Eastern Interconnection Planning Collaborative

FINAL DRAFT

Gas-Electric System Interface Study

Target 2 Report

Evaluate the Capability of the Natural Gas Systems to Satisfy the Needs of the Electric Systems

DOE Award Project

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EXECUTIVE SUMMARY

The shale gas boom coupled with the proliferation of efficient, natural gas-fired electric generation capacity has increased demands on gas infrastructure across North America, especially in the Eastern Interconnection. Shale gas production from the Marcellus and Utica formations located in close proximity to the major gas markets in the Northeast and Midwest has, in many cases, supplanted traditional production and delivery from the Gulf of Mexico, the Rocky Mountains, and western and Atlantic Canada. Favorable shale gas economics and increasing demand have continued to spur growth in gas production, thereby heightening concern regarding future pipeline infrastructure adequacy in the Study Region. The Study Region encompasses six Participating Planning Authorities (PPAs): Independent Electricity System Operator (IESO) of Ontario, Independent System Operator – New England (ISO-NE), Midcontinent Independent System Operator (MISO), New York Independent System Operator (NYISO), PJM Interconnection (PJM), and the Tennessee Valley Authority (TVA).

The purpose of the Target 2 study was to evaluate the adequacy of the interstate gas pipeline network to meet the coincident peak demands of local gas distribution companies (LDCs) serving firm residential, commercial, and industrial (RCI) customers, as well as gas-capable electric generators across the Study Region. To meet the Target 2 objectives, a five-step approach was utilized:

1. Develop a chronological dispatch model of the electric system for the years 2018 and 2023 in order to estimate hourly gas demands for each gas-capable unit across the Study Region, under a range of scenarios and sensitivities.
2. Combine the forecasts of generator gas demand with forecasts of RCI gas demand to represent seasonal coincident peak days in 2018 and 2023 across the Study Region.
3. Quantify unserved gas demand using optimization modeling of the gas infrastructure network for the peak hour of the summer and winter peak day in 2018 and 2023, and allocate the unserved demand to affected generators lacking firm transportation entitlements.
4. Identify the gas transportation constraints causing the unserved peak hour demand.
5. Determine potential mitigation measures to reduce or eliminate transportation constraints affecting generation.

Key findings for each PPA are summarized below (in alphabetical order). The identification of affected generation in a given location does not indicate that electric system reliability in that location is in jeopardy. The reported affected generation represents a seasonal peak hour condition under a fixed dispatch pattern. As such, although dual-fuel capability has been identified, iterative redispatching has not been performed to investigate the availability of gas-fired generation at other locations, or other mitigation measures ascribable to non-gas fired generation resources. The “adequate” and “constrained” characterizations are used to describe the ability of the gas pipeline network to meet electric generator gas demand under study dispatch assumptions, and do not reflect on the pipelines’ adequacy to serve firm customers.

In IESO, the gas infrastructure is adequate under the reference market conditions and resource mix during winter 2018, with a negligible amount of affected generation. In winter 2023, the level of gas-fired generation is much higher than in 2018 due to nuclear retirements and the reduction in nuclear availability during plant refurbishments. Nevertheless, the deliverability associated with Ontario's vast pipeline and storage infrastructure means that the amount of affected generation does not materially increase in 2023. Under scenarios and sensitivities driving high winter gas demand, the analysis reveals winter peak hour pipeline constraints in 2018 and 2023 due to the 100% utilization of the TransCanada mainline in western Ontario and in Quebec to serve RCI customers and generators with firm service, including those behind the Enbridge and Union local distribution systems. However, the constraints are negligible in relation to total gas-fired generation across the province, reflecting the firm character of service associated with the majority of gas-fired generators' arrangements with TransCanada and the LDCs. There are no constraints in the summer in 2018 or 2023.

In ISO-NE, the gas infrastructure is constrained in winter 2018 and 2023 under nearly all of the market conditions and resource mixes tested in the scenarios and sensitivities. These constraints reflect both commodity supply and transportation deficits. Nearly all of the gas-fired generators in New England lack primary firm entitlements, thereby limiting access to natural gas during cold snaps. The deliverability shortfall is explained by upstream transportation bottlenecks into New England along the major pipeline pathways linking Marcellus with New York and New England, as well as the anticipated continued decline in traditional imports from Canada. Limiting receipts at the LNG import facilities in New Brunswick and Massachusetts increases the deliverability shortfall in New England, particularly on the Algonquin and Tennessee mainlines around Boston. While there are many new pipeline projects on the drawing boards for New England, only Spectra's AIM Project and Tennessee's Connecticut Expansion Project, both comparatively small pipeline expansions, have been incorporated in the scenarios tested, due to the development status of the projects at the time study inputs were set. The affected gas-fired generation is mitigated fully in 2018 and 2023 when high daily spot market gas prices place oil-fired generation, and, to a much lesser extent, coal-fired generation, in merit. In case sensitivities, the postulated reutilization of the LNG import terminals at both Canaport and Distrigas materially lessens the amount of affected generation. There are no constraints in summer 2018, but by summer 2023, growth in electric loads increases transportation deficits affecting generation throughout the region.

In MISO, the gas infrastructure is adequate in 2018 and 2023 under the market conditions and resource mixes in nearly all scenarios and sensitivities tested. In addition to the large amount of conventional underground storage throughout MISO, the addition of major pipeline facilities coupled with the reversal of flow to accommodate shale gas production provide ample deliverability and operating flexibility to serve gas-fired generation across the MISO footprint in 2018 and 2023, including under extreme winter gas demands when high daily spot prices occur. A relatively small transportation deficit arises in MISO North/Central only in winter 2018 and 2023 if there is heightened attrition of coal-fired capacity coupled with low gas prices and high load. Under such high gas demand conditions, certain of the pipelines serving MISO North/Central are fully utilized, resulting in significant affected generation. There are no significant constraints in MISO South, which is safeguarded by close proximity to traditional production both on and offshore the Gulf of Mexico, and by a network of interconnected gas gathering, conventional storage and transportation infrastructure to serve loads in MISO South as well as downstream markets across the Eastern Interconnection. The anticipated commercialization of LNG export facilities in the Gulf of Mexico does not result in increased transportation constraints affecting generation in MISO South. There are no significant transportation constraints affecting gas-fired generation during the summer in 2018 or 2023 in either MISO North/Central or MISO South.

In NYISO, the gas infrastructure is constrained in winter 2018 and 2023 under nearly all market conditions and resource mixes in the scenarios and sensitivities tested. Most generation in NYISO is served under non-firm transportation arrangements. Despite the large pipeline buildout to accommodate shale gas production from Marcellus to upstate and downstate New York, Ontario and New England, generators throughout NYISO are exposed to pipeline constraints and/or local delivery constraints during cold snaps when LDCs exercise their superior rights in order to serve RCI load. During the winter peak hour, nearly all pipelines in New York – Constitution, Empire, Dominion, Millennium, and Tennessee – run at 100% capacity to serve RCI loads in New York, New England, and Ontario. Constrained Transco segments in PJM also affect downstream New York generators. The quantity of affected gas-fired generation is reduced, but not eliminated, when high daily spot market gas prices place oil-fired generation, and, to a much lesser extent, coal-fired generation, in merit. Conditions which increase winter gas demand, such as low gas prices and deactivation of nuclear capacity, significantly increase the amount of affected generation. Importantly, there is a significant amount of dual-fuel capacity located in southeastern NY which is available to mitigate the effect of these gas constraints on the bulk electric system. Conversely, expanded pipeline infrastructure to accommodate more production from Marcellus decreases the amount of affected generation. There are no significant transportation constraints affecting gas-fired generation during the summer in 2018 or 2023.

In PJM, depending on location, the gas infrastructure is either adequate or moderately constrained, in winter 2018 and 2023. During the winter peak hour, pipeline segments in PJM on Dominion, Columbia, East Tennessee, Eastern Shore, Tennessee, Texas Eastern, and Transco run at 100% capacity. Most of the affected generation is located in Maryland, Virginia, the Delmarva Peninsula, Eastern Pennsylvania, and New Jersey, where pipelines are fully utilized to serve RCI demands and where the demand for natural gas for electric generation is high relative to available pipeline and storage capacity. Elsewhere in PJM, including Chicago, there is adequate deliverability and operational flexibility to accommodate the coincident RCI and electric generation requirements. Unlike other PJM locations, most of the generating capacity where locational constraints have been identified in Eastern MAAC, Southwest MAAC and Virginia are located behind LDCs, and therefore delivery is constrained during the peak heating season. The quantity of affected gas-fired generation is reduced, but not eliminated, when high daily spot market gas prices put coal and, to a lesser extent, oil-fired generation in merit. The quantity of affected generation increases in winter 2023, due to the growth in RCI loads relative to the incremental capacity created through gas infrastructure additions. Heightened attrition of coal-fired capacity coupled with low gas prices and high load increases the quantity of affected generation in 2018 and 2023. Conversely, incremental pipeline infrastructure additions to accommodate increased production from Marcellus decrease the amount of affected generation in both winter 2018 and winter 2023. While transportation deficits drop markedly in PJM during the summer peak hour in 2018 and 2023, there is still a moderate amount of affected generation on the Delmarva Peninsula, Maryland, and Virginia due to constraints on Columbia, Dominion, Eastern Shore, and Transco.

In TVA, the gas infrastructure is adequate under the market conditions and resource mixes tested in all sensitivities and scenarios. TVA holds firm transportation entitlements on various pipelines to meet all or the majority of the daily gas requirements for its fleet of combined cycle plants and peakers. Pipeline constraints identified within TVA, such as on the East Tennessee mainline, do not affect any TVA generation. TVA also has dual fuel storage capability for many generation plants. The extensive network of pipelines serving TVA reasonably assures infrastructure adequacy during cold snaps and extreme temperatures during the summer.

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List of Abbreviations

AECI	Associated Electric Cooperative, Inc.
AEO	Annual Energy Outlook
Bbl	Barrel
Bcf	Billion cubic feet
Bcf/d	Billion cubic feet per day
Btu	British thermal units
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CAPP	Central Appalachia
CDA	Central Delivery Area
CEMS	Continuous emission monitoring system
CSAPR	Cross-State Air Pollution Rule
DOE	Department of Energy
DR	Demand response
Dth	Dekatherm
EBB	Electronic Bulletin Board
EDA	Eastern Delivery Area
EE	Energy efficiency
EIA	Energy Information Agency
EIPC	Eastern Interconnection Planning Collaborative
EISPC	Eastern Interconnection States Planning Council
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
EUR	Estimated ultimate recovery
FERC	Federal Energy Regulatory Commission
FOA	Funding Opportunity Announcement
GJ	Gigajoule
Gulf	Gulf of Mexico
GW	Gigawatt
HEU	Highly enriched uranium
HGDS	High Gas Demand Scenario
IESO	Independent Electricity System Operator of Ontario
ILB	Illinois Basin
INGAA	Interstate Natural Gas Association of America
IRP	Integrated resource plan
ISO-NE	Independent System Operator-New England
LAI	Levitan & Associates, Inc.
LDA	Local delivery area
LDC	Local distribution company
LGDS	Low Gas Demand Scenario
LHV	Lower Hudson Valley
LNG	Liquefied natural gas
MAOP	Maximum allowable operating pressure
Marcellus	Marcellus shale natural gas producing region
MATS	Mercury and Air Toxics Standards
Mcf	Thousand cubic feet
MDth	Thousand dekatherms
MDth/d	Thousand dekatherms per day
MISO	Midcontinent Independent System Operator
MMBtu	Million British thermal units
MMcf	Million cubic feet
MMcf/d	Million cubic feet per day
MRO	Midwest Reliability Organization
MW	Megawatt

MWh Megawatt hour

MWh/h Megawatt hour per hour

NAPP Northern Appalachia

NCDA North Central Delivery Area

NDA Northern Delivery Area

NEB National Energy Board

NERC North American Electric Reliability Corporation

NPT Northern Pass Transmission

NREL National Renewable Energy Laboratory

NYISO New York Independent System Operator

NYMEX New York Mercantile Exchange

OEB Ontario Energy Board

O&M Operation and maintenance

PA Planning Authority

PJ Picojoule

PJM PJM Interconnection, LLC

PPA Participating Planning Authority

PRB Powder River Basin

PV Photovoltaic

RCI Residential, commercial, industrial

RFO Residual fuel oil

RGDS Reference Gas Demand Scenario

RGGI Regional Greenhouse Gas Initiative

RPS Renewable portfolio standard

RTO Regional Transmission Organization

SCF Standard cubic feet

SERC SERC Reliability Corporation

SIP State Implementation Plan

SPP Southwest Power Pool

SSC Stakeholder Steering Committee

SMDA Sault Ste. Marie Delivery Area

STEO Short term energy outlook

TOTS Transmission Owner Transmission Solutions

TRR Technically recoverable resources

TVA Tennessee Valley Authority

UCAP Unforced capacity

UIB Uinta Basin

ULSD Ultra-low sulfur distillate

VOM Variable O&M

WDA Western Delivery Area

Working Group Steady State Modeling and Load Flow Working Group

WTI West Texas Intermediate

List of Pipeline Short Names

Algonquin	Algonquin Gas Transmission LLC
Alliance	Alliance Pipeline LP
AM AlaTenn	American Midstream (AlaTenn) LLC
AM MidLa	American Midstream (MidLa) LLC
ANR	ANR Pipeline Company
Big Sandy	Big Sandy Pipeline LLC
Bison	Bison Pipeline LLC
Creole Trail	Cheniere Creole Trail Pipeline, LP
CNYOG	Central New York Oil and Gas LLC
Columbia Gas	Columbia Gas Transmission LLC
Columbia Gulf	Columbia Gulf Transmission LLC
Constitution	Constitution Pipeline Company
Crossroads	Crossroads Pipeline Company
Destin	Destin Pipeline Company LLC
Dominion	Dominion Transmission, Inc.
Dominion Cove Point	Dominion Cove Point LNG, LP
East Tennessee	East Tennessee Natural Gas LLC
Eastern Shore	Eastern Shore Natural Gas Company
Empire	Empire Pipeline, Inc.
Enable	Enable Gas Transmission LLC
Equitrans	Equitrans, LP
Fayetteville Express	Fayetteville Express Pipeline LLC
Florida Gas	Florida Gas Transmission Company LLC
Granite State	Granite State Gas Transmission, Inc.
Great Lakes	Great Lakes Gas Transmission LP
Guardian	Guardian Pipeline LLC
Gulf Crossing	Gulf Crossing Pipeline Company LLC
Gulf South	Gulf South Pipeline Company, LP
Horizon	Horizon Pipeline Company LLC
Iroquois	Iroquois Gas Transmission System, LP
KM Illinois	Kinder Morgan Illinois Pipeline LLC
KM Louisiana	Kinder Morgan Louisiana Pipeline LLC
KO Transmission	KO Transmission Company
M&N	Maritimes & Northeast Pipeline LLC
Midcontinent Express	Midcontinent Express Pipeline LLC

Midwestern	Midwestern Gas Transmission Company
Millennium	Millennium Pipeline Company LLC
Mississippi River	Enable Mississippi River Transmission LLC
MoGas	MoGas Pipeline LLC
NFG	National Fuel Gas Supply Corporation
NGPL	Natural Gas Pipeline Company of America LLC
NGO	NGO Transmission, Inc.
Northern Border	Northern Border Pipeline Company
Northern Natural	Northern Natural Gas Company
Ozark	Ozark Gas Transmission LLC
Panhandle Eastern	Panhandle Eastern Pipe Line Company, LP
PNGTS	Portland Natural Gas Transmission System
Rockies Express	Rockies Express Pipeline LLC
Sabal Trail	Sabal Trail Transmission, LLC
Sabine	Sabine Pipe Line LLC
Southeast Supply Header	Southeast Supply Header LLC
Southern	Southern Natural Gas Company LLC
Southern Star Central	Southern Star Central Gas Pipeline, Inc.
Tennessee	Tennessee Gas Pipeline Company LLC
Texas Eastern	Texas Eastern Transmission, LP
Texas Gas	Texas Gas Transmission LLC
Tiger	ETC Tiger Pipeline LLC
TransCanada	TransCanada PipeLines Ltd.
Transco	Transcontinental Gas Pipe Line Company LLC
Trans-Union	Trans-Union Interstate Pipeline, L.P.
Trunkline	Trunkline Gas Company LLC
Union Gas	Union Gas Ltd.
USG	USG Pipeline Company LLC
Vector	Vector Pipeline LP
Viking	Viking Gas Transmission Company
WBI Energy	WBI Energy Transmission, Inc.

Glossary of Key Terms and Phrases

Affected generation is gas-fired generation expressed in megawatt-hours (MWh) which the gas network simulation model indicates cannot be served during the seasonal peak hour due to pipeline infrastructure constraints. The identification of affected generation in a given gas network location does not indicate that electric system reliability in that location is in jeopardy.

Area is either of two context-dependent geographic areas. In the gas sector, area is a non-gas simulation model reference to a gas-production field or to one or more delivery markets. In the electric sector, area refers to the electric simulation model-defined load-serving area and may also refer to the generation resources within the area.

Constrained refers to the inability of the gas pipeline network to deliver all the gas demands of electric generators in a given gas simulation model location under the electric generation dispatch and gas system modeling assumptions of this study.

Constraint is a portion of the gas infrastructure, generally a pipeline segment that cannot serve all the gas demand of affected generators in the gas simulation model location. A constraint does not result in any unserved gas demand for firm gas demand customers. A constraint does not constitute evidence of electric system reliability problems.

Duration of a constraint is the number of consecutive days in a winter or summer season when the pipeline network is unable to deliver all the gas demanded by generators during the peak hour of gas demand.

Frequency of a constraint is the number of days in a season when the pipeline network is unable to deliver all the gas demanded by generators during the peak hour of gas demand.

Location almost always refers to a defined geographic area in the gas simulation model, which include pipeline segments and residential, commercial and industrial (RCI) and electric generator customer demands. As configured in the gas simulation model, locations are one or more states or provinces or a subdivision of a state or province.

Peak day is the day with the highest coincident electric load over the Study Region for the winter or summer season.

Peak hour is the hour with the maximum total generator gas demand across the Study Region on the seasonal peak electric load day. The peak hour may differ across the sensitivity cases, but remains the same across the three scenarios for each of the four seasons studied (winter and summer of 2018 and 2023).

Pipeline segment is a portion of each pipeline represented in GPCM.

Study Region encompasses the six Participating Planning Authorities (PPAs): Independent Electricity System Operator (IESO) of Ontario, Independent System Operator – New England (ISO-NE), Midcontinent Independent System Operator (MISO), New York Independent System Operator (NYISO), PJM Interconnection (PJM), and the Tennessee Valley Authority (TVA). Certain interconnected external regions were also modeled in GPCM and AURORAxmp.

Unserved generator gas demand is expressed in MDth and represents the amount of natural gas at the full load heat rates of the affected generators that cannot be provided at the various locations incorporated in the gas simulation model.

Zone is either of two context-dependent geographic references in the report. In the gas sector, zone refers to a market section of a pipeline. In the electric sector, zone refers to one or more load areas that are not modeled with internal transmission constraints in the electric transmission zonal topology of AURORAxmp.

Note on Conversion Factors

Natural gas is measured by volume or heating value. The standard measure of heating value in the English system of units is millions of British thermal units or "MMBtu." Dekatherms (Dth) are also a standard unit of measurement. One Dth is equal to ten therms or one MMBtu. The standard measure of heating value in the metric system is gigajoule (GJ); one GJ is slightly smaller than one MMBtu (1 GJ = .948 MMBtu).

The standard measure of gas volume in the English system of units is standard cubic feet or "scf." The "s" for standard is typically omitted in expressing gas volume in cubic feet. Therefore "scf" is typically shortened to "cf." Because the heating value of natural gas is not uniform across production areas, there is no one fixed conversion rate between gas volume and heating value. Pipeline gas in North America usually has a heating value reasonably close to 1,000 Btu/cf. Therefore, for discussion purposes, one thousand cubic feet (Mcf) is roughly equivalent to one million Btu (MMBtu).

The standard measure of gas volume in the metric system is cubic meters (m^3). The conversion between metric and English volume measures is 1 m^3 = 35.31 cf. There are a number of different volumetric conventions used in Canada and the U.S.

$$\mathbf{1\ Mcf \approx 1\ MMBtu = 1\ Dth \approx 1\ GJ}$$

$$\mathbf{1\ Bcf = 1{,}000\ MMcf \approx 10^6 MMBtu = 10^6 Dth \approx 10^6\ GJ = 1\ PJ}$$

FOREWORD

In mid-2009, the Department of Energy (DOE) issued a funding opportunity announcement (FOA), "Resource Assessment and Interconnection-level Transmission Analysis and Planning," DE-FOA-0000068, funded by the American Recovery and Reinvestment Act of 2009. PJM Interconnection, LLC (PJM) was selected as the recipient of the Topic A portion of this FOA for the Eastern Interconnection and subsequently entered into a cooperative agreement with DOE's National Energy Technology Laboratory. The Eastern Interconnection Planning Collaborative (EIPC) was formed in 2009 by 25 of the major eastern utilities to conduct the work of PJM's award under this funding opportunity, DE-OE0000343. PJM's award under DOE's funding opportunity was divided into two phases – Phase 1 and Phase 2. Phase 1 focused on the formation of a diverse stakeholder group, the SSC, and its work to model public policy "futures" through the use of macroeconomic models. This first work effort examined eight futures chosen by the SSC. The final undertaking in Phase 1 was for the SSC to choose three futures scenarios to pass onto Phase 2 of the project. Phase 2 of this project focused on conducting the transmission studies and production cost analyses on the three scenarios chosen by the stakeholders at the end of Phase 1. This work included developing transmission options, performing a number of studies regarding grid reliability and production costs of the transmission options, and developing generation and transmission cost estimates for each of the three scenarios.

This project is intended to complement the work of the Eastern Interconnection Topic B recipient of DE-FOA-0000068, the National Association of Regulatory Utility Commissions, and its awardee, the EISPC. EISPC comprises regulatory representatives from the 39 states of the Eastern Interconnection, along with the District of Columbia, and the City of New Orleans. The work has also benefited from close interaction with an SSC representing a wide range of interests. DOE is additionally supporting the program through work at selected national laboratories. The EIPC is grateful to DOE and to all the above participants for their contributions.

Subsequent to issuing the draft Phase 2 report, the DOE noted the rapid changes in the natural gas market since the beginning of the study. In particular, the discovery and development of new natural gas resources and the increasing reliance on natural gas for power generation raised questions about the sufficiency of the natural gas infrastructure to support the anticipated need for natural gas power production. As such, the DOE provided the EIPC an extension to perform additional technical analyses to evaluate the interaction between the natural gas and electric systems. Six members of the EIPC, the PPAs, identified four Targets for analysis under the DOE extension. The Final Draft Target 1 Report, *Baseline the Existing Natural Gas-Electric System Interfaces*, was issued on April 4, 2014. In the Target 1 study, Levitan & Associates, Inc. (LAI) developed a baseline assessment of the natural gas infrastructure and electric interfaces affecting the PPAs' ability to rely on gas-fired generation. In the Target 1 study, LAI reported that the natural gas infrastructure across the Study Region was not designed to meet the coincident gas requirements of the higher priority gas utility sendout to residential, commercial and industrial (RCI) loads, and the lower priority loads associated with gas-fired generators lacking primary firm transportation entitlements. While some gas-fired generators have firm entitlements from liquid sourcing points to plant gate stations, in particular, the Tennessee Valley Authority (TVA) and those in Ontario, gas-fired generators' dependence on non-firm transportation arrangements elsewhere in the Study Region may cause locational constraints in response to the increased use of natural gas to replace deactivated or retired coal plants over the forecast period. In this Target 2 study, LAI evaluates the adequacy of the natural gas infrastructure in 2018 and 2023 to meet the expected RCI loads and gas-fired generator requirements on a Winter Peak Day and a Summer Peak Day.

As further discussed in Section 1, this Target 2 study is based on the existing and planned gas pipeline and storage infrastructure, generation and electric transmission resources, and other market conditions known to the PPAs and LAI as of April 2014. The Target 2 analysis was performed from late 2013 through mid 2014. A draft report was submitted to the PPAs on September 30, 2014. The draft report of September 30, 2014 was subsequently posted for stakeholder comment on January 30, 2015. This final draft reflects the incorporation of the stakeholder comments received through March 2, 2014.

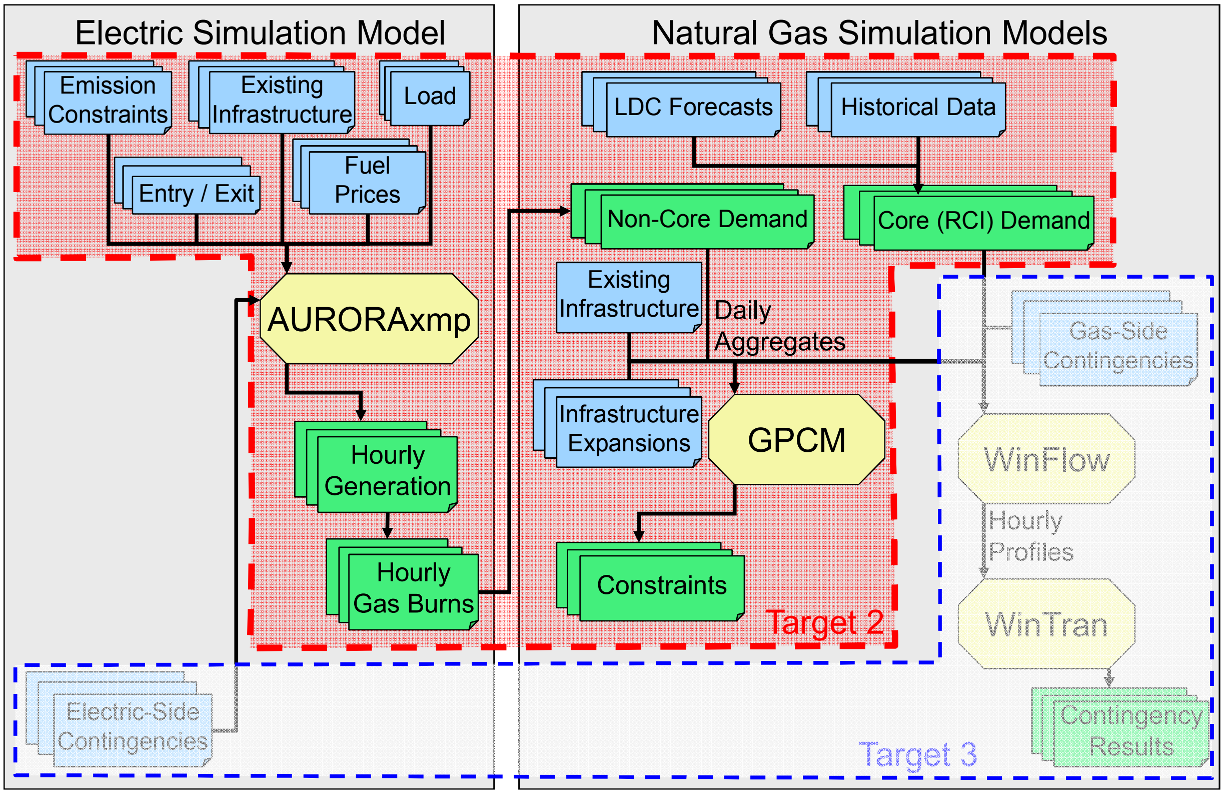
1 INTRODUCTION AND OVERVIEW OF APPROACH

This report encompasses Target 2 of the EIPC's DOE extension: *Evaluate the Capability of the Natural Gas Systems to Satisfy the Needs of the Electric Systems.* In this Target 2 study, LAI evaluated the ability of the natural gas network to meet the demands of both RCI gas customers and gas-fired electric generation customers at 5-year and 10-year planning horizons. The Target 2 analysis spans the Study Region, encompassing the consolidated footprint of the six PPAs, for two calendar years, 2018 and 2023. The primary goals of the Target 2 research are:

- *first*, to develop a chronological dispatch model of the electric system representing the five-year (2018) and ten-year (2023) horizons that will be used to estimate hourly gas demands for each gas-capable unit that is 15 MW or greater across the Study Region;
- *second*, to incorporate the forecasts of generator gas demand with forecasts of RCI gas demand, to represent seasonal peak days at the five-year and ten-year horizons across the Study Region;
- *third*, to identify gas infrastructure constraint points and to evaluate infrastructure adequacy to meet generation gas demand on seasonal peak days; and,
- *fourth*, to determine potential mitigation measures to address gas infrastructure constraints.

The analytical approach to addressing these Target 2 goals is illustrated in Figure 1. Based on a forecast of delivered fuel prices, electric load, a representation of transmission and generation resources and other input data, the electric simulation model, AURORAxmp, was used to forecast electric generation and gas demand by individual power plant or generation unit for each hour of 2018 and 2023. Importantly, the generator gas burns produced by AURORAxmp represent unconstrained gas delivery under the study assumptions. The seasonal peak hour for generator gas demand was defined as the hour with the maximum total generator gas demand across the Study Region on the seasonal peak electric load day. The forecasted peak hour generator gas demand was assumed to occur simultaneously with the forecasted peak hour RCI gas demand across the Study Region to provide coincident winter and summer peak-day, peak-hour gas demands for 2018 and 2023. The analysis also examined the daily coincident peak hour gas demand during the three winter months and three summer months of both study years.

Figure 1. Model Overview



The combined generation and RCI demands on the peak hour of the winter and summer peak days were input into the gas transport model, GPCM, to simulate the operation of the natural gas infrastructure serving the Study Region.[1] GPCM addresses the complex interactions among supply areas, storage facilities, pipeline networks, and consumers – both RCI customers and power generation. GPCM optimizes supplier deliveries, utilization of storage assets, and flows across pipelines in order to serve customer demands throughout the system under the forecasted conditions. GPCM attempts to serve both RCI and generator demands using the available pipeline and storage infrastructure. To the extent there is insufficient pipeline and storage infrastructure to serve RCI demands and gas-fired generation requirements on a coincident basis, the RCI demand is given priority over that portion of total gas-fired generation requirements that do not have firm pipeline transportation entitlements. Across the Study Region, the majority of gas-fired generators are served under non-firm transportation arrangements. As discussed in the Target 1 report, generators located in IESO and TVA are the exception to this general rule. Deliverability issues and system constraints are identified at locations where the model solution results in transportation deficits. Transportation deficits result in unserved generator gas demand. A transportation deficit is the quantity of interstate pipeline capacity required to meet

[1] Originally known as the Gas Pipeline Competition Model, GPCM is a gas pipeline network optimization model that incorporates partial equilibrium economics to reach a solution. LAI licenses GPCM from RBAC, Inc., a California-based software and data firm, for purposes of technical assessment of market developments across North America. More information about GPCM model structure and approach can be found in Appendix A.

the coincident gas requirements of RCI customers and gas-fired generation minus the available pipeline capacity.

The GPCM analysis of constraints was performed on the peak hour of the peak day in the peak winter and summer months in 2018 and 2023.[2] Data and software limitations prevented modeling all winter and summer season hours in GPCM. This approach provides a reasonable upper bound on hourly gas demands by season. The method produces conservative results from a gas infrastructure deliverability standpoint suitable for purposes of this study. In addition to examining the constraints on the winter and summer coincident peak hours in GPCM, the frequency and duration of such constraints over the course of each season were estimated outside of GPCM, based on the expected chronological profile of the RCI and generator daily peak hour gas demands for three winter and three summer months. The seasonal peak hour GPCM modeling is analogous to the EIPC Roll-Up Integration Cases that simulate the integrated power system for the summer peak hours in 2018 and 2023. For each electric and RCI sector customer, a chronological profile of daily peak hour demand was developed using electric simulation model hourly output or historical RCI demand data, respectively. For each constrained segment, the chronological profiles of the daily peak hour demands served by that segment and the downstream pipeline segments were summed to estimate the total gas that would desirably flow across a segment during the peak hour of each day during the season assuming no constraints. The maximum hourly flow capability of the segment, defined as the daily segment capacity divided by 24, was then compared to the aggregate RCI and electric power daily peak hour demands to determine the number and chronological pattern of days when the desired segment flow during the peak hour exceeds the pipeline's physical capacity.

The capability of the gas infrastructure has been evaluated under three future gas demand scenarios: the Reference Gas Demand Scenario (RGDS), the High Gas Demand Scenario (HGDS) and the Low Gas Demand Scenario (LGDS). Formulation of the three gas demand scenarios is intended to reveal the level and profile of gas demand under a defined set of market, regulatory and operating conditions formulated to test the capability of natural gas infrastructure across the Study Region to meet the coincident gas requirements of RCI customers and gas-fired generators.[3] Each of the gas demand scenarios is driven by a consistent set of primary gas demand drivers of both RCI gas customers' demands and gas-fired electric generation fuel requirements. The RGDS represents a forecast that is in accord with the economic, market, and regulatory assumptions characterizing the resource planning process of each of the PPAs. The RGDS represents a base case that is consistent with the scenarios that the PPAs use for transmission planning and capacity reliability analyses. The HGDS and LGDS represent energy futures in which the key drivers of natural gas demand depart significantly from the values reflected in the RGDS. The key drivers include the levels of electric load and RCI gas demand,

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[2] Consistent with this approach, full withdrawal capability from storage is assumed to be available during the peak hour. We assume that the gas will be withdrawn to meet demands without regard to price or the need to have storage on hand for some future period; in other words, the withdrawal capability of the facility is the limiting factor. Because the model runs only for the peak day, there are no assumptions regarding off-peak injection capability because no off-peak periods are modeled. Cycles of withdrawal and injection are not modeled in the daily model.

[3] The natural gas infrastructure across the Eastern Interconnection has been built to serve the contract demands of firm shippers. Shippers that do not hold firm transportation contracts rely on released capacity, third-party arrangements with entitlement holders, and interruptible transportation arrangements.

the mix of generation resources, and natural gas prices. The HGDS and the LGDS are *not* intended to reflect extreme conditions or low probability events, but reasonable bounds around the realm of plausible input uncertainties. The HGDS represents a "plausible maximum" level and profile of gas requirements across the Study Region, driven primarily by increased deactivation or retirement of coal and nuclear plants, lower delivered natural gas prices, and higher electric loads. The LGDS represents a "plausible minimum" level and profile of gas requirements, driven primarily by the displacement of gas-fired generation vis-à-vis increased penetration of wind and solar photovoltaic (PV) resources, higher delivered natural gas prices, and lower electric loads.

The starting point for the RGDS is the Roll-Up Integration Cases of the Eastern Interconnection prepared by the EIPC Steady State Modeling and Load Flow Working Group (Working Group).[4] The Working Group consists of representatives from each NERC-registered Planning Authority (PA) that is party to the EIPC Analysis Team Agreement. A Roll-Up Integration Case is an integrated power flow model incorporating the regional transmission and resource expansion plans for the Eastern Interconnection as the plans existed in 2013. The Working Group prepared the 2018 and 2023 models in 2013 by aggregating the resources, planning forecasts, and reliability standards of EIPC members, with sufficient analysis of the rolled-up plan to ensure simultaneous feasibility of the individual submitted plans. As a steady-state power flow model, the Roll-Up Integration Cases simulate the integrated power system for two "snapshots," the 2018 and 2023 summer peak hours. Input data to the RGDS used the summer capabilities of the resources included in the Roll-Up Integration Cases. Transmission transfer limits and hourly load forecasts for the entire year, consistent with the summer peak hour data used in the Roll-Up Integration Cases, were provided to LAI by the six PPAs. Seasonal capabilities of thermal and hydro generators and hourly expected generation of renewable resources were used in order to model all 8760 hours of each study year.

Since the preparation of the Roll-Up Integration Cases in 2013, there have been certain changes in actual and planned transmission infrastructure and resources, thereby causing the PPAs to delineate updates to the input assumptions for the RGDS. Also, the Roll-Up is developed for transmission studies, which use certain assumptions that differ from those used for resource adequacy studies. Accordingly, in early 2014, the PPAs provided lists of actual and planned system updates, including new resources, queue withdrawals, new planned transmission projects, and new actual and planned generator deactivations, since the provision of data used in the Roll-Up Integration Cases. Also, certain generator ratings were revised based on new uprates and derates. The PPAs also provided updated transmission transfer capability data associated with the new planned transmission projects. These infrastructure changes have been incorporated into an update of the RGDS, referred to as "RGDS Sensitivity 0" or "RGDS S0". In some figures, this is shortened to "R0". Similarly, the HGDS and LGDS based on updated infrastructure information for the RGDS were constructed, as indicated in Figure 2. These are referred to as HGDS S0 and LGDS S0, respectively, and shortened to H0 and L0 in some figures. To test the impact of changing a single variable or set of variables, a set of sensitivities has been formulated

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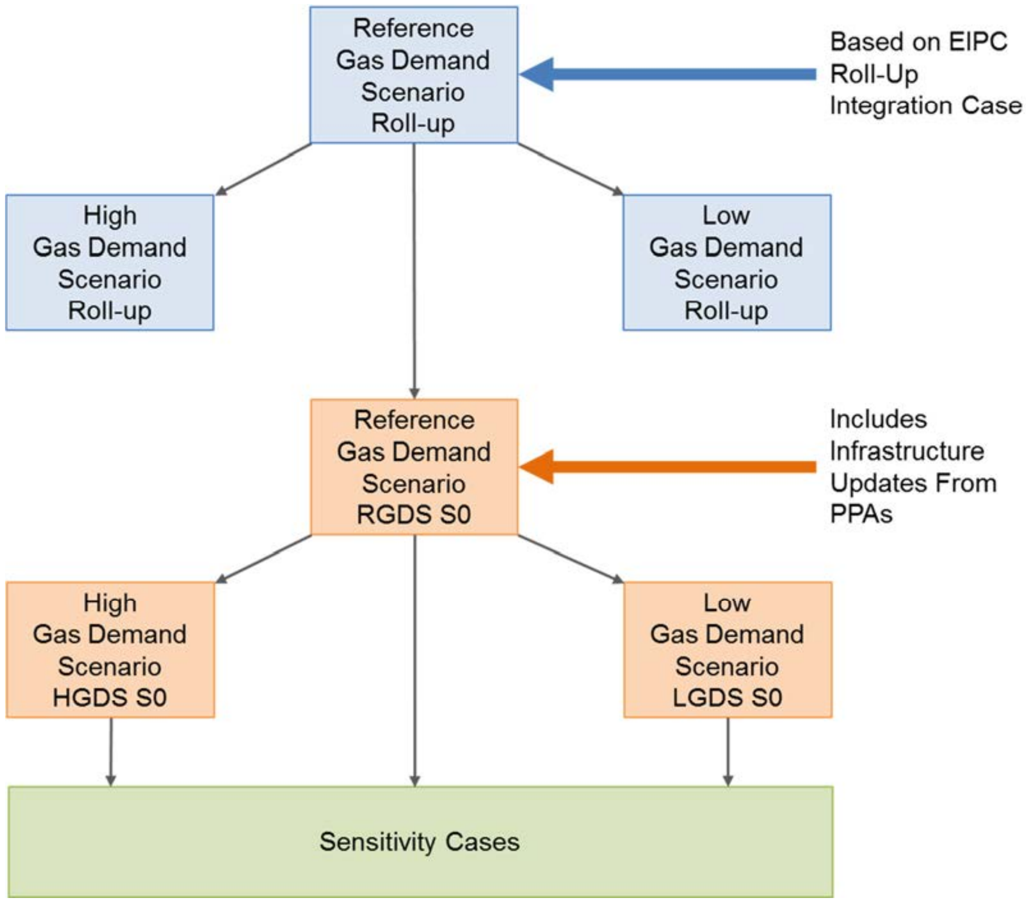
[4] Eastern Interconnection Planning Cooperative Steady State Modeling and Load Flow Working Group, *Report for 2018 and 2023 Roll-Up Integration Cases, Final Report*, February 14, 2014.

http://www.eipconline.com/uploads/FINAL_EIPC_Roll-up_Report_Feb14-2014.pdf based on input from the PPAs and the SSC. As indicated in Figure 2, the S0 gas demand scenarios constitute the foundation for all of the subsequent sensitivities that have been tested in this Target 2 analysis. Although the three Roll-up scenarios were analyzed, their results are less meaningful than those for the S0 cases and associated sensitivities due to the inclusion of updated information in the S0 cases and other changes as noted above. Therefore, results from the Roll-up scenarios are included in Appendix T and will not be further discussed in the body of this report.

Figure 2. Scenarios and Sensitivities



2 SUMMARY OF RESULTS

The rapid development of shale gas in North America over the last five years has dramatically changed the operational and market dynamics across the Study Region. Massive new supplies located in close proximity to the major gas markets in the Northeast and Midwest are expected to more deeply penetrate the Study Region over the 5 and 10-year forecast horizon. Shale gas production from the Marcellus and Utica basins will continue to supplant traditional production and delivery from the Gulf of Mexico, the Rocky Mountains, and both western and Atlantic Canada. Favorable shale gas economics will continue to spur growth in gas production over the 5 and 10-year forecast horizons, thereby heightening gas/electric interdependencies affecting pipeline infrastructure adequacy across six PPAs.

New pipeline and gas gathering infrastructure will be needed to expand the takeaway capacity out of the shale producing basins for core and electric generation end-users. Many pipeline projects that seek to redress the Marcellus and Utica takeaway constraints have already been added to the pipeline topology of the Study Region. Many more are either under construction or awaiting FERC certification. These projects include new pipeline segments and laterals, pipeline expansions and flow reversals. Deliverability will be enhanced through recent and anticipated pipeline additions in PJM, MISO North/Central, and NYISO, and, to a lesser extent, through flow reversals into IESO and TVA. Unlike the other PPAs, ISO-NE remains exposed to frequent deliverability constraints over the planning horizon due to the absence of large new projects into the region, the decline of gas production from Atlantic Canada, the material loss of indigenous LNG supply within New England, and, most importantly, ISO-NE's heavy reliance on gas-fired generation throughout the year.

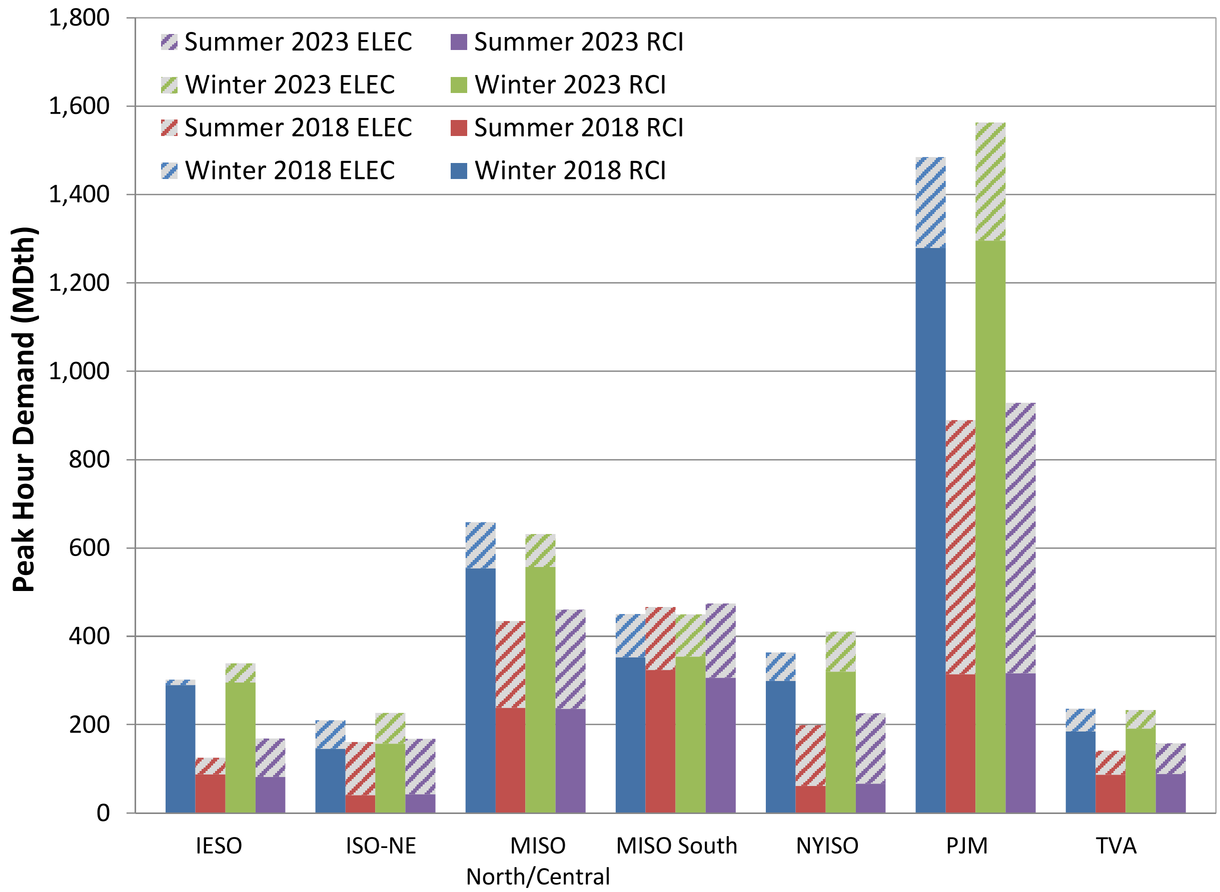
2.1 Key Findings of Three Gas Demand Scenarios

The quantitative analysis to accomplish Target 2 research objectives has facilitated an assessment of transportation constraints affecting gas-fired generation loads across six PPAs during the three peak winter months and three peak summer months of 2018 and 2023.

2.1.1 Peak Hour Gas Demand for Electric Generation and RCI Sectors

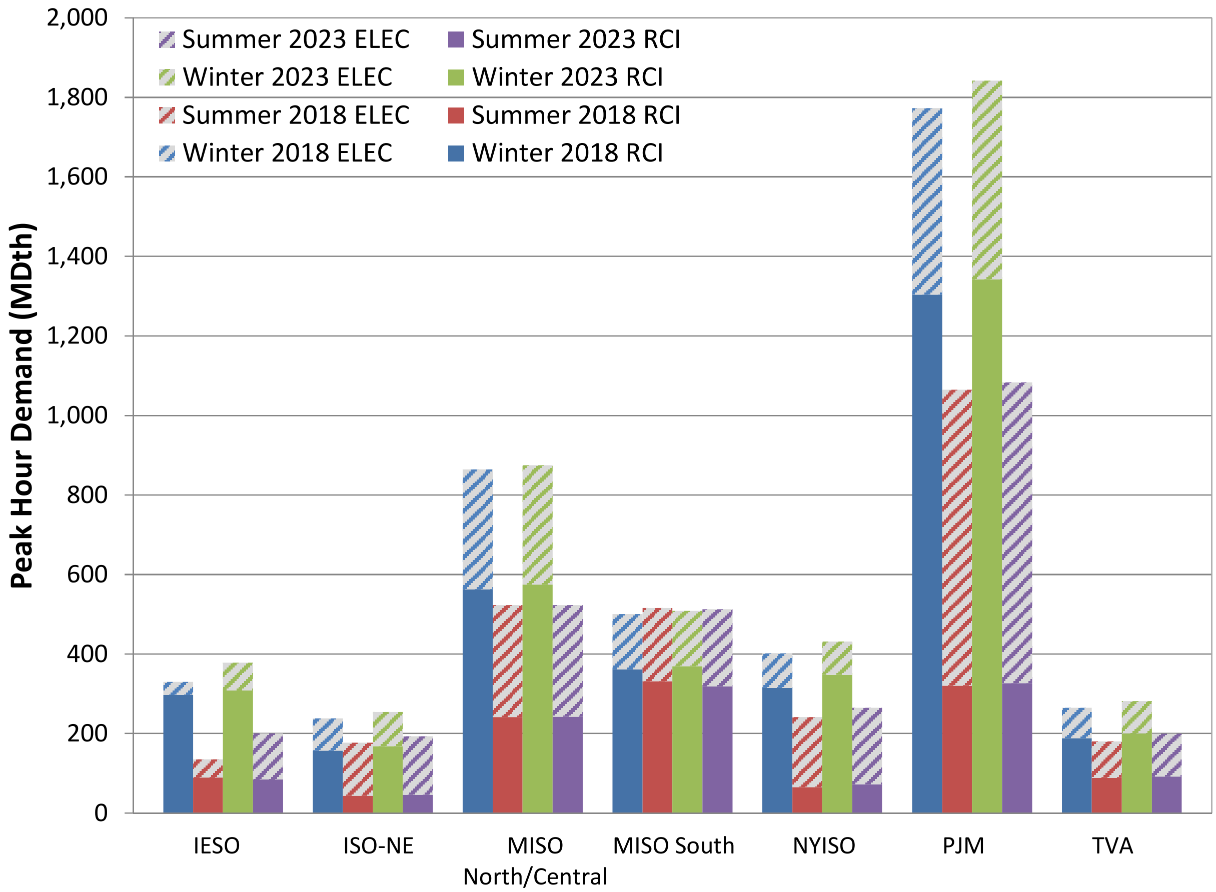
By season and year, the combined peak hour gas demands for the RCI and electric generation sectors for the RGDS S0 are shown in Figure 3. The electric generation demand is stacked on top of the RCI loads in each PPA. In the RGDS, the level of gas-fired generation for each PPA reflects the current load forecasts, transmission topology and transfer limits, resource entry and exit, and plant performance parameters provided by the PPAs.

Figure 3. RGDS S0 Total Peak Hour Gas Demands by Season and Year



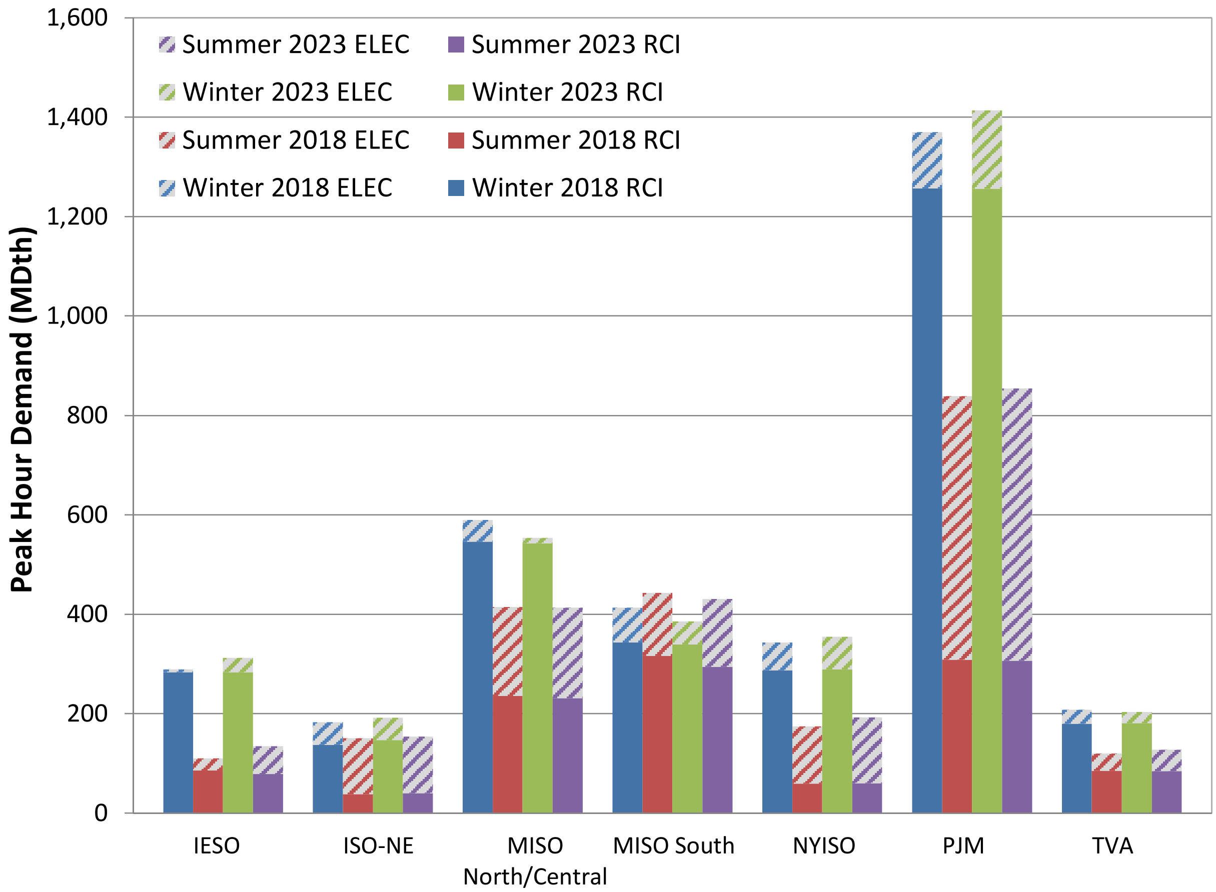
The increased gas demand for generation and RCI requirements under the HGDS S0 are shown in Figure 4, and reveal a substantial increase in peak hour gas-fired generation in MISO North/Central and PJM, reflecting the substitution of gas-fired generation for coal, in particular. In both absolute and relative terms, this effect is less pronounced in other PPAs.

Figure 4. HGDS S0 Total Peak Hour Gas Demands by Season and Year



The decreased gas demand for generation and RCI requirements under the LGDS S0 are shown in Figure 5. LGDS S0 results reveal a substantial reduction in gas-fired generation in MISO North/Central and PJM, in particular. Higher delivered gas prices incorporated in the LGDS S0 effectively increase LMPs relative to the marginal cost of coal generation. In-merit coal generation boosts coal unit capacity factors in MISO North/Central and PJM, thereby reducing gas-fired generation requirements in the peak hour of the peak day, as well as on an annual basis. However, in light of substantial increases in year-over-year shale gas production from Marcellus and Utica, as well as other shale plays in North America, uncertainties surrounding the number of LNG export facilities over the study period, and the existing E&P outlook, the high natural gas price forecast underlying the LGDS has a lower probability of occurrence than the forecasts underlying the other scenarios.

Figure 5. LGDS S0 Total Peak Hour Gas Demands by Season and Year



2.1.2 Determination of Affected Generation

Based on the level of gas-fired generation derived from the electric simulation analysis, the RCI load forecasts, and the results of the GPCM modeling, LAI quantified the delta between each gas demand and the amount of gas delivered to meet each demand as unserved generator gas demand (MDth) in each GPCM location during the peak hour of the peak day, and then calculated the amount of corresponding affected generation (MWh) based on heat rates. "Affected generation" is therefore gas-fired generation which GPCM indicates cannot be served during the seasonal peak hour due to pipeline infrastructure constraints. The identification of affected generation in a given location does not indicate that electric system reliability in that location is in jeopardy. The reported affected generation represents a seasonal peak hour condition under a fixed dispatch pattern; as such, iterative redispatching has not been performed to investigate the availability of gas-fired generation at other locations, or other mitigation measures ascribable to non-gas fired generation resources.

Affected generation by no means constitutes a failure of the pipelines and LDCs to plan adequately for anticipated peak hour gas-fired generation requirements, but rather signifies transportation deficits by location under an "idealized" set of market assumptions. Due to the limited public availability of third-party firm supply and transportation arrangements, the analysis does not account for generators with firm supply arrangements under Asset

Management Agreements. Thus, affected generators are all generators within a GPCM customer group identified as being fully or partially unserved that do not hold firm transportation entitlements in their own name.[5] These assumptions account for the fact that pipelines and storage companies design and operate their respective systems to ensure adequate deliverability to meet the coincident demand requirements of firm entitlement holders. Hence, all transportation deficits are borne by non-firm customers, in this case, gas-fired generators lacking transportation entitlements. No specific assumption has been made regarding the character of service associated with the non-firm generators that are served. They could be utilizing released capacity, secondary firm transportation, interruptible transportation, third-party fuel supply arrangements, or other special services described in the Target 1 report.

In Figure 6 to Figure 9, peak hour affected generation is summarized for Winter and Summer 2018 and Winter and Summer 2023. These bar charts present the results for the RGDS S0 (R0), HGDS S0 (H0), and LGDS S0 (L0). A few salient observations by PPA follow:

- *In Ontario*, under expected conditions underlying the RGDS, there is limited affected generation in IESO, reflecting the firm character of service associated with the majority of gas-fired generators directly connected to TransCanada, or served by either Enbridge or Union Gas. The increase in gas required in Winter 2023 relative to 2018 reflects nuclear retirements, the refurbishment outage of certain nuclear units, and addition of new gas-fired capacity, thereby increasing gas demand to meet peak hour reliability requirements. There are no constraints in the summer. The substantial amount of affected generation in Ontario in HGDS S0 also reflects the increased capacity factors of the minority of generation plants in Ontario that lack firm entitlements and the assumed delay of return to service of nuclear units being refurbished.

- *In New England*, nearly all gas-fired generation is affected during Winter 2018 and 2023 across each of three scenarios, reflecting the lack of primary firm entitlements for gas-fired generation. In the three scenarios, the New Mystic combined cycle plant operates on natural gas as a firm customer of the Suez Distrigas LNG import facility. The adverse scheduling restrictions captured across RGDS S0, HGDS S0 and LGDS S0 are explained by upstream transportation bottlenecks into the region as well as the decline in traditional production from Atlantic Canada and LNG imports for regasification into the back end of the Algonquin and Tennessee mainlines around Boston, MA. Significant transportation constraints affect gas-fired generation for the peak hour in Summer 2023 in all three scenarios, reflecting growth in LDC and electric loads and increased reliance on gas-fired generation during the summer.

- *In the Mid-Continent – both MISO North/Central and MISO South* – the addition of major pipeline facilities through the study horizons coupled with the reversal of flow to accommodate shale gas production provides ample deliverability to serve gas-fired generation across MISO's footprint in RGDS S0 and LGDS S0. Only in HGDS S0 is there a significant transportation deficit during the peak hour of the peak day in Winter 2018 and 2023. This restriction is limited to MISO North/Central, reflecting the

[5] Generators holding firm entitlements directly with a pipeline were identified in Exhibits 4 through 9 of the Target 1 report.

substantial reduction in coal-fired generation and the significant increase in gas-fired generation in this scenario. MISO South is benefited by massive and interconnected gas gathering, conventional storage and transportation infrastructure to serve indigenous loads as well as downstream markets throughout the Eastern Interconnect. There are no transportation constraints during the summer over the study horizon.

- *In New York,* under all scenarios, nearly all gas-fired generation scheduled to meet electric demand on the peak hour of the peak day in Winter 2018 and 2023 is affected under all scenarios. Like ISO-NE, most generation in NYISO is served under non-firm transportation arrangements. On the peak hour of the winter peak days in 2018 and 2023, pipelines across New York run at or near capacity limits to serve RCI loads in New York, as well as downstream RCI demand in New England. Although it is not explicitly modeled in the Target 2 analysis, the New York Facilities System operated by Con Edison and NGrid is known to limit deliveries to downstate generators under cold weather conditions or other restrictive events. There are no material transportation constraints affecting gas-fired generation during the summer over the planning horizon.

- *In the mid-Atlantic,* there is a significant amount of affected generation in PJM during the peak hour of the peak day in Winter 2018 and 2023 under all scenarios. Most of the affected generation is located in SWMAAC, EMAAC, and Virginia, where RCI demands require near-full utilization of the available pipeline infrastructure and the demand for natural gas to serve electric generation is high relative to the remaining pipeline and storage capacity that is available after RCI demands are met. Scheduled gas-fired generation and the corresponding affected generation significantly increases during the winter in HGDS S0, reflecting the reduction in coal based generation when delivered gas prices decline and coal plant attrition is increased. While transportation deficits drop markedly in PJM during the summer, there is still a moderate amount of affected generation on the Delmarva Peninsula, in Maryland, and in Virginia due to deliverability constraints on Columbia, Dominion, Eastern Shore, and Transco.

- *In the TVA region,* there is no affected generation under any scenario. This is because TVA has and will continue to arrange firm transportation entitlements on various pipelines serving TVA to meet all or the majority of the daily gas requirements for its fleet of combined cycle plants and peakers.

Figure 6. Peak Hour Affected Generation – Winter 2018

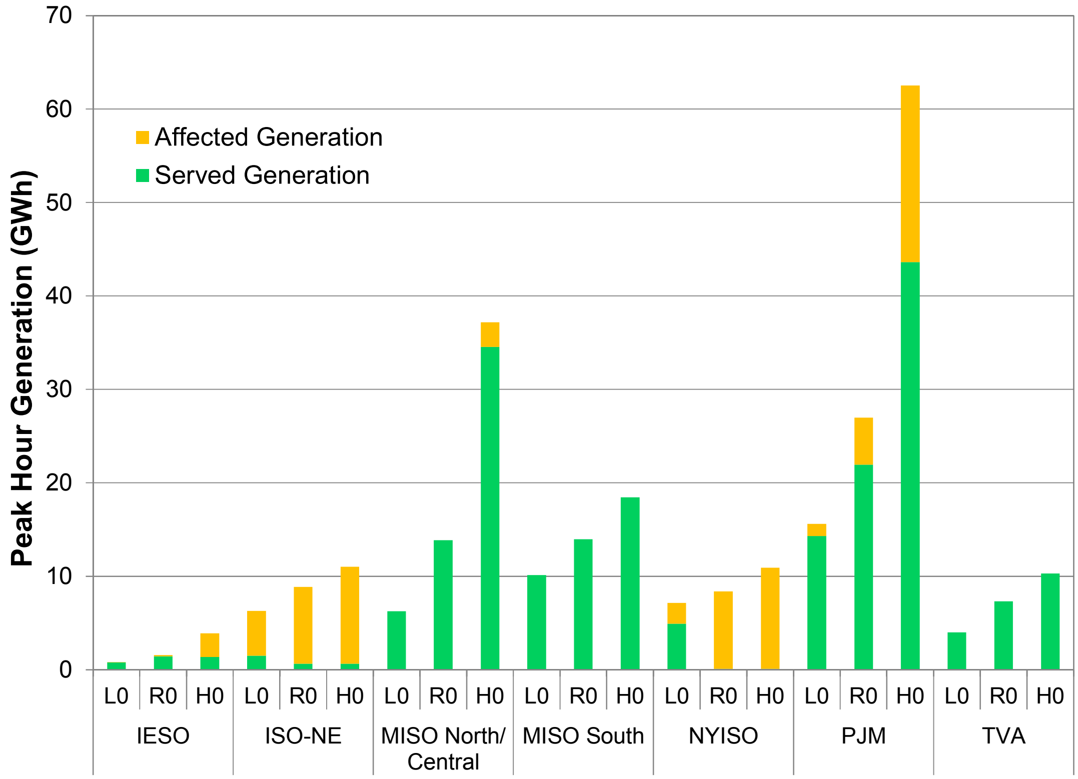


Figure 7. Peak Hour Affected Generation – Summer 2018

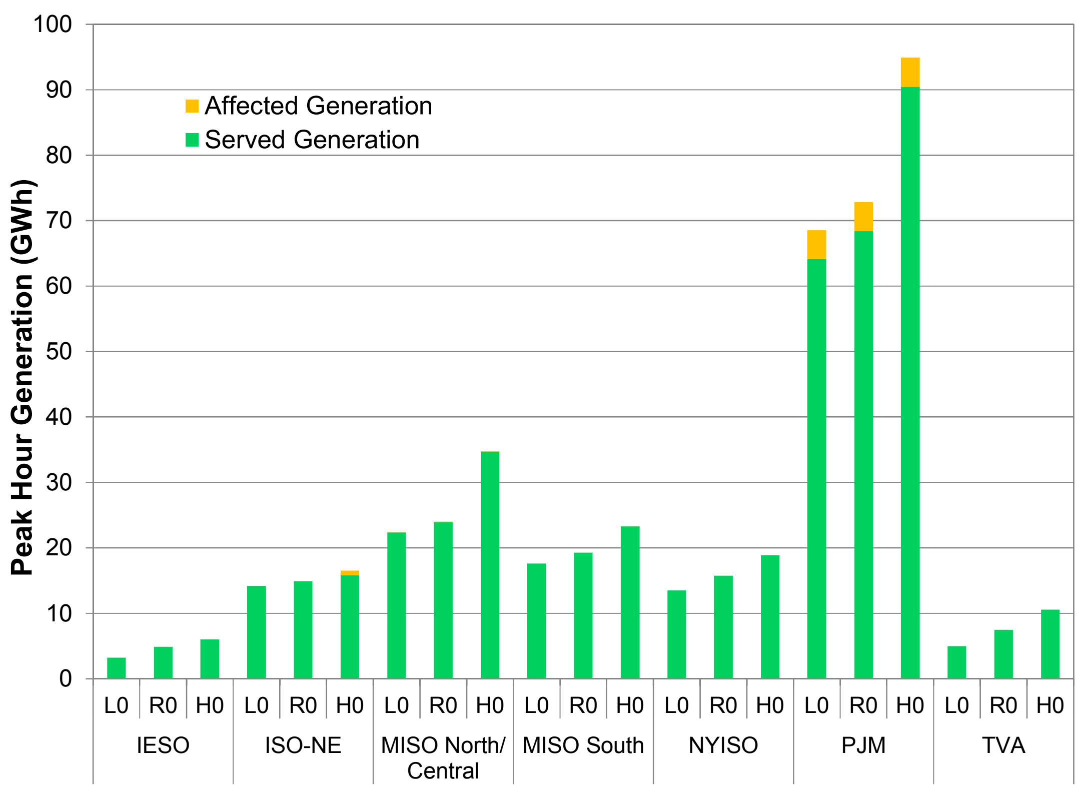


Figure 8. Peak Hour Affected Generation – Winter 2023

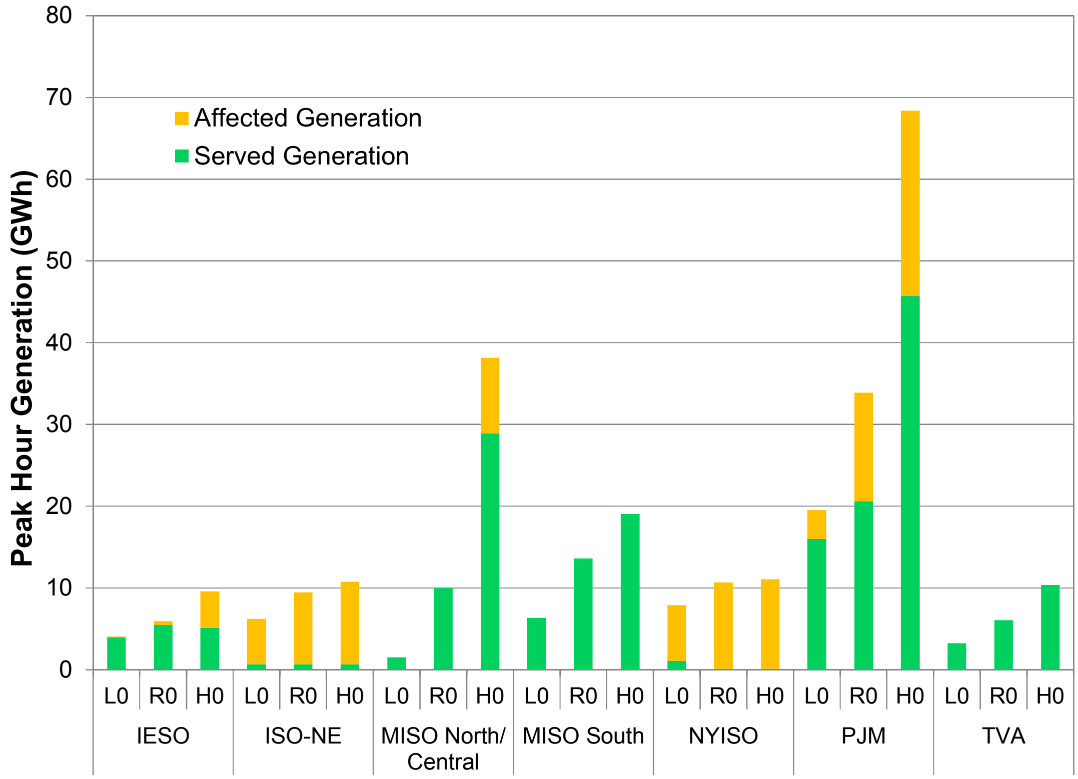
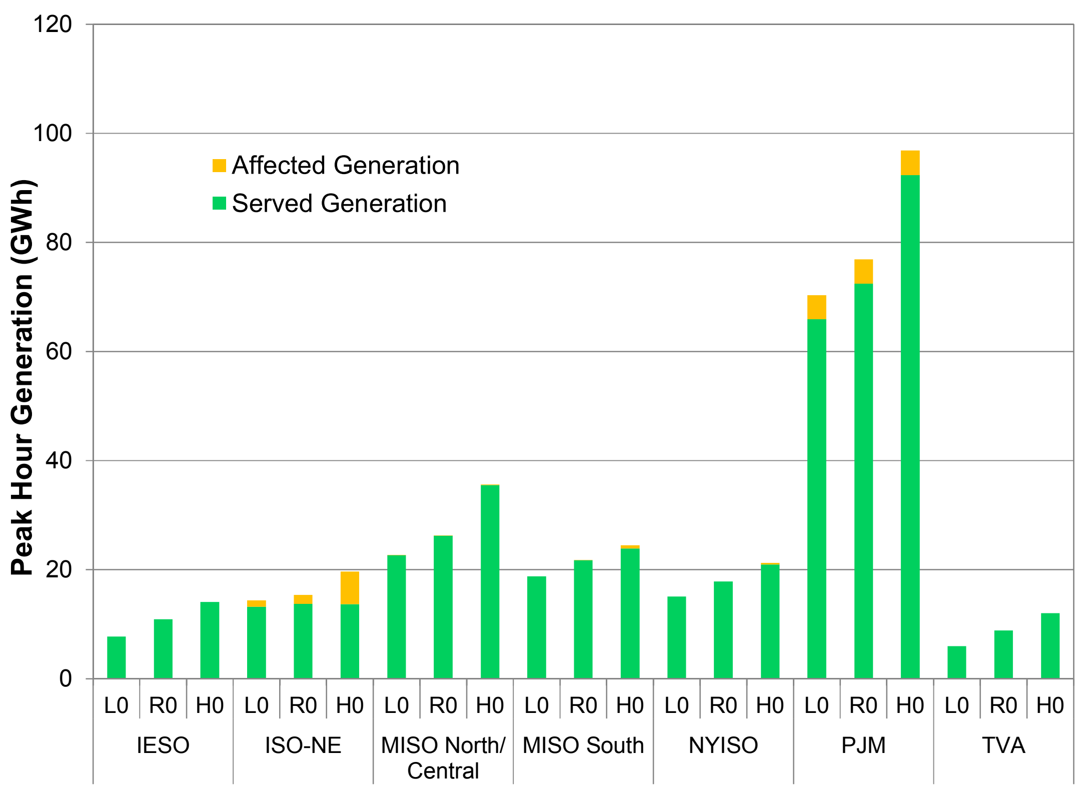


Figure 9. Peak Hour Affected Generation – Summer 2023



2.1.3 Affected Generation by GPCM Location and Winter Peak Day Gas Pricing

Not captured in the S0 results are the higher than average monthly delivered natural gas prices when pipeline congestion during cold snaps puts upward pressure on gas prices, resulting in additional substitution of other fuels. Therefore, the level of peak hour gas demand for electric generation constitutes an upper limit under S0 fuel prices. To evaluate the gas demand for electric generation during the winter peak hour under market conditions, sensitivity S1 incorporates generally higher winter peak day spot gas prices.

In Figure 10, the locations across the Study Region with peak hour affected generation are reported for RGDS S0 and RGDS S1 in Winter 2018. The locations correspond to the locations defined in the GPCM model and not to the zones or areas defined for the electric simulation modeling. In charting the GPCM locations with affected generation, it is important to note that a location is shown as orange to the extent there is *any* generation that is unserved on the peak hour of the peak day. When higher cold day spot gas prices under S1 assumptions are tested, eastern Pennsylvania turns green, reflecting oil- and coal-based generation in merit. Under S1 prices, New England turns green, reflecting oil-based generation in merit. Ontario Western and Ontario Eastern turn orange as a result of higher LMPs in other PPAs increasing exports of power from mostly relatively low cost affected generation tied to relatively low cost gas in Western Canada.[6]

The relative magnitude of the unserved peak hour gas demand stated in MDth and corresponding affected generation stated in MWh are presented in Table 1 for each of the three scenarios. The locations shown in Table 1 are GPCM locations and are listed alphabetically. Locations are not reported by pipeline because often LDC loads (including the generators served by LDCs) are served by multiple pipelines. RBAC, Inc., the developer of GPCM, has configured the locations in GPCM to be defined as states and provinces, or as sub-divisions of states and provinces; the locations do not correspond to electric system regions. When viewed in conjunction, Figure 10 and Table 1 provide for a meaningful perspective on the spatial distribution of affected generation and the relative magnitude of unserved gas-fired generation during the peak hour of the peak day in Winter 2018 for each of three scenarios. The volume of unserved gas demand and corresponding affected generation for S1 are also presented in Table 2.

[6] Ontario Western and Ontario Eastern correspond to TransCanada's Western Delivery Area and Eastern Delivery Area, respectively. See Section 4.1 for more information on the definition of GPCM locations.

Figure 10. RGDS S0 v. S1 Winter 2018: GPCM Locations with Peak Hour Affected Generation

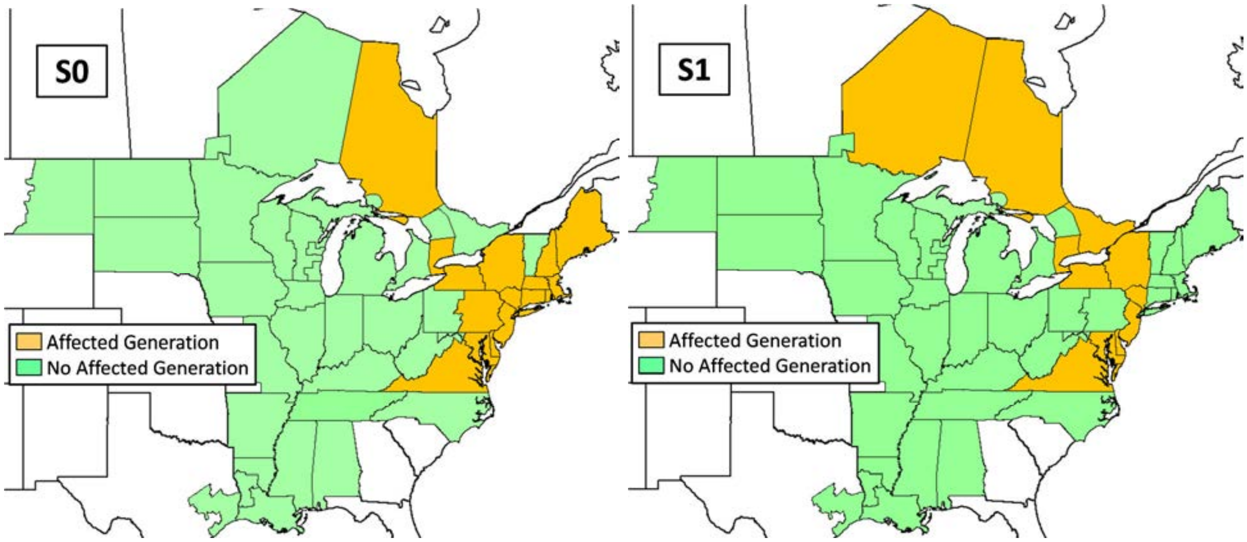


Table 1. Winter 2018 Peak Hour Unserved Generation Demand and Affected Generation

GPCM Location	LGDS S0 Unserved Generation Gas Demand (MDth)	LGDS S0 Affected Generation (MWh)	RGDS S0 Unserved Generation Gas Demand (MDth)	RGDS S0 Affected Generation (MWh)	HGDS S0 Unserved Generation Gas Demand (MDth)	HGDS S0 Affected Generation (MWh)
Connecticut	9.1	1,205	16.0	2,200	21.8	2,990
Delaware	1.1	151	1.6	199	1.3	173
Maine	7.6	1,045	7.6	1,045	9.5	1,292
Maryland Eastern	0.0	0	5.0	539	5.0	539
Massachusetts Eastern	11.4	1,557	12.8	1,781	11.9	1,656
Massachusetts Western	0.0	0	7.8	1,059	7.8	1,059
New Hampshire	4.4	589	9.4	1,245	15.1	1,958
New Jersey	0.0	0	11.2	1,385	23.7	3,101
New York Central Northern	0.6	71	24.4	3,419	43.2	5,224
New York City	9.5	1,236	17.7	2,336	20.6	2,581
New York Long Island	8.7	912	9.4	1,054	8.7	1,025
New York Southern	0.0	0	10.9	1,312	10.9	1,312
New York Western	0.0	0	1.6	179	5.2	699
Ontario Central (CDA)	0.2	28	0.5	55	1.6	181
Ontario Eastern (EDA)	0.0	0	0.0	0	12.2	1,247
Ontario Northern (NDA)	0.0	0	0.8	113	1.2	155
Ontario St. Clair	0.0	0	0.0	0	7.0	950
Ontario Western (WDA)	0.0	0	0.0	0	0.0	0
Pennsylvania Eastern	0.0	0	1.0	143	67.1	9,097
Pennsylvania Western	0.0	0	0.0	0	11.0	1,574
Rhode Island	3.1	410	6.7	887	10.8	1,403
Virginia	8.5	1,146	21.0	2,755	34.2	4,404
Wisconsin Eastern (RFC)	0.0	0	0.0	0	14.8	1,814
Wisconsin Western (MROE)	0.0	0	0.0	0	6.8	838

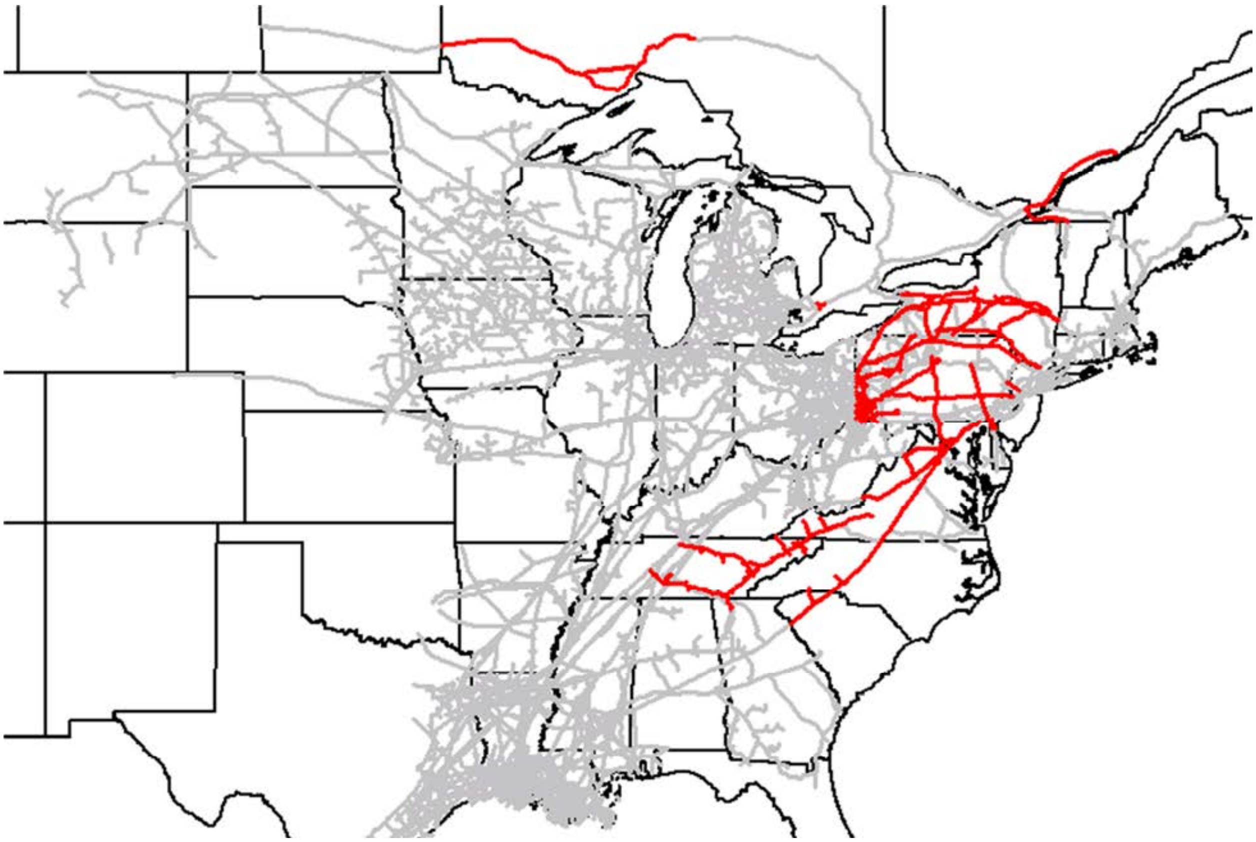
As shown in Table 2, when high winter 2018 peak day spot delivered gas prices tested in RGDS S1 are incorporated in the electric simulation model, the magnitude of the affected generation decreases substantially, and, in many locations is eliminated. Zero affected generation represents oil- and/or coal-fired generation in economic merit. Moreover, LAI recognizes that gas scheduling restrictions to accommodate the nomination/confirmation cycles in the Day Ahead or Real Time Market often deter gas-fired generators without firm entitlements from nominating *any* natural gas for next day delivery during cold snaps. In New York Southern, Ontario (NDA, WDA, and EDA), and Virginia, the affected generation increases under S1 prices, reflecting the increased demand for gas-fired generation from those generators tied to favorable price indices. For example, Dominion South Point or AECO-C pricing points have and are expected to increase much less than most other pricing points across the Study Region on a winter peak day.

Table 2. RGDS S0 v. RGDS S1 Winter 2018: Peak Hour Unserved Generation Demand and Affected Generation

GPCM Location	S0 Unserved Generation Gas Demand (MDth)	S0 Affected Generation (MWh)	S1 Unserved Generation Gas Demand (MDth)	S1 Affected Generation (MWh)
Connecticut	16.0	2,200	0.0	0
Delaware	1.6	199	0.1	9
Maine	7.6	1,045	0.0	0
Maryland Eastern	5.0	539	3.3	311
Massachusetts Eastern	12.8	1,781	0.0	0
Massachusetts Western	7.8	1,059	0.0	0
New Hampshire	9.4	1,245	0.0	0
New Jersey	11.2	1,385	0.7	92
New York Central Northern	24.4	3,419	6.7	754
New York City	17.7	2,336	0.0	0
New York Long Island	9.4	1,054	0.0	0
New York Southern	10.9	1,312	14.3	1,537
New York Western	1.6	179	1.6	179
Ontario – Central (CDA)	0.5	55	0.5	55
Ontario – East (EDA)	0.0	0	0.5	74
Ontario – North (NDA)	0.8	114	1.5	186
Ontario – West (WDA)	0.0	0	0.4	38
Pennsylvania Eastern	1.0	143	0.0	0
Rhode Island	6.7	887	0.0	0
Virginia	21.0	2,755	23.5	3,028

RBAC Inc.'s division of pipelines into segments is embedded in the GPCM infrastructure, and does not always correspond to pipeline tariff-defined zonal divisions, instead relying on locational boundaries in some cases when a tariff zone extends across multiple GPCM locations. The pipeline segments that are constrained during the peak hour of the peak day in winter 2018 for RGDS S0 are shown in red in Figure 11. These pipeline segments represent bottlenecks that equate to transportation deficits affecting gas-fired generators. In conducting this analysis, RCI load is always served fully.[7]

Figure 11. RGDS S0 Winter 2018: Peak Hour Constraints



The results indicate that the areas of greatest congestion are in and around the Northeast, particularly in the New York-Pennsylvania area, where large amounts of gas sourced from Marcellus and Utica, as well as conventional production from the Gulf of Mexico, flow to demand centers across the Study Region. The red across the New York-Pennsylvania area signifies the near complete utilization of existing pipeline and storage infrastructure, a dynamic reflecting more demand for shale gas than take-away capacity in Winter 2018. The red across discrete line segments in TVA does not constrain gas-fired generation in TVA – TVA's generators have firm entitlements – but does result in downstream constraints affecting generation in PJM.

