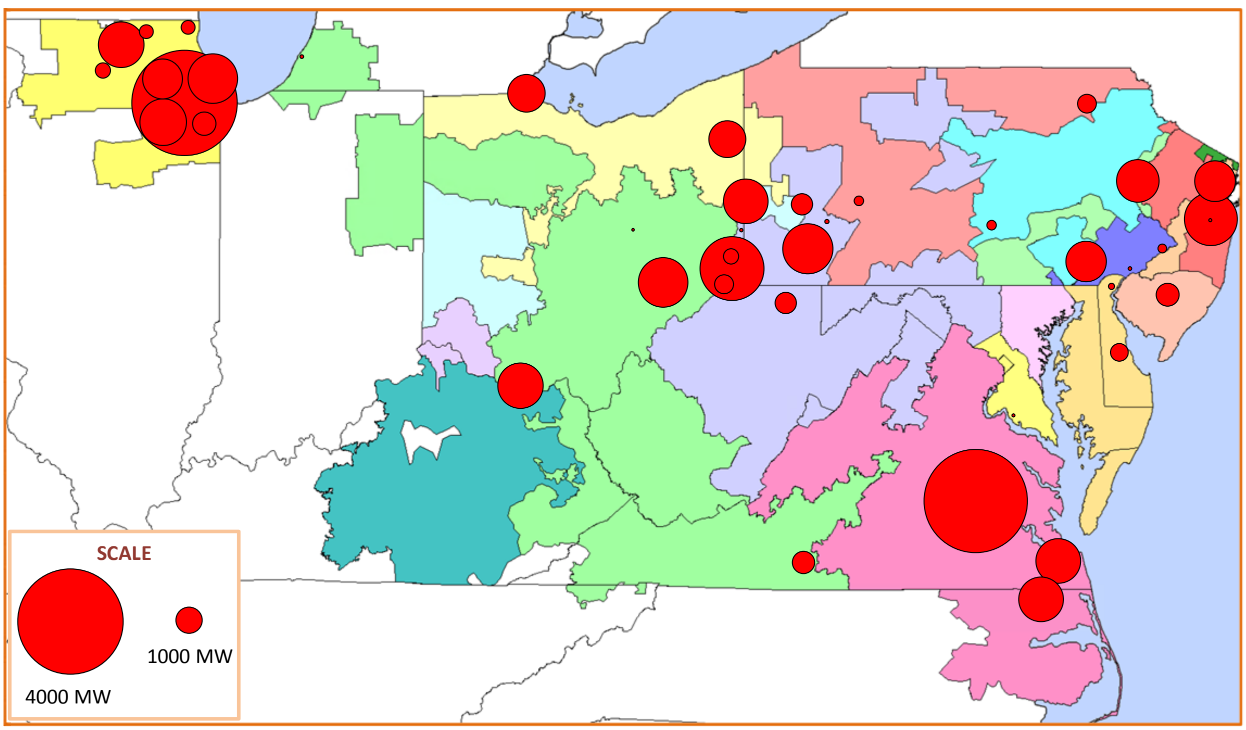

Figure 2.5: Replacement Natural Gas-Fired Generation Locations

The study results, depicted in Figure 2.6, show that, with the proposed retirement of the generators in consideration for this study, multiple thermal overloads would need to be addressed in 230 kV, 345 kV, and 500 kV transmission networks. Additionally, some studied contingencies resulted in unacceptable voltage or power flow performance, which would also need to be addressed to prevent local voltage issues or more severe BPS instability.

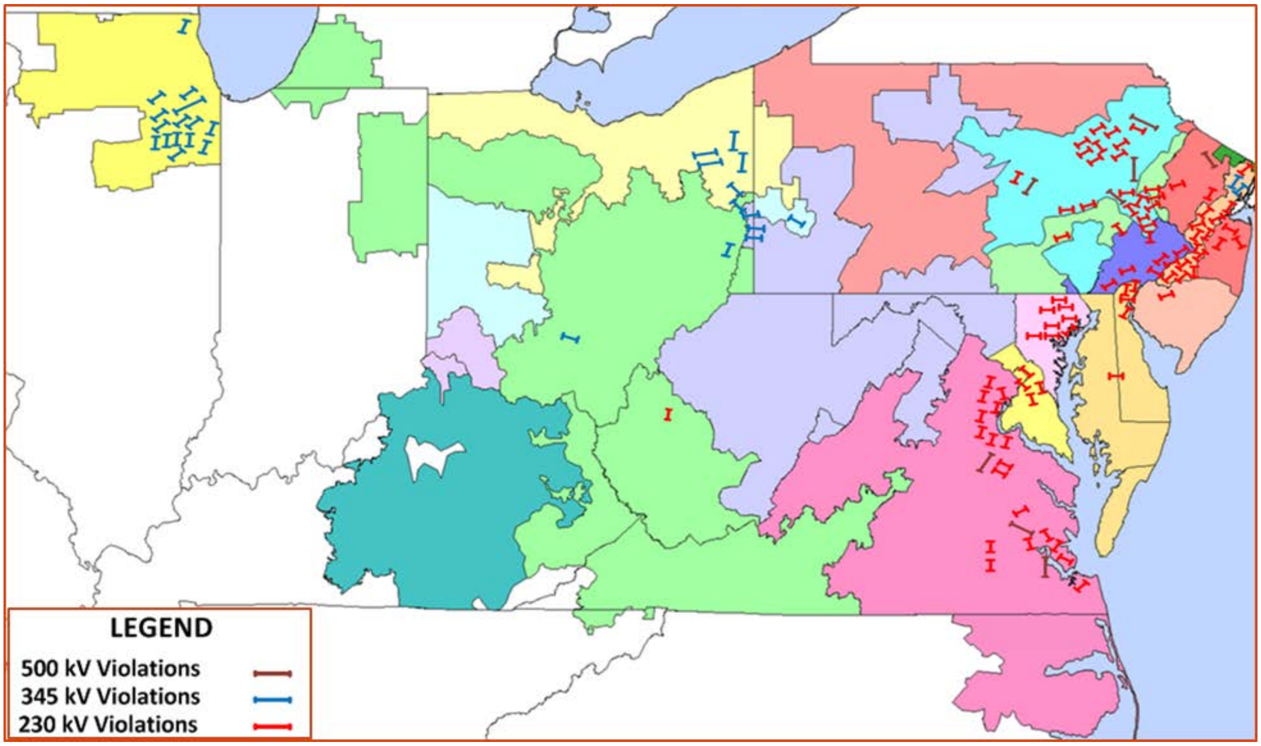

Figure 2.6: Location of Thermal Violations in Studied Case Summer 2022

Like the ERCOT study, the study of the PJM-area performed by PSE&G illustrates the type of transmission system upgrades that could be needed to address an accelerated retirement scenario and that the system reinforcements could be extensive. Specific transmission system needs, alternatives, and decisions are developed using rigorous transmission planning processes.

Key Finding

Transmission planning studies performed for this stress-test scenario found that BPS transmission system reinforcements, generation dispatch requirements, and new operating procedures would be needed to support generator retirements and replacements to maintain reliability criteria. Large amounts of generator retirements within a short time frame could result in extensive transmission network upgrade requirements that may not currently be included in transmission expansion plans. As electric transmission is very time consuming to design, site, and permit, transmission planners and operators must be prepared to use various mechanisms, either in- or out-of-market, and could include steps to delay generator retirements until these transmission upgrades are completed.

Chapter 3: Processes for Managing Generator Retirements

Regulatory structures and resource planning processes are important factors in determining the timing and location of generator retirements. In the same way, these factors affect how generator retirement risks are identified and mitigated. Processes to plan for generator retirements vary across the North American BPS depending on regulatory and wholesale market structures and regional policies. In some parts of the grid, ISOs and RTOs are responsible for planning and coordinating among regulated utilities, merchant generators, and private transmission owners for the introduction of new generation, the deactivation of existing generation, and other infrastructure changes that are needed to ensure the reliability of the grid and successful operation of wholesale markets. Elsewhere, vertically integrated utilities are largely responsible for developing generation and transmission plans within their jurisdiction and obtaining approval from state or provincial regulators. The variations in regulatory and market structures result in diverse mechanisms, approaches, and responsibilities across the North American BPS.

Many states and provincial authorities have established requirements to maintain necessary amounts of generation resources to meet anticipated demand. In these jurisdictions, resource planning and generator retirement decisions must be approved by regulators or other governmental agencies. Areas with specific integrated resource planning or regulated capacity requirements may present lower risk—as this regulation can prevent generator retirements from occurring before suitable replacement resources have been built to maintain resource adequacy.