[7] RCI demands, human needs and otherwise, have been given the same priority in GPCM, with generators known to hold firm transportation at the same priority. In actuality, some industrial demands are interruptible, but the interruptible terms and conditions governing an LDC's right to curtail service to industrial customers are not generally in the public domain. Therefore LAI made the simplifying assumption that industrial demand is no different in terms of scheduling priority than other residential and commercial loads. The quantitative impact of this assumption varies by location depending on the amount of industrial demand included in the RCI forecast with the same pipeline connections as affected generation. While a portion of the unserved demand could potentially be shifted to industrial customers from affected generation, the total amount of locational unserved demand and the frequency and duration of the relevant constraint's occurrence would remain unchanged.

These results indicate that pipeline utilization – *not gas deliverability* – is the key constraint. Pipeline utilization represents the fractional use of a pipeline's certificated capability, while gas deliverability reflects the ability of the pipelines doing business in the PPA to transport sufficient commodity gas to meet the coincident gas requirements of RCI customers and gas-fired generators. The distinction between use and delivery capability is vital to the interpretation of these results. For example, the pipelines in New England (Tennessee, Algonquin, Iroquois, Maritimes & Northeast, and PNGTS) are gray, not red, an ostensible paradox in light of the region's well documented deliverability constraints throughout the heating season, November through March. The gray shading should not be construed as evidence of unconstrained deliverability to generators in New England. Instead, model solutions reveal that deliverability *into* New England is the bottleneck, as shown in red across Pennsylvania and New York, reflecting the complete or near complete utilization of primary pipelines linking Marcellus with market centers in NYISO, ISO-NE and IESO. Upstream constraints in Pennsylvania, New Jersey, and New York result in the underutilization of existing west-to-east pipeline capacity within New England on a peak day. Insufficient commodity supplies from Atlantic Canada result in the substantial underutilization of pipeline capacity from the north, a problem in part mitigated by north to south flows from Quebec on PNGTS to northern New England. In sum, this example highlights the impacts that a constraint can, and in many cases does, have on deliverability beyond the constrained segment's physical footprint, while the absence of a constraint on a given segment does not mean that all demands served by that segment are met, if one or more upstream constraints limit the flow of gas into the not-fully-utilized segment.

2.1.4 Frequency and Duration of Constraints

In performing the Target 2 analysis, emphasis has been placed on the frequency and duration of pipeline congestion for the peak hour of each day during the three peak winter and three peak summer months affecting scheduled gas-fired generation across the Study Region. Under S0 prices for each of three scenarios, the total number of constrained days on various pipelines affecting the delivery of gas to gas-fired generators in six PPAs is presented in Table 3. The constraints are listed alphabetically. A detailed discussion regarding the location of the pipeline segments and constraints can be found in Section 6 in the Report.

Table 3. S0 Winter 2018: Total Number of Constrained Days by Scenario

Constraint	LGDS	RGDS	HGDS
Alliance	0	0	10
ANR Northern Illinois	0	0	60
Columbia Gas VA/MD	8	23	57
Columbia Gas W PA/NY	0	21	17
Constitution	89	25	90
Dominion Eastern NY	0	15	21
Dominion Western NY	0	4	34
Dominion Southeast	0	22	22
East Tennessee Mainline	0	9	26
Eastern Shore	21	51	20
Empire Mainline	0	16	60
Great Lakes East	0	0	66
Midwestern	0	0	55
Millennium	7	83	67
NB/NS Supply	44	58	56
NGPL IA/IL North	0	0	51
NGPL IA/IL South	0	0	48
Northern Border Chicago	0	0	46
Northern Natural D	0	0	8
Tennessee Z4 PA	4	62	79
Tennessee Z5 NY	49	90	90
Texas Eastern M2 PA South	79	50	90
Texas Eastern M3 North	19	39	82
TransCanada Ontario West	2	12	8
TransCanada Quebec	23	30	29
Transco Leidy Atlantic	0	59	90
Transco Z5	0	9	21
Transco Z6 Leidy to 210	41	8	90
Union Gas Dawn	3	4	6
Viking Z1	0	0	24

Primary observations from the frequency and duration analysis reveal the following:

- Under the RGDS, there is a high frequency and long duration of pipeline bottlenecks that limit the availability of gas for generation in the MAAC portion of PJM, NYISO, and ISO-NE for a substantial portion of the heating season. Under monthly average gas basis forecast pricing assumptions underlying RGDS S0, the frequency and duration of pipeline bottlenecks can be characterized as moderate to high , especially in New York, New England, the Delmarva Peninsula, Maryland and Virginia, where gas-fired generation is largely dependent on non-firm transportation arrangements.

- Under RGDS assumptions, when higher daily spot gas pricing assumptions underlying the S1 case are tested, there is a substantial reduction in transportation deficits that place affected generation on the peak hour of the peak day in the MAAC portion of PJM, NYISO and ISO-NE, reflecting oil and coal-fired generation in merit. There are no significant transportation deficits in MISO North/Central or MISO South. There are no transportation deficits in TVA under S0 or S1 pricing, reflecting TVA's firm transportation entitlements to serve their fleet of gas-fired generators. In relation to affected generation elsewhere in the Study Region, transportation deficits in IESO under S0 prices are negligible.

- Under the HGDS, the frequency and duration of pipeline bottlenecks limiting the availability of gas for generation are compounded in response to the substitution of gas-fired generation capacity for coal-fired capacity, in particular, as well as the lower LMPs resulting from the projection of lower gas prices, thereby reducing generation output from existing coal-fired generators. The increased frequency and duration of transportation deficits to serve generator demands represents a plausible upper limit on pipeline constraints and is presented for comparison sake in relation to the RGDS. The gas pipeline and storage infrastructure tested in the HGDS is the same as the gas infrastructure delineated in the RGDS. In practice, gas-electric interaction effects would potentially induce generation owners to secure fuel resources and transporters to add or improve deliverability in anticipation of increased gas-fired generation or price pressures affecting unit performance.

- Under the LGDS, the frequency and duration of pipeline bottlenecks limiting the availability of gas for generation is substantially reduced, reflecting increased renewable generation, lower electric load, and much higher commodity gas prices across the Study Region. In response to higher gas prices, capacity factors from the existing coal fleet increase. The LGDS S0 results represent a plausible lower limit on gas transportation constraints affecting the scheduling of gas-fired generation during the peak winter months.

2.2 Key Findings of the Sensitivity Cases

In addition to the three discrete gas demand scenarios and the S1 sensitivities, the PPAs and EIPC stakeholders defined an array of other sensitivities to illustrate the impact of changing one or more variables. All of the sensitivity cases, listed in Table 4, are based on one of the corresponding S0 scenarios.

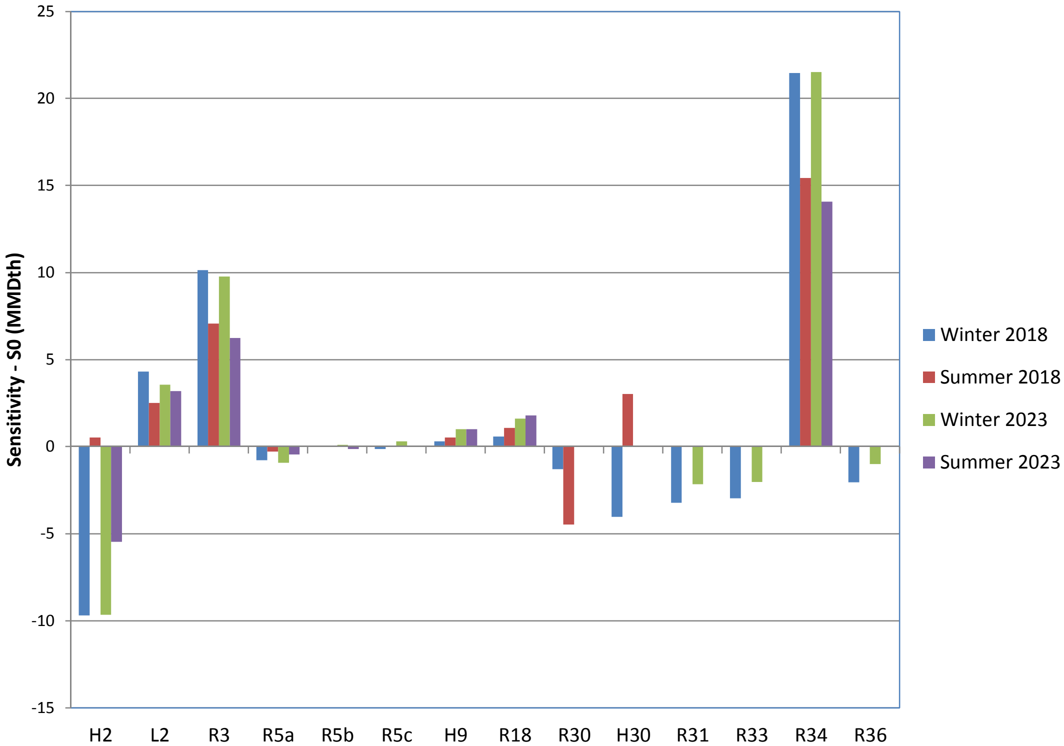
Table 4. Sensitivity Cases

Sensitivity	Description	Year & Season
RGDS S1 HGDS S1 LGDS S1	Apply market gas prices for peak winter day	Winter 2018 Winter 2023
HGDS S2 LGDS S2	Remove decremental (incremental) gas price changes from the HGDS (LGDS)	Winter 2018 Summer 2018 Winter 2023 Summer 2023
RGDS S3	Significantly lower delivered gas prices	Winter 2018 Summer 2018 Winter 2023 Summer 2023
RGDS S5a	Deactivation of additional coal and nuclear resources, replaced by wind and solar resources	Winter 2018 Summer 2018 Winter 2023 Summer 2023
RGDS S5b	Deactivation of additional coal and nuclear resources, replaced by imports of Quebec hydropower	Winter 2023 Summer 2023
RGDS S5c	Deactivation of additional coal and nuclear resources, replaced by EE/DR	Winter 2018 Summer 2018 Winter 2023 Summer 2023
HGDS S9	Ontario nuclear units scheduled to be refurbished instead reach the end of life after 2018 and before 2023; Indian Point 2 & 3 retire by end of 2015	Winter 2018 Summer 2018 Winter 2023 Summer 2023
RGDS S13	Increased infrastructure to enable additional Marcellus/Utica flows to neighboring PPAs	Winter 2018 Summer 2018 Winter 2023 Summer 2023
RGDS S14	Increased gas storage availability and deliverability	Winter 2018 Summer 2018 Winter 2023 Summer 2023
RGDS S16	Increased sendout from Canaport and Distrigas LNG terminals	Winter 2018 Summer 2018 Winter 2023 Summer 2023
RGDS S18	High electric load growth	Winter 2018 Summer 2018 Winter 2023 Summer 2023

Sensitivity	Description	Year & Season
RGDS S19	High industrial gas demand	Winter 2018 Summer 2018 Winter 2023 Summer 2023
RGDS S23	Increased LNG exports from U.S. terminals	Winter 2018 Summer 2018 Winter 2023 Summer 2023
RGDS S30 HGDS S30	Bar gas use in dual fuel resources	Winter 2018 Summer 2018
RGDS S31	Very cold snap with 90/10 electric and RCI gas demands	Winter 2018 Winter 2023
RGDS S33	S31 + high forced outage rate for coal and oil units	Winter 2018 Winter 2023
RGDS S34	Maximum gas demand on electric sector	Winter 2018 Summer 2018 Winter 2023 Summer 2023
RGDS S36	S33 + Selected nuclear units unavailable	Winter 2018 Winter 2023
RGDS S37	S13 + Canaport converted to LNG export facility	Winter 2023 Summer 2023

Figure 12 shows total peak day gas demand for electric generation across the entire Study Region by sensitivity, expressed as the difference between each sensitivity and the corresponding S0 scenario. For example, the data shown for RGDS S3 (shortened to R3) are total peak day electric generation demand for RGDS S3 *minus* total peak day electric generation demand for RGDS S0 across the Study Region. Similarly, the data for HGDS S2 (shortened to H2) are total peak day electric generation gas demand for HGDS S2, *minus* total peak day electric generation gas demand for HGDS S0 across the Study Region. The gas demand is summed over the entire peak day because peak hour gas use is not coincident between each pair of cases. The relative magnitude and direction (positive or negative) of the differential gas demand help to explain the results of the GPCM analysis of the sensitivity cases. Only the sensitivity cases that use different electric sector assumptions are shown in Figure 12.

Figure 12. Total Study Region Peak Day Electric Generation Gas Demand: Sensitivity *minus* S0



For each of the sensitivity cases, figures provided in Section 7 of the report illustrate the quantity of affected generation relative to total gas-fired generation, arising from gas transportation deficits. Table 5 and Table 6 present the amount of affected generation dispatch in the coincident peak hour relative to the total peak load in the respective PPA for all scenarios and sensitivities. Thus, these tables show affected generation as a share of the peak electric demand served by all types of resources, and not just gas-capable resources. Only winter results are shown, because relative to total peak load, the affected generation in the summer seasons is zero or negligible for all PPAs, under all scenarios and sensitivities. The tables use yellow background to indicate moderate shares (5% to 25%) of affected generation to peak load, and red background for higher shares.

Table 5. Peak Hour Affected Generation as Percent of Peak Load - Winter 2018

Scenario/ Sensitivity	IESO	ISO-NE	MISO North/ Central	MISO South	NYISO	PJM	TVA
RGDS S0	1%	38%	0%	0%	36%	4%	0%
HGDS S0	11%	48%	4%	0%	46%	15%	0%
LGDS S0	0%	23%	0%	0%	10%	1%	0%
RGDS S1	2%	0%	0%	0%	11%	3%	0%
HGDS S1	2%	0%	0%	0%	21%	8%	0%
LGDS S1	0%	0%	0%	0%	0%	2%	0%
HGDS S2	5%	36%	0%	0%	2%	11%	0%
LGDS S2	0%	30%	0%	0%	17%	2%	0%
RGDS S3	1%	45%	0%	0%	47%	11%	0%
RGDS S5a	0%	32%	0%	0%	30%	4%	0%
RGDS S5c	0%	45%	0%	0%	36%	3%	0%
HGDS S9	14%	48%	4%	0%	52%	14%	0%
RGDS S13	0%	33%	0%	0%	15%	3%	0%
RGDS S14	1%	38%	0%	0%	36%	4%	0%
RGDS S16	1%	14%	0%	0%	36%	4%	0%
RGDS S18	3%	44%	0%	0%	39%	4%	0%
RGDS S19	1%	38%	0%	0%	36%	7%	0%
RGDS S23	1%	38%	0%	0%	36%	4%	0%
RGDS S30	1%	43%	0%	0%	15%	4%	0%
HGDS S30	5%	43%	0%	0%	19%	12%	0%
RGDS S31	2%	0%	0%	0%	17%	8%	0%
RGDS S33	2%	0%	0%	2%	17%	8%	0%
RGDS S34	8%	51%	8%	0%	51%	25%	1%
RGDS S36	2%	0%	0%	0%	17%	8%	0%

Table 6. Peak Hour Affected Generation as Percent of Peak Load - Winter 2023

Scenario/ Sensitivity	IESO	ISO-NE	MISO North/ Central	MISO South	NYISO	PJM	TVA
RGDS S0	2%	38%	0%	0%	44%	10%	0%
HGDS S0	19%	43%	12%	0%	45%	17%	0%
LGDS S0	1%	25%	0%	0%	29%	3%	0%
RGDS S1	2%	0%	0%	0%	17%	8%	0%
HGDS S1	6%	0%	0%	0%	20%	8%	0%
LGDS S1	2%	0%	0%	0%	5%	2%	0%
HGDS S2	11%	31%	0%	0%	4%	13%	0%
LGDS S2	1%	27%	0%	0%	25%	5%	0%
RGDS S3	9%	43%	0%	0%	36%	17%	0%
RGDS S5a	1%	31%	0%	0%	45%	10%	0%
RGDS S5b	2%	41%	0%	0%	45%	10%	0%
RGDS S5c	2%	40%	0%	0%	44%	11%	0%
HGDS S9	21%	42%	12%	0%	52%	17%	0%
RGDS S13	2%	23%	0%	0%	12%	4%	0%
RGDS S14	2%	38%	0%	0%	44%	10%	0%
RGDS S16	2%	13%	0%	0%	44%	10%	0%
RGDS S18	4%	40%	0%	0%	44%	11%	0%
RGDS S19	2%	38%	0%	0%	44%	10%	0%
RGDS S23	2%	38%	0%	0%	44%	10%	0%
RGDS S31	6%	0%	0%	0%	19%	7%	0%
RGDS S33	6%	0%	0%	0%	18%	7%	0%
RGDS S34	22%	50%	14%	2%	47%	32%	1%
RGDS S36	6%	0%	0%	0%	19%	7%	0%
RGDS S37	2%	38%	0%	0%	32%	4%	0%

For the three S0 scenarios, a comparison of Table 5 and Table 6 with Figure 6 and Figure 8 indicates that the affected generation in ISO-NE and NYISO is a large portion of not only the PPA's total gas-fired capacity, but also of total load. Affected generation in PJM represents a significantly smaller share of total load than of total gas-fired generation.

Comparisons across the sensitivity cases in Figure 12, Table 5, and Table 6 reveal the following:

- The only variable changed in the S1, S2, and S3 sensitivities (relative to the corresponding S0 base scenario) is gas price. Increasing gas prices in HGDS S1 and HGDS S2 relative to HGDS S0 and in LGDS S1 relative to LGDS S0 results in a significant decrease in gas usage and in affected generation. Decreasing gas prices in LGDS S2 and RGDS S3 relative to LGDS S0 and RGDS S0, respectively, increases gas usage and affected generation across nearly all PPAs. The changes in gas prices present some exceptions to the general pattern of results, particularly where there is a significant amount of gas-fired generation tied to lower cost pricing points, thereby changing the level of transmission interchange between neighboring PPAs and between zones within a PPA.

- The S1 sensitivities, as well as RGDS S31, RGDS S33, and RGDS S36 all incorporate high spot gas prices during a cold snap. In ISO-NE, NYISO, and, to a lesser extent, PJM, the material reduction in affected generation reflects broad substitution of oil-fired generation for gas. The substitution effect in PJM's RTO and MISO North/Central also reflects the reduction in affected generation as a result of increased coal-fired generation.

- RGDS S5a, RGDS S5b, RGDS S5c, and HGDS S9 involve substitution of non-gas-fired resources (coal and nuclear) for other types of non-gas-fired resources (wind, solar, hydro, and EE/DR.) Thus, the impacts on affected generation are negligible, as expected.

- RGDS S13 involves increased infrastructure to transport incremental volumes from the Marcellus and Utica shale production area to neighboring PPAs. The difference in affected generation in PJM is comparatively small as the affected generators in Delaware, Maryland, and Virginia are served by or located downstream of Columbia Gas, Dominion, Eastern Shore, and Transco segments that are constrained in RGDS S0 and not expanded by the incremental infrastructure projects assumed in RGDS S13. Affected generation in NYISO and ISO-NE is reduced in Winter 2018 because greater volumes of gas can move west to east as a result of assumed infrastructure improvements to segments that are constrained in RGDS S0. Affected generation in PJM, NYISO and ISO-NE is further reduced in Winter 2023 following the addition of Tennessee's Northeast Energy Direct Project in Q4-2018, not in time to ameliorate constraints on the peak hour of the peak day in 2018, which is assumed to occur in January.[8]

- RGDS S14 involves a 10% increase in conventional storage capacity and daily withdrawal capability at storage facilities across the Study Region. In most cases, storage facilities are located upstream of the pipeline constraints identified in RGDS S0. Therefore, expanding withdrawal capability does not have a commensurate impact on deliverability to gas-fired generators.

- RGDS S16 involves the reenergization of the Distrigas and Canaport LNG import terminals. Assumed utilization of the regasification capability at both import terminals revitalizes the operational flexibility on Tennessee's high pressure system around Boston, Algonquin's medium pressure system around Boston, and Maritimes & Northeast's (M&N's) high pressure system into Northern New England. Affected generation in ISO-NE is significantly reduced as a result of east-end gas supply availability. However, the import volumes are not sufficient to reduce affected generation in NYISO or PJM.

- RGDS S23 and RGDS S37 involve increased LNG exports. In RGDS S23 the in-service dates for the Cove Point and Freeport export facilities are advanced so that they are active in 2018, the Lake Charles export facility is assumed to be in service in 2018, and the Cameron export facility is assumed to be in service in 2023. The addition of LNG export

[8] Tennessee's Northeast Energy Direct Project is a Kinder Morgan pipeline.

facilities in MISO South does not impact the affected gas-fired generation across the Study Region. The advancement of the Dominion Cove Point export facility does result in approximately 1 GWh of incremental affected generation in PJM relative to RGDS S0 due to the increase in exports from 400 MDth/d to 1,000 MDth/d and the assumed prioritization of export volumes, which are transported via the constrained Columbia Gas, Dominion, and Transco pipeline segments in Virginia and Maryland. Like the turnaround of the Dominion LNG facility, in RGDS S37 the Canaport LNG import terminal is switched around for daily liquefaction to export up to 1.0 Bcf/d. Tennessee's Northeast Energy Direct Project, which is assumed to expand transportation capacity from Marcellus to Dracut by 2.2 Bcf/d, and Algonquin's Atlantic Bridge Project, which is assumed to be commercialized with a total capacity of 600 MDth/d in RGDS S13, are supplemented by incremental capacity on M&N to enable transportation from eastern Massachusetts to Canaport. These improvements would enable gas to flow south to north on M&N for export without any denigration of RCI customers' entitlements. Affected generation in ISO-NE is unchanged in RGDS S37 relative to RGDS S0, but reduced relative to RGDS S13 because gas from Marcellus that is available for delivery to generators following additional infrastructure improvements is instead allocated to exports in RGDS S37.

- RGDS S30, HGDS S30 and RGDS S34 involve forcing the type of fuel used by dual-fuel units. In S30, dual-fuel units are restricted to burning only oil or coal, while in S34, dual fuel units are restricted to burning only gas. The impacts of these sensitivities are therefore linked to the amount of dual-fuel capacity in each PPA. Affected generation in NYISO is significantly reduced in Winter 2018 in RGDS S30. The HGDS 30 reduction in affected generation is more widespread, with effects seen in IESO, ISO-NE, MISO North/Central, NYISO and PJM. In RGDS S34, the amount of affected generation significantly increases in IESO, ISO-NE, MISO North/Central, PJM and NYISO in both Winter 2018 and Winter 2023, with a smaller amount of affected generation also appearing in TVA during Winter 2018 and Winter 2023 and in MISO South during Winter 2023.

- RGDS S18 and RGDS S19 involve increased gas demand due to higher electric load and higher industrial demand, respectively. The amount of affected generation in RGDS S18 generally increases relative to RGDS S0, commensurate with the increase in load and consequent gas demand. The only change in the amount of affected generation is a notable increase in PJM for Winter 2018, specifically in eastern Pennsylvania and New Jersey, which are the easternmost locations with significant deliveries to non-firm generators in RGDS S0, and therefore first to be affected when west-to-east flows are instead allocated to increased firm demand in RGDS S19.

2.3 Mitigation Measures to Alleviate or Avoid Pipeline Constraints

The most economical means of mitigating a specific constraint are highly dependent on the unique characteristics of the pipeline and of the individual affected generators. Mitigation of the constraint therefore involves one or more physical infrastructure improvements and/or leveraging of existing dual fuel infrastructure to ensure that supply and demand are in balance not only on the peak hour of the peak day in Winter 2018 or Winter 2023, but also throughout the three-month peak heating season, January, February and December, as well as during the summer to the extent a constraint materializes during extreme heat. In delineating the potential mitigation measures applicable to reduce or eliminate constraints across the Study Region, LAI has focused on Winter 2018. This is because Winter 2023 is beyond the normal pipeline and storage company planning and investment horizon.

There are a number of mitigation measures available to pipeline companies, generation companies, fuel suppliers, and/or PPAs to alleviate a pipeline constraint affecting gas-fired generation. *For high frequency and/or long duration constraints* resulting in the non-scheduling or interruption of gas-fired generation in one or more PPAs, one of the most economic mitigation measures, in lieu of adding backup fuel capability, may be the installation of additional pipeline capacity that is available throughout the peak heating season, in particular, but more generally throughout the year to support gas-fired generation. In order to install additional capacity, a pipeline would need to demonstrate market support in the form of a service agreement for firm transportation or firm storage as part of a Certificate of Public Convenience and Necessity application filing at FERC. In LAI's experience, additional pipeline capacity can be realized in a variety of ways (from high cost to low cost):

- a pipeline company may develop a new pipeline from a liquid sourcing point to the market center to support incremental gas-fired generation;

- a pipeline may install loopline and/or additional compression along the constrained segment, subject to maximum allowable operating pressure (MAOP) limitations.

In addition to pipeline solutions, a gas-fired generator may add dual fuel capability to facilitate fuel assurance.

Examples where high frequency and/or long duration constraints could be alleviated by increased capacity resulting from the installation of loopline and/or compression include: Tennessee's Zone 4 and Zone 5 segments from Marcellus; Transco's Leidy Atlantic segment from Pennsylvania to Maryland and Virginia; and, Texas Eastern's M3 Northern path into New Jersey and downstate New York. As discussed in Section 8, other loopline and compression mitigation measures are recommended to alleviate both high and moderate frequency and duration constraints.

For low frequency, short duration constraints resulting in the non-scheduling or interruption of gas-fired generation in one or more PPAs, the most economic mitigation measure may be the use of liquid fuels. The use of liquid fuels may be obtained from existing oil tanks, or it may require the installation of new oil tanks to accommodate the drawdown of ULSD for combined cycle and/or simple cycle units. To the extent the low frequency, low duration constraints occur during a substantial portion of the heating season and there is idled LNG import capacity available from one or more existing pipelines, one mitigation measure would incorporate a financial approach. Such a financial approach would involve bringing additional cargoes to an existing LNG import facility through a seasonal service from an LNG supplier or marketer, which may be a viable mitigation measure in ISO-NE for either the Distrigas terminal in Massachusetts or the Canaport terminal in New Brunswick. In PJM, the Cove Point terminal is assumed to convert to an export facility, but a potential mitigation measure would be to contract with shippers holding firm transportation and/or storage rights on the Cove Point system to redeploy gas otherwise bound to the liquefaction plant for brief duration during cold snaps or short term operating contingencies, and utilize the existing LNG storage infrastructure at to maintain timely export shipments.

Throughout the Study Region, construction of new satellite LNG tanks either on a pipeline or behind an LDC citygate is not considered a viable mitigation measure to ameliorate a low frequency, short duration constraint, although use of existing or new on-site oil storage tanks and dual-fuel capability is a potential mitigation measure for this type of constraint. Comparing the costs of dual-fuel capability and incremental firm transportation capacity to provide fuel assurance is the focus of the Target 4 analysis. From high cost to low cost, potential mitigation measures include:

- a PPA, fuel supplier, or marketer could arrange for a seasonal LNG peaking service requiring the commitment of one or more destination flexible cargoes to the Repsol Canaport and/or Suez Distrigas import facilities, or by contracting for short-term flow diversions with shippers holding firm service at the Dominion Cove Point LNG export terminal;

- a generator could add dual-fuel capability by modifying equipment and constructing on-site oil tank capacity, while lining up oil inventory to assure adequate fuel deliverability during one or more cold snaps throughout the peak heating season;

- an LDC could activate industrial gas Demand Response to deliver gas via displacement to one or more generators otherwise short gas supply; and,

- a generator could use existing oil inventory held in storage to supplant pipeline rendered supply.

There are diverse mitigation measures designed to alleviate low frequency, short duration constraints. Innovative mitigation measures that may obviate the need for new pipeline and/or compression include commercial initiatives such as implementation of a seasonal peaking service or flow day diversion arrangement with Dominion Cove Point's export customers to alleviate constraints on Dominion Southeast. Another commercial mitigation measure could include bringing additional cargoes into the LNG import terminals in New Brunswick and eastern Massachusetts to revitalize deliverability throughout the heating season in New England. Use of existing oil storage in PJM, NYISO and ISO-NE to alleviate constraints on pipelines from Marcellus to major market centers in the mid-Atlantic and greater Northeast is also a possible mitigation measure to facilitate reliability objectives in three of six PPAs.

2.4 Summary of Key Market Dynamics and Risk Factors

The impact of various market dynamics and the underlying risk factors affecting gas infrastructure adequacy in six PPAs are summarized in Table 7. Based on the results for the three scenarios and array of case sensitivities, risk factors are intended to represent the impact of specific physical or commercial factors affecting the gas infrastructure adequacy in each of six PPAs. As shown across the rows in Table 7, LAI has defined twelve market dynamics or risk factors affecting gas infrastructure adequacy in each of six PPAs. A brief discussion follows.

- "Transport deficits" pertains to the frequency and duration of locational constraints that affect generation by location within one or more PPAs.

- "New pipeline additions" pertains to the number and size of the pipeline and/or storage facility additions by 2018, but it does not pertain to LAI's treatment of generic pipeline additions in 2023 to keep pace with increased RCI loads.

- "Proximity to shale gas" pertains to the PPA's physical proximity to major shale gas reserves in Marcellus and Utica shale basins, in particular.

- "Reversal-of-flow" pertains to the benefits of operational flexibility attributable to low technology improvements pipeline operators are able to implement on a fast track to accommodate the increased penetration of shale gas across much of the Study Region.

- "Available coal output" pertains to the potential retirement of additional coal resources across the Study Region relative to the assumed level of coal deactivations in the RGDS and the HGDS due to environmental regulation and economic pressures on the profitability of coal generation due to low cost natural gas.

- "Nuclear retirements / delay" pertains to the retirement of specific nuclear generation units or the possibility of units being delayed due to refurbishment.

- "LNG Import Constraints" pertains to the large loss of the LNG import capability at the Repsol Canaport facility in New Brunswick and the Suez Distrigas facility outside Boston. It does not represent any loss of LDCs' satellite storage capability behind the citygate.

- "LNG Export Constraints" pertains to the potential transportation bottlenecks that may materialize in PJM and/or MISO South attributable to dedicated deliverability to support the LNG export regime from one facility in Maryland and various facilities in the Gulf of Mexico.

- "Transmission transfer limits (Electric)" pertains to the impact of new electric transmission projects added to the electric topology of the Study Region in regard to the impact on pipeline infrastructure adequacy.

- "Generator firm transportation entitlements" pertains to the relative number of gas-fired generators in each PPA that rely on firm rather than non-firm transportation entitlements – both interstate or interprovincial, as well as local arrangements where such generation is located behind the citygate – as well as the portion of a generator's Maximum Daily Quantity (MDQ) that is firm.

- "Generation reliance on non-firm arrangements" pertains to the relative number of gas-fired generators in each PPA that rely on non-firm transportation arrangements for all or the majority of the generator's MDQ.

- "Dual fuel capability" pertains to the relative portion of gas-fired generation in each PPA that also has dual fuel capability, which may help withstand daily restrictions regarding the scheduling of natural gas under non-firm arrangements.

- Finally, "renewables penetration" pertains to the relative amount of wind generation operating in each PPA, coupled with new resources in each PPA's generation queue. To the extent there are disruptions in wind output due to random days when the wind does not blow, the PPA would be expected to rely more on gas-fired generation.

Based on the results of the scenario and case sensitivity analyses, in distilling the impact of the uncertainty factors across the scenarios and sensitivities evaluated, green shading should be interpreted as negligible or no impact associated with the market dynamic or risk criterion affecting gas-fired generators in each PPA during the winter 2018 season. Summer considerations are not part of the evaluation presented below. Yellow shading should be interpreted as low to moderate impact to affected generation. Red shading should be interpreted as high impact affecting the scheduling of gas-fired generation. Throughout the remainder of this section, LAI has limited its comments to subject areas that have been shaded red.

Table 7. Summary of Risk Factors and Market Dynamics Affecting Gas Infrastructure Adequacy in Six PPAs (Winter 2018)

Market Dynamic and/or Risk Factor	IESO	ISO-NE	MISO		NYISO	PJM	TVA
			North/ Central	South			
Transport Deficits							
New Pipeline Additions							
Proximity to Shale Gas							
Reversal-of-Flow							
Available Coal Output							
Nuclear Retirements/delay							
LNG Import Constraints							
LNG Export Constraints							
Transmission Transfer Limits (Electric)							
Generator FT Entitlements							
Generator Reliance on Non-Firm Arrangements							
Dual Fuel Capability							
Renewables Penetration							

- In IESO, the only significant risk factor affecting the scheduling of gas-fired generation in any of the sensitivities pertains to nuclear availability. IESO reports that one Bruce unit and one Darlington unit are scheduled to be out for refurbishment in 2018, returning before 2023. One other Bruce unit and two Darlington units are scheduled to be out for refurbishment in 2023. The possible retirement or delayed restart of various nuclear units heightens IESO's dependence on gas-fired generation, a significant portion of which may be expected to rely on non-firm transportation arrangements. In relation to total electricity demand in Ontario and that derived from gas-fired generators with assured fuel supply, the amount of affected generation is small.

- In ISO-NE, *regarding frequency and duration results,* transportation deficits recur throughout the peak heating season due to upstream constraints into New England on both Tennessee and Algonquin, the decline in north-to-south flow on M&N, and the loss of daily regasification of LNG into Tennessee and Algonquin. Boundary flow assumptions into M&N and PNGTS do not alleviate mainline constraints ascribable to west-to-east or south-to-north flows from Marcellus into the region. *Regarding new pipeline additions*, unlike the other PPAs, pipeline additions into New England to accommodate shale gas production are limited to Spectra's scaled down 342-MDth/d AIM Project and Tennessee's 72-MDth/d Connecticut Expansion Project. Entitlement holders for both projects are LDCs and municipal utilities in New England, not gas-fired generation companies. *Regarding proximity to shale gas*, the load center in New England is about 300 miles from the current production center in Marcellus. There is no known developable supply in New England's geologic formations. *Regarding reversal of flow,* such pipeline improvements provide operators with greater flexibility for forward- and back-hauls to accommodate shale gas production. This operational dynamic does not apply in New England. *Regarding LNG import constraints*, the decline in LNG imports reflects a valuation difference in the U.K., E.U. and Asia relative to the U.S., in particular New England. Destination-flexible cargoes are therefore expected to head elsewhere, not New England.[9][10] The loss of daily regasification into M&N, Tennessee, and Algonquin from the Repsol Canaport and Suez Distrigas LNG import terminals reduces supply as much as 1.2 Bcf/d, thereby exacerbating the decline in the region's portfolio diversity. ISO-NE's increased dependence on transportation arrangements from Marcellus vis-à-vis Tennessee and Algonquin exposes regional generators to systematic non-scheduling of nominations or interruptions whenever congestion materializes in New York. *Regarding generator reliance on non-firm transportation arrangements*, the majority of gas-fired generators throughout New England rely on secondary firm, interruptible transportation or Asset Management Agreements for all or the lion's share of their MDQs. When pipeline congestion materializes, generators in New England experience constraints on the availability of natural gas to generator plant gates throughout the region. Collectively, the red marks for six evaluation criteria place gas-fired generators substantially affected throughout the peak heating season in 2018 and 2023.

- In MISO North/Central, the region's coal fleet will come under several new environmental requirements between now and the end of the study period. EPA's Mercury and Air Toxics Standard (MATS) requires compliance prior to 2018. Some coal-fired unit owners intend to invest in new technology to control mercury emissions, or have announced their retirement. While the resource mix for 2018 in the RGDS reflects expected coal plant attrition, the actual rate of attrition may be higher, and potentially even higher than the assumed attrition in the HGDS resource mix, thereby increasing reliance on gas-fired resources across the PPA. Strategies to reduce carbon emissions from existing plants to achieve proposed targets under Section 111(d) of the Clean Air Act (EPA's proposed "Clean Power Plan"), as well as implementation of the Cross-State Air Pollution Rule (CSAPR) and a more stringent air quality standard for

[9] Exelerate Energy's Northeast Gateway offshore LNG terminal is being tested for deliveries during the 2014-15 heating season due to expected high spot prices. Due to the timing of this development, it has not been incorporated in the primary study parameters.

[10] After completion of this analysis in 2014, there were increased LNG shipments to New England during the 2014-15 winter season. This change may or may not be indicative of market dynamics in 2018 and/or 2023. The impact of significant regasification at Canaport in Distrigas is addressed in Sensitivity 16. It would not be feasible to revise the assumptions used in the base case model underlying the RGDS, LGDS, or HGDS.

ozone, may further result in increasing economic pressures on coal units before 2023. EPA standards for cooling water intake structures were recently finalized. Some existing steam plants, as well as some nuclear units, may be required to retrofit new technologies to meet standards to protect aquatic life. Plants will be off-line during the retrofit, thereby reducing available generation capacity. Some units may not be able to rationalize the investment, and may elect to retire.

- In NYISO, *regarding frequency and duration results and generators' reliance on non-firm transportation arrangements,* the transportation deficits in the Capital District, Lower Hudson Valley (LHV), and downstate New York recur throughout the peak heating season in response to high RCI loads locally and downstream in New England. As a general rule, generators in NYISO rely on non-firm transportation arrangements, particularly in downstate New York across the New York Facilities System. High LDC sendout during cold snaps therefore subordinates gas demand for generators that depend on slack delivery capability on Transco, Texas Eastern, Tennessee, Millennium, Dominion, Columbia, and Iroquois for secondary firm or interruptible transportation service. While recent expansions on Texas Eastern and Transco into the New York Facilities System materially improves the delivery profile of Marcellus gas supply into downstate New York, receipts at key gate stations in the Capital District, LHV, New York City, and Long Island are dedicated to serve RCI loads during the peak heating season, and upstream constraints limit transportation of incremental gas supplies. The anticipated commercialization of the Constitution pipeline increases Iroquois's supply diversity, but the Constitution constraint limits deliverability to generators served by Iroquois. These risk factors are offset by the significant amount of dual-fuel capacity located in southeastern NY which is available to mitigate the effect of gas deliverability constraints on the bulk electric system.

- In PJM, *regarding frequency and duration results* and *generators' reliance on non-firm transportation arrangements*, the transportation deficits in Virginia, Eastern Maryland, and the Delmarva Peninsula are affected by intermittent constraints due to deliverability limitations on Columbia Gas, Dominion, and Transco. Generators on the Delmarva peninsula experience more frequent constraints due to deliverability limitations on Eastern Shore relative to the amount of RCI demand served by the pipeline. Constraints on Texas Eastern that limit gas flows from west to east on both the northern and southern lines through Pennsylvania during approximately half of the heating season affect generators not only in eastern Pennsylvania and New Jersey, but also in downstate New York and New England. Several significant pipeline expansion projects have been announced since the study inputs were set that may help to alleviate some of these constraints. Like generators in ISO-NE, NYISO, and MISO, the majority of generators in PJM do not have firm transportation entitlements for all or a portion of their respective MDQs. High RCI sendout during the peak heating season therefore exposes gas-fired generators to potential transportation deficits. *Regarding uncertainties surrounding the availability of coal generation*, the prior MISO discussion is applicable to PJM as well. *Regarding nuclear availability*, uncertainties surrounding the continued operation of Byron and Quad Cities in Illinois and the retirement of Oyster Creek in New Jersey may result in transportation constraints as gas-fired generation supplants lost nuclear energy production.

- In TVA, there are no significant transportation constraints that are forecast over the study horizon. TVA's procurement policy ensures fuel deliverability under adverse operating conditions across interstate pipelines serving the south, mid-Atlantic and greater Northeast.

3 ELECTRIC SECTOR GAS DEMANDS

This section describes the key inputs to and results of the AURORAxmp model, which was used to determine hourly gas demands for the three winter and three summer months of 2018 and 2023. It provides an explanation of the basis for determining the generating resources that were included in each scenario in the AURORAxmp model and how the default resource data in AURORAxmp and the data received from the PPAs were reconciled. The modeling of the resources for each scenario is discussed, including how renewable resources and demand response resources were represented in the model. The resource differences for each of the scenarios are summarized. Other key assumptions, including the fuel price and emission allowance price forecasts are discussed. In the final subsection, the gas demands for the electric generation sector are presented for each PPA, under each scenario, year, and season.

3.1 ELECTRIC SYSTEM MODEL

A set of electric system production simulation runs of the three scenarios and multiple sensitivity cases was conducted using the AURORAxmp platform in order to delineate the hourly level of gas demand for gas-fired generators on a peak winter day and peak summer day, and throughout the winter and summer seasons. The simulations were conducted for two study years, 2018 and 2023. AURORAxmp is a comprehensive electricity system modeling software and data package.[11] AURORAxmp simulates the unit commitment and economic dispatch of individual generating units based on the operating characteristics of each unit, such as maximum capacity and minimum load, heat rate curves, fuel and emissions costs, minimum up and down times, and non-fuel variable O&M expense. The core of AURORAxmp is a fast hourly dispatch algorithm that simulates the commitment and dispatch of power plants in a chronological, multi-zone, transmission-constrained system. For this study, LAI used AURORAxmp's transport transmission (zonal) modeling capability. Scenario-specific gas prices, loads, and resources were data inputs for the RGDS, HGDS, and LGDS. Multiple "change sets" were created to replace selected data items relative to these base data sets for the sensitivity cases.

3.1.1 Electric Transmission Topology

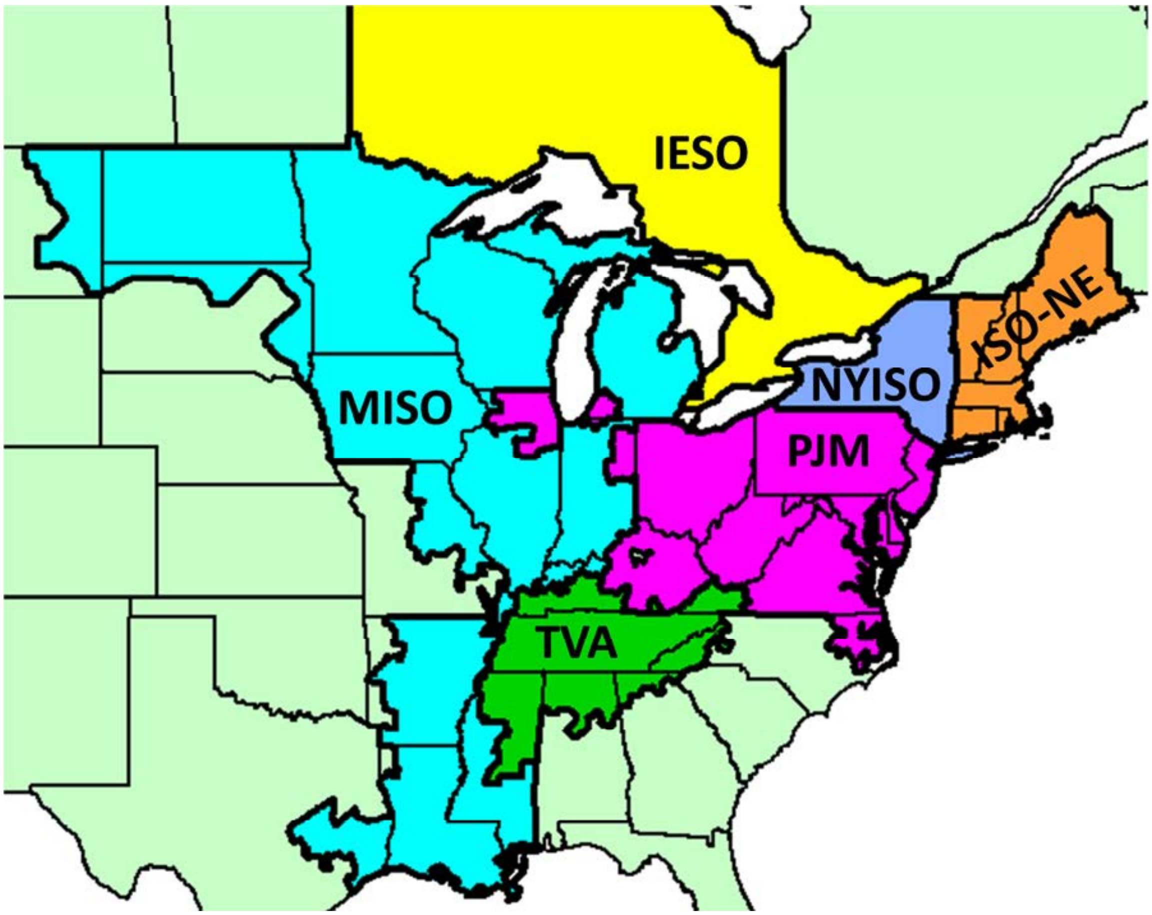
The Study Region encompasses the electricity market areas for all six PPAs, as shown in Figure 13. The electric system model region also includes surrounding balancing areas and transmission interchange between the PPAs and their neighboring balancing areas. The external zones included in the neighboring balancing areas are Quebec, New Brunswick, Manitoba, Midwest Reliability Organization (MRO-US West), Southwest Power Pool (SPP), SERC South, VACAR South, Associated Electric Cooperative Inc. (AECI), and LG&E and KU Services Company (LGE).[12] The external zones were modeled in order to allow hourly interchanges between PPAs and external zones to respond to the range of scenario or sensitivity drivers that represent different conditions within the Study Region. This approach captures any impact changes in external energy flows would have on the commitment and dispatch of gas-fired

[11] EPIS, Inc. has licensed the AURORAxmp software and database to users since its founding in 1996. LAI is a licensee of AURORAxmp.

[12] Manitoba is part of the MISO reliability coordination area, but is not part of the MISO market area. Market areas for the PPAs are used as the geographic basis for this study.

generators within the six PPAs. Florida and Saskatchewan, while part of the Eastern Interconnection, were not modeled because they were assumed to have no material impact on the commitment and dispatch of gas-fired units within the six PPAs. This "open" border representation is particularly important for the two external zones, LGE and AECI, which link surrounding PPA zones, and allow power transfers between PPA zones.

Figure 13. Geographic Overview of Study Region



Each of the PPAs is divided into zones based on transmission constraints. Each zone is comprised of one or more local delivery areas (LDA or "area"). Exhibit 1 provides a list of the PPAs, zones, and areas included in the Study Region.

The PPAs provided information regarding the transfer limits between zones and multi-zone simultaneous interface limits. LAI assembled the information provided by the PPAs to create the "pipes and bubbles" diagram shown in Figure 14, which is consistent with the transmission system represented in the Roll-up Integration Case models. The HGDS and the LGDS utilize the same transmission topology shown in Figure 14. The zone-to-zone transfer limits differ by flow direction for some links. The multi-zone interface limits for PJM and NYISO represent physical flow constraints. The interface envelope around the TVA zones is a policy constraint to prevent simultaneous net exports.

Hurdle rates ($/MWh) for transfers between jurisdictions, provided in Exhibit 2, are similar to but may be higher than actual wheeling rates. No hurdle rates were used for transfers between zones within a PPA. The same real dollar hurdle rates were used for both the 2018 and 2023 cases by escalating at the general rate of inflation. For the same links, the hurdle rates used in the EIPC Phase 1 Study were adopted. For links not modeled in the EIPC Phase 1 Study, LAI developed additional consistent hurdle rates. ISO-NE hurdle rates for transfers to Quebec and New Brunswick were based on current ISO-NE OATT Schedule 8 through-and-out (TOUT) rates, and the same rates were applied to flows into ISO-NE. NYISO hurdle rates for transfers from (to) Quebec were assumed to be the same as the Phase 1 Study hurdle rates for NYISO exchanges with IESO. IESO hurdle rates for transfers from (to) Quebec were assumed equal to Ont_N – MRO_MB rates from the EIPC Phase 1 Study.

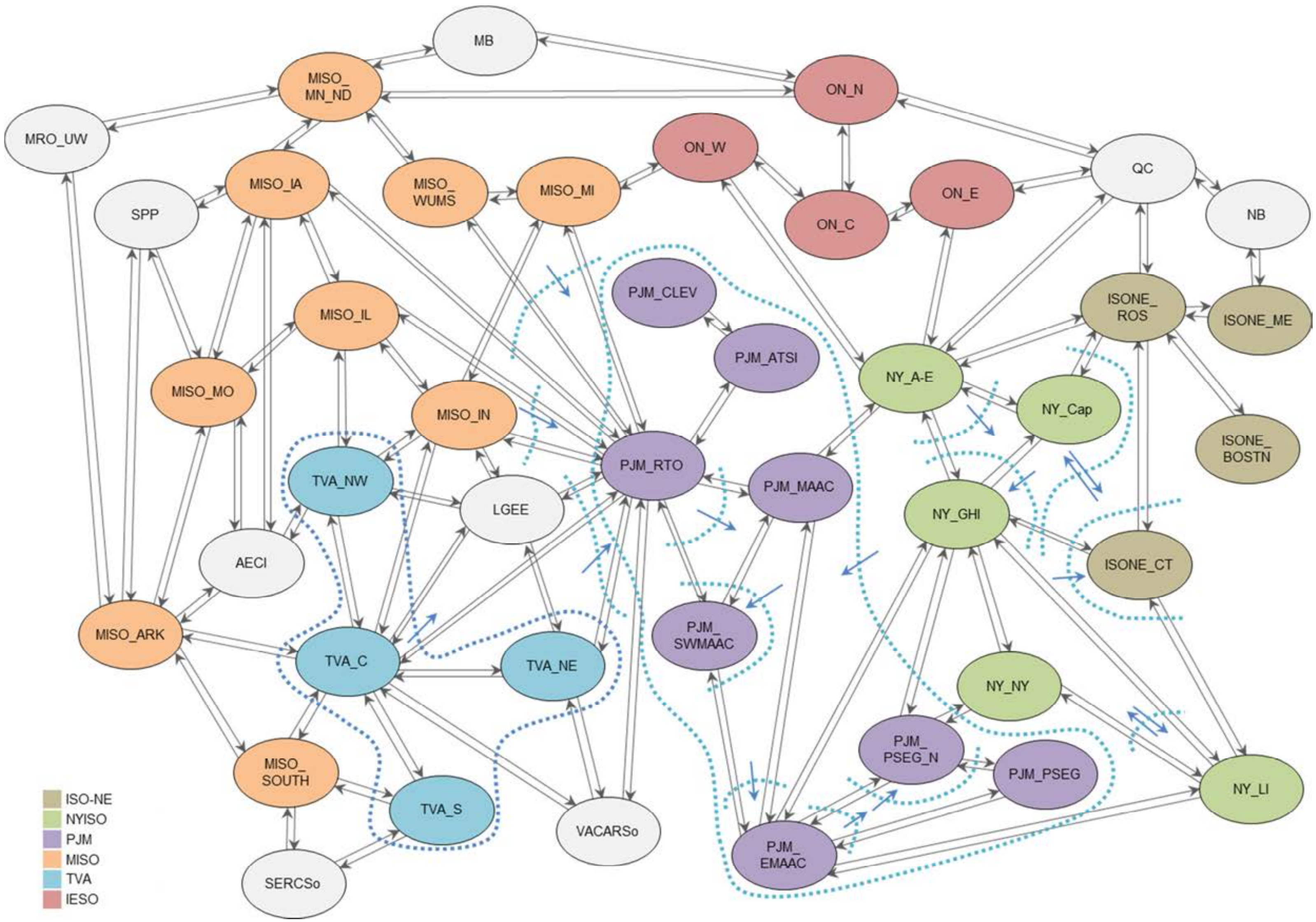
For the RGDS S0, as well as the HGDS S0 and the LGDS S0 cases, the PPAs provided information regarding new transmission projects, which were incorporated into the zonal transfer capability limits of the transmission topology or as a virtual generator. These projects are:

- NYISO: TOTS project 1 – Marcy-South Series Compensation (including Fraser – Coopers Corners reconductoring)
- NYISO: TOTS project 2 – Rock Tavern – Ramapo Second 345kV Line
- NYISO: TOTS project 3 – Staten Island Unbottling (Series of 345kV transmission line upgrades)
- ISO-NE: Northern Pass Transmission (NPT) HVDC line and projects in support of NPT
- PJM: Multiple projects[13]

All of these projects increase transfer limits by 2018.

13 Over 200 transmission projects at various voltage levels have been included in PJM's transmission project updates to the Roll-up Cases.
http://www.eipconline.com/uploads/List_of_PPA_Transmission_Projects_for_Update_to_Roll-up_5-14-14.pdf

Figure 14. Electric System Topology



In the model topology represented in Figure 14, the names of five PJM zones (bubbles) have been shortened, omitting the term "rest of" but should be understood as follows:

- PJM_RTO includes all PJM loads and resources except those in PJM_ATSI and PJM_MAAC.
- PJM_ATSI includes all ATSI loads and resources except those in PJM_CLEV.
- PJM_MAAC includes all MAAC loads and resources except those in PJM_EMAAC and PJM_SWMAAC.
- PJM_EMAAC includes all EMAAC loads and resources except those in PJM_PSEG.
- PJM_PSEG includes all PSEG loads and resources except those in PJM_PSEG_N.

Except for the PJM imports interface limit, the other multi-zone interface limits in PJM represent nested constrained areas.

3.1.2 Electric Load

3.1.2.1 RGDS Load

Each PPA provided some combination of the following data consistent with the summer peak hours data provided for the Roll-Up Integration Cases: historic hourly load by area, base year hourly load profiles, and monthly or annual peak demand and average energy forecasts or growth factors over the Study Period. LAI supplemented the load data provided directly by the PPAs with publicly available information to create load data for AURORAxmp.[14] These data consist of hourly profiles by modeled area for a base (typical) year expressed as percentages of annual average demand (MWh/h) by area for the base year, annual peak demand (MW) by area for the base year, annual growth factors for peak demand over the Study Period, and average growth factors for total annual energy load by area over the Study Period. The model aggregates hourly area loads into zonal loads. The AURORAxmp default load data was used for the area loads of the external zones.

Annual average energy and peak load by zone for the RGDS are included in Exhibit 3. The RGDS load represents normal (50:50) weather conditions, consistent with the assumption of the Roll-Up Integration Cases.

3.1.2.2 HGDS and LGDS Loads

The HGDS incorporates higher electric loads, driven by an assumed increase in economic activity relative to the RGDS. The LGDS incorporates lower electric loads, reflecting a decrease in economic activity relative to the RGDS. For the U.S. PPAs, the electric loads in the

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[14] PPA load forecast data in Excel files are posted at: http://www.pjm.com/planning/resource-adequacy-planning/load-forecast-dev-process.aspx and http://www.iso-ne.com/trans/celt/report/

Supplemental information from: ISO-NE, *2013 Regional System Plan*, available at http://www.iso-ne.com/trans/rsp/index.html and *NYISO 2013 Load and Capacity Data "Gold Book*," available at:

http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Documents_and_Resources/Planning_Data_and_Reference_Docs/Data_and_Reference_Docs/2013_GoldBook.pdf alternative gas demand scenarios were scaled using factors calculated from the regional electricity forecasts tabulated as "Delivered Energy Consumption All Sectors" in the Energy Information Administration (EIA) *Annual Energy Outlook 2013* (AEO2013).[15] For each region modeled in the AEO2013 that is within the EIPC footprint, the ratios of the High Economic Growth Case electricity consumption relative to the Reference Case electricity consumption were calculated for 2018 and 2023. Similarly, the ratios of the AEO2013 Low Economic Growth Case to the Reference Case were calculated for 2018 and 2023 for each region. The ratios calculated from the AEO2013 regions were applied to the corresponding areas. For areas that straddle two AEO2013 regions, the ratios were averaged. The RGDS annual peak load and average energy load values were multiplied by these ratios for each of the two study years to form the electric load assumptions for the HGDS and the LGDS. For Ontario, the electric loads for the HGDS are based on IESO's high growth demand forecast, while the electric loads for the LGDS were assumed to have an annual decline of 0.5% from the RGDS. The load multipliers are provided in Exhibit 4.

3.1.3 RGDS Resources

3.1.3.1 <u>Summary of Resources Based on Roll-Up Integration Cases</u>

Resources in the AURORAxmp model comprising the RGDS were reconciled with the resources in the Roll-Up Integration Cases. At the bus level, the resources in the Roll-Up Integration Cases were mapped to resources defined in the EPIS database for AURORAxmp. The focus of the reconciliation was on units larger than 15 MW, but smaller resources are also included based on data either from the PPAs or otherwise available through the default EPIS data. Aggregation or disaggregation of individual units at a generating station to a named resource entity was done as required for consistency. Some busses are common for multiple units, and some resources include multiple generators on multiple busses. The reconciled list of resources by PPA included in the RGDS is provided in Exhibit 5.[16] Capacities shown for thermal resources are their summer ratings, taken to the extent possible from the Roll Up Integration Case, while full or nameplate ratings are shown for hydro, wind, solar, and demand response (DR) resources. In the AURORAxmp model, net capability by season is used. Thermal resources, especially combustion turbines, tend to have higher winter than summer capabilities. PPA or publicly-available data were used for seasonal capability profiles. New resources for external areas were added to the default AURORAxmp database of existing resources, based on Appendix C of the Roll-Up Integration Cases study. The resources in the external areas were held the same for all scenarios and sensitivities. A summary of capacities aggregated by fuel and technology type across the Study Region based on the Roll-Up Integration Cases is illustrated in Figure 15. Details are provided in Exhibit 6.

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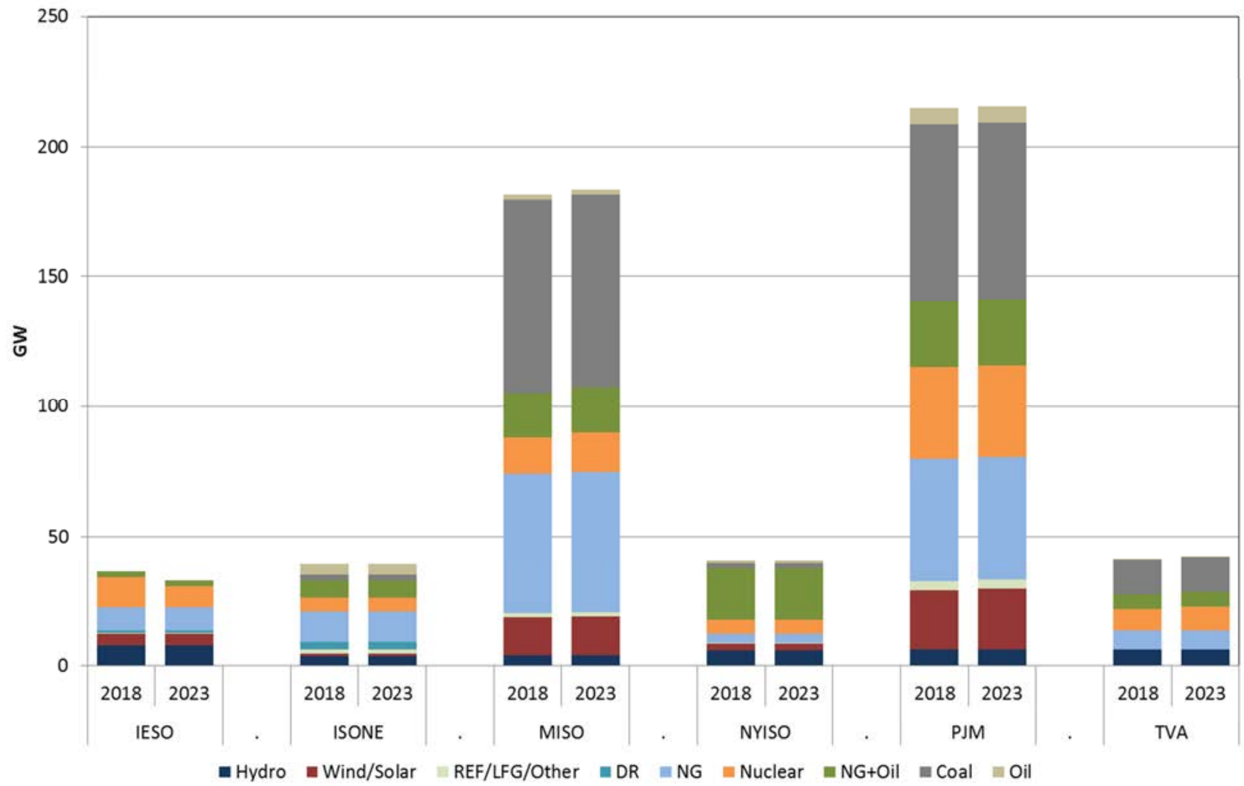
[15] http://www.eia.gov/forecasts/archive/aeo13/

[16] Adjustments to unit capacities from the Roll-Up Integration Cases have been made in Exhibit 5 for consistency.

Figure 15. Summary of Capacity by Technology and Fuel Type in RGDS Based on Roll-Up Integration Cases, 2018 and 2023



Subsequent to incorporation of the resources from the Roll-Up Integration Cases into an AURORAxmp database, the PPAs provided LAI with a list of existing or planned resource changes that have occurred since the Roll-Up Integration Cases data were finalized.[17] These changes include:

- New generation resources not included in the Roll-Up Integration Cases.
- Removal of planned new resources based on queue withdrawal notices.
- Uprates and derates of existing resources.
- Unit retirements or deactivations which have occurred or will occur prior to or during the study period.

This updated information has been used to construct the list of resources and capacities in the RGDS S0 scenario. A summary of the S0 resources by technology and fuel type is shown in Figure 16, with details provided in Exhibit 5. There is little noticeable difference in total capacity or technology and fuel mix between 2018 and 2023. This is because the queue for each PPA has very few retirement or new entry generators beyond 2018. Lists of at-risk generators

[17] Incremental transmission projects are listed on page 42.

were incorporated in formulating the HGDS rather than in the RGDS. The changes from the RGDS Roll-Up to the S0 resource capacities, aggregated by fuel and technology type across the Study Region, are illustrated in Figure 17. Details are provided in Exhibit 6.

Figure 16. Summary of Capacity by Technology and Fuel Type in RGDS S0, 2018 and 2023

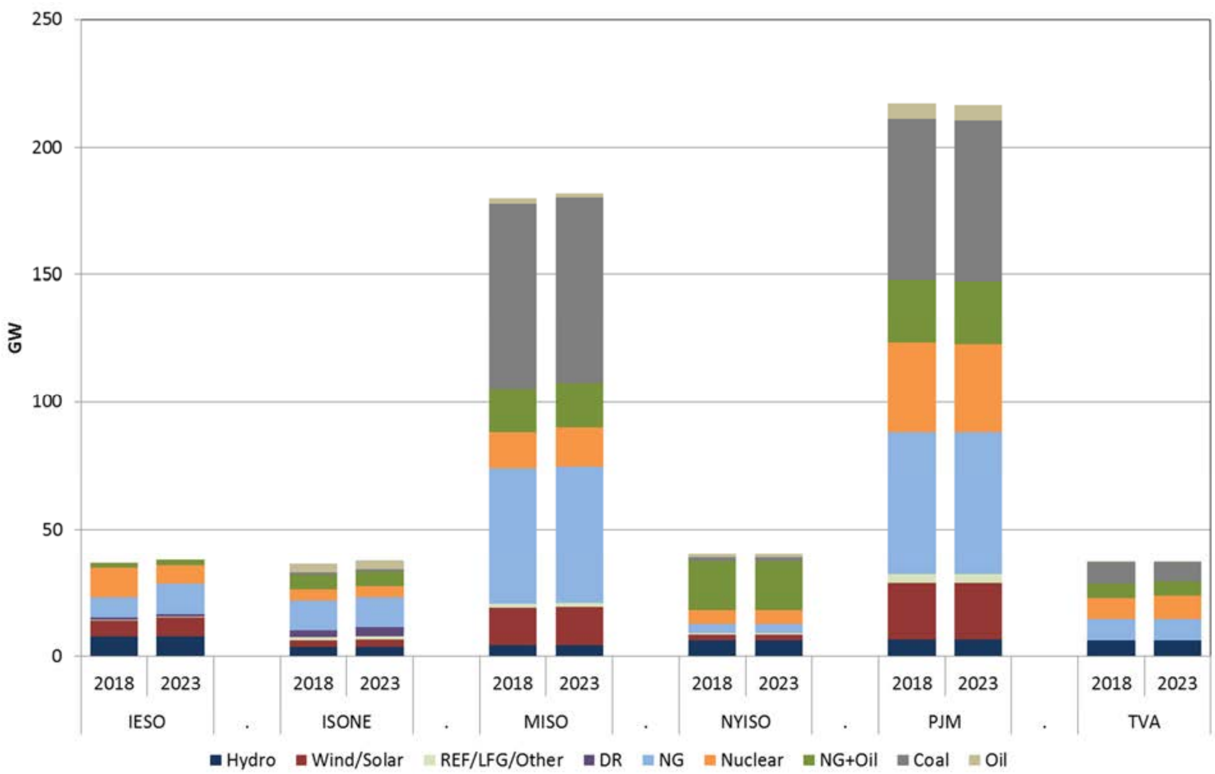
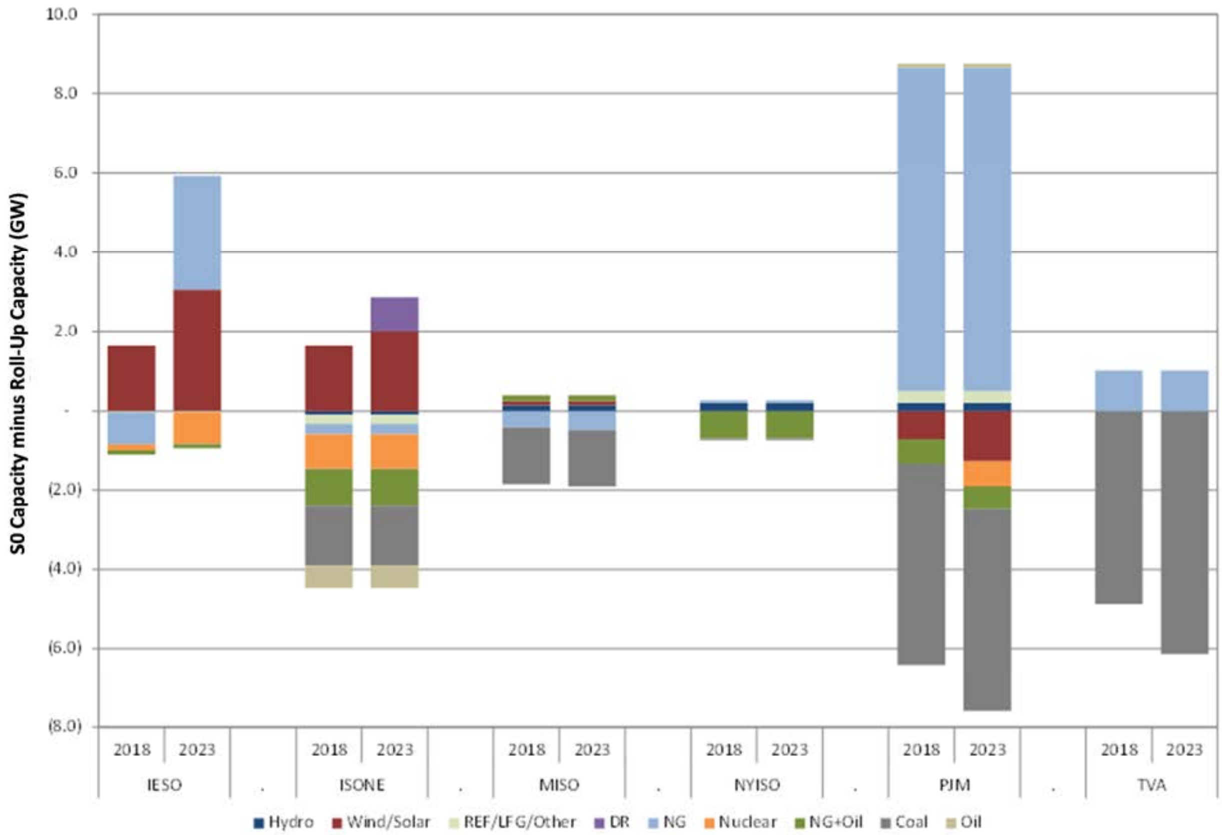


Figure 17. Summary of Resource Capacity Changes by Technology and Fuel Type in RGDS (S0 minus Roll –up)



3.1.3.2 Energy Profiles for Renewable Resources

PPAs with significant hydro energy generation, NYISO and IESO, provided monthly hydro energy profiles and monthly lower and upper limits on hydro dispatch for large hydroelectric plants or all hydroelectric resources in a zone. AURORAxmp hydro dispatch run control settings were used to schedule hourly hydro dispatch. Due to time constraints for this study and model limitations, the hourly dispatch of Ontario resources was flatter across the day than for actual dispatch, especially for the summer season. This results in a conservative assumption that increases gas-fired generation by Ontario resources during peak hours.

The AURORAxmp database includes hourly energy production profiles for existing and planned wind resources in most areas. These hourly energy production profiles are commonly referred to as “wind shapes” and have been differentiated by area and for onshore or offshore wind turbines. For U.S. locations, the production profiles are based on the National Renewable Energy Laboratory (NREL) Eastern Wind Dataset, which includes onshore and offshore energy production data.[18] Where such data were missing in the default AURORAxmp database from EPIS for U.S. areas that have no existing wind capacity, LAI developed consistent data from information obtained directly from the NREL Eastern Wind Dataset. NREL data cover three

[18] http://www.nrel.gov/electricity/transmission/eastern_wind_methodology.html

years, 2004 through 2006. The average of these three years was used to develop the wind shapes. For Ontario, the IESO provided LAI with ten years of hourly wind shape data for each Zone within IESO. The average of the wind data for the same three years, 2004 to 2006, was used for the IESO zones.

There are only a small number of areas with solar PV resources in the Roll-up Report. LAI used NREL's PVWATTS model to generate hourly solar shapes for each area where new solar PV resources are installed in any scenario.[19]

3.1.3.3 Demand Response Resources

Active DR resources that are fully dispatched when the price reaches a pre-defined threshold are represented in AURORAxmp as "virtual generators." Energy efficiency (EE) is either embedded in the load forecast and therefore are not explicitly modeled as a resource, or is modeled as a virtual generators if it is price-responsive[20]

The levels of the activation or "trigger" energy prices for "virtual generators" representing DR resources are set by considering the number of hours that the DR resource can be activated in a season or year for each program. The DR trigger prices are set at the level that would result in activation of the DR resources for the applicable number of program hours during certain system conditions.[21] The trigger price of virtual generators representing EE resources is set at zero to ensure activation of the EE resources at all system conditions.

3.1.3.4 Deactivated Units

The resources in the AURORAxmp model exclude existing units that the PPAs have designated as being idled, mothballed, retired, or otherwise deactivated prior to the 2018 or 2023 study years. The RGDS Roll-up resource list conforms to the Roll-Up Integration Cases, and the RGDS S0 includes updated retirement information provided by the PPAs.

3.1.4 HGDS Resources

The resources specified for the HGDS are premised on a significant increase in natural gas usage, primarily driven by lower natural gas prices and greater deactivation of existing coal-fired resources relative to the RGDS. More resources are also needed in every PPA to maintain the minimum planning reserve margin for the higher loads projected for the HGDS. The increased coal-fired capacity attrition is the result of lower LMPs relative to the marginal cost of coal-fired energy, which reflects higher environmental compliance costs relative to the RGDS. In the HGDS, the loss of this coal-fired capacity is replaced entirely by additional gas-fired combined cycle resources. The HGDS incorporates the simplifying assumption that the replacement gas-

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[19] http://rredc.nrel.gov/solar/calculators/pvwatts/version1/

[20] A virtual generator may be used to represent demand response programs, injections of energy from a transmission line, or power contracts by representing its dispatch via generator characteristics such as fuel cost or generation schedule. Like an actual power plant, a virtual generator allows the specified resource to contribute to the energy and peak electrical demand in its designated area.

[21] DR trigger prices are differentiated by PPA and may vary by program.

fired resources would likely be located at or near the deactivated generating stations, and that the additional capacity gas-fired resources would be distributed so as to maintain minimum planning reserve margins, in order to more fully utilize existing electric transmission infrastructure.

To determine which resources to deactivate for the HGDS, LAI started with the resource lists for the RGDS S0 and the RGDS Roll-up. From these resources, LAI removed all of the "at-risk" units that were identified by several PPAs.[22] These at-risk units may include oil-fired steam units and coal resources for the U.S. PPAs and specific Ontario nuclear units for which plant refurbishments may result in delays in return to service. For PPAs that did not provide "at risk" lists or other specific deactivations for the HGDS, LAI relied on published reports that provided an outlook of potential future coal retirements, on a net summer capacity basis aggregated by region. These reports are listed in Table 8. Data in the EIA and NERC studies were reasonably consistent across the Study Region. Absent a specific at-risk list from a PPA, the net attrition of coal plants for each study year relative to 2014 was used to derive the total amount of coal-fired resources deactivated in the PPA region. Adjustments were made to conform NERC regions to the PPA footprint. The recent MISO survey of generation owners (listed in Table 8) provided an indication of the strategies that coal plants expect to undertake to comply with new EPA regulations. Thus, for MISO, the quantity of deactivated coal-fired capacity in the HGDS is based on the capacity of coal-fired plants identified in the survey responses in which generation plant owners indicated that repowering to a non-coal fuel to meet environmental requirements is likely to be uneconomic. In IESO, there are no remaining coal resources in the RGDS. Coal use by Ontario generators ended in 2013.

Table 8. Sources of Deactivated Coal Capacity Forecasts

EIA Annual Energy Outlook (AEO) 2014 Early Release[23] http://www.eia.gov/forecasts/aeo/er/tables_ref.cfm
North American Electric Reliability Corporation (NERC) 2013 Long-Term Reliability Assessment, December 9, 2013. http://www.nerc.com/pa/RAPA/ra/Pages/default.aspx
4th Quarter 2013 EPA Survey Update, MISO Planning Advisory Committee Meeting, 2/19/2014. Sum of capacity responding as "Uneconomic/Replace" and "Repower" plus half of capacity under "TBD" and "No Response" https://www.misoenergy.org/Library/MeetingMaterials/Pages/PAC.aspx

The reports listed in Table 8 do not identify the specific units deemed to be "at risk." If the total capacity of the designated at-risk units provided by a PPA, plus the new deactivations not included in the Roll-Up Integration Case was less than the target retirement quantity based on the

[22] Resources that are present in the RGDS Roll-up but retired or deactivated in the RGDS S0 are also considered to be "at risk" and thus are deactivated for both the HGDS Roll-up and the HGDS S0.

[23] The Final AEO2014 report was released by EIA in April 2014. The regional data tables required to derive the quantity of deactivated coal resources by area were not included in the April 2014 release and therefore were not available when the analysis was conducted. However, there was no difference in the total US coal capacity forecast between the Early Release and the Final AEO2014, so the regional data were assumed to be identical between the Early Release and the Final versions.

reports listed in Table 8, we applied the following criteria to prioritize additional units for deactivation:[24]

1. Low capacity factor − Units that had a capacity factor below 50% in 2013, based on EPA CEMS (continuous emission monitoring system) data

2. Low efficiency − Smaller units with higher heat rates

3. Lack of mercury emission controls – Coal units that do not have emissions controls, in particular wet scrubbers and activated carbon injection, will need significant upgrades and consequently will require large investments to comply with federal Mercury and Air Toxics Standards (MATS) requirements

4. Age − Older coal units are deactivated before newer units.

For purposes of the Target 2 analysis, the PPAs have made the assumption that replacement gas-fired capacity is located in the same area as the deactivated coal units. Additionally, generic gas-fired capacity was added in the HGDS as needed to maintain approximately the same reserve margins as in the RGDS, with priority given to areas with the largest capacity shortfall relative to the RGDS. Therefore, no change to the determination of transfer capability limits across the Study Region was required. For the purposes of the zonal electric modeling topology, the location specificity need only be at the zone level. For purposes of associating the generic gas units with a gas market pricing point, the area level provides the nearest pipeline location reference. Some replacement gas-fired capacity could be repowered at the sites of deactivated coal units, but that is not a focus of this study or an explicit selection criterion. Most of the generic gas-fired capacity additions are combined cycle plants.

The resource mix in the HGDS S0 relative to the RGDS Roll-up is provided in Exhibit 6 and illustrated in Figure 18 through Figure 23 for each PPA. Replacement gas-fired capacity is added in 550 MW blocks. Due to the assumed "lumpiness" of replacement capacity blocks, the match between deactivated capacity and replacement capacity is approximate. In the case of IESO, the incremental deactivated nuclear capacity in the HGDS represents a delay in return from refurbishment. IESO does not assume a long-term investment in replacement capacity is needed during the nuclear refurbishment program period. Therefore, no replacement gas-fired capacity was added in Ontario to cover the postulated delayed restart of certain Ontario nuclear units.

[24] A detailed financial analysis was not conducted on individual coal plants.