ISO/RTO Area Mechanisms

Deactivation Notification: ISO and RTOs require GOs to notify them of intent to deactivate generators a minimum of 90–180 days (timelines vary by ISO/RTO). Generator deactivation processes provide a period for ISO/RTO planners to evaluate the generator retirement for adverse impacts to BPS reliability and to develop mitigation plans. In some ISO/RTO areas, other market participants are invited to comment on reliability impacts of the planned retirement. Transmission system upgrades that are needed to accommodate the generator retirement are added to transmission expansion plans per the RTO or ISO processes.

Reliability Must Run: When the ISO or RTO determines that a unit planning to retire is needed for reliability, and no other solutions are readily available within the specified time frame, it may seek an RMR agreement with the GO. These agreements are not intended to be long-term, but rather they could provide a stop-gap measure while necessary transmission system upgrades are designed, permitted, and constructed. GOs may be offered financial incentives based on their estimates of eligible costs to continue to operate under terms specified in the RMR. Typical costs that may be considered include (but are not limited to) labor, materials and supplies, operations and maintenance costs to continue operating, and taxes. The offer of an RMR does not assure the delay in the planned retirement—as parties may fail to reach RMR agreement. RMR contracts typically are limited to covering fuel and operating and maintenance costs and might not be sufficient to incentivize an owner to maintain operations that are needed for reliability.

Capacity Market: Many ISOs and RTOs operate a forward capacity market (FCM), which obtains longer-term commitments (one to three years) for resource capacity needed to ensure reliability. The FCM provides market signals that stimulate investment both in maintaining existing generation and in encouraging the development of new resources, which can include new generating plants, demand response, and energy efficiency programs. FCM commitments provide planners with anticipated resource quantities and locations for use in resource adequacy assessments and long-range transmission planning studies. Capacity resources may also provide advanced notification of plans to retire (e.g., three-plus years). Additionally, some RTOs and ISOs have further enhanced their capacity market to include incentives for performance and penalties for non-performance during stressed conditions.

Regulated Utilities: The generation fleet serving the RTO area may include both merchant generation and generation from traditionally regulated utilities. In states and provinces with traditionally regulated utilities, generator retirement decisions are part of the regulatory process. Regulators and utilities in these areas evaluate impacts and approve utility generator retirements within the regulated jurisdiction in addition to deactivation processes specified by the RTO. The regulatory process can provide oversight in addition to ISO/RTO mechanisms that further reduces the potential for utility generator retirements to impact reliability. It can also provide RTO planners with additional lead-time above deactivation notification timelines to consider future system needs resulting from potential utility generation retirements.

Table 3.1 highlights some features of the generator deactivation processes in ISO and RTO areas shown in Figure 3.1.

Table 3.1: ISO and RTO Planning Process Summary	
ISO/RTO Area	**Process Features Affecting Generator Retirements**
PJM	• Retirement notifications are required at least 90 days in advance. • PJM notifies the GO within 30 days of identified reliability concerns and provides an estimate of time frame sought for continued operation. • Within 60 days of deactivation request, the GO provides response to a request for continued operation. • Within 90 days of deactivation request, PJM posts necessary transmission upgrades to address reliability impacts of the generator retirement on its transmission planning website. • When needed for reliability and agreed to by the GO, PJM negotiates RMR agreements with the GO according to the cost recovery option in the PJM Tariff. • A FCM is operated to procure resource adequacy three years ahead with incremental auctions conducted at least three times prior to the delivery year to account for changes in demand and supply side assumptions.
ERCOT	• Retirement notifications are required at least 150 days before discontinuing operations. • ERCOT has 60 days to assess impacts. • If a reliability need is found, ERCOT has an additional 90 days to enter an RMR agreement, contract with another party to provide an alternative solution to address the need, or identify a suitable operational solution to mitigate the reliability issue. • ERCOT does not operate a capacity market. The energy-only market includes scarcity prices that can go as high as $9,000/MWh with reserve price adders to incentivize development of new generation. The Texas Public Utility Commission monitors the effectiveness of the incentives.

Table 3.1: ISO and RTO Planning Process Summary	
ISO/RTO Area	**Process Features Affecting Generator Retirements**
Midcontinent ISO	• Retirement notifications are required at least 26 weeks prior to retirement effective date. • MISO conducts an annual survey of market participants to capture future resource adequacy projections. • Many generator resources in the MISO area come from state-regulated utilities that are included in state resource planning. • A capacity market is operated annually to demonstrate resources are available to reliably operate the electric system over the next planning year. However, the market is not the primary means for providing resource adequacy. Load-serving entities are required to procure sufficient capacity for anticipated load, either through the market, bi-lateral agreement, or self-supply. • Like an RMR, MISO may enter into a temporary system support resource service agreement with generation resources that are planning to retire but are needed to remain in operation to maintain reliability of the BPS.
Ontario Independent Electric System Operator (IESO)	• Retirement notifications are required six-months in advance. • IESO regularly produces long-term (20-year) and short term (18-month) outlooks of electricity demand, conservation, supply, and transmission. As part of the IESO's commitment to open and transparent planning, the IESO will publish a five-year reliability outlook twice a year starting December 2019 focused on resource adequacy. • Market participants who wish to de-register their facilities are required to file a notice of request to de-register with the IESO. If the IESO's technical assessments of this request conclude that de-registration would affect the local reliability of the IESO-controlled grid, the IESO may enter a Reliability Must Run contract. • IESO's outlooks have been used to inform procurements and have successfully ensured the supply adequacy of Ontario. IESO is developing a market-based mechanism for acquiring incremental generation resources in the future, including a capacity market.
ISO-NE	• ISO-NE operates an FCM annually to procure capacity resources three years in advance. • Generator retirements are processed through the FCM, providing three-year advance notice of plans for retirement.
California ISO	• Retirement notifications are required 60 days in advance. • An RMR unit can be designated by CAISO to meet unmet reliability need. • California ISO operates a year-ahead and month-ahead resource adequacy program for procuring capacity for load-serving entities.

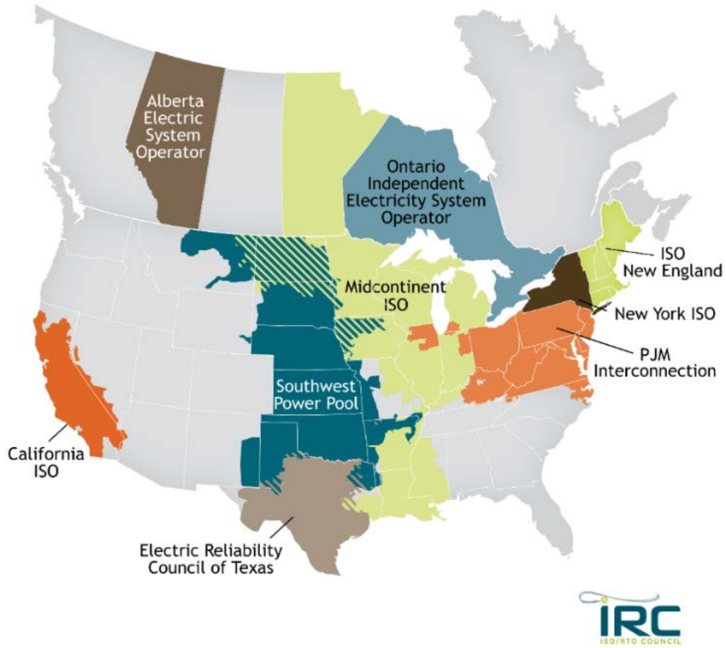

Figure 3.1: ISO/RTO Areas

Non-RTO Areas

The southeast and western parts of the United States (with the exception of the California and Nevada areas within California ISO) do not operate ISO/RTO markets. In these areas, electric utilities develop integrated resource plans and submit them to state regulators. The plans identify long-range demand expectations and resource needs, including planned generation additions and retirements. Generator retirements are subject to public service commission approval and/or decertification, and they are planned with transmission entities to ensure reliability criteria are considered in decision process. These regulatory provisions for resource and transmission system adequacy can reduce risks from generation retirements.

Key Finding

Various processes, mechanisms, and backstops are in place to manage generator retirements:

In many states and provinces, for example, retirements go through the same integrated resource planning processes that are used to permit new additions. The states and provinces have the ability to control the pace of transition from older generation to new.

Market areas are more complex but have various tools such as forward capacity markets (FCMs), regional transmission expansion processes, market-based mechanisms and tools (e.g., demand response, conservation and efficiency initiatives), and/or temporary out-of-market actions that can all support challenges arising from unexpected retirements in organized market areas. Reliability-must-run (RMR) agreements are an example of an out-of-market action that system operators can pursue to retain needed, but otherwise uneconomic, capacity to address identified reliability issues. Where implemented by tariff, RMRs provide ISOs and RTOs with a mechanism for providing temporary added financial incentives to generator units that are planned for retirement but needed for reliability. The key concern with the tools in market areas is that they provide economic incentives and signals to uneconomic units that are needed for reliability. The efficacy of those signals should be tested to ensure that they are delivering the desired outcomes. For example, a three-year forward capacity market might be inadequate to secure longer term supply; similarly, RMR contracts typically only cover fuel and operating and maintenance costs and might not be sufficient to incentivize an owner to maintain operations that are needed for reliability.

Conclusion

The stress-test scenario provides valuable insight about risks to the BPS that could arise if the pace of desired retirements is accelerated. From these insights, NERC developed recommendations to help address reliability concerns:

- **Review Planning Processes and Market Mechanisms to Mitigate Reliability Risks:** In wholesale electricity market areas, market operators should assess whether existing tools are adequate to manage significant levels of generation retirements. New mechanisms should also be explored if necessary, such as new market constructs that value resources differently or new out-of-market solutions that can control the pace of generation retirements when needed. Additionally, RTOs and ISOs should evaluate the efficacy of their existing tools to ensure that the retirement pace is managed consistently with the development of any needed supplemental transmission or fuel infrastructure. In regulated utility areas, the integrated resource planning process and mandatory resource adequacy requirements likely mitigate reliability risks; however, these processes should explicitly consider fuel diversity and fuel infrastructure adequacy to the extent they currently do not.
- **Incorporate Fuel Assurance Analysis in Generator Retirement Processes:** Transmission and resource planners should incorporate fuel assurance analysis in generator retirement assessments. Fuel supply contingency scenarios used in system planning studies should be developed or adapted for assessing the potential impact of generator retirements as part of generator retirement planning and approval processes. Fuel assurance analysis should consider specific regional fuel mixes, fuel supply infrastructure, new infrastructure requirements for replacement resources, and contractual provisions that govern fuel delivery (i.e., firm vs. non-firm). In a previous assessment, NERC recommended that industry consider the loss of key natural gas infrastructure in their planning studies, including extreme event analysis conducted as part of NERC Reliability Standard TPL-001-4.[39] Additionally, NERC has initiated efforts with both the electric and natural gas industries to develop guidelines for NERC entities to use for analyzing fuel supply disruptions and their potential impact on the BPS; this should continue.
- **Provide Regulatory Flexibility to Respond to Changing Infrastructure Needs:** Regulators and policymakers should consider ways to expedite regulatory and environmental permitting processes for transmission upgrades and energy infrastructure. When a generator’s planned retirement is delayed to allow for completion of transmission system upgrades, expedited regulatory proceedings can help minimize the delay. Where more natural gas generation is needed, more natural gas pipeline capacity will likely also be needed. As in past studies, NERC encourages regulators to support and approve the construction of new natural gas pipeline and storage capacity to meet electric generation needs as well as capabilities for back-up liquid fuels to manage extreme conditions or fuel disruptions.

While the stress-test scenario was applied to only certain areas, stakeholders in all areas should be aware of the potential consequences of generation retirements and take steps to manage the pace as dictated by local conditions. This assessment should not be interpreted to mean the BPS cannot be operated reliably given the change in the generation resource mix; rather, NERC’s scenario reaffirms that risk-informed planning and existing tools can assure continued reliability of the BPS while managing evolutionary changes to the generation resource mix. The pace of the current change creates potential challenges to reliability that must be understood and addressed.

Successfully managed, the changing resource mix can provide positive outcomes including potential benefits to reliability and security of the BPS. Less reliance on large, centralized generation stations and greater use of dispersed

[39] See NERC Special Reliability Assessment *Potential Bulk Power System Impacts due to Severe Disruptions on the Natural Gas System:* https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SPOD_11142017_Final.pdf

networks comprised of smaller diversified generation resources can provide operating and planning flexibility. Additionally, some fuel assurance risks diminish with the changing resource mix: the effects of adverse weather on coal stockpiles or fossil fuel resupply infrastructure may be reduced when natural gas pipelines supply a greater proportion of the generating fleet. Attaining reliability enhancements associated with the changing resource mix is possible when the different challenges to fuel assurance and ERSs are addressed.

The BPS has gone through many changes over the years, and each change requires adaptation, education, and continuous learning. As required by Section 215 of the Federal Power Act, NERC as the ERO shall conduct periodic assessments of the reliability and adequacy of the BPS. These independent assessments provide insights into the possible, so stakeholders and policymakers can address emerging issues. NERC takes its job of assuring the reliability of the North American BPS seriously and will continue to identify and analyze reliability trends, evaluate events and issues, and work with stakeholders to assess and reduce risks to the present and future grid.

Appendix A: Detailed Results of Resource Adequacy Analysis

Table A.1: Detailed Results of Resource Adequacy Analysis—Reference Case (2022)											
		Confirmed Retirements		Resources (MW)							
Area	Reference Margin	Coal Retirements	Nuclear Retirements	Gas (Existing)	Gas (Tier 1)	Coal	Nuclear	Other Gen	Other Resource	Net Internal Demand (MW)	Planning Reserve Margin
MISO	15.8%	6,936	810	56,591	3,622	57,792	11,955	10,218	611	122,666	14.8%
NPCC New England	16.9%	0	671	13,530	2,617	917	3,331	10,410	89	25,747	20.0%
NPCC New York	15.0%	0	2,042	16,490	784	1,011	3,334	16,333	2,256	32,140	25.1%
PJM	16.6%	5,186	5,374	63,395	14,128	54,432	28,620	25,202	1,786	147,256	27.4%
SERC-E	15.0%	4,753	0	20,409	2,254	17,384	8,653	5,051	338	47,118	14.8%
SERC-SE	15.0%	0	0	30,269	100	18,979	8,018	6,709	-1,541	46,014	35.9%
SPP	12.0%	880	0	31,813	404	23,439	1,943	9,144	-81	53,116	25.5%
Texas RE-ERCOT	13.8%	0	0	46,568	3,883	14,696	4,981	8,088	520	75,240	4.6%
WECC-RMRG	14.2%	536	0	6,468	352	8,994	0	2,277	-2,721	12,662	21.4%
WECC-SRSG	15.8%	0	0	16,293	510	8,964	3,937	2,836	-1,907	25,168	21.7%

Table A.2: Detailed Results of Resource Adequacy Analysis—Generation Retirement Scenario (2022)											
		Scenario Retirements (MW)		Resources (MW)							
Area	Reference Margin	Coal Retirements	Nuclear Retirements	Gas (Existing + Tier 1)	Gas (Tier 2)	Coal	Nuclear	Other Gen	Other Resource	Net Internal Demand (MW)	Planning Reserve Margin
MISO	15.8%	17,337	5,380	60,213	11,509	40,454	6,575	22,920	343	122,666	15.8%
NPCC New England	16.9%	273	0	16,148	0	644	3,331	10,410	89	25,747	18.9%
NPCC New York	15.0%	303	0	17,274	0	707	3,334	16,333	2,256	32,140	24.2%
PJM	16.6%	16,330	13,018	77,523	13,484	38,103	15,602	25,202	1,786	147,256	16.6%
SERC-E	15.0%	5,215	3,894	22,663	0	12,169	4,759	5,051	338	47,118	-4.5%
SERC-SE	15.0%	5,694	2,200	30,369	0	13,286	5,818	6,709	-1,541	46,014	18.7%
SPP	12.0%	7,032	770	32,217	0	16,407	1,173	9,547	-81	53,116	10.8%
Texas RE-ERCOT	13.8%	4,409	0	50,451	11,015	10,287	4,981	8,332	520	75,240	13.8%
WECC-RMRG	14.2%	2,698	0	6,820	0	6,296	0	2,277	-2,721	12,662	0.1%
WECC-SRSG	15.8%	2,689	1,313	16,803	1,000	6,275	2,624	2,893	-1,907	25,168	10.0%

Appendix B: ERCOT Planning Study

The *May 2018 ERCOT Planning Study of Generation Retirements* is included in the following pages.