Figure 18. Resources by Scenario and Year – IESO

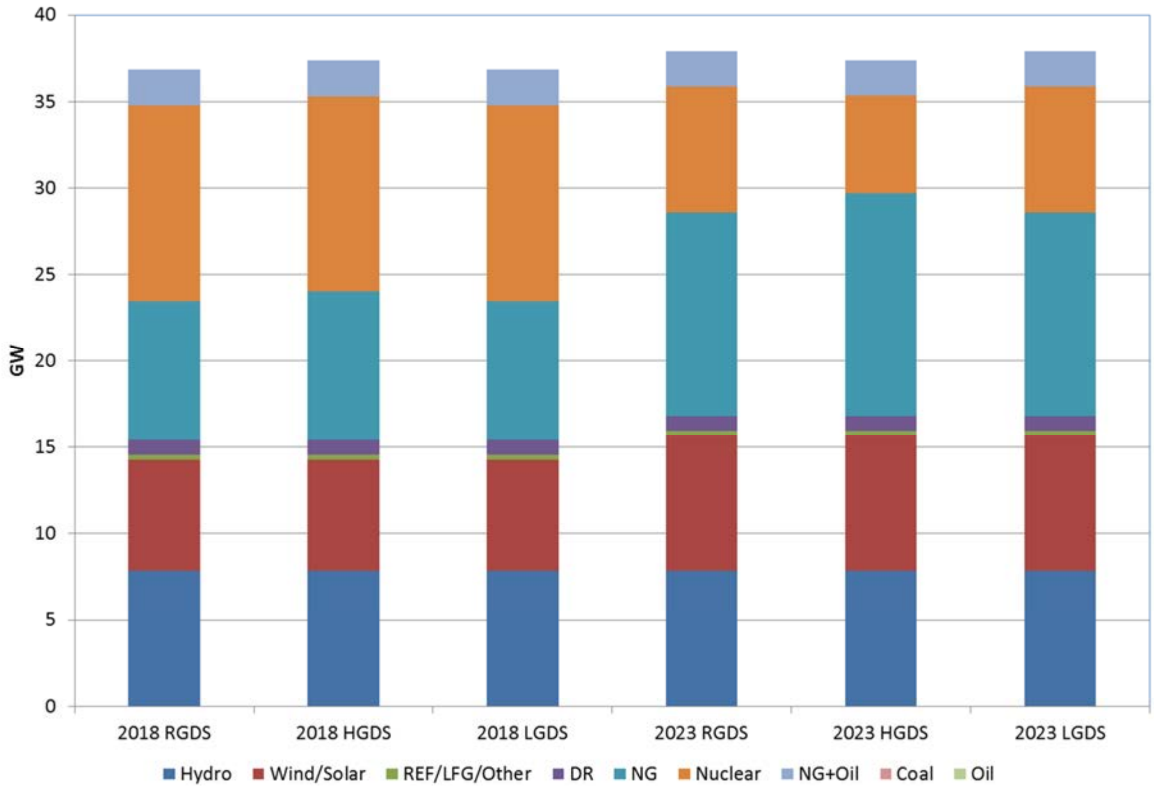


Figure 19. Resources by Scenario and Year – ISO-NE

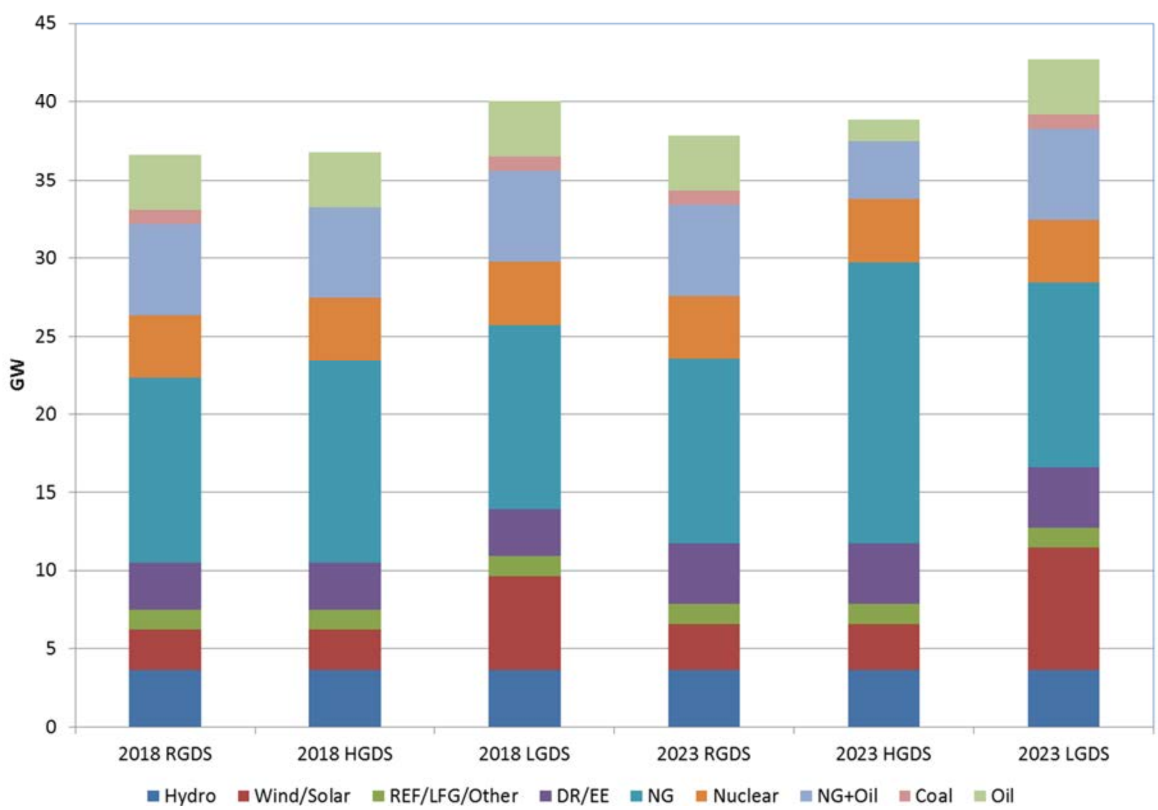


Figure 20. Resources by Scenario and Year – MISO

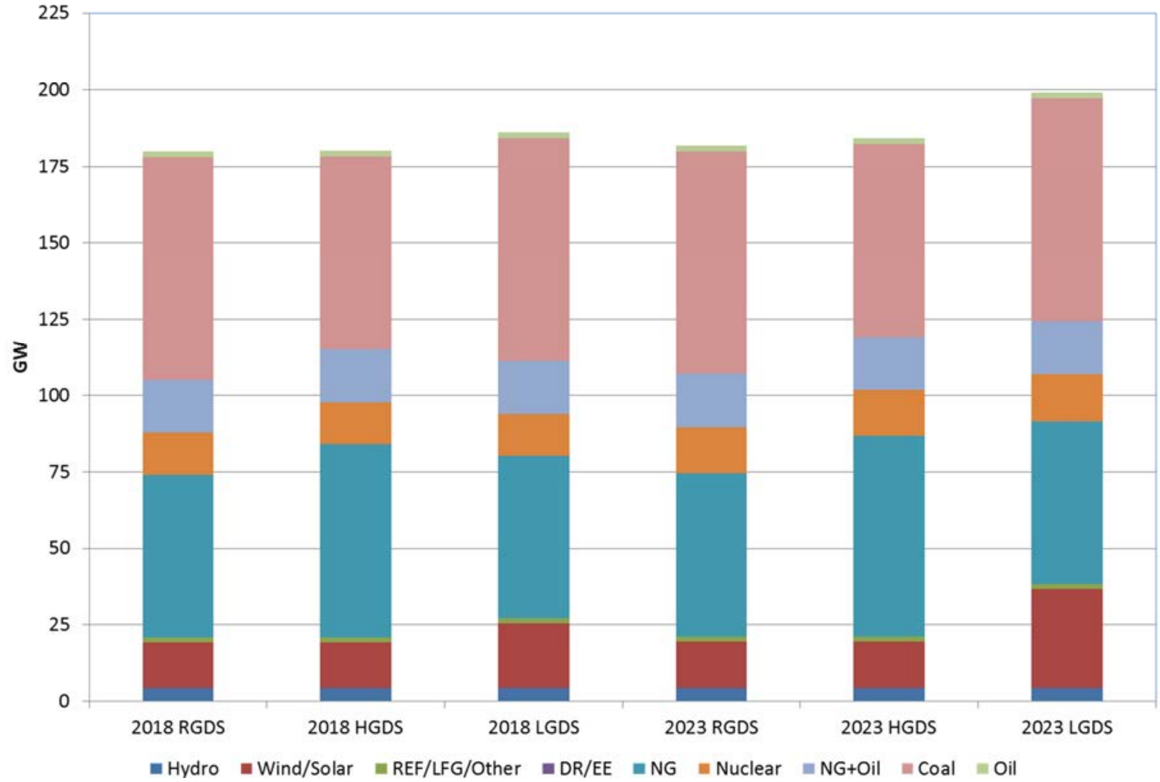


Figure 21. Resources by Scenario and Year – NYISO

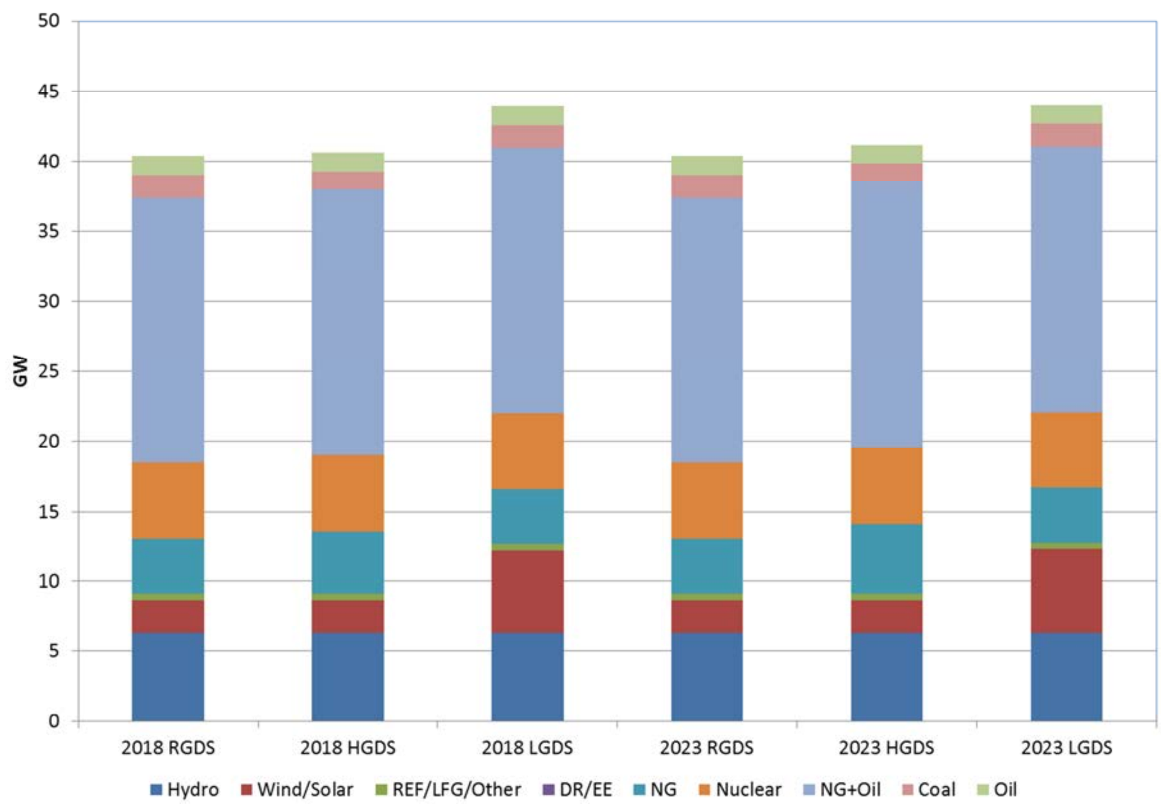


Figure 22. Resources by Scenario and Year – PJM

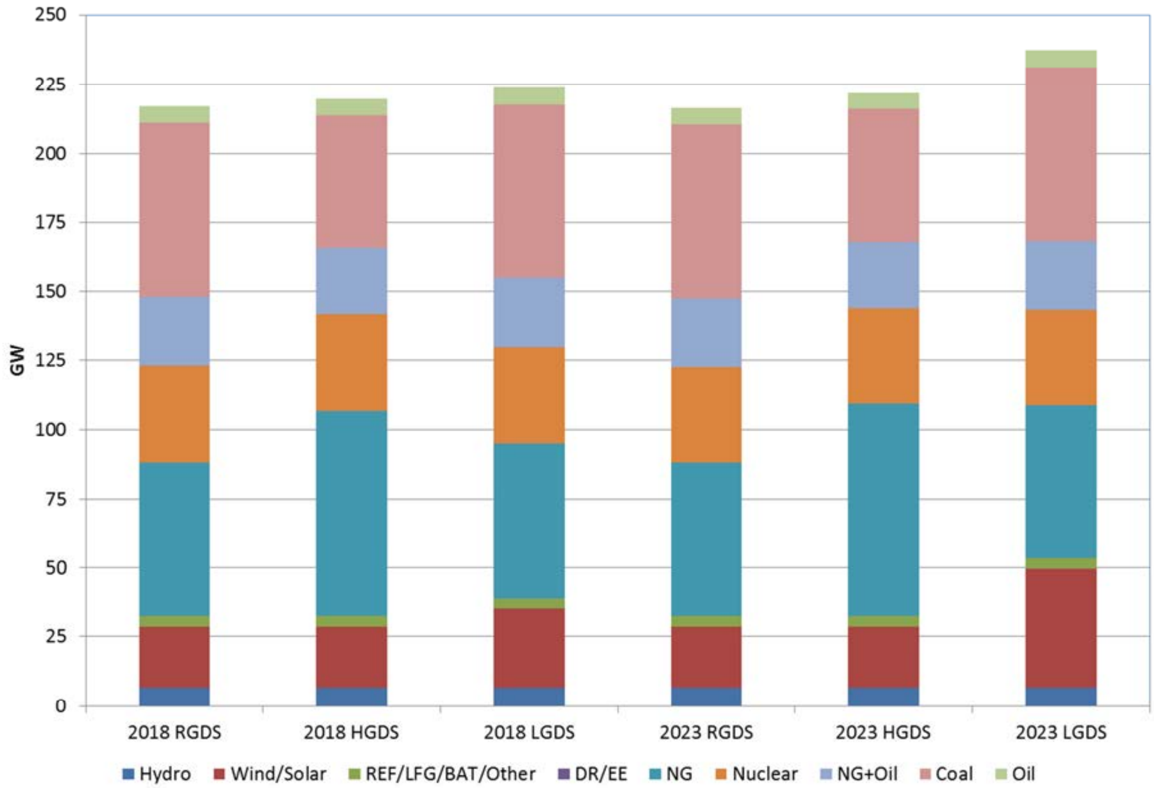
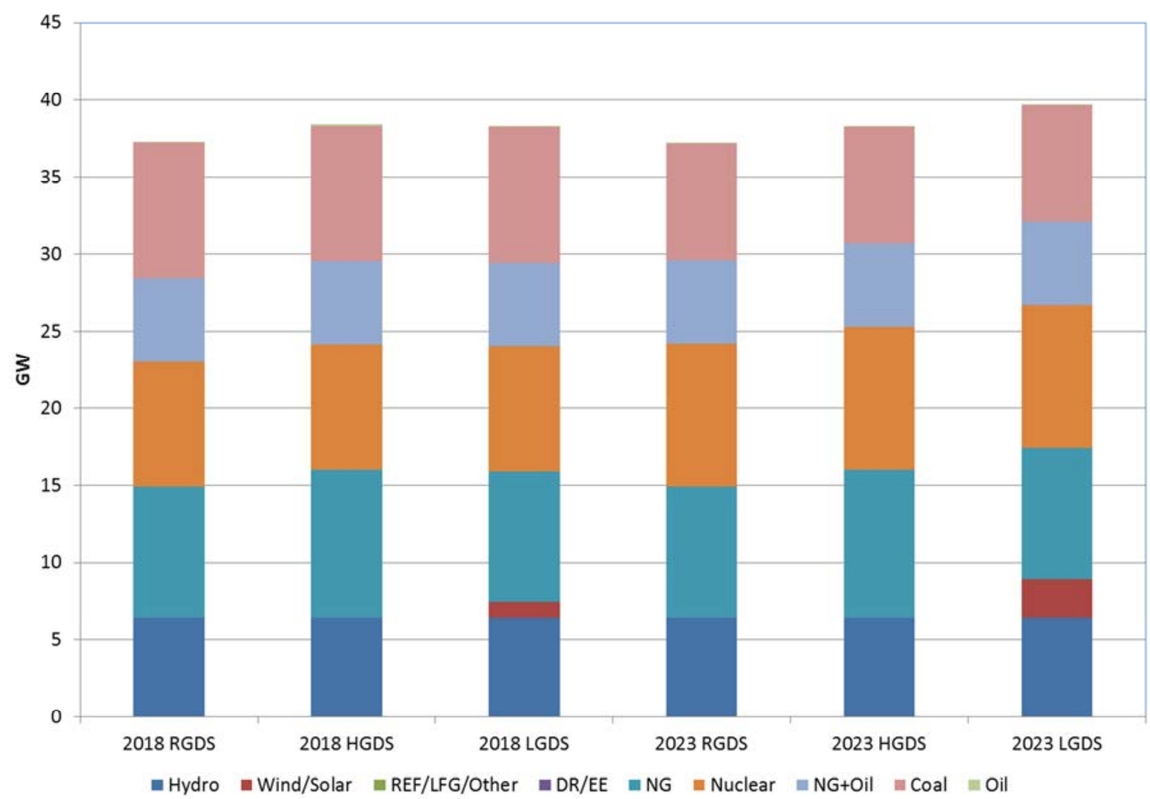


Figure 23. Resources by Scenario and Year – TVA



3.1.5 LGDS Resources

The LGDS incorporates increased penetration of renewable resources and EE/DR relative to the RGDS. For IESO, the RGDS already includes renewable resources consistent with Provincial goals. Therefore, Ontario wind and solar resources in the LGDS are the same as the resources in the RGDS. For ISO-NE, MISO, NYISO, and PJM, the majority of the incremental renewable resources were assumed to be onshore wind capacity, which was added to achieve approximately the total aggregate requirements of the states' renewable portfolio standard (RPS) goal for the two study years.[25] One-half of the targeted renewable resource capacity was included for states with non-binding renewable energy goals. Additional wind resources in most PPAs were added in the locations of existing wind resources in the area, unless there were no wind resources anywhere in that area. Any shortfall was then made up by grossing up resources in each area as needed to achieve the total RPS and one-half of the non-binding target capacity. The LGDS therefore incorporates the simplifying assumption that the incremental wind resources will be sited near the existing wind resource locations across the Study Region.

[25] Although RPS programs are state jurisdictional, most state rules provide for interstate imports of wind or other renewable energy to be qualified under RPS. Rules for RPS qualification of renewable energy imports vary from state to state, but it is common for states to qualify out-of-state renewable resources provided that the energy is delivered within the control area.

Table 9. State RPS Requirements[26]

State	Class 1 / Tier 1 2018	Class 1 / Tier 1 2023	Solar 2018	Solar 2023
CT	17.00%	20.00%	*Note 1*	
DC	14.35%	17.50%	1.15%	2.50%
DE	14.50%	19.25%	1.50%	2.75%
IL	12.22%	19.27%	0.78%	1.23%
IN*	4.00%	7.00%	*Note 2*	
MA	13.00%	18.00%	400 MW	
MD	14.40%	18.00%	1.40%	2.00%
ME	10.00%	10.00%	*Note 2*	
MI	10.00%	10.00%	*Note 2***	
MN***	27.50%	30.00%	-	1.50%
MO	NA	14.70%	NA	0.30%
ND*	10.00%	10.00%	*Note 2*	
NH	8.70%	13.20%	0.30%	0.30%
NJ	12.33%	17.88%	1591 GWh	3433 GWh
NY	30.00%	30.00%	*Note 2*	
OH	6.24%	11.04%	0.26%	0.46%
PA	6.16%	7.50%	0.34%	0.50%
RI	14.50%	16.00%	3 MW	3 MW
VA*	7.00%	12.00%	*Note 2*	
VT*	20.00%	28.00%	*Note 2*	
WI	10.00%	10.00%	*Note 2*	
WV*	10.00%	15.00%	*Note 2*	

Note 1: Zero-emission Renewable Energy Credits (ZRECs) are procured by EDCs under 15-year contracts through the ZREC program. Up to $8 million in new ZREC contracts may be procured each year.

Note 2: Solar PV qualifies as a Class 1 / Tier 1 resource. There is no specific solar requirement.

Note 3: If solar is a carve-out from Class 1 / Tier 1, only the remaining Class 1 / Tier 1 percent is shown.

* Voluntary target.

** No specific solar RPS target, but solar resources receive bonus credits.

*** Requirement for Xcel Energy (interpolated). Other public and non-public utilities have lower targets.

[26] RPS requirements as percent of electricity sales, unless otherwise noted.

For states within the Study Region with solar RPS targets, incremental solar PV resources were added in areas corresponding to those states.[27] For each state covering multiple areas, the incremental solar PV resources were distributed in proportion to the peak load demand in each area.

For TVA, the incremental onshore wind capacity is based on the "Strategy C - Diversity Focused Resource Portfolio" developed for TVA's 2011 Integrated Resource Plan (IRP), which envisions 2,500 MW of new renewable resources by 2020.[28] The incremental wind resources in TVA were distributed in areas where it is windiest based on NREL wind resource data.[29]

The lower electric load forecast used for the LGDS implicitly embeds a higher penetration rate of DR and EE resources.

The net changes in resource mix in the LGDS relative to the RGDS are provided in Exhibit 6 and illustrated in Figure 18 through Figure 23. Wind and solar resources are included as installed capacity in these figures, rather than available (unforced) capacity, thereby increasing the total installed capacity in the LGDS relative to the RGDS.

3.2 FUEL PRICE FORECASTS

The EIA *Annual Energy Outlook 2013* (AEO2013) was used as the basis for the fuel price forecasts. At the time that AURORAxmp modeling was performed, only the December 2013 preliminary version of the 2014 edition of the *Annual Energy Outlook*, which only reported the preliminary Reference Case outlook, was available. Therefore the 2013 edition was used in order to have AEO-based information as the basis for the fuel price forecasts. The AEO2013 forecasts take into consideration the laws and regulations that were in effect as of the end of September 2012 and the proposed regulations that the EIA anticipated would be promulgated after the completion of the AEO2013 forecasts. These regulations are assumed to remain unchanged over the AEO2013 forecast period. The forecast assumptions regarding environmental regulations include the continuation of the Clean Air Interstate Rule (CAIR) in response to the court vacation of the CSAPR and the scheduled implementation of the MATS.[30] Other key assumptions for AEO2013 include real gross domestic product growth of 2.75 percent annually over the study period (through 2023), overall U.S. population growth averaging 0.95 percent per year, and non-farm employment growth of 1.2 percent each year.[31]

Fuel prices for resources in the external zones outside of the Study Region are also consistent with the forecasts of the prices in AEO2013.

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[27] Most states with solar RPS targets require that the solar resources be sited within the state.

[28] TVA, *Integrated Resource Plan, TVA's Environmental and Energy Future*, March 2011, p. 99. TVA is in the process of developing a new IRP.

[29] http://apps2.eere.energy.gov/wind/windexchange/wind_maps.asp

[30] On April 28, 2014 the U.S. Supreme Court reversed a previous lower court ruling which had vacated CSAPR. The earliest that this development could be reflected in the EIA forecasts would be for AEO2015 and more likely in a later AEO. It remains to be seen if the reinstatement of CSAPR will have a significant impact of the forecasted price of fuels beyond impacts of CAIR and MATS which have already been taken into consideration in AEO2013.

[31] AEO2013 Macroeconomic Indicators table.

For both the HGDS and LGDS, only the natural gas price forecast changes, while the forecasts for oil, coal and nuclear fuel prices remain the same as in the RGDS. Thus, for the HGDS and LGDS there are relative price changes between natural gas and other generation fuels compared to the RGDS, which alters the dispatch of gas-capable resources relative to other resources.

3.2.1 RGDS Fuel Prices

3.2.1.1 Natural Gas Price Forecasts

The natural gas price forecasts from AEO2013 were supplemented by the EIA's February 2014 *Short-Term Energy Outlook* (STEO). While the prices in AEO2013 are annual, STEO provides a monthly outlook. LAI utilized the monthly pattern of prices in STEO to shape the annual forecast of Henry Hub natural gas from AEO2013.

The AEO2013 Reference Case projects growth in gas production through 2023 and beyond, driven primarily by the continued development of shale gas. In the AEO Reference Case, the U.S. is projected to be a net natural gas exporter by 2020. Lower 48 gas production is projected to increase from 23.7 Tcf in 2013 to 27.5 Tcf in 2023, reflecting a 42% increase in shale gas production. By 2023 shale gas production is expected to comprise almost one-half of total U.S. gas production.

Key assumptions underlying the AEO gas production forecasts involve determining the estimated ultimate recovery (EUR) for gas wells. Based on available historical gas well production data, EIA analyzes well decline curves to calculate the expected EUR per well. The average EUR per well is combined with other information and assumptions such as resource potential, well spacing, and total technically recoverable resources, to project gas production. Well gas projections are aggregated to arrive at production estimates for specific basins and resource plays such as the Marcellus and Utica shales.

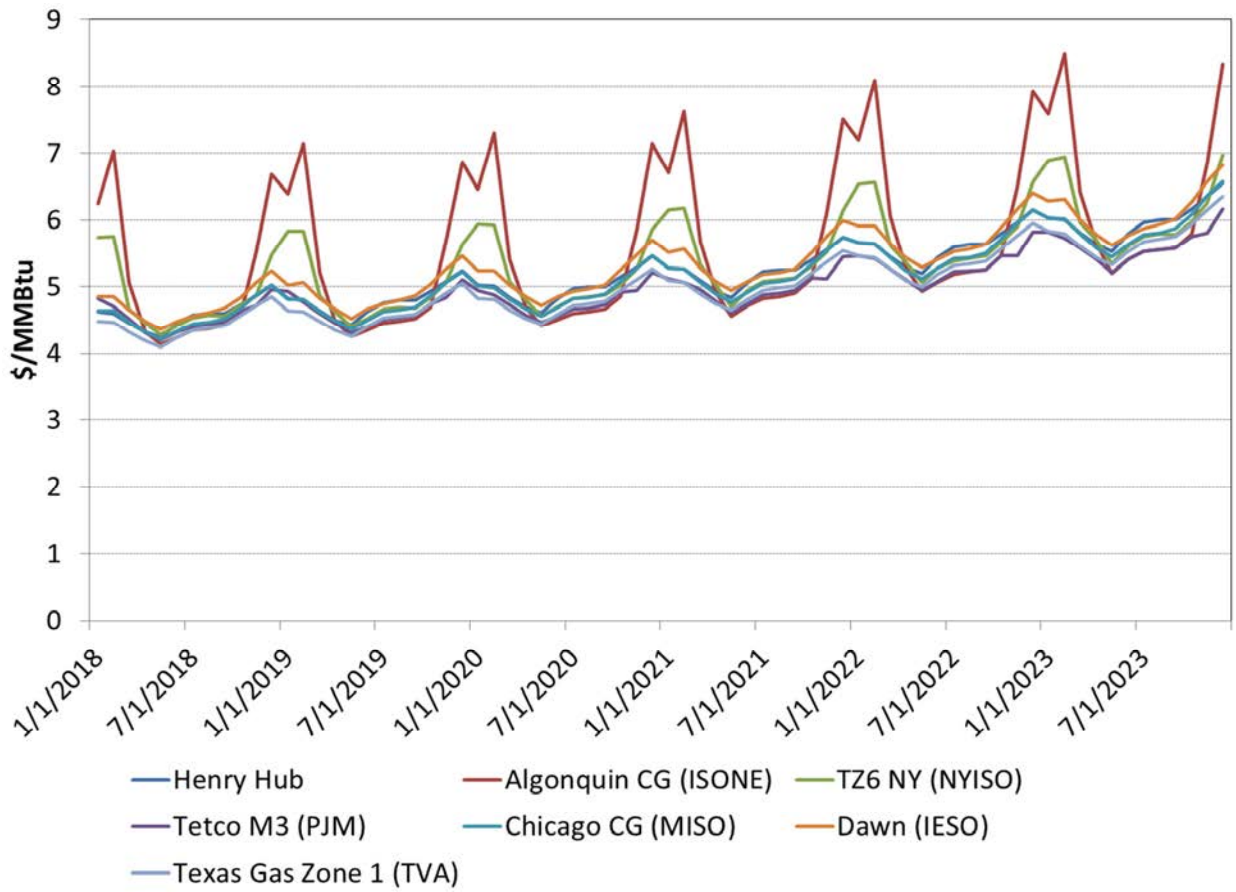
The EIA projections show total natural gas consumption growing at an average of 0.7% annually, with residential and commercial consumption remaining flat and industrial gas consumption growing by a total of almost 15% through 2023. Gas use in the electric generation sector declines slightly from 2013 through 2015, then grows through 2018, leveling off at around 8.3 Tcf/year over the planning horizon.[32] Natural gas prices remain relatively low over the study period. Henry Hub gas prices are projected to increase at an average annual nominal rate of 5.4%, reaching an average price for 2023 of \$5.68/MMBtu from an annual average price of \$3.36/MMBtu in 2013.

Natural gas basis differentials for pricing points across the Study Region were developed using the 2013 fourth quarter database for the monthly version of the GPCM model. Key inputs to that forecast are described in Exhibit 7. The same basis forecast was used for all three scenarios. The GPCM modeling system contains data for more than 90 market pricing points across North America. Data for 35 of these pricing points were utilized as inputs for the AURORAxmp simulation modeling. Figure 24 shows the forecast of the monthly Henry Hub prices as well as forecasts of delivered gas prices (Henry Hub plus basis) at several key regional market pricing

[32] This represents 32% and 30% of total dry gas production in 2018 and 2023, respectively.

points. As indicated, some markets, particularly New England, New York and to a lesser extent parts of eastern PJM, experience pronounced spot price spikes during the peak winter months.

Figure 24. RGDS Natural Gas Price Forecast, Selected Points



In response to continued growth in gas production from the Marcellus shale, and to a lesser extent the Utica shale, delivered gas prices at key pricing points in parts of the Study Region fall below the Henry Hub price during some or all of the non-heating season, reflecting negative basis at these points. The exception in the illustration is in Ontario at the Dawn storage hub, where prices exhibit positive basis throughout the year.

3.2.1.2 Oil Price Forecast

The fuel oil price forecasts used in the production simulation modeling are based on the AEO2013 forecast of West Texas Intermediate (WTI) crude oil, the most commonly used North American crude oil benchmark. The forecast of fuel oil prices starts with the STEO WTI crude monthly prices through December 2015, and is extended over the rest of the Study Period at a rate that is consistent with the WTI price escalation in AEO2013. The forecast price for each oil product used as fuel for electric generation was developed based on an analysis of the historic relationship between prices for each product and WTI. Forecasts for distillate oil were shaped to reflect seasonal pricing patterns using NYMEX forward curves.

Oil production in the United States under the AEO Reference Case forecast increases to 2019 then gradually decreases over the remainder of the forecast horizon. The increase in oil production is driven by the development of tight oil formations, which include oil produced from low permeability *(i.e.*, tight) shale, sandstone and carbonate formations. Under the forecast assumptions for the AEO Reference Case, crude oil production rises through 2016 and levels off at around 7.5 million barrels per day through the rest of the forecast horizon. Tight oil production reaches 2.8 million barrels per day by 2020 and remains at close to that level through 2023. Increasing domestic oil production coupled with a moderation in transportation demand due to a tightening of fuel efficiency standards results in declining U.S. imports of crude oil and petroleum products. The U.S., which became a net exporter of petroleum products in 2011, remains a net exporter throughout the forecast period.

The AEO Reference Case oil production forecasts are based on available well production data, the costs of drilling and operating wells, estimated initial production rates for existing and new wells, as well as current and projected decline curves. The EIA determined the oil EURs, total technically recoverable resources (TRR) and, ultimately, the forecasts of crude oil production based on these data and assumptions. Determinations of EUR and TRR tend to improve over time as more well performance data become available. EURs for both gas and oil wells are a key component for the AEO production forecasts. Changes to the EURs allow EIA to develop alternative resource cases and price forecasts on a consistent basis.

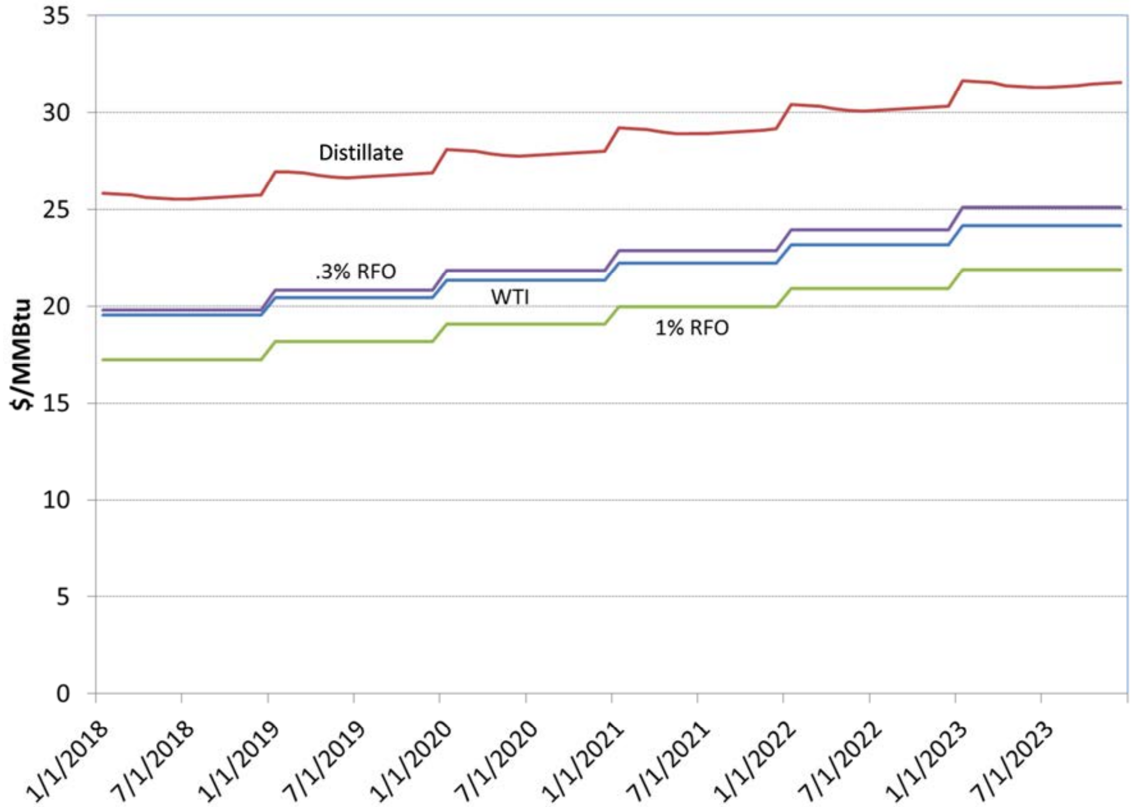
Regional refined petroleum product prices for the most commonly used liquid fuels, including distillates and residual fuel oil (RFO), were projected based on the WTI price forecast and the historical relationships between WTI and product prices.[33] Figure 25 shows the price forecast for WTI and the relevant liquid fuel prices. The forecast of WTI prices reaches $102.22/Bbl ($2012) in 2023 as compared with the price in 2013 of $97.14/Bbl ($2012), an increase in real terms of 5.2 percent over the forecast period.

The AEO2013 oil and gas price forecasts reflect the rising trend in the oil to gas price ratio that has occurred in North America in recent years. Traditionally, the ratio of the crude oil price in $/Bbl to the price of natural gas in $/Mcf had been around 6:1, reflecting an approximate ratio of 1:1 or parity on a Btu-equivalent basis. With rapid growth in gas production in North America, the ratio has increased dramatically, reflecting the divergence between natural gas prices in North America and WTI, which generally reflects global oil prices. Under the AEO2013 Reference Case forecast, the oil to gas price ratio is 27:1 (4.7:1 on a Btu basis) in 2013 and declines only slightly to 23.5:1 (4.1:1) in 2023.

The forecast of prices for oil products used for electricity generation as well as the WTI forecast is indicated in Figure 25

[33] The strong historical correlation between WTI prices and the prices for distillate and RFO is expected to continue over the study period.

Figure 25. Oil Price Forecasts



3.2.1.3 Coal Price Forecast

The forecast of coal prices, shown in Figure 26, is based on the long-term trends in prices for each of the coal supply basins of relevance: Central Appalachia (CAPP), Northern Appalachia (NAPP), Illinois Basin (ILB), Powder River Basin (PRB), and Uinta Basin (UIB) which is representative of Rocky Mountain bituminous coal.[34] Current coal basin prices were escalated at the average annual escalation rates for these five basins, taken from AEO2013. Current transportation costs between the supply basin and major consuming areas, escalated at the rate of general inflation, have been added to the basin prices to obtain delivered coal prices for each consuming region.[35]

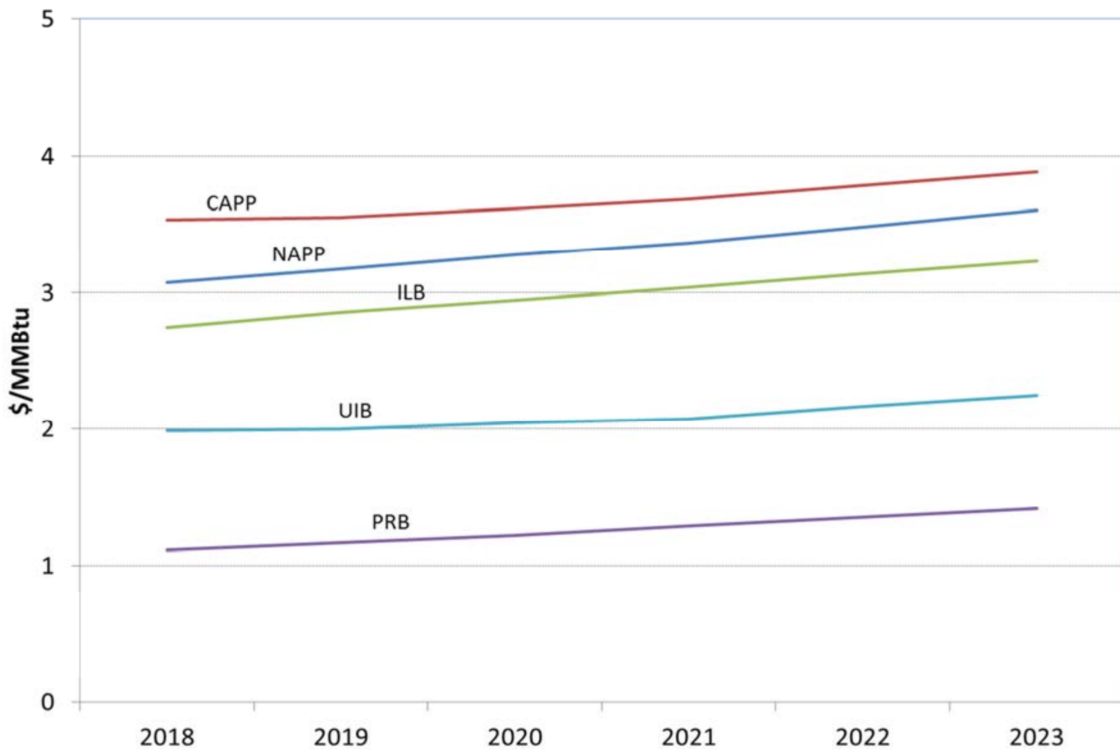
The AEO2013 coal basin price forecasts consider a number of variables, including mining capacity and capacity utilization, labor productivity, capital and operating costs, and reserve depletion. The primary drivers for increasing coal prices in the AEO2013 Reference Case are the continuing decline in mining productivity and reserve depletion. Mining productivity is forecast to decline in all of the coal supply basins, but the drop is greatest in CAPP, which is also most affected by reserve depletion. Over the forecast period, total coal production declines through 2016, with the largest declines in production occurring in CAPP and NAPP. These

[34] Coal prices for other sources, such as lignite from North Dakota or the Gulf Coast, for the external zones modeled in Aurora are also based on the AEO basin price forecasts.

[35] EIA, *Coal Transportation Rates to the Electric Power Sector*, Table 13, released November 16, 2012.

production declines are made up to a certain extent by coal produced in the PRB and ILB which have lower costs relative to the Appalachian basins. The AEO2013 Reference Case forecasts coal production to begin to grow slowly after 2016 primarily as the result of growing coal exports and higher gas prices. Key assumptions underlying the AEO2013 coal price forecasts include continuing regulation of emissions under CAIR and MATS and no greenhouse gas emissions regulations over the forecast period.

Figure 26. Coal Price Forecast



3.2.1.4 Nuclear Fuel Price Forecast

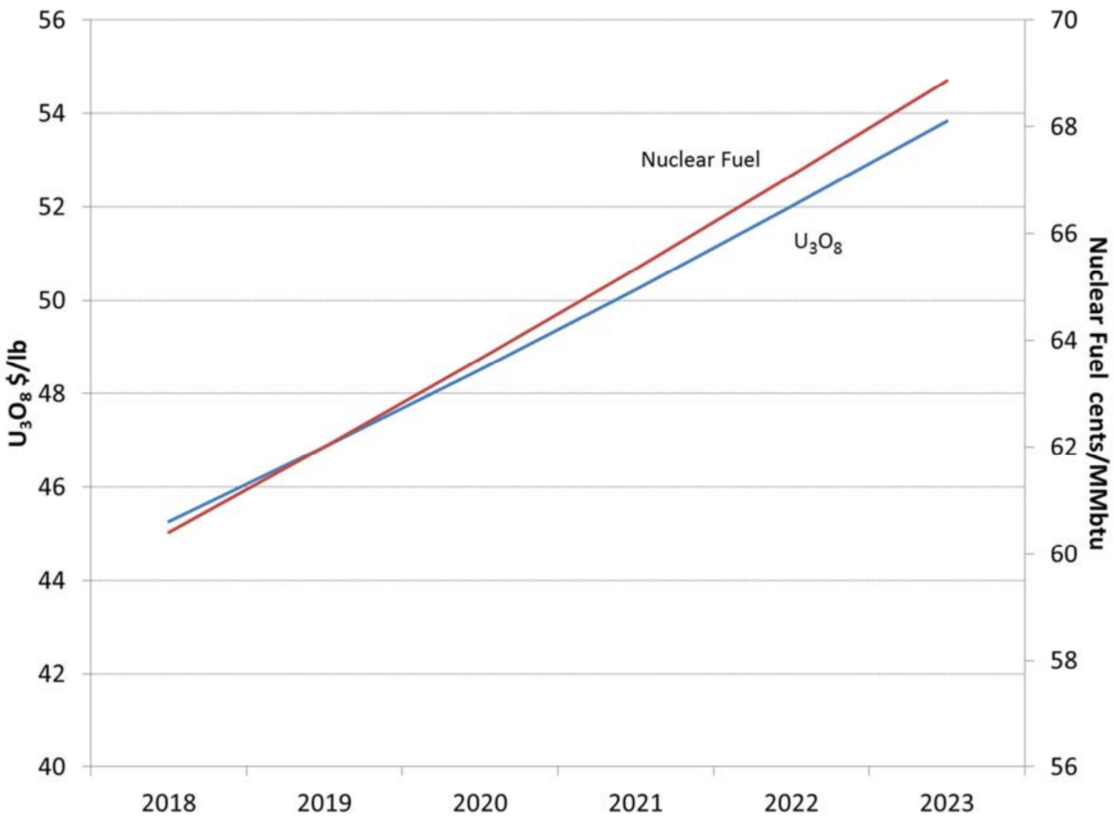
The forecast of nuclear fuel prices is driven by uranium (U_3O_8) prices, which are expected to amount to about 40% of total nuclear fuel costs over the forecast horizon. Nuclear fuel costs also include the costs of conversion (6%), enrichment (38%) and fabrication (16%).[36] No recent forecast of nuclear fuel prices was available from EIA. Therefore, LAI developed a forecast of nuclear fuel prices based on expected uranium prices that is consistent with EIA's available price forecasts and market assumptions. The forecast of uranium prices starts with a forward price curve that provides monthly prices through 2017.[37] Uranium prices, as shown in Figure 27, are projected to average \$36/lb in 2013 increasing to an average of \$45/lb in 2018, and to an average of \$54/lb in 2023. Also shown in Figure 27 are nuclear fuel prices expressed on a \$/MMBtu equivalent basis, which increase from \$0.53/MMBtu in 2013 to \$0.69/MMBtu in 2023.

[36] Nuclear fuel supply is comprised of mined and enriched U_3O_8, utility stockpiles of uranium, and secondary sources such as recycled spent fuel and recycled weapons grade uranium and plutonium.

[37] Globex NYMEX futures prices updated in December 2013.

A number of supply developments are expected to impact uranium prices over the forecast horizon, including planned production increases in Canada, Australia and Kazakhstan. The highly enriched uranium (HEU) blending agreement with Russia provided the equivalent of 20 million pounds of U_3O_8 to the market annually. This program ended as of December 2013. The loss of this HEU supply and growing demand driven by new nuclear plants planned and under construction in China, in particular, as well as other worldwide locations will result in prices that are expected to escalate at an average annual rate that exceeds the general rate of inflation. The escalation rate used is consistent with the AEO forecast assumptions and reflects the slower growth in nuclear construction post-Fukushima.

Figure 27. Nuclear Fuel Price Forecast

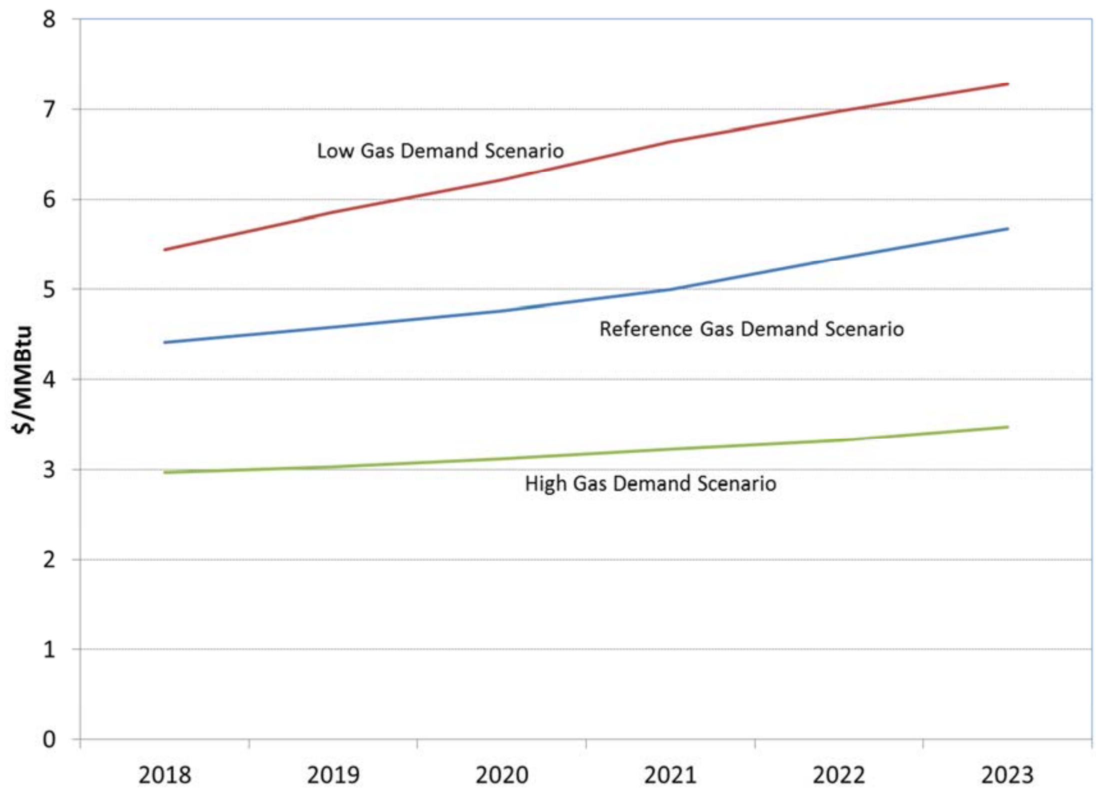


3.2.2 HGDS and LGDS Natural Gas Prices

The forecast of natural gas prices for the HGDS is based on the AEO2013 High Oil and Gas Resource Case, which results in gas prices that average 29% lower over the period of 2013 through 2023 as compared with the AEO2013 Reference Case forecast. The key assumption driving the AEO2013 High Oil and Gas Resource Case forecast assumes EURs for shale and tight gas that are 100% higher than in the Reference Case. Undiscovered resources are assumed to be 50% higher. These assumptions result in more natural gas produced at lower costs for a longer period, thereby sustaining a lower gas price trajectory than for the AEO2013 Reference Case. Figure 28 shows the Henry Hub gas price forecasts for the RGDS, the HGDS and the LGDS based on the alternate AEO2013 Oil and Gas Resource Cases.

The forecast of natural gas prices at the Henry Hub for the LGDS is based on the AEO2013 Low Oil and Gas Resource Case, which results in natural gas prices that are 23% higher than for the AEO2013 Reference Case forecast. For this forecast case, the EIA assumed that EURs for shale and tight gas formations would be 50% lower than for the AEO2013 Reference Case. This results in higher gas costs and lower production, which in turn results in the higher natural gas prices for the LGDS shown in Figure 28.

Figure 28. Comparison of Alternative Gas Demand Scenario Henry Hub Gas Prices



3.2.3 S1 versus S0 Peak Day Gas Prices

In the S0 scenarios, delivered natural gas prices at the array of pricing points across the Study Region (and surrounding external modeled areas) reflect average monthly basis. In S1, in order to reflect natural gas pricing on a peak winter day, the market prices are based on the historic peak winter daily spot gas trading day of January 27, 2014. This date had the highest average prices for six pricing points reflective of each of six PPAs: Chicago Citygate, Transco Zone 6-NY, TETCO M3, Algonquin Citygates, Texas Gas Zone 1, and the Dawn storage hub in southern Ontario.[38] These "next day" prices would be reflected in commitment and dispatch for January 28, 2014, and, to a lesser extent, January 29, 2014.

In order to model this sensitivity, these historic winter high spot prices for natural gas were inflated to 2018 and 2023 prices. The prices were applied for the entire month of January in both

[38] Source: Bloomberg LP

study years to account for similar high prices for the days leading up to the peak day, which would have an impact on generator commitment status at the start of the peak day. However, in keeping with the S1 description as an adjustment of gas prices to reflect market pricing on a peak day, the AURORAxmp results are analyzed only for the winter peak day in GPCM. The winter peak day is assumed to be the day with the highest coincident electric load in the Study Region. For 2018 the peak day is January 18, and for 2023 it is January 12. No other changes have been made to the RGDS, HGDS, and LGDS assumptions. As a result of the S1 sensitivity only applying to the peak day, frequency and duration analysis cannot be performed.

3.3 Environmental Requirements and Assumptions

3.3.1 RGDS Environmental Assumptions

Federal, state, and provincial environmental laws and regulations establish requirements for emissions, cooling water intake and discharge, fuel type, and other operating conditions for generating units, particularly fossil-fired units.[39] Compliance with increasingly stringent regulations may require some plants to install new pollution control equipment or other environmental mitigation technologies, incur additional operating costs, and modify operations. Generating resources which cannot rationalize new capital investment, increases in variable operating cost, or operating constraints that may be needed to comply with current or anticipated new requirements will retire or possibly repower. The RGDS resources are consistent with announced plant retirements reflected in the Roll-Up Integration Case and in the S0 updates provided by the PPAs.

In the U.S., the two primary sets of regulations affecting retirement decisions are MATS and the final regulations under Section 316(b) of the Clean Water Act (CWA). As noted in Section 3.1.2.2, compliance with MATS regulations will materially impact the economics of fossil-fueled plants, particularly coal-fired plants.[40] Currently, the rules will go into effect in 2015, but a one-year extension will be generally granted for plants that need to install emissions control equipment, and an additional year may be granted if the extended maintenance outage or unit retirement would create reliability concerns. A number of older coal plants have already made the decision to retire rather than investing in retrofitting the emissions controls necessary to comply with MATS and other pending rules.

On June 2, 2014, EPA released a proposed plan to address carbon emissions from existing power plants using its authority under Section 111(d) of the Clean Air Act (CAA). EPA's "Clean Power Plan" is expected to reduce emissions from the power sector by 30 percent from 2005 levels by 2030 by setting state-specific emission reduction goals, which states will be responsible for meeting through their respective state implementation plans (SIPs). The carbon standards are intended to afford each state considerable flexibility in developing its own implementation plan, which may include a "portfolio of measures," including those that could be taken beyond the affected sources. SIPs are due in June 2016. States may choose to alter their generation mix or develop EE and DR projects to meet carbon reduction goals. They may work alone or cooperate

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[39] Federal environmental laws refer to the U.S. and Canada.

[40] Residual oil-fired units that operate for a limited number of hours per year may avoid the majority of the new MATS requirements.

together, similar to the efforts by the RGGI states and the Western Carbon Initiative. Because future requirements under the SIPs are unknown at this time, and because the compliance period may extend beyond the end of the study horizon, the RGDS makes no explicit assumptions regarding how the resource mix the U.S. PPAs may be affected by future greenhouse gas emission requirements.

Many coal and oil-fired steam plants, as well as nuclear units may be affected by the regulations recently issued under CWA Section 316(b), governing cooling water intake structures. The regulations establish standards for reducing impingement and entrainment of aquatic organisms in cooling water intakes for existing power plants. The final 316(b) rule was issued in May 2014, and becomes effective on October 14, 2014. The rule will be implemented through the existing National Pollutant Discharge Elimination System (NPDES) permit program. When facilities submit their applications for their NPDES permit renewals, they must provide all information required under the new 316(b) rules. The final compliance date for each facility depends on when its existing NPDES permit will expire, how much time the EPA (or delegated state agency) will grant the facility to prepare its permit renewal application, and how long it will take the EPA or state agency to review and approve the permit application. EPA acknowledges that facilities will require about at least 3 years to prepare the permit renewal applications. Thus, it is likely that the earliest date that a facility would need to be in compliance (or decide to retire) would be after 2018.

Canada's "Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations" established performance standards for new coal units and also for existing units that have reached the end of their useful life, generally assumed to be 50 years. While the federal regulation requires the first wave of coal plant retirements no later than 2019, the Ontario government has accelerated the schedule of coal retirements within the Province. The *RGDS* reflects the announced and pending retirement of all coal generation in IESO. Lambton was retired in October 2013. Nanticoke also retired at the end of 2013. The Ontario provincial government recently announced the conversion of one 150 MW generator at the Thunder Bay station to a biomass facility by 2015, with the second generator being retired in 2014.[41] The Atikokan station has been converted to biomass and returned to service in 2014.

3.3.1.1 Allowance Price Forecast

AURORAxmp incorporates NO_x, SO_2, and CO_2 unit-specific emission rates and applicable emission allowance costs for all fossil fueled facilities in the model. All allowances, including those which are allocated to generators at no cost and auctioned allowances, are treated as variable operating costs and priced at their opportunity cost, that is, the market price for the year that the allowance is used or retired.

For the RGDS, the emissions allowance price forecast assumes that the reinstated CSAPR essentially remains an extension of the federal NO_x and SO_2 cap-and-trade program under CAIR, applicable to states where CAIR currently applies.[42] CAIR allowances continue to be traded,

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[41] Both the *RGDS* and the *RGDS* Update assume both existing Thunder Bay units are permanently retired.

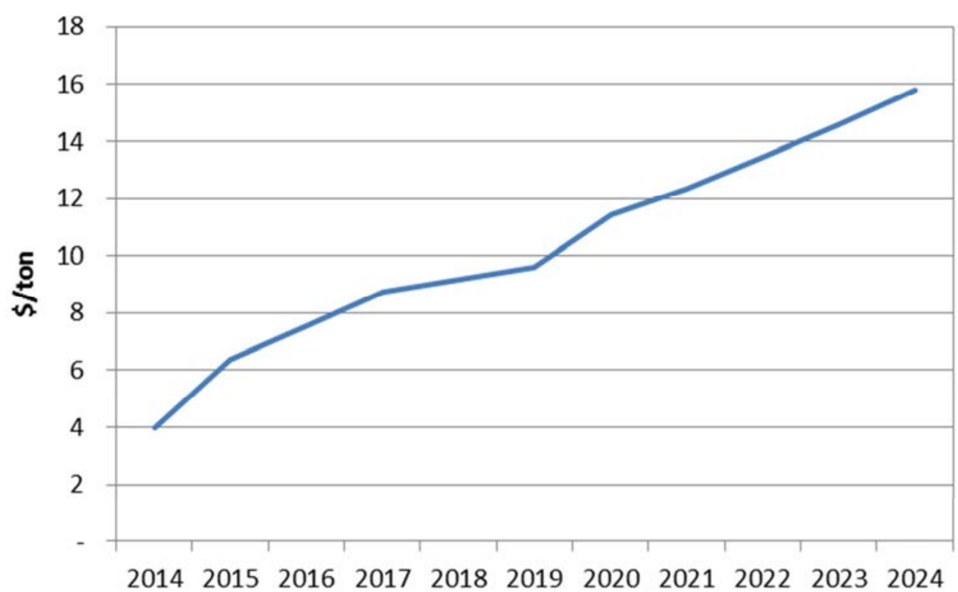
[42] Note that states there are a few states in the Study Region that are covered by CSAPR but are not covered by CAIR. To be consistent with the fuel price forecast, the CAIR state applicability has been retained.

albeit thinly. Current CAIR annual NO_x allowances have recently traded at \$44/ton, and seasonal NO_x allowance prices at \$20/ton.[43] SO_2 allowances have recently held steady at approximately \$1.44/ton.[44] For modeling purposes, we have applied these reported prices, and escalated them at the assumed annual rate of inflation over the study period.

3.3.1.2 Carbon Assumptions

In the RGDS, we assume that the Regional Greenhouse Gas Initiative (RGGI) model rule and allowance market, as modified by the 2012 RGGI Program Review, will persist over the study period for the current RGGI footprint. We have adopted the CO_2 allowance price forecasts developed by the RGGI Working Group for the 2012 Program Review, and have averaged the "91 Cap Bank Model Rule" and the "91 Cap Alt Bank Model Rule" as the basis for the price forecast.[45] Beyond 2020, we applied a trend line to extend the forecast for the remainder of the study period, as shown in Figure 29. These CO_2 allowance prices apply only to fossil units located within the current RGGI footprint.

Figure 29. CO_2 Allowance Price Forecast (RGDS)



Along with Quebec, British Columbia, Manitoba, California, and several other western U.S. States, Ontario is a member of the Western Climate Initiative. In 2009, Ontario enacted Bill 185, which requires the Ministry of Environment to develop a greenhouse gas reduction program. While the law enables the implementation of a provincial cap-and-trade system for CO_2 emissions, other measures, such as deactivation of the coal units in the Province, have been used to accomplish reduction goals. Therefore, the RGDS does not incorporate a CO_2 allowance price for fossil generating units in IESO.

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[43] Argus *Air Daily*, January 13, 2014.

[44] Platts *Megawatt Daily*, March 13, 2014.

[45] See: http://www.rggi.org/docs/ProgramReview/February11/13_02_11_IPM.pdf

3.3.2 HGDS and LGDS Environmental Assumptions

For the HGDS, it is assumed that the cost of compliance with pending or proposed environmental rules including SIPs implemented under CAA Section 111(d), compounded by increased pressure on the "dark spread," will drive further fossil unit retirements relative to the RGDS. LAI has not postulated any specific new regulations or requirements, but instead made the assumption that the resource mix in the HGDS is a result of, and consistent with, the projected fuel prices and environmental mandates. As further described in Section 3.1.4, These incremental retirements are only in the US PPAs. In IESO, there are no remaining coal units to remove for the HGDS.

For the HGDS, LAI assumed that the environmental requirements do *not* include any departure from RGDS assumptions regarding RGGI or emission allowance prices. The NO_x, SO_2, and CO_2 emission allowance prices in the HGDS and the LGDS are the same as the RGDS. The forecasted levels of NO_x and SO_2 allowance prices are low in comparison to other dispatch costs, so varying their prices would not have much impact on results. For CO_2 allowance prices, it is not known whether the current RGGI cap-and-trade system will be extended across the entire Study Region, and the assumed changes in generation mix and natural gas prices for the HGDS and LGDS may in part be thought to reflect different greenhouse gas policies.

In the LGDS, the larger penetration of renewables in the capacity mix tracks RPS requirements. In part, public policy to maintain or strengthen scheduled increases in annual RPS requirements is driven by environmental concerns.

3.4 ELECTRICITY PRODUCTION SIMULATION MODEL RESULTS

The AURORAxmp generator gas demand simulation output data are intermediate results that are used as input data to GPCM. Other output data have been used to support the reasonableness of the electric simulation model gas burn results. These key indicator variables were aggregated to prepare summary information by scenario, year, and PPA. Exhibits that show results by season include January, February, and December in the Winter season and June, July, and August in the Summer season. These results for the RGDS, HGDS, and LGDS are displayed in the following Exhibits:

- Exhibit 8 displays average monthly on-peak (7x16) LMPs for the winter and summer seasons in 2018 and 2023 for each PPA.
- Exhibit 9 charts the monthly net imports for the winter and summer seasons in 2018 and 2023 for each PPA. Net imports are shown as a percent of total monthly demand.
- Exhibit 10 includes tables of annual capacity factors for 2018 and 2023 by technology and fuel type.
- Exhibit 11 includes tables of total seasonal generation for 2018 and 2023 by technology and fuel type.

- Exhibit 12 includes tables of total seasonal gas use for 2018 and 2023 by technology and fuel type for the gas-capable resources.

- Exhibit 13 includes tables of peak hour gas use for 2018 and 2023 by technology and fuel type for the gas-capable resources. The data reflects the gas use peak hour on the coincident winter and electric peak load days. The coincident winter peak load days are January 18, 2018 and January 12, 2023. The coincident summer peak load days are July 17, 2018 and July 11, 2023.

In Exhibit 8, LMPs are roughly comparable on average for the six PPAs between the winter and summer seasons. In the RGDS, summer LMPs increase relative to winter LMPs in 2023, consistent with tighter summer reserve margins in 2023. The HGDS tends to have lower LMPs than the RGDS, mainly as a result of lower natural gas prices and the addition of combined cycle plants that replace deactivated coal plants. The LGDS has LMPs that are roughly comparable to those for the RGDS. Offsetting higher natural gas prices in the LGDS are lower loads and increased generation from renewable resources.

In Exhibit 9, Study Region net imports in the winter and summer seasons are generally slightly negative for all three scenarios. In the LGDS, Study Region net imports turn positive for three of the 2018 summer and winter season months. Consistent with recent history, NYISO is the largest net importer among the six PPAs.

Exhibit 10 shows, as expected, that capacity factors of natural gas capable resources tend to increase in the HGDS and decrease in the LGDS. In contrast, the capacity factors of coal generation units tends to decline in both the HGDS and the LGDS, even though the HGDS scenario included additional deactivations of coal plants. In the LGDS the addition of renewable resources and lower electric loads tended to reduce coal unit capacity factors. Likewise, Exhibit 11 shows increased generation from natural gas capable resources in the HGDS and decreased generation from those resources in the LGDS.

Season total gas use by electric generators, shown in Exhibit 12, and peak hour gas use on the seasonal peak electric load day, shown in Exhibit 13, indicate the magnitudes of the incremental gas demand by generators in the HGDS and decremental gas demand in the LGDS. For the winter season over the Study Region, the HGDS results in slightly more than twice as much gas use by generators in both years, and the LGDS has slightly less than one-half as much gas use. On the winter peak electric load days, the peak hour gas use is nearly twice the RGDS level in the HGDS and over 40% less in the LGDS in both years. These significant upward and downward impacts of the changes in assumptions for the HGDS and LGDS are generally as expected. One of the main reasons is that in the RGDS relative natural gas and coal prices make natural gas-fired generation roughly competitive with coal-fired generation. The higher or lower natural gas prices alone will make a significant difference in seasonal and peak hour gas use. In addition, the larger (smaller) share of natural gas capable capacity and higher (lower) electric load in the HGDS (LGDS) contribute to the relative changes in total seasonal and peak hour gas use by generators.

Figure 30 through Figure 36 present electric sector gas demand for the three scenarios, and compare the peak seasonal results between scenarios. Figures showing the demand by location within each PPA can be found in Exhibit 14.

Figure 30. RGDS S0 Electric Sector Gas Demand by Season and Year

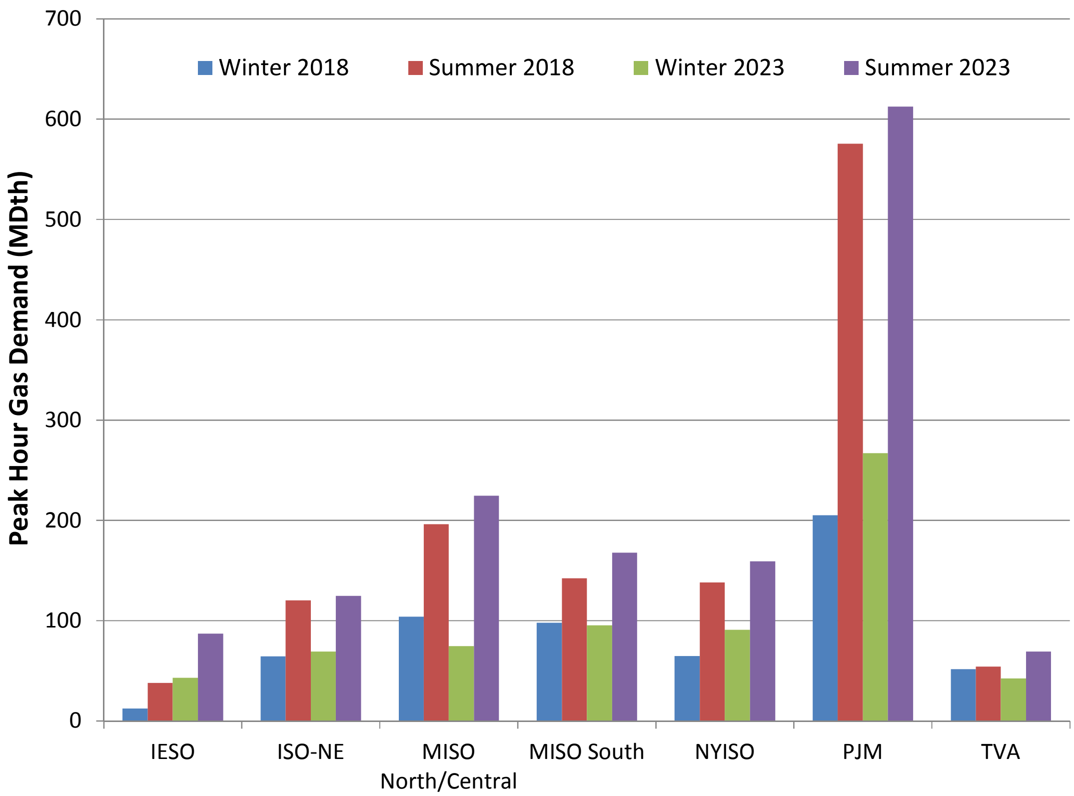


Figure 31. HGDS S0 Electric Sector Gas Demand by Season and Year

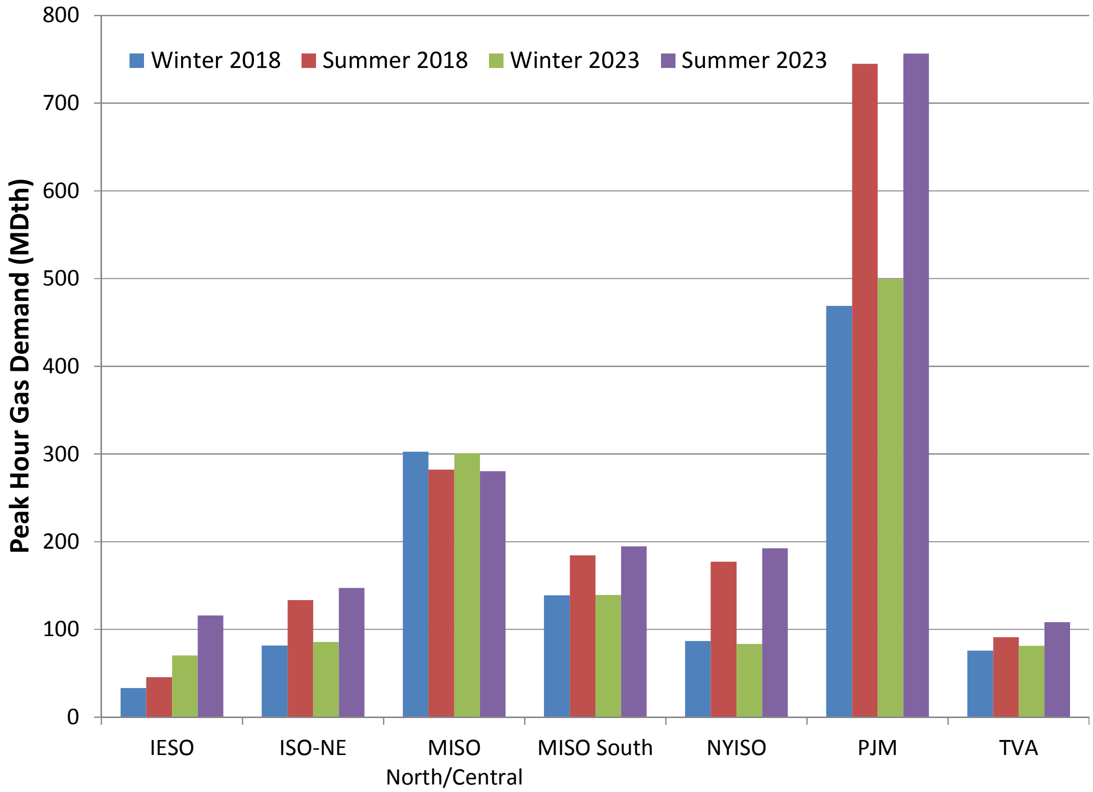


Figure 32. LGDS S0 Electric Sector Gas Demand by Season and Year

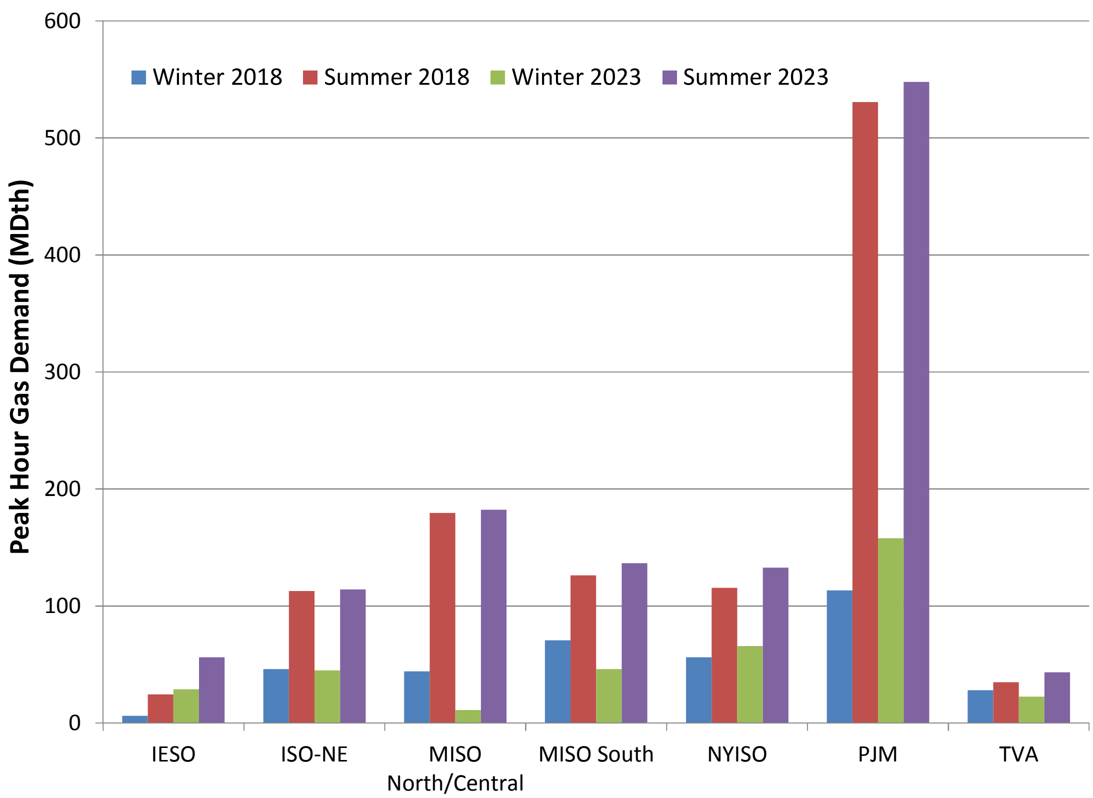


Figure 33. S0 Electric Sector Gas Demand by Scenario – Winter 2018

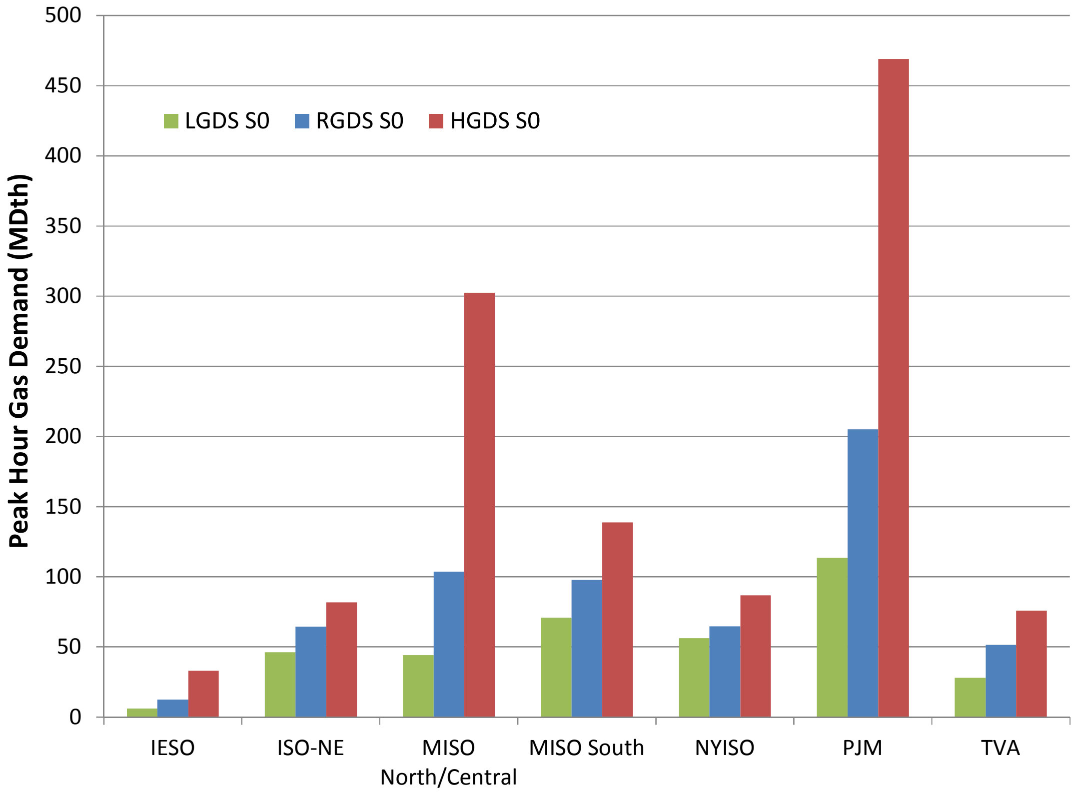


Figure 34. S0 Electric Sector Gas Demand by Scenario – Summer 2018

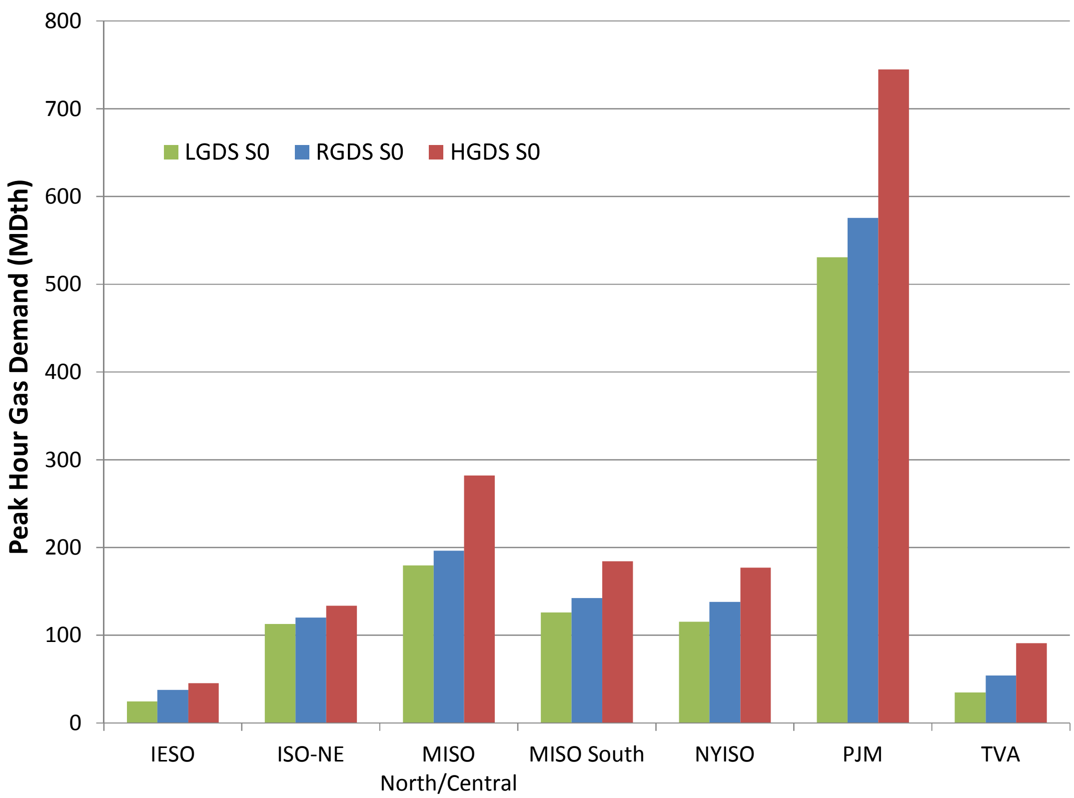


Figure 35. S0 Electric Sector Gas Demand by Scenario – Winter 2023

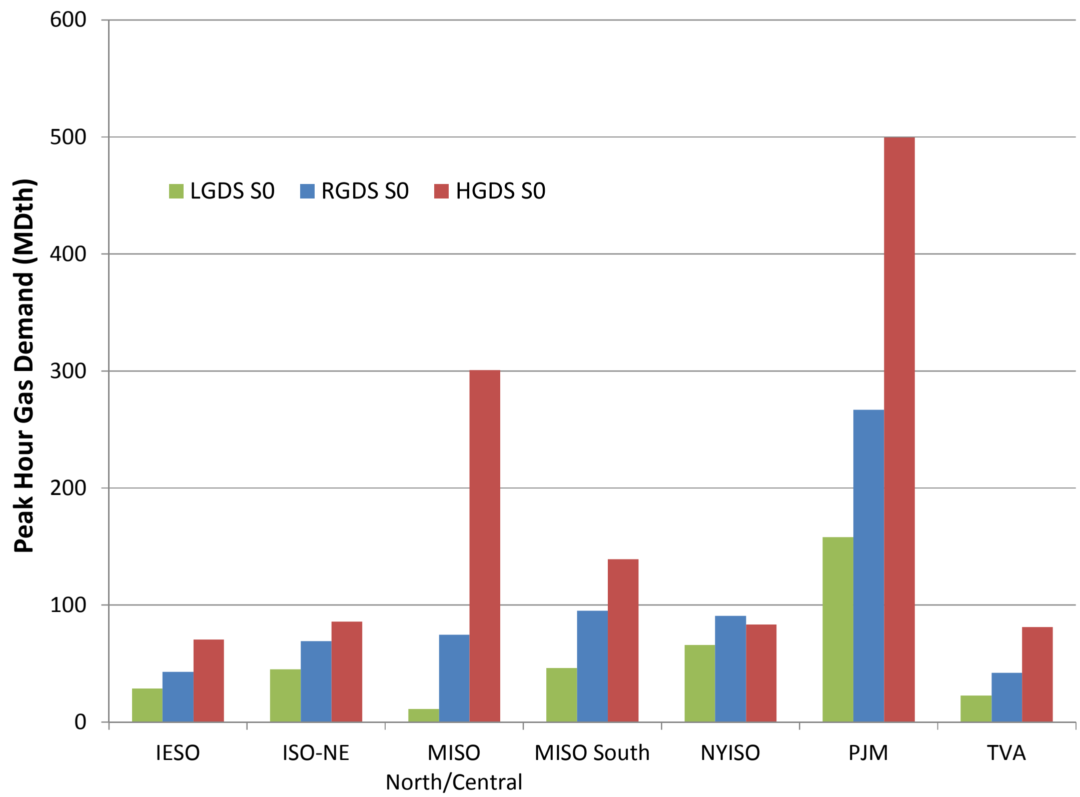


Figure 36. S0 Electric Sector Gas Demand by Scenario – Summer 2023

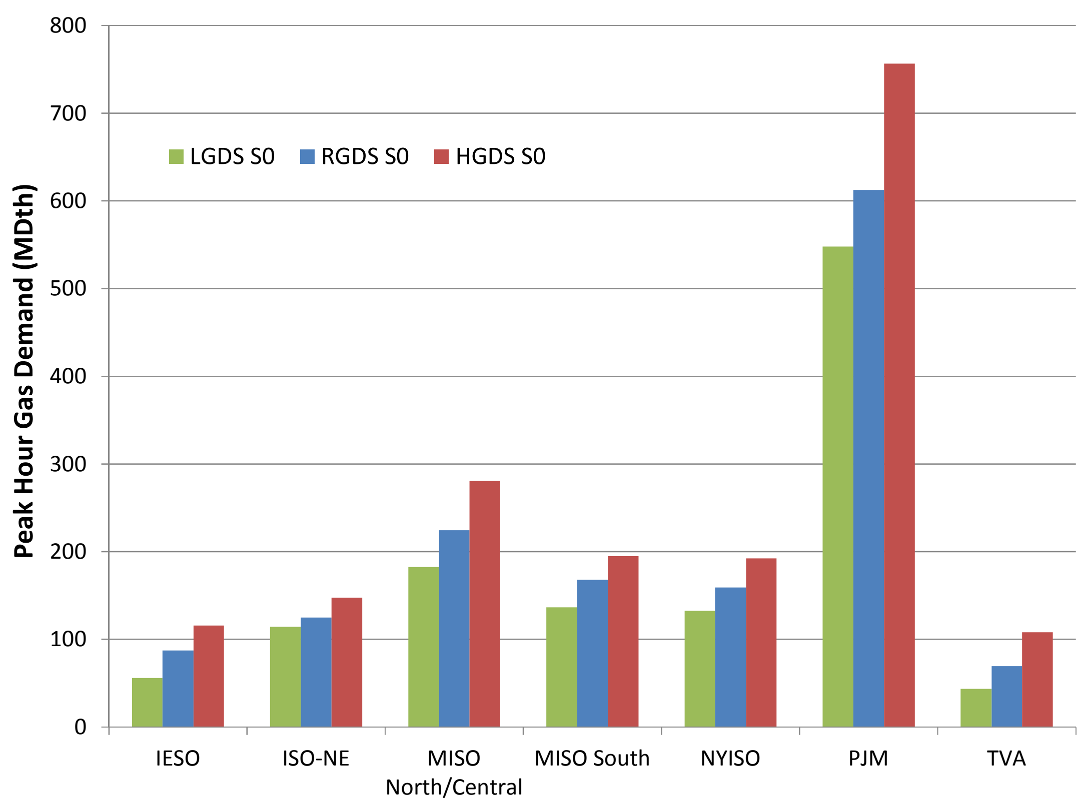


Figure 37 through Figure 42 compare the S0 versus S1 electric sector gas demands across the PPAs, for each of the scenarios.

The relative reductions in gas demand in S1 compared to S0 are most pronounced in ISO-NE, followed in order by MISO North/Central, NYISO, and PJM. Reductions in these four PPAs in all three scenarios results from substitution of oil and coal-fired generation for generally higher-priced gas in S1. The relative changes in gas demand in IESO, TVA, and MISO South in S1 are small, either negative or positive. The small absolute changes for these two PPAs is primarily explained by their gas-capable generators being indexed to pricing points such as Henry Hub or AECO, which did not experience substantial changes in gas prices on the winter peak day in S1. In fact, the AECO price in S1 is below its RGDS S0 January 2023 price and below both the January 2018 and 2023 prices in LGDS S0. The Henry Hub price in S1 is also below its January 2023 price in LGDS S0. Henry Hub prices are linked to many generators in TVA and MISO South. Six other gas pricing points close to Henry Hub that are tied to other generators in MISO South also have slightly lower January 2023 prices in S1. The lower LGDS S1 than LGDS S0 prices in January 2023 for generators in IESO, MISO South, and TVA explain their higher gas use in LGDS S1. It is important to recognize that spatial gas network constraints and spatial weather patterns can result in price decreases in some locations and price increases in other locations. The S1 prices were selected on the January 2014 day that had the highest simple average price for one representative location in each of the six PPAs, rather than noncoincident high prices in each PPA.