ERCOT Generation Retirement NERC Study

Version 1.0

Document Revisions

Date	Version	Description	Author(s)
05/02/2018	1.0	Final Draft	Ping Yan, Naga Kota, Minnie Han
		Reviewed by	Jeff Billo

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1. Introduction

In October 2017, generation resource owners in the ERCOT region filed “Notices of Suspension of Operations” to retire more than 4000 MW of generation by the first quarter of 2018. In the 2018 Long-Term System Assessment (LTSA) Current Trends scenario, the ERCOT model showed that an additional approximately 4500 MW of coal plants may potentially retire by the end of 2020 due to economic reasons. Counting the recently retired or mothballed units (including those that retired or mothballed earlier in 2017) together with the coal units that may potentially retire as identified in the ERCOT 2018 LTSA model, ERCOT has 1159 MW of gas generators and 9599 MW of coal units (49.6% of its 19350 MW installed coal capacity) that were operational in early 2017 but could retire/mothball by the end of 2020.

ERCOT Transmission Planning Assessment performed this special assessment per NERC request to understand the potential impacts of this accelerated coal generation retirements on ERCOT BES transmission reliability. ERCOT performed a similar analysis as part of its 2016 Regional Transmission Plan (RTP)[1]. The results of the 206 study showed that most of the transmission issues caused by the accelerated retirement of coal generation were located in the North/ North Central region with approximately 178 circuit-miles of 345-kV lines and 23 circuit-miles of 138-kV lines post-contingency overloaded.

The locations of the retired/mothballed and potentially retired generators are illustrated in the map below.

[1] http://www.ercot.com/news/presentations/2016

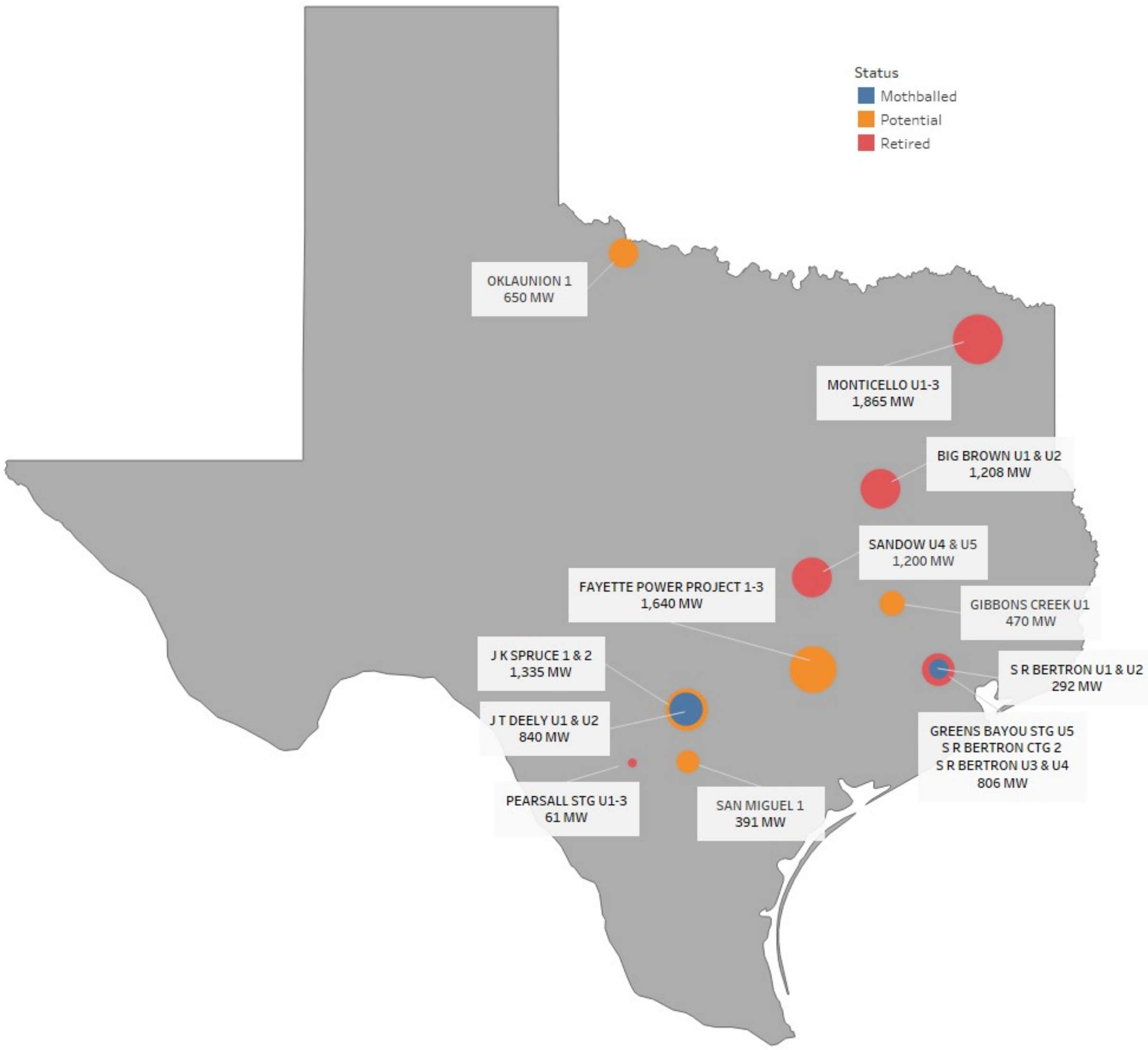

Figure 1.1: ERCOT Special Assessment Generation Retirement Map

2. Study Case and Assumptions

Based on ERCOT's past experience, summer peak operating conditions impose the most challenges to transmission system reliability. The results from the previous analysis performed as part of the 2016 RTP showed that most of the transmission system issues caused by the accelerated retirement of coal generation were located in the North/ North Central region. Therefore, this study focused on summer peak conditions in the North/ North Central region of the ERCOT system.

The final 2023 North/North Central Summer Peak case from the 2017 RTP was used as the base case in the study. The load forecast used in the RTP summer peak cases is conservative at 90th percentile for the study region. Unless otherwise noted, all assumptions used in this study are consistent with 2017 RTP[2]. The following modifications were made to the selected base case to create the study case.

A. All the retired/mothballed/potentially retired generators were taken offline if not already offline in the case. The list of these generators can be found in Table 1 and Table 2 in the Appendix.
B. The generation and load imbalance that resulted from step A was then addressed by following the steps described below:
    i) The wind and solar generators in all weather zones were dispatched based on the summer peak average capacity contribution as reported in the December 2017 Capacity, Demand, and Reserves (CDR) report.[3] The coastal wind[4] generators were dispatched at 59% of their installed capacity, and the non-coastal wind generators were dispatched at 14% of their installed capacity. All the solar generators were dispatched at 75% of their installed capacity.
    ii) ERCOT added any new generators that have met the conditions of ERCOT Planning Guide Section 6.9, Addition of Proposed Generation to the Planning Models, if they were not already included in the base case. ERCOT Planning Guide Section 6.9 conditions for adding a generator to the Planning Models include the following:
        - Has Standard Generation Interconnection Agreement (SGIA)
        - Has provided full financial commitment
        - Has given the Transmission Service Provider (TSP) notice to proceed
        - Has obtained an air permit and provided certification of access to cooling water supplies (for conventional generators only)

        The wind and solar generators added in this step were dispatched in the same way as step i.
    iii) ERCOT then added other generators in the interconnection queue with only an SGIA that have not met other ERCOT Planning Guide Section 6.9 conditions as discussed above. For conventional generators, only generators with an air permit were added. The Point of Interconnection (POI) and installed capacity of the generators were based on the SGIA. The wind and solar generators added in this step were dispatched in the same way as step i.

    The list of generators added in steps ii and iii can be found in Table 3 and 4 of the appendix. The locations of the generators added in step iii are illustrated in the following map.

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[2] http://www.ercot.com/news/presentations/2017

[3] http://www.ercot.com/content/wcm/lists/143977/CapacityDemandandReserveReport-Dec2017.pdf

[4] The coastal wind region comprises the following 11 Texas counties along the southern Gulf Coast: Cameron, Willacy, Kenedy, Kleberg, Nueces, San Patricio, Refugio, Aransas, Calhoun, Matagorda, and Brazoria. The non-coastal region consists of all other counties in the ERCOT Region.

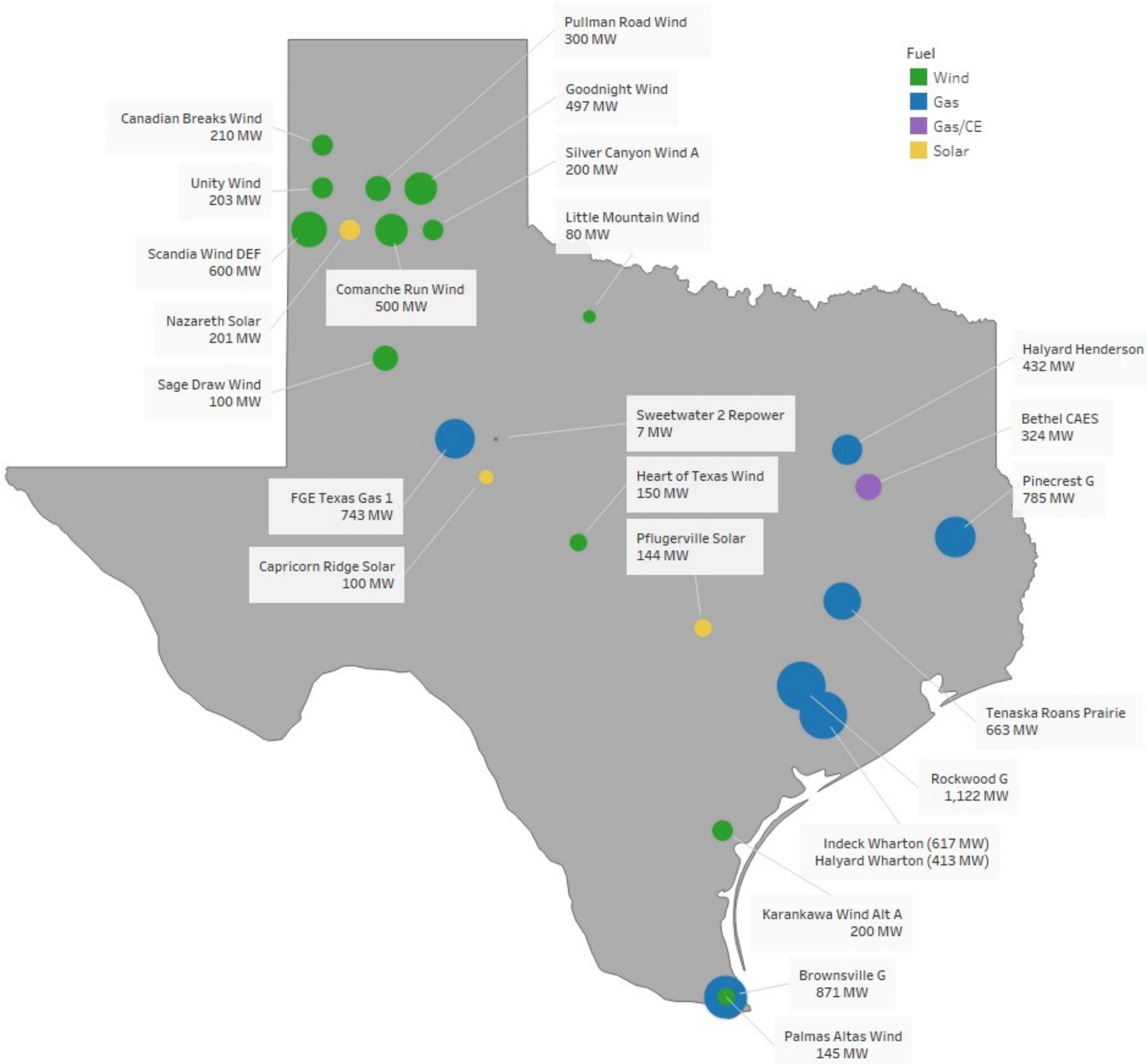

Figure 2.1: ERCOT Generation Addition Map with SGIA Only

3. Study Criteria and Methodology

The study region was defined as the North and North Central weather zones in the ERCOT footprint.

ERCOT evaluated all P0, P1, P2-1, P7 and selected P3 contingencies.

For thermal limits, ERCOT monitored all transmission lines and transformers (excluding generator step-up transformers) 100-kV and above in the study region:

- Rate A under pre-contingency conditions
- Rate B under post-contingency conditions

For voltage criteria, ERCOT monitored all buses 100-kV and above in the study region to ensure that they did not exceed their pre-contingency and post-contingency limits.

4. Study Results

The study results showed that there are 124 circuit-miles of 345-kV transmission lines post-contingency overloaded, and another 12 circuit-miles of 138-kV transmission lines post-contingency overloaded. The location of the overloaded lines can be found in the following map, and the detailed summary of the thermal violations can be found in Table 5 of the Appendix. ERCOT did not observe any voltage criteria violations.

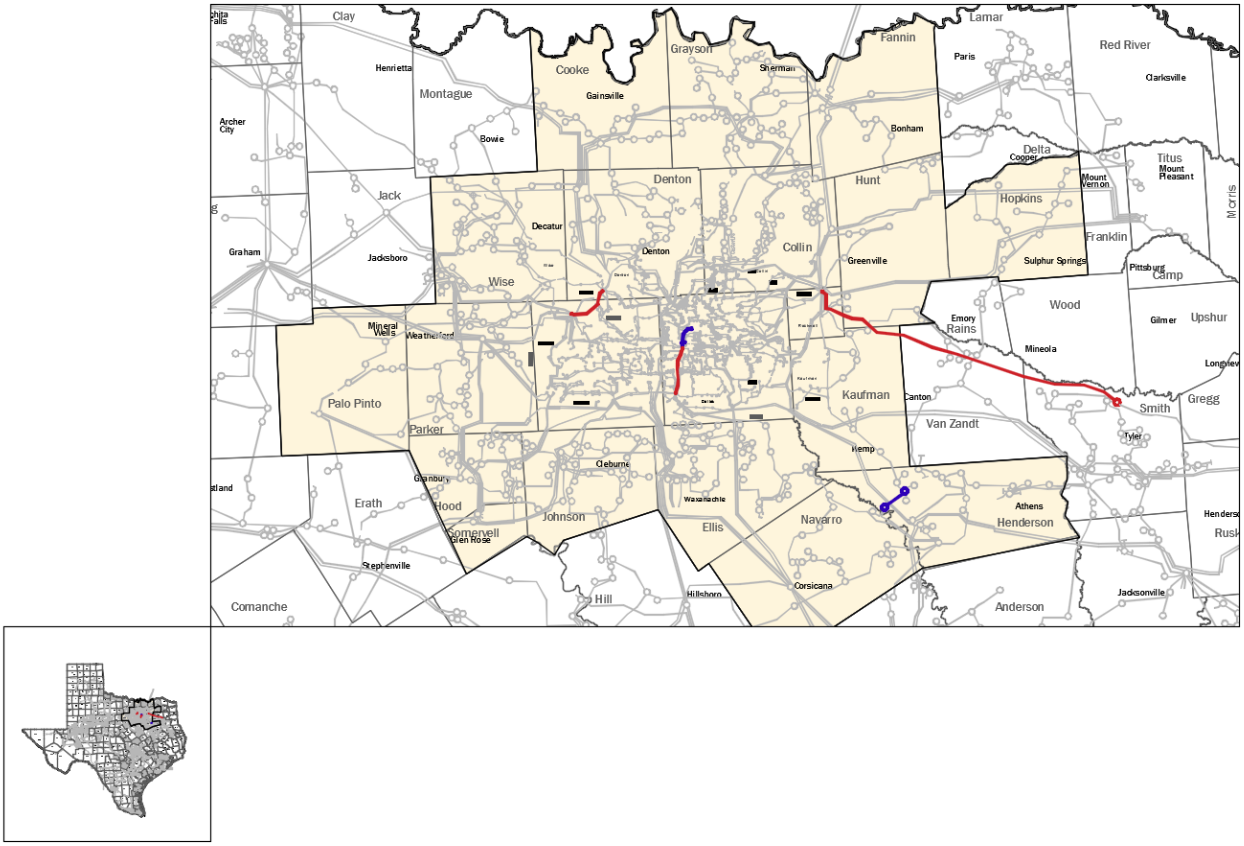

Figure 4.1: Thermal Violation Map

5. Observations

The results of this study are consistent with similar analysis that was performed as part of the 2016 RTP. A detailed analysis of potential transmission system improvement alternatives was not conducted for this assessment, but some of the overloaded facilities are currently single circuit transmission lines constructed on double circuit towers. It may be possible for these overloads to be relieved by adding the second circuit to the transmission towers. ERCOT also observed that some of the overloads may be driven by assumed gas generation additions. Therefore, it is possible that these overloads may not occur if generation additions occur in different locations. Lastly, the results showed that the highest overload was 105%, which was on an approximately two-mile long 138-kV line.