Figure 37. RGDS S1 vs. S0 Electric Sector Gas Demands – Winter 2018

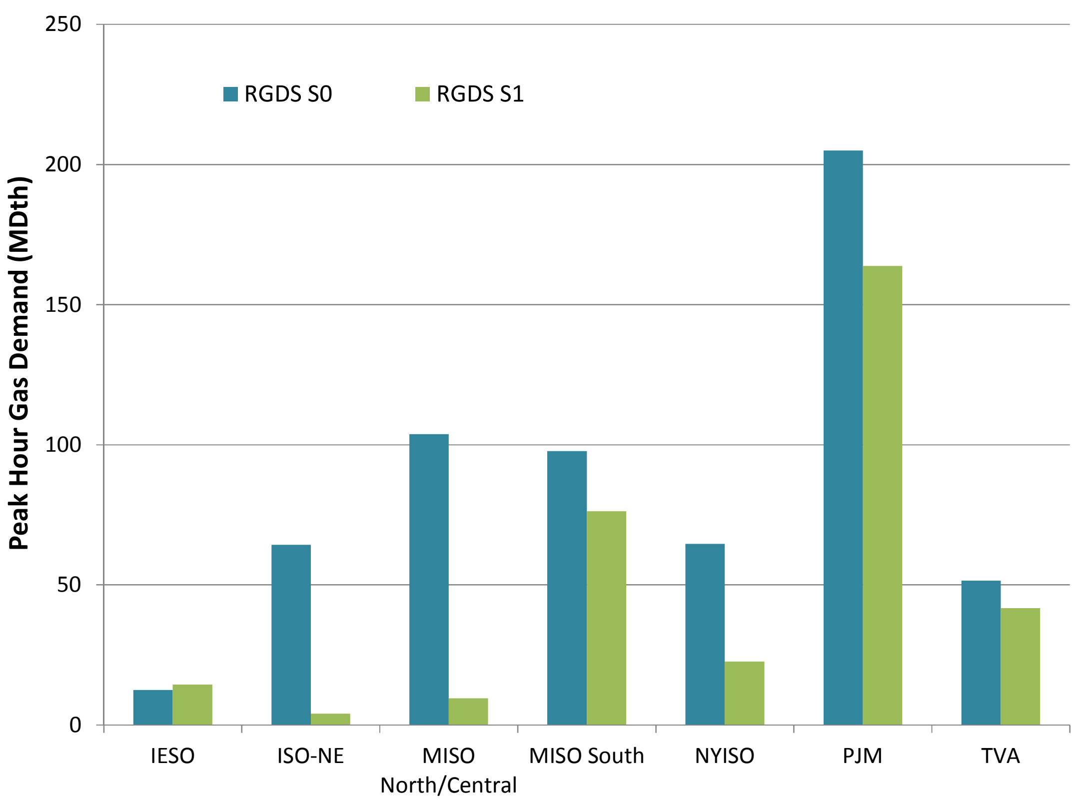


Figure 38. RGDS S1 vs. S0 Electric Sector Gas Demands – Winter 2023

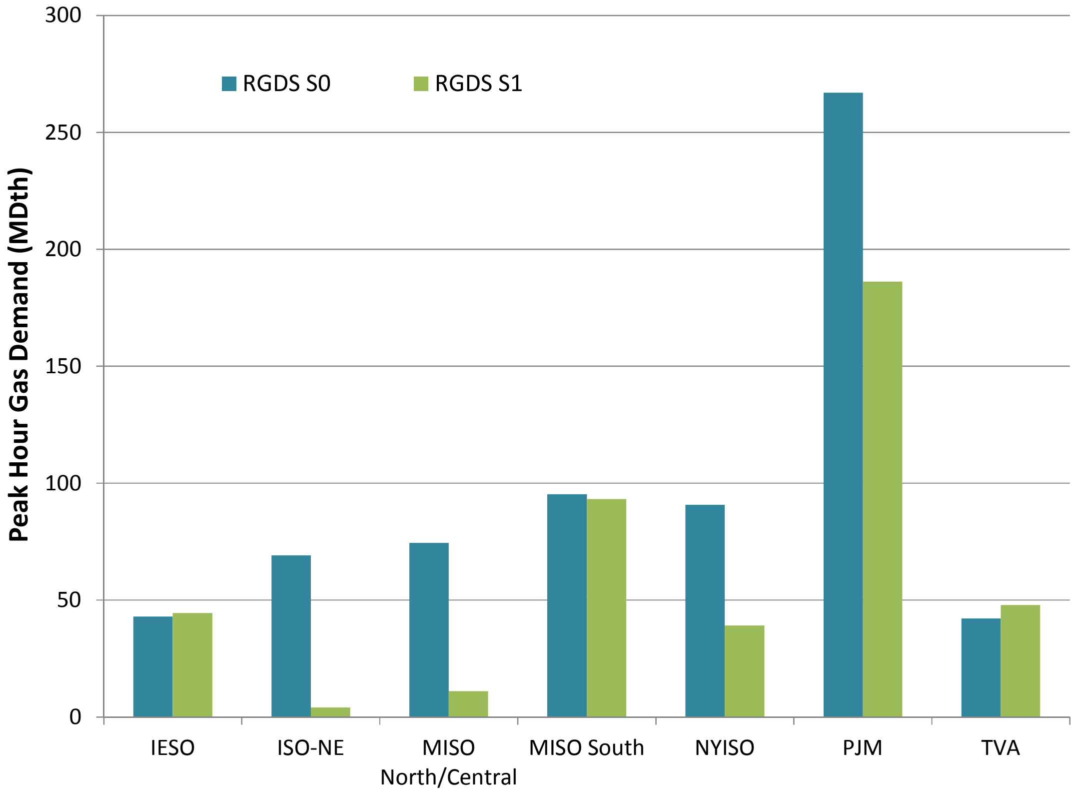


Figure 39. HGDS S1 vs. S0 Electric Sector Gas Demands – Winter 2018

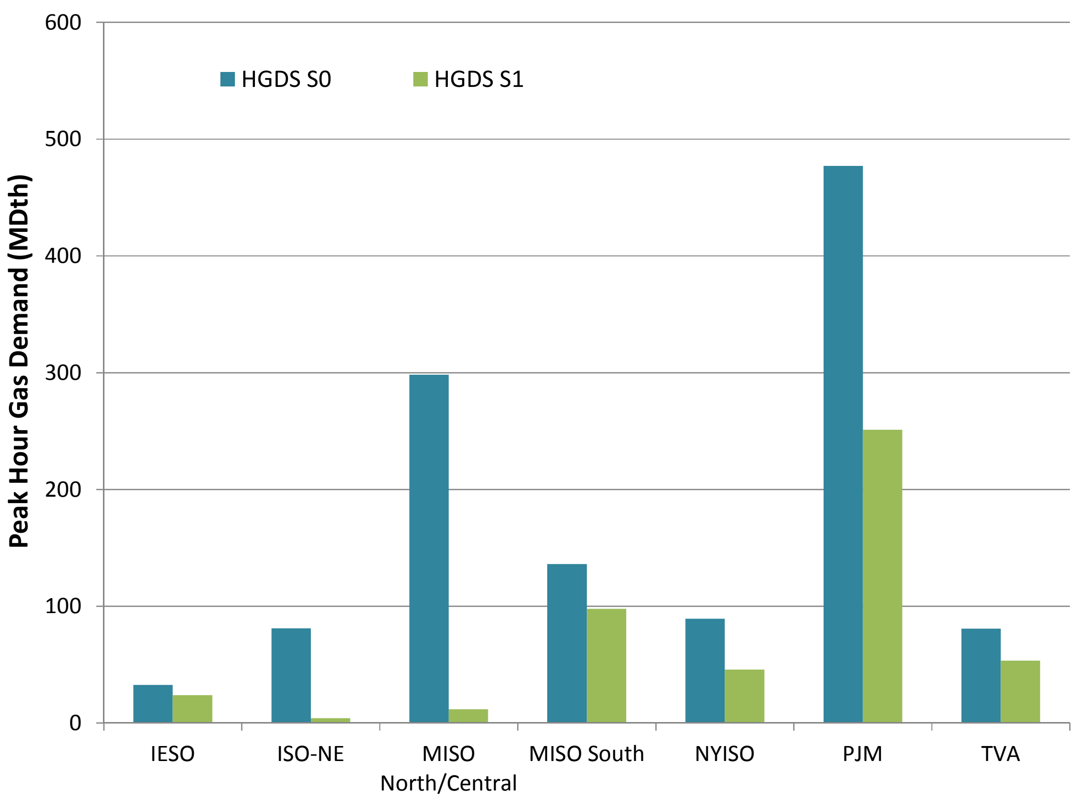


Figure 40. HGDS S1 vs. S0 Electric Sector Gas Demands – Winter 2023

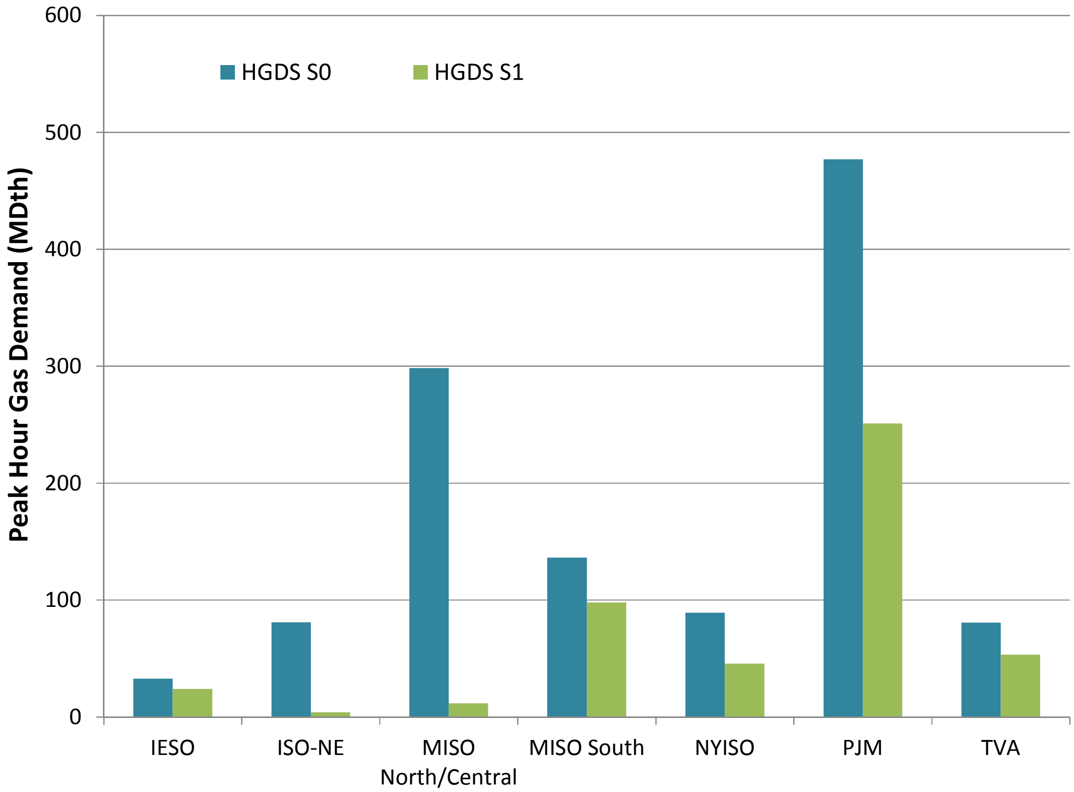


Figure 41. LGDS S1 vs. S0 Electric Sector Gas Demands – Winter 2018

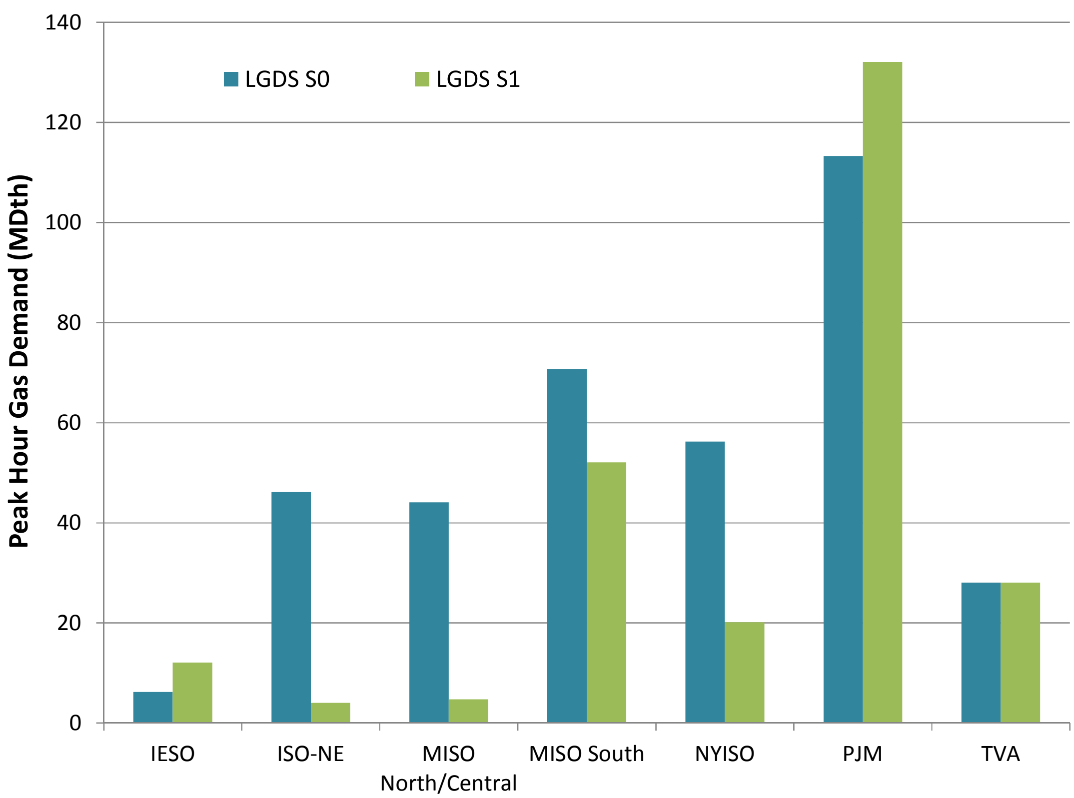
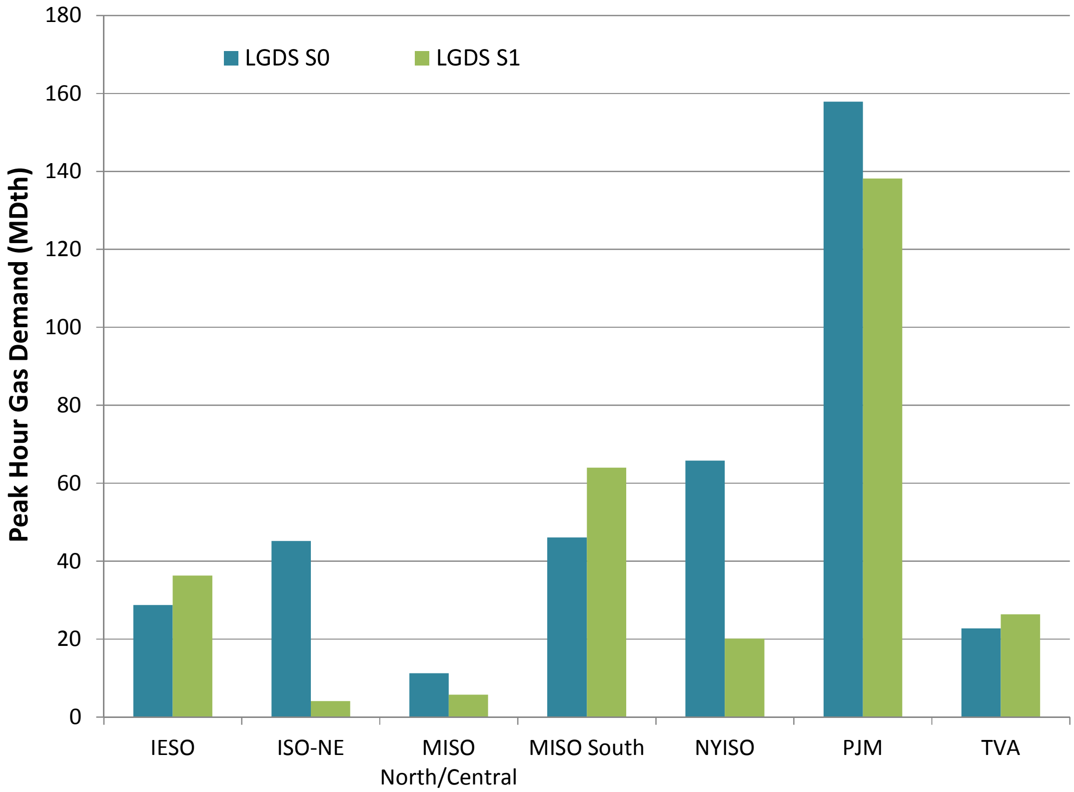


Figure 42. LGDS S1 vs. S0 Electric Sector Gas Demands – Winter 2023

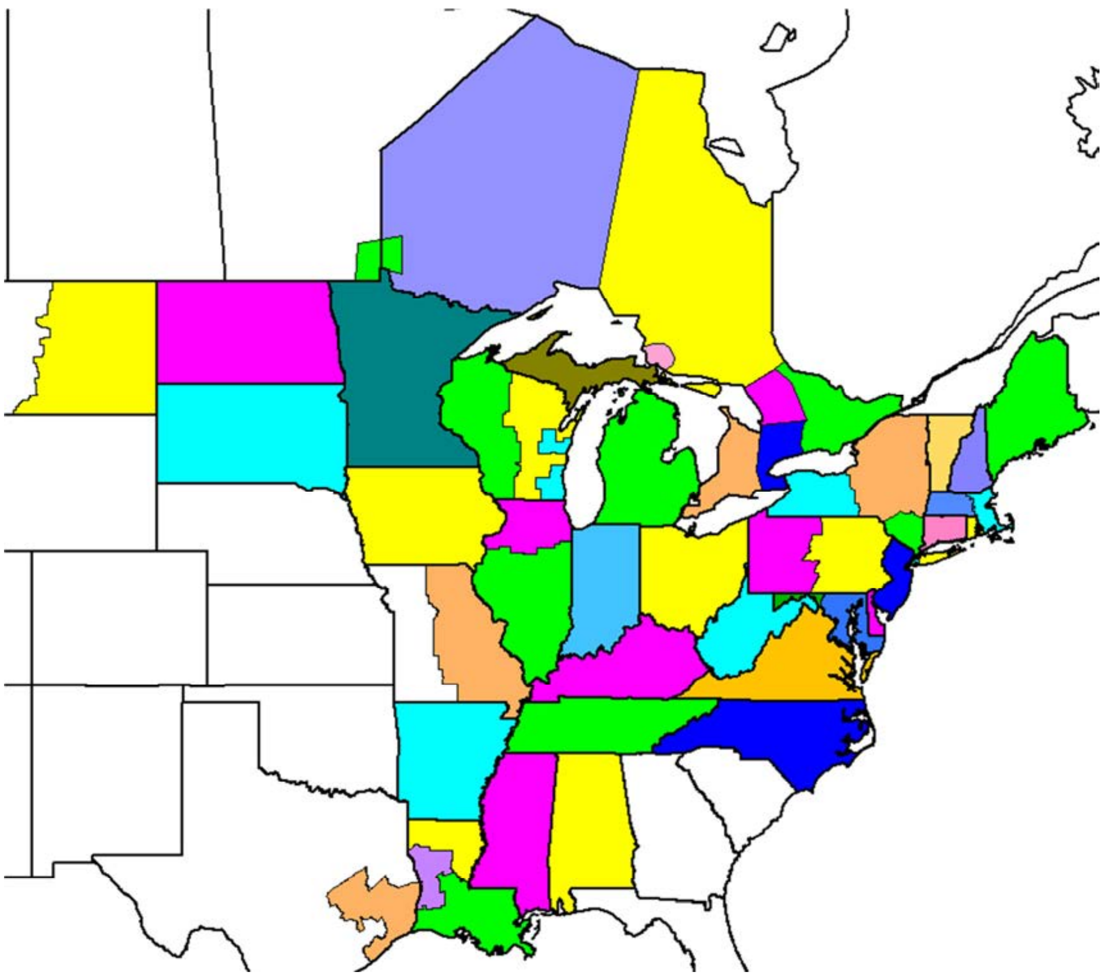


4 RCI SECTOR GAS DEMAND

4.1 METHODOLOGY

LAI's forecasts of local distribution company (LDC) gas demands for RCI customers were derived primarily based on historical pipeline delivery data and publicly available LDC forecasts and Integrated Resource Plans. Using historical pipeline data from 2011 through 2013, LAI first developed annual profiles of demand for LDC and industrial customers within each of the GPCM locations illustrated in Figure 43. GPCM locations are geographic aggregations of customers by location. For example, "New York Western" is an aggregation of more than 20 customers, including gas-fired generators. Customer aggregations reflect LDCs' connections to various pipelines, for example, NFG and NYSEG, but also includes miscellaneous industrial demands, *i.e.*, either direct connects or behind the LDC's citygate. In most cases, the GPCM locations correspond to states. For the states and province where this is not the case, Figure 44 through Figure 48 identify the intrastate and intraprovincial locations.

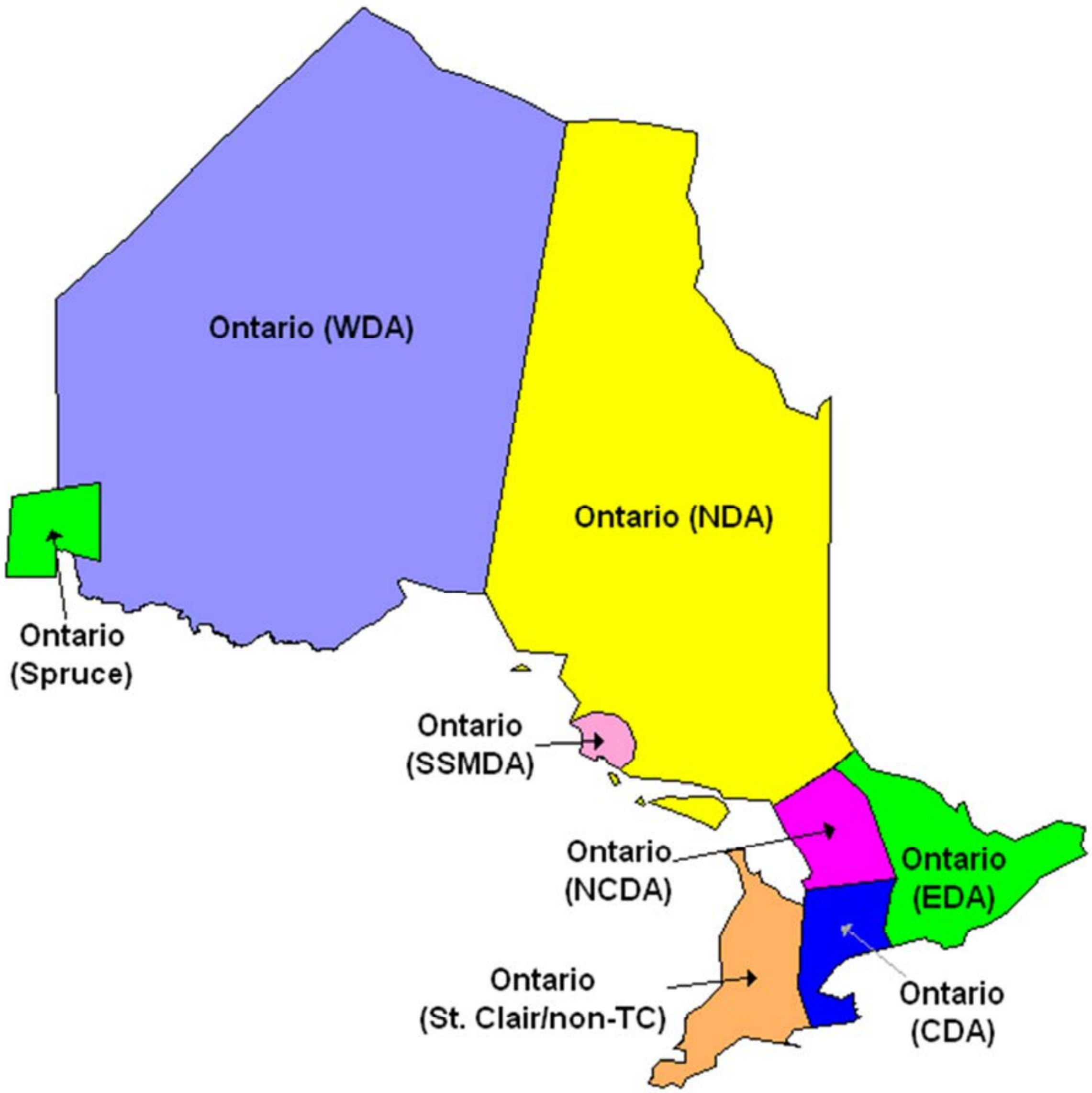
Figure 43. GPCM Locations in the Study Region[46]



[46] Color coding is meant only to signify how additional state or provincial separations have been defined.

In Ontario, GPCM locations correspond to TransCanada's Delivery Areas, with the exception of the Southwest Delivery Area, which is part of the St. Clair/non-TC location that also includes the majority of the Union transmission system and the Vector system.

Figure 44. GPCM Locations in Ontario[47]



[47] The high concentration of gas-fired generation in certain areas, particularly behind the Enbridge and Union Gas local distribution systems, warrants multiple locations in GPCM for the purpose of electric generator customer aggregation.

Figure 45. GPCM Locations in Maryland, Massachusetts and Pennsylvania

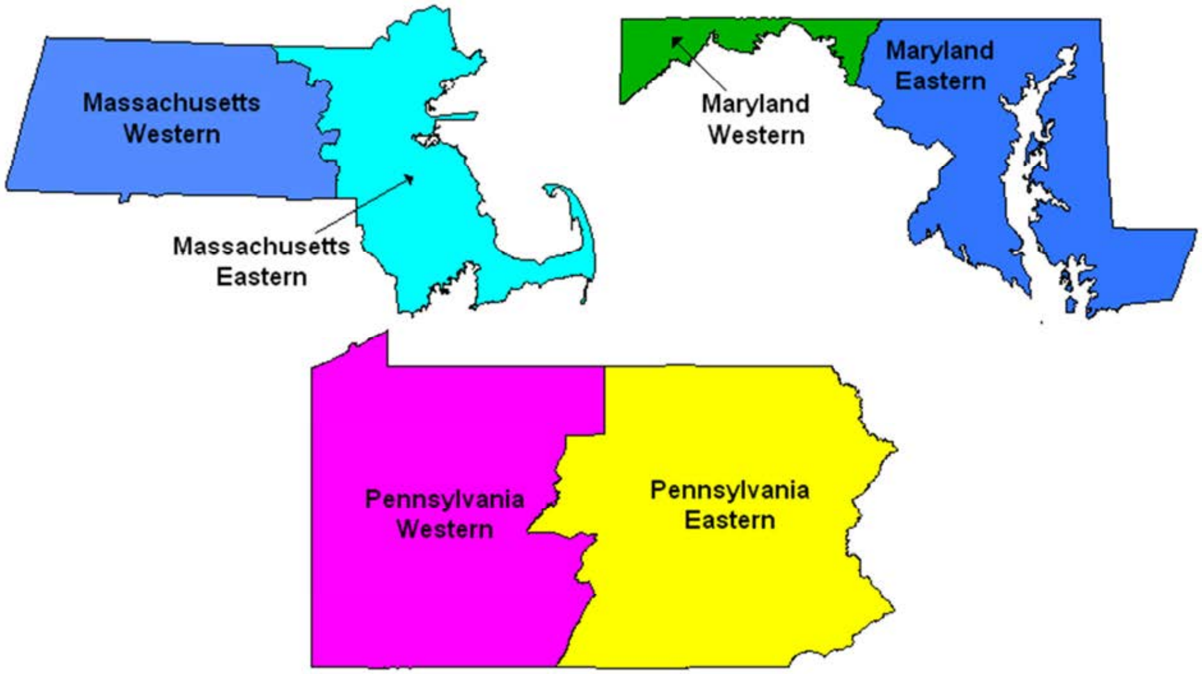


Figure 46. GPCM Locations in New York

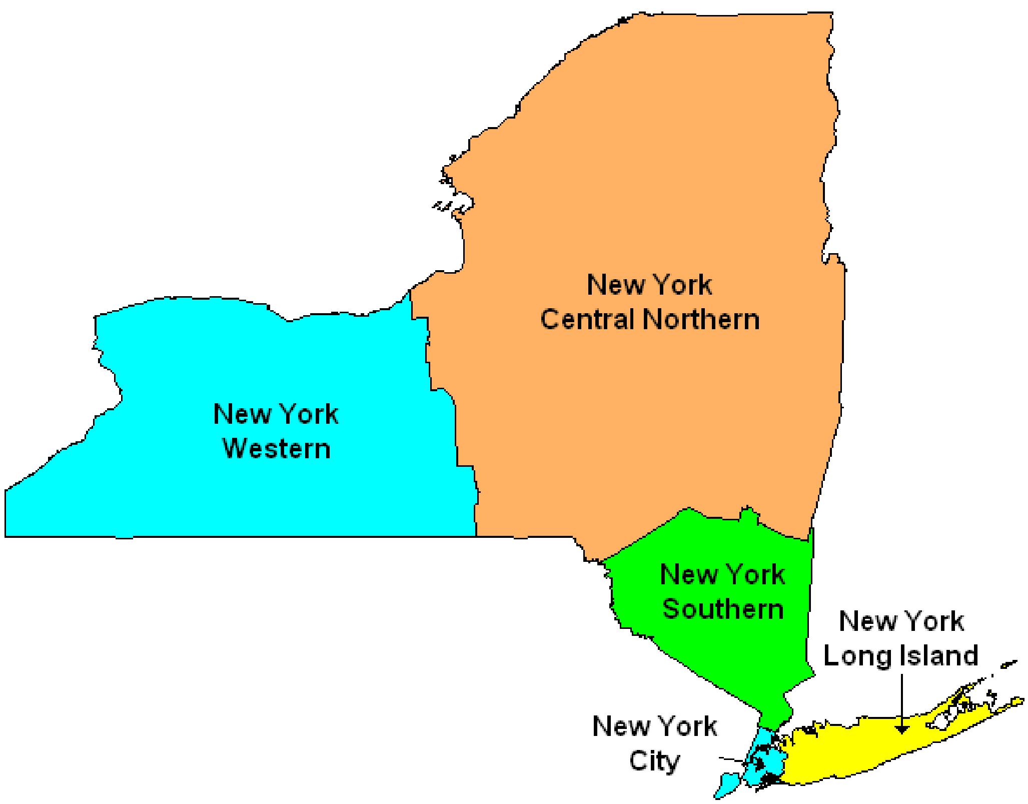


Figure 47. GPCM Locations in Illinois, Michigan, Missouri and Wisconsin

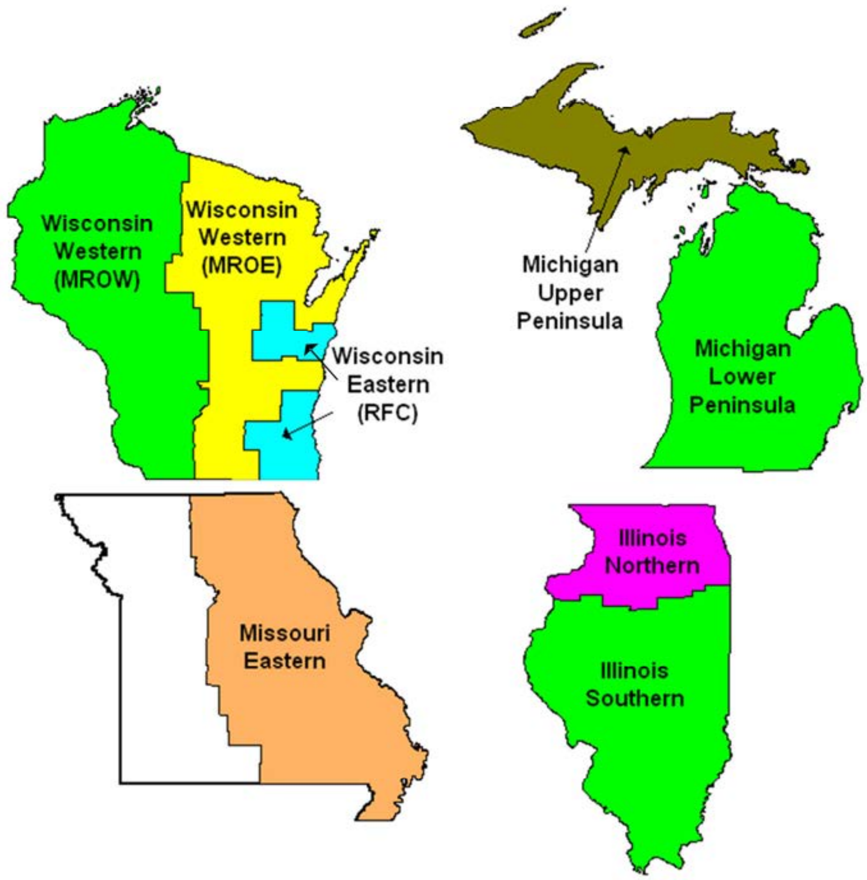
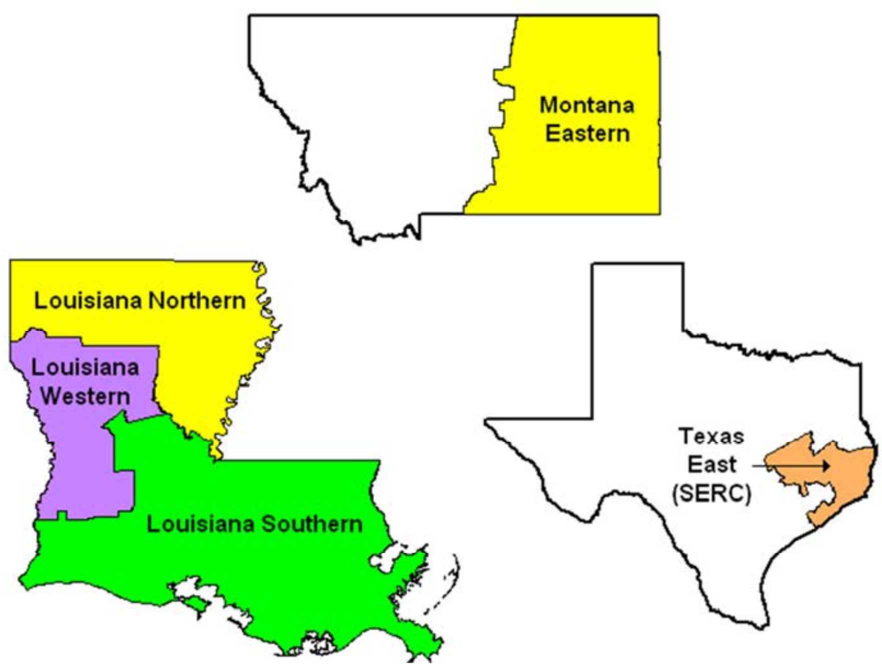
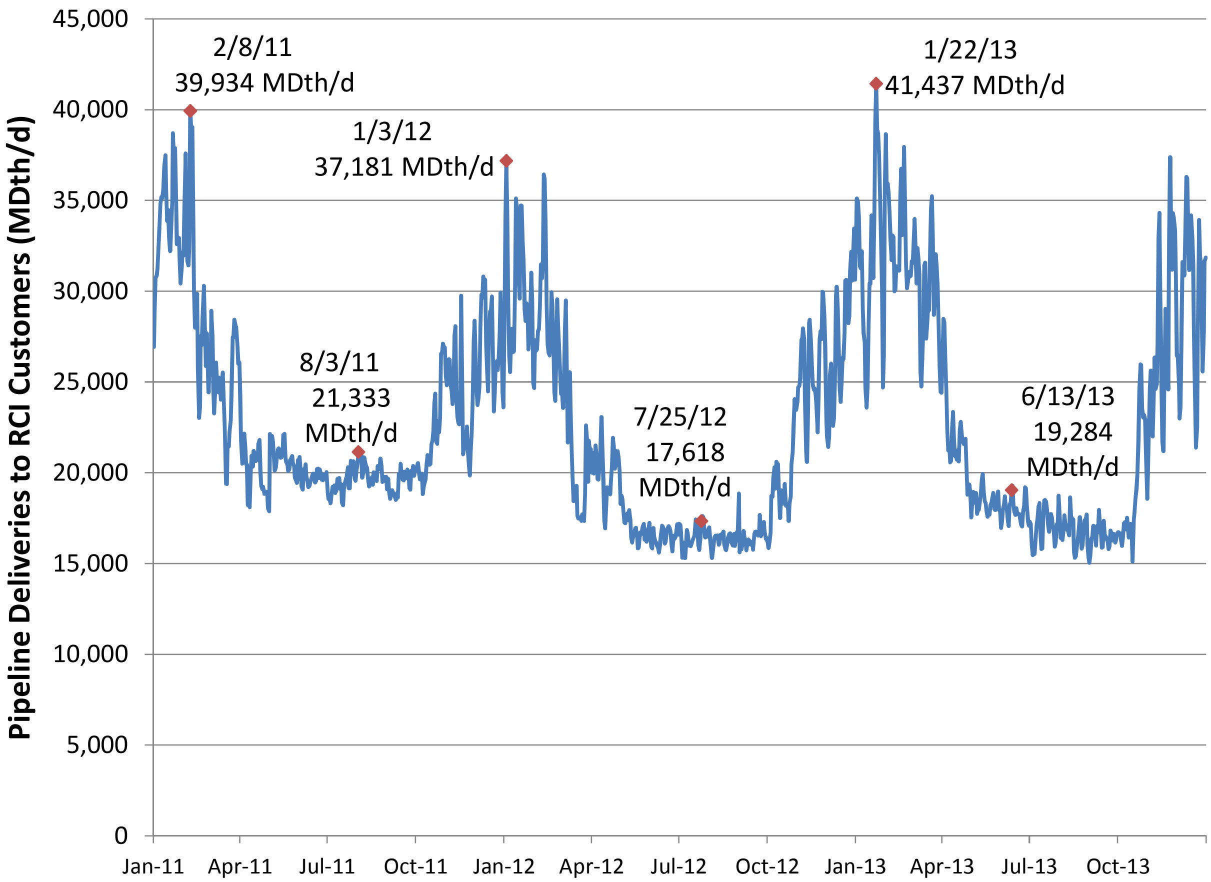


Figure 48. GPCM Locations in Louisiana, Montana and Texas



For LDCs serving gas-fired generators behind the citygate, generator gas demand was subtracted from the pipeline deliveries using heat input data from EPA's Clean Air Markets Program CEMS database.[48] The seasonal peak days within each year were identified for each pipeline delivery point operator (or customer) and for the Study Region as a whole.[49] Figure 49 shows the total pipeline deliveries to RCI customers over the three-year historical period. This data series was used to identify the seasonal Study Region coincident RCI peak days, defined as the day during each season with the greatest total demand across all RCI customers in the Study Region, which are also indicated in the figure by date and volume. While the winter peak days represent a demand spike relative to other seasonal days, the summer peak days do not differ significantly from the seasonal averages due to the relative flatness of the seasonal demand trend.

Figure 49. Historical Pipeline Deliveries to RCI Customers in the Study Region



For each customer, the demand on the customer-specific seasonal peak day and the demand on the Study Region coincident seasonal RCI peak day were compared to determine a scaling factor to be applied to the forecast of non-coincident seasonal peak demand calculated for the customer. This adjustment is necessary because RCI customers' peak demands do not occur simultaneously across the Study Region due to changing weather patterns and other factors, and to simply

48 http://ampd.epa.gov/ampd/

49 In some cases, multiple adjacent delivery point operators were grouped in order to streamline the analysis.

combine the non-coincident peak forecasts would result in an overestimation of peak day RCI demand. For example, cold weather does not occur uniformly across the Study Region footprint. An example scaling factor calculation is shown in Figure 50 and Table 10 for Connecticut Natural Gas.

Figure 50. Connecticut Natural Gas RCI Demand[50]

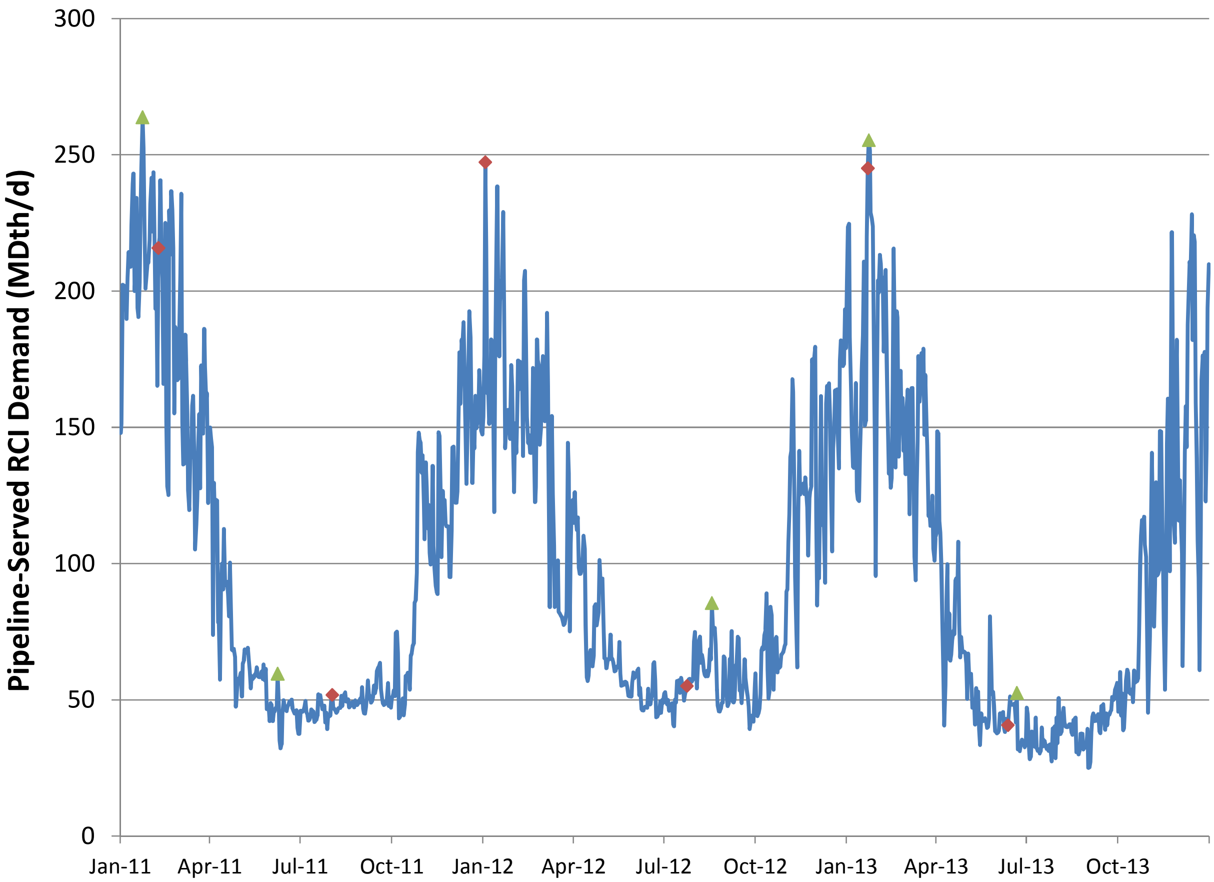


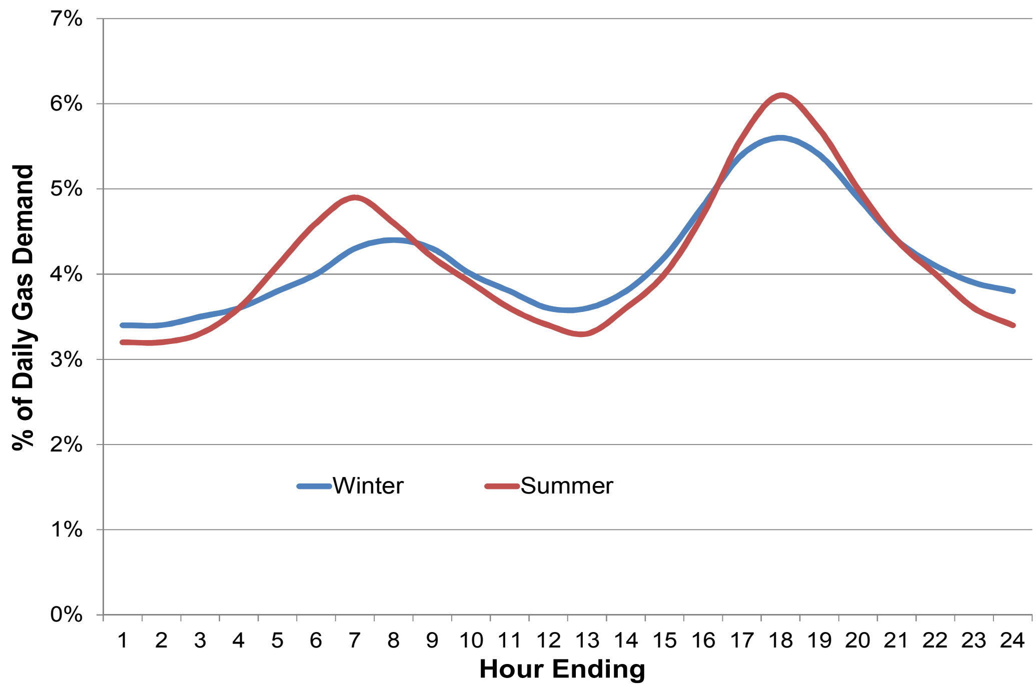
Table 10. Coincident v. Non-Coincident Scaling Factor Calculation

	Winter			Summer		
Year	Non-Coincident Peak (Dth/d)	Coincident Peak (Dth/d)	Scaling Factor	Non-Coincident Peak (Dth/d)	Coincident Peak (Dth/d)	Scaling Factor
2011	263,868	215,796	82%	59,568	46,769	79%
2012	247,314	247,314	100%	85,499	55,676	65%
2013	255,438	245,089	96%	52,487	44,972	86%
Average			93%			76%

[50] Red diamonds represent Study Region coincident peak days; green triangles represent Connecticut Natural Gas non-coincident peak days. In the case of the 2012 winter peak in January, the coincident and non-coincident peaks occur on the same day.

In addition to adjusting each customer's forecast of non-coincident peak demand to a coincident peak condition, LAI has also applied a peak hour scaling factor in order to test the natural gas infrastructure at maximum daily utilization, rather than average daily utilization. Based on the intraday profiles shown in Figure 51, which were developed using LAI's professional judgment and limited reporting of peak hour factors in LDC forecasts and other public sources, 5.6% and 6.1% of the daily demand is assumed to be delivered to customers during the peak hour on a winter and summer day, respectively.[51]

Figure 51. Intraday Seasonal Gas Demand Profiles



4.2 Calculation of Non-Coincident Peak Demands

In order to calculate the RCI demand for each customer for which a public forecast was not available, the average non-coincident peak day deliveries in 2011, 2012 and 2013 were averaged and escalated at the gas demand scenario-specific growth rates reported in the following sections.

Where LDC-specific forecasts were found to be publicly available, the seasonal peak day information for 2018 and 2023 was either extracted or extrapolated.[52,53] Most LDCs report only an annual peak day, representing the winter peak. In the absence of a forecast for summer load growth rate, LAI applied an LDC's winter load growth rate on a percentage basis to the summer as well in order to account for LDC-specific forecast assumptions, such as customer expansion.

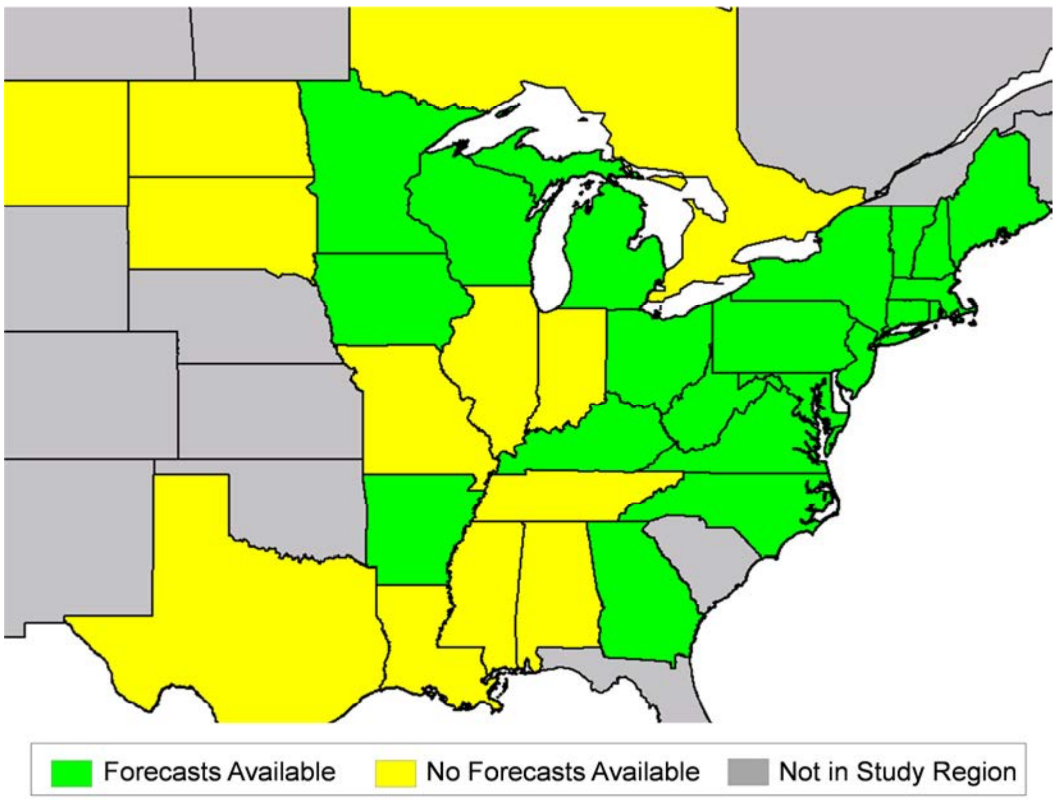
[51] Average hourly demand would represent 4.2% of daily demand.

[52] Most LDCs report only an annual winter peak day.

[53] LDC filings generally cover a forecast period from 3 to 5 years. Target 2 research objectives require study parameters to be extended to 2023, a year that is outside the forecast period for most LDCs in the Study Region. LAI has applied the average of the growth rates reported in the demand forecasts over the study period.

Figure 52 shows the states where public demand forecasts were available for some or all LDCs. Exhibit 15 lists the forecast filings and other documents collected by LAI for specific LDCs operating in the Study Region.[54] In some cases, the public version of a forecast document was either redacted to remove the relevant information, or insufficient information was available to calculate a growth rate. In these cases, the default approach using historical pipeline delivery data was applied.

Figure 52. Availability of Publicly-Filed LDC Demand Forecasts[55]



4.3 RGDS RCI DEMAND

For LDCs where no forecast was found to be publicly-available, LAI escalated the historical non-coincident peak demand using a load growth rate based on the total gas consumption forecast for the residential, commercial, industrial, and transportations sectors in the AEO2013 Reference Case. The consumption forecast is differentiated by census division, therefore the

[54] States across the Study Region maintain diverse filing requirements, which may include Integrated Resource Plans, Long-Term Gas Supply Plans, Gas Hedging and Purchase Strategies, Winter Supply Plans, or other filings which, in some cases, include long-term forecasts. Filings which compare peak day supply and demand, commonly known as "resources and requirements" tables, are useful insofar as they delineate supply sources behind the citygate.

[55] Some state commissions allow LDCs to keep demand forecast filings confidential. Some state commissions conduct informal meetings regarding procurement practices and portfolio management. LDC filing requirements are generally more comprehensive and transparent in the Northeast, particularly in states that promote oil-to-gas conversions.

load growth rates, shown in Table 11 were applied based on each LDC's or customer's location. AEO2013 reports that decreases in residential gas demand are the result of "population shifts to warmer regions of the country and improvements in appliance efficiency."[56]

Table 11. RGDS RCI Load Growth Rates[57]

Census Division	2018 Total Growth Rel. to 2013	2018 Annual Growth Rate (2013-2018)	2023 Total Growth Rel. to 2018	2023 Annual Growth Rate (2018-2023)
New England (CT, ME, MA, NH, RI, VT)	2.91%	0.58%	2.55%	0.51%
Middle Atlantic (NJ, NY, PA)	1.41%	0.28%	0.92%	0.18%
East North Central[58] (IL, IN, MI, OH, WI)	0.80%	0.16%	-1.22%	-0.24%
West North Central[59] (IA, MN, MO, ND, SD)	2.67%	0.53%	-0.45%	-0.09%
South Atlantic (DC, DE, GA, MD, NC, VA, WV)	6.19%	1.24%	2.97%	0.59%
East South Central (AL, KY, MS, TN)	2.56%	0.51%	1.29%	0.26%
West South Central (AR, LA, TX)	7.21%	1.44%	3.31%	0.66%
Mountain (MT)	2.93%	0.59%	1.88%	0.38%

Figure 53 shows the RGDS RCI forecast by PPA for the peak demand hour within each season. Figures showing the RCI forecast by location within each PPA for the RGDS are presented in Exhibit 14.

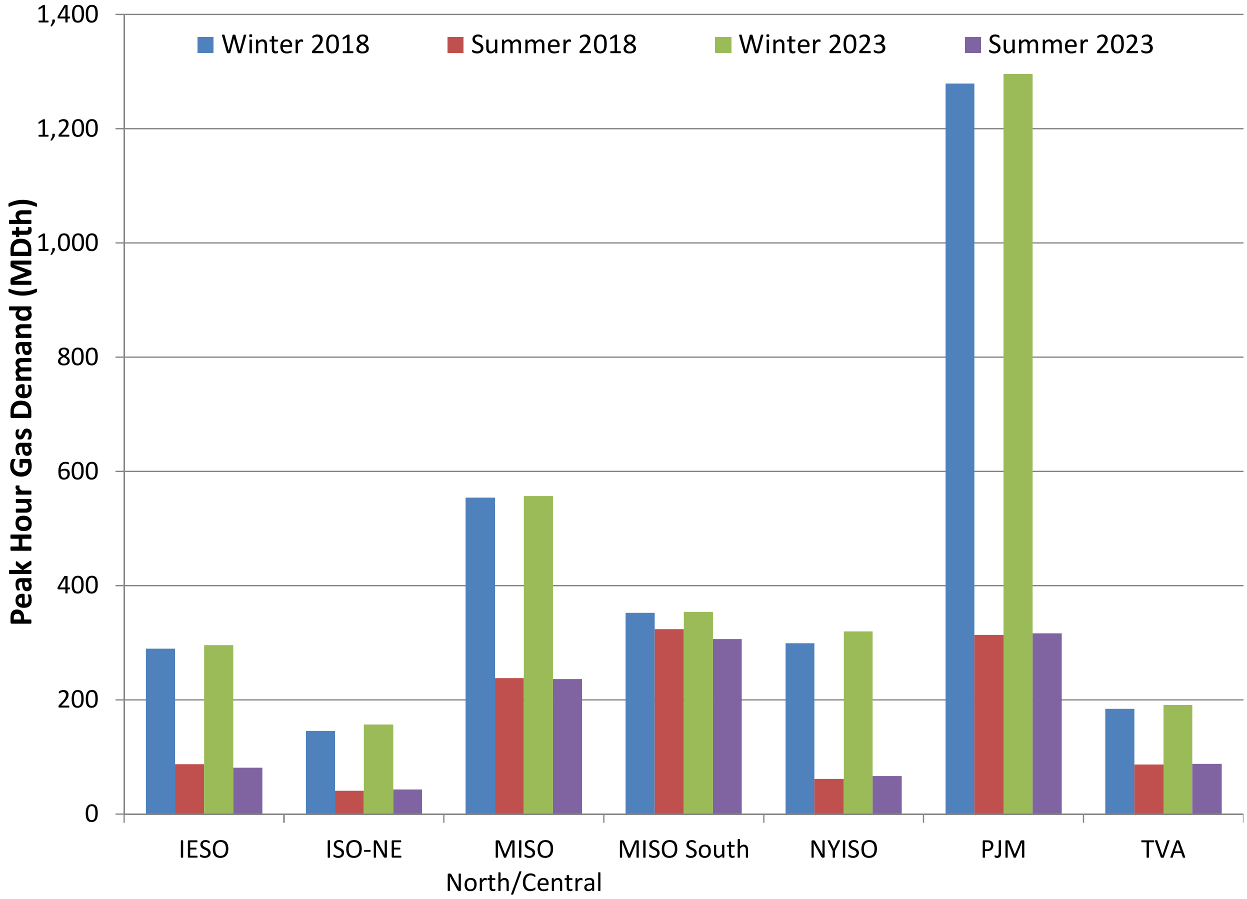
[56] Source: AEO2013, page MT-21

[57] Only locations within the Gas-Electric Study Region are included in this table.

[58] For the East North Central census division, AEO2013's Reference Case forecasts a decrease in residential demand from 1.195 Tcf in 2018 to 1.126 in 2023, a decrease in commercial demand from 0.713 Tcf in 2018 to 0.709 Tcf in 2023, an increase in industrial demand from 1.257 Tcf in 2018 to 1.287 Tcf in 2023, and an increase in transportation demand from 0.009 Tcf in 2018 to 0.011 Tcf in 2023, resulting in a net decrease in total gas demand from 3.174 Tcf in 2018 to 3.135 in 2023.

[59] For the West North Central census division, AEO2013's Reference Case forecasts a decrease in residential demand from 0.398 Tcf in 2018 to 0.383 in 2023, a decrease in commercial demand from 0.3043 Tcf in 2018 to 0.299 Tcf in 2023, an increase in industrial demand from 0.681 Tcf in 2018 to 0.693 Tcf in 2023, and an increase in transportation demand from 0.004 Tcf in 2018 to 0.006 Tcf in 2023, resulting in a net decrease in total gas demand from 1.388 Tcf in 2018 to 1.381 in 2023.

Figure 53. RGDS Peak Hour RCI Demand by Season and Year



4.4 HGDS RCI DEMAND

Similar to the RGDS, if no LDC forecast was found to be publicly-available, LAI escalated the historical non-coincident peak demands using load growth rates based on the AEO2013 High Economic Growth Case, shown in Table 12.

Table 12. HGDS RCI Load Growth Rates

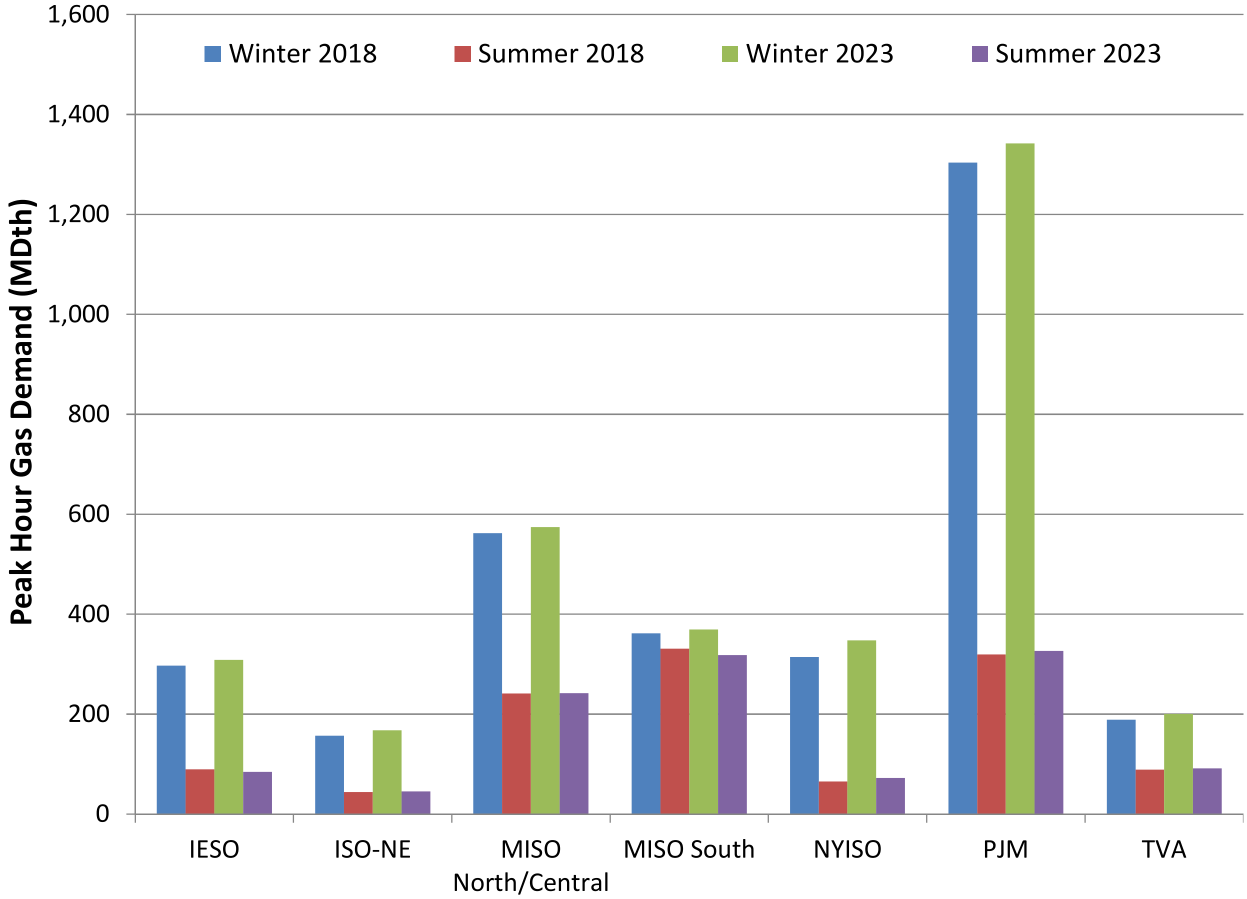
Census Division	2018 Total Growth Rel. to 2013	2018 Annual Growth Rate	2023 Total Growth Rel. to 2018	2023 Annual Growth Rate
New England (CT, ME, MA, NH, RI, VT)	4.52%	0.90%	3.82%	0.76%
Middle Atlantic (NJ, NY, PA)	2.70%	0.54%	2.05%	0.41%
East North Central[60] (IL, IN, MI, OH, WI)	2.33%	0.47%	-0.23%	-0.05%
West North Central (IA, MN, MO, ND, SD)	4.03%	0.81%	0.46%	0.09%
South Atlantic (DC, DE, GA, MD, NC, VA, WV)	8.18%	1.64%	4.57%	0.91%
East South Central (AL, KY, MS, TN)	4.79%	0.96%	2.85%	0.57%
West South Central (AR, LA, TX)	10.06%	2.01%	5.08%	1.02%
Mountain (MT)	5.14%	1.03%	4.29%	0.86%

If an LDC included a higher load growth case in its publicly-filed forecast, LAI used that information. Where an LDC forecast was available, but did not contain a higher load growth case, the ratio between the relevant AEO2013 growth rates for the RDGS and HGDS was applied to the provided growth rate in order to calculate a scaled higher demand.

Figure 54 shows the HGDS RCI forecast by PPA for the peak demand hour within each season. Figures showing the RCI forecast by location within each PPA for the HGDS are presented in Exhibit 14.

[60] For the East North Central census division, AEO2013's High Economic Growth Case forecasts a decrease in residential demand from 1.197 Tcf in 2018 to 1.133 in 2023, a decrease in commercial demand from 0.710 Tcf in 2018 to 0.703 Tcf in 2023, an increase in industrial demand from 1.309 Tcf in 2018 to 1.369 Tcf in 2023, and an increase in transportation demand from 0.009 Tcf in 2018 to 0.012 Tcf in 2023, resulting in a net decrease in total gas demand from 3.225 Tcf in 2018 to 3.217 in 2023.

Figure 54. HGDS Peak Hour RCI Demand by Season and Year



4.5 LGDS RCI DEMAND

The LGDS RCI forecast was developed using load growth rates based on the AEO2013 Low Economic Growth Case, shown in Table 13.

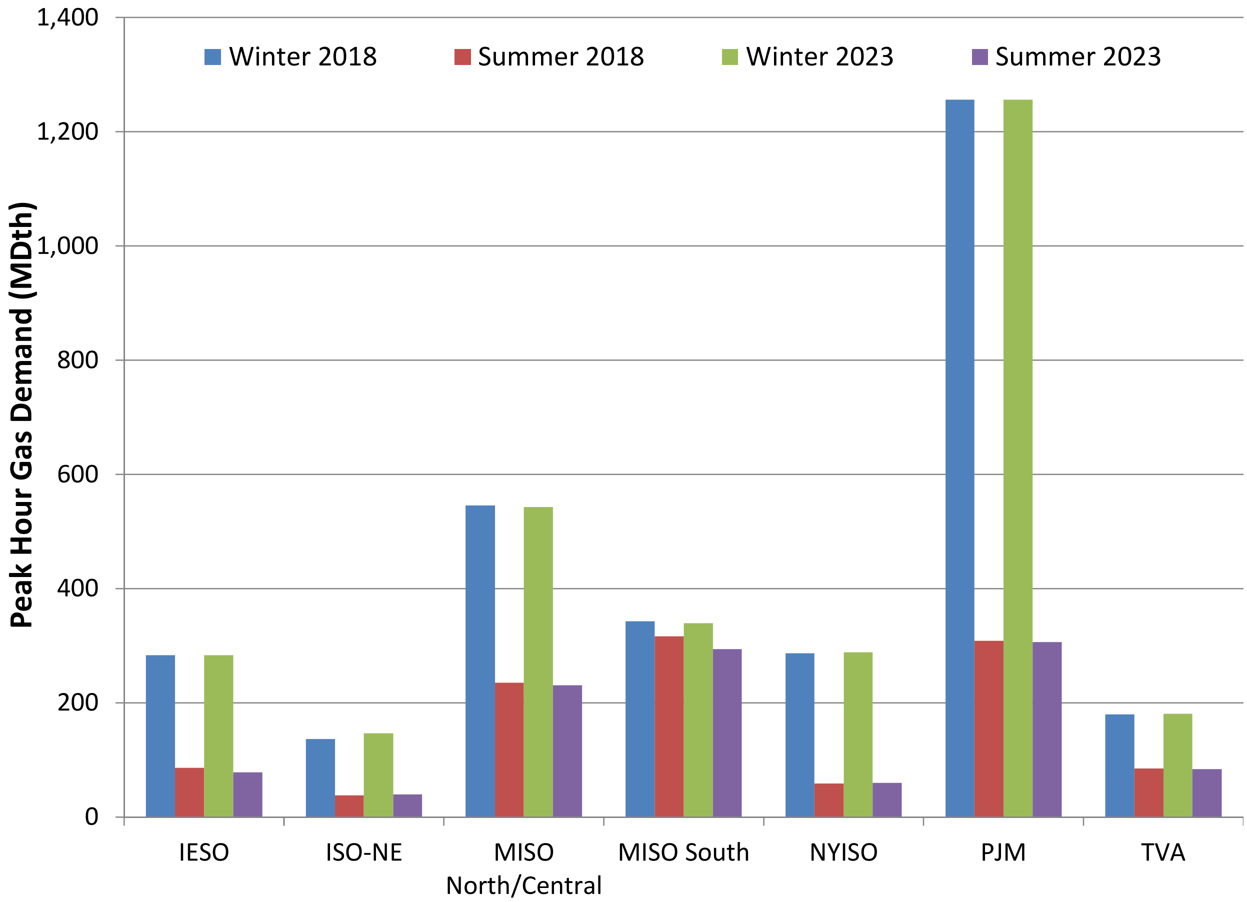
Table 13. LGDS RCI Load Growth Rates

Census Division	2018 Total Growth Rel. to 2013	2018 Annual Growth Rate	2023 Total Growth Rel. to 2013	2023 Annual Growth Rate
New England (CT, ME, MA, NH, RI, VT	1.52%	0.30%	0.96%	0.19%
Middle Atlantic (NJ, NY, PA)	0.54%	0.11%	-0.29%	-0.06%
East North Central (IL, IN, MI, OH, WI)	-0.85%	-0.17%	-2.39%	-0.48%
West North Central (IA, MN, MO, ND, SD)	0.99%	0.20%	-1.35%	-0.27%
South Atlantic (DC, DE, GA, MD, NC, VA, WV)	4.37%	0.87%	1.24%	0.25%
East South Central (AL, KY, MS, TN)	0.28%	0.06%	-0.61%	-0.12%
West South Central (AR, LA, TX)	4.04%	0.81%	1.07%	0.21%
Mountain (MT)	0.65%	0.13%	0.48%	0.10%

If an LDC included a lower load growth case in its publicly-filed forecast, LAI used that information. Where an LDC forecast was available, but did not contain a lower load growth case, the ratio between the relevant AEO2013 growth rates for the RDGS and LGDS was applied to the provided growth rate in order to calculate a scaled higher demand.

Figure 55 shows the LGDS RCI forecast by PPA and by location within each PPA for the peak demand hour within each season. Figures showing the RCI forecast by location within each PPA for the LGDS are presented in Exhibit 14.

Figure 55. LGDS RCI Demand by Season and Year



4.6 Comparison Among Gas Demand Scenarios

The following four figures compare the RGDS, HGDS and LGDS forecasts presented in the previous sections.

Figure 56. RCI Demand by Scenario – Winter 2018

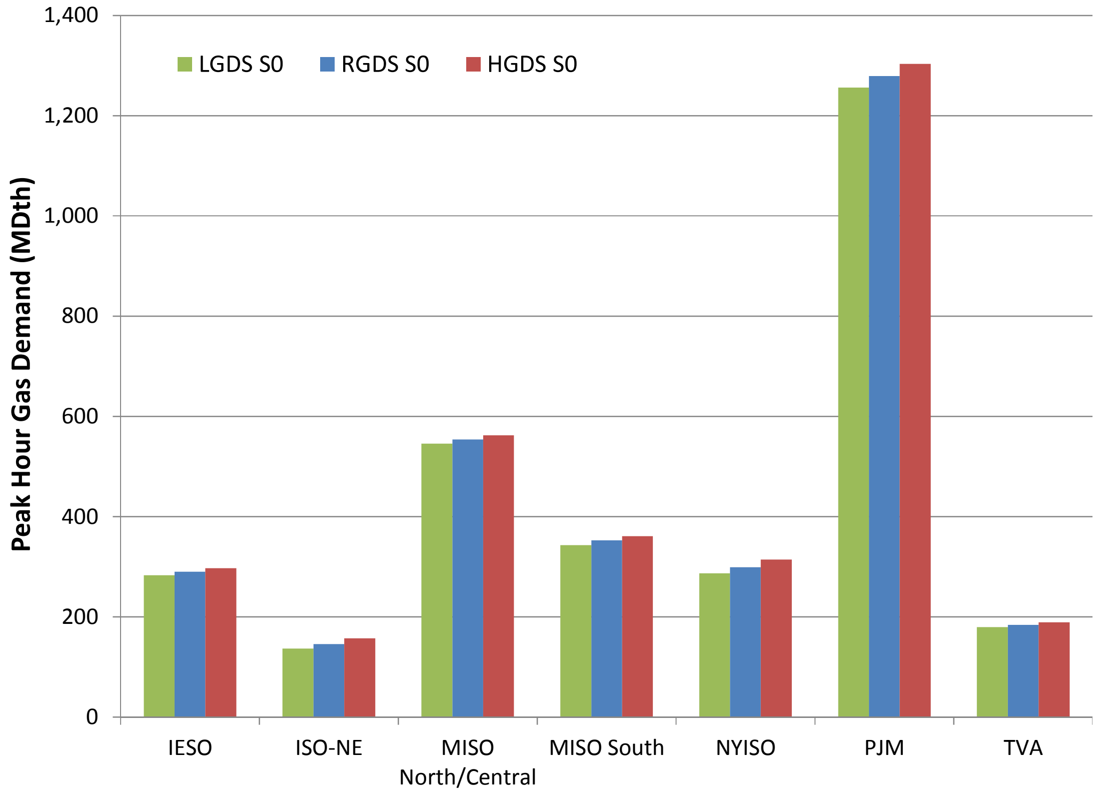


Figure 57. RCI Demand by Scenario – Summer 2018

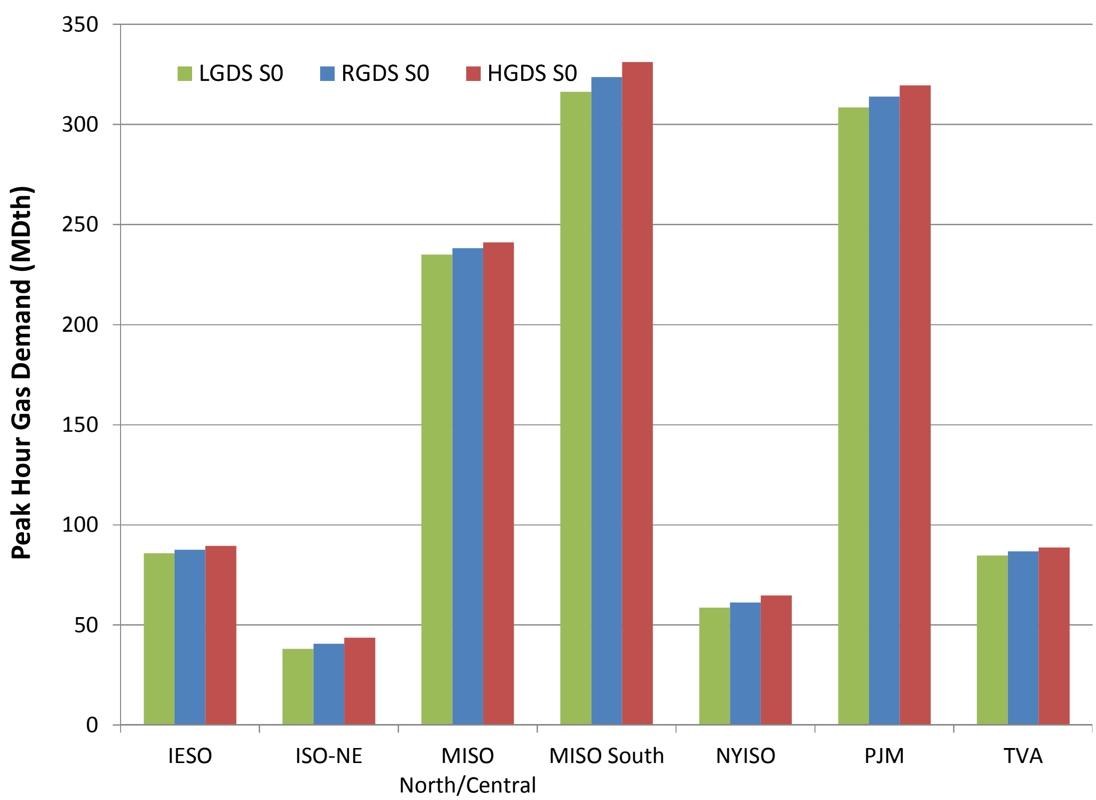


Figure 58. RCI Demand by Scenario – Winter 2023

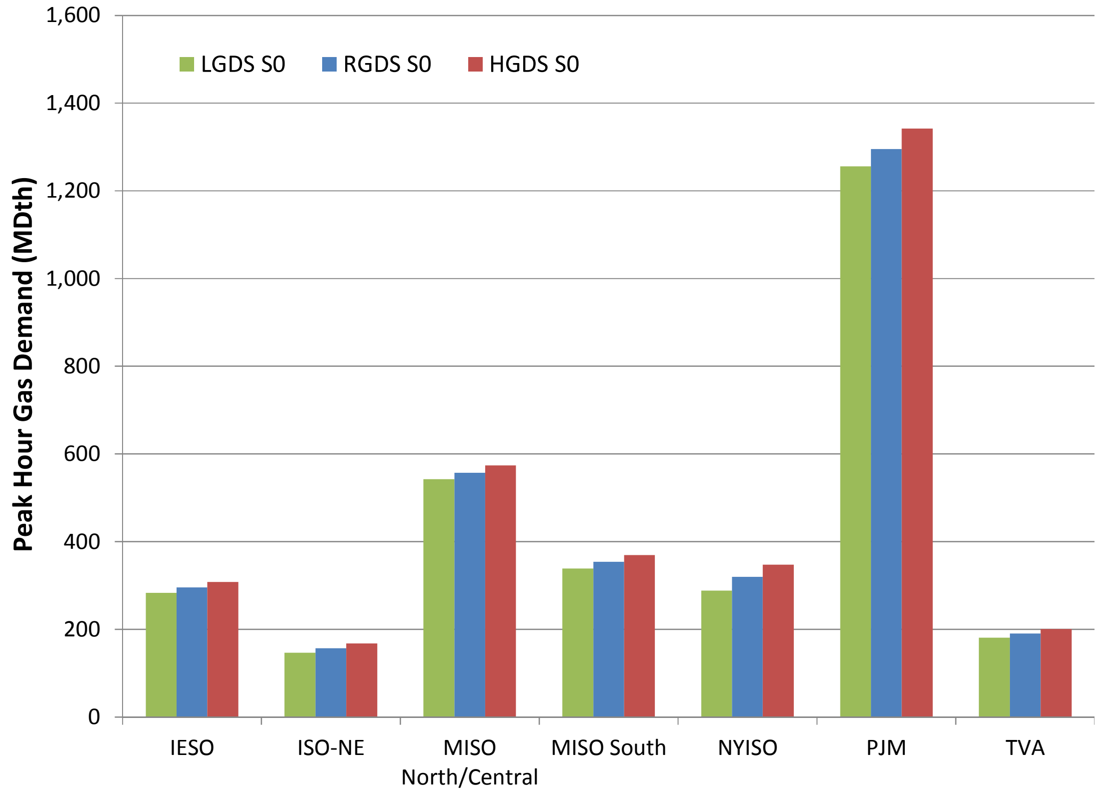
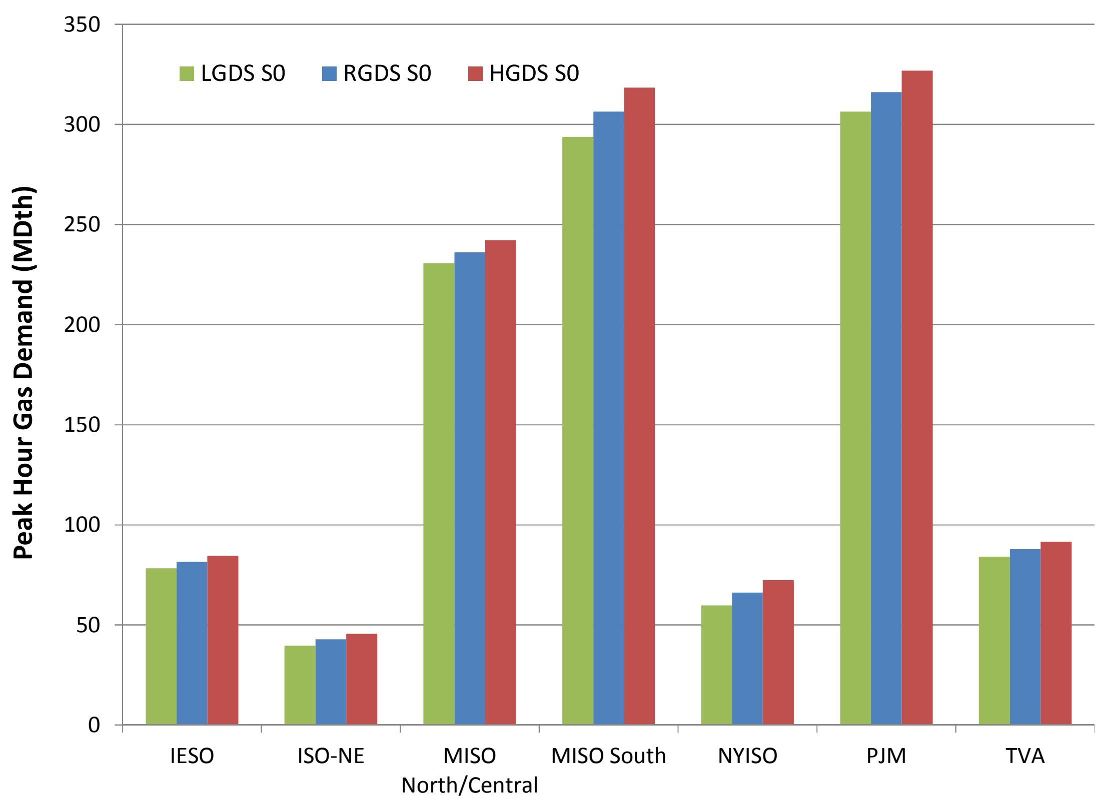


Figure 59. RCI Demand by Scenario – Summer 2023



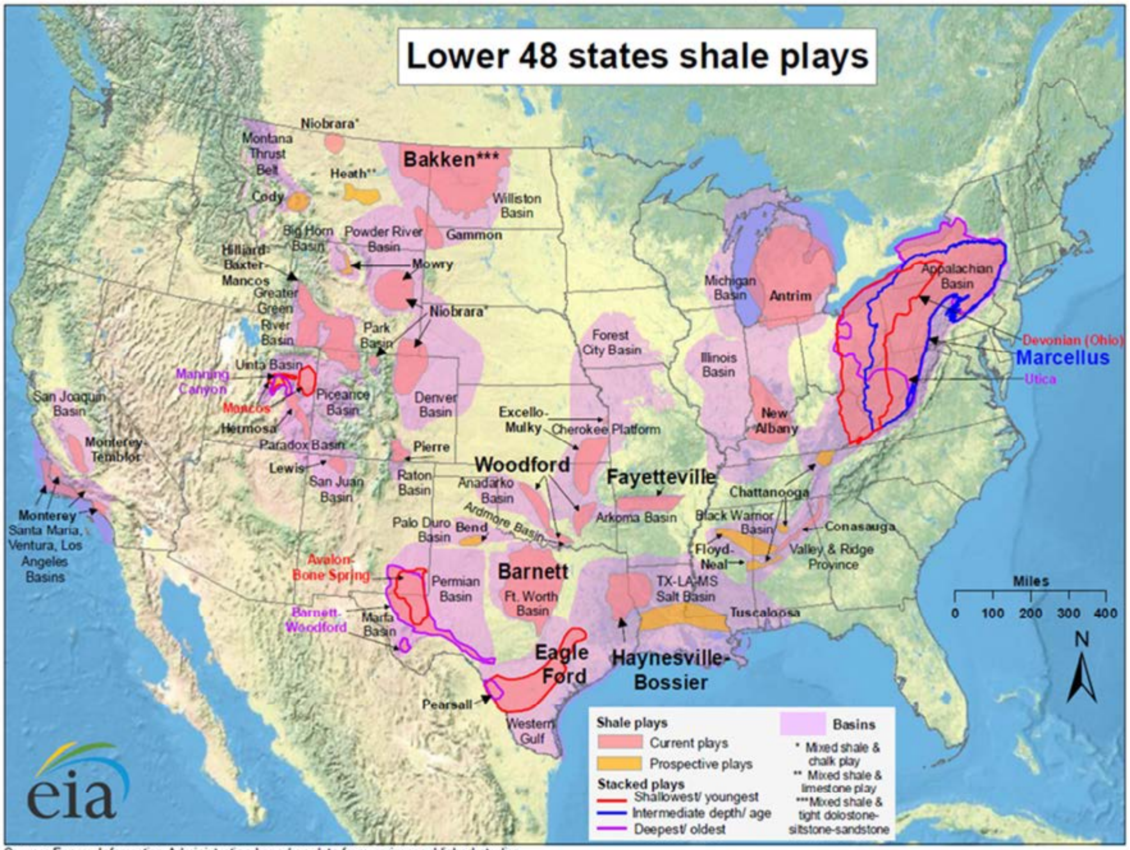
5 MARKET STRUCTURE UNDERLYING THE INTEGRATION OF ELECTRIC AND RCI SECTOR GAS DEMANDS

5.1 BACKGROUND ON SHALE GAS PRODUCTION AND MARKET DYNAMICS

The recent rapid development of the major shale plays has radically changed gas market dynamics and gas flows on the pipelines serving the Study Region. It is for this reason that EIPC study objectives are centered on infrastructure capability rather than gas supply into and within the Study Region. Following the start of large scale commercial production from the Barnett shale in the late 1990s, shale gas production has developed rapidly at many of the shale plays through North America shown in Figure 60. In 2000, U.S. shale gas production averaged 820 MMcf/d, less than 2% of total U.S. gas production. By Q1-2014, shale gas production amounted to 34 Bcf/d, almost one-half of total US gas production.[61] Technologies such as horizontal drilling and hydraulic fracturing, first applied to the Barnett shale, have been transferred and improved to allow economic production in shale plays such as the Marcellus and Utica in the Northeast, and the Haynesville, Fayetteville and the Woodford in the Mid-Continent. These plays, which currently produce 21 Bcf/d, will be the primary supply sources driving the market dynamics in the Study Region over the forecast period.

[61] U.S. EIA Shale Gas Production through April 2014.

Figure 60. Shale Plays in Lower 48 States[62]



Source: Energy Information Administration based on data from various published studies.
Updated: May 9, 2011

The most recent EIA data shows Marcellus and Utica production continuing to grow while production from the Fayetteville and Woodford plays remain flat. Production from Haynesville declined. Rig counts over the past year have declined overall in each of these plays, but increasing drilling efficiency has helped to increase or maintain production. Gas prices and production economics rather than resource limitations are driving current production growth. Dry gas production in most of the Marcellus and in the "sweet spots" of the Haynesville are economic when gas prices are roughly \$4.00 per MMBtu.[63] However, many parts of the Haynesville – primarily a dry gas play – are not economic at current gas prices. Wet gas production includes natural gas liquids that are priced higher than dry gas. The value of natural gas liquids contribute to making gas production economic in the western parts of the Marcellus, the Utica, and the Woodford at current gas prices.[64]

Production economics continue to improve in most of the shale plays due to improving technology. Improved technology includes multi-well drilling pads, improved fracturing design, and improved fracturing fluids. The relatively rapid production decline curves experienced by

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[62] www.eia.gov/oil_gas/rpd/shale_gas.pdf

[63] D. Pursell, Tudor Pickering Holt & Co., *Macro Natural Gas and Oil Thoughts*, May 2, 2013.

[64] Natural gas liquids, such as ethane, propane, butane and natural gasoline are generally priced in accord with crude oil prices.

many shale gas wells have *not* resulted in reductions in overall shale gas production due to the large areal extent of the continuous shale formations along with well recompletions and re-fracturing. The primary example of the ability of shale plays to maintain or grow production in the face of individual well decline curves is the grandfather of the shale plays, the Barnett in Texas. Barnett production has remained at around 4 Bcf/d since 2008 despite numerous predictions by industry specialists that the play would experience rapidly declining production.

The Marcellus shale play has had, and will continue to have, the greatest impact on gas flows and pipeline developments across the Study Region. Located adjacent to the major markets of the Northeast and Midwest, the ascension of Marcellus production places a major supply source close to markets that had traditionally relied on long-haul transportation from Western Canada, the Gulf Coast, Rocky Mountains, and the Midcontinent producing fields. Marcellus production has grown exponentially, increasing from about 2 Bcf *for all of calendar year 2008* to the current *daily* rate of 16.7 Bcf.[65] The rapid ascent of Marcellus production has therefore strained existing gas infrastructure as there has not been sufficient pipeline gathering and takeaway capacity to keep pace with production. Additional production growth in the Marcellus and Utica shales will be dependent on expanding pipeline takeaway capacity. Facing lower prices in areas with constrained takeaway capacity, Marcellus producers have executed long term transportation supply agreements as "anchor tenants" in order to support the growth of pipeline infrastructure across the Eastern Interconnect. In addition to an array of "supply-push" pipeline projects sponsored by Marcellus producers, other pipeline expansion projects have long term commitments from LDCs, and, to a lesser extent, generators and end-users.

As discussed in Appendix B, many new pipeline as well as expansions to existing pipelines are supply-push arrangements whereby producers have agreed to "foot the bill" on a long term basis to ensure good access to premium markets.[66] Numerous pipeline projects have been announced that seek to redress the Marcellus takeaway constraints. These projects include new pipeline segments and laterals, pipeline expansions and flow reversal projects. The new projects and expansions are seeking to increase gas flows to markets throughout the Northeast, Midwest and Southeast, while pipeline flow reversals such as on Rockies Express, Tennessee and Transco seek to utilize existing pipeline infrastructure by reversing traditional flows so that Marcellus gas can move into markets formerly served by traditional south to north and west to east gas flows. The relevant projects are discussed later in Section 5.2.