6. Appendix

Table 1: Generation units that have recently filed for Notice of Suspension of Operations

Unit	Capacity (MW)	Status	Fuel
J T DEELY U1	420.0	Mothballed	COAL
J T DEELY U2	420.0	Mothballed	COAL
BIG BROWN U1	606.0	Retired	COAL
BIG BROWN U1	602.0	Retired	COAL
MONTICELLO U1	535.0	Retired	COAL
MONTICELLO U2	535.0	Retired	COAL
MONTICELLO U3	795.0	Retired	COAL
SANDOW U4 - PUN	600.0	Retired	COAL
SANDOW U5	600.0	Retired	COAL
S R BERTRON U1	118.0	Mothballed	GAS
S R BERTRON U2	174.0	Mothballed	GAS
GREENS BAYOU STG U5	371.0	Retired	GAS
S R BERTRON CTG 2	13.0	Retired	GAS
S R BERTRON U3	211.0	Retired	GAS
S R BERTRON U4	211.0	Retired	GAS
PEARSALL STG U1	19.0	Retired	GAS
PEARSALL STG U2	22.0	Retired	GAS
PEARSALL STG U3	20.0	Retired	GAS

Table 2: Coal units retired by models used in 2018 LTSA Generation Expansion Process

Unit	Capacity (MW)	Status	Fuel
FAYETTE POWER PROJECT 1	604.0	Potential	COAL
FAYETTE POWER PROJECT 2	599.0	Potential	COAL
FAYETTE POWER PROJECT 3	437.0	Potential	COAL
GIBBONS CREEK U1	470.0	Potential	COAL
J K SPRUCE 1	560.0	Potential	COAL
J K SPRUCE 2	775.0	Potential	COAL
OKLAUNION 1	650.0	Potential	COAL
SAN MIGUEL 1	391.0	Potential	COAL

Table 3: Generators that met Planning Guide Section 6.9 conditions

Unit	Projected COD	Fuel	Capacity (MW)	Meets Planning Guide Section 6.9 Conditions?
Brazoria Energy G	1/2019	Gas	96	Y
Lamesa Solar B (Phase II)	12/2018	Solar	50	Y
Edmondson Ranch Wind	9/2019	Wind	292	Y
Tahoka Wind	10/2018	Wind	300	Y
Emerald Grove Solar	5/2019	Solar	108	Y
Waymark Solar	12/2018	Solar	182	Y
Panhandle Wind 3	12/2020	Wind	248	Y
Denton Energy Center	7/2018	Gas	226	Y
Stella 1 Wind	12/2018	Wind	201	Y
Loma Pinta Wind	12/2018	Wind	200	Y
Cabezon Wind	4/2019	Wind	238	Y
Cactus Flats Wind	6/2018	Wind	148	Y
Infinity Live Oak Wind	12/2019	Wind	200	Y
Gopher Creek Wind	1/2019	Wind	158	Y
Blue Summit Battery	8/2017	Storage	30	Y

Table 4: Generators with SGIA only

Unit	Projected COD	Fuel	Capacity (MW)	Meets Planning Guide Section 6.9 Conditions?
Indeck Wharton	2/2019	Gas	654	N
Halyard Wharton	6/2019	Gas	419	N
Bethel CAES	11/2020	Gas/CE	324	N
Pinecrest G	4/2020	Gas	785	N
Tenaska Roans Prairie	4/2019	Gas	663	N
Halyard Henderson	6/2020	Gas	432	N
Sage Draw Wind	6/2019	Wind	300	N
Goodnight Wind	12/2018	Wind	497	N
Little Mountain Wind	3/2019	Wind	80	N
Silver Canyon Wind A	10/2019	Wind	200	N
Nazareth Solar	10/2019	Solar	201	N
Unity Wind	10/2019	Wind	203	N
Canadian Breaks Wind	7/2019	Wind	210	N
Scandia Wind DEF	5/2019	Wind	600	N
Pullman Road Wind	10/2019	Wind	300	N
Comanche Run Wind	12/2019	Wind	500	N
Karankawa Wind Alt A	12/2019	Wind	200	N
Palmas Altas Wind	12/2019	Wind	145	N
Pflugerville Solar	12/2019	Solar	144	N
Capricorn Ridge Solar	12/2018	Solar	100	N
Heart of Texas Wind	12/2018	Wind	150	N
FGE Texas 1 Gas	10/2020	Gas	743	N
Sweetwater 2 repower	6/2018	Wind	7	N
Brownsville G	12/2020	Gas	871	N
Rockwood G	7/2019	Gas	1122	N

Table 5: Thermal violations summary

From Bus	To Bus	From Bus kV	To Bus kV	Highest Overload (≥100%)	Length (miles)
Cedar Hill Switch	Norwood Switch	345	345	103	12
Hicks Switch	Roanoke Switch	345	345	101	33
Nipak Tap	Cedar Creek	138	138	100	7
Norwood Switch	Regal Row	138	138	105	2
Norwood Switch	Empire Central Tap 2	138	138	103	2
Regal Row	Empire Central Tap 1	138	138	101	1
Shamburger Switch	Royse Switch	345	345	101	79

Appendix C: Public Service Electric & Gas (PSE&G) Study

The *July 2018 PSE&G Planning Study of Generation Retirements* is included in the following pages.

PSEG

NERC SPECIAL ASSESMENT

Accelerated Nuclear & Coal Generation Retirements Study

PJM RTO Region

Prepared by:
Qamar H. Arsalan, Ph.D., P.E., Manager Transmission Planning
Daniel Hutt, Principal Staff Engineer
William LaVista, P.E., Principal Staff Engineer

Reviewed by:
Esam Khadr, Senior Director Transmission Planning

Date: July 12, 2018

Public Service Electric & Gas

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1. Introduction

Since 2008, the discovery of new natural gas reserves from shale formations and the development of advanced drilling techniques have led to an abundance of natural gas in the marketplace. The laws of supply and demand, in turn, have sent natural gas prices to historic lows. As a result, the prices of all sources of electricity, including nuclear and coal, have decreased significantly. Therefore, unfavorable market conditions are driving the marginal cost of conventional generation to be higher than that of the gas generators.

Availability of cheap natural gas, higher nuclear regulatory costs, and poor capacity factor of coal units are some of the factors which are creating substantial financial pressure on nuclear and coal units. This situation could lead to widespread retirements of existing nuclear and coal generators. In the last three years almost 9,700 MW of coal generation has been retired in the PJM area. Since 2013, several nuclear plants across the United States have either shut down or announced their early retirements due to economic pressures. Rapid retirements of conventional generators and their replacement with gas generators could greatly impact the operating characteristics of the bulk power system (BPS). Declining fuel diversity is exposing the BPS to the new challenges. This special assessment was requested by NERC to examine the impact of accelerated nuclear and coal generation retirements on BPS operational reliability in PJM RTO area.

2. Scope

NERC requested PSE&G to study the replacement of nuclear and coal with gas generators in the PJM RTO region for the year 2022. This study would involve both; summer peak and winter peak loadflow cases of 2022. In each case, the nuclear and coal generation, across PJM, would be completely replaced by gas generation. PJM queue generation would be used as the proxy for the location of new gas units. Impact of the displacement of generation would be studied in terms of the thermal and voltage violations.

3. Study Assumptions and Model Development

(a) Assumptions

The study is based on the following key assumptions:

1. Natural gas generation is the energy of choice to replace deactivating nuclear and coal generation
2. Sufficient natural gas generation is available by 2022 to compensate for the generation deactivation
3. All existing natural gas generation in PJM can operate at max output
4. Only in-service natural gas units are scaled up to 100% and cannot exceed 100% of max output
5. Only active queue generators are modeled
6. The queue generation can be scaled beyond the Capacity Interconnection Rights (CIRs[1])
7. For each queue generator, maximum reactive power generation limit (Qmax) is set to 60% of the maximum reactive power generation limit (Pmax), and minimum reactive power generation limit (Qmin) is set to -40% of Pmax

[1] The rights to input generation as a Generation Capacity Resource into the transmission system at the point of Interconnection.

(b) Software Tools

For modeling purposes, Siemens PTI Power System Simulator PSS/E v33 software tool, was used. For performing contingency analyses, PowerGem's TARA software tool was used.

(c) Development of the Power Flow base-cases

PJM provided following 2022 summer and winter peak load modeling data. These cases were received in January of 2018.