5.2 NATURAL GAS INFRASTRUCTURE ASSUMPTIONS

To account for the expansion of gas infrastructure from 2014 to 2018 in the GPCM constraint analysis model, LAI evaluated the status of various pipeline certificate applications before FERC. Pipeline infrastructure projects were identified for inclusion in the GPCM model of the three gas demand scenarios if precedent agreements sufficient to support a project's construction were publicly known as of April 22, 2014, based on FERC filings, open season notice, or other

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[65] Platts *Gas Daily*, August 26, 2014, p. 2.

[66] Producers as anchor shippers rationalize the cost of incremental firm transportation entitlements by comparing the enhanced operating revenues derived from commodity gas sales when deliverability constraints as well as shut-in wells are reduced or alleviated through infrastructure additions.

pipeline announcement or press release.[67] Precedent agreements between pipeline project developers and customers are the outcome of commercial negotiations following an open season bid by the customer, and represent a commitment to contract for firm transportation capacity in the event that the project is built. These agreements are used to demonstrate market support to FERC, a prerequisite for regulatory approval.

The new pipeline facilities meeting this criterion and included in the pipeline model topology are listed in Table 14 and described in Appendix B.

Table 14. Pipeline Infrastructure Projects included in the Gas Demand Scenarios

Pipeline	Project	FERC Docket #
Algonquin	AIM	CP14-96
	Atlantic Bridge (with M&N)[68]	PF14-5
	Salem Lateral	N/A
ANR[69]	Glen Karn 2015	N/A
	Southeast Mainline Flow Reversal	N/A
Columbia Gas[70]	East Side Expansion	CP14-17
	Giles County	CP13-125
	Line 1570	CP13-478
	Smithfield III Expansion	CP13-477
Constitution	Constitution Pipeline	CP13-499
Creole Trail	Creole Trail Expansion	CP13-552
	CCTPL Expansion	CP12-351
Crossroads	Unity Pipeline Diluent	N/A
Dominion Cove Point	Cove Point Liquefaction	CP13-113
Dominion	Allegheny Storage	CP12-72
	Clarington Project[71]	CP14-496
	Natrium to Market	CP13-13
East Tennessee	Kingsport Expansion	CP13-534
	Wacker	CP12-484
Eastern Shore	TETCO Supply Expansion	CP14-67
	White Oak Lateral	CP13-498
Empire	Tuscarora Lateral (with NFG)	CP14-112

[67] INGAA facilitated pipeline commentary and input to the delineation of pipeline and storage infrastructure additions included in the gas demand scenarios.

[68] 100 MDth/d of incremental capacity associated with the Atlantic Bridge Project is included in the primary Gas Demand Scenarios. The remainder of the project's capacity is included in Sensitivity 13.

[69] The Lebanon Lateral 2014 Reversal Project is not listed here because it is already in service.

[70] The VEPCO-Warren County Project is not listed here because it is already in service.

[71] The Clarington Project was previously known as the WV West Project.

Pipeline	Project	FERC Docket #
Equitrans	H-164	CP14-90
	H-305	CP14-130
	Jefferson Compressor Station Expansion	CP13-547
	West Uprate and Blacksville Compressor Station Expansion	CP14-492
Great Lakes	MAOP Reduction	CP14-116
Gulf South	Southeast Market Expansion	CP13-96
Iroquois	Wright Compressor Station	CP13-502
NFG	Mercer Expansion	CP13-530
	Northern Access 2015	CP14-100
	West Side Expansion and Modernization	CP14-70
NGPL	2012 NGPL Storage Optimization	CP11-547
Northern Natural	West Leg 2014	CP13-528
Rockies Express	Seneca Lateral Project	CP13-539
Sabal Trail	Sabal Trail	PF14-1
Southeast Supply Header	SESH Expansion	CP14-87
Southern	Zone 3 2016 Expansion	N/A
Tennessee	Broad Run Expansion	N/A
	Broad Run Flexibility	N/A
	Connecticut Expansion	N/A
	Niagara Expansion	CP14-88
	Rose Lake Expansion	CP13-3
	Uniondale Expansion	CP13-526
	Utica Backhaul Transportation	N/A
Texas Eastern	Gulf Market Expansion	N/A
	OPEN	CP14-68
	TEAM 2014	CP13-84
	Uniontown to Gas City	CP14-104
Texas Gas[72]	Ohio-Louisiana Access	N/A
TransCanada	Energy East Expansion	NEB #14-04-04
	Parkway to Maple – Kings North	N/A
Transco	Atlantic Sunrise	PF14-8
	Dalton Expansion	PF14-10
	Gulf Trace	N/A
	Hillabee Expansion	PF14-6
	Leidy Southeast	CP13-551
	Mobile Bay South III Expansion	CP13-523
	Northeast Connector	CP13-132
	Rock Springs Expansion	PF14-6
	Rockaway Delivery Lateral	CP13-36
	Virginia Southside Expansion	CP13-30
	Woodbridge Delivery Lateral	CP14-18

[72] The Texas Gas Abandonment Project is not listed here because it was withdrawn from FERC consideration.

Pipeline	Project	FERC Docket #
Trunkline	Mainline Abandonment	CP12-491
Union Gas	Parkway D and NPS 48 Brantford-Kirkwall	OEB #EB-2013-0074
	Parkway West	OEB #EB-2012-0433
WBI Energy	Garden Creek II	CP14-50

5.3 LNG IMPORTS AND EXPORTS

The AEO2013 projects total annual LNG exports to increase from 30 Bcf in 2013 to 830 Bcf (2.3 Bcf/day) by 2023. Consistent with the AEO2013 forecast, the RGDS phases in operation of new LNG export terminals to accommodate the projected increase in exports. The capacities and timing for the proposed export terminals is based on the list of Applications Received by the DOE Office of Fossil Energy to Export Domestically Produced LNG from the Lower-48, which was compiled by FERC as of March 24, 2014. The aggregate capacity of the proposed projects on this list far exceeds the AEO forecasts of LNG exports over the forecast horizon. The RGDS includes only three proposed projects that are either under construction or have made the most progress toward receiving the necessary approvals. LAI included the Dominion Cove Point terminal as one of the export terminals that will become operational during the study period, along with two terminals on the Gulf Coast: Sabine Pass in Louisiana and the Freeport terminal in Texas. The Sabine Pass terminal is currently under construction and will be the only terminal in operation in 2018. Freeport and Cove Point are assumed to be operational in 2022 and 2023, respectively.[73] The total capacity of these three export terminals amounts to almost 5.0 Bcf/day, which exceeds the average daily projected exports in 2023. However, since the export terminals will not run at full capacity every day of the year, the operation of these facilities is consistent with the AEO2013 forecast of annual LNG exports. The HGDS and LGDS incorporate the same assumptions with respect to LNG exports.

5.4 COMBINED GAS DEMAND FORECASTS

For purposes of this study, the peak seasonal electric sector and RCI sector gas demands, as identified in Sections 3.4 and 4 of this report, respectively, have been assumed to occur coincidentally. While RCI demand is greater than electric generator demand in the winter, more detailed hourly load shape forecasts are available for electric load than for RCI load. It was assumed that the maximum winter electric load occurs on a very cold day when RCI load for heating is also highest. In the summer, RCI load is low and not very temperature sensitive, so the coincidence assumption makes little difference in the calculation of combined gas demand in the summer season.

Figure 61, Figure 62 and Figure 63 show the combined gas demand forecasts for the RCI and electric sectors in RGDS S0, HGDS S0, and LGDS S0, respectively. Similar figures showing the combined demand by GPCM location within each PPA are presented in Exhibit 14.

[73] Sensitivity 23 tests a higher level of LNG exports and development of additional U.S. export facilities over the study period, based on the AEO2014 Reference Case. See Section 7.5.

Figure 61. RGDS S0 Total Gas Demands

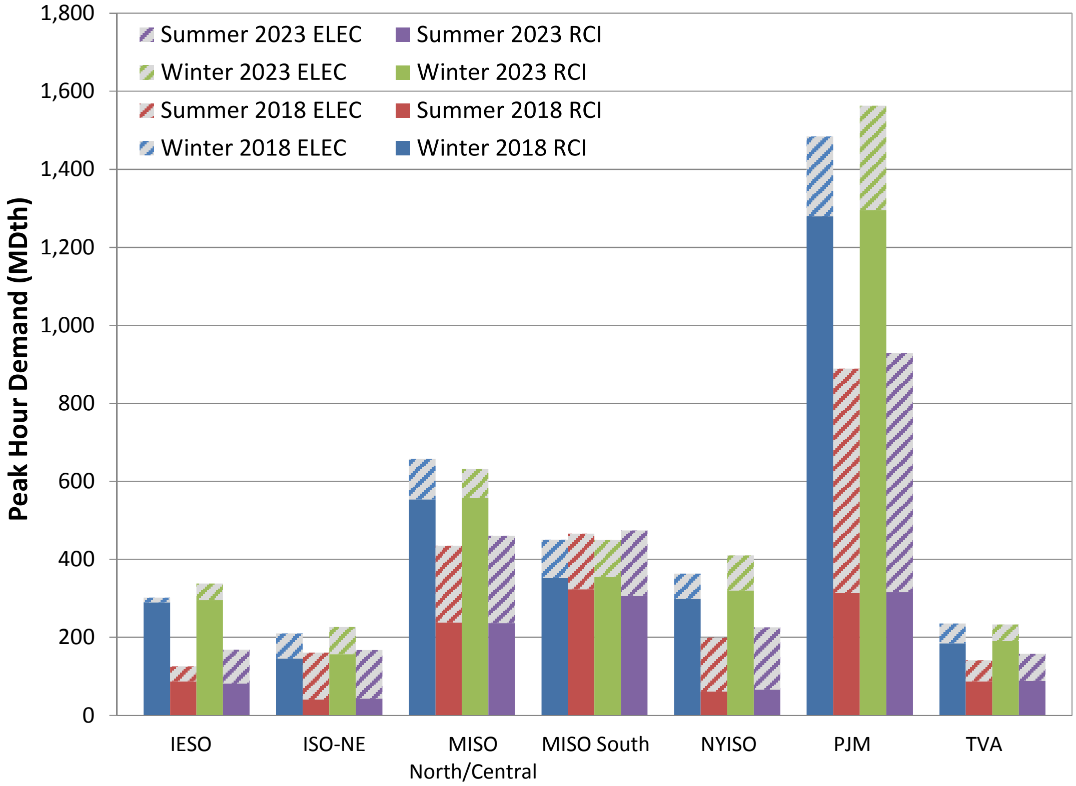


Figure 62. HGDS S0 Total Gas Demands

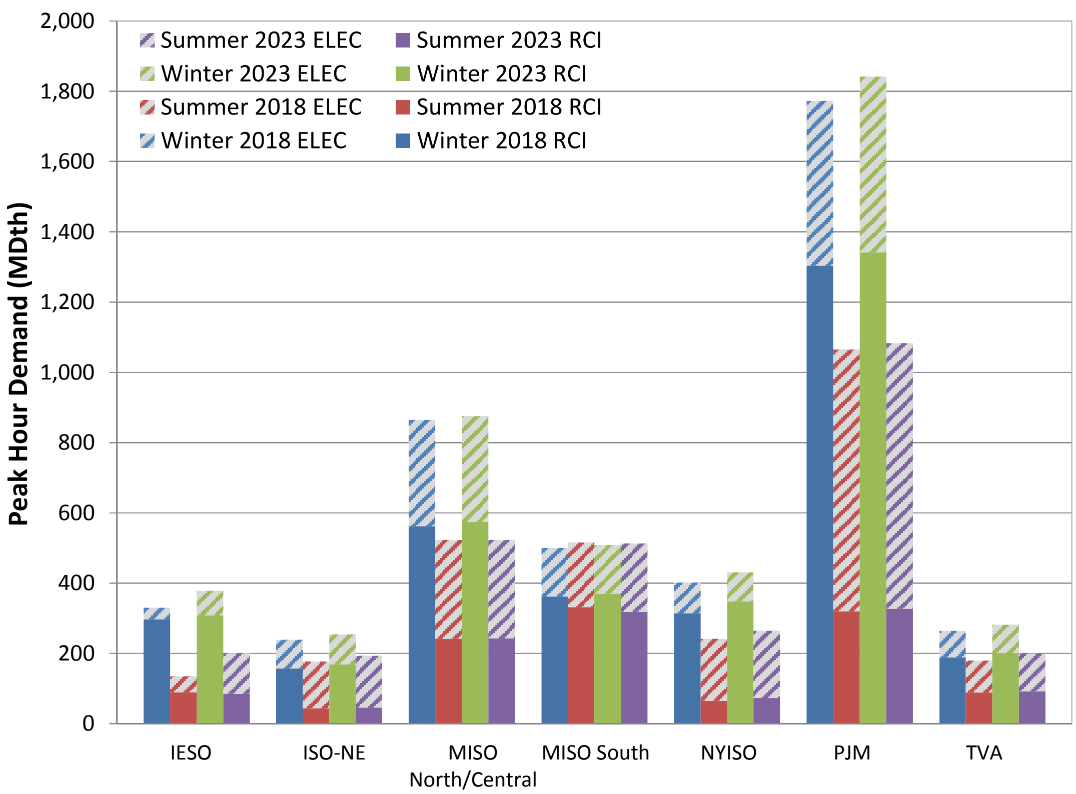
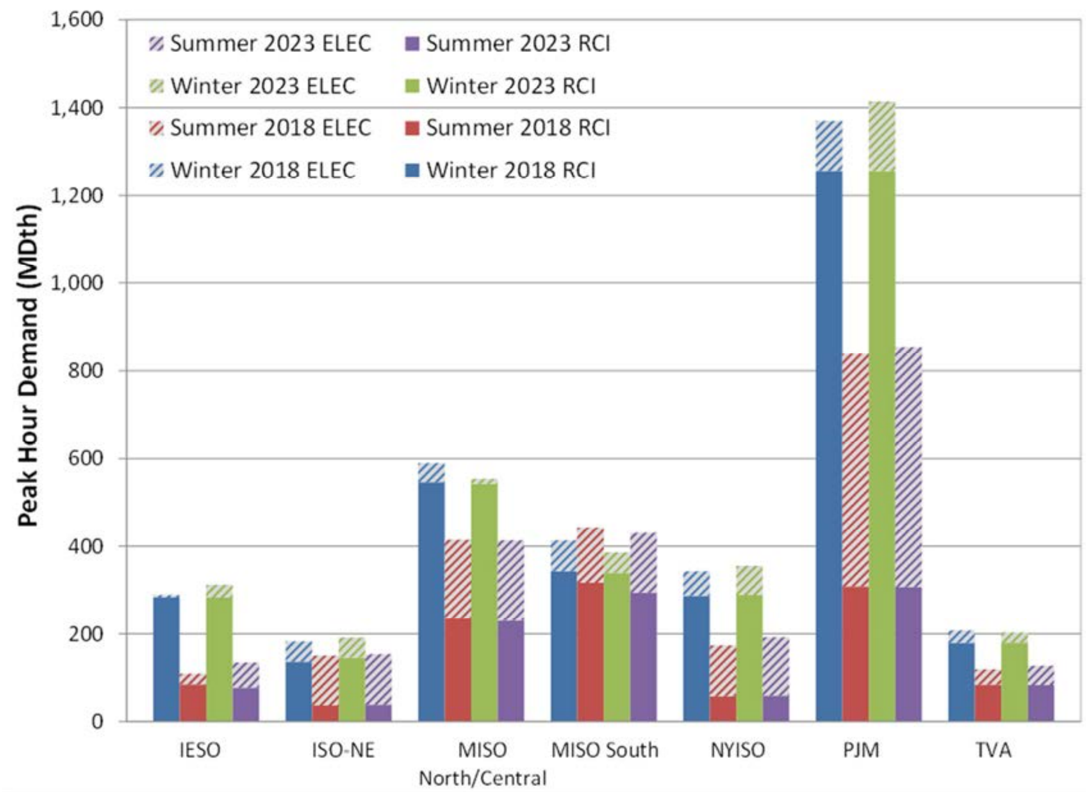


Figure 63. LGDS S0 Total Gas Demands



The following four figures compare the relative demands by PPA across the scenarios for each modeled peak season.

Figure 64. Total S0 Gas Demand by Scenario – Winter 2018

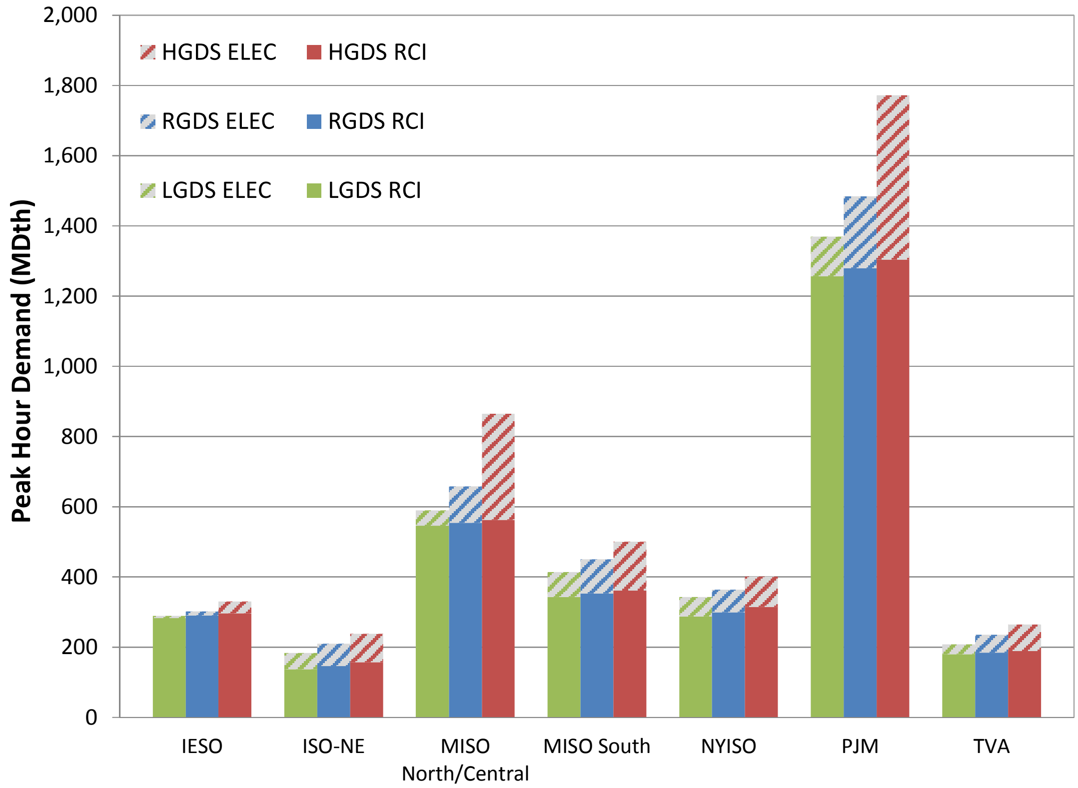


Figure 65. Total S0 Gas Demand by Scenario – Summer 2018

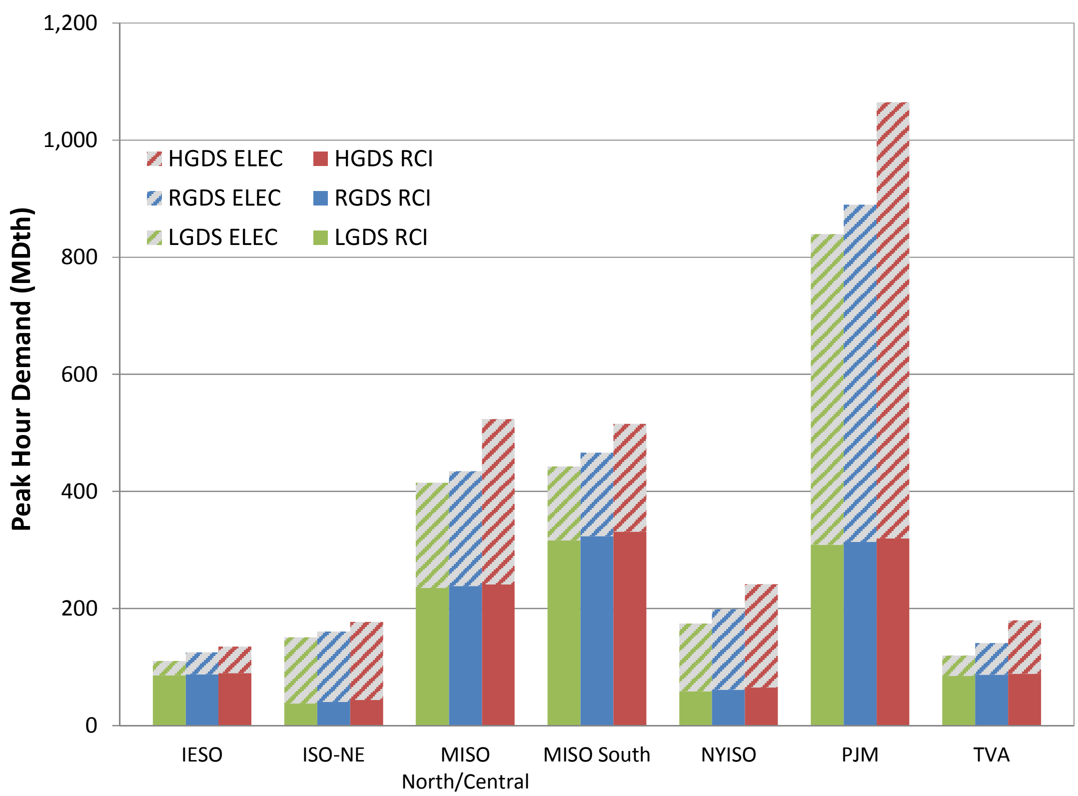


Figure 66. Total S0 Gas Demand by Scenario – Winter 2023

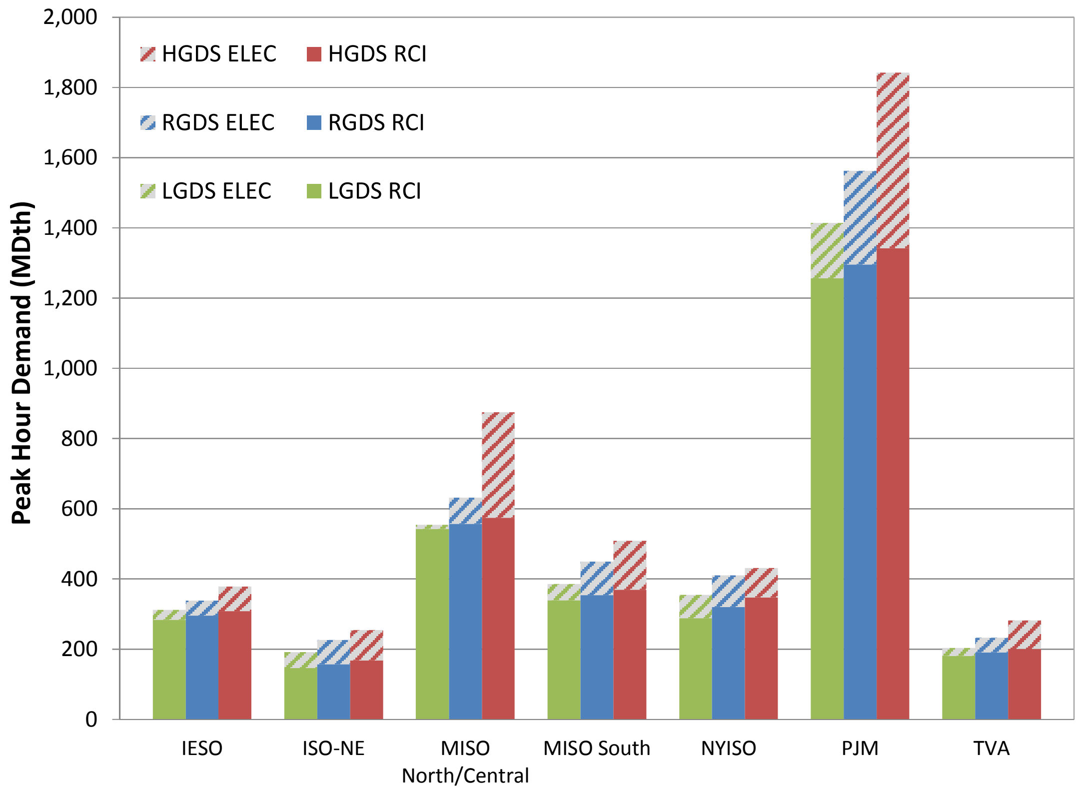
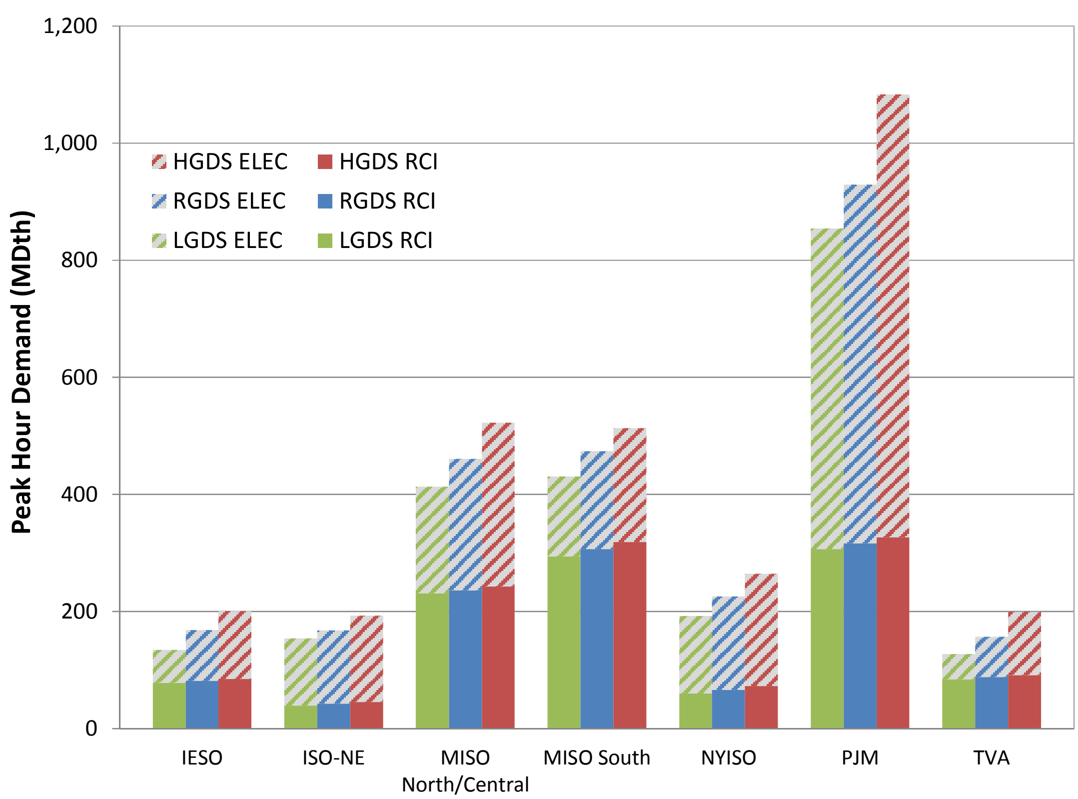


Figure 67. Total S0 Gas Demand by Scenario – Summer 2023



6 IDENTIFICATION OF GAS INFRASTRUCTURE CONSTRAINTS

6.1 ANALYSIS METHODS

The identification of gas constraints across the Study Region is based on market research, statistical analysis, and use of simulation models to reveal transportation constraints during the peak hour of the peak day in the winter and summer of 2018 and 2023. As discussed in Section 4.1, the forecast of RCI loads reflects a relatively standard approach to LDC send out. This standard approach was based on historical pipeline delivery data and publicly available LDC forecasts and Integrated Resource Plans. The forecast of demand for gas-fired generators was derived from AURORAxmp for dispatch and GPCM for gas pricing basis. The sum of the RCI and electric generator loads for each scenario or case sensitivity was expressed on a peak hour basis on a coincident basis, and then run through the GPCM model to identify constrained pipeline segments, where pipeline segments are defined in the GPCM infrastructure as portions of each pipeline in the model.[74] Based on GPCM solutions oriented around the peak day, LAI has been able to identify the size of the transportation deficit, the pipeline route segment(s) underlying the constraint, and the aggregate amount of affected gas-fired generation for each of three distinct scenarios or case sensitivities. Seasonal chronological profiles of demand were formulated for the three peak winter months, January, February and December, as well as the three peak summer months, June, July and August.

To validate GPCM functionality, its model results were compared against recent pipeline operating profiles observed during the Polar Vortex in January 2014. Pipeline flow dynamics during the Polar Vortex constitute a good proxy for the Winter peak day conditions in 2018. Validation efforts revealed reasonable accord between GPCM and pipeline utilization data obtained from various pipelines' electronic bulletin boards (EBBs). For example, GPCM winter model runs in 2018 revealed slack deliverability in New England due to upstream bottlenecks on Tennessee and Algonquin, the principal pipelines linking Marcellus to New England. A review of EBB utilization levels reported by pipelines for January 3, 2014, the peak gas delivery day in New England, confirmed upstream constraints across the supply chain from Marcellus to New York and Connecticut, thus explaining the underutilization of the pipeline network in Massachusetts, especially in and around Boston and southeastern Massachusetts.[75] Also explaining the slack deliverability in and around Boston is the decline in LNG sendout from the Suez Distrigas LNG facility. Comparable efforts were made to validate utilization levels across representative pipeline segments in other PPAs. For purposes of Target 2 research, LAI reports that the model has been reasonably calibrated.

In addition, technical assistance from pipelines in the Study Region was solicited in Q2 and Q3-2014 before GPCM runs were finalized. LAI coordinated a review of GPCM assumptions applicable to specific pipelines through INGAA, which facilitated members' review of maximum pipeline flow, segment capacity, and interconnect flow capability, among other things.

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[74] For example, GPCM divides Algonquin into six segments: Algonquin NJ NY, Algonquin CT, Algonquin Mendon, Algonquin MA SE, Algonquin MA NE and Algonquin Hubline.

[75] We note the higher than forecast utilization of M&N, shown in orange, from the Baileyville import point across Maine into northern Massachusetts. This is primarily due to high use of the LNG import terminal at Canaport in January 2014. In contrast, LAI assumes no LNG imports from Canaport in the RGDS in 2018.

6.1.1 Analysis of Peak Hour Constraints

For purposes of this study, the standard monthly GPCM model was customized to create a daily version of the model in order to analyze the ability of the gas pipeline network to meet daily peak hour loads under a variety of market conditions. In consultation with the PPAs, RBAC, GPCM's designer, and stakeholders LAI chose not to attempt to model the gas market on an hourly or other chronological basis. This was due primarily to the lack of sub-daily data for the gas market. Most deregulated electric markets are conducted on an hourly and/or sub-hourly basis. The gas market, on the other hand, is conducted primarily on a daily basis, but restrictions within the gas day typically govern how pipeline capacity is allocated among shippers across the system. While there are gas transactions that occur bilaterally on an intraday basis between participants, they are not part of an organized exchange and are, as such, typically invisible to the market. Furthermore, the analysis of factors related to the operation of pipelines that affect flows from hour to hour, such as pipeline pressure and reliance on line pack to serve demand during periods of scarcity, are beyond the scope of Target 2. Attempts to incorporate such factors into these results would require models of such size and complexity as to be impractical from a computational perspective given the large size of the Study Region. Validation of such models would also be difficult given the scarcity of intraday data described above. For these reasons, LAI adopted the modeling approach described below and elsewhere in the report to analyze and identify peak-hour constraints. The identification of peak hour constraints will support the transient modeling to be conducted in Target 3, which will highlight the operation of certain pipeline systems on an intraday basis following various gas or electric side contingency events.

In the simulations, constraints emerged when the coincident gas requirements ascribable to gas utility RCI customers and gas-fired generators across the Study Region were considered under the conditions captured by each of three demand scenarios or the array of sensitivities. As discussed in Section 5.2, the pipeline network modeled in GPCM includes new pipeline facilities currently in service, or expected to be in service over the planning horizon.

For each scenario, the gas demands for RCI customers and electric generation customers peak hours of the coincident winter and summer peak days were used to populate the GPCM model. [76]

GPCM revealed the maximum delivery capability by location across the Study Region. In other words, with the daily peak hour demand profile generated by the Aurora results embedded in the model, GPCM was run to determine whether all demands could be served during the seasonal peak hour. In some cases, all demands were met; in others, there was insufficient deliverability and some pipeline customers were left unserved.[77] Globally, priority was given to RCI customers and generators known to hold firm transportation entitlements before gas generators not known to hold firm transportation entitlements.[78] As such, in instances and locations where

[76] In limited instances, curves representing demand for LNG exports consistent with the assumptions described in section 5.3 were also added.

[77] Modeled solutions in GPCM result in subordination of gas burns for generators in order to ensure that firm entitlement holders' are able to meet RCI send-out requirements over the forecast period.

[78] A listing of the gas generators that hold firm pipeline entitlements is provided in Exhibits 4 through 9 to the Target 1 report. Generators in IESO and TVA are assumed to exercise their right-of-first-refusal such that the

there was unserved demand, that deficit was allocated to generators relying on non-firm service.[79]

The amount of unserved gas for generation at each of the locations shown in Figure 43 was tabulated for the peak hour of the winter and summer seasons. To tabulate the amount of unserved gas for generation and to then interpret the corresponding level of impact associated with a pipeline's ability to render that supply, LAI formulated a number of rules characterizing deliverability for gas-fired generators. The pipeline and storage infrastructure across the Study Region is designed and operated to ensure that the needs of firm entitlement holders, which we assume includes all RCI customers and selected gas-fired generators, as noted above, are always served. Non-firm customers, which comprise most gas-fired generators, have secondary priority.[80] The designation of affected generation represents insufficient pipeline transportation capacity to serve both the superior, firm gas demands of the RCI customers and the subordinated gas demands of the non-firm gas-fired generators on a coincident basis during the seasonal peak hour. Generators holding firm transportation entitlements are assumed to be served along with RCI customers. Delineation of affected generation therefore does not signify a pipeline design or operating flaw. Nor does it indicate any impact to electric system reliability as no mitigation measures have yet been applied to either the electric or gas systems. This nomenclature is meant only to signify insufficient pipeline capacity to serve the demands of gas-fired generators under a specific set of market, economic and environmental assumptions formulated to define each of three scenarios or the array of sensitivities. Potential mitigation measures − for the both the electric and gas systems are discussed in Section 8.

The designation of impact is used synonymously with scheduling constraints affecting a pipeline's ability to transport natural gas to a shipper that lacks a primary firm entitlement. As discussed in the Target 1 report, such shippers typically rely on secondary firm capacity release arrangements, interruptible transportation, or third party arrangements with marketers. Aside from generators known to hold firm transportation entitlements, the model does not apply a specific pipeline character of service to gas-fired generators. Although generators can have firm supply and transportation arrangements with third-party marketers and other suppliers, these arrangements are not publicly known and therefore could not be accounted for in the prioritization of service.[81] Generators with secondary firm service would be subordinated to

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current firm entitlements will still be in place in 2018 and 2023, regardless of the current contract expiration dates. Incremental generators in these PPAs are also assumed to hold firm entitlements. Firm transportation contracts associated with generators in the other four PPAs are assumed to end on the expiration dates listed in the Target 1 report Exhibits.

[79] The GPCM model solutions also captured the utilization of pipeline assets, measured as a utilization rate being equal to the flow of gas across that asset divided by the asset's total capacity. Assets include pipeline segments, interconnects, etc.; the GPCM modeling paradigm and structure is described in Appendix A.

[80] Generators are classified as non-firm for purposes of this analysis if they are not known to hold firm transportation entitlements. Third-party arrangements with suppliers and marketers are not publicly known, and therefore are not incorporated in the study assumptions. Generators relying on capacity released by LDCs or other secondary firm capacity would be subject to recall or subordination in the event of a peak demand condition, and are therefore also classified as non-firm within the two-level priority system used in GPCM.

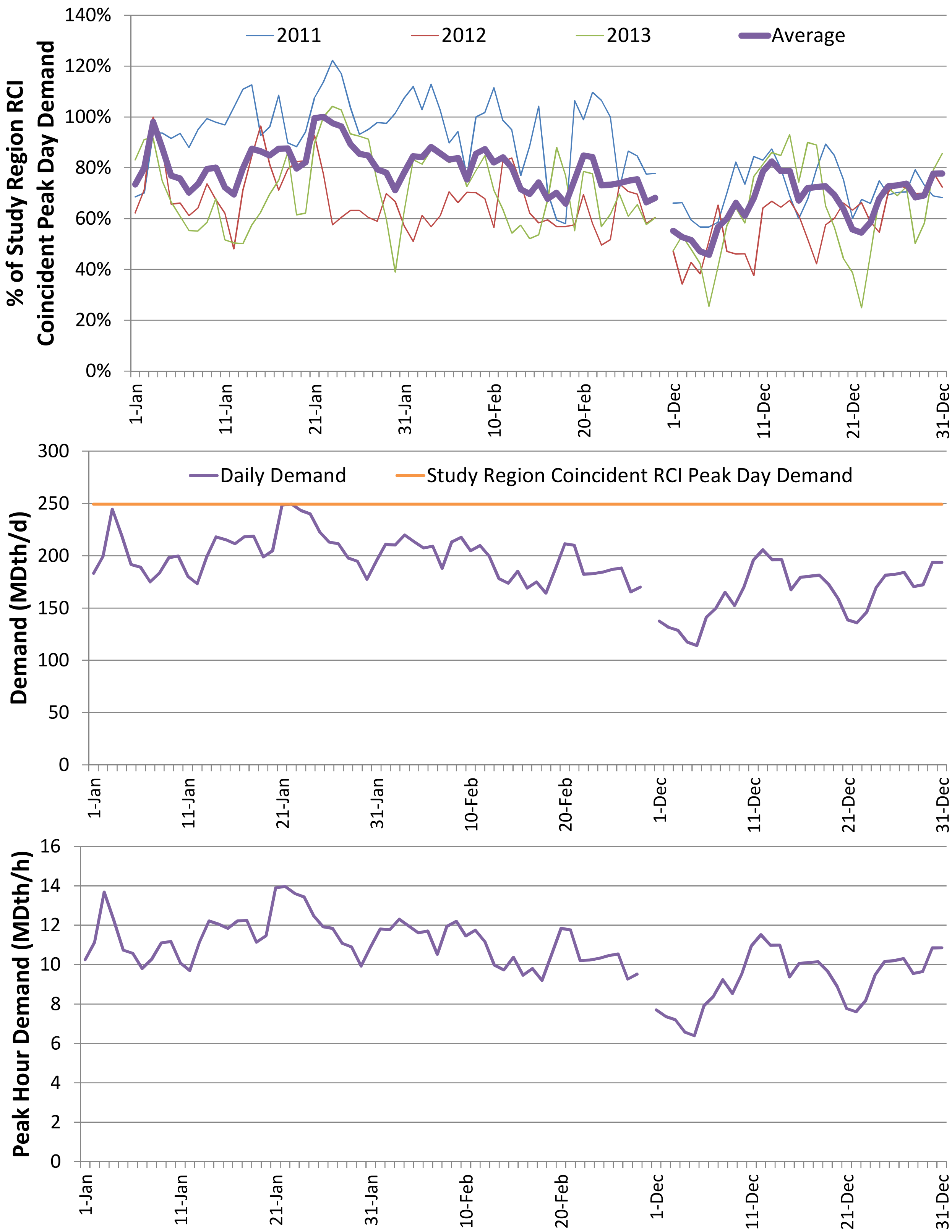
[81] This is a conservative assumption that potentially results in reporting of greater unserved demand and affected generation than would be the case if incremental pipeline capacity expansions had been included to meet the demands of generators willing to pay for firm service.

primary firm service, which is consistent with the prioritization applied in GPCM. Finally, capacity released to generators by LDCs would be subject to recall during a peak demand event. On a peak day, generators submitting secondary or non-firm nominations that cannot be served by the pipeline would not be scheduled, which can deter these shippers from submitting nominations during known high demand periods, particularly given the costly imbalance charges or penalty exposure during such periods.

6.1.2 Seasonal Constraints Measurement

In addition to examining the peak hour constraints on the winter and summer peak days in GPCM, the frequency and duration of those constraints over the course of each season were estimated based on the expected chronological peak hour demand profiles. For each electric and RCI sector customer, a chronological demand profile was developed using electric simulation model output or historical RCI demand data, respectively. For electric sector customers, the peak hourly demand for each day was extracted from the Aurora model results. For RCI sector customers, determination of the chronological peak hour demand profile required several steps. First, the percentage of each day's demand relative to the demand on the seasonal Study-Region coincident RCI peak day was calculated for each winter and summer period over the three year period from 2011 to 2013. Second, the three percentages for each date, e.g. January 14th, were averaged to yield a genericized profile relative to the Study Region coincident RCI peak day. Third, the daily percentages were multiplied by the customer's forecasted demand on the relevant peak day. Finally, the peak hourly demand for each day was calculated using the same percentages listed in Section 4.1, 5.6% and 6.1% for the winter and summer, respectively. An example of this calculation is shown in Figure 68 for Connecticut Natural Gas during Winter 2018.

Figure 68. Example Calculation of Chronological Seasonal Demand Profile

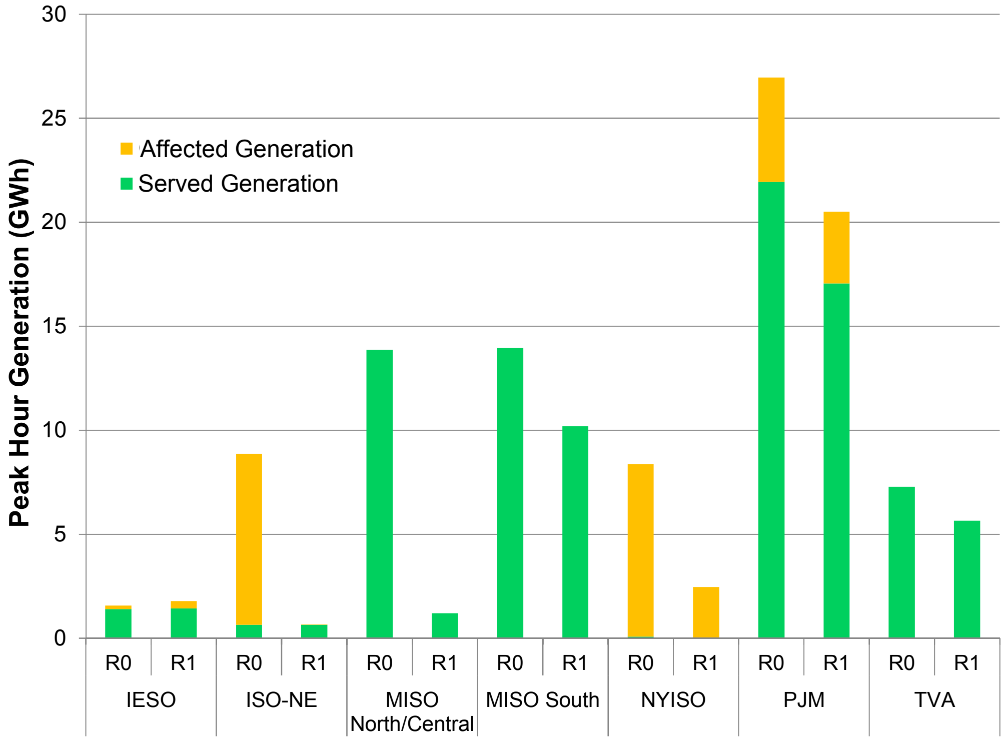


For each constrained segment, the chronological profiles of the daily peak hour demands served by that segment and the downstream pipeline segments were summed to determine the total gas that would flow across a segment in the peak hour of each day during the season assuming no constraints. The maximum hourly flow capability of the segment, defined as $1/24^{th}$ of the daily segment capacity modeled in the GPCM, was then compared to the daily total peak hour demand to determine the number and chronological pattern of days when the desired amount of segment flow during the peak hour exceeded the segment's physical capacity, resulting in a constraint.

6.1.3 Presentation of Results

For each set of seasonal results presented in this section, three summary figures and two summary tables provide an overview of the peak hour affected generation, peak hour constraints, and the frequency and duration of the constraints. The peak hour is defined as the hour of the electric load peak day that has the maximum generation gas demand. The applicable measure is the affected generation (in MWh) rather than the Dependable Maximum Net Capability capacity (MW) of affected generators. Affected generation was determined by LAI to be a more appropriate measure of impact than affected capacity because it measures the economic demand for gas-fired generation in AURORAxmp, while the capacity of the generators in a GPCM location cannot be allocated between served and affected capacity. The first figure, an example of which is shown in Figure 69, shows the amount of dispatched gas-fired generation to which gas can be delivered (in green), relative to the amount of dispatched gas-fired generation to which gas cannot be delivered (in orange). Results have been summarized by PPA, except in the case of MISO which has been sub-divided into MISO North/Central and MISO South. Generation in the latter category is characterized as "affected" due to gas infrastructure constraints limiting deliveries during the seasonal peak hour. Where applicable, multiple scenarios or sensitivities are shown side-by-side for comparison purposes. In these figures, the x-axis is labeled with a letter indicating the scenario and a number indicating the sensitivity, for example "R1" corresponds to RGDS S1.

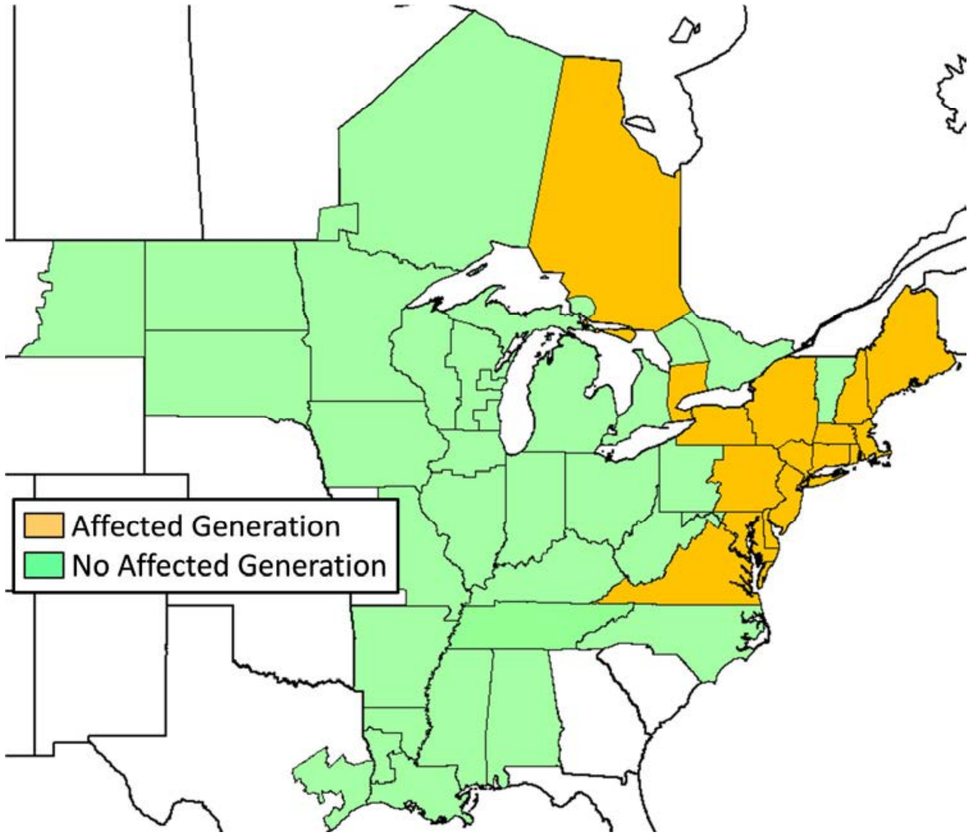
Figure 69. Example: Peak Hour Affected Generation



The second summary figure for each set of seasonal results, an example of which is shown in Figure 70, is a map identifying GPCM locations, shaded in orange, in which some or all of the dispatched generation is affected during the seasonal peak hour.[82] It is important to note that a GPCM location is shaded orange if *any* generation is affected during the seasonal peak hour. Other graphical and tabular information presented in this section must be reviewed in order to calibrate the frequency and duration of the potential transportation deficit. GPCM locations shaded in green do not have any affected generation, either because the full quantity of gas demand can be met or because no generation is dispatched during the seasonal peak hour.

[82] The GPCM locations are described in Section 4.1.

Figure 70. Example: GPCM Locations with Peak Hour Affected Generation



This map is accompanied by a summary table listing the unserved generation gas demand and affected generation during the peak hour for the orange-shaded locations. An example of this table is shown in Table 15. The column entitled "Unserved Generator Gas Demand" reflects the amount of gas that cannot be delivered to generators scheduled for dispatch in AURORAxmp during the peak hour. The column titled "Affected Generation" column expresses the corresponding MWh associated with the unserved generation gas demand. To quantify the Affected generation, LAI used the full-load heat rate for each generator.

Table 15. Example: Unserved Generator Gas Demand and Affected Generation

GPCM Location	Unserved Generator Gas Demand (MDth)	Affected Generation (MWh)

The third summary figure for each set of seasonal results, an example of which is shown in Figure 71, is a map showing the gas pipeline infrastructure in the Study Region, with the constrained segments that result in unserved gas demand, and therefore affected generation, during the seasonal peak hour highlighted in red.

Pipeline infrastructure that is less than fully utilized is not highlighted in red as a constrained segment. This should not be interpreted as necessarily sufficient to meet all gas-fired generation in a particular location. Comparing Figure 70 to Figure 71 highlights the impacts that a constraint can, and in many cases does, have on deliverability beyond the constrained segment's physical location, while the absence of a constraint on a given segment does not mean that all demands served by that segment are met, if one or more upstream constraints limit the flow of gas into the not-fully-utilized segment. An example of this nuance is in New England, where there is significant affected generation due to upstream pipeline constraints in New York and Pennsylvania as well as underutilization of other pipeline and LNG infrastructure both within and into New England. Maps showing the relative level of pipeline utilization across all pipeline segments in the Study Region are included in Exhibit 16 for each scenario and sensitivity.

Figure 71. Example: Peak Hour Constraints

The constraint map is accompanied by a summary table listing the constrained segments shown in red, and the frequency and duration statistics for each constraint that exists during the peak hour for the relevant season.[83] An example of this table is shown in Table 16. The column entitled "# of Events" shows the number of times during the Winter or Summer that the constraint is in effect during the peak hour of one or more consecutive days. The column entitled "Min. Duration" shows the shortest number of consecutive days with the constraint in effect during the peak hour. The column "Max. Duration" shows the longest number of consecutive days with the constraint in effect during the peak hour. The column entitled "Total # of Days" shows the total number of days during the season, when the constraint is in effect during the peak hour.

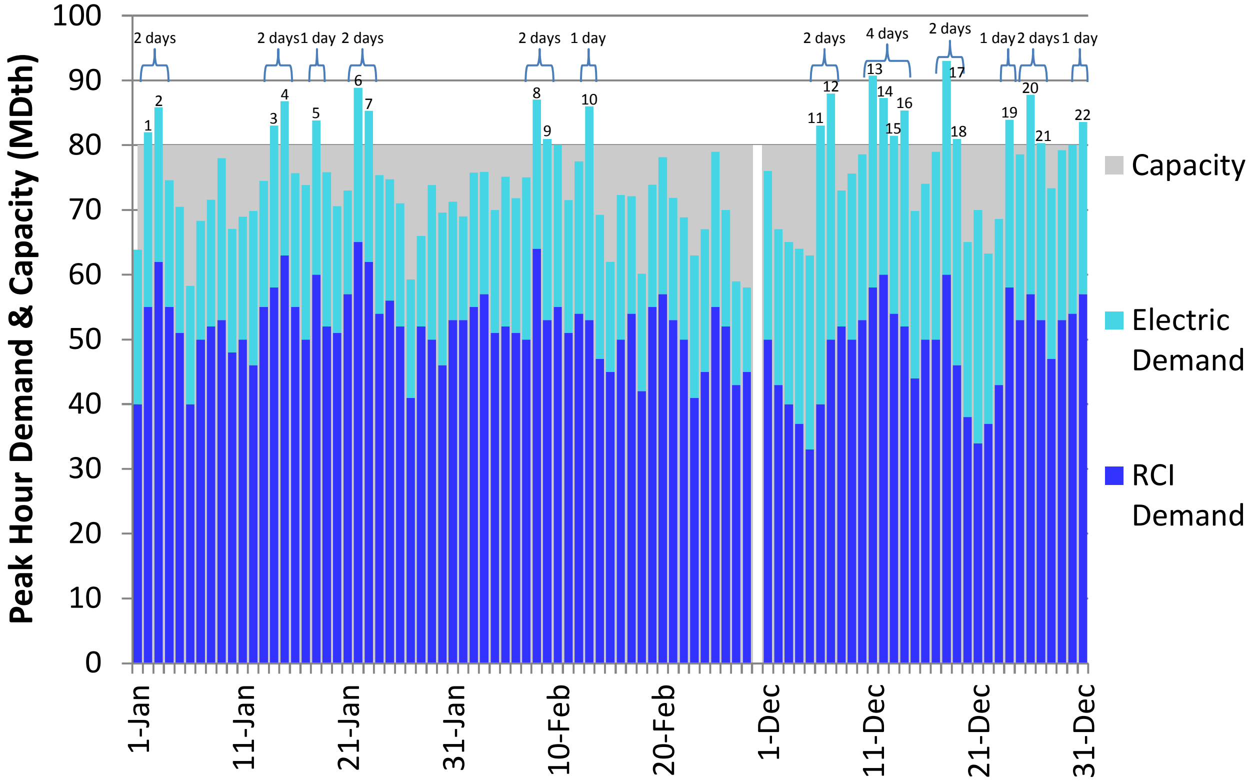
[83]The scope of analysis for S1 was characterized as adjustment of natural gas locational basis adders to reflect market pricing on a peak day. Daily basis fluctuations are significant during the winter season and typically small during the summer season. Hence, the S1 analysis was limited to the winter peak day. Consistent with the S0 (and Roll Up) analysis, electric loads were forecast on a 50:50 basis, as were RCI loads. All case sensitivities presented in the Target 2 report are limited to changes in single variables. A more complete analysis beyond the scope of S1 would simulate daily weather-related fluctuations in electric and RCI loads as well as gas transport bases, due to their common weather drivers during the heating season.

Table 16. Example: Constraint Frequency and Duration

Constraint	# of Events	Min. Duration (Days)	Max. Duration (Days)	Total # of Days

For each specific constraint within each set of seasonal results, the frequency and duration of the constraint's occurrence during Winter or Summer is presented in two figures, which can be found in the CEII appendix corresponding to each scenario or sensitivity. The first figure, an example of which is shown in Figure 72 presents the forecasted daily peak hour gas demand for the RCI and generation sectors relative to the constrained segment's capacity. This figure illustrates the frequency of constraint occurrence, and the number of consecutive days with a peak hour constraint associated with each occurrence. The dark blue and light blue column segments represent RCI demand and electric demand, respectively. In some cases, there is a third demand category for LNG exports. The gray area represents the segment capacity. In the figures showing Winter seasonal demand, the vertical white line represents the break between February and December. In the example, each day with total peak hour demand in excess of segment capacity is numbered, and the number of consecutive days is marked next to each bracket representing a constraint event. Each of these figures is accompanied by a summary table listing the number of constraint events, the minimum number of consecutive days with a peak hour constraint, the maximum number of consecutive days with a peak hour constraint, and the total number of days with a peak hour constraint for the season.

Figure 72. Example: Chronological Demand

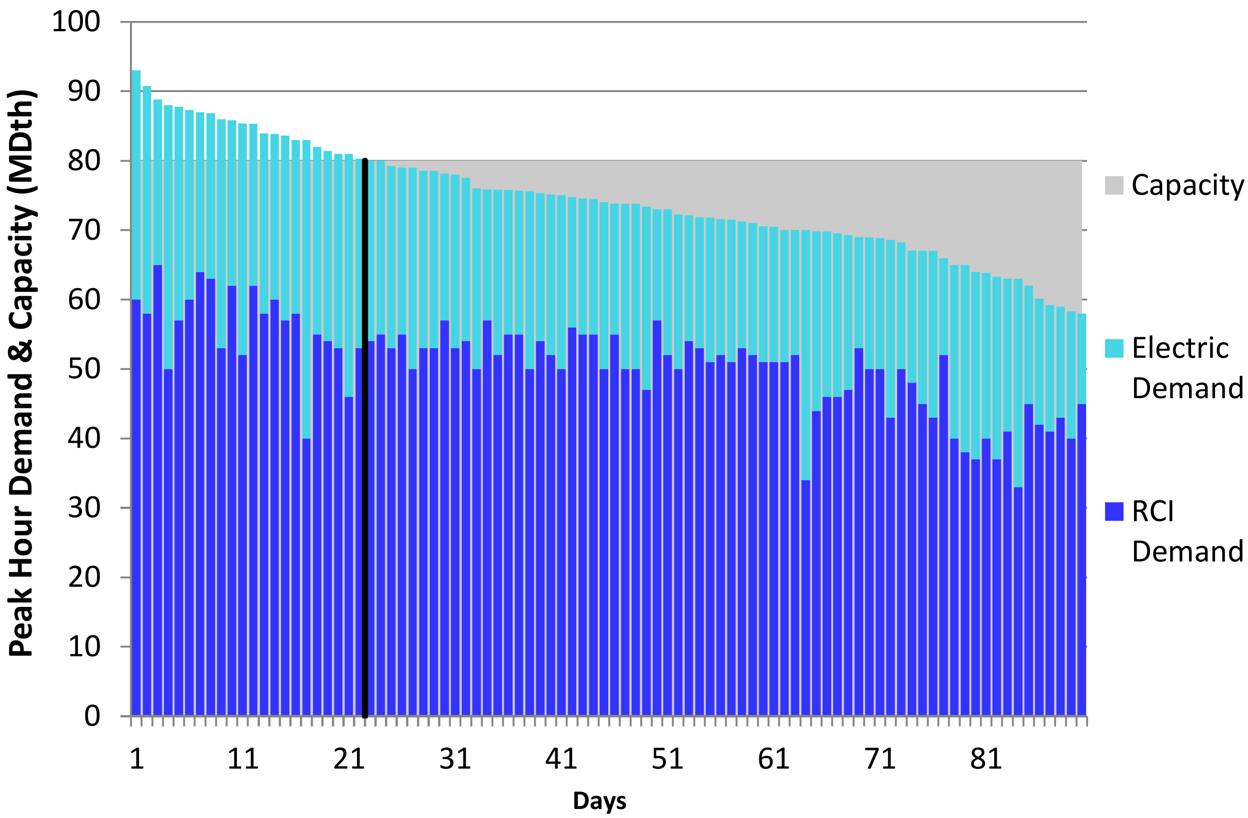


# of Events	Min. Duration	Max. Duration	Total # of Days
12	1	4	22

The second figure further illustrates the total number of days with a peak hour constraint by presenting the same RCI and generation sector gas demands in descending order.[84] An example is shown in Figure 73. In these figures, the vertical black line separates the days with a peak hour constraint from those without a peak hour constraint.

[84] For purposes of the demand duration curve figure the relative contributions of the RCI and generation sectors for each day are maintained, sorted based on the total for each day.

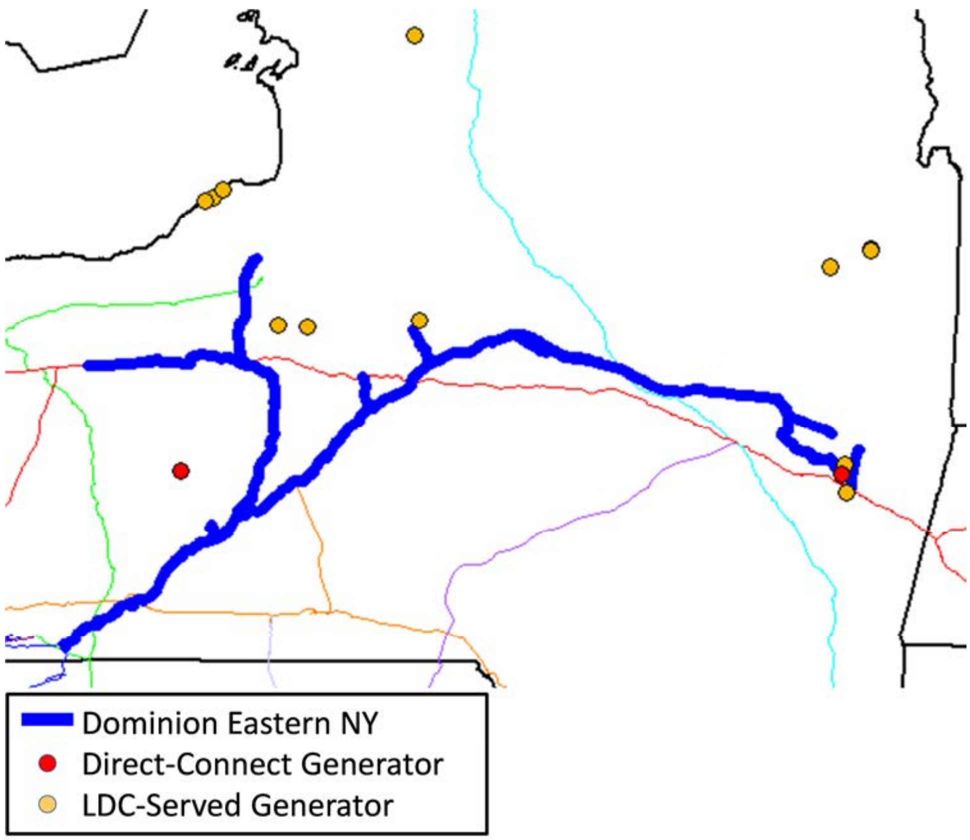
Figure 73. Example: Descending Demand



These frequency and duration figures are based on a daily version of the GPCM model that is calibrated for the seasonal peak hour in relation to the rest of the season. GPCM was run only for the peak hour of the season. Hence, in performing this analysis LAI has extended the network flow pattern at the seasonal peak hour to the rest of the season. The frequency and duration results therefore indicate expected relative congestion during the peak hours of the non-peak days, but do not indicate that the amount of peak hour demand in excess of segment capacity is necessarily affected. Where generators that are unserved during the seasonal peak hour can receive gas from multiple pipelines, the generator demands for each day have been allocated between the connected pipelines for purposes of generating the frequency and duration results. Where constraints arise in the peak hour of the peak day, no additional gas could be transported to serve electric generation. On the other 89 days over the three winter months, it is possible that on certain days gas demand greater than the constrained segment's capacity could be re-routed along a less economical path with a less frequent constraint, minimizing the unserved demand on any given day, and potentially reducing the frequency and duration of a particular constraint. Also, lower cost, economically desirable segments could become more frequently constrained as flows shift to those paths on days with available capacity. For these reasons, the amount of affected generation above the capacity line in the frequency and duration figures signifies a plausible upper limit since GPCM was not run for the peak hour of every day over the three months of each season.

The first time a particular constraint is reported in the results below, a map of the constraint location, including the pipeline segment of relevance as well as locations of affected generators, is presented. In these figures, an example of which is shown in Figure 74, the potentially affected generators are color-coded based on whether the generator is directly connected to the constrained pipeline, located behind an LDC that is served by the constrained pipeline, directly connected to a pipeline downstream (via interconnect) of the constrained pipeline, or otherwise behind an LDC connected to a secondary pipeline. Locational constraints in GPCM reflect the aggregation of RCI loads and gas-fired generation loads rather than individual RCI meters or power plants. Therefore the Target 2 analysis assumes that constraints at a specific citygate would preclude deliveries to gas-fired generation behind the citygate, unless the generator has a firm entitlement to interstate / interprovincial pipeline capacity and local transportation. To the extent an LDC has multiple pipeline connections at various citygates, local service to gas-fired generators without firm entitlements may be accommodated. The Target 2 analysis does not include any specific modeling of LDC facilities behind the city gates.

Figure 74. Example: Constraint Map



6.2 RGDS S0 AND S1 ANALYSIS

Consistent with the PPAs' study design and research objectives, the EIA-based mid fuel price forecast of average monthly natural gas prices in RGDS S0 allows for a substantial amount of gas-fired generation in many locations. This is because gas prices are below oil prices on a price parity basis, and efficient gas-fired generators are often competitive with coal-fired generation. Unlike oil and coal, natural gas prices are highly volatile throughout the winter season, particularly during cold snaps when combined RCI and electric sector gas demands are high. For this reason, the S1 analysis examines the impact of higher-than-average daily spot prices on the coincident peak winter day in 2018 and 2023. Overall, the January 2014 higher spot gas prices used in the S1 analysis are considerably above the mid-price forecast of monthly average prices for January of 2018 and 2023. However, some regions and pipeline pricing points experienced much larger price increases in January 2014 than others. The S1 price assumptions place oil-capable and certain coal-fired resources in merit, thereby reducing the amount of gas-fired generation required to meet electric energy and reliability needs. Reflecting high gas prices on January 27th, all other things being the same, the net effect of the S1 sensitivity is to place oil-fired generation in economic merit in many parts of the Study Region, thereby reducing the total demand for natural gas for electric generation.

As discussed in Section 3.4 and illustrated in Figure 37 and Figure 38, peak hour gas demand by generators is reduced overall in RGDS S1 relative to S0 across the Study Region. This effect is pronounced in ISO-NE, MISO North/Central, NYISO, and PJM in both 2018 and 2023, which have much higher peak day spot gas prices in S1 than in S0. MISO South, TVA, and IESO show little reduction, or a slight increase (for IESO), in coincident peak hour gas demand in RGDS S1, which is consistent with those PPAs having small increases in peak day gas prices in S1. The slight increase in generator gas demand in IESO results from greater energy exports to surrounding PPAs as a result of their gas price-based increase in LMPs. Figure 75 and Figure 76 present the combined RCI and electric generation sector gas demands across the Study Region. Notice that at the winter peak hour, RCI demand is far larger than generator gas demand in every PPA, and that RCI demand is held constant between S0 and S1.

Figure 75. RGDS S1 vs. RGDS S0 Winter 2018 Total Peak Hour Gas Demand

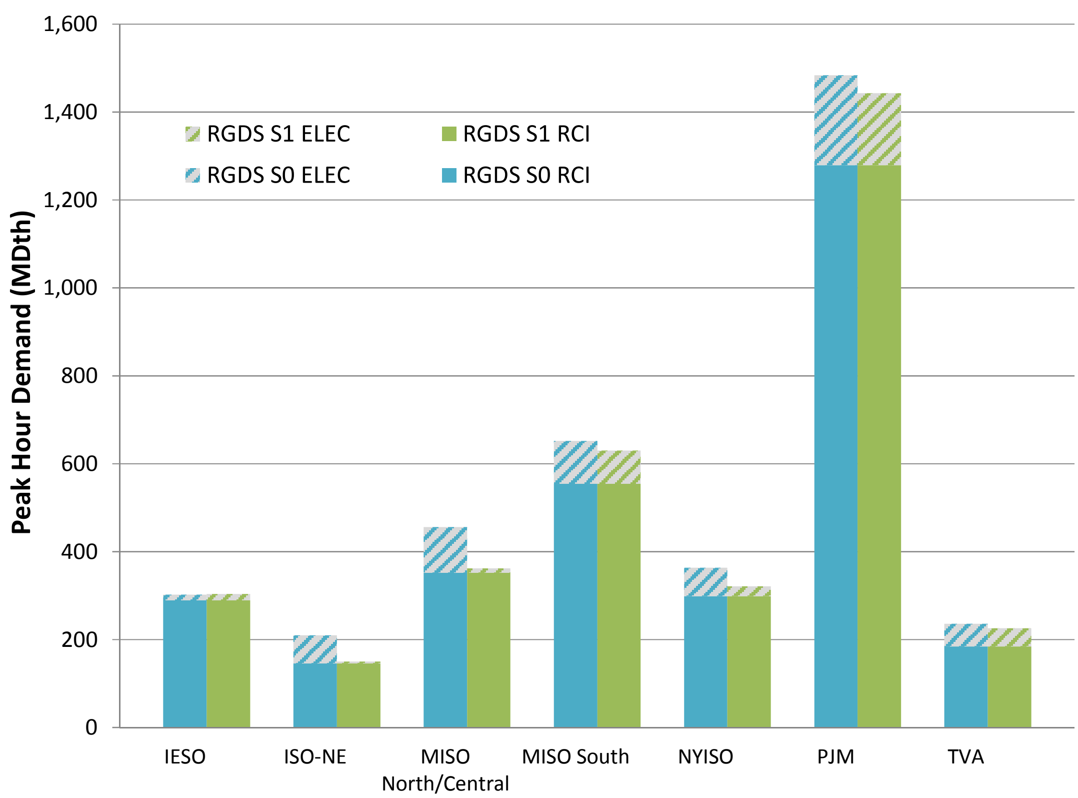
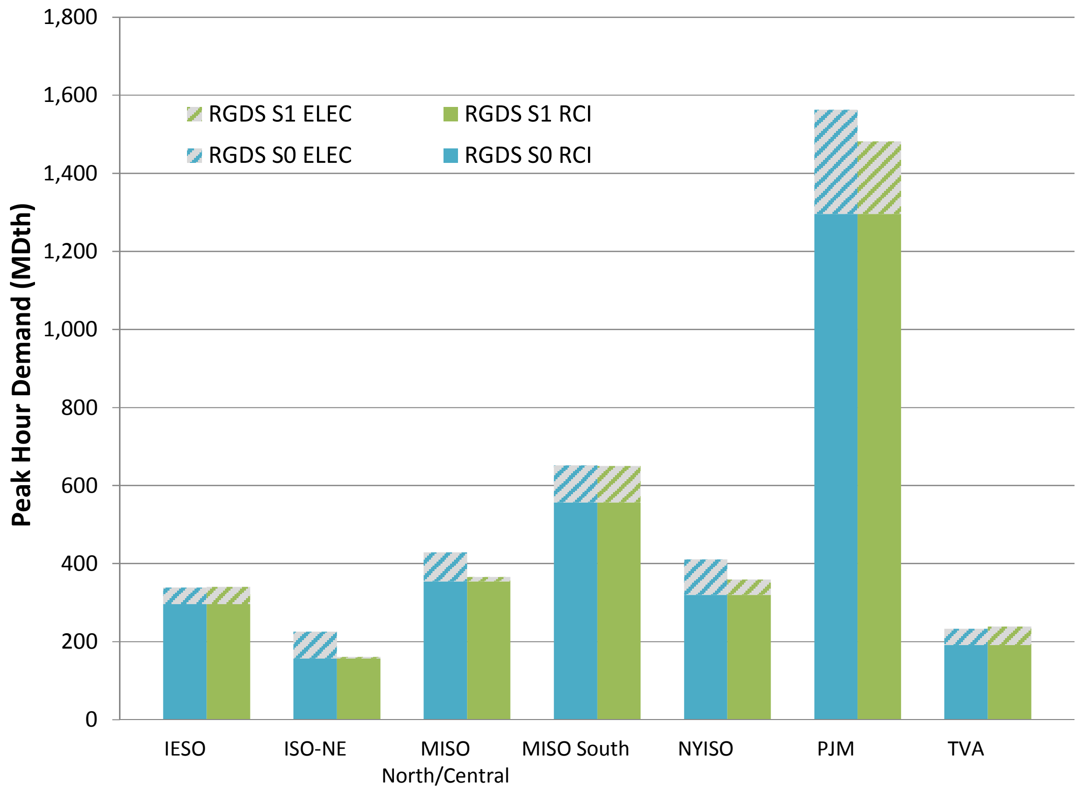


Figure 76. RGDS S1 vs. RGDS S0 Winter 2023 Total Peak Hour Gas Demand



Because peak hour generator gas demand is generally lower in S1 than S0, peak hour affected generation falls as well. The following subsections compare and discuss the magnitude of the affected generation in S0 versus S1 across the Study Region.

6.2.1 RGDS S0 and RGDS S1 – Winter 2018

Figure 77 summarizes the affected generation during the Winter 2018 peak hour by PPA for RGDS S0 and RGDS S1. Moving from left to right, the amount of affected gas-fired generation in IESO is negligible in both RGDS S0 and RGDS S1. In New England, almost all of the gas-fired generation scheduled by ISO-NE in the peak hour of the peak day in Winter 2018 cannot be delivered under RGDS S0 pricing assumptions, but the affected generation is eliminated under RGDS S1 pricing assumptions when high daily spot prices put oil fired generation in merit across the PPA. In MISO North/Central and MISO South, the impact of higher gas prices under RGDS S1 assumptions substantially reduces gas-fired generation, reflecting the increased capacity factors of coal resources in the PPA. However, because of the vast pipeline and storage infrastructure across MISO, study results do not reveal transportation constraints causing gas-fired generation to be affected. In NYISO, the impact of higher daily spot prices under RGDS S1 assumptions substantially reduces affected generation, reflecting the substitution of residual oil-fired generation and, to a lesser extent, ULSD-fired generation, across the New York Facilities System. The reduction in gas-fired generation also occurs, but, to a lesser extent, in the Capital District and LHV. In PJM, there is substantial affected gas-fired generation under both RGDS S0 and RGDS S1 pricing assumptions, although the amount of affected gas-fired generation is significantly lower when higher daily spot prices are reflected in the scheduling of gas-fired generation. The reduction in total gas-fired generation reflects oil resources in merit as well as the increased capacity factor of coal plants in PJM. Finally, in TVA there is no affected generation due to TVA's firm entitlements for the majority of gas-fired generation in the PPA. Total gas-fired generation is reduced in RGDS S1 reflecting TVA's use of its dual fuel capability when gas prices are high.

Figure 77. RGDS S0 v. RGDS S1 Winter 2018: Peak Hour Affected Generation

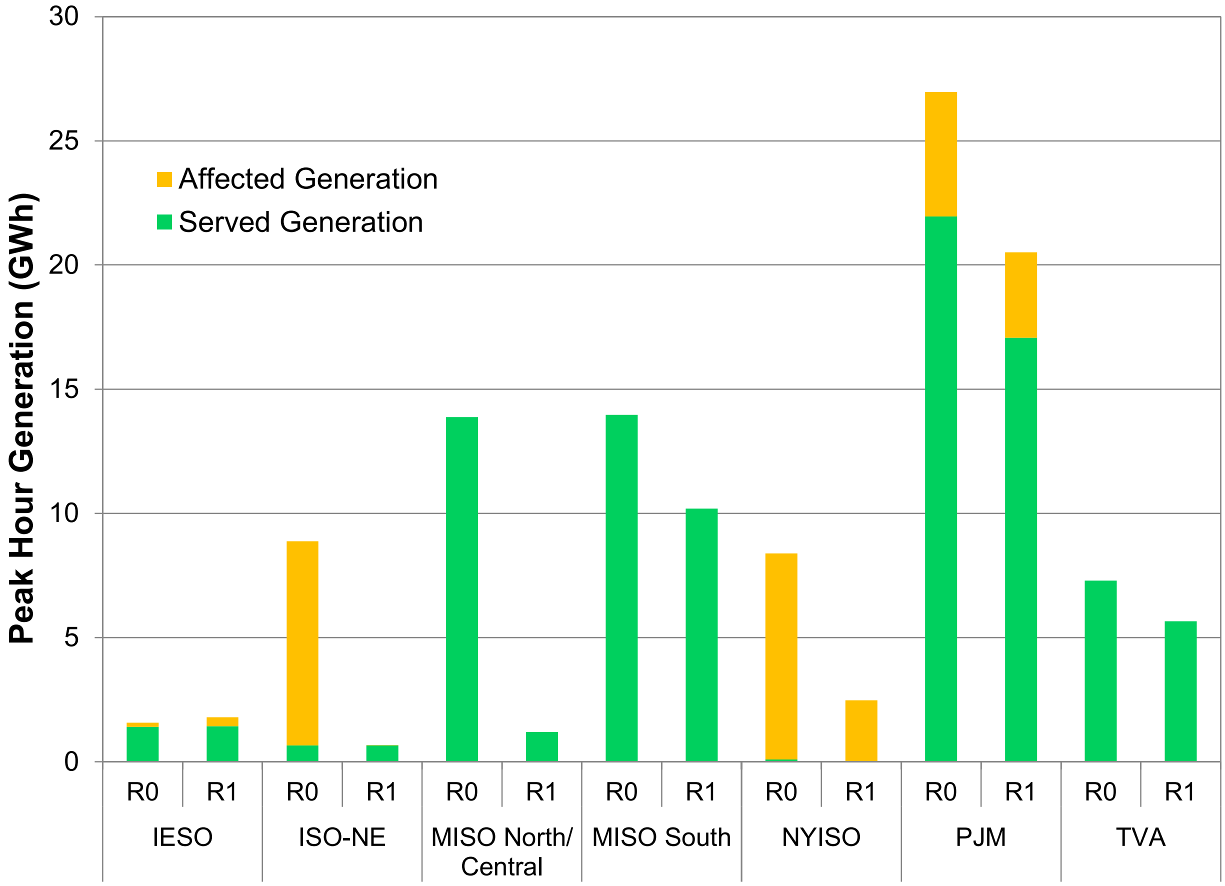


Figure 78 illustrates the GPCM locations with unserved generator gas demand. The unserved demand and resultant affected generation by location are quantified in Table 17. Because GPCM locations that have any affected generation due to infrastructure constraints are shown in orange, it is important to review Figure 78 together with Table 17 summary data in order to calibrate the magnitude of the impact. As shown in Figure 78 and Table 17, there is substantial affected generation in PJM, NYISO and ISO-NE under RGDS S0 pricing assumptions. Because oil fired generation and, to a lesser extent, some coal-fired generation, is not in economic merit, the quantity and profile of gas required by gas-fired generation is high relative to available pipeline capacity. Moreover, RCI loads across the Study Region must be served first, thereby reducing the available pipeline capacity for gas-fired generators lacking firm pipeline entitlements. Under high daily spot gas prices assumed in RGDS S1, there is a large reduction in gas-fired generation in PJM, NYISO and ISO-NE.

The increase in affected generation in certain GPCM locations under RGDS S1 pricing assumptions requires explanation. New York Southern and Virginia, for example, have some gas-fired generation that are benefited under low cost delivered gas prices indexed to Dominion South Point or Columbia Appalachia, pricing points generally applicable to gas sourced from Marcellus.[85] Dominion South Point prices diverged from other major pricing indices during the Polar Vortex that occurred in January 2014, by remaining low, and are assumed to remain comparatively low in relation to winter cold day spot gas prices at other pricing points across the Study Region in 2018.

[85] Reflecting transportation constraints during January 2014, the DTI-South Point price did not increase by much in relation to Transco Z6-NY, Transco Z6-NNY, Transco Z5, AGT Citygates, IGTS Zone 2, and Chicago Citygates, among others.

Figure 78. RGDS S0 v. RGDS S1 Winter 2018: GPCM Locations with Peak Hour Affected Generation

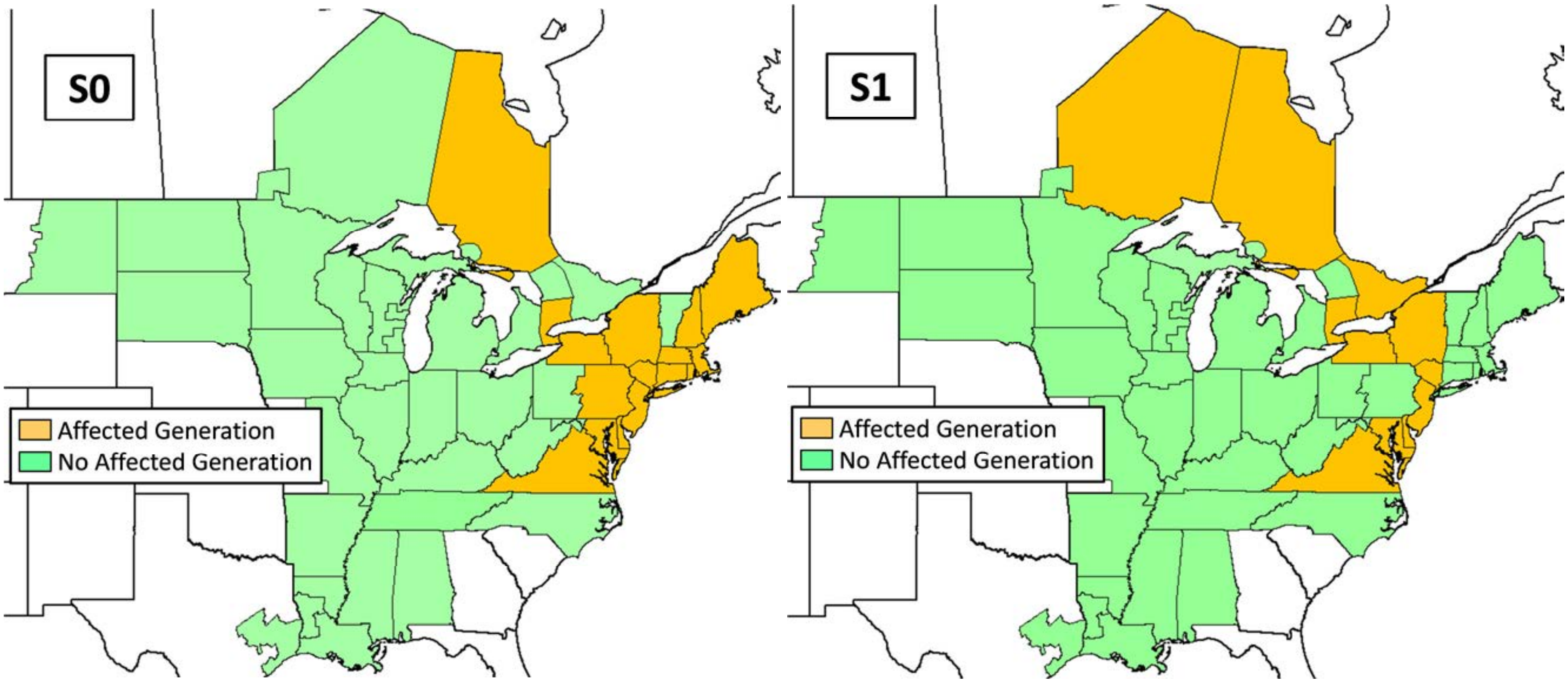


Table 17. RGDS S0 v. RGDS S1 Winter 2018: Peak Hour Unserved Generator Gas Demand and Affected Generation

GPCM Location	S0 Unserved Generation Gas Demand (MDth)	S0 Affected Generation (MWh)	S1 Unserved Generation Gas Demand (MDth)	S1 Affected Generation (MWh)
Connecticut	16.0	2,200	0.0	0
Delaware	1.6	199	0.1	9
Maine	7.6	1,045	0.0	0
Maryland Eastern	5.0	539	3.3	311
Massachusetts Eastern	12.8	1,781	0.0	0
Massachusetts Western	7.8	1,059	0.0	0
New Hampshire	9.4	1,245	0.0	0
New Jersey	11.2	1,385	0.7	92
New York Central Northern	24.4	3,419	6.7	754
New York City	17.7	2,336	0.0	0
New York Long Island	9.4	1,054	0.0	0
New York Southern	10.9	1,312	14.3	1,537
New York Western	1.6	179	1.6	179
Ontario (CDA)	0.5	55	0.5	55
Ontario (EDA)	0.0	0	0.5	74
Ontario (NDA)	0.8	114	1.5	186
Ontario (WDA)	0.0	0	0.4	38
Pennsylvania Eastern	1.0	143	0.0	0
Rhode Island	6.7	887	0.0	0
Virginia	21.0	2,755	23.5	3,028

Figure 79 shows the constrained pipeline segments that result in the affected generation for RGDS S0 and RGDS S1 during the Winter 2018 peak hour. The same segments are constrained during the seasonal peak hour for both RGDS S0 and RGDS S1. The peak hour constraints reflected in Figure 79 capture natural gas flow dynamics from Western Canada and the Marcellus and Utica production basins on the peak hour of the peak day in 2018. Constraints west to east on TransCanada reflect the complete utilization of the TransCanada mainline to serve RCI and other firm generator customers behind the Enbridge and Union LDCs, as well as TransCanada's direct connected generators. Union Gas's Dawn segment is constrained on a peak day as well, with storage withdrawals and interconnection receipts, primarily from Vector, filling the segment to capacity. Other constraints in southern Ontario capture the reversal-of-flow from south-to-north on U.S. pipelines serving RCI loads in southern Ontario and Quebec.

Constraints in New York reflect delivery limitations on Columbia, Dominion, Transco, Tennessee, Millennium, Empire, and the new Constitution pipeline.[86] These pipelines link Marcellus with RCI loads in New York, New England, and southern Ontario, and therefore run at or near capacity limits on a peak day.

[86] The Constitution pipeline is designed to move 650,000 Dth/d of gas from Susquehanna County, PA to Iroquois and Tennessee in Schoharie County, NY.

Constraints in PJM reflect delivery limitations on Tennessee, Texas Eastern, Dominion, Columbia, East Tennessee and Eastern Shore, pipelines linking Marcellus with RCI loads in PJM, New York and New England.

Constraints in TVA reflect delivery limitations on East Tennessee, but do not result in affected generation in the PPA due to TVA's firm entitlements. As noted above, the resultant affected generation is downstream of TVA in PJM, specifically, Virginia.

Figure 79. RGDS S0 & RGDS S1 Winter 2018: Peak Hour Constraints

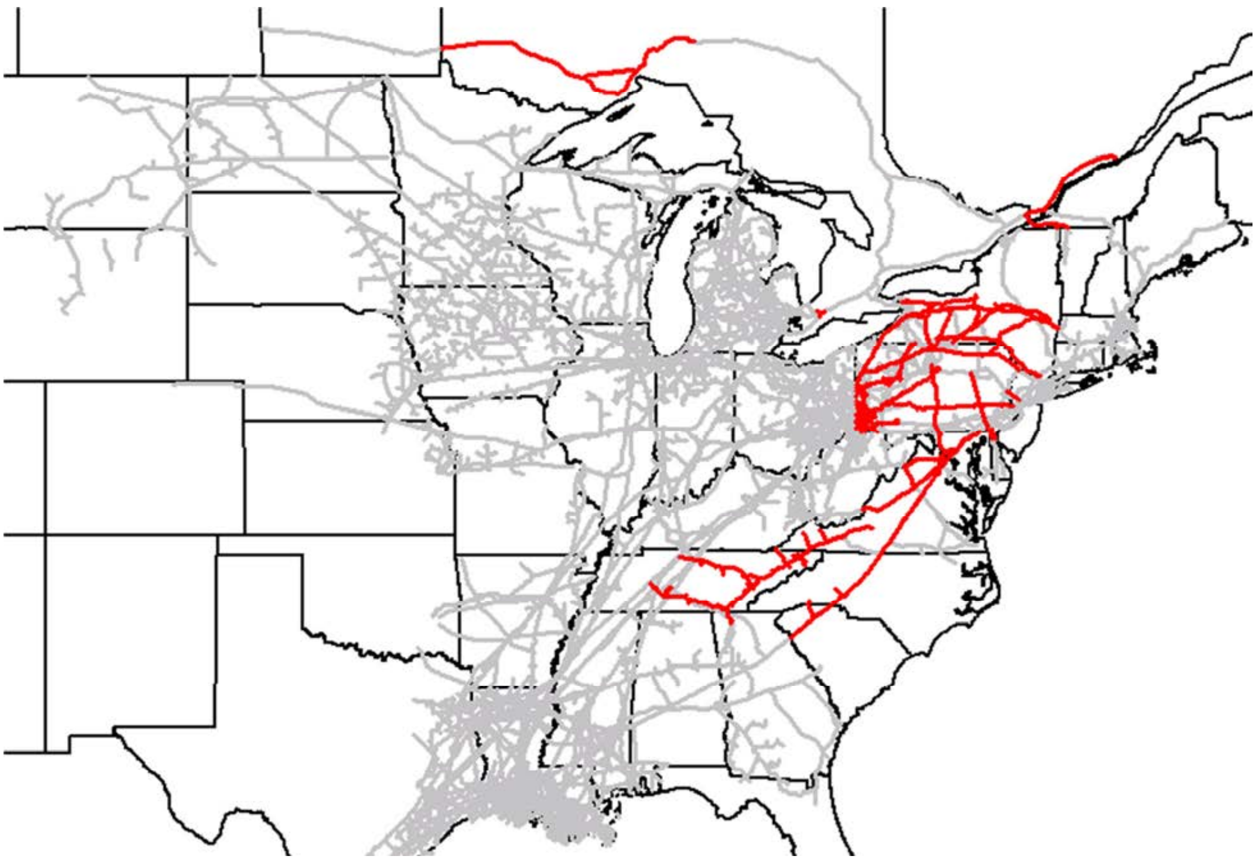


Table 18 summarizes the results of the frequency and duration analysis, with the detailed results presented following the table. All constraints shown in this table are also in effect during the RGDS S1 peak demand hour.

Table 18. RGDS S0 Winter 2018: Frequency and Duration of Daily Peak Hour Constraints

Constraint	# of Events	Min. Duration (Days)	Max. Duration (Days)	Total # of Days
Columbia Gas VA/MD	12	1	5	23
Columbia Gas W PA/NY	11	1	5	21
Constitution	5	1	12	25
Dominion Eastern NY	6	1	6	15
Dominion Western NY	1	4	4	4
Dominion Southeast	7	1	12	22
East Tennessee Mainline	7	1	2	9
Eastern Shore	11	1	10	51
Empire Mainline	5	1	12	21
Millennium	4	1	59	83
NB/NS Supply	13	1	20	58
Tennessee Z4 PA	10	1	7	30
Tennessee Z5 NY	2	31	59	90
Texas Eastern M2 PA South	10	1	15	50
Texas Eastern M3 North	10	2	7	39
TransCanada Ontario West	5	1	5	12
TransCanada Quebec	9	1	14	30
Transco Leidy Atlantic	8	2	23	59
Transco Z5	3	1	7	9
Transco Z6 Leidy to 210	5	1	3	8
Union Gas Dawn	2	1	3	4

The results captured in Table 18 indicate that the areas of greatest congestion are in and around the Northeast, particularly in the New York-Pennsylvania, where large amounts of gas sourced from Marcellus and Utica, as well as conventional production from the Gulf of Mexico, flow to demand centers across the Study Region. Therefore the preponderance of red across the New York-Pennsylvania area signifies the near complete utilization of existing pipeline and storage infrastructure on a peak day, a dynamic reflecting more demand for shale gas than take-away capacity in the Winter 2018, even with the pipeline expansion projects incorporated in RGDS S0, which are described in Section 5.2. Michigan's abundant conventional storage infrastructure is used throughout the heating season to supplement pipeline rendered supply, thereby putting upward pressure on the state wide utilization of gas infrastructure to meet RCI and generator sendout in MISO and PJM on a coincident basis. However, the abundance of conventional storage capacity in MISO North/Central does not result in deliverability constraints during the winter seasonal peak hour.

The results shown in Figure 79 represent pipeline utilization – *not gas deliverability*. The distinction is important. For example, the pipelines in Massachusetts – Tennessee, Algonquin, and M&N – are shaded gray, an ostensible paradox in light of the region's well documented deliverability constraints throughout the heating season, November through March. The absence of red coding should not be construed as evidence of unconstrained deliverability to generators in

NEMA/Boston, SEMA, or elsewhere in Massachusetts (as discussed in greater detail below). Instead, model solutions reveal that deliverability *into* Massachusetts is the bottleneck, as shown in red across New York and Connecticut, reflecting the complete or near complete utilization of primary pipelines linking Marcellus with market centers in NYISO, ISO-NE and IESO. Simply put, upstream constraints in New York and Connecticut result in the underutilization of existing pipeline capacity within Massachusetts on a peak day. Moreover, the flow pattern on M&N into northern New England and Massachusetts is shaded gray, reflecting the substantial underutilization of this pathway in 2018 due to the forecasted decline in gas production from Sable Island, utilization of gas produced from Deep Panuke predominantly in the Maritimes, and the anticipated reduction in the regasification volumes from the Repsol Canaport LNG import terminal in New Brunswick. Utilization across Iroquois Zone 2 serving the Lower Hudson Valley, Connecticut and Long Island remains high, but is below 100% of the pipeline's Zone 2 segment capability. Again, upstream bottlenecks on Algonquin and Tennessee result in the appearance of "spare" pipeline capacity in Massachusetts and northern New England.

As these data indicate, the locations with generation at the highest impact are primarily those located at or near the end of the supply chain, New England, for one. There are "hot spots" in other PPAs, however. A number of other locations that are affected are due to regional pipeline or storage constraints in New York and PJM, in particular, EMAAC and SWMAAC, as well as the size of the RCI load relative to local deliverability conditions to serve gas-fired generation behind the citygate.[87] Additionally, we note that there are a significant number of locations where the relative impact increases between 2018 and 2023. The increased characterization of impact in 2023 is explained by the growth in RCI loads coupled with the more complete utilization of the known infrastructure additions added to the RGDS in 2018.

In ISO-NE, the Algonquin and Tennessee segments transporting gas into New England from west to east are fully utilized either in or upstream of New England, thereby limiting the amount of gas available to fill New England's gas infrastructure. While Suez Distrigas, the owner of the LNG import terminal in Everett, MA, meets its delivery requirements to the New Mystic generation station, additional regasification quantities into the back end of the Algonquin and Tennessee mainlines are zero.[88] North-to-south flows from Atlantic Canada to Northern New England reflect net export from Sable Island and Deep Panuke, not regasification of LNG at the Canaport LNG import terminal in New Brunswick. As previously discussed, the absence of red coding in much of New England represents percentage utilization of the route segment capability, not deliverability. Hence, the upstream bottlenecks from Marcellus to New York and Connecticut similarly impair Algonquin's and Tennessee's ability to serve generators on a winter peak day, in particular, and, more generally, throughout the heating season, to downstream delivery points in New England.

[87] The character of service associated with gas-fired generation served at the local level is typically quasi-firm or fully interruptible, thereby exposing gas-fired generation to scheduling restrictions during the heating season, November through March. Generators in Ontario behind the Enbridge or Union systems hold firm entitlements for all or the majority of the daily fuel requirements. TVA has firm transportation rights as well.

[88] Distrigas also serves a comparatively small quantity to the NGrid local distribution system to serve RCI customers.

In MISO North/Central, winter peak day storage withdrawals result in full utilization of the local reticulated pipeline capacity in order to provide storage volumes to RCI and generator customers both in Michigan and in the rest of MISO North/Central. The gray segments in Michigan represent reticulated systems, which are modeled in GPCM due to the high connectivity among pipelines, conventional underground storage facilities and the in-state LDCs that serve RCI. In Iowa, the Northern Natural Gas System north of Ventura does not experience constraints during winter peaks when large volumes are flowing into the system from Northern Border.[89]

In MISO South, there is massive pipeline and storage deliverability to serve RCI and generator loads in Louisiana and downstream markets in MISO South, as well as the southeastern part of the Eastern Interconnect, in particular, Florida. Insofar as supply availability is not a constraint from the onshore and offshore Gulf Coast, pipeline takeaway capacity becomes the limiting factor, especially on Transco, Florida Gas Transmission and Southern Natural Gas Co., among others.

New York is located along the supply path from the Marcellus region to downstream markets in New England and Ontario. Therefore the segments moving gas from west to east and south-to-north remain highly utilized. Although transportation capacity *into* New York City has recently been significantly expanded, upstream constraints on Texas Eastern and Transco limit deliveries to downstate customers.

Continued growth in supply from Marcellus and Utica shales is dependent on the concomitant increase in pipeline and gas gathering takeaway capacity. The comparatively low cost of shale gas relative to the Henry Hub, Rocky Mountains and Western Canada results in continued shale gas penetration across the Study Region. Shale gas from Marcellus is flowing west to MISO, north to Ontario through New York, south to the mid-Atlantic and Southeast, and west-to-east into the New York Facilities System and into New England. Shale gas production coupled with substantial infrastructure expansion largely displaces traditional gas flowing from the Gulf of Mexico to five of six PPAs. As a result, the pipeline and storage infrastructure linking the production area to the market center runs full on a winter peak day and throughout the majority of the heating season. Utilization of the gas infrastructure on a summer peak day also runs full or near full, particularly from the shale production areas in Ohio and western Pennsylvania. In MISO South, RCI customers and gas-fired generators continue to be served from conventional production from the Gulf of Mexico over the forecast period, supplemented by shale gas flowing from north to south along pipelines that are implementing flow reversal expansion projects.

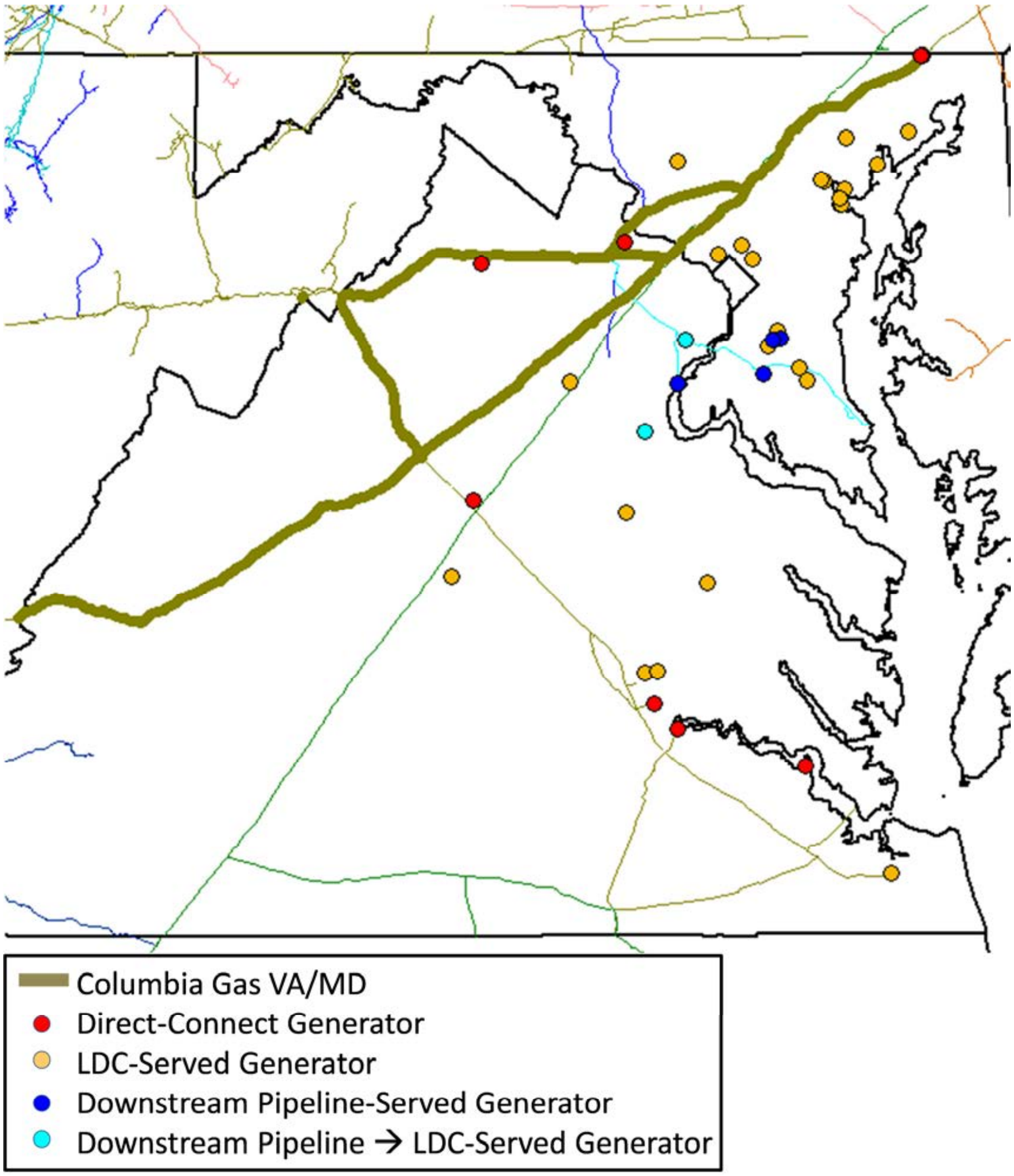
6.2.1.1 Columbia Gas Virginia / Maryland

The 100% peak hour utilization on Columbia Gas's Virginia/Maryland segment, which is modeled with a capacity of 2,477 MDth/d, potentially affects generators directly connected to Columbia in Maryland and Virginia; generators behind LDCs served by Columbia Gas in Maryland and Virginia; and generators served by Dominion Cove Point and PPL Interstate

[89] NNG serves LDCs and direct connected generators, the majority of which hold firm transportation entitlements. Northern Natural Gas Co./MidAmerican Energy Holdings Co., NAESB Gas-Electric Harmonization Forum, Houston, April 22-23, 2014.

downstream of interconnections with Columbia Gas. The locations of these generators are shown in Figure 80.

Figure 80. Generators Downstream of Columbia Gas VA/MD Constraint

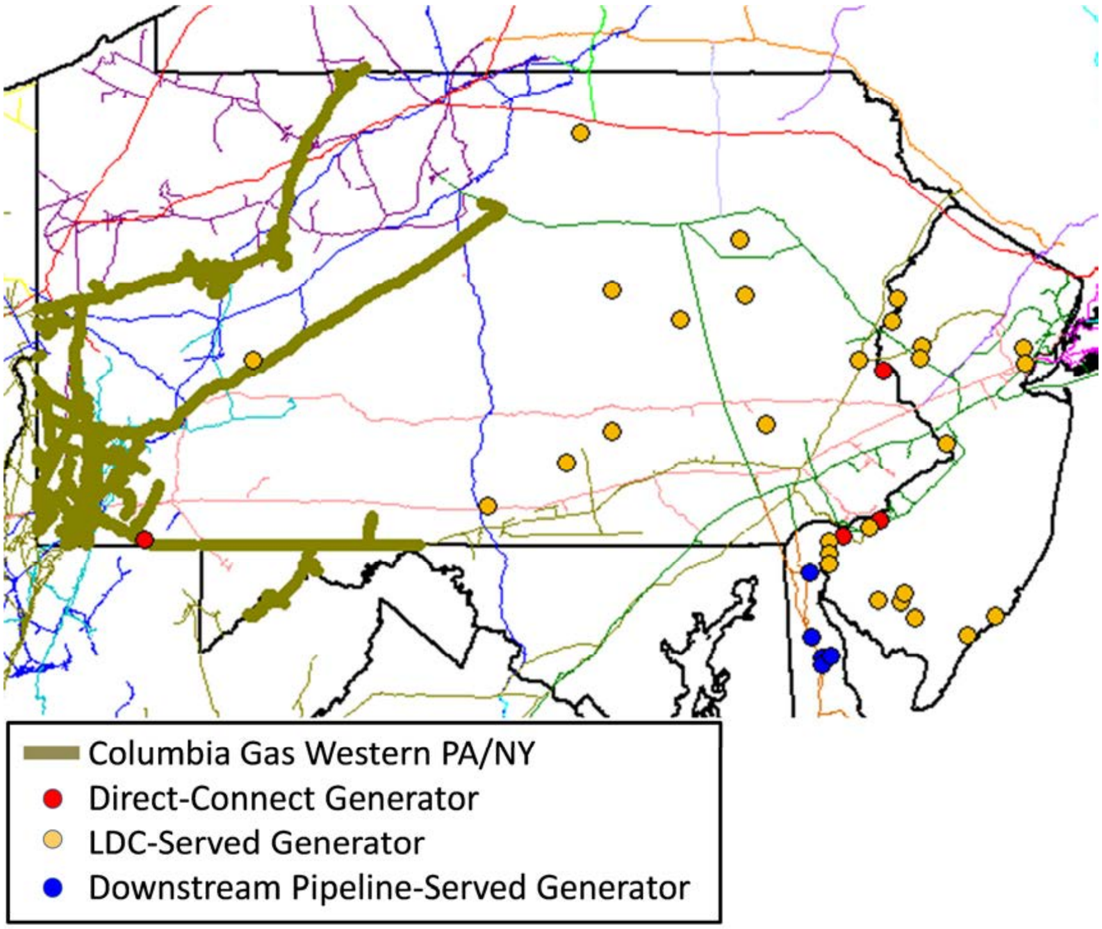


The seasonal daily forecasts of RCI and generator gas demand downstream of the constrained segment are shown in Figure C1 and Figure C2 relative to the capacity of the segment.

6.2.1.2 Columbia Gas Western Pennsylvania / New York

The 100% peak hour utilization on Columbia Gas's Western Pennsylvania / New York segment, which is modeled with a capacity of 1,131 MDth/d, potentially affects generators directly connected to Columbia in Pennsylvania, New Jersey, Virginia and Maryland, and generators behind LDCs served by Columbia Gas in Pennsylvania, New Jersey, Delaware, Maryland and Virginia. The locations of these generators are shown in Figure 81.

Figure 81. Generators Affected by Columbia Gas W PA/NY Constraint

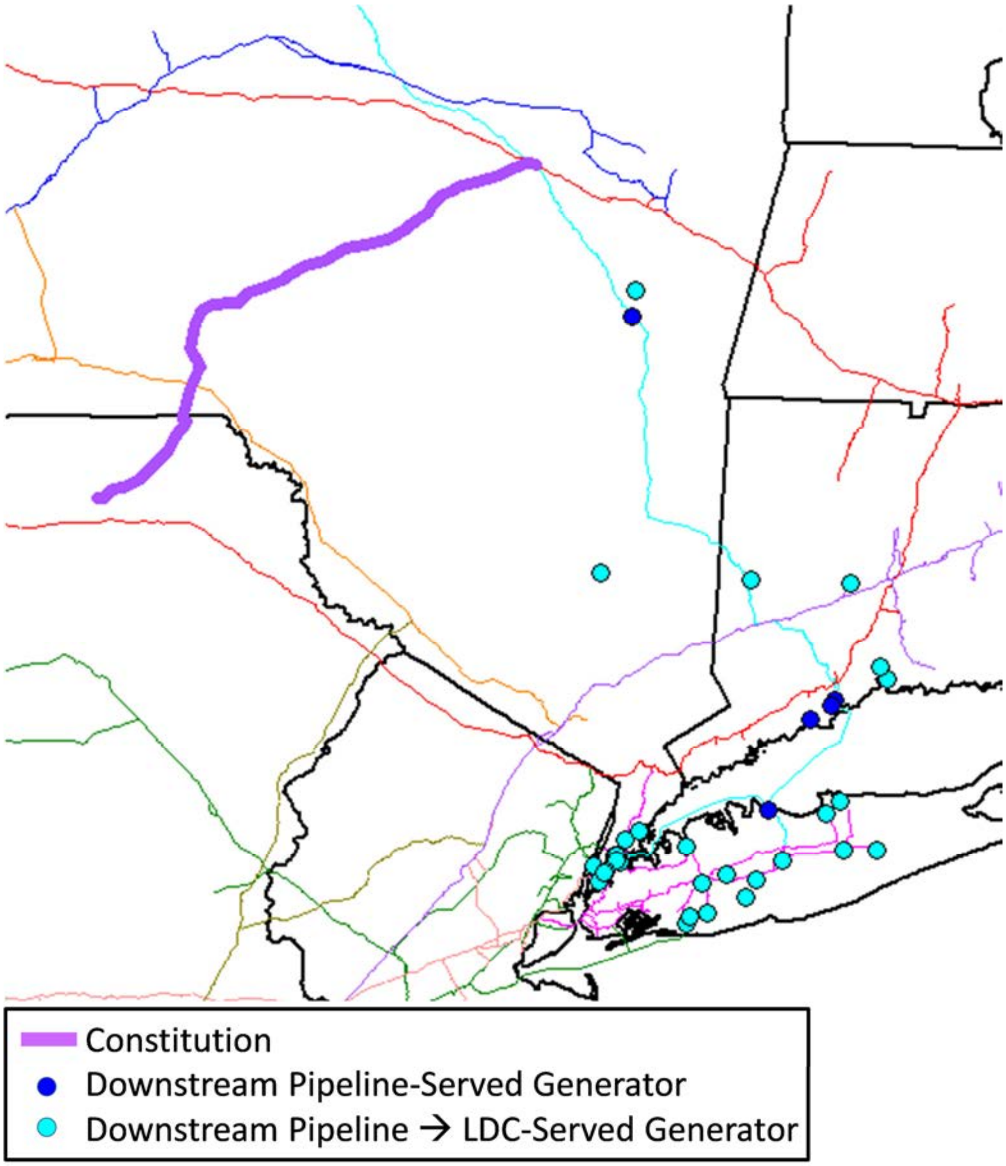


The seasonal daily forecasts of RCI and generator gas demand downstream of the constrained segment are shown in Figure C3 and Figure C4 relative to the capacity of the segment. Under the RGDS S0 gas price assumptions, total peak hour demand for Columbia Gas Western PA/NY transportation exceeds pipeline capacity for a total of 21 days.

6.2.1.3 Constitution Pipeline

Constitution's proposed delivery capacity is 650 MDth/d. The 100% peak hour utilization on Constitution potentially affects generators served by Iroquois both directly and behind LDCs in New York, and Connecticut. The locations of these generators are shown in Figure 82.

Figure 82. Generators Downstream of Constitution



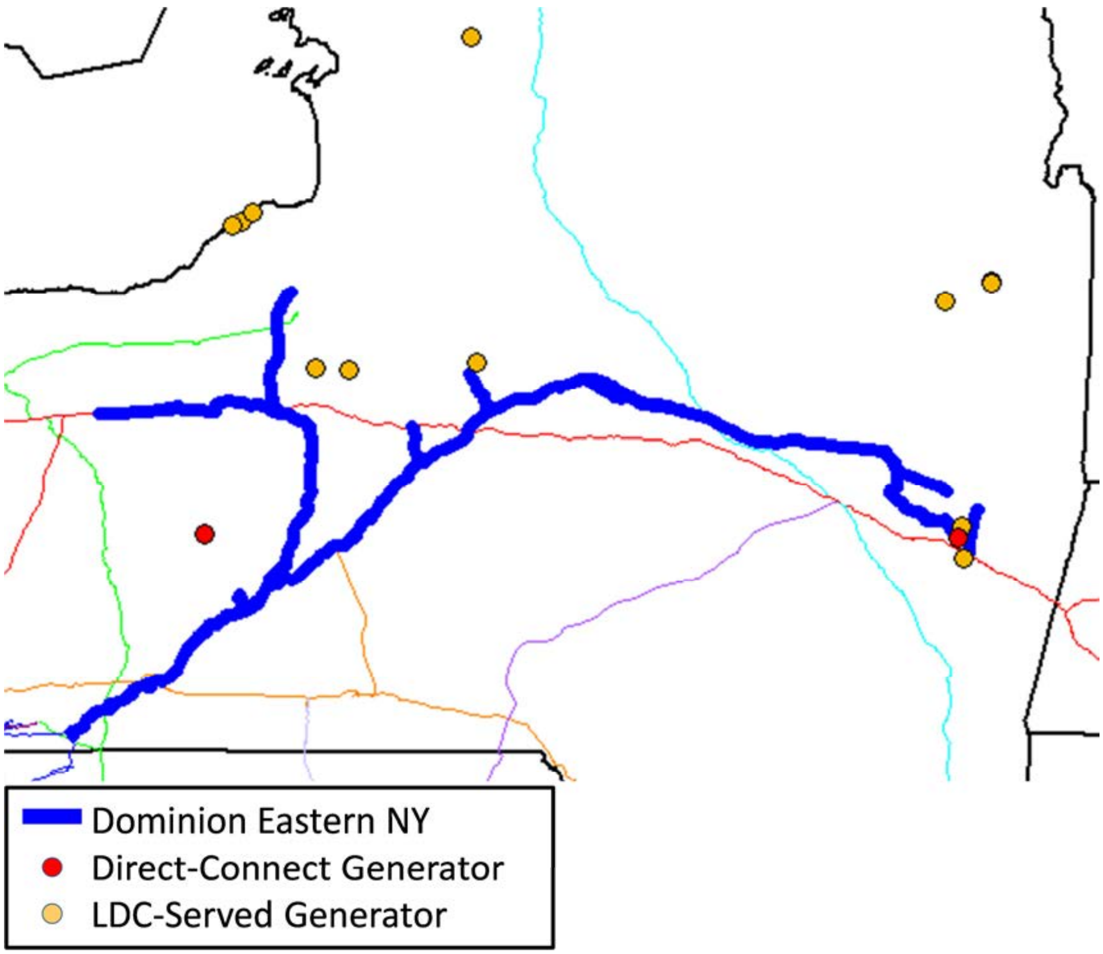
The seasonal daily forecasts of RCI and generator gas demand downstream of the constrained segment are shown in Figure C5 and Figure C6 relative to the capacity of the segment. Because Constitution links upstate New York, southern New England and southern Ontario to Marcellus supply, Constitution's capacity factor is likely to remain high irrespective of downstream demand levels on Iroquois. Various pipeline interconnections are expected to enable flow to other downstream customers. The commercialization of the Constitution pipeline allows Iroquois to support the reversal-of-flow along Zone 1 from Wright, NY to Waddington, NY through the proposed South-to-North Project.[90]

[90] The South-to-North Project, which is included in S13 but not in the RGDS, is designed to support up to 300 MDth/d of south-to-north flow to Zone 1 delivery points and Waddington.

6.2.1.4 Dominion Eastern New York

Dominion's Eastern New York segment is modeled with a capacity of 907 MDth/d. The 100% peak hour utilization on Dominion's Eastern New York segment potentially affects generators directly connected to Dominion and behind LDCs served by Dominion. The locations of these generators are shown in Figure 83.

Figure 83. Generators Affected by Dominion Eastern NY Constraint

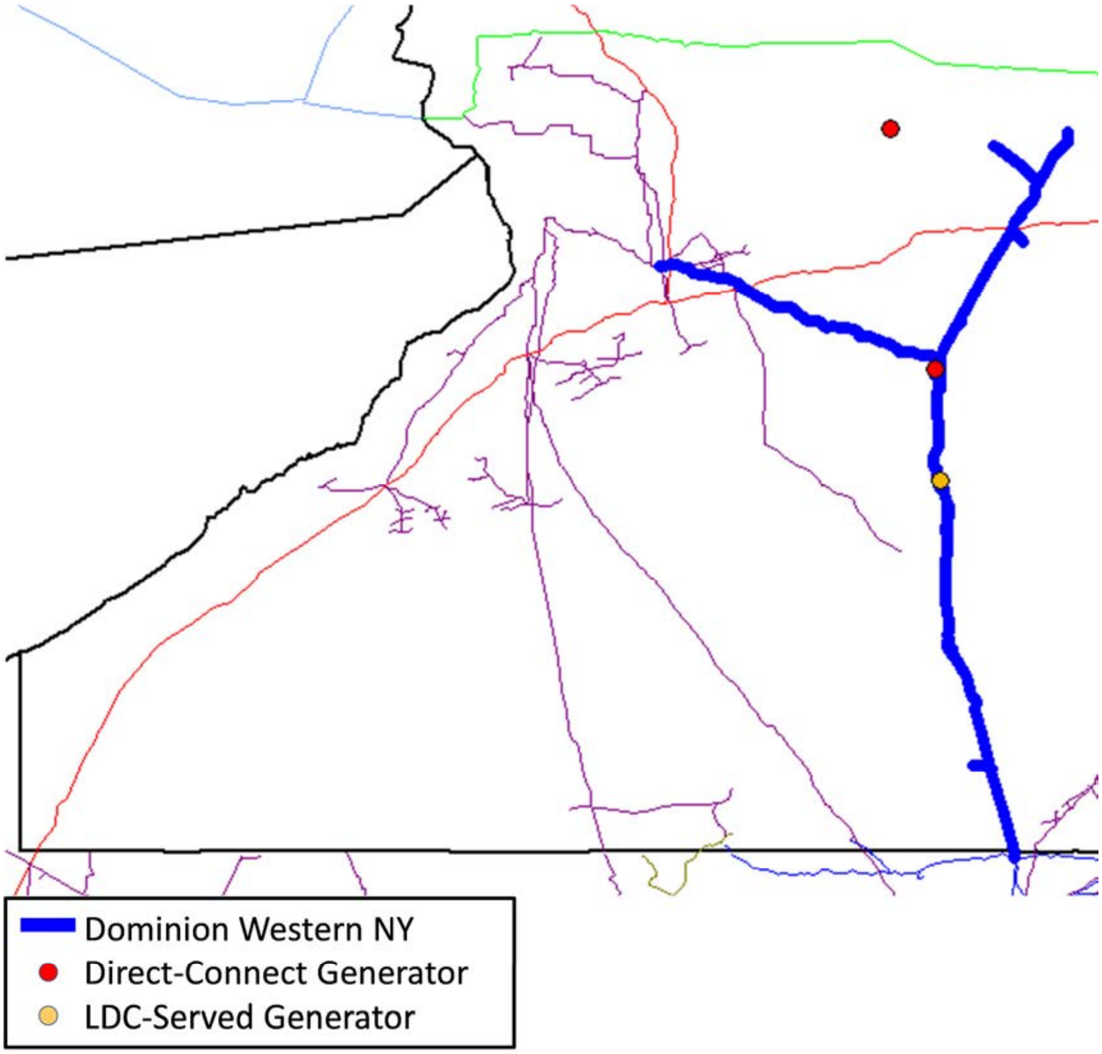


The seasonal daily forecasts of RCI and generator gas demand downstream of the constrained segment are shown in Figure C7 and Figure C8 relative to the capacity of the segment. On Dominion Eastern NY peak hour demand exceeds pipeline capacity for a total of 15 days.

6.2.1.5 Dominion Western New York

Dominion Western New York is modeled with a capacity of 557 MDth/d. The 100% utilization on Dominion's Western New York segment potentially affects generators directly served by Dominion and behind LDCs served by Dominion. The locations of the plants in each category are shown in Figure 84.

Figure 84. Generators Affected by Dominion Western NY Constraint

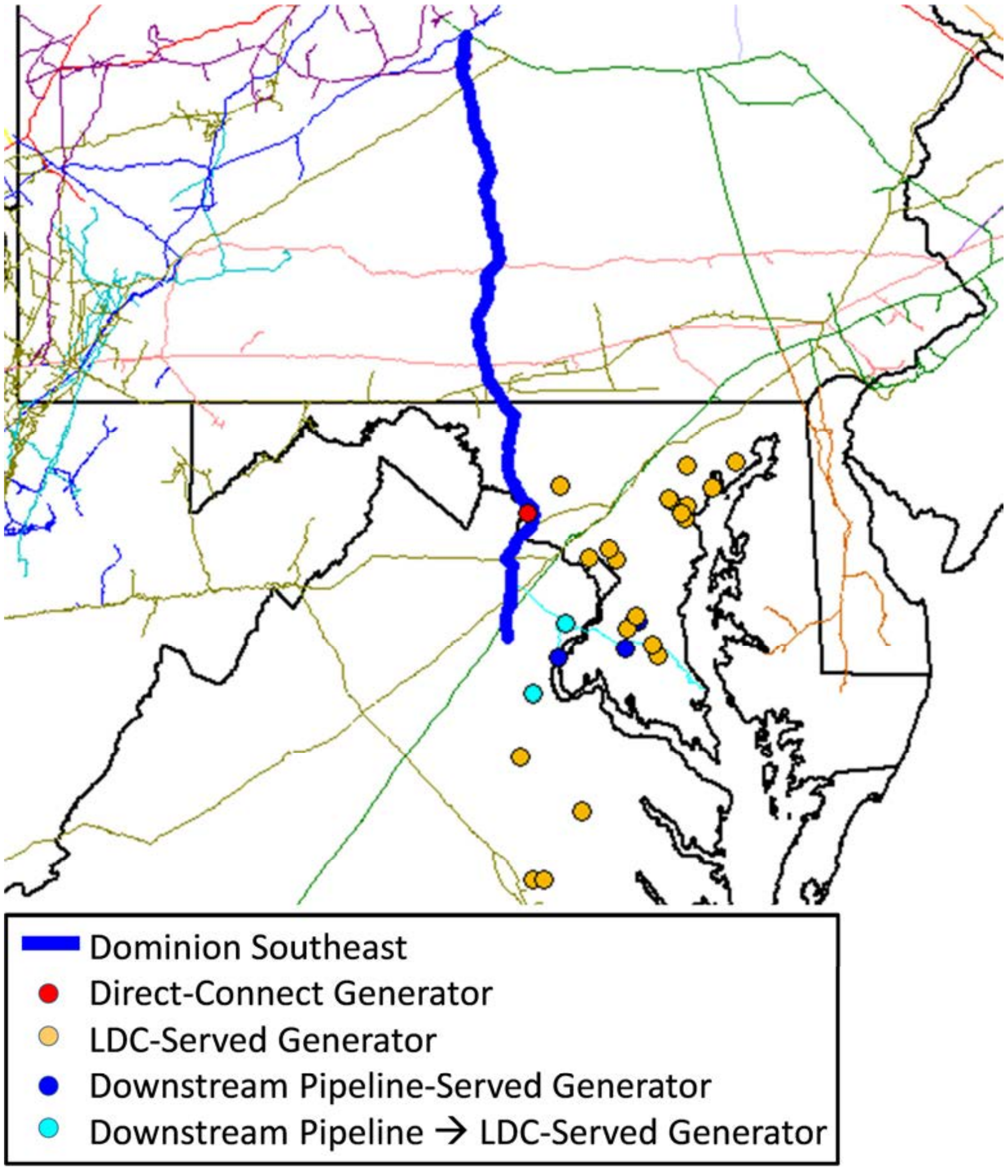


The seasonal daily forecasts of RCI and generator gas demand downstream of the constrained segment are shown in Figure C9 and Figure C10 relative to the capacity of the segment. Under the RGDS S0 assumptions, total peak hour demand exceeds pipeline capacity for four days in mid-January.

6.2.1.6 Dominion Southeast

Dominion Southeast is modeled with a capacity of 540 MDth/d. The 100% peak hour utilization on Dominion's Southeast segment serving Virginia and Maryland potentially affects generators directly served by Dominion, generators behind LDCs served by Dominion, and generators served by Dominion Cove Point via interconnect. The locations of these generators are shown in Figure 85.

Figure 85. Generators Affected by Dominion Southeast Constraint



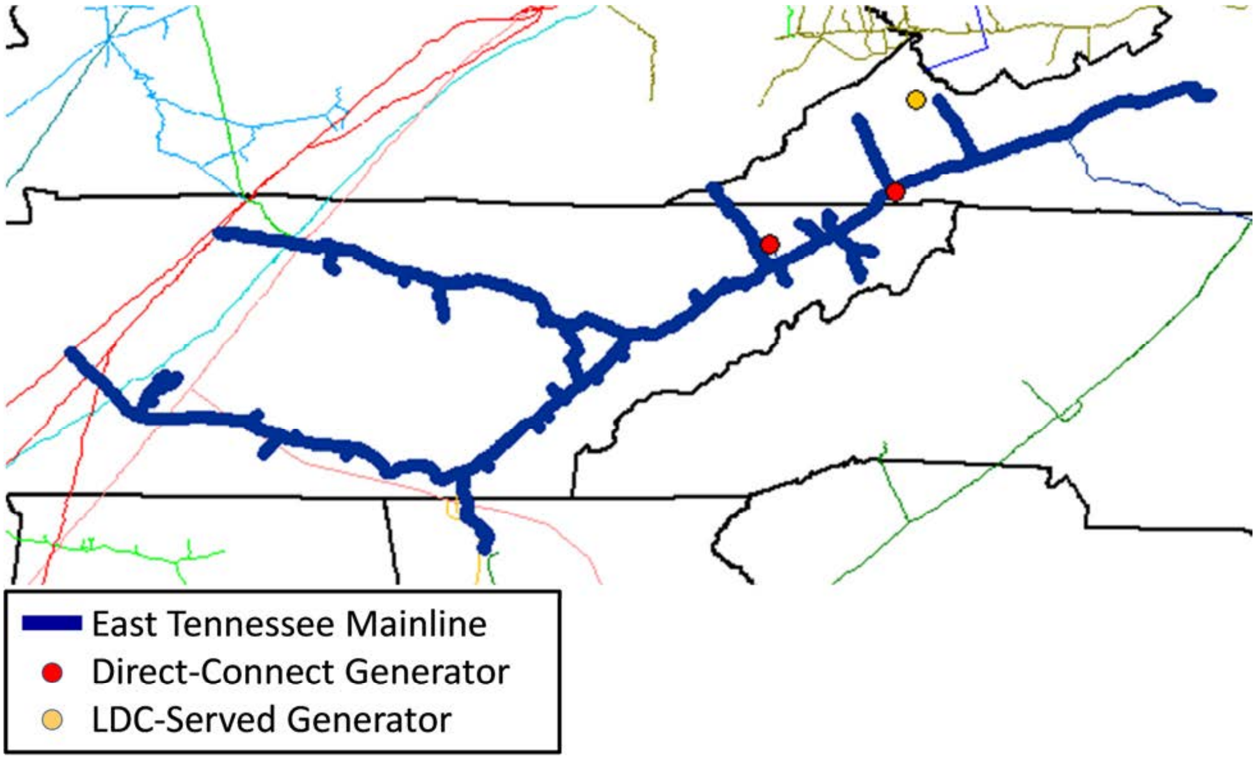
The seasonal daily forecasts of RCI and generator gas demand downstream of the constrained segment are shown in Figure C11 and Figure C12 relative to the capacity of the segment. Peak hour demand on Dominion Southeast exceeds pipeline capacity on 22 days under the RGDS S0 assumptions. The generators located along this segment generally source gas from Marcellus tied to prices at Dominion South-Point, which reflects negative basis differentials relative to the Henry Hub pricing throughout the year. In light of the anticipated divergence between Dominion South-Point and other price indices on a peak day, generators along Dominion Southeast experience high capacity factors.

6.2.1.7 <u>East Tennessee Mainline</u>

The East Tennessee mainline is modeled with a capacity of 800 MDth/d. The 100% peak hour utilization on East Tennessee's mainline potentially affects generators directly connected to East

Tennessee and generators behind LDCs served by East Tennessee. The locations of these generators are shown in Figure 86.

Figure 86. Generators Affected by East Tennessee Mainline Constraint

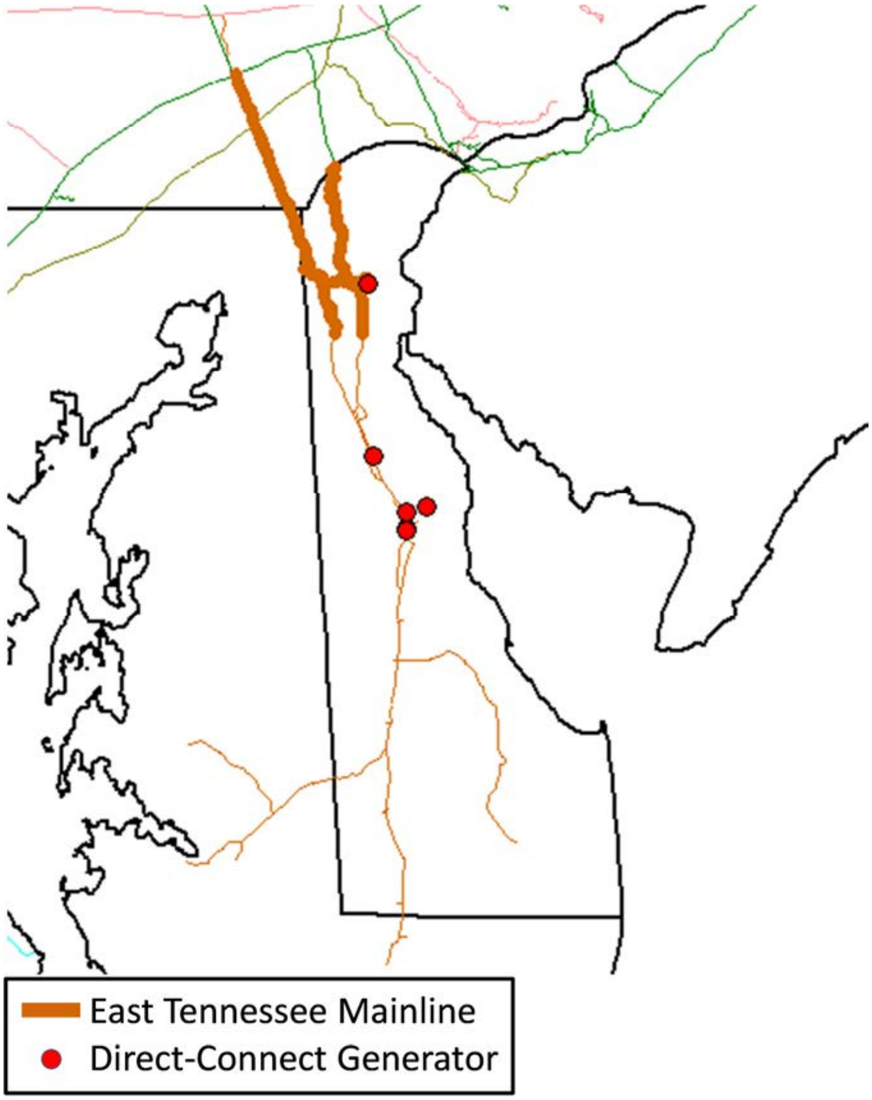


The seasonal daily forecasts of RCI and generator gas demand downstream of the constrained segment are shown in Figure C13 and Figure C14 relative to the capacity of the segment. East Tennessee would experience 9 days when total demand exceeds pipeline capacity. On these days only a small amount of generator gas demand is potentially unserved.

6.2.1.8 Eastern Shore

Eastern Shore is modeled with a capacity of 203 MDth/d. The 100% peak hour utilization rate on Eastern Shore's Receipt Zone 1 and Delivery Zone 2 potentially affects generators on the Delmarva Peninsula that are served by Eastern Shore. The locations of these generators are shown in Figure 87.

Figure 87. Generators Affected by Eastern Shore Constraint

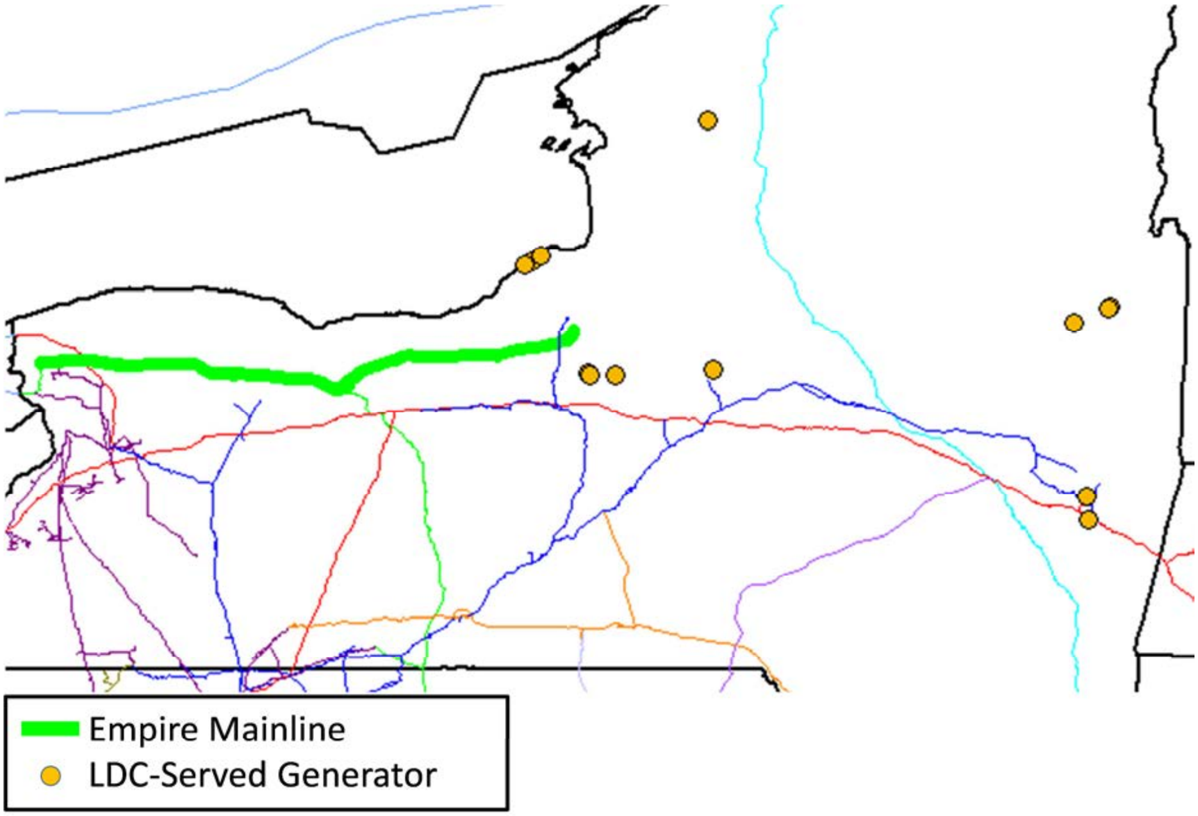


The seasonal daily forecasts of RCI and generator gas demand downstream of the constrained segments are shown in Figure C15 and Figure C16 relative to the capacity of the segments. Total demand on Eastern Shore exceeds pipeline capacity on 51 days with substantial generator gas demand unserved in January, February and December. The frequency and duration results show heavy congestion in Delaware as LDCs rely on Eastern Shore for RCI send out throughout the winter. The high frequency of transportation deficits on Eastern Shore would be expected to constrain gas-fired generation on the Delmarva Peninsula.

6.2.1.9 Empire Mainline

The Empire mainline is modeled with a capacity of 525 MDth/d. The 100% peak hour utilization on the Empire mainline across upstate New York potentially affects generators on the Niagara Mohawk LDC system. The locations of these generators are shown in Figure 88.

Figure 88. Generators Affected by Empire Mainline Constraint

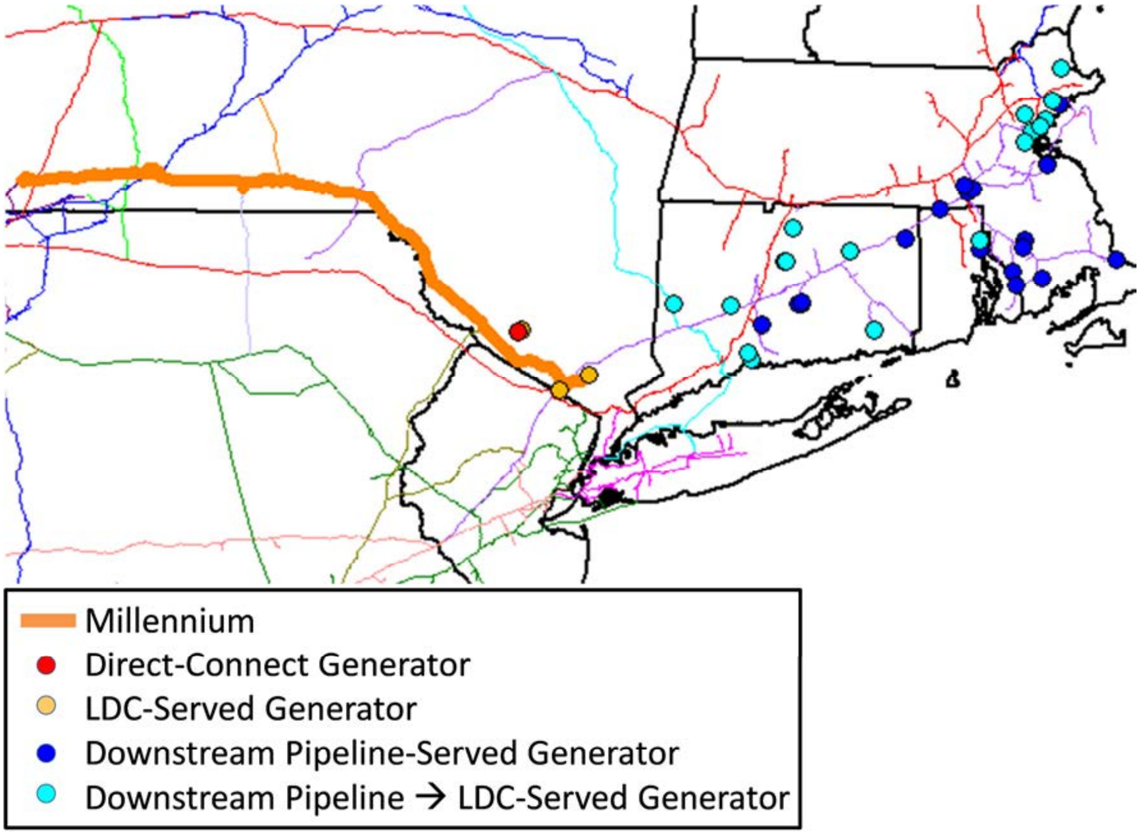


The seasonal daily forecasts of RCI and generator gas demand downstream of the constrained segment are shown in Figure C17 and Figure C18 relative to the capacity of the segment. Total demand on Empire exceeds pipeline capacity on 16 days.

6.2.1.10 Millennium

Millennium is modeled with a capacity of 784 MDth/d. The 100% peak hour utilization on Millennium's mainline potentially affects generators directly connected to Millennium, generators behind LDCs served by Millennium, and generators served by Algonquin, particularly in southern New England. The locations of these generators are shown in Figure 89.

Figure 89. Generators Affected by Millennium Constraint

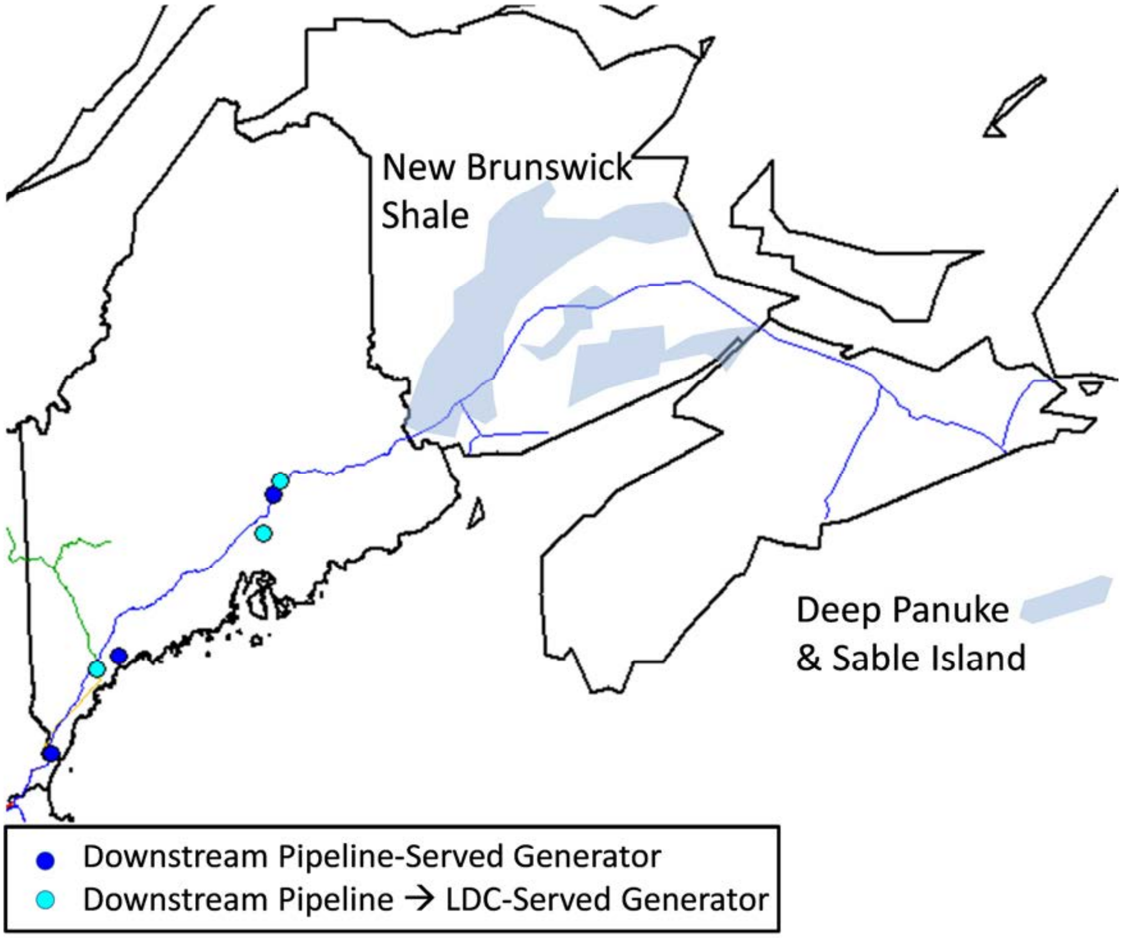


The seasonal daily forecasts of RCI and generator gas demand downstream of the constrained segment are shown in Figure C19 and Figure C20 relative to the capacity of the segment. Because it links Marcellus supply to markets in New York, New England and southern Ontario, Millennium's capacity factor is expected to be very high. The consistent pattern of constraints throughout almost all of the three winter months reflects the high demand for transportation services on this strategic pathway in the heart of the market. Downstream firm demand in New England also pulls significant volumes from Millennium, because it is a primary supply to Algonquin.

6.2.1.11 <u>New Brunswick Supply / Nova Scotia Offshore Supply</u>

Limitations on Atlantic Canada production have a direct bearing on available supply to meet the gas requirements of generators in Northern New England. Production from Atlantic Canada is capped at approximately 24 MDth/d in New Brunswick and approximately 599 MDth/d for Nova Scotia Offshore. In the RGDS S0, we have assumed that the Canaport LNG import facility will *not* regasify LNG for sendout to M&N due to supply chain uncertainty affecting destination-flexible cargoes. Even though there is slack deliverability on M&N, insufficient gas production from Atlantic Canada coupled with the loss of Canaport vaporization potentially affects generators directly connected to M&N in Maine and New Hampshire as well as generators located behind LDCs served by M&N in Maine. The locations of these generators are shown in Figure 90. Generators located in the Canadian Maritimes would also be affected by this supply constraint, but have not been included in the summary results shown below.

Figure 90. Generators Affected by New Brunswick / Nova Scotia Supply Constraint

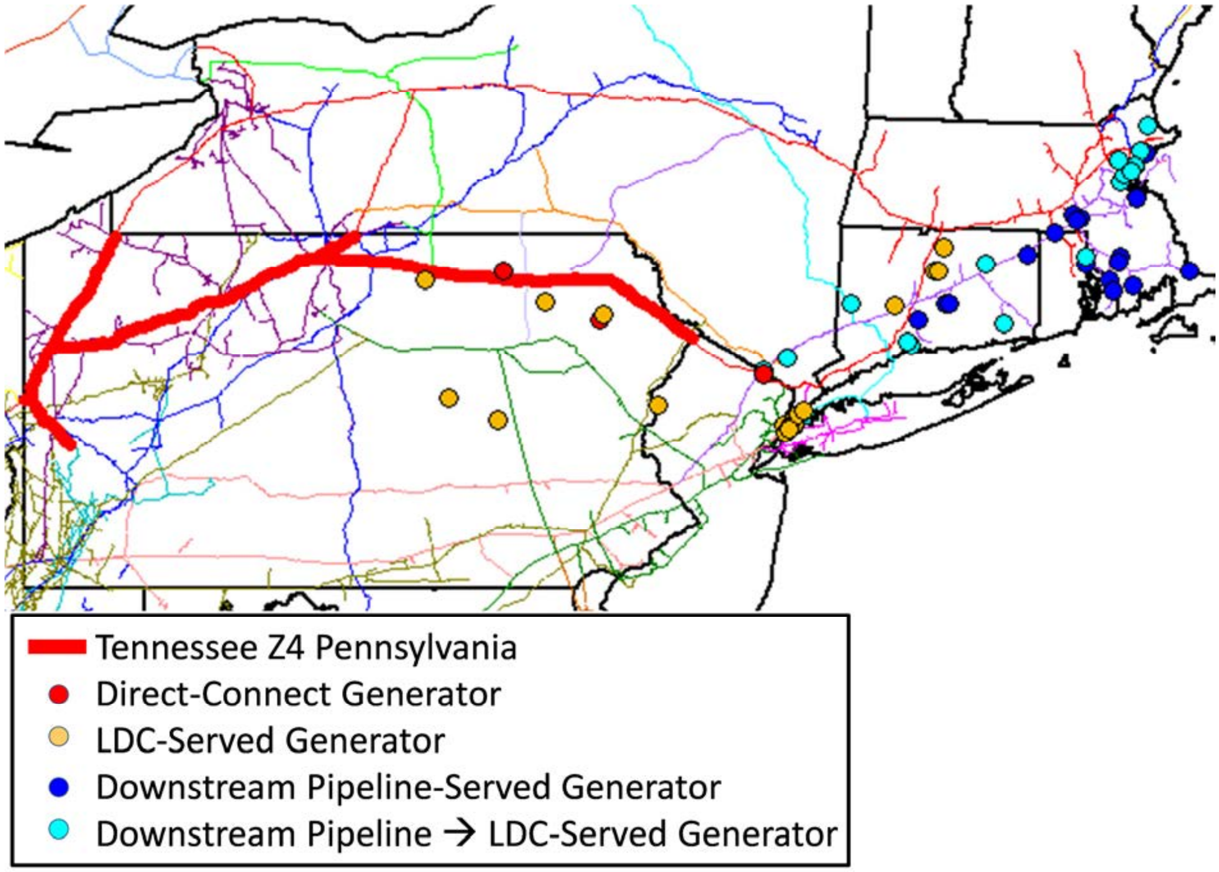


The seasonal daily forecasts of RCI and generator gas demand downstream of the supply limitation are shown in Figure C21 and Figure C22 relative to the total production capacity. The frequency of the constraint reflects insufficient natural gas supply rather than a transportation infrastructure limitation. The generator gas demand in these figures only reflects generators located in the Study Region.

6.2.1.12 Tennessee Zone 4 Pennsylvania

Tennessee Zone 4 Pennsylvania is modeled with a capacity of 1,887 MDth/d. The 100% peak hour utilization on Tennessee's Zone 4 segment in Pennsylvania potentially affects generators directly connected to Tennessee in Pennsylvania and New Jersey; generators behind LDCs served by Tennessee in Pennsylvania, New Jersey, downstate New York and Connecticut; and generators served by Algonquin either directly or via LDC in New England. The locations of these generators are shown in Figure 91.

Figure 91. Generators Affected by Tennessee Z4 PA Constraint

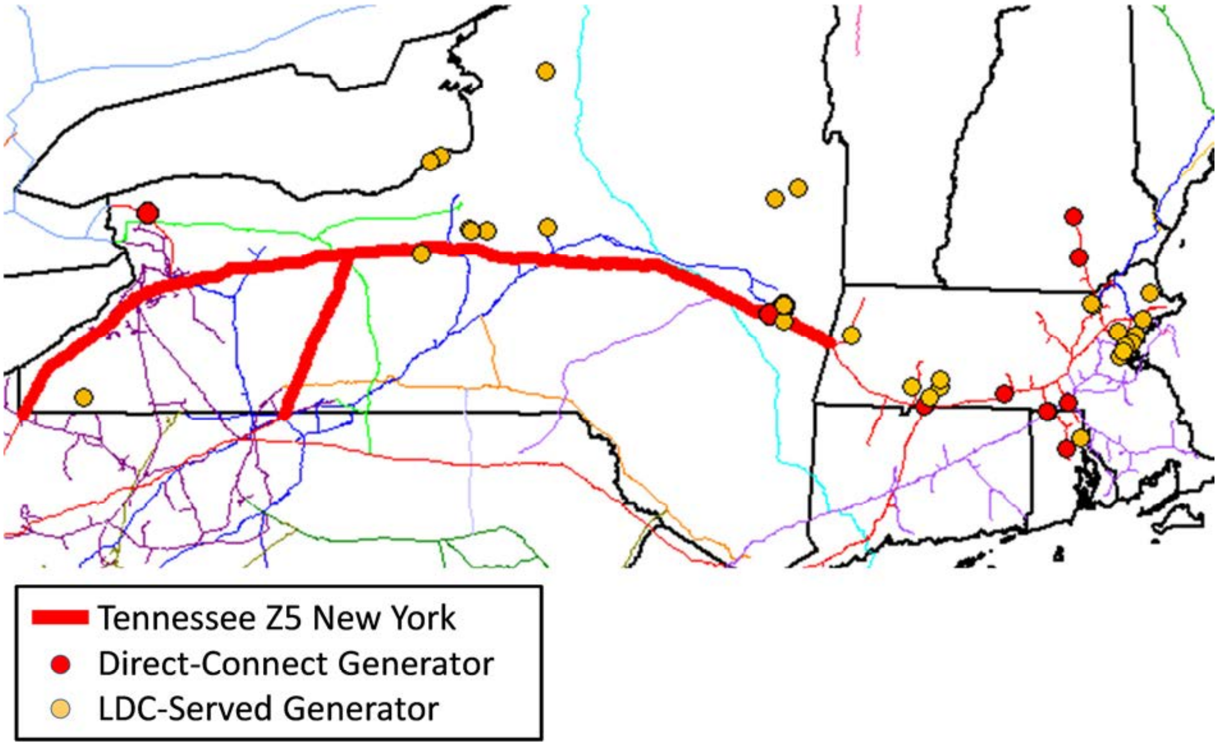


The peak hour demand forecasts of RCI and generator gas demand downstream of the constrained segment are shown in Figure C23 and Figure C24 relative to the capacity of the segment. As a supply segment connected to Marcellus production, additional interconnection flows to downstream pipelines would likely utilize the remaining available capacity on days shown here as unconstrained. This segment of the Tennessee mainline is anticipated to remain constrained throughout most of the three peak winter months in response to high demand for Marcellus production and the high RCI and generator gas demands on Tennessee and Texas Eastern in PJM, NYISO and ISO-NE. Under RGDS S0 pricing assumptions, transportation deficits would potentially affect generation in PJM and ISO-NE, in particular.

6.2.1.13 Tennessee Zone 5 New York

Tennessee Zone 5 New York is modeled with a capacity of 1,189 MDth/d. The 100% peak hour utilization on Tennessee's Z5 New York segment potentially affects generators directly connected to Tennessee in upstate New York, Massachusetts, Rhode Island and New Hampshire; generators behind LDCs served by Tennessee in upstate New York, Massachusetts, Connecticut and Rhode Island; and generators served by Iroquois, Granite State and PNGTS either directly or behind an LDC. The locations of these generators are shown in Figure 92.

Figure 92. Generators Affected by Tennessee Z5 NY Constraint

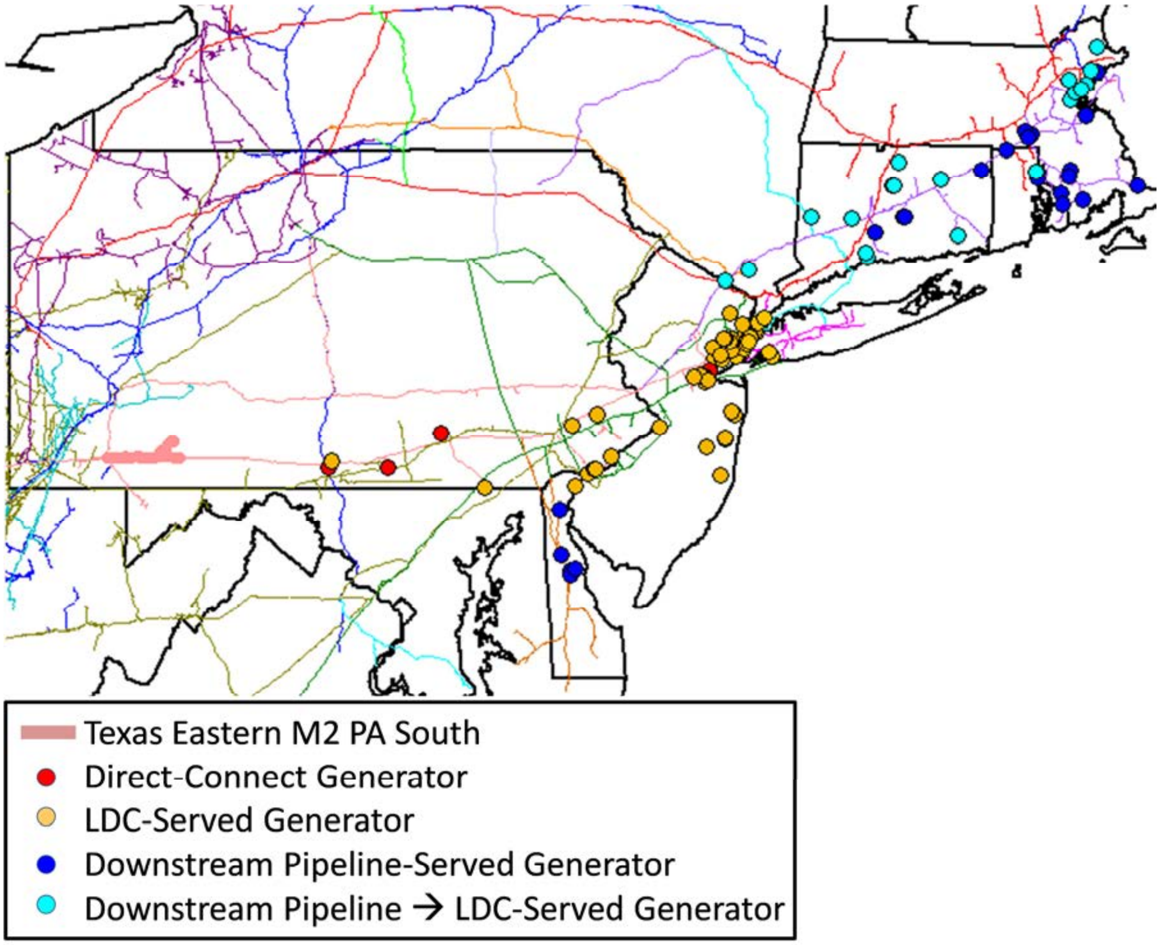


The seasonal daily forecasts of RCI and generator gas demand downstream of the constrained segment are shown in Figure C25 and Figure C26 relative to the capacity of the segment. Tennessee Z5 NY is highly constrained throughout the entire three month peak winter demand period with total demand exceeding pipeline capacity on 90 days. While gas-fired generation across Tennessee Z5 NY is served throughout the peak heating season, substantial transportation constraints materialize downstream due to the demand for shale gas and the limited takeaway capacity across the Tennessee mainline to accommodate gas-fired generators in PJM, NYISO and ISO-NE.

6.2.1.14 Texas Eastern M2 PA – Southern Branch

The Texas Eastern M2 PA – Southern Branch is modeled with a capacity of 2,068 MDth/d. The 100% peak hour utilization on the southern branch of Texas Eastern's Zone M2 segment through Pennsylvania potentially affects generators directly connected to Texas Eastern in Pennsylvania, generators behind LDCs in Pennsylvania, Delaware and downstate New York. Generators that are served by Algonquin and Eastern Shore either directly or behind an LDC would also potentially be affected. The locations of these generators are shown in Figure 93.

Figure 93. Generators Affected by Texas Eastern M2 PA South Constraint

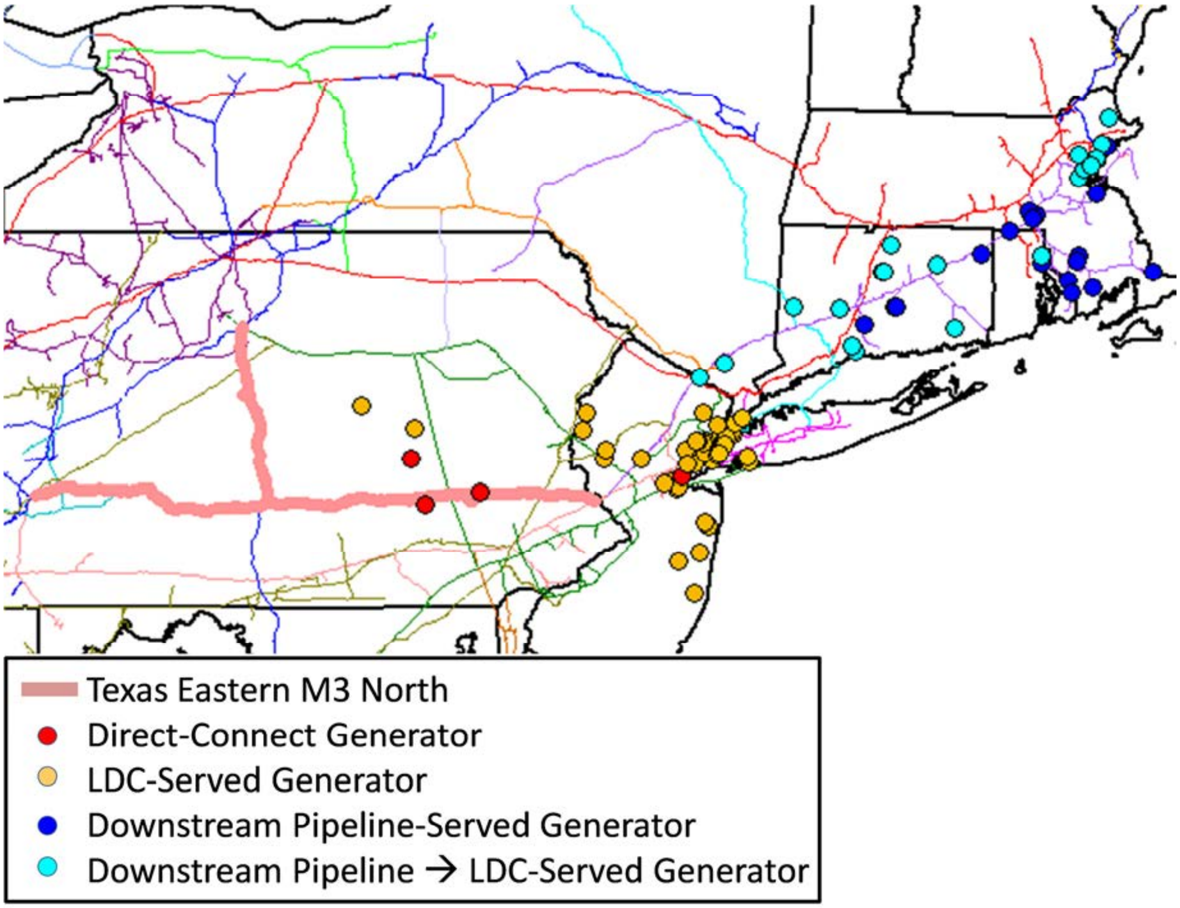


The seasonal daily forecasts of RCI and generator gas demand downstream of the constrained segment are shown in Figure C27 and Figure C28 relative to the capacity of the segment. In light of its strategic location in the heart of Marcellus, this segment is highly utilized throughout the three peak heating season months, with a constraint during the peak hour on 50 days.

6.2.1.15 <u>Texas Eastern M3 – Northern Line</u>

The Texas Eastern M3 Northern Line is modeled with a capacity of 2,987 MDth/d. The 100% peak hour utilization on the Northern line through Pennsylvania potentially affects generators directly connected to Texas Eastern in New Jersey and Pennsylvania, generators behind LDCs served by Texas Eastern in New Jersey, Pennsylvania and downstate New York, as well as generators served by Algonquin both directly and behind LDCs. The locations of these generators are shown in Figure 94.

Figure 94. Generators Affected by Texas Eastern M3 North Constraint

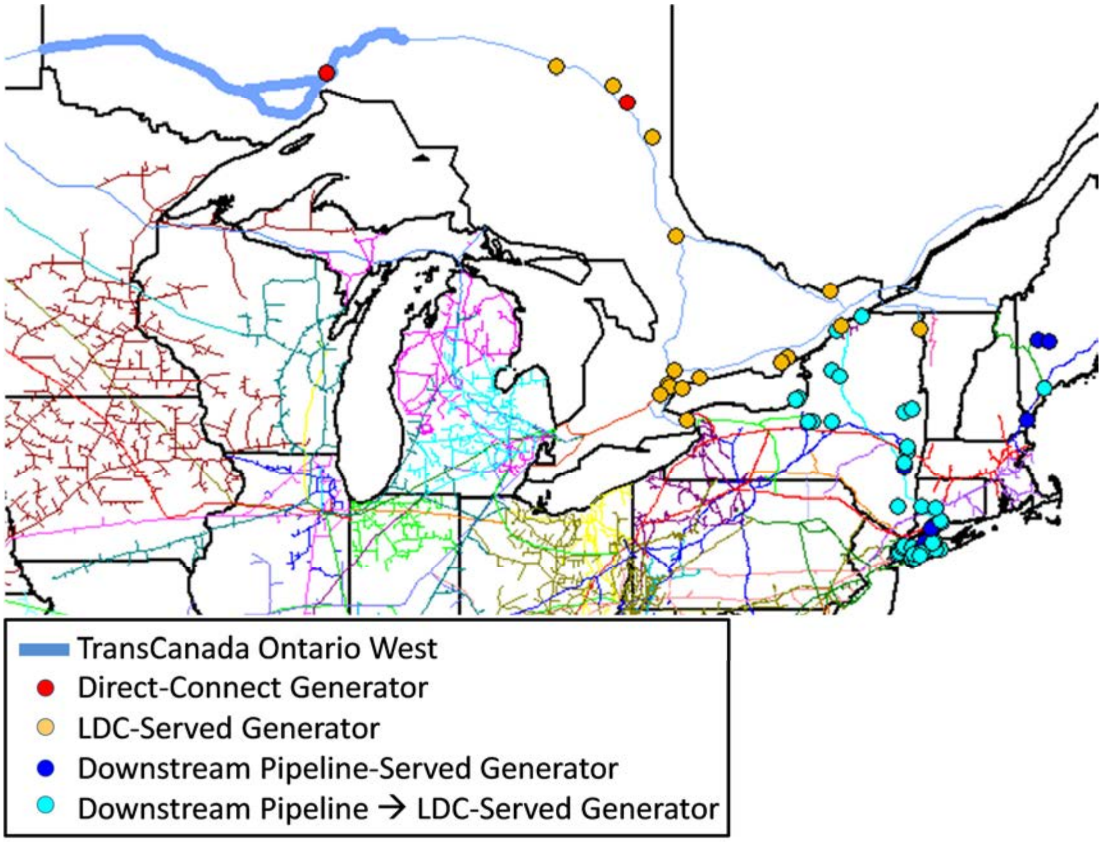


The seasonal daily forecasts of RCI and generator peak hour gas demand downstream of the constrained segment are shown in Figure C29 and Figure C30 relative to the capacity of the segment. FT entitlements on this segment are held primarily by LDCs, producers and marketers with very little FT held directly by generators. Similarly to the previous Texas Eastern constraint, this segment is highly utilized flowing shale gas to market, with peak hour constraints on 39 days during the heating season.

6.2.1.16 <u>TransCanada Ontario West</u>

TransCanada's Western Ontario segment is modeled with a capacity of 3,148 MDth/d. The 100% peak hour utilization on TransCanada's Western Ontario segment potentially affects generators directly connected to TransCanada and generators behind the Enbridge and Union local distribution systems. The locations of these generators are shown in Figure 95.

Figure 95. Generators Affected by TransCanada Western Ontario Constraint

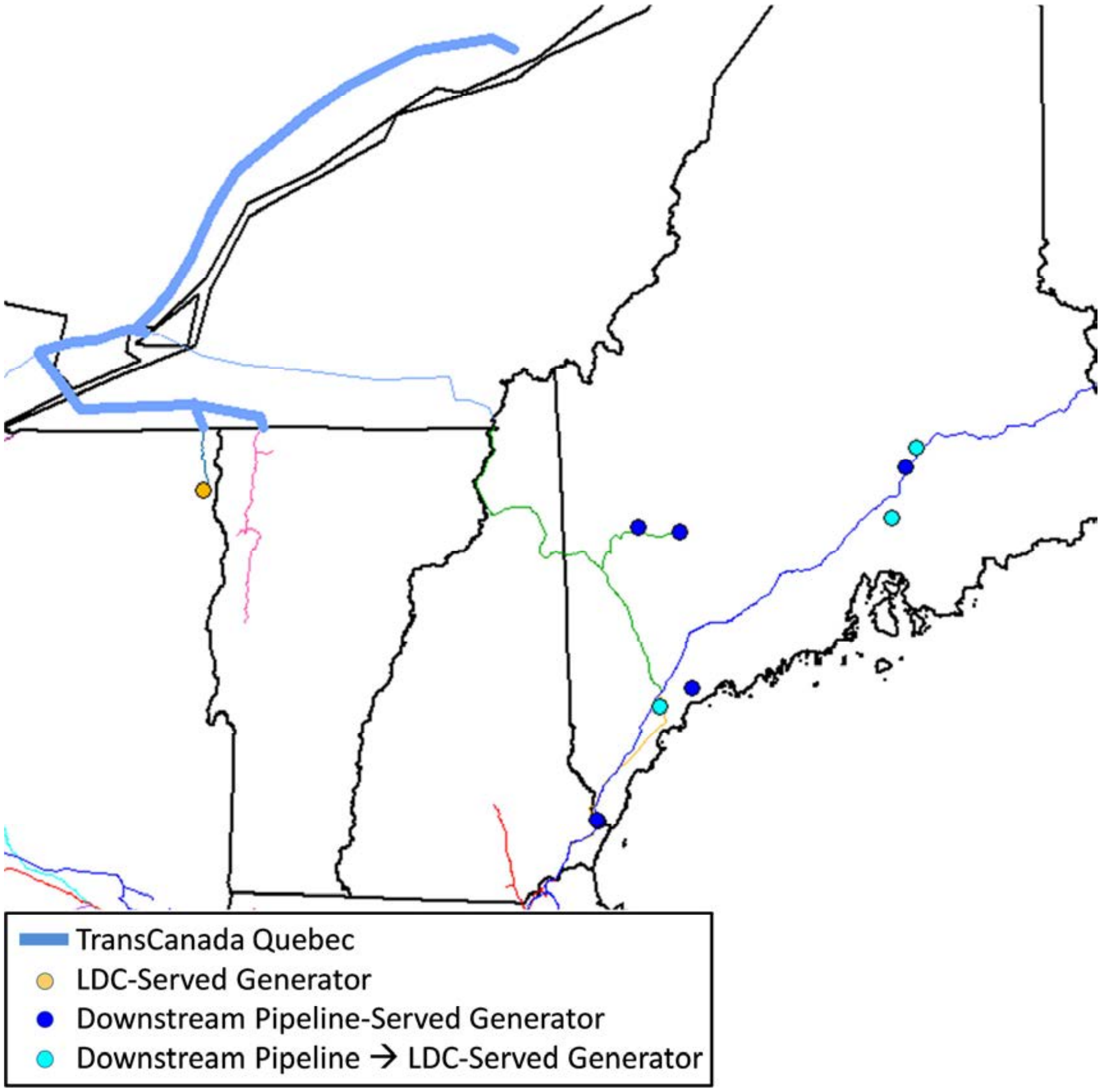


The seasonal daily forecasts of RCI and generator gas demand downstream of the constrained segment are shown in Figure C31 and Figure C32 relative to the capacity of the segment. The majority of gas-fired generators directly connected to TransCanada or served locally by Enbridge or Union have firm transportation entitlements. Some generators served by TransCanada's Western Ontario segment do not have firm transportation entitlements for all or the majority of their respective MDQ's. A comparatively small portion of the scheduled gas-fired generation under S0 price assumptions cannot be served due to the utilization of storage capacity for RCI send-out during the peak hour on the peak day.