1. 2017 Series RTEP 2022 SUM Non MTX-042617-no FSA_V3
2. 2017 Series RTEP 2022 WIN NON-MTX-060217_No FSA_V1

Above cases were used to develop base-cases for summer and winter respectively by replacing the nuclear and coal generation with gas generation. Statistics of nuclear, coal, and gas generation across PJM is shown in Table 1. Locations of nuclear and coal generators are shown in Figure 1.

Table 1: Generation Statistics across PJM as of

FUEL	Winter 2022	Summer 2022
	MW	
Dispatched Nuclear Gen.	33,253	27,829
Dispatched Coal Gen.	35,540	43,119
Total (Nuclear + Coal)	68,793	70,948
Available Gas Reserve[1]	28,756	15,983
Deficiency[2]	-40,037	-54,965
Available Queue Gen. (CIRs)	34,987	34,987
Beyond Queue Gen. CIRs[3]	-5,050	-19,978

1: P*max* - P*gen*

2: (Nuclear + Coal) - Available Gas Reserve

3: Deficiency + Available Queue Gen.

Base-cases for summer and winter 2022 were developed by deactivating all the nuclear and coal generation with gas generation. In the base-cases the existing gas generators are dispatched to almost 80% of P*max*. To utilize the existing gas generation reserve, all the units were scaled up to 100% of P*max.* Since the existing gas generation reserve is insufficient, as shown in Table 1, new gas generation in the PJM generation interconnection queue was activated. Locations of the new gas generators are shown in Figure 2. After utilizing the 100% Capacity Injection Rights (CIRs) of all the queue generators, there was still MW deficiency, which was compensated by scaling up the queue generation beyond the CIRs of the queue generation.

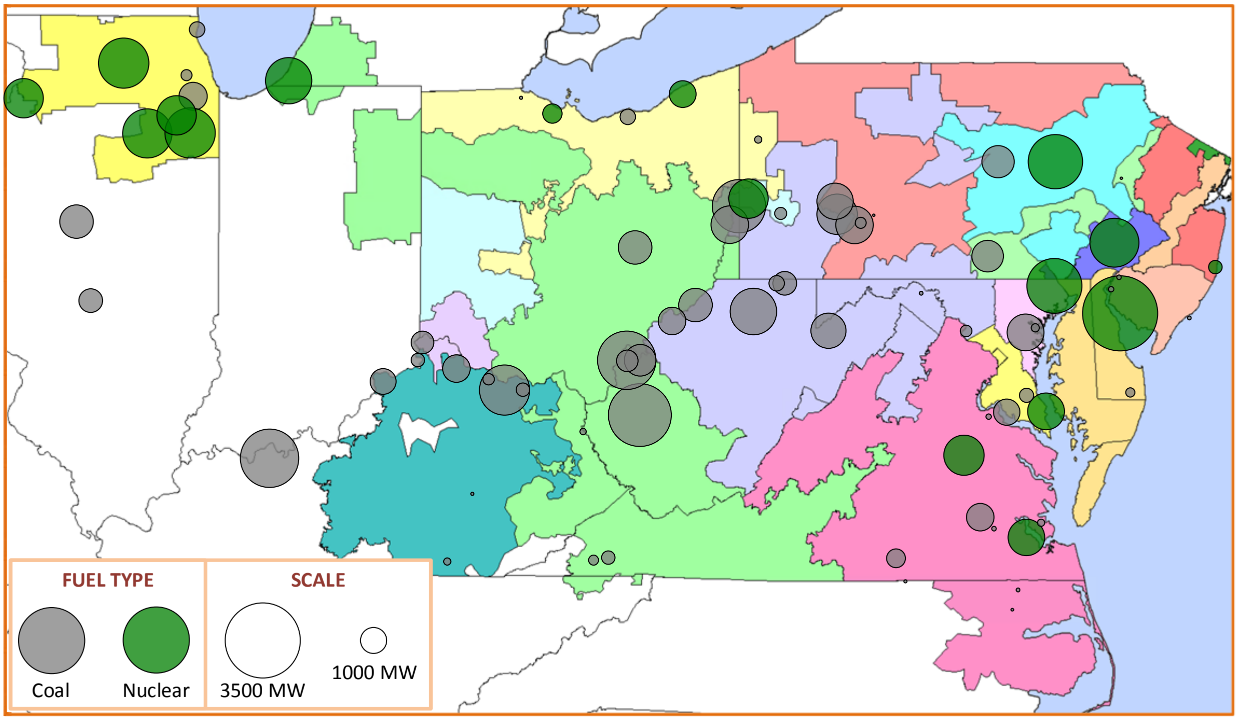

Figure 1: Nuclear and Coal Generation across PJM

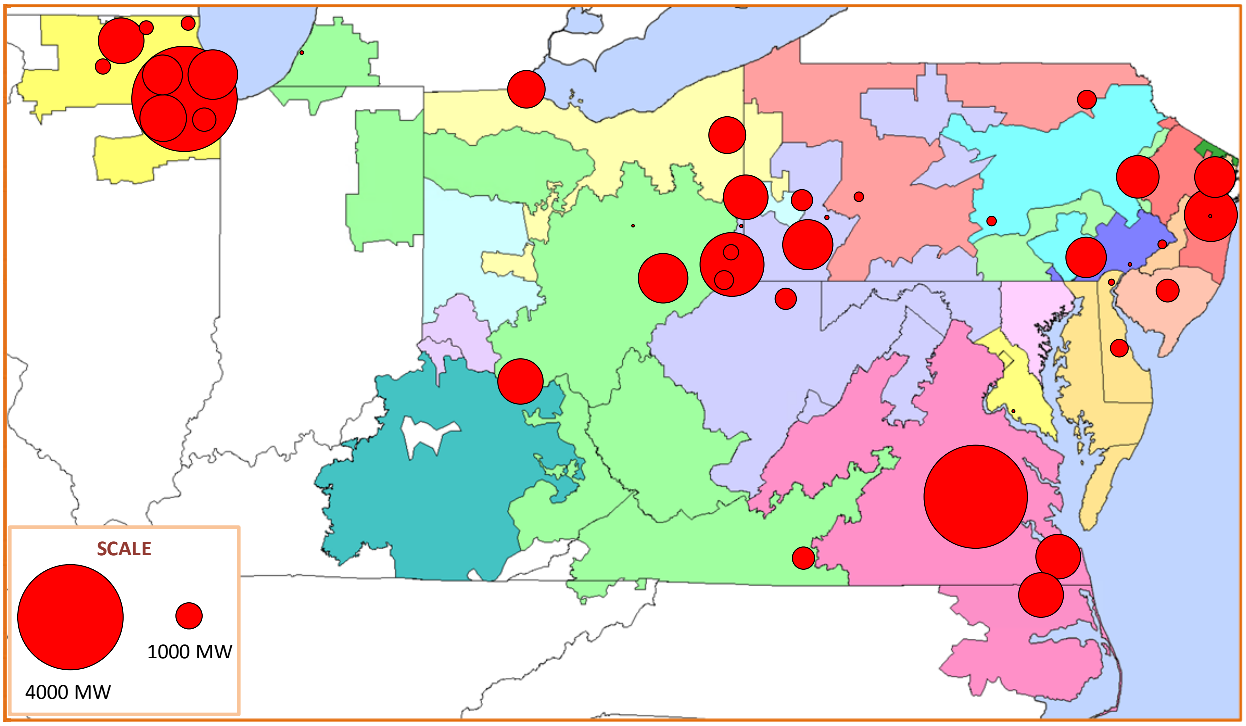

Figure 2: Location of Scaled Queue Generation across PJM

4. Results

Summary of the thermal and voltage violation is shown in Table 2 and Table 3 respectively. Single, Bus, Stuck Breaker, Tower, and N-1-1 contingencies were performed using the PJM provided contingency files on the developed cases for winter and summer of 2022. A thermal violation is considered, if the power flow through a facility exceeds its emergency rating and a voltage violation is considered, if a facility fails voltage drop or voltage magnitude criteria. Only 230kV and above facility violations are reported in the result.

The results show only unique overloads i.e. an overloaded facility that is identified in Singles is not counted in Bus, Stuck Breaker, etc. An overloaded facility was removed from the list of violations, if network upgrade of that facility has been identified as part of the PJM queue generation interconnection process. Locations of thermal violations in summer and winter of 2022 are depicted in Figure 3 and Figure 4 respectively. While performing studies, nine different scenarios (6 in summer and 3 in winter) were found for which the loadflow couldn't converge after the occurrence of a contingency. In all such scenarios, the cause of non-convergence was the lack of sufficient transmission to deliver the power to the load centers.