6.2.1.17 <u>TransCanada Quebec</u>

TransCanada Quebec is modeled with a capacity of 1,320 MDth/d. The 100% peak hour utilization on TransCanada's Quebec segment potentially affects generators served by PNGTS, North Country and Vermont Gas. The locations of these generators are shown in Figure 96. Limitations for customers in Quebec could arise from this constraint, but such limitations have not been included in the results reported below.

Figure 96. Generators Affected by TransCanada Quebec Constraint

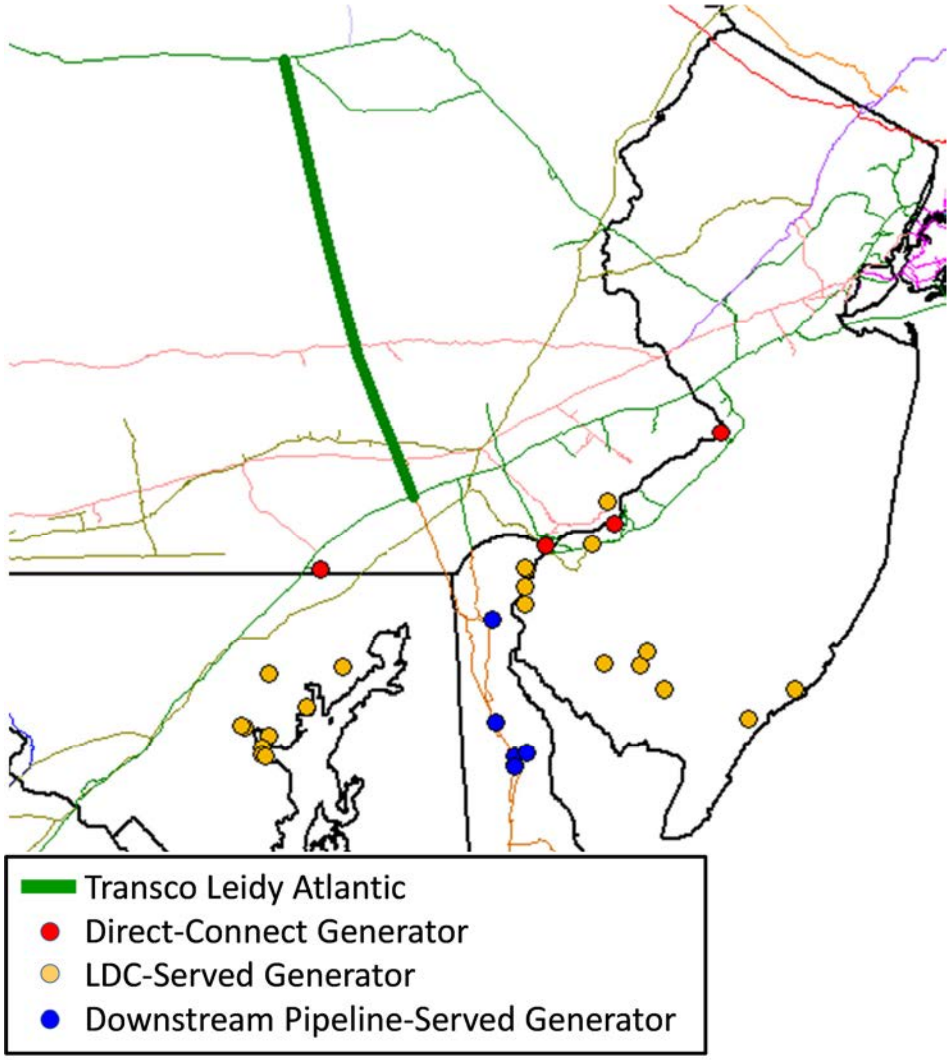


The seasonal daily forecasts of RCI and generator peak hour demand downstream of the constrained segment are shown in Figure C33 and Figure C34 relative to the capacity of the segment. The generator gas demand in these figures includes only gas demand at generators in the Study Region. Gas demand from non-Study Region generators is not included in the tabulation of results.

6.2.1.18 <u>Transco Leidy Atlantic</u>

The Transco Leidy Atlantic segment is modeled with a capacity of 1,700 MDth/d. The 100% peak hour utilization on Transco's Leidy Atlantic segment potentially affects generators directly connected to Transco in New Jersey, Maryland, Pennsylvania and Virginia and generators behind LDCs served by Transco in Delaware, New Jersey, Pennsylvania, Maryland, Virginia and North Carolina. The locations of these generators are shown in Figure 97.

Figure 97. Generators Affected by Transco Leidy Atlantic Constraint

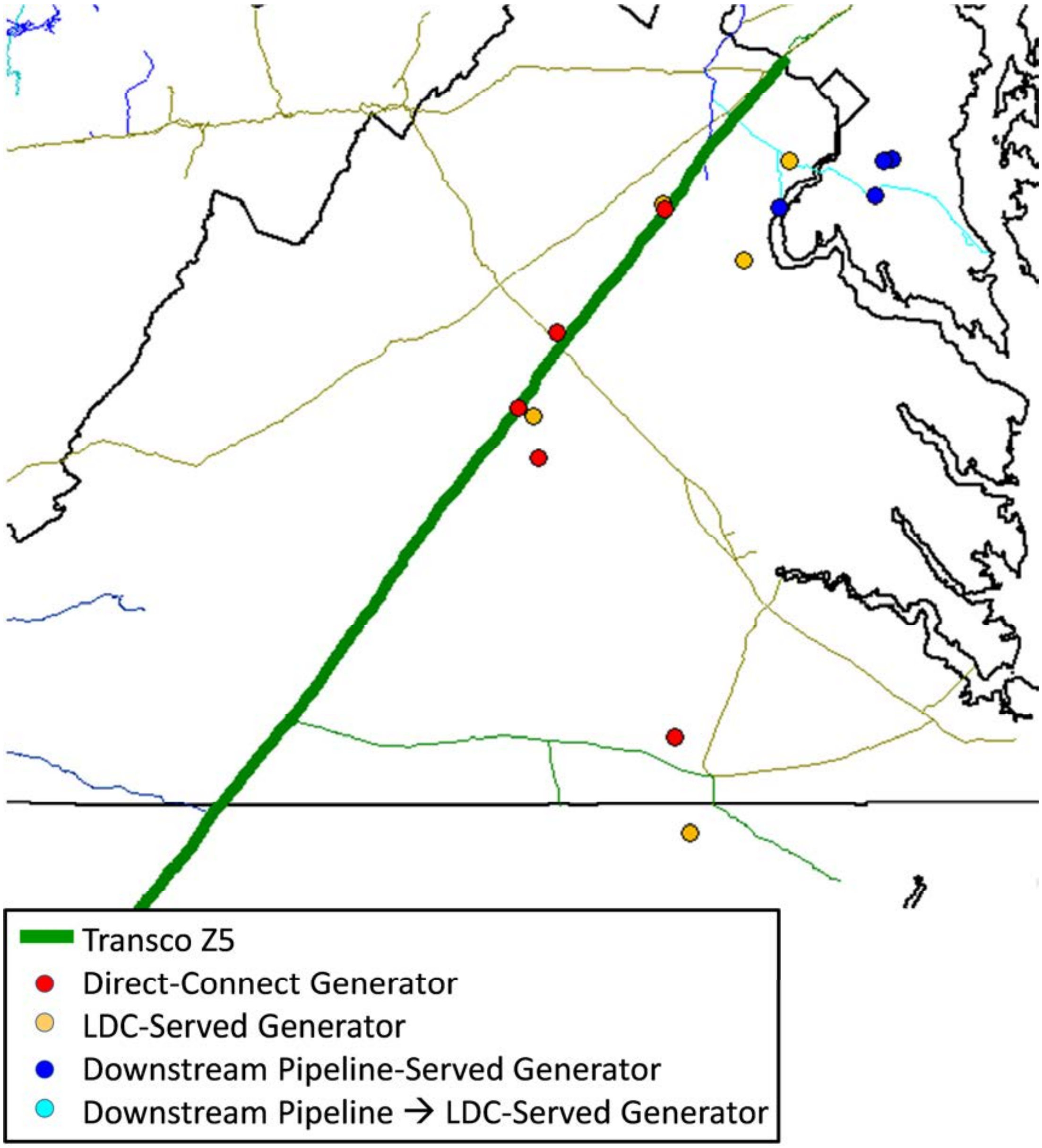


The seasonal daily forecasts of RCI and generator gas demand downstream of the constrained segment are shown in Figure C35 and Figure C36 relative to the capacity of the segment. Transco Leidy Atlantic is a key pathway for moving Marcellus gas to markets in southeastern PJM and the Southeast. Given the lower priced gas that can be accessed through this segment, there are frequent constraints limiting service to gas-fired generators in southeastern PJM during the peak hour of 59 days during the heating season.

6.2.1.19 Transco Zone 5

Transco Zone 5 is modeled with a capacity of 3,967 MDth/d. The 100% peak hour utilization on Transco's Zone 5 segment potentially affects Study Region generators directly connected to Transco in Virginia and generators behind LDCs served by Transco in North Carolina and Virginia. The locations of these generators are shown in Figure 98. Non-Study Region generators in North Carolina and South Carolina could also be affected, but are not included in the results shown below.

Figure 98. Generators Affected by Transco Zone 5 Constraints

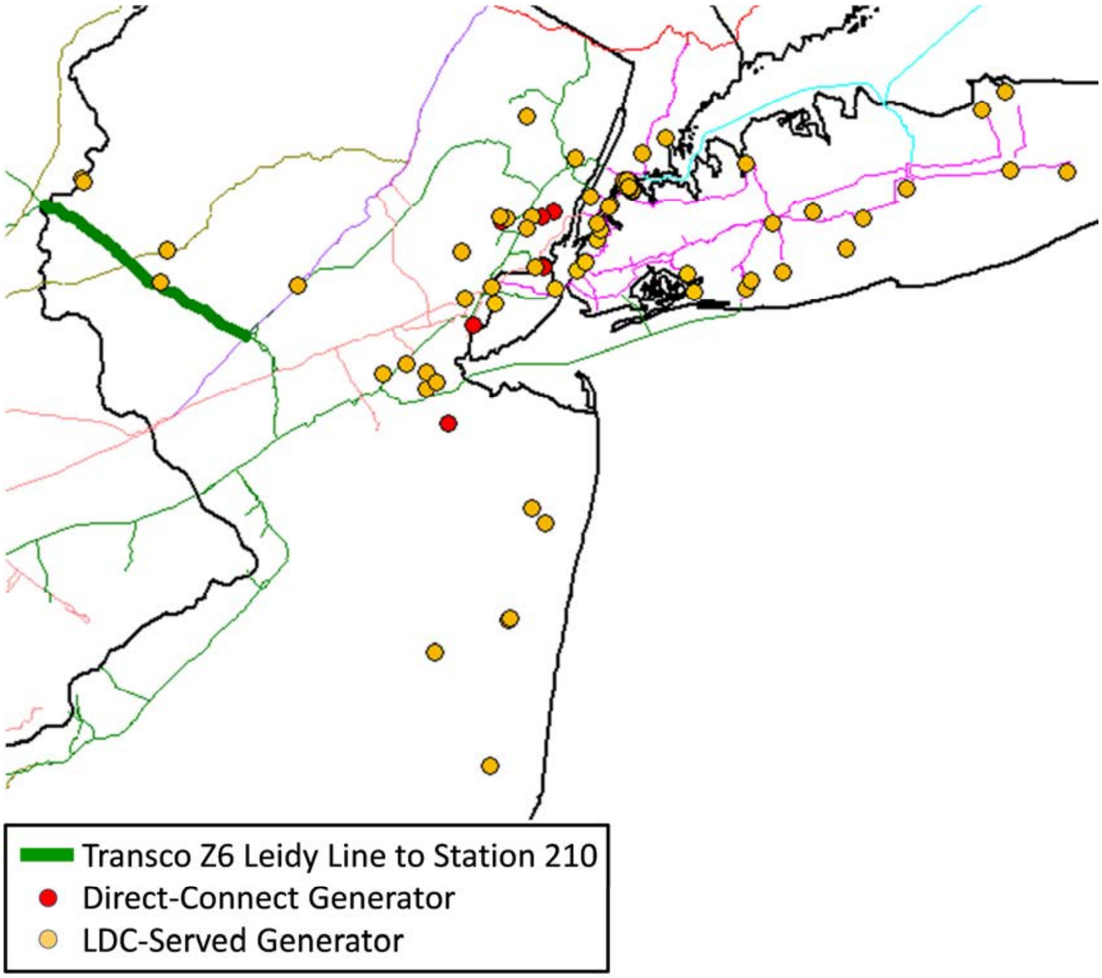


The seasonal daily forecasts of RCI and generator gas demand downstream of the constrained segment are shown in Figure C37 and Figure C38 relative to the capacity of the segment. A constraint is seen during the peak hour on nine days during the heating season. The generator gas demand in these figures includes only gas demand at generators in the Study Region. Transco Zone 5 shows low gas-fired generation in Virginia on a peak winter day, attributable to much lower prices on Dominion South Point.

6.2.1.20 Transco Zone 6 Leidy Line to Station 210

The Transco Zone 6 Leidy to Station 210 segment is modeled with a capacity of 3,310 MDth/d. The 100% peak hour utilization on this segment potentially affects generators directly connected to Transco in New Jersey and Pennsylvania and generators behind LDCs served by Transco in New Jersey, Pennsylvania, New York City and Long Island. The locations of generators served along this Transco segment are shown in Figure 99.

Figure 99. Generators Affected by Transco Leidy Line to Station 210 Constraint

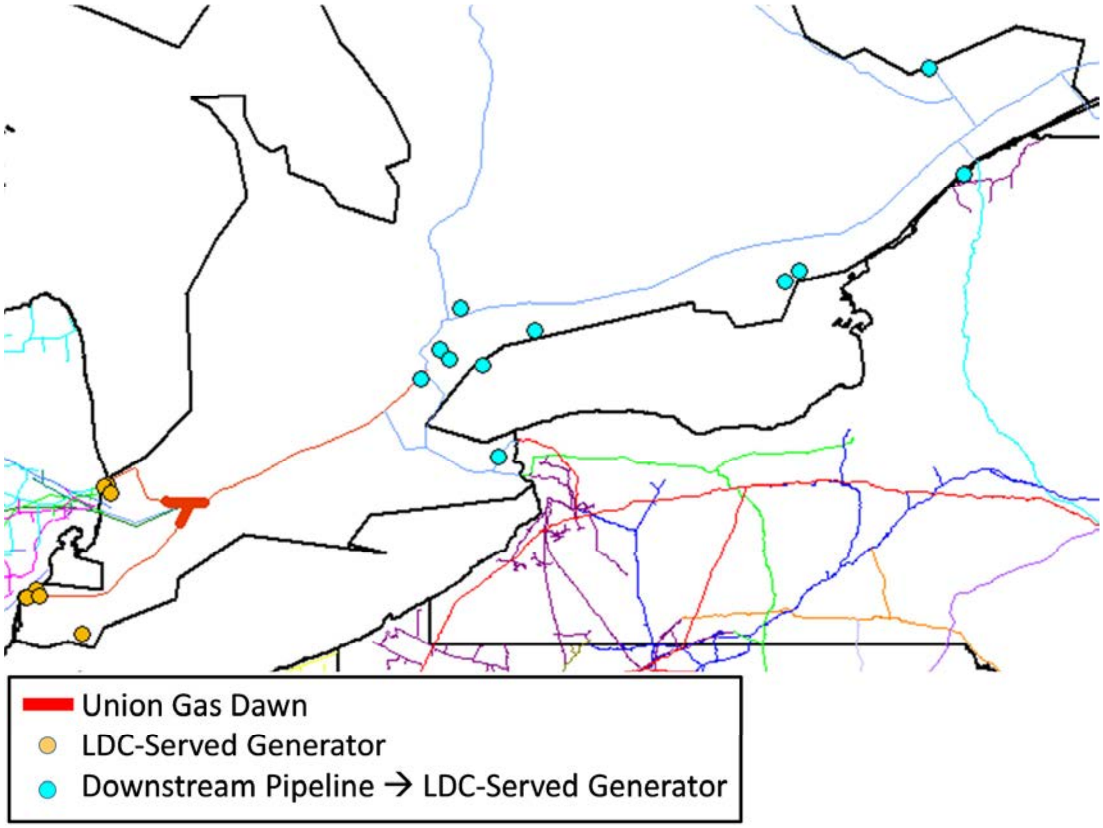


The seasonal daily forecasts of RCI and generator gas demand downstream of the constrained segment are shown in Figure C39 and Figure C40 relative to the capacity of the segment. The Leidy Line to Station 210 is a major pathway for the delivery of Marcellus gas into the Transco Zone 6-NY and Zone 6-NNY market areas, including some of the highest concentration of LDC loads in the U.S. This constraint is estimated to occur during the peak hour of eight days during the heating season, with minimal excess demand relative to the segment capacity.

6.2.1.21 Union Gas Dawn

The 100% peak hour utilization on Union Gas's Dawn segment, which is modeled with a capacity of 5,000 MDth/d, potentially affects generators directly connected to Union, generators directly connected to TransCanada, and generators served by the Union Gas and Enbridge distribution systems. The locations of these generators are shown in Figure 100.

Figure 100. Generators Affected by Union Gas Dawn Constraint



The seasonal daily forecasts of RCI and generator peak hour gas demand downstream of the constrained segment are shown in Figure C41 and Figure C42 relative to the capacity of the segment. Pipeline capacity on Union is adequate to meet total demand for all but four days. The preponderance of the volumes shipped on this segment reflects firm RCI demands, with negligible unserved generator gas demand that could potentially be met by supplies flowing on unconstrained paths.

6.2.2 RGDS S0 – Summer 2018

Figure 101 summarizes the affected generation during the Summer 2018 peak hour by PPA for RGDS S0. Almost all of the peak hour electric generation gas demand is served with the exception of relatively small amounts in southern Illinois and southeastern PJM (Maryland, Delaware and Virginia).

Figure 101. RGDS S0 Summer 2018: Peak Hour Affected Generation

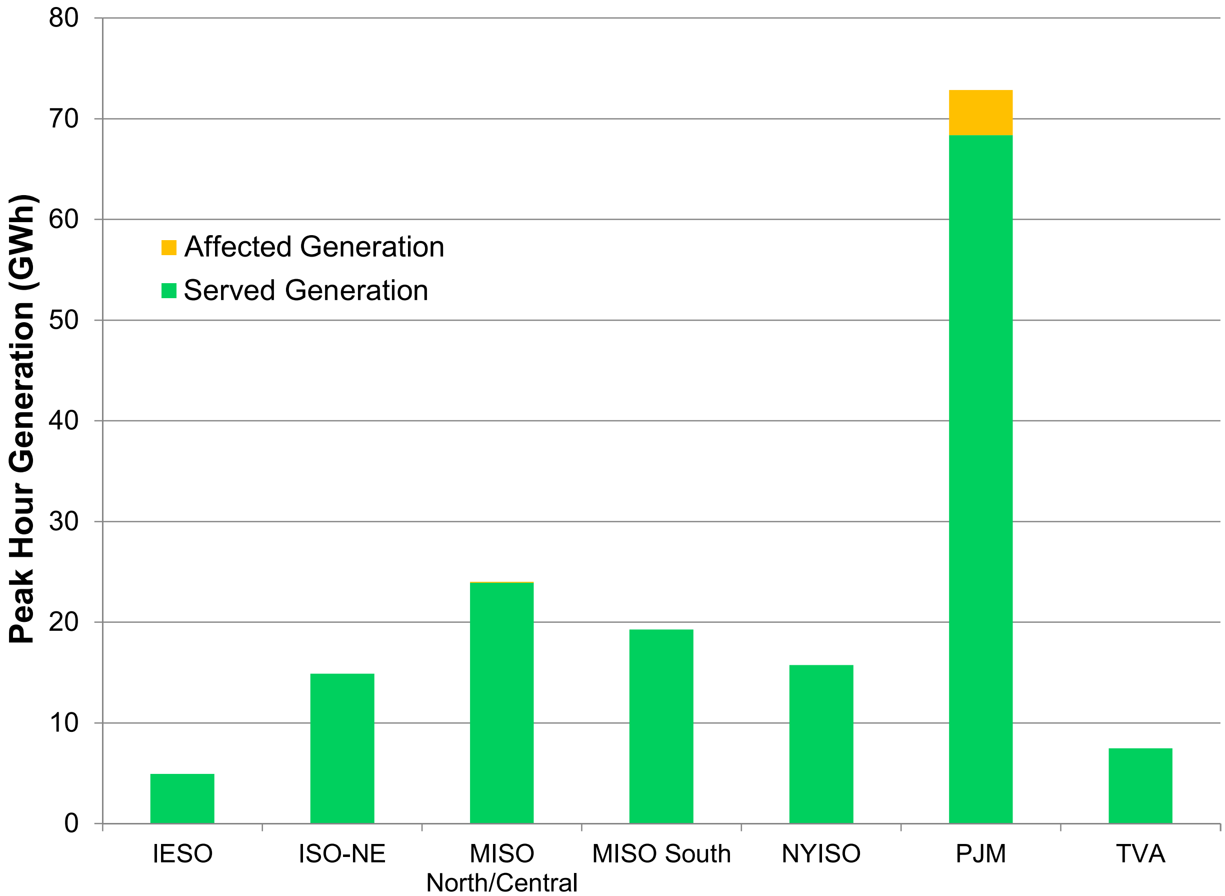


Figure 102 illustrates the GPCM locations with unserved generator gas demand. The unserved demand and resultant affected generation by location are quantified in Table 19. The quantity of affected generation in southern Illinois is small in relation to total gas-fired generation scheduled to be operating on the peak hour of the Summer peak day in 2018. The quantity of affected generation in Virginia on the peak hour of the Summer peak day in 2018 is significant, however. Relative to Virginia, unserved gas demand and affected generation in MAAC – both SWMAAC and EMAAC – are much higher, particularly in the Delmarva Peninsula.

Figure 102. RGDS S0 Summer 2018: GPCM Locations with Peak Hour Affected Generation

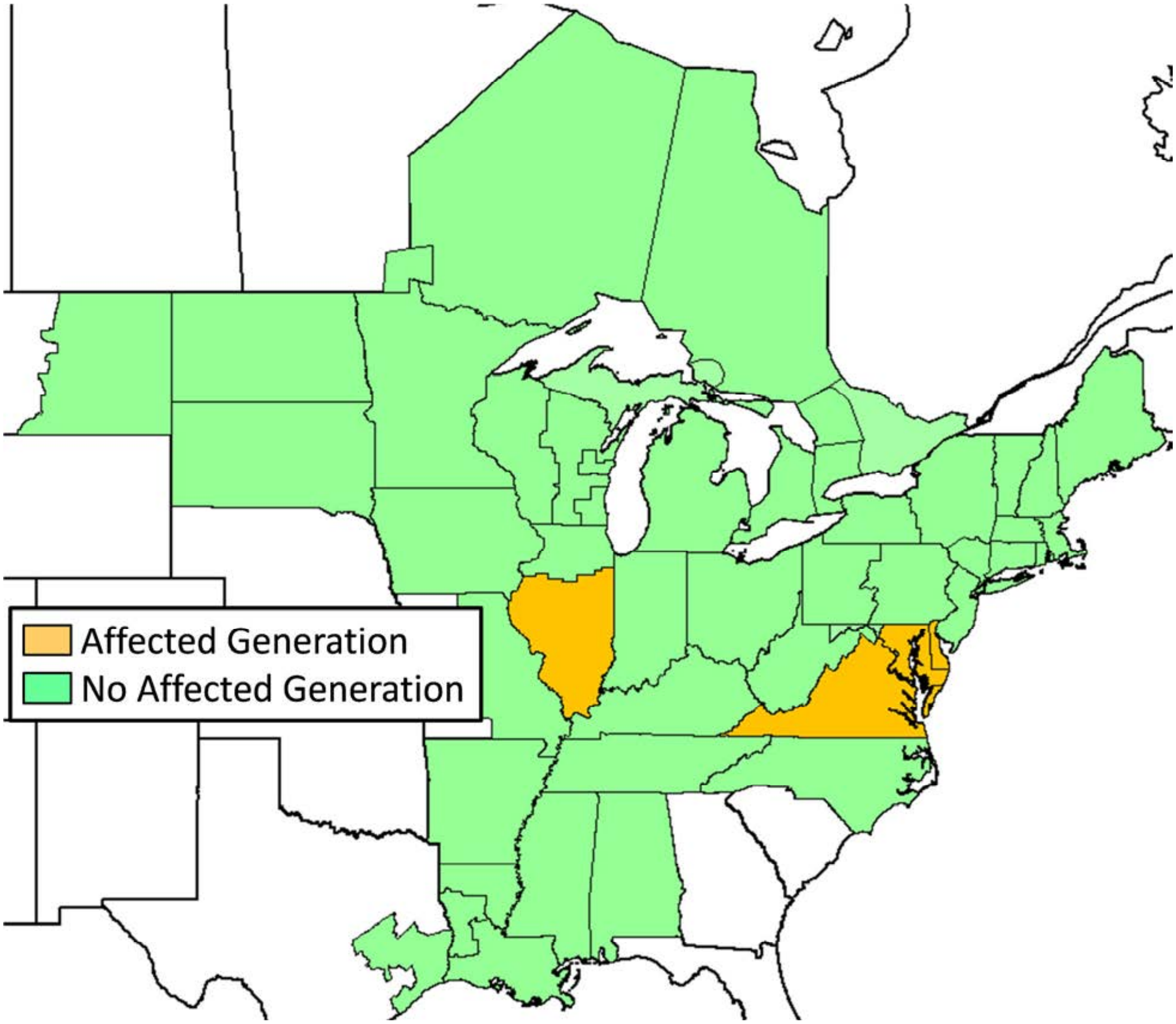


Table 19. RGDS S0 Summer 2018: Peak Hour Unserved Generator Gas Demand and Affected Generation

GPCM Location	Unserved Generator Gas Demand (MDth)	Affected Generation (MWh)
Delaware	9.0	1,217
Illinois Southern	1.0	110
Maryland Eastern	16.7	2,361
Virginia	8.4	936

Figure 103 shows the constrained pipeline segments that result in gas-fired affected generation during the Summer 2018 peak hour. The RGDS S0 summer constraints involve primarily the lines moving Marcellus gas to the south to generators in Virginia and Maryland, Columbia Gas VA/MD and Dominion Southeast as well as flows along Transco in the Zone 5 market area. The

Eastern Shore segment is limited to serving generators in Delaware and parts of eastern Maryland.

Figure 103. RGDS S0 Summer 2018: Peak Hour Constraints

Table 20 summarizes the results of the frequency and duration analysis, and detailed results by pipeline segment are provided in the following sub-sections.

Table 20. RGDS S0 Summer 2018: Frequency and Duration of Daily Peak Hour Constraints

Constraint	# of Events	Min. Duration (Days)	Max. Duration (Days)	Total # of Days
Columbia Gas VA/MD	1	1	1	1
Dominion Southeast	3	1	2	5
Eastern Shore	7	1	6	19
Texas Eastern Zone ETX	4	1	6	12
Transco Z5	7	2	6	18

6.2.2.1 Columbia Gas Virginia / Maryland

The 100% peak hour utilization on Columbia Gas's Virginia/Maryland segment, which is modeled with a capacity of 2,477 MDth/d, potentially affects generators directly connected to Columbia in Maryland and Virginia, generators behind LDCs served by Columbia Gas in

Maryland and Virginia, and generators served by Dominion Cove Point and PPL Interstate downstream of interconnections with Columbia Gas. The locations of these generators are shown in Figure 80 on page 125.

The seasonal daily forecasts of RCI and generator gas demand downstream of the constrained segment are shown in Figure C43 and Figure C44 relative to the capacity of the segment. There is only one day in which a small amount of generator gas demand exceeds the segment's capacity.

6.2.2.2 Dominion Southeast

Dominion Southeast is modeled with a capacity of 540 MDth/d. The 100% peak hour utilization on Dominion's Southeast segment serving Virginia and Maryland potentially affects generators directly served by Dominion, generators behind LDCs served by Dominion, and generators served by Dominion Cove Point via interconnect. The locations of these generators are shown in Figure 85 on page 130.

The seasonal daily forecasts of RCI and generator gas demand downstream of the constrained segment are shown in Figure C45 and Figure C46 relative to the capacity of the segment. There are 4 days when total demand significantly exceeds segment capacity during the peak hour, and one day with a minor exceedance.

6.2.2.3 Eastern Shore

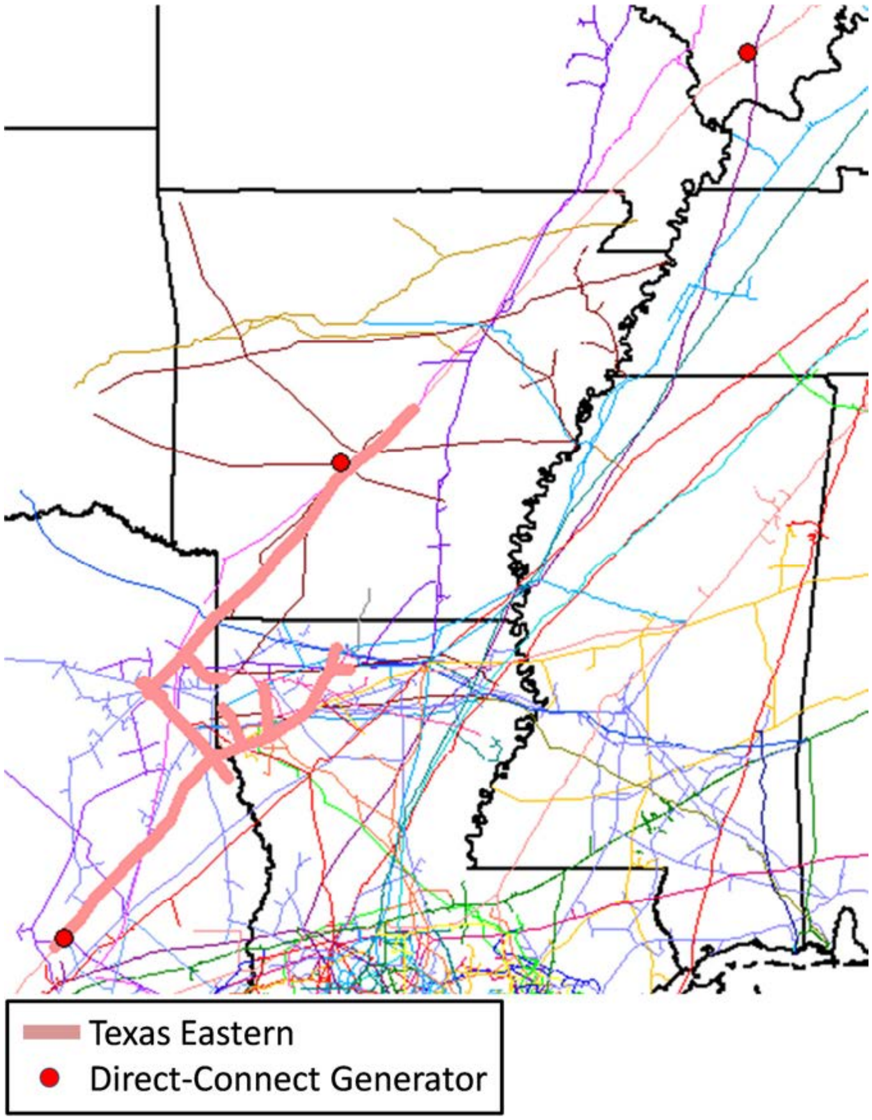
Eastern Shore is modeled with a capacity of 203 MDth/d. The 100% peak hour utilization rate on Eastern Shore's Receipt Zone 1 and Delivery Zone 2 potentially affects generators on the Delmarva Peninsula that are served by Eastern Shore. The locations of these generators are shown in Figure 87 on page 132.

The seasonal daily forecasts of RCI and generator gas demand downstream of the constrained segments are shown in Figure C47 and Figure C48 relative to the capacity of the segments. All of the summer RCI demand is easily served by Eastern Shore. Despite the decline in RCI demand during the summer, during 18 of the 19 days with unserved demand significant amounts of generator gas demand would be unserved under the RGDS S0 price assumptions.

6.2.2.4 Texas Eastern Zone ETX

The 100% peak hour utilization on Texas Eastern's East Texas segment, which is modeled with a capacity of 623 MDth/d, potentially affects generators directly connected to Texas Eastern in Texas, Arkansas and Illinois. The locations of these generators are shown in Figure 104.

Figure 104. Generators Affected by Texas Eastern ETX Constraint



The seasonal daily forecasts of RCI and generator gas demand downstream of the constrained segment are shown in Figure C49 and Figure C50 relative to the capacity of the segment. While the preponderance of gas-fired generation can be served along Texas Eastern's Zone ETX segment, there is significant potentially unserved generator gas demand in southern Illinois, in particular.

6.2.2.5 Transco Zone 5

Transco Zone 5 is modeled with a capacity of 3,967 MDth/d. The 100% peak hour utilization on Transco's Zone 5 segment potentially affects Study Region generators directly connected to Transco in Virginia and generators behind LDCs served by Transco in North Carolina and Virginia. The locations of these generators are shown in Figure 98 on page 143. Non-Study Region generators in North Carolina and South Carolina could also be affected, but are not included in the results shown below.

The seasonal daily forecasts of RCI and generator gas demand downstream of the constrained segment are shown in Figure C51 and Figure C52 relative to the capacity of the segment. Despite the decreased RCI demand during the summer, total demand significantly exceeds pipeline capacity on 14 of the 18 days with a peak hour constraint under the RGDS S0 assumptions.

6.2.3 RGDS S0 and RGDS S1 – Winter 2023

Figure 105 summarizes the affected generation during the Winter 2023 peak hour by PPA for RGDS S0 and RGDS S1. The level of gas-fired generation and gas-fired affected generation in 2023 is substantially the same as that shown in 2018 in five of six PPAs. The exception is IESO, where the level of gas-fired generation is much higher than in 2018 due to nuclear retirements and more nuclear units out of service during refurbishment. In light of Ontario's vast pipeline and storage infrastructure as well as the amount of gas-fired generation with firm entitlements, the level of gas-fired affected generation in Ontario in 2023 does not materially increase, however.

The generally lower gas demand in RGDS S1 reflect the higher peak day gas prices assumed and the additional coal and oil-fired generation that is dispatched. TVA's gas-fired generation increases slightly in RGDS S1 because its plants have pricing similar to Henry Hub, which did not increase much on January 2014 cold days. Likewise, IESO gas-fired generation increases slightly because its generators obtaining gas indexed to AECO did not experience a significant price increase. TVA and IESO had a comparative advantage in natural gas dispatch costs in RGDS S1 compared to other areas, such as the Northeast, which experienced large bases over Henry Hub in January 2014. Higher LMPs resulting from the S1 peak day gas price assumptions allowed slightly more gas generation in TVA and IESO to be economic.

Figure 105. RGDS S0 v. S1 Winter 2023: Peak Hour Affected Generation

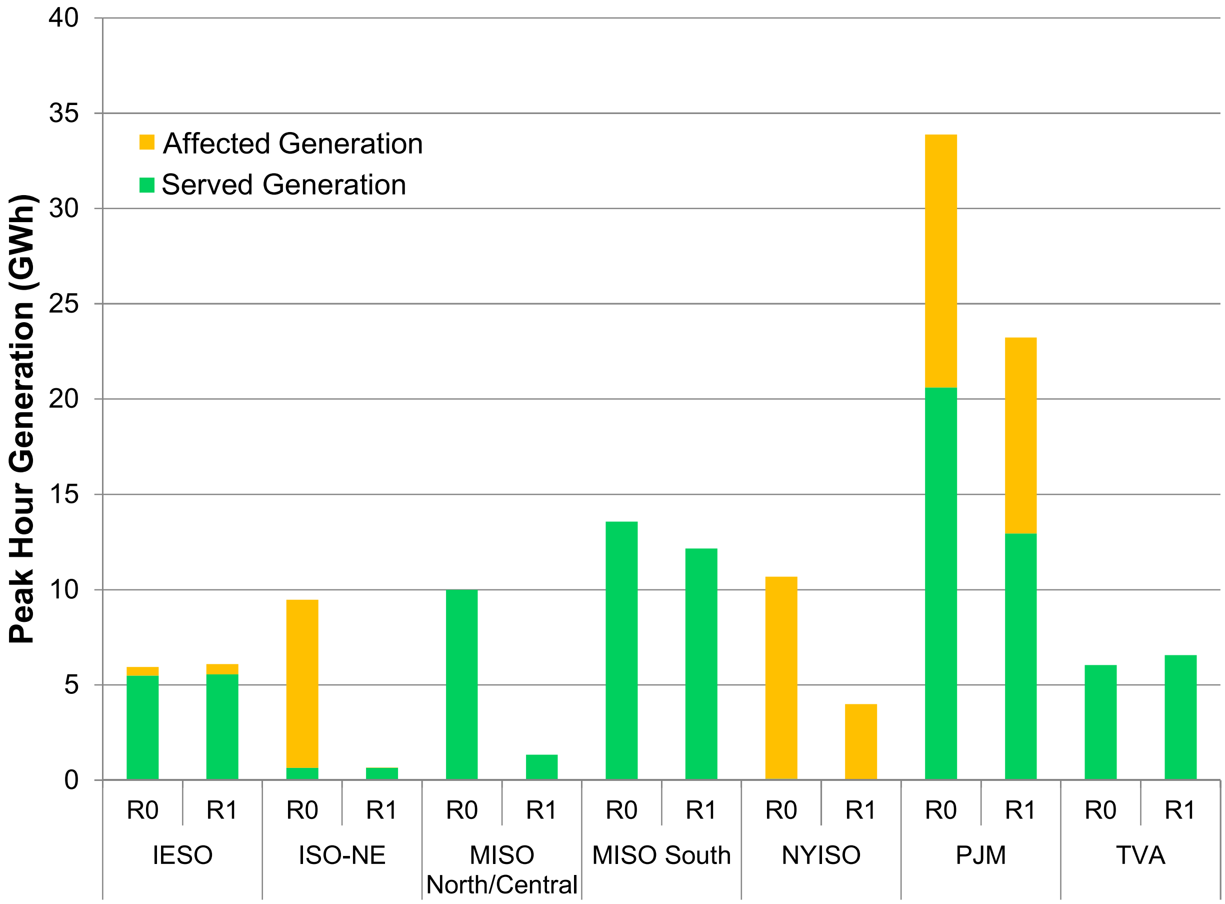


Figure 106 illustrates the GPCM locations with unserved generator gas demand. The unserved gas demand and resultant affected generation by location are quantified in Table 21.

Figure 106. RGDS S0 v. S1 Winter 2023: GPCM Locations with Peak Hour Affected Generation

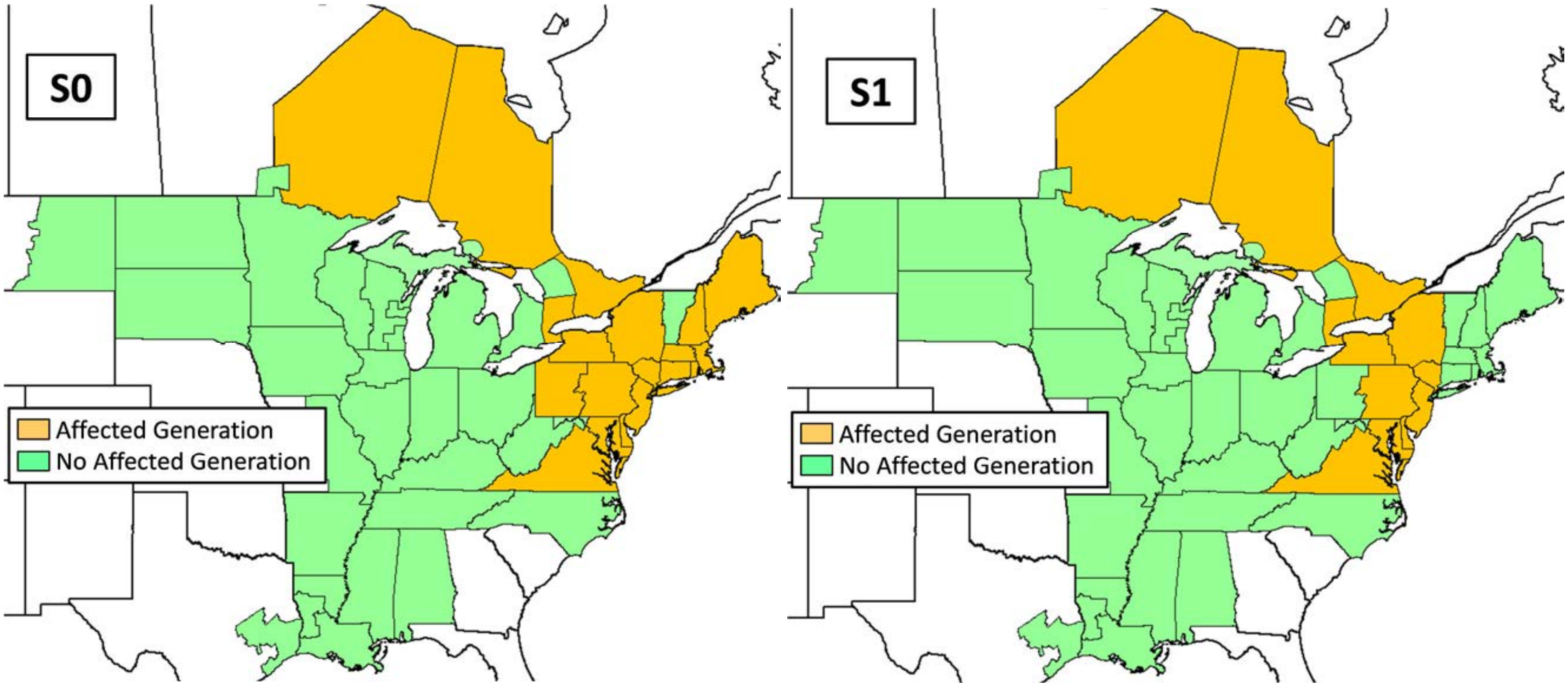


Table 21. RGDS S0 v. RGDS S1 Winter 2023: Peak Hour Unserved Generator Gas Demand and Affected Generation

GPCM Location	S0 Unserved Generation Gas Demand (MDth)	S0 Affected Generation (MWh)	S1 Unserved Generation Gas Demand (MDth)	S1 Affected Generation (MWh)
Connecticut	15.6	2,140.2	0.0	0.0
Delaware	1.3	172.6	0.1	9.1
Maine	9.1	1,231.9	0.0	0.0
Maryland Eastern	5.0	538.9	3.3	311.5
Massachusetts Eastern	14.6	2,024.7	0.0	0.0
Massachusetts Western	9.3	1,239.4	0.0	0.0
New Hampshire	9.4	1,244.6	0.0	0.0
New Jersey	10.7	1,371.8	0.7	92.6
New York Central Northern	40.1	4,764.2	23.1	2,259.4
New York City	19.8	2,665.2	0.0	0.0
New York Long Island	12.8	1,291.8	0.0	0.0
New York Southern	15.1	1,628.8	14.3	1,537.2
New York Western	2.2	247.2	1.7	196.2
Ontario (CDA)	0.5	55.1	0.5	55.1
Ontario (EDA)	2.1	249.1	2.1	249.1
Ontario (NDA)	1.2	154.5	1.5	186.2
Ontario (WDA)	0.0	0.0	0.4	38.0
Pennsylvania Eastern	43.5	5,989.5	44.4	5,630.6
Pennsylvania Western	6.7	960.7	0.0	0.0
Rhode Island	7.1	935.5	0.0	0.0
Virginia	35.4	4,237.3	35.4	4,237.3

Figure 107 shows the constrained pipeline segments that result in the affected generation for S0 and S1 during the Winter 2023 peak hour.

Figure 107. RGDS S0 v. S1 Winter 2023: Constraints

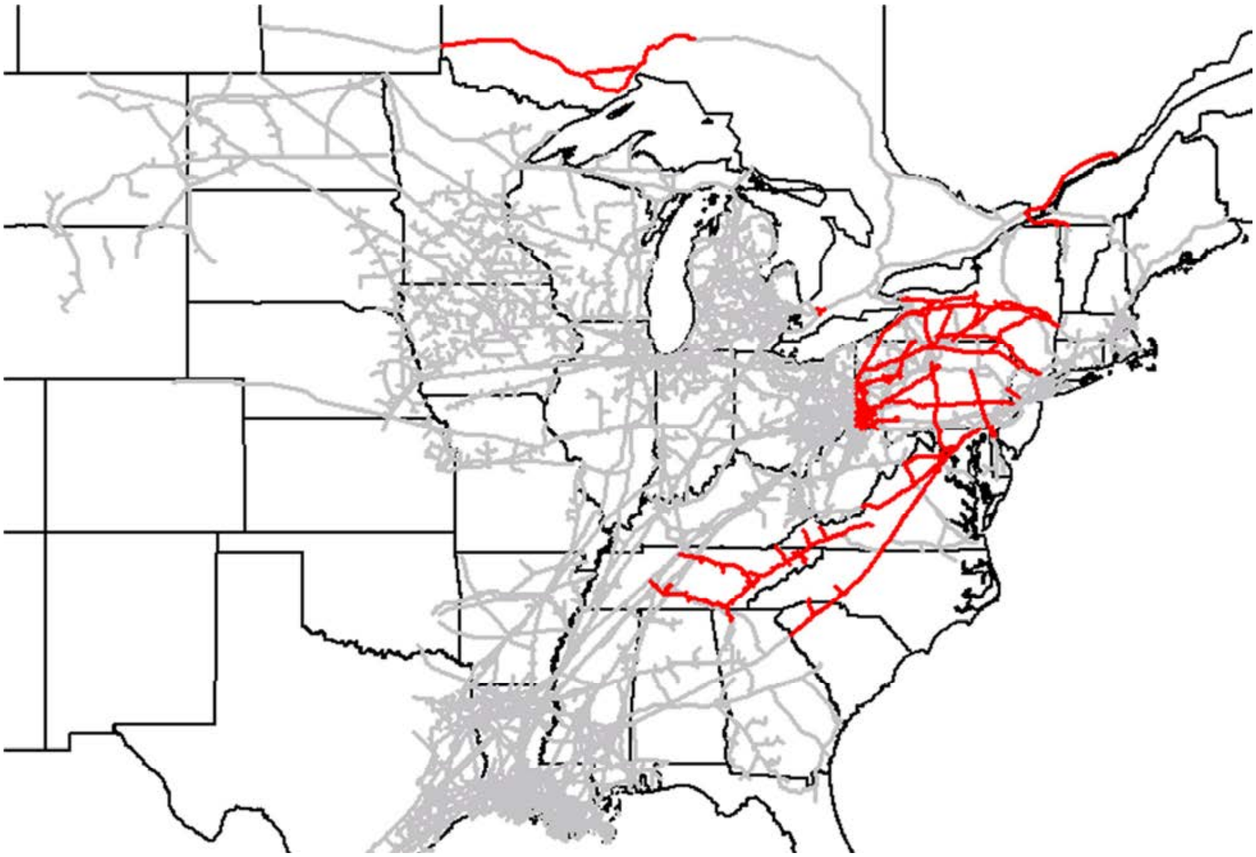


Table 22 summarizes the results of the frequency and duration analysis. Detailed charts are provided in the following subsections.

Table 22. RGDS S0 Winter 2023: Frequency and Duration of Daily Peak Hour Constraints

Constraint	# of Events	Min. Duration (Days)	Max. Duration (Days)	Total # of Days
Columbia Gas VA/MD	6	1	52	80
Columbia Gas W PA/NY	15	1	5	28
Constitution	2	31	59	90
Dominion Eastern NY	9	1	16	58
Dominion Western NY	1	5	5	5
Dominion Southeast	4	1	52	85
East Tennessee Mainline	5	1	5	11
Eastern Shore	12	1	15	63
Empire Mainline	8	1	44	61
Millennium	7	1	37	68
NB/NS Supply	2	31	59	90
Tennessee Z4 PA	7	1	8	25
Tennessee Z5 NY	3	1	59	89
Texas Eastern M2 PA South	7	1	46	81
Texas Eastern M3 North	6	1	17	47
TransCanada Ontario West	4	1	6	11
TransCanada Quebec	6	1	14	34
Transco Leidy Atlantic	3	4	59	89
Transco Z5	8	1	2	9
Transco Z6 Leidy to 210	5	1	55	86
Union Gas Dawn	3	1	2	4

Generally, the congestion patterns are similar to those observed for the winter 2018 peak day, though with a higher overall level of gas demand and therefore somewhat more gas constraints. This is explained by the inclusion of additional load growth from 2018 through 2023. Consistent with the congestion patterns observed in 2018, the primary constraints are located on the pipeline segments serving the Northeast in the northern portion of PJM as well as Western and central New York.

6.2.3.1 Columbia Gas Virginia / Maryland

The 100% peak hour utilization on Columbia Gas's Virginia/Maryland segment, which is modeled with a capacity of 2,679 MDth/d, an increase of 202 MDth/d over the 2018 capacity. The locations of the potentially affected generators are shown in Figure 80 on page 125.

The seasonal daily forecasts of RCI and generator gas demand downstream of the constrained segment are shown in Figure C53 and Figure C54 relative to the capacity of the segment. The total number of days in which demand exceeded pipeline capacity increased to 80 from 23 in 2018 reflecting demand growth that exceeded the increase in capacity.

6.2.3.2 Columbia Gas Western Pennsylvania / New York

The 100% peak hour utilization on Columbia Gas's Western Pennsylvania / New York segment, which is modeled with a capacity of 1,131 MDth/d, no increase from the 2018 capacity. The locations of the potentially affected generators are shown in Figure 81 on page 126.

The seasonal daily forecasts of RCI and generator gas demand downstream of the constrained segment are shown in Figure C55 and Figure C56 relative to the capacity of the segment. The total number of days in which demand exceeded pipeline capacity increases by 7 days relative to 2018.

6.2.3.3 Constitution Pipeline

Constitution's proposed delivery capacity is 650 MDth/d unchanged from 2018. The 100% peak hour utilization on Constitution potentially affects generators served by Iroquois both directly and behind LDCs. The locations of these generators are shown in Figure 82 on page 127.

The seasonal daily forecasts of RCI and generator gas demand downstream of the constrained segment are shown in Figure C57 and Figure C58 relative to the capacity of the segment. Because Constitution links upstate New York, New England and southern Ontario to low-cost Marcellus supply, Constitution's capacity factor is likely to remain high irrespective of downstream demand levels on Iroquois, as interconnections would enable flow to other downstream customers. The total number of days in which demand exceeded pipeline capacity increases materially to 90 days from 25 days in 2018.

6.2.3.4 Dominion Eastern New York

Dominion's Eastern New York segment is modeled with a capacity of 907 MDth/d, no change from the 2018 capacity. The locations of the potentially affected generators are shown in Figure 83 on page 128.

The seasonal daily forecasts of RCI and generator gas demand downstream of the constrained segment are shown in Figure C59 and Figure C60 relative to the capacity of the segment. The total number of days in which total demand exceeded the pipeline capacity increases from 15 in 2018 to 58 in 2023.

6.2.3.5 Dominion Western New York

Dominion Western New York is modeled with a capacity of 557 MDth/d, unchanged from 2018. The locations of the potentially affected plants in each category are shown in Figure 84 on page 129.

The seasonal daily forecasts of RCI and generator gas demand downstream of the constrained segment are shown in Figure C61 and Figure C62 relative to the capacity of the segment. There is virtually no change relative to 2018 in the total number of days in which demand exceeds pipeline capacity.

6.2.3.6 Dominion Southeast

Dominion Southeast is modeled with a capacity of 555 MDth/d, an increase of 15 MDth/d over 2018. The locations of the potentially affected generators are shown in Figure 85 on page 130.

The seasonal daily forecasts of RCI and generator gas demand downstream of the constrained segment are shown in Figure C63 and Figure C64 relative to the capacity of the segment. The total number of days in which demand exceeded pipeline capacity increases substantially to 85 from 22 days in 2018.

6.2.3.7 East Tennessee Mainline

The East Tennessee mainline is modeled with a capacity of 800 MDth/d, unchanged from the 2018 capacity. The locations of the potentially affected generators are shown in Figure 86 on page 131.

The seasonal daily forecasts of RCI and generator gas demand downstream of the constrained segment are shown in Figure C65 and Figure C66 relative to the capacity of the segment. The total number of days for which demand exceeds pipeline capacity increases by two days over 2018.

6.2.3.8 Eastern Shore

Eastern Shore is modeled with a capacity of 203 MDth/d, the same capacity as modeled for 2018. The locations of the potentially affected generators are shown in Figure 87 on page 132.

The seasonal daily forecasts of RCI and generator gas demand downstream of the constrained segments are shown in Figure C67 and Figure C68 relative to the capacity of the segments. The total number of days for which total demand exceeds pipeline capacity increases to 63 days in 2023 as compared with 51 days in 2018.

6.2.3.9 Empire Mainline

The Empire mainline is modeled with a capacity of 525 MDth/d, unchanged from the capacity modeled in 2018. The locations of the potentially affected generators are shown in Figure 88 on page 133.

The seasonal daily forecasts of RCI and generator gas demand downstream of the constrained segment are shown in Figure C69 and Figure C70 relative to the capacity of the segment. The total number of days for which demand exceeds pipeline capacity increases substantially from 16 in 2018 to 60 in 2023.

6.2.3.10 Millennium

Millennium is modeled with a capacity of 784 MDth/d, unchanged from the capacity modeled for 2018. The locations of the potentially affected generators are shown in Figure 89 on page 134.

The seasonal daily forecasts of RCI and generator gas demand downstream of the constrained segment are shown in Figure C71 and Figure C72 relative to the capacity of the segment. Because it links Marcellus supply to markets in New York, New England and Ontario, Millennium's capacity factor is expected to be high. The total number of days for which demand exceeds pipeline capacity declines to 68 days from 83 days in 2018. The reduction in the frequency of transportation constraints reflects the change in relative interconnection flows into Algonquin from 2018 to 2023.

6.2.3.11 New Brunswick Supply / Nova Scotia Offshore Supply

Limitations on Atlantic Canada production have a direct bearing on available supply to meet the gas requirements of generators in Northern New England. Production from Atlantic Canada reaches approximately 40 MDth/d, an increase of 16 MDth/d over 2018 in New Brunswick. Overall, production declines from 599 MDth/d in 2018 to 243 MDth/d in 2023 for Nova Scotia Offshore, reflecting the near depletion of the SOEP wells and the production decline curves for Deep Panuke. In the RGDS, for both 2018 and 2023 LAI assumed that the Canaport LNG import facility will not regasify LNG for sendout to M&N due to supply chain uncertainty affecting destination-flexible cargoes. Even though there is slack deliverability on M&N, insufficient gas production from Atlantic Canada coupled with the loss of Canaport vaporization potentially affects generators directly connected to M&N in Maine and New Hampshire as well as generators located behind LDCs served by M&N in Maine. The locations of these generators are shown in Figure 90 on page 135. Generators located in the Canadian Maritimes would also be affected by this supply constraint, but have not been included in the summary results.

The seasonal daily forecasts of RCI and generator gas demand downstream of the supply limitation are shown in Figure C73 and Figure C74 relative to the total production capacity. The generator gas demand in these figures includes only gas demand at generators in the Study Region; demand from non-Study Region generators is not included. The number of days for which total demand exceeds supply increases from 58 days in 2018 to 90 days in 2023.

6.2.3.12 Tennessee Zone 4 Pennsylvania

Tennessee Zone 4 Pennsylvania is modeled with a capacity of 1,887 MDth/d, reflecting no change in modeled capacity from 2018. The locations of the affected generators are shown in Figure 91 on page 136.

The seasonal daily forecasts of RCI and generator gas demand downstream of the constrained segment are shown in Figure C75 and Figure C76 relative to the capacity of the segment. As a supply segment connected to Marcellus, additional interconnection flows to downstream pipelines would likely utilize the remaining available capacity on days shown here as unconstrained. The total number of days for which demand exceeds pipeline capacity declines from 62 days in 2018 to 25 days in 2023.

6.2.3.13 Tennessee Zone 5 New York

Tennessee Zone 5 New York is modeled with a capacity of 1,189 MDth/d, the same capacity as modeled for 2018. The locations of the affected generators are shown in Figure 92 on page 137.

The seasonal daily forecasts of RCI and generator gas demand downstream of the constrained segment are shown in Figure C77 and Figure C78 relative to the capacity of the segment. The total number of days for which demand exceeds capacity remains essentially the same, 90 days in 2018 as compared with 89 days in 2023.

6.2.3.14 Texas Eastern M2 Pennsylvania – Southern Branch

The Texas Eastern M2 Pennsylvania – Southern Branch is modeled with a capacity of 2,068 MDth/d, unchanged from the capacity modeled for 2018. The locations of the potentially affected generators are shown in Figure 93 on page 138.

The seasonal daily forecasts of RCI and generator gas demand downstream of the constrained segment are shown in Figure C79 and Figure C80 relative to the capacity of the segment. The number of days for which demand exceeds pipeline capacity increases substantially from 50 days in 2018 to 81 days in 2023.

6.2.3.15 Texas Eastern M3 – Northern Line

The Texas Eastern M3 Northern Line is modeled with a capacity of 2,987 MDth/d, unchanged from the capacity modeled for 2018. The locations of the potentially affected generators are shown in Figure 94 on page 139.

The seasonal daily forecasts of RCI and generator gas demand downstream of the constrained segment are shown in Figure C81 and Figure C82 relative to the capacity of the segment. The total number of days for which demand exceeds pipeline capacity increases from 39 days for 2018 to 47 days for 2023.

6.2.3.16 TransCanada Ontario West

TransCanada's Western Ontario segment is modeled with a capacity of 3,148 MDth/d, unchanged from the capacity modeled for 2018. The locations of the potentially affected generators are shown in Figure 95 on page 140.

The seasonal daily forecasts of RCI and generator gas demand downstream of the constrained segment are shown in Figure C83 and Figure C84 relative to the capacity of the segment. The total number of days for which demand exceeds pipeline capacity declines slightly from 12 days in 2018 to 11 days in 2023.

6.2.3.17 TransCanada Quebec

TransCanada Quebec is modeled with a capacity of 1,320 MDth/d, unchanged from the capacity modeled for 2018. The 100% peak hour utilization on TransCanada's Quebec segment potentially affects generators served by PNGTS, North Country, and Vermont Gas. The locations of these generators are shown in Figure 96 on page 141. Customers in Quebec could also be affected by this constraint, but such limitations have not been included in the results reported below.

The seasonal daily forecasts of RCI and generator gas demand downstream of the constrained segment are shown in Figure C85 and Figure C86 relative to the capacity of the segment. The generator gas demand in these figures includes only gas demand at generators in the Study Region. Again, unserved demand from non-Study Region generators is not included in the tabulation of results. The total number of days for which demand exceeds pipeline capacity increases from 30 days in 2018 to 34 days in 2023.

6.2.3.18 Transco Leidy Atlantic

The Transco Leidy Atlantic segment is modeled with a capacity of 1,700 MDth/d, unchanged from the capacity modeled for 2018. The locations of the potentially affected generators are shown in Figure 97 on page 142.

The seasonal daily forecasts of RCI and generator gas demand downstream of the constrained segment are shown in Figure C87 and Figure C88 relative to the capacity of the segment. The total number of days for which demand exceeds pipeline capacity increases significantly from 59 for 2018 to 89 for 2023.

6.2.3.19 Transco Zone 5

Transco Zone 5 is modeled with a capacity of 3,967 MDth/d, the same modeled capacity as for 2018. The 100% peak hour utilization on Transco's Zone 5 segment potentially affects Study Region generators directly connected to Transco in Virginia and generators behind LDCs served by Transco in North Carolina and Virginia. The locations of these generators are shown in Figure 98 on page 143. Non-Study Region generators in North Carolina and South Carolina could also be affected, but are not included in the results shown below.

The seasonal daily forecasts of RCI and generator gas demand downstream of the constrained segment are shown in Figure C89 and Figure C90 relative to the capacity of the segment. The generator gas demand in these figures includes only gas demand at generators in the Study Region. The total number of days for which demand exceeded pipeline capacity is unchanged in 2023 relative to 2018.

6.2.3.20 Transco Zone 6 Leidy Line to Station 210

The Transco Zone 6 Leidy to Station segment is modeled with a capacity of 3,310 MDth/d, unchanged from the capacity modeled for 2018. The locations of the potentially affected generators are shown in Figure 99 on page 144.

The seasonal daily forecasts of RCI and generator gas demand downstream of the constrained segment are shown in Figure C91 and Figure C92 relative to the capacity of the segment. The total number of days for which demand exceeds pipeline capacity dramatically increases from 8 days for 2018 to 86 days for 2023, signifying heightened producer and end-user reliance on the Zone Leidy Line to move Marcellus gas to market.

6.2.3.21 Union Gas Dawn

The 100% peak hour utilization on Union Gas's Dawn segment, which is modeled with a capacity of 5,000 MDth/d, the same capacity modeled for 2018. The locations of the potentially affected generators are shown in Figure 94 on page 145.

The seasonal daily forecasts of RCI and generator gas demand downstream of the constrained segment are shown in Figure C93 and Figure C94 relative to the capacity of the segment. The number of days for which demand exceeds pipeline capacity remains low at 4 days, the same as for 2018.

6.2.4 RGDS S0 Summer 2023

Figure 108 summarizes the affected generation during the Summer 2023 peak hour by PPA.

Figure 108. RGDS S0 Summer 2023: Peak Hour Affected Generation

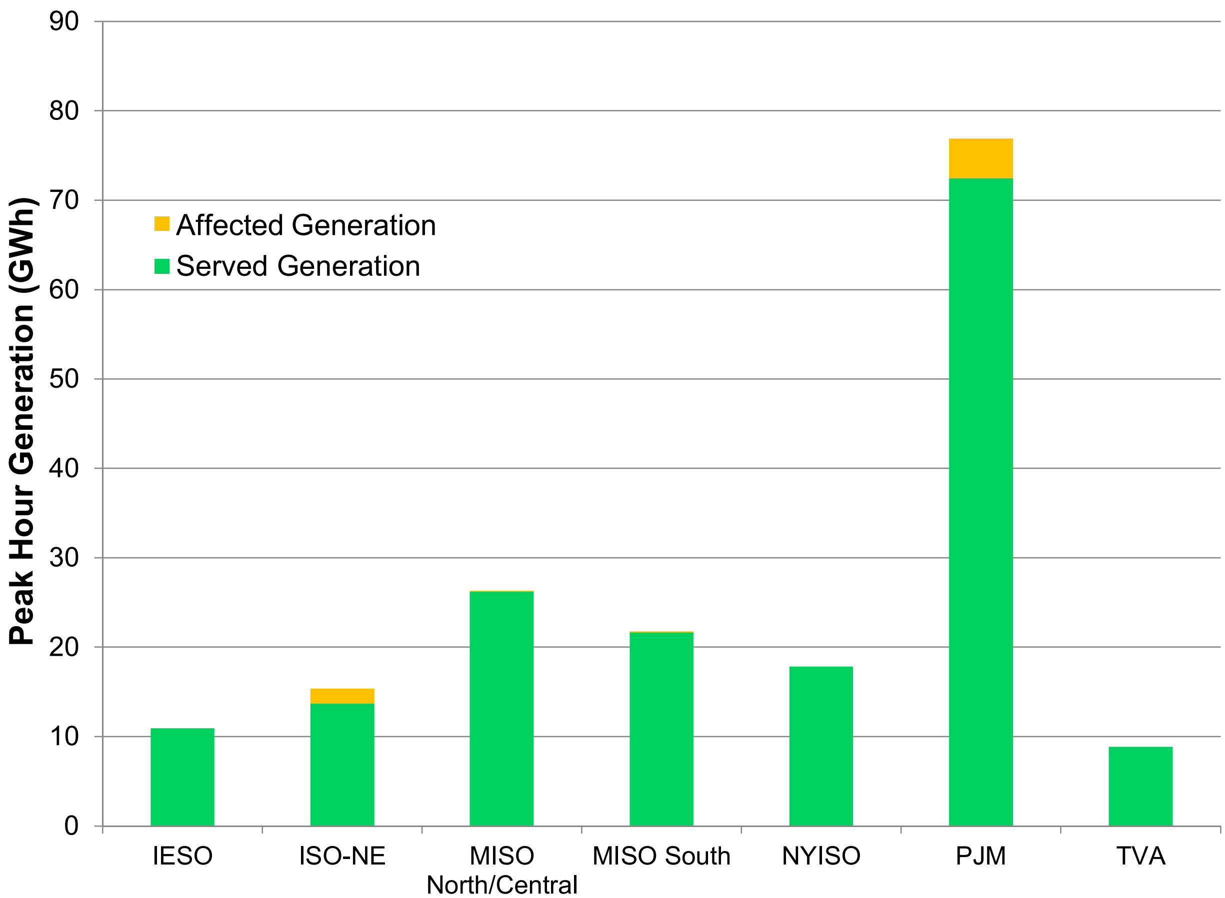


Figure 109 summarizes the unserved demand by GPCM location. The unserved demand and affected generation by location are quantified in Table 23. As compared with the RGDS S0 for 2018, additional pipeline constraints are indicated with additional affected generation in northern New England due to the assumed continued deterioration in boundary flows from Atlantic

Canada. There is also significant affected generation in PJM in Virginia and the Delmarva Peninsula. The affected generation shown in southern Illinois and Texas East is negligible.

Figure 109. RGDS S0 Summer 2023: GPCM Locations with Peak Hour Affected Generation

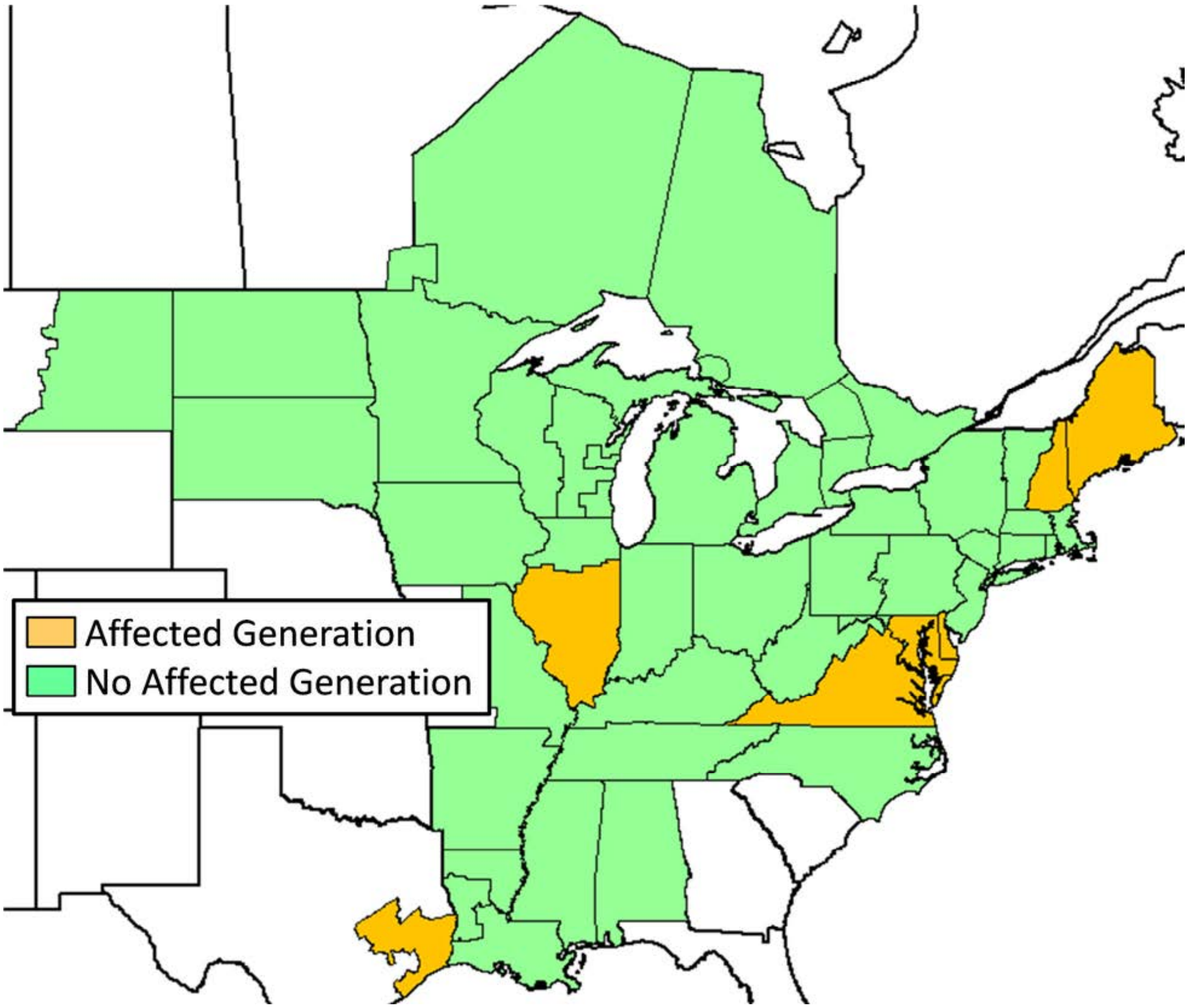


Table 23. RGDS S0 Summer 2023: Peak Hour Unserved Generator Gas Demand and Affected Generation

GPCM Location	Unserved Generator Gas Demand (MDth)	Affected Generation (MWh)
Delaware	8.5	1,175.1
Illinois Southern	1.0	111.5
Maine	6.1	805.1
Maryland Eastern	16.7	2,360.7
New Hampshire	7.6	857.4
Texas East (SERC)	0.6	81.2
Virginia	8.4	936.3

Figure 110 shows the constrained pipeline segments that result in affected generation during the Summer 2023 peak hour.

Figure 110. RGDS S0 Summer 2023: Constraints

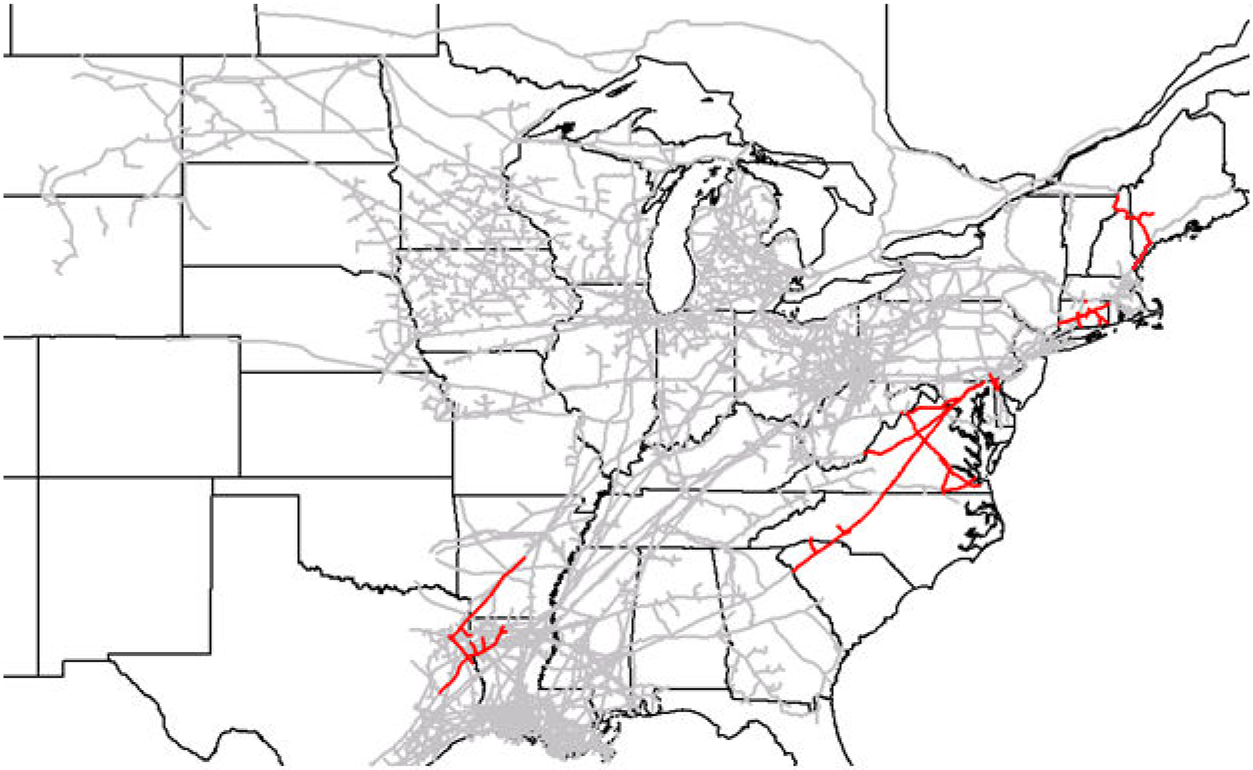


Table 24 summarizes the results of the frequency and duration analysis. Detailed results are provided in the following sub-sections.

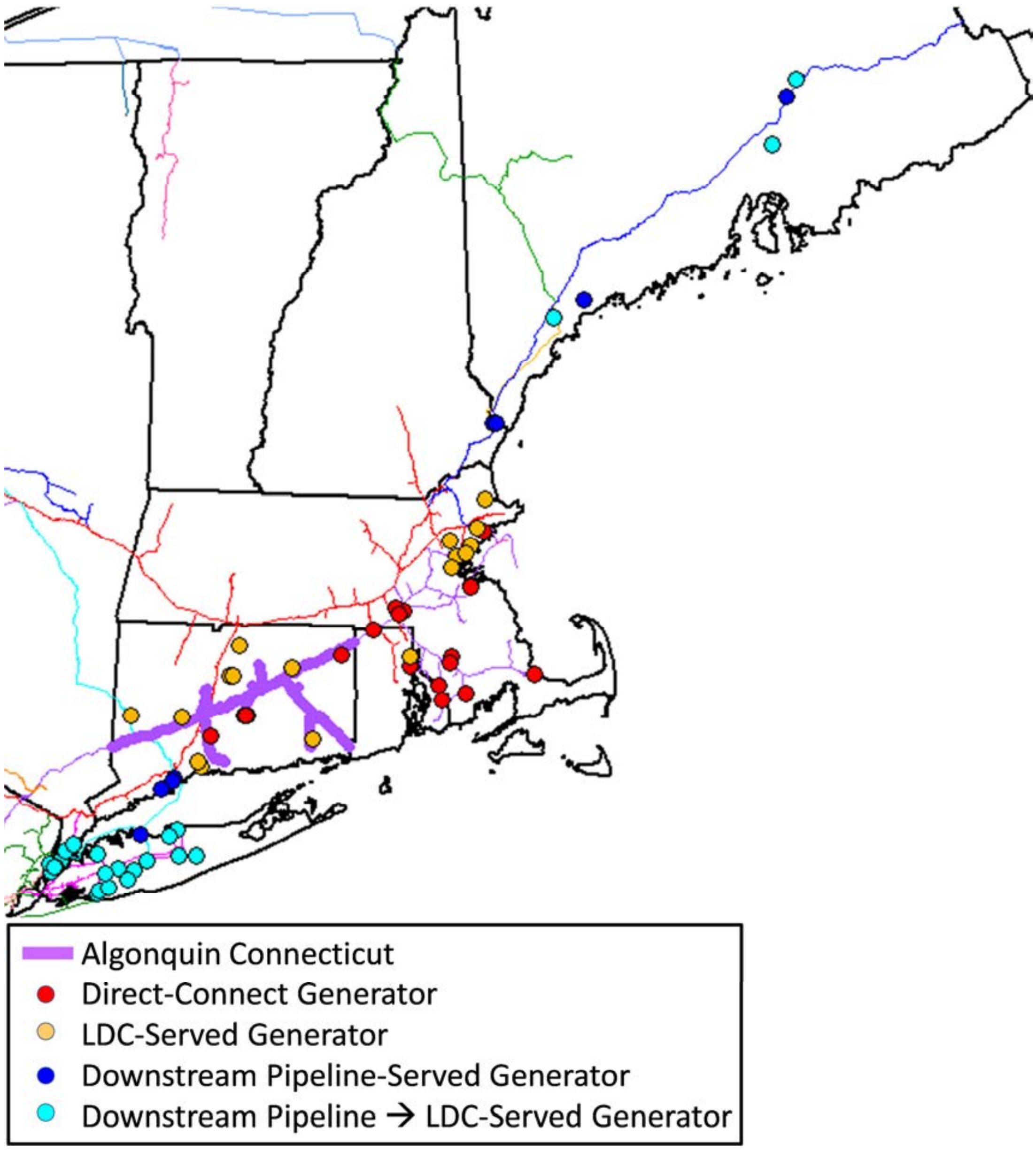
Table 24. RGDS S0 Summer 2023: Frequency and Duration of Daily Peak Hour Constraints

Constraint	# of Events	Min. Duration (Days)	Max. Duration (Days)	Total # of Days
Algonquin Connecticut	6	1	3	12
Columbia Gas VA/MD	2	1	3	4
Dominion Southeast	9	1	7	27
Eastern Shore	9	1	7	27
NB/NS Supply	5	2	27	70
PNGTS N of Westbrook	10	1	8	41
PNGTS S of Westbrook	11	1	7	33
Texas Eastern Zone ETX	7	1	6	17
Transco Z5	6	1	6	16

6.2.4.1 Algonquin Connecticut

The 100% peak hour utilization on Algonquin's Connecticut segment, which is modeled with a capacity of 1,827 MDth/d, potentially affects generators directly connected to Algonquin in Connecticut, Massachusetts and Rhode Island, generators directly connected to M&N in Maine and New Hampshire, and generators served by LDCs connected to Algonquin and M&N. The locations of these generators are shown in Figure 111.

Figure 111. Generators Affected by Algonquin CT Constraint



The seasonal daily forecasts of RCI and generator gas demand downstream of the constrained segment are shown in Figure C95 and Figure C96 relative to the capacity of the segment. Reflecting continued west-to-east transportation patterns across the Algonquin mainline, the

Algonquin CT constraints result in 12 days in the summer 2023 for which demand exceeds pipeline capacity.

6.2.4.2 Columbia Gas Virginia / Maryland

The 100% peak hour utilization on Columbia Gas's Virginia/Maryland segment is modeled with a capacity of 2,679 MDth/d, an increase of 202 MDth/d for 2023 as compared with 2018. The locations of the potentially affected generators are shown in Figure 80 on page 125.

The seasonal daily forecasts of RCI and generator gas demand downstream of the constrained segment are shown in Figure C97 and Figure C98 relative to the capacity of the segment. The total number of days for which demand exceeds pipeline capacity increases from one day for the summer of 2018 to 4 days for 2023.

6.2.4.3 Dominion Southeast

Dominion Southeast is modeled with a capacity of 555 MDth/d, an increase over the capacity modeled for the summer 2018 of 15 MDth/d. The locations of the potentially affected generators are shown in Figure 85 on page 130.

The seasonal daily forecasts of RCI and generator gas demand downstream of the constrained segment are shown in Figure C99 and Figure C100 relative to the capacity of the segment. The number of days for which demand exceeds pipeline capacity increases significantly from 5 days for the summer of 2018 to 27 days for the summer of 2023, resulting in substantial gas-fired affected generation during the peak cooling season.

6.2.4.4 Eastern Shore

Eastern Shore is modeled with a capacity of 203 MDth/d, the same as the capacity modeled for the summer of 2018. The locations of the potentially affected generators are shown in Figure 87 on page 132.

The seasonal daily forecasts of RCI and generator gas demand downstream of the constrained segments are shown in Figure C101 and Figure C102 relative to the capacity of the segments. The total number of days for which demand exceeds pipeline capacity increases from 19 days for the summer of 2018 to 27 days for summer 2023.

6.2.4.5 New Brunswick Supply / Nova Scotia Offshore Supply

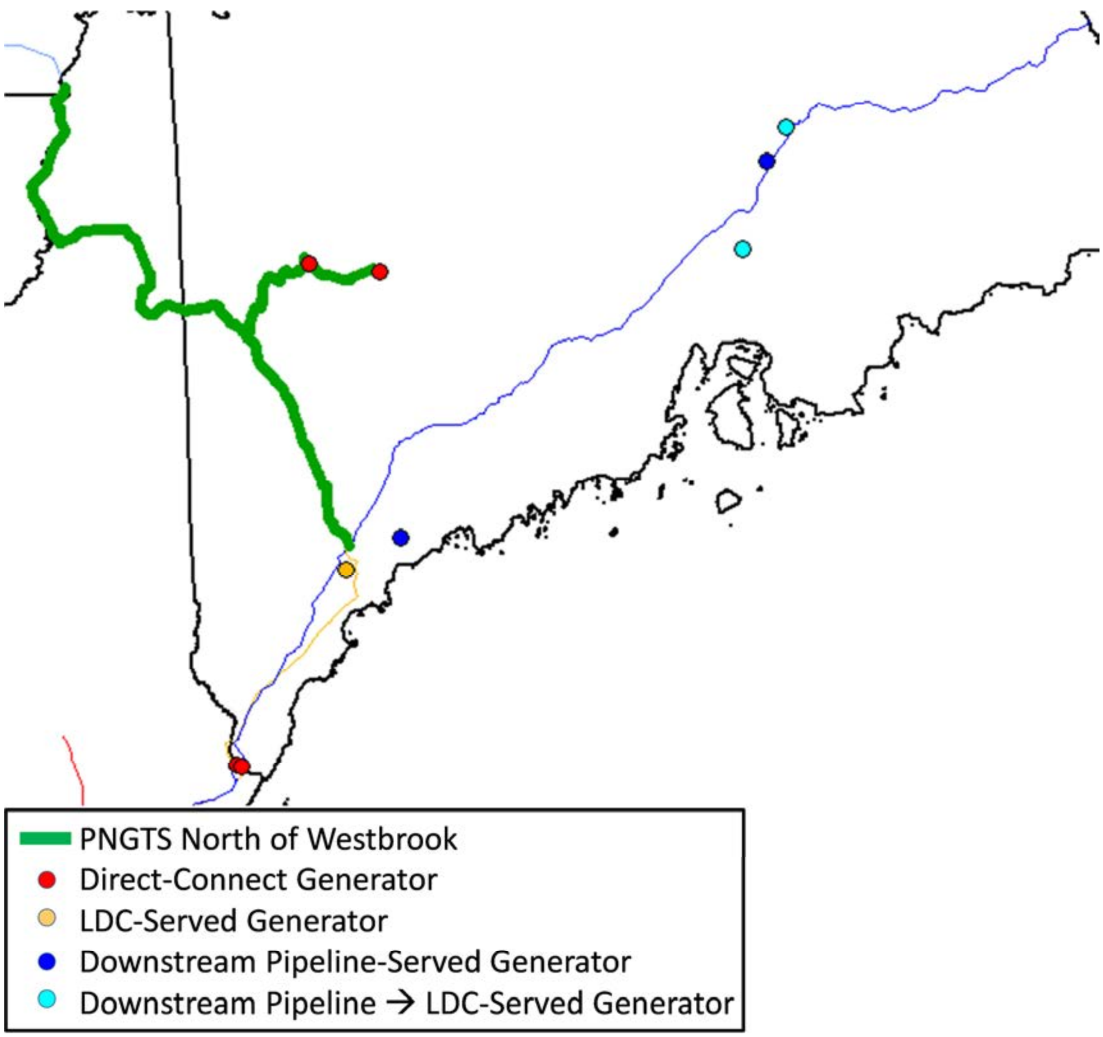
Limitations on Atlantic Canada production for the summer 2023 are the same as for the winter 2023, reaching 40 MDth/d in New Brunswick and 243 MDth/d for Nova Scotia Offshore. In the RGDS, we have assumed that the Canaport LNG import facility will not regasify LNG for sendout to M&N due to supply chain uncertainty. Even though there is slack deliverability on M&N, insufficient gas production from Atlantic Canada coupled with the loss of Canaport vaporization potentially affects generators directly connected to M&N in Maine and New Hampshire. The locations of these generators are shown in Figure 90 on page 135. Again, adverse operating impacts in the Maritimes have not been included in the summary results.