Table 2: Thermal Violations across PJM in 2022 (Winter & Summer)

VOLTAGE (kV)	SINGLES		BUS		STUCK BKR		TOWER		N-1-1	
	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum
230	9	12	1	0	2	2	0	3	39	67
345	0	10	0	1	0	1	1	0	8	15
500	1	2	0	0	0	0	0	0	1	6
Total	10	24	1	1	2	3	1	3	48	88

Table 3: Voltage Violations across PJM in 2022 (Winter & Summer)

VOLTAGE (kV)	SINGLES		BUS		STUCK BKR		TOWER		N-1-1	
	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum
230	12	9	1	15	15	25	30	34	60	94
345	1	1	0	1	1	1	0	19	3	7
500	18	10	2	5	2	14	0	5	19	27
Total	31	20	3	21	18	40	30	58	82	128

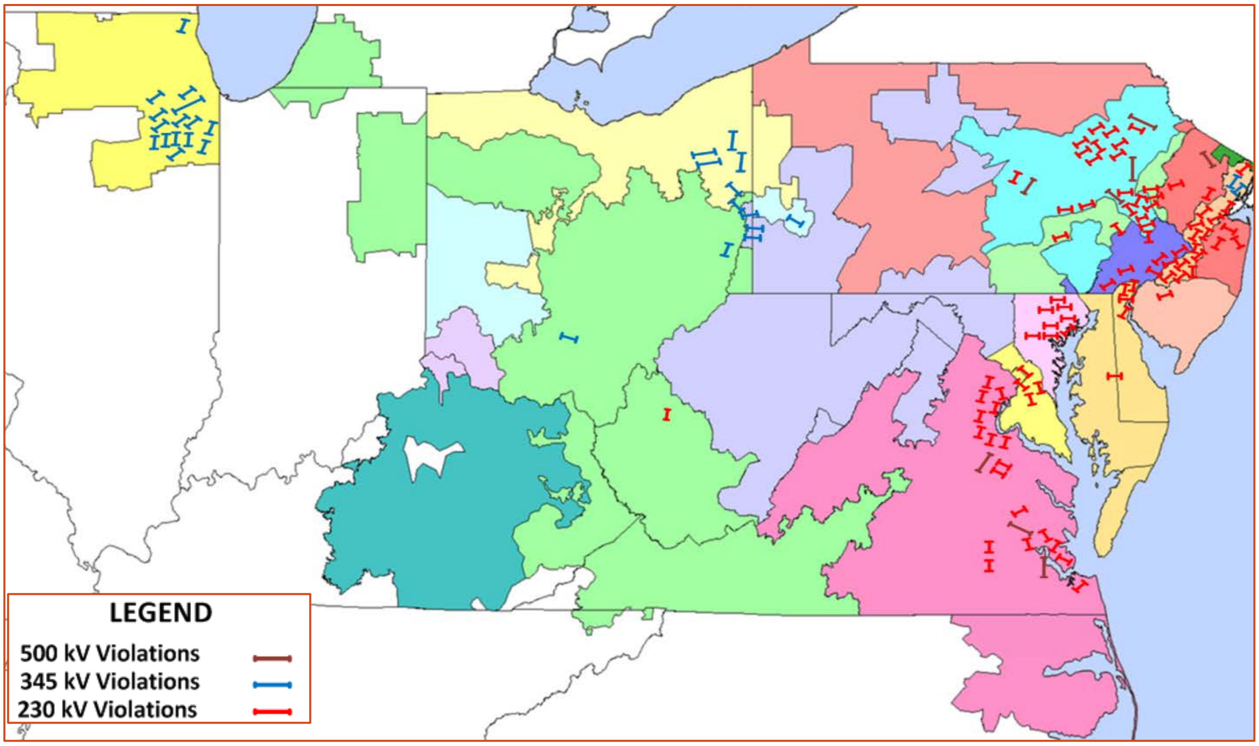

Figure 3: Location of Thermal Violations in summer of 2022

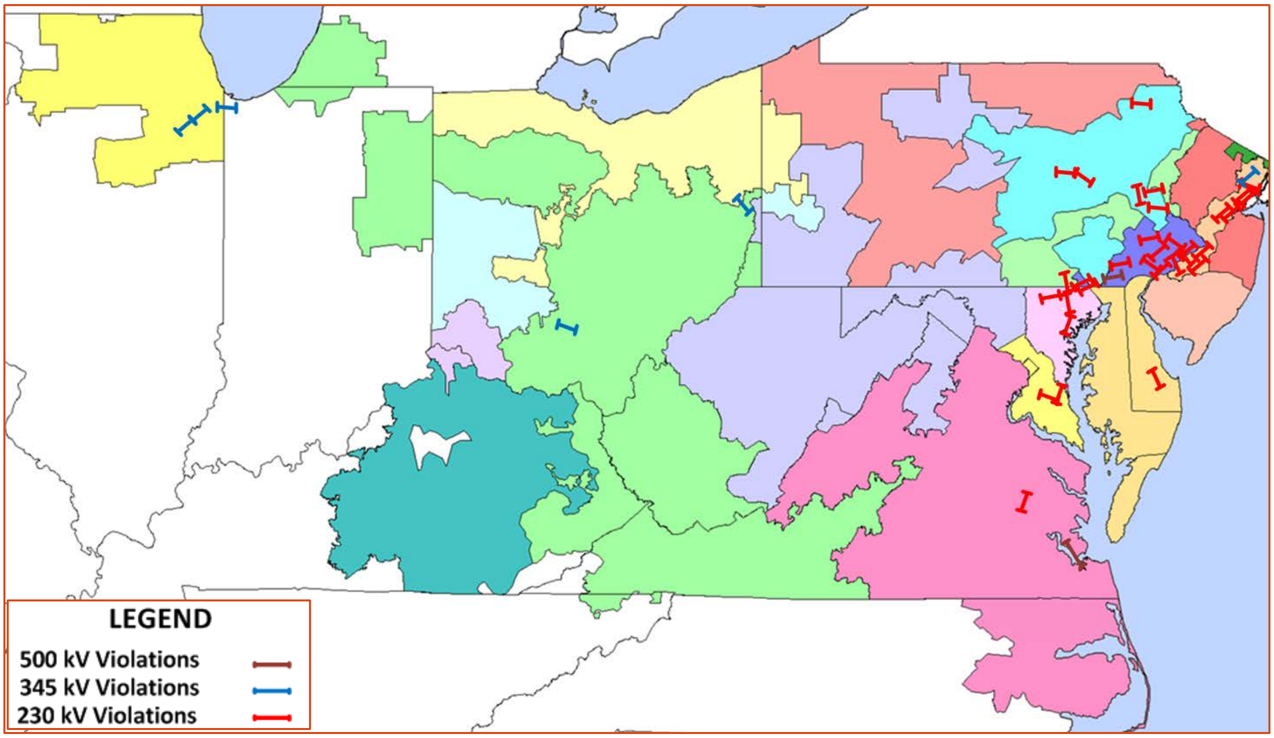

Figure 4: Location of Thermal Violations in winter of 2022

5. Discussion

Across PJM RTO region, existing nuclear and coal generation capacity is approximately 70,000 MW, which is almost 50% of the of PJM's total MW production. As the fuel mixture redistributes, the new PJM interconnections will not be the same MW size, built in the same locations or connect to the same voltage network. Results indicate that accelerated nuclear and coal generation retirement would require accelerated large scale reinforcement of transmission infrastructure. In this study, only electrical contingencies were studies. Gas contingencies, involving loss of gas pipeline(s) and/or compressor stations would have more severe impacts on the reliability especially during winter season when system goes through several maintenance outages of transmission lines.

Fuel interruptions during extreme weather events or other unforeseen incidents would deteriorate the reliability of the electric grid. In April of 2016, a 30-inch interstate natural gas transmission pipeline that runs 9,096 miles and carries natural gas from the Gulf Coast to the northeastern U.S. exploded in western Pennsylvania. Since 1998, almost 800 serious pipeline incidents have been recorded[2]. Having up to 90% of a generation fleet relying on a fuel shared between industrial and residential customers as well as the bulk electric generation, would expose the power system to a reliability risk. Nuclear and coal ensure fuel diversity, which is necessary to protect the reliable and affordable flow of energy.

[2] Pipeline and Hazardous Materials Safety Administration (PHMSA) - https://hip.phmsa.dot.gov/analyticsSOAP/saw.dll?Portalpages