The seasonal daily forecasts of RCI and generator gas demand downstream of the supply limitation are shown in Figure C103 and Figure C104 relative to the total production capacity. The generator gas demand in these figures only includes generators in the Study Region. Reflecting the deterioration in boundary flow from Atlantic Canada, by summer 2023 the total number of days for which demand exceeds available supply in northern New England totals 70 days as compared to zero days in summer 2018.

6.2.4.6 PNGTS North of Westbrook

The 100% peak hour utilization on PNGTS's North of Westbrook segment, which is modeled with a capacity of 223 MDth/d, potentially affects generators directly connected to PNGTS in New Hampshire in Maine, generators served by LDCs connected to PNGTS, and generators served by M&N either directly or via LDC. The locations of these generators are shown in Figure 112.

Figure 112. Generators Affected by PNGTS North of Westbrook Constraint



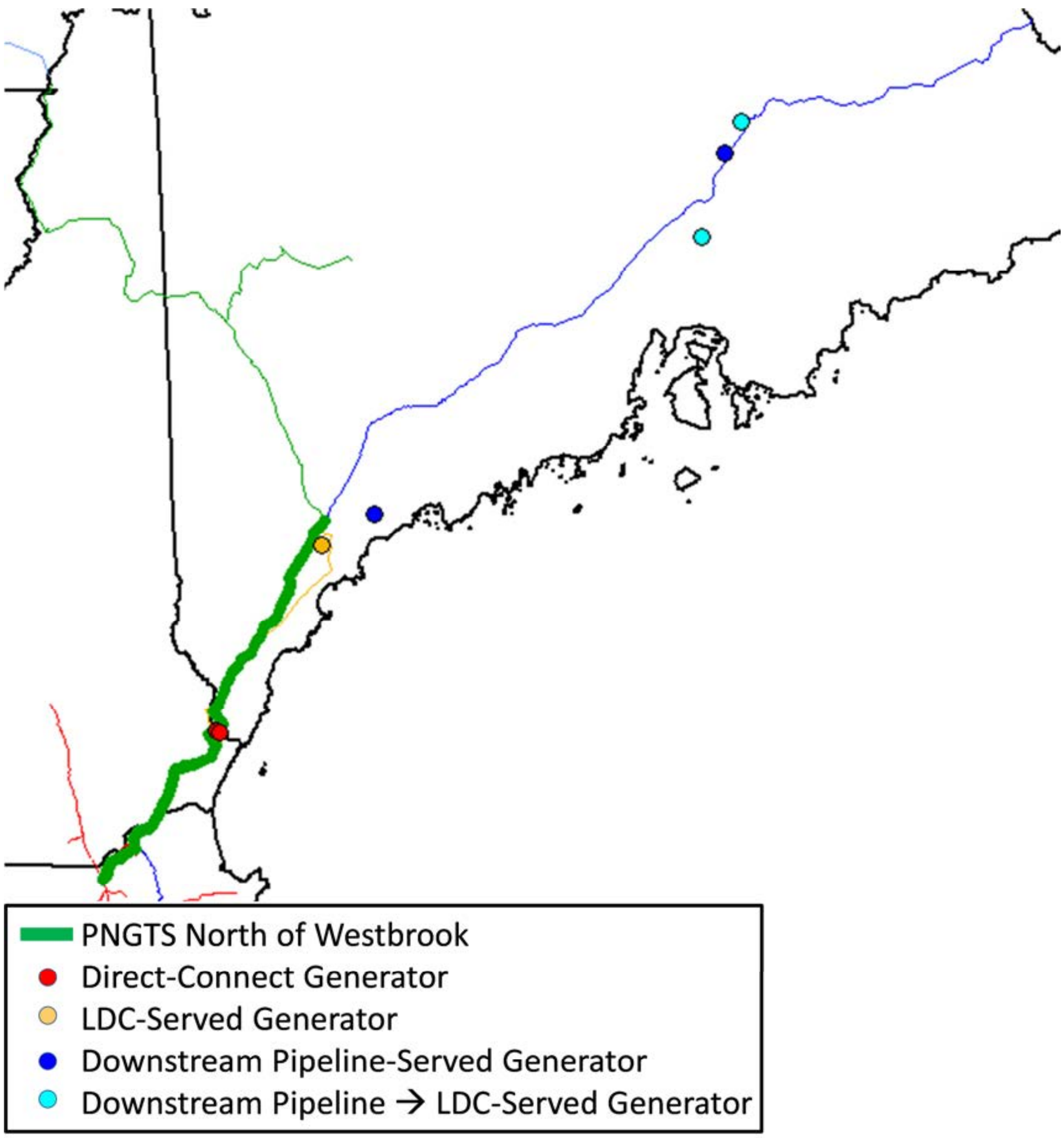
The seasonal daily forecasts of RCI and generator gas demand downstream of the constrained segment are shown in Figure C105 and Figure C106 relative to the capacity of the segment.

Reflecting capacity availability into PNGTS from TransCanada during the summer, this pipeline segment is constrained during the peak hour of 41 days of the 2023 cooling season.

6.2.4.7 PNGTS South of Westbrook

The 100% peak hour utilization on PNGTS's South of Westbrook segment, which is modeled with a capacity of 300 MDth/d, potentially affects generators directly connected to PNGTS in New Hampshire, generators served by Maine LDCs connected to PNGTS, and generators served by M&N either directly or via LDC. The locations of these generators are shown in Figure 113.

Figure 113. Generators Affected by PNGTS South of Westbrook Constraint



The seasonal daily forecasts of RCI and generator gas demand downstream of the constrained segment are shown in Figure C107 and Figure C108 relative to the capacity of the segment. This constraint occurs during the peak hour of 33 days in 2023.

6.2.4.8 Texas Eastern Zone ETX

The 100% peak hour utilization on Texas Eastern's East Texas segment is modeled with a capacity of 623 MDth/d, the same capacity as modeled for 2018. The locations of the potentially affected generators are shown in Figure 104 on page 150.

The seasonal daily forecasts of RCI and generator gas demand downstream of the constrained segment are shown in Figure C109 and Figure C110 relative to the capacity of the segment. The number of days for which demand exceeds pipeline capacity increases from 12 days for summer 2018 to 17 days for summer 2023.

6.2.4.9 Transco Zone 5

Transco Zone 5 is modeled with a capacity of 3,967 MDth/d, the same capacity as modeled for 2018. The locations of the potentially affected generators are shown in Figure 98 on page 143. Generators located in outside the Study Region in North Carolina and South Carolina could also be affected, but are not included in the results shown below.

The seasonal daily forecasts of RCI and generator gas demand downstream of the constrained segment are shown in Figure C111 and Figure C112 relative to the capacity of the segment. The total number of days for which demand exceeds pipeline capacity decreases slightly from 18 days in the summer 2018 to 16 days in 2023.

6.3 HGDS S0 AND HGDS S1 ANALYSIS

The HGDS captures increased gas demands relative to the gas demands in the RGDS. The primary drivers of the changes in gas demand by generators represented in the HGDS relate to increased coal retirements, replacement of coal generation with gas-fired resources, lower natural gas prices at delivery points across the Study Region, and higher electric loads. RCI customer gas demands are also assumed to be higher. Importantly, the gas demands for power generation in MISO North/Central and PJM are materially higher than in the RGDS. The gas demands for power generation in the other PPAs are also higher than in the RGDS.

6.3.1 HGDS S0 and HGDS S1 – Winter 2018

Figure 114 summarizes the affected generation during the Winter 2018 peak hour by PPA for HGDS S0 and HGDS S1. When the high winter peak day spot prices of the S1 case sensitivity are used in AURORAxmp, the level of gas-fired generation in the peak hour of the peak day in Winter 2018 decreases significantly across the Study Region. The relative reduction in generator gas demand is less for IESO, MISO South, and TVA because the assumed peak day gas prices for generators in those PPAs only increase slightly relative to the increases at most locations for the other PPAs.. Like the RGDS S1, there is almost no gas-fired generation scheduled in New England. Therefore, the affected generation under S1 pricing (shown below as H1) is zero. In the HGDS S0, there is a substantial amount of affected generation in ISO-NE, NYISO and PJM. There is comparatively little affected generation in IESO and MISO North/Central. Under S1 (H1) high peak day spot prices, total affected generation remains significant only in NYISO and PJM, in particular, MAAC. However, the substitution of oil and coal-fired generation when gas prices are high across the majority of the Study Region significantly reduces the total amount of gas affected generation relative to the S0 price assumptions.

Figure 114. HGDS S0 v. S1 Winter 2018: Peak Hour Affected Generation

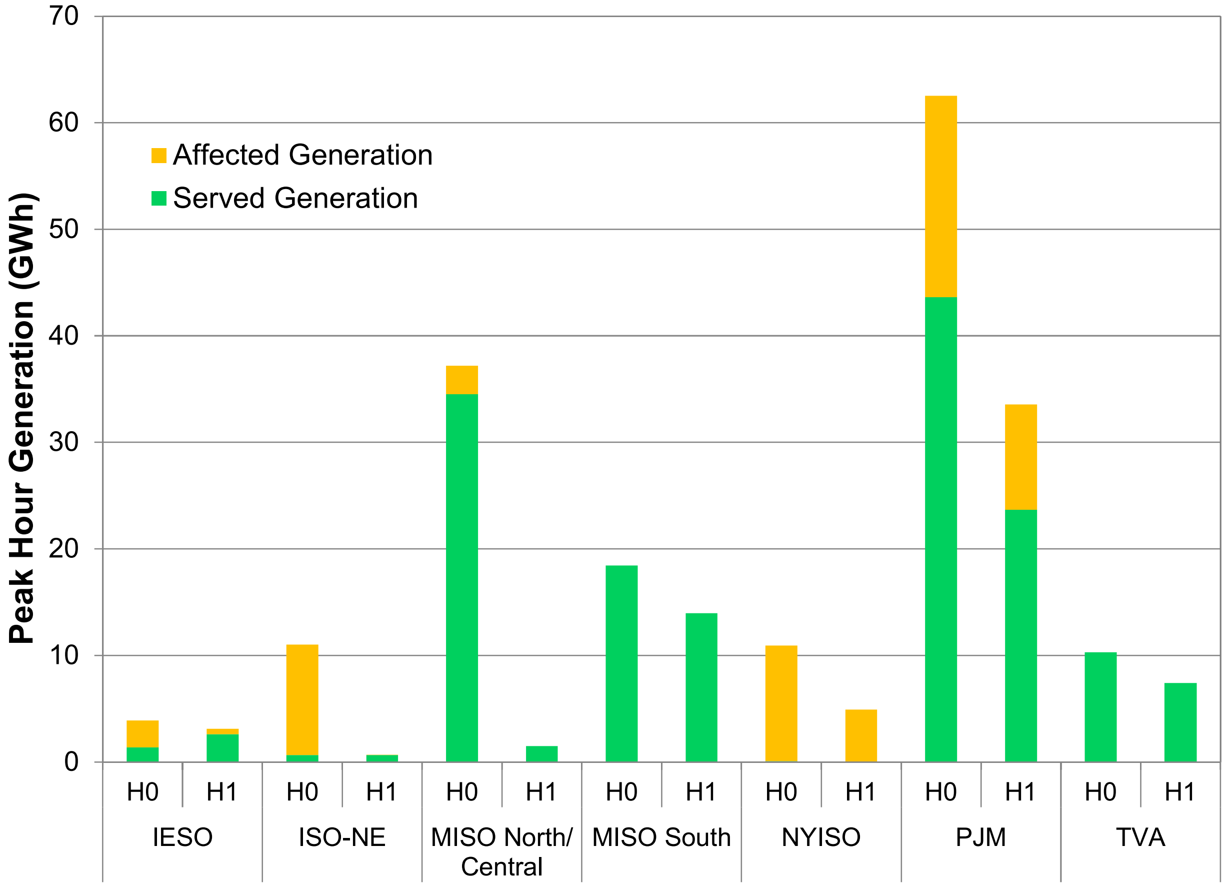


Figure 114 illustrates the GPCM locations with unserved generator gas demand during the peak hour. The unserved demand and resultant affected generation by location are quantified in Table 25.

Figure 115. HGDS S0 v. HGDS S1 Winter 2018: GPCM Locations with Peak Hour Affected Generation

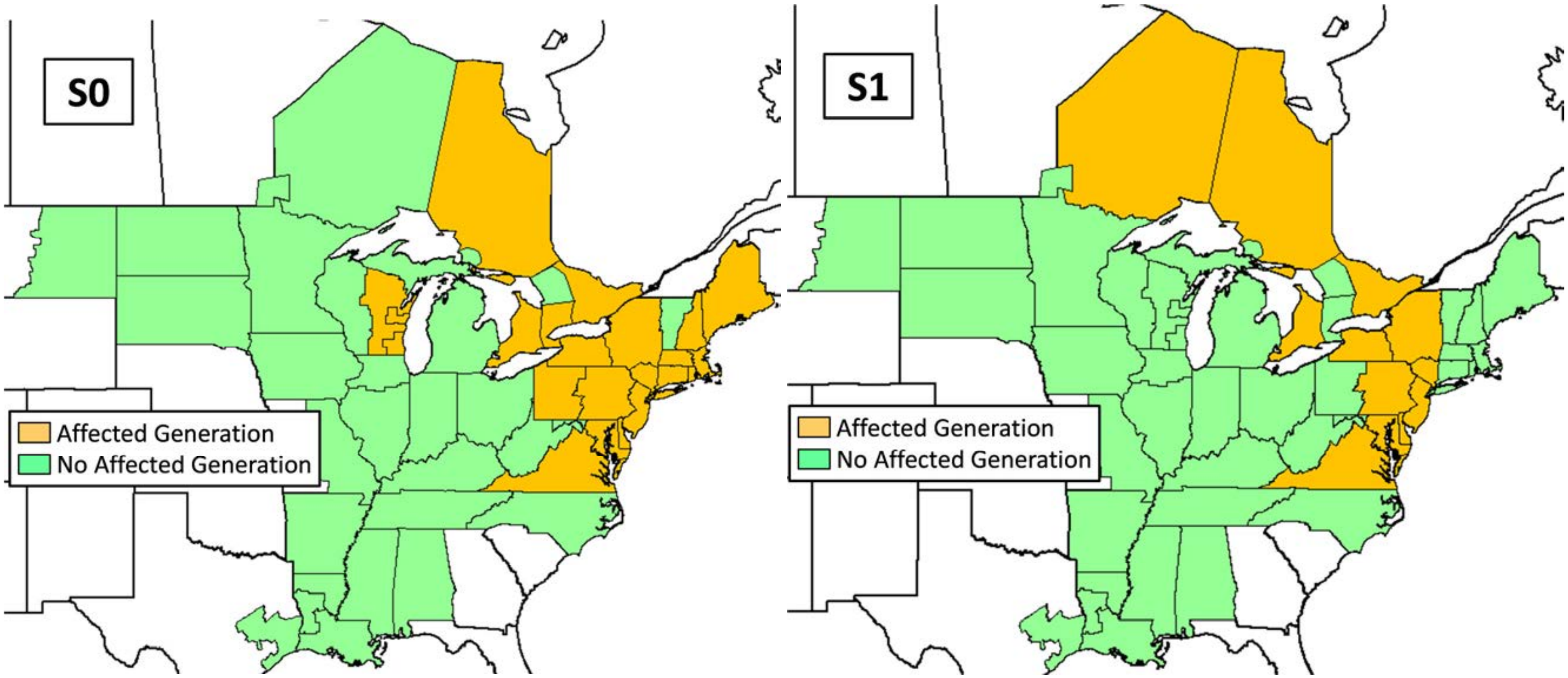


Table 25. HGDS S0 v. HGDS S1 Winter 2018: Peak Hour Unserved Generator Gas Demand and Affected Generation

GPCM Location	S0 Unserved Generation Gas Demand (MDth)	S0 Affected Generation (MWh)	S1 Unserved Generation Gas Demand (MDth)	S1 Affected Generation (MWh)
Connecticut	21.8	2,990.2	0.0	0.0
Delaware	1.3	172.6	0.1	9.1
Maine	9.5	1,292.2	0.0	0.0
Maryland Eastern	5.0	538.9	3.3	311.5
Massachusetts Eastern	11.9	1,655.5	0.0	0.0
Massachusetts Western	7.8	1,058.9	0.0	0.0
New Hampshire	15.1	1,958.1	0.0	0.0
New Jersey	23.7	3,100.6	0.7	92.6
New York Central Northern	43.2	5,223.8	25.9	2,636.6
New York City	20.6	2,581.1	0.0	0.0
New York Long Island	8.7	1,025.0	0.0	0.0
New York Southern	10.9	1,312.3	14.3	1,537.2
New York Western	5.2	698.9	5.6	736.2
Ontario (CDA)	1.6	180.5	0.5	55.1
Ontario (EDA)	12.2	1,246.6	2.1	249.1
Ontario (NDA)	1.2	154.5	1.5	186.2
Ontario (St. Clair)	7.0	950.1	0.0	0.0
Ontario (WDA)	0.0	0.0	0.4	38.0
Pennsylvania Eastern	67.1	9,096.5	44.4	5,630.6
Pennsylvania Western	11.0	1,574.1	0.0	0.0
Rhode Island	10.8	1,402.5	0.0	0.0
Virginia	34.2	4,404.1	25.2	3,219.5
Wisconsin Eastern (RFC)	14.8	1,813.7	0.0	0.0
Wisconsin Western (MROE)	6.8	837.9	0.0	0.0

Figure 116 shows the constrained pipeline segments that result in affected generation for HGDS S0 and HGDS S1 during the Winter 2018 peak hour.

Figure 116. HGDS S0 v. HGDS S1 Winter 2018: Peak Hour Constraints

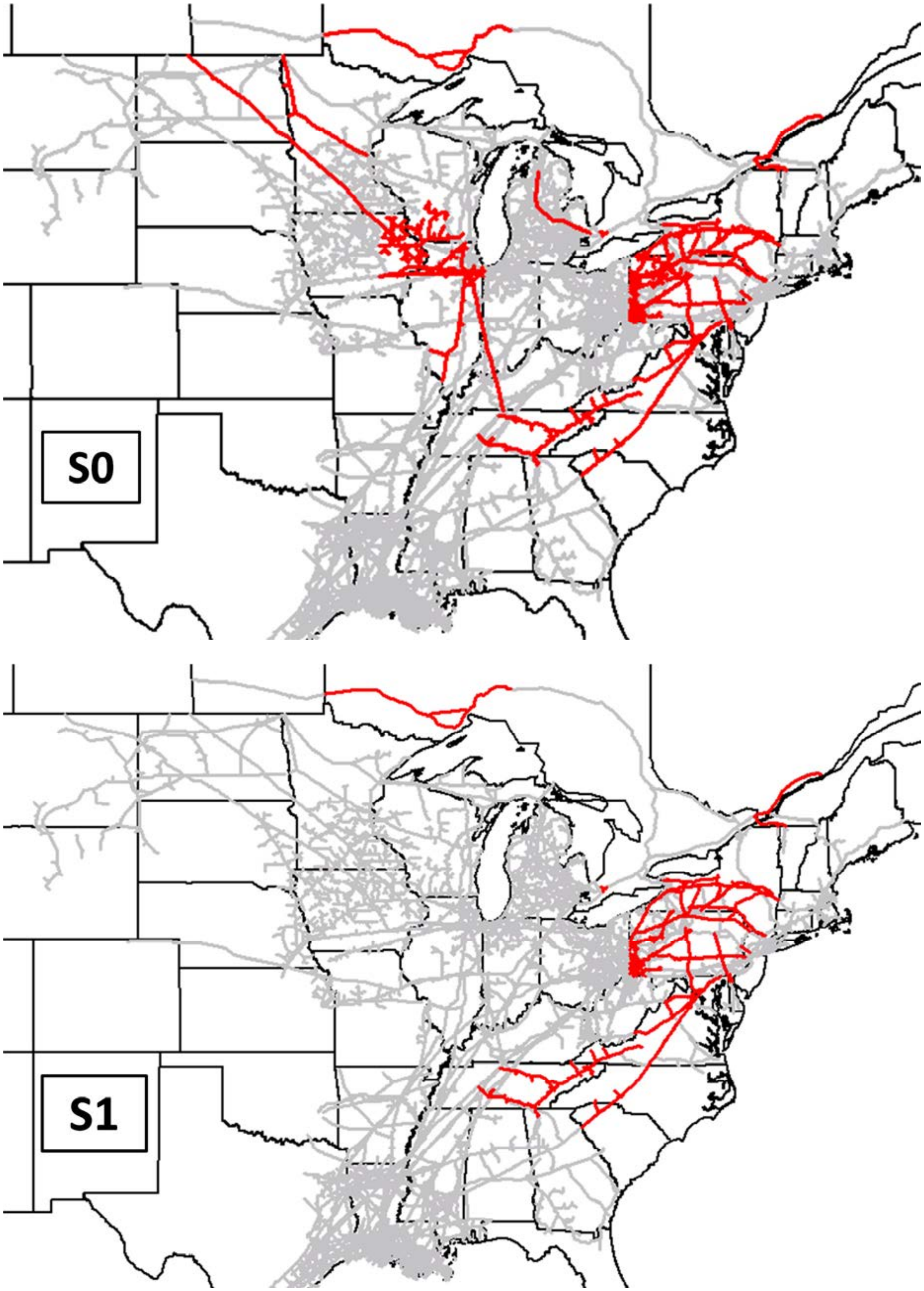


Table 26 summarizes the results of the frequency and duration analysis, with the detailed results presented in the following subsections. Constraints that are also in effect during the HGDS S1 peak hour are indicated with an asterisk (*). For each of the constrained segments listed in Table 26, potentially affected generators are shown in Appendix D and charts illustrating the seasonal daily forecasts of RCI and generator gas peak hour demand downstream of the constrained segment relative to the capacity of the segment are included in Appendix E.

Table 26. HGDS S0 Winter 2018: Frequency and Duration of Daily Peak Hour Constraints

Constraint	# of Events	Min. Duration (Days)	Max. Duration (Days)	Total # of Days
Alliance	4	1	6	10
ANR Northern Illinois	10	1	35	60
Columbia Gas VA/MD*	12	2	13	57
Columbia Gas W PA/NY*	10	1	3	17
Constitution*	2	31	59	90
Dominion Eastern NY*	8	1	10	21
Dominion Western NY*	6	1	15	34
Dominion Southeast*	6	1	13	22
East Tennessee Mainline*	6	2	8	26
Eastern Shore*	8	1	5	20
Empire Mainline*	7	1	44	60
Great Lakes East	12	1	30	66
Midwestern	19	1	10	55
Millennium*	8	2	37	67
NB/NS Supply*	16	1	20	56
NGPL IA/IL North	11	1	20	51
NGPL IA/IL South	12	1	11	48
Northern Border Chicago	14	1	10	46
Northern Natural D	4	1	4	8
Tennessee Z4 PA*	5	1	48	76
Tennessee Z5 NY*	2	31	59	90
Texas Eastern M2 PA South*	2	31	59	90
Texas Eastern M3 North*	4	1	51	82
TransCanada Ontario West*	3	1	5	8
TransCanada Quebec*	8	1	14	29
Transco Leidy Atlantic*	2	31	59	90
Transco Z5*	8	1	12	21
Transco Z6 Leidy to 210*	2	31	59	90
Union Gas Dawn*	4	1	3	6
Viking Z1	11	1	10	24

6.3.2 HGDS S0 – Summer 2018

Figure 117 summarizes the affected generation during the Summer 2018 peak hour by PPA.

Figure 117. HGDS S0 Summer 2018: Peak Hour Affected Generation

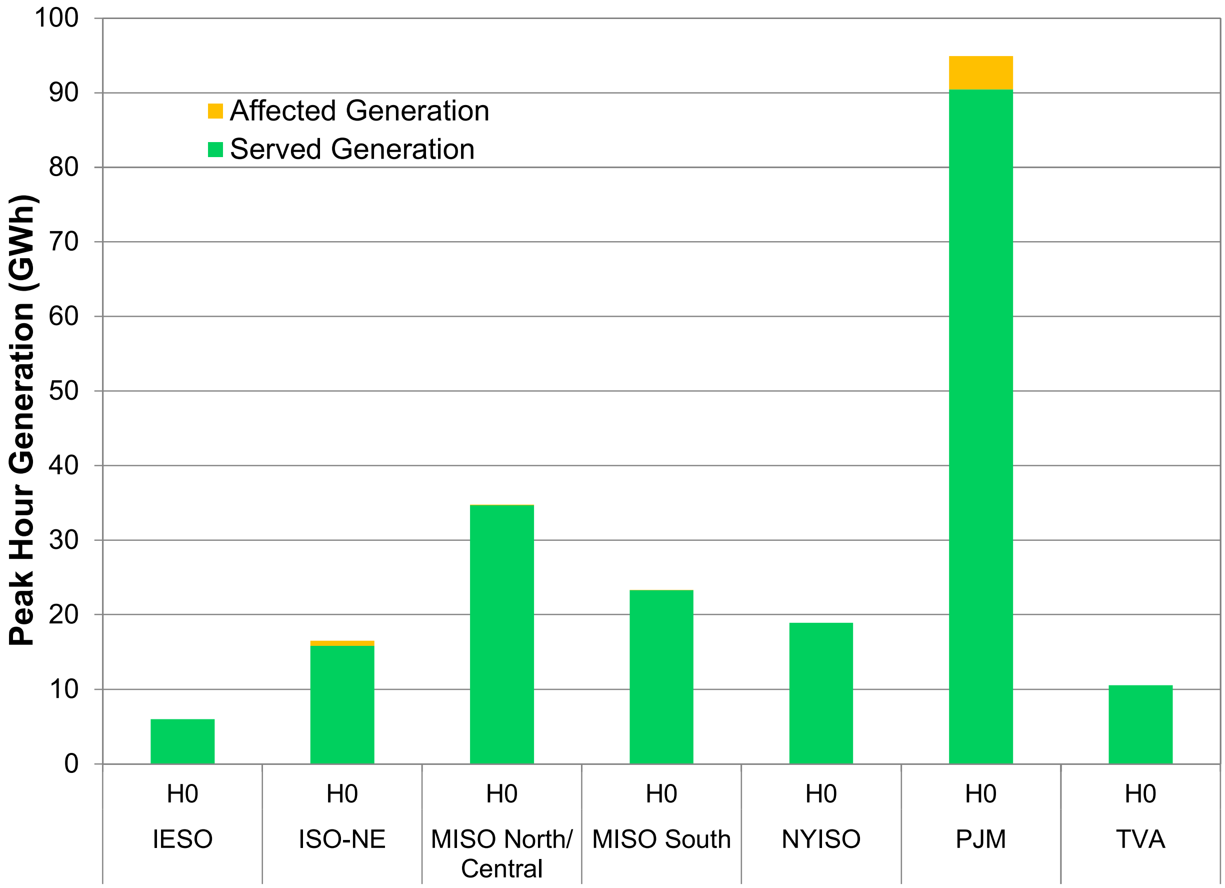


Figure 118 summarizes the unserved demand by GPCM location. The unserved demand and affected generation by location are quantified in Table 27.

Figure 118. HGDS S0 Summer 2018: GPCM Locations with Peak Hour Affected Generation

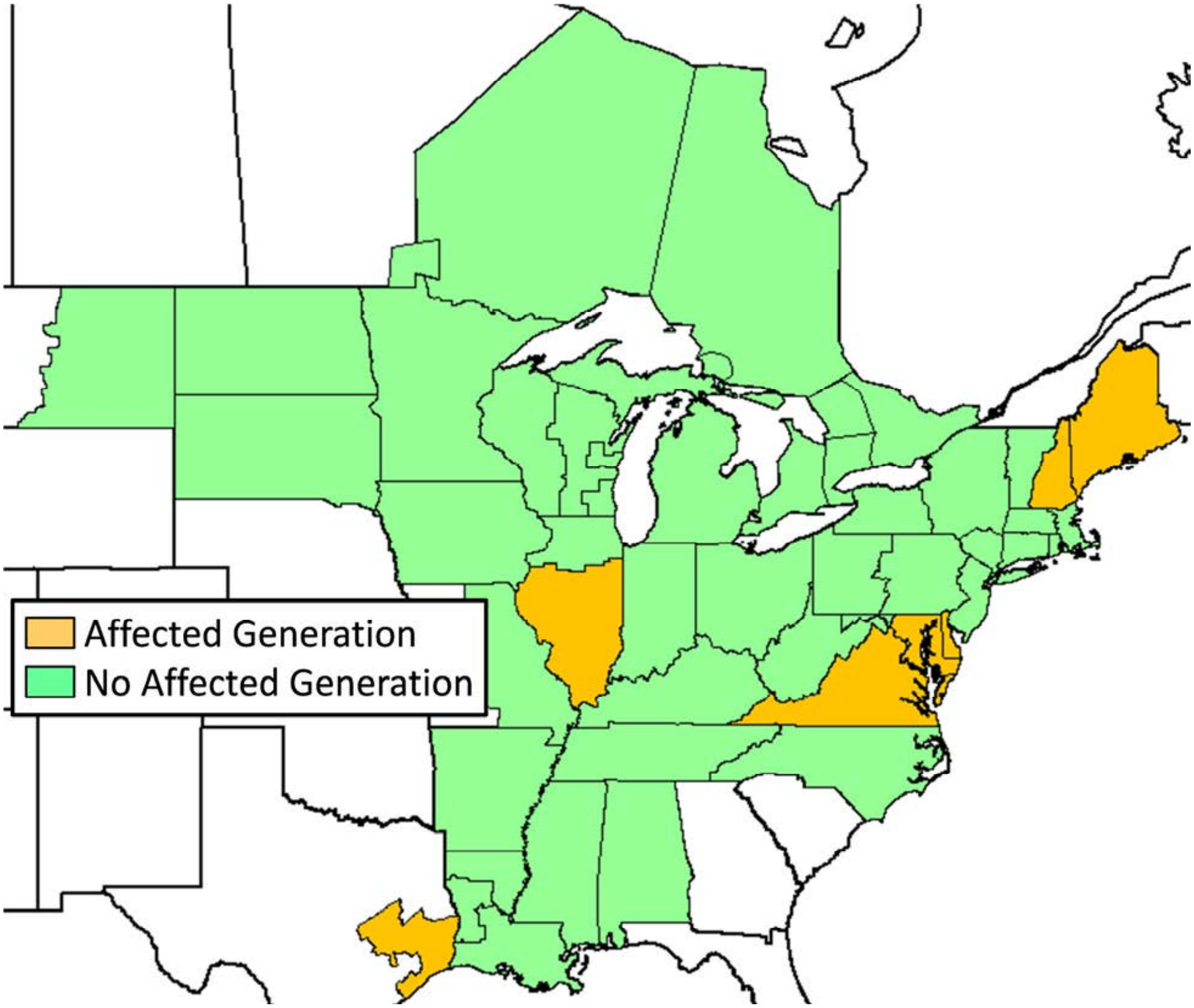


Table 27. HGDS S0 Summer 2018: Peak Hour Unserved Generator Gas Demand and Affected Generation

GPCM Location	Unserved Generator Gas Demand (MDth)	Affected Generation (MWh)
Delaware	8.4	1,162.1
Illinois Southern	1.0	111.5
Maine	4.0	540.4
Maryland Eastern	16.7	2,360.7
New Hampshire	1.4	162.9
Texas East (SERC)	0.5	69.6
Virginia	8.4	936.3

Figure 119 shows the constrained pipeline segments, in red, that result in the affected generation shown in Figure 118 during the Summer 2018 peak hour. These summer constraints primarily result from the much higher gas demand for generation in the HGDS, driven by replacement of coal plants by new gas-fired resources, much lower gas prices that make gas more economic than coal in more areas, and higher electric loads.

Figure 119. HGDS S0 Summer 2018: Peak Hour Constraints

Table 28 summarizes the results of the frequency and duration analysis. For each of the constrained segments listed in Table 28, potentially affected generators are shown in Appendix D and charts illustrating the seasonal daily forecasts of RCI and generator gas demand downstream of the constrained segment relative to the capacity of the segment are included in Appendix E.

Table 28. HGDS S0 Summer 2018: Frequency and Duration of Daily Peak Hour Constraints

Constraint	# of Events	Min. Duration (Days)	Max. Duration (Days)	Total # of Days
Algonquin Connecticut	8	1	5	21
Columbia Gas VA/MD	5	1	2	6
Dominion Southeast	15	1	7	37
Eastern Shore	6	1	18	45
NB/NS Supply	3	1	73	79
PNGTS N of Westbrook	11	1	7	28
PNGTS S of Westbrook	12	1	8	48
Texas Eastern Zone ETX	9	1	9	24
Transco Z5	6	1	6	16

6.3.3 HGDS S0 and HGDS S1 – Winter 2023

Figure 120 summarizes the affected generation during the Winter 2023 peak hour by PPA for HGDS S0 and HGDS S1. When the high peak day spot prices characteristic of the S1 case sensitivity are used in AURORAxmp, the level of gas-fired generation and gas-fired affected generation in the peak hour of the peak day in Winter 2023 decreases significantly across the Study Region. As for 2018, the reduction in generator gas demand is less for IESO and TVA because gas prices for their generators increase less than for those in the other PPAs.

Figure 120. HGDS S0 v. S1 Winter 2023: Peak Hour Affected Generation

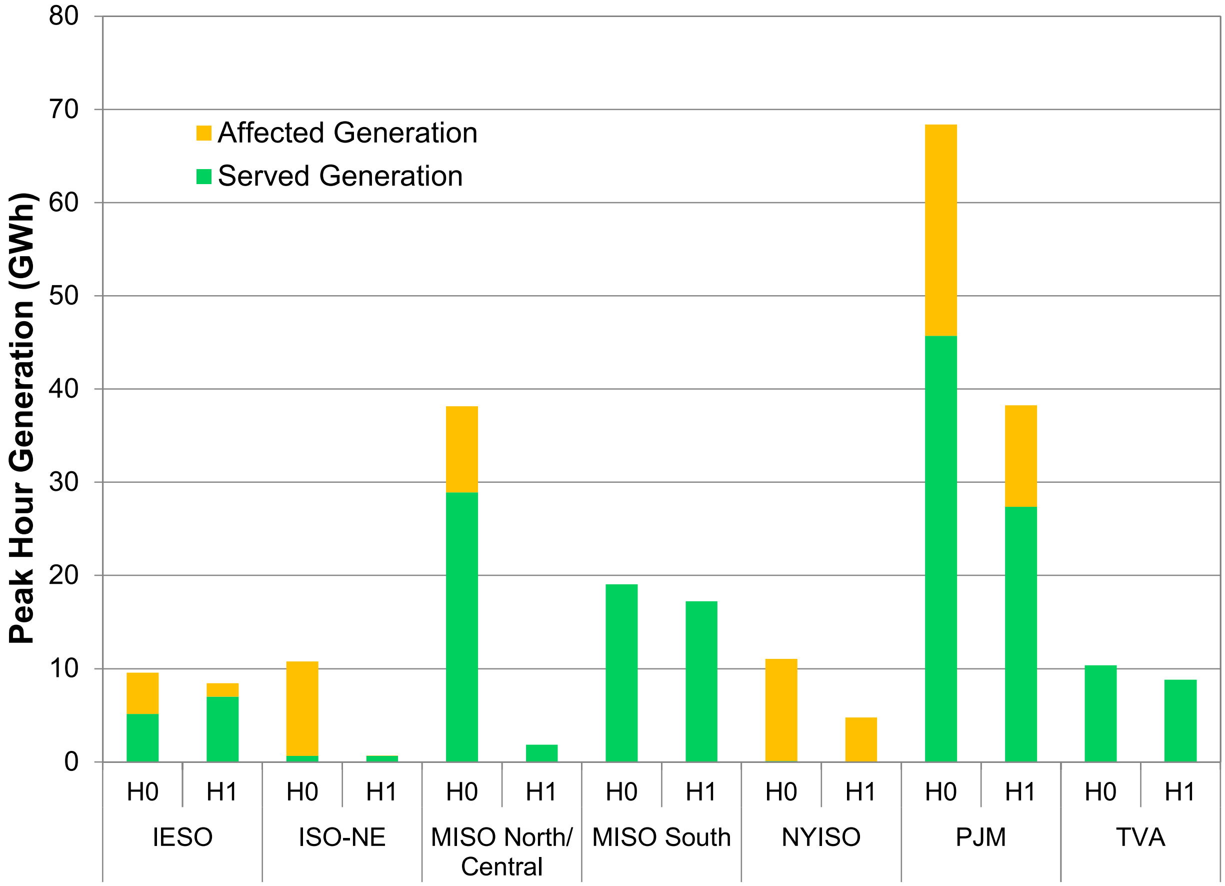
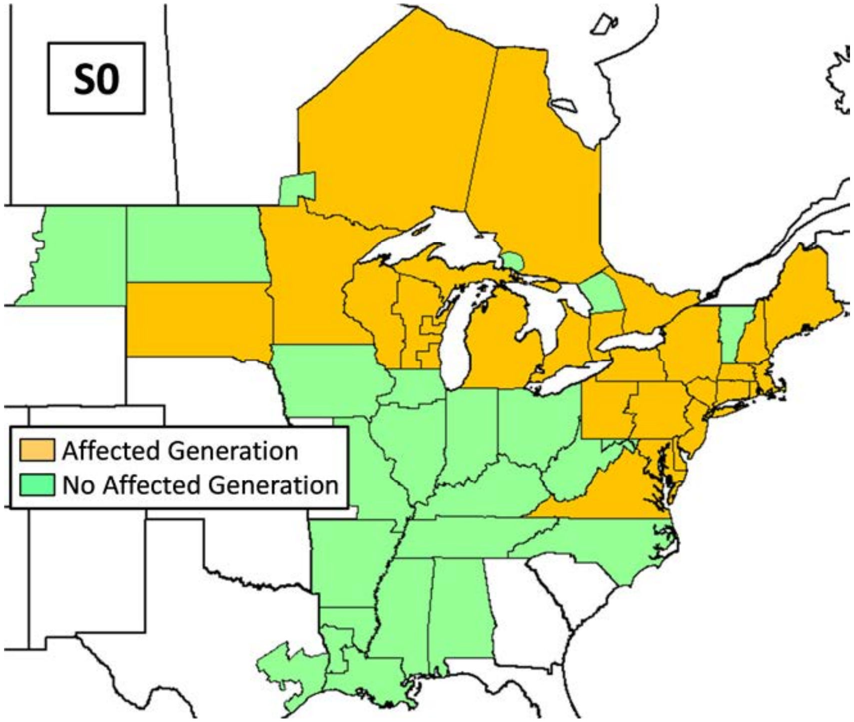


Figure 121 summarizes the unserved generator gas demand by GPCM location. The unserved demand and affected generation by location are quantified in Table 29. Under H0, the retirement of coal units across MISO North/Central coupled with the replacement of gas-fired capacity to meet MISO reliability requirements causes significant transportation constraints in MISO North/Central. However, the magnitude of the transportation constraints is significantly reduced under S1 (H1) price assumptions.

Figure 121. HGDS S0 v. S1 Winter 2023: GPCM Locations with Peak Hour Affected Generation



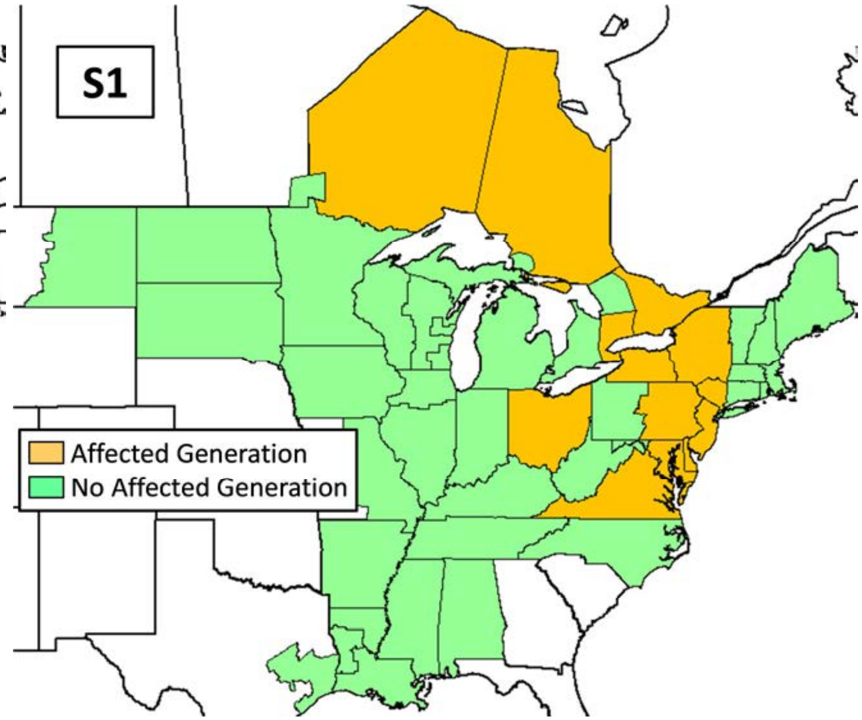


Table 29. HGDS S0 v. S1 Winter 2023: Peak Hour Unserved Generator Gas Demand and Affected Generation

GPCM Location	S0 Unserved Generation Gas Demand (MDth)	S0 Affected Generation (MWh)	S1 Unserved Generation Gas Demand (MDth)	S1 Affected Generation (MWh)
Connecticut	13.4	1,864.7	0.0	0.0
Delaware	0.3	30.4	0.1	9.1
Maine	12.7	1,798.8	0.0	0.0
Maryland Eastern	6.3	666.6	3.3	315.6
Massachusetts Eastern	16.3	2,261.5	0.0	0.0
Massachusetts Western	7.8	1,058.9	0.0	0.0
Michigan Lower Peninsula	0.1	10.5	0.0	0.0
Michigan Upper Peninsula	3.6	519.8	0.0	0.0
Minnesota	15.7	1,971.8	0.0	0.0
New Hampshire	16.7	2,284.2	0.0	0.0
New Jersey	16.9	2,351.6	0.7	92.7
New York Central Northern	42.4	4,958.4	24.8	2,494.7
New York City	20.8	2,521.6	0.0	0.0
New York Long Island	12.0	1,251.1	0.0	0.0
New York Southern	13.8	1,502.5	14.3	1,537.2
New York Western	5.6	736.2	5.6	736.2
Ontario (CDA)	1.6	180.5	0.5	55.1
Ontario (EDA)	12.2	1,652.5	8.5	1,132.7
Ontario (NDA)	1.2	154.5	1.5	186.2
Ontario (St. Clair)	17.2	2,410.3	0.0	0.0
Ontario (WDA)	0.4	38.0	1.4	38.0
Pennsylvania Eastern	93.3	12,864.1	44.4	5,630.6
Pennsylvania Western	11.0	1,574.1	0.0	0.0
Rhode Island	6.3	837.5	0.0	0.0
South Dakota	1.0	135.9	0.0	0.0
Virginia	42.3	5,181.0	35.4	4,237.3
Wisconsin Eastern (RFC)	30.3	3,921.0	0.0	0.0
Wisconsin Western (MROE)	20.2	2,466.8	0.0	0.0
Wisconsin Western (MROW)	2.1	216.0	0.0	0.0

Figure 122 shows the constrained pipeline segments, in red, that result in the gas-fired affected generation shown in Figure 120 during the Winter 2023 peak hour for HGDS S0 and HGDS S1.

Figure 122. HGDS S0 v. S1 Winter 2023: Constraints

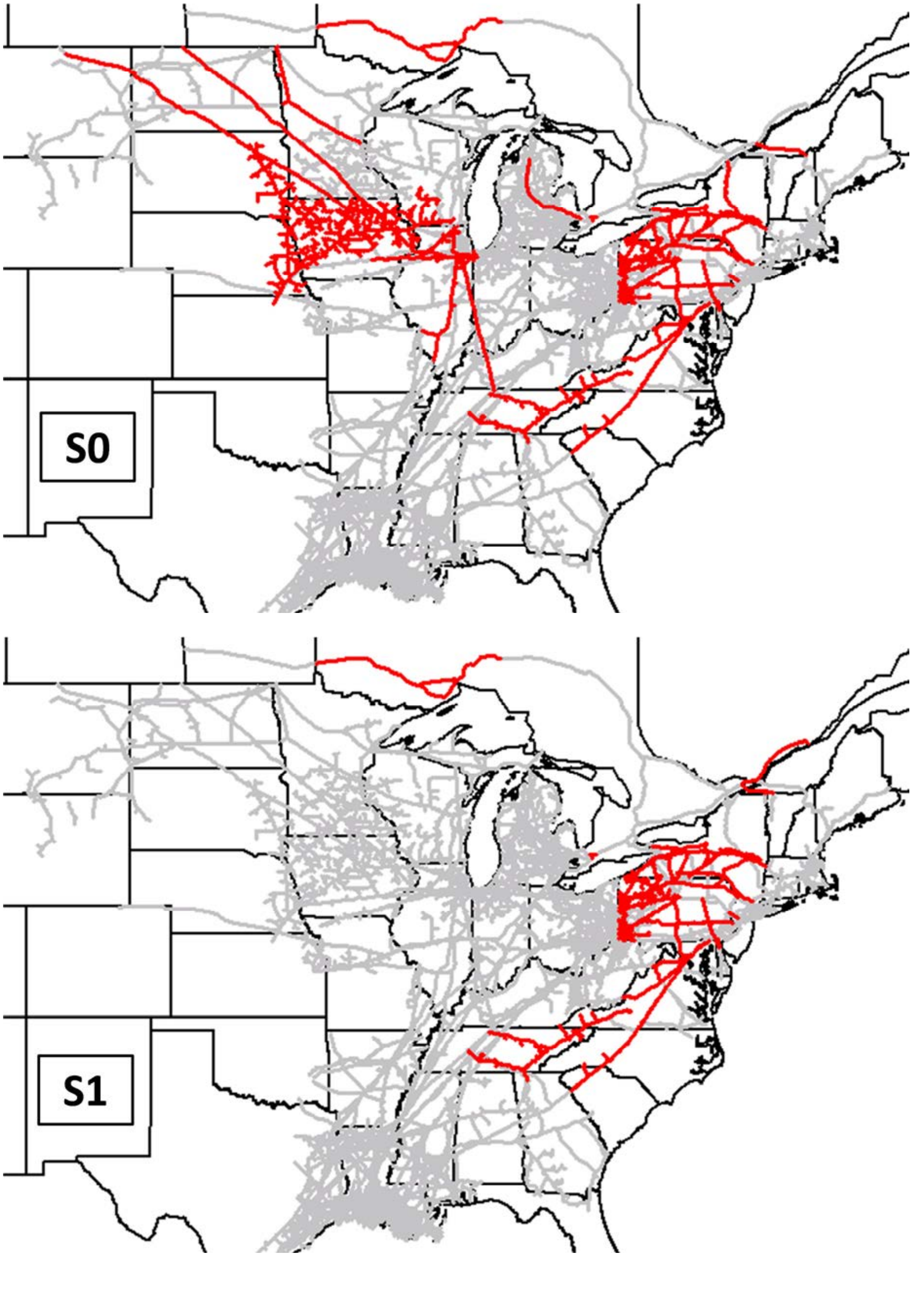


Table 30 summarizes the results of the frequency and duration analysis. For each of the constrained segments listed in Table 30, potentially affected generators are shown in Appendix D and charts illustrating the seasonal daily forecasts of RCI and generator gas demand downstream of the constrained segment relative to the capacity of the segment are included in Appendix E.

Table 30. HGDS S0 Winter 2023: Frequency and Duration of Daily Peak Hour Constraints

Constraint	# of Events	Min. Duration (Days)	Max. Duration (Days)	Total # of Days
Alliance	4	1	6	9
ANR Northern Illinois	10	1	17	56
Columbia Gas VA/MD*	6	1	52	81
Columbia Gas W PA/NY*	9	2	23	68
Constitution*	2	31	59	90
Dominion Eastern NY*	7	1	14	41
Dominion Western NY*	7	1	15	37
Dominion Southeast*	3	1	54	86
East Tennessee Mainline*	6	2	8	26
Eastern Shore*	4	1	3	7
Empire Mainline*	7	1	16	41
Great Lakes East	3	14	59	88
Iroquois Zone 1	2	31	59	90
Midwestern	21	1	9	56
Millennium*	2	31	59	90
NB/NS Supply*	6	1	5	16
NGPL IA/IL North	9	1	20	53
NGPL IA/IL South	10	1	11	42
Northern Border Mainline	2	1	2	3
Northern Natural ABC	11	1	32	53
Northern Natural D	10	1	10	27
Tennessee Z4 PA*	6	2	48	77
Tennessee Z5 NY*	3	4	59	89
Texas Eastern M2 PA South*	2	31	59	90
Texas Eastern M3 North*	3	3	58	88
TransCanada Ontario West*	5	2	11	21
TransCanada Quebec to PNGTS	2	31	59	90
Transco Leidy Atlantic*	5	4	28	86
Transco Z5*	7	1	14	28
Transco Z6 Leidy to 210*	2	31	59	90
Union Gas Dawn*	6	1	5	15
Vector Z1	4	1	8	12
Viking Z1	12	1	17	58

6.3.4 HGDS S0 – Summer 2023

Figure 123 summarizes the gas-fired affected generation during the Winter 2018 peak hour by PPA.

Figure 123. HGDS S0 Summer 2023: Peak Hour Affected Generation

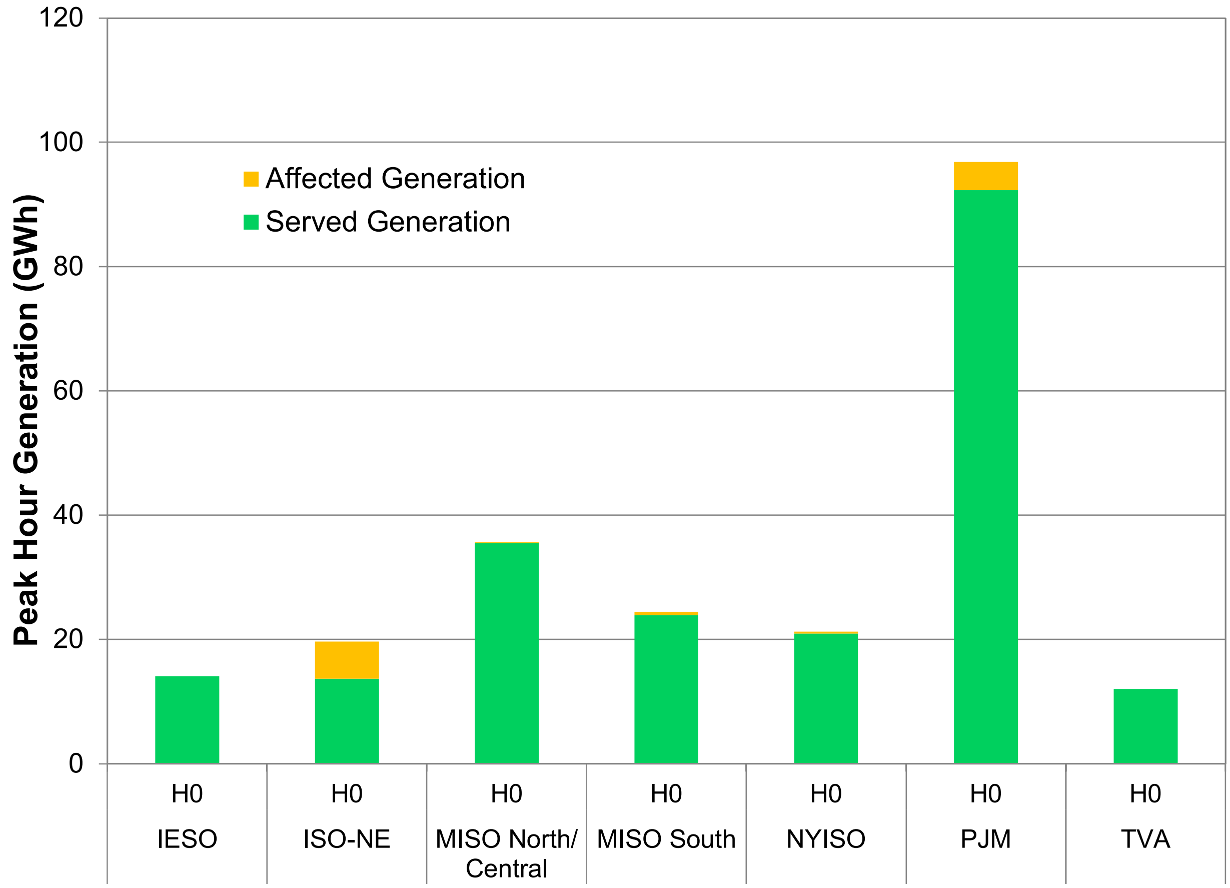


Figure 124 summarizes the unserved demand by GPCM location. The unserved demand and affected generation by location are quantified in Table 31. These summer 2023 constraints are more pronounced than for summer 2018, resulting from even higher gas demand for generation in 2023, driven by further replacement of coal plants by new gas-fired resources, continuation of low gas prices that make gas more economic than coal in many areas, and even higher electric loads.

Figure 124. HGDS S0 Summer 2023: GPCM Locations with Peak Hour Affected Generation

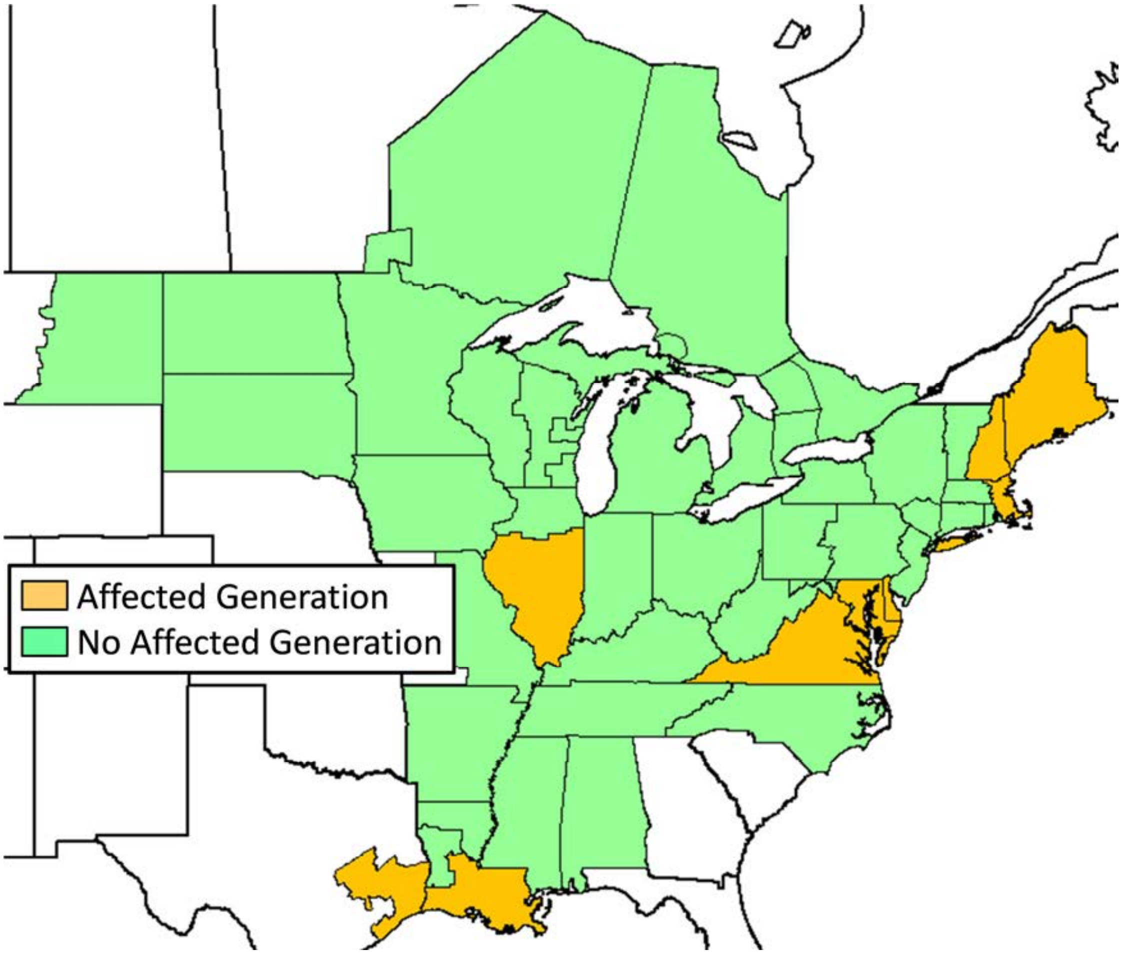


Table 31. HGDS S0 Summer 2023: Peak Hour Unserved Generator Gas Demand and Affected Generation

GPCM Location	Unserved Generator Gas Demand (MDth)	Affected Generation (MWh)
Delaware	9.1	1,237.0
Illinois Southern	1.0	111.5
Louisiana Southern	3.1	331.2
Maine	17.3	2,334.5
Maryland Eastern	16.7	2,360.7
Massachusetts Eastern	19.6	2,654.4
New Hampshire	7.2	979.5
New York Long Island	3.5	342.0
Texas East (SERC)	1.5	208.8
Virginia	8.4	936.3

Figure 125 shows the constrained pipeline segments, in red, that result in the affected generation shown in Figure 123 during the Summer 2018 peak hour.

Figure 125. HGDS S0 Summer 2023: Peak Hour Constraints

Table 32 summarizes the results of the frequency and duration analysis. For each of the constrained segments listed in Table 30, potentially affected generators are shown in Appendix D and charts illustrating the seasonal daily forecasts of RCI and generator gas demand downstream of the constrained segment relative to the capacity of the segment are included in Appendix E.

Table 32. HGDS S0 Summer 2023: Frequency and Duration of Daily Peak Hour Constraints

Constraint	# of Events	Min. Duration (Days)	Max. Duration (Days)	Total # of Days
Algonquin Connecticut	8	1	23	56
Columbia Gas VA/MD	5	1	6	13
Dominion Southeast	10	1	19	68
Eastern Shore	9	1	15	40
Gulf South Zone 2 HH	6	2	10	31
Iroquois Z1 → Z2	7	2	8	33
NB/NS Supply	5	6	23	68
PNGTS N of Westbrook	6	2	23	70
PNGTS S of Westbrook	5	2	31	72
Tennessee Z5 NY	1	92	92	92
Texas Eastern Zone ETX	10	1	17	42
Transco Z5	8	1	16	39

6.4 LGDS S0 and S1 Analysis

The LGDS captures decreased gas demands relative to the gas demands in the RGDS. The primary drivers of the changes in gas demand by generators represented in the LGDS relate to increased capacity of wind and solar resources, higher natural gas prices at delivery points across the Study Region, and lower electric loads. RCI customer gas demands are also assumed to be lower. Importantly, the gas demands for power generation in MISO North/Central and PJM are materially lower than in the RGDS. The gas demands for power generation in the other PPAs are also lower than in the RGDS.

6.4.1 LGDS S0 and S1 – Winter 2018

Figure 126 summarizes the gas-fired affected generation during the Winter 2018 peak hour by PPA for LGDS S0 and LGDS S1.

Figure 126. LGDS S0 v. S1 Winter 2018: Peak Hour Affected Generation

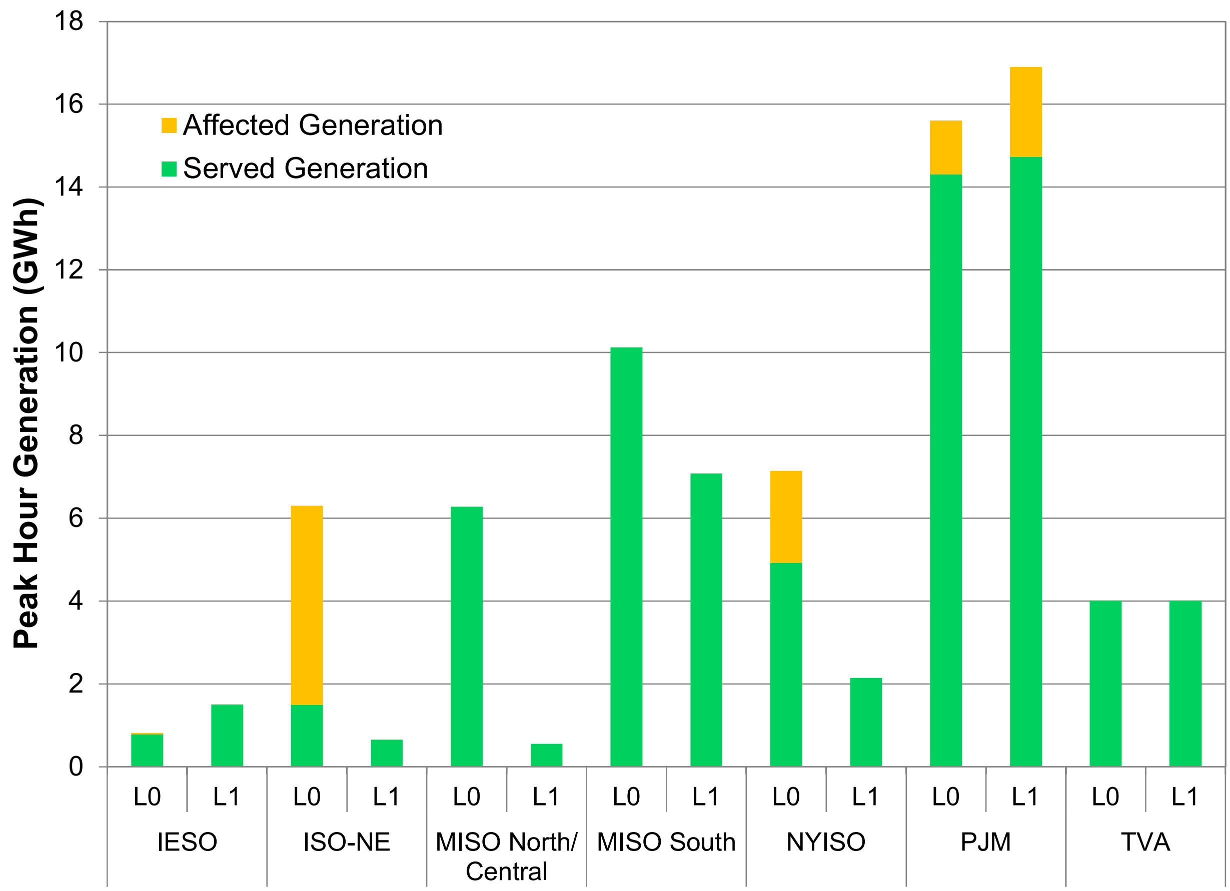


Figure 127 summarizes the unserved gas demand by GPCM location. The unserved gas demand and affected generation by location are quantified in Table 33. The very small amount of affected generation in LGDS S0 for IESO disappeared in S1 despite an increase in generator gas demand because the gas network flow pattern changed favorably for Ontario.

Figure 127. LGDS S0 v. S1 Winter 2018: GPCM Locations with Peak Hour Affected Generation

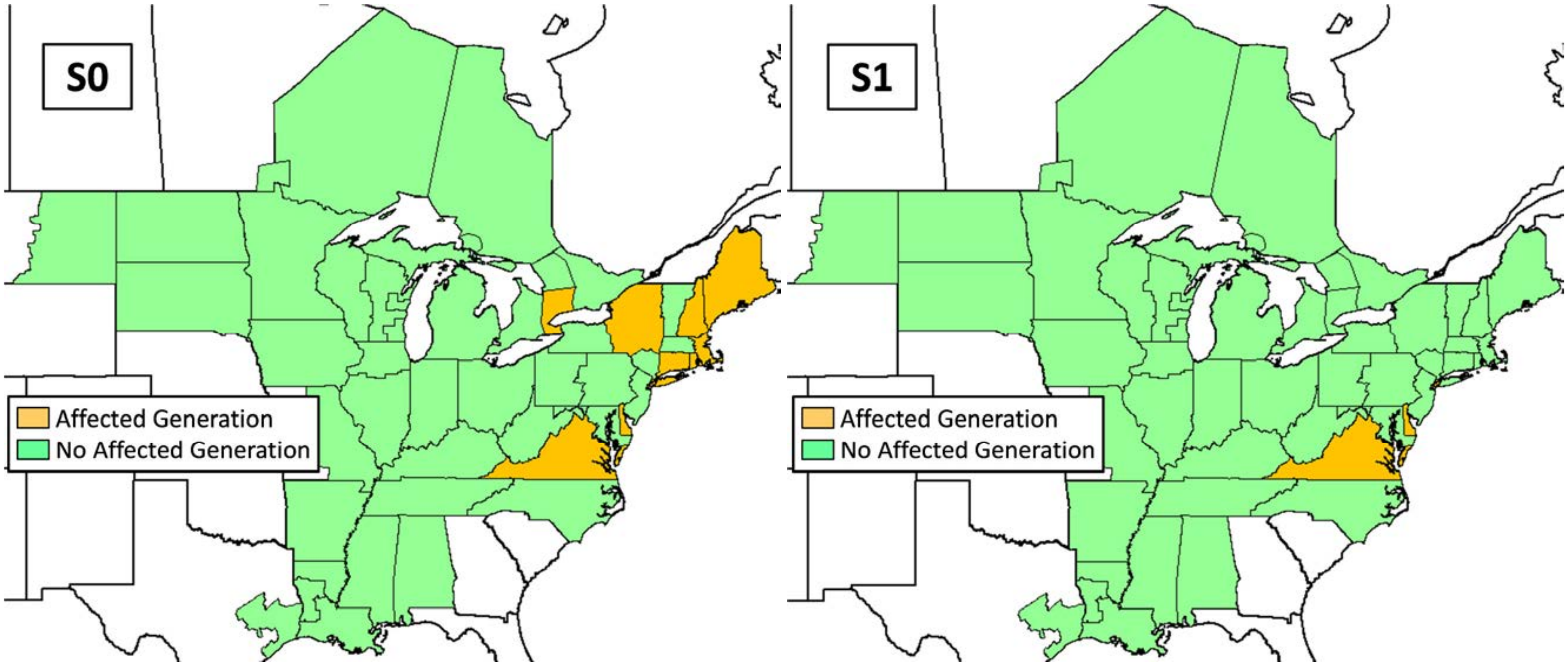
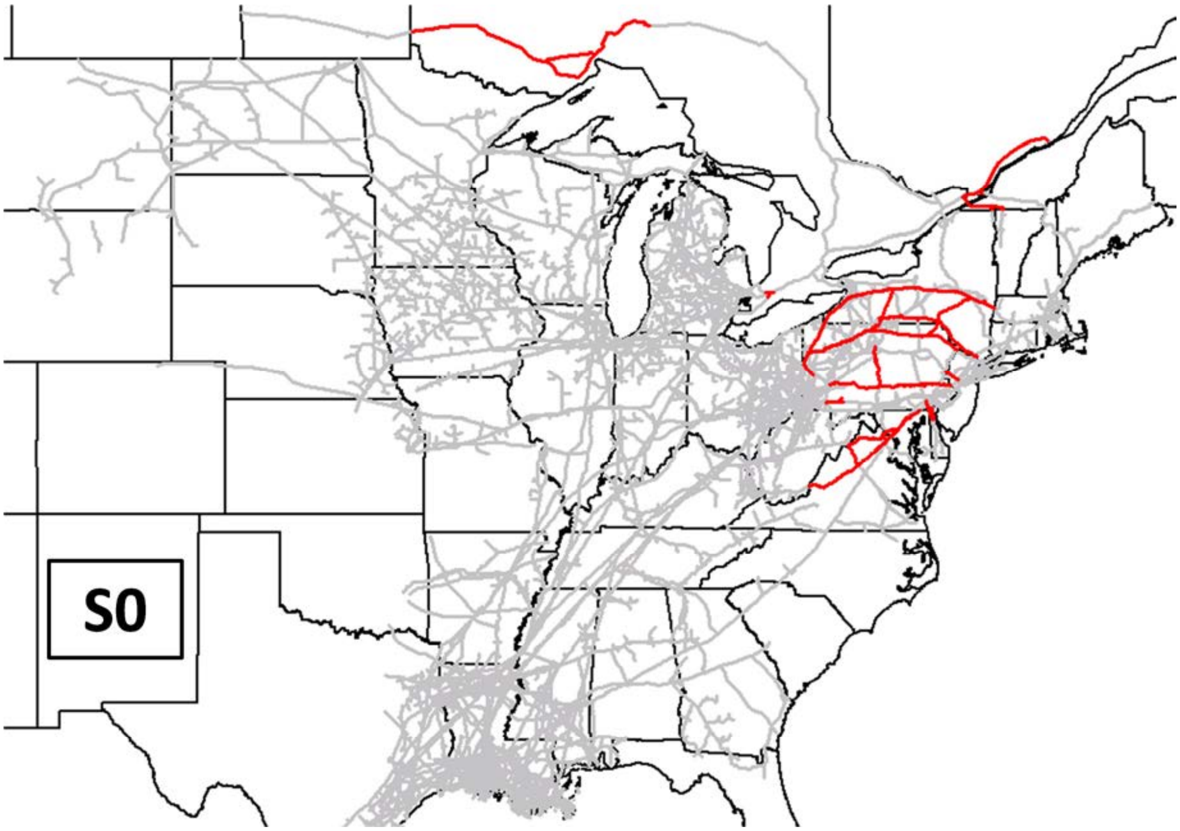


Table 33. LGDS S0 v. S1 Winter 2018: Peak Hour Unserved Generation Gas Demand and Affected Generation

GPCM Location	S0 Unserved Generation Gas Demand (MDth)	S0 Affected Generation (MWh)	S1 Unserved Generation Gas Demand (MDth)	S1 Affected Generation (MWh)
Connecticut	9.1	1,205.3	0.0	0.0
Delaware	1.1	151.2	0.1	9.1
Maine	7.6	1,044.6	0.0	0.0
Massachusetts Eastern	11.4	1,557.2	0.0	0.0
New Hampshire	4.4	589.2	0.0	0.0
New York Central Northern	0.6	71.1	0.0	0.0
New York City	9.5	1,235.8	0.0	0.0
New York Long Island	8.7	912.1	0.0	0.0
Ontario (CDA)	0.2	27.5	0.0	0.0
Rhode Island	3.1	409.7	0.0	0.0
Virginia	8.5	1,146.4	16.5	2,158.7

Figure 128 shows the constrained pipeline segments, in red, that result in the gas-fired affected generation shown in Figure 126 during the Summer 2018 peak hour.

Figure 128. LGDS S0 v. S1 Winter 2018: Peak Hour Constraints



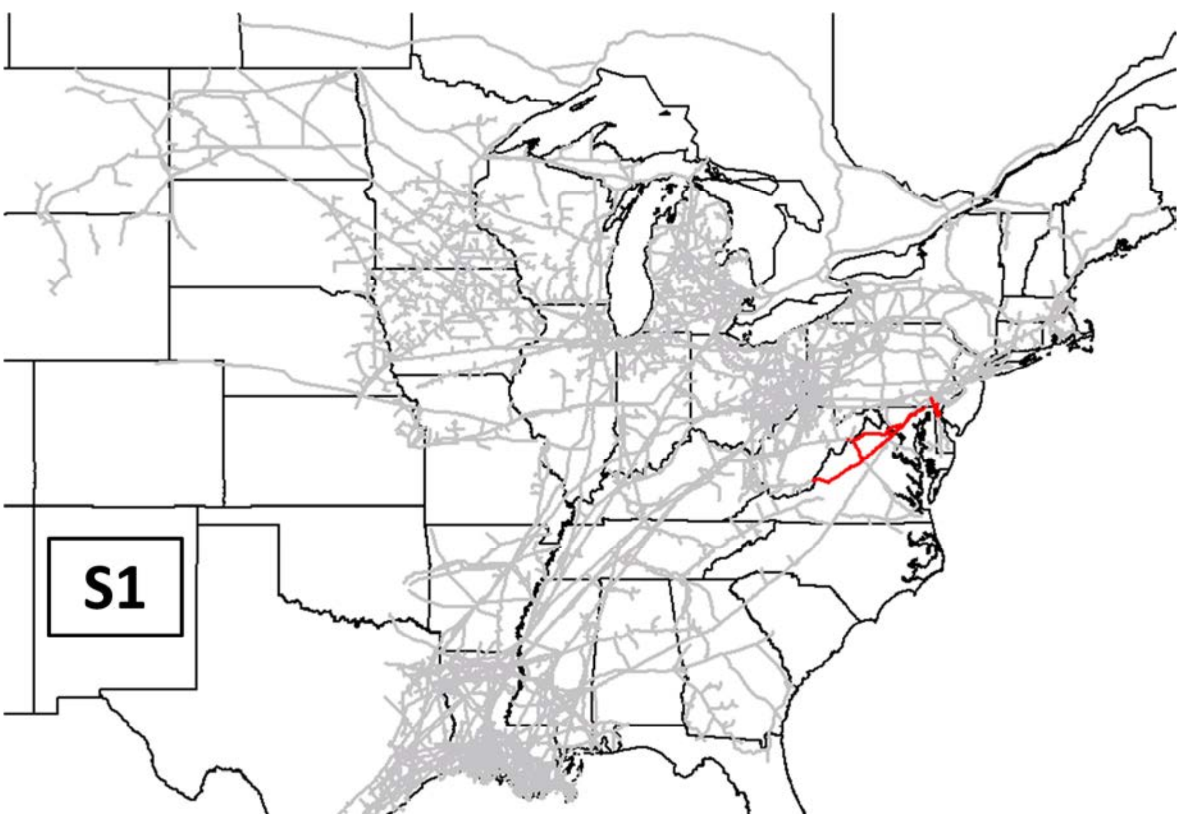


Table 34 summarizes the results of the frequency and duration analysis. For each of the constrained segments listed in Table 34, potentially affected generators are shown in Appendix D and charts illustrating the seasonal daily forecasts of RCI and generator gas demand downstream of the constrained segment relative to the capacity of the segment are included in Appendix E.

Table 34. LGDS S0 Winter 2018: Frequency and Duration of Daily Peak Hour Constraints

Constraint	# of Events	Min. Duration (Days)	Max. Duration (Days)	Total # of Days
Columbia Gas VA/MD*	6	1	2	8
Constitution	3	11	47	89
Eastern Shore*	11	1	6	21
Millennium	4	1	4	7
NB/NS Supply	16	1	10	44
Tennessee Z4 PA	3	1	2	4
Tennessee Z5 NY	12	1	14	49
Texas Eastern M2 PA South	4	1	48	79
Texas Eastern M3 North	8	1	5	19
TransCanada Ontario West	1	2	2	2
TransCanada Quebec	10	1	7	23
Transco Z6 Leidy to 210	12	1	13	41
Union Gas Dawn	2	1	2	3

6.4.2 LGDS S0 Summer 2018

Figure 129 summarizes the gas-fired affected generation during the Summer 2018 peak hour by PPA.

Figure 129. LGDS S0 Summer 2018: Peak Hour Affected Generation

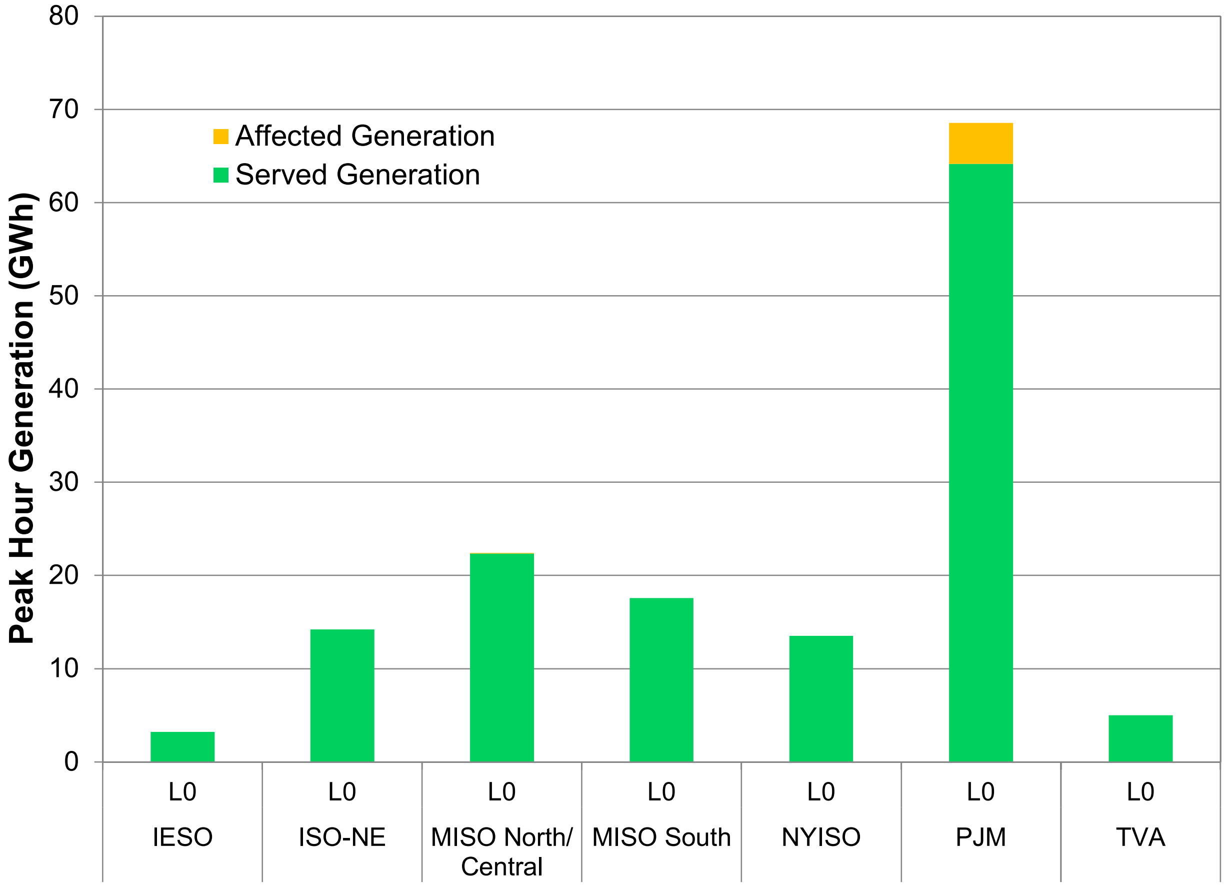


Figure 130 summarizes the unserved gas demand by GPCM location. The unserved gas demand and affected generation by location are quantified in Table 35.

Figure 130. LGDS S0 Summer 2018: GPCM Locations with Peak Hour Affected Generation

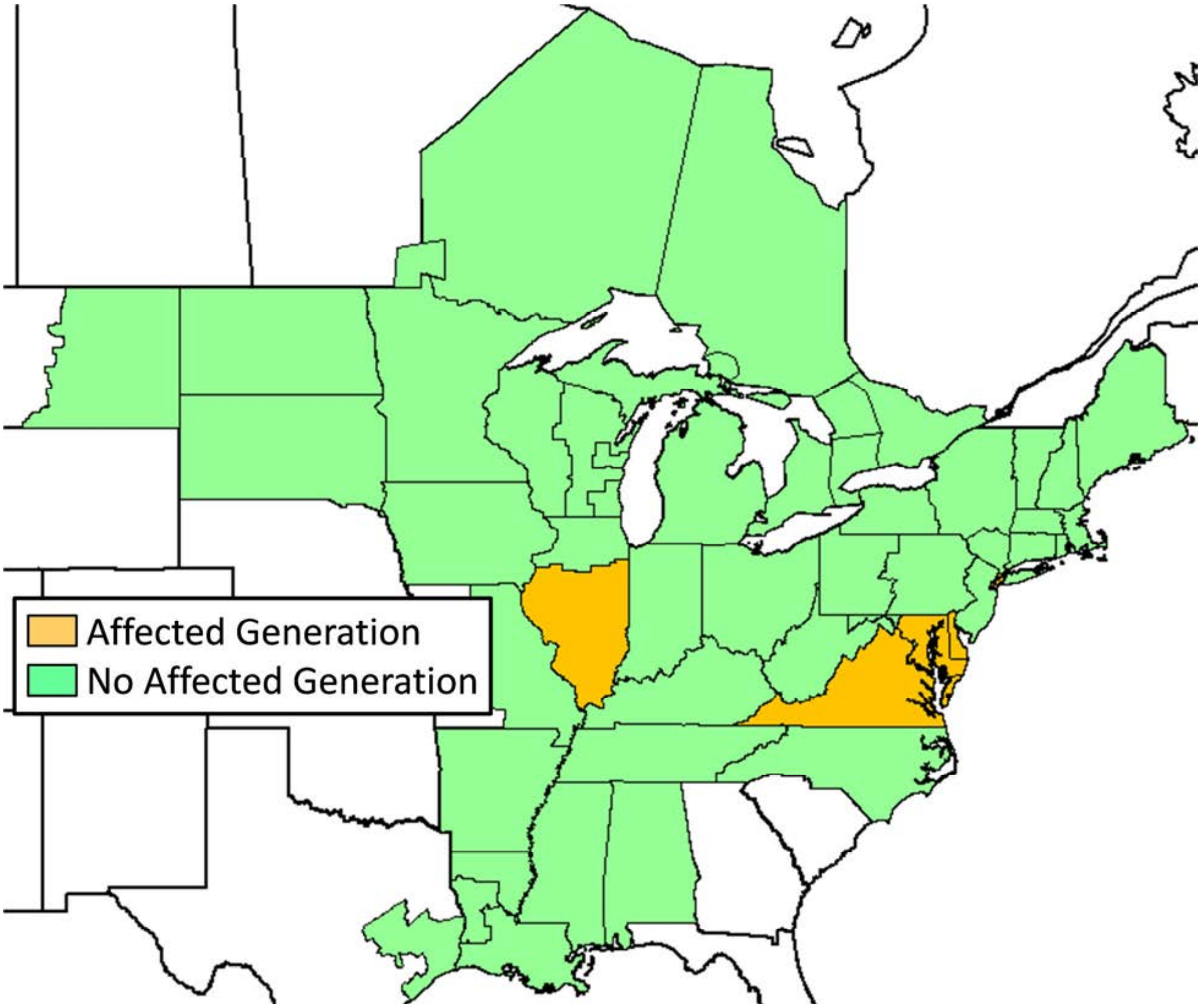


Table 35. LGDS S0 Summer 2018: Peak Hour Unserved Generator Gas Demand and Affected Generation

GPCM Location	Unserved Generator Gas Demand (MDth)	Affected Generation (MWh)
Delaware	8.0	1,119.1
Illinois Southern	0.5	50.2
Maryland Eastern	16.7	2,360.7
Virginia	8.4	936.3

Figure 131 shows the constrained pipeline segments, in red, that result in the gas-fired affected generation shown in Figure 129 during the Summer 2018 peak hour.

Figure 131. LGDS S0 Summer 2018: Peak Hour Constraints

Table 36 summarizes the results of the frequency and duration analysis. For each of the constrained segments listed in Table 30, potentially affected generators are shown in Appendix D and charts illustrating the seasonal daily forecasts of RCI and generator gas demand downstream of the constrained segment relative to the capacity of the segment are included in Appendix E.

Table 36. LGDS S0 Summer 2018: Frequency and Duration of Daily Peak Hour Constraints

Constraint	# of Events	Min. Duration (Days)	Max. Duration (Days)	Total # of Days
Columbia Gas VA/MD	2	1	1	2
Dominion Southeast	1	1	1	1
Eastern Shore	9	1	4	17
Texas Eastern Zone ETX	7	1	6	15
Transco Z5	3	1	3	6

6.4.3 LGDS S0 and S1 – Winter 2023

Figure 132 summarizes the gas-fired affected generation during the Winter 2023 peak hour by PPA for LGDS S0 and LGDS S1.

Figure 132. LGDS S0 Winter 2023: Peak Hour Affected Generation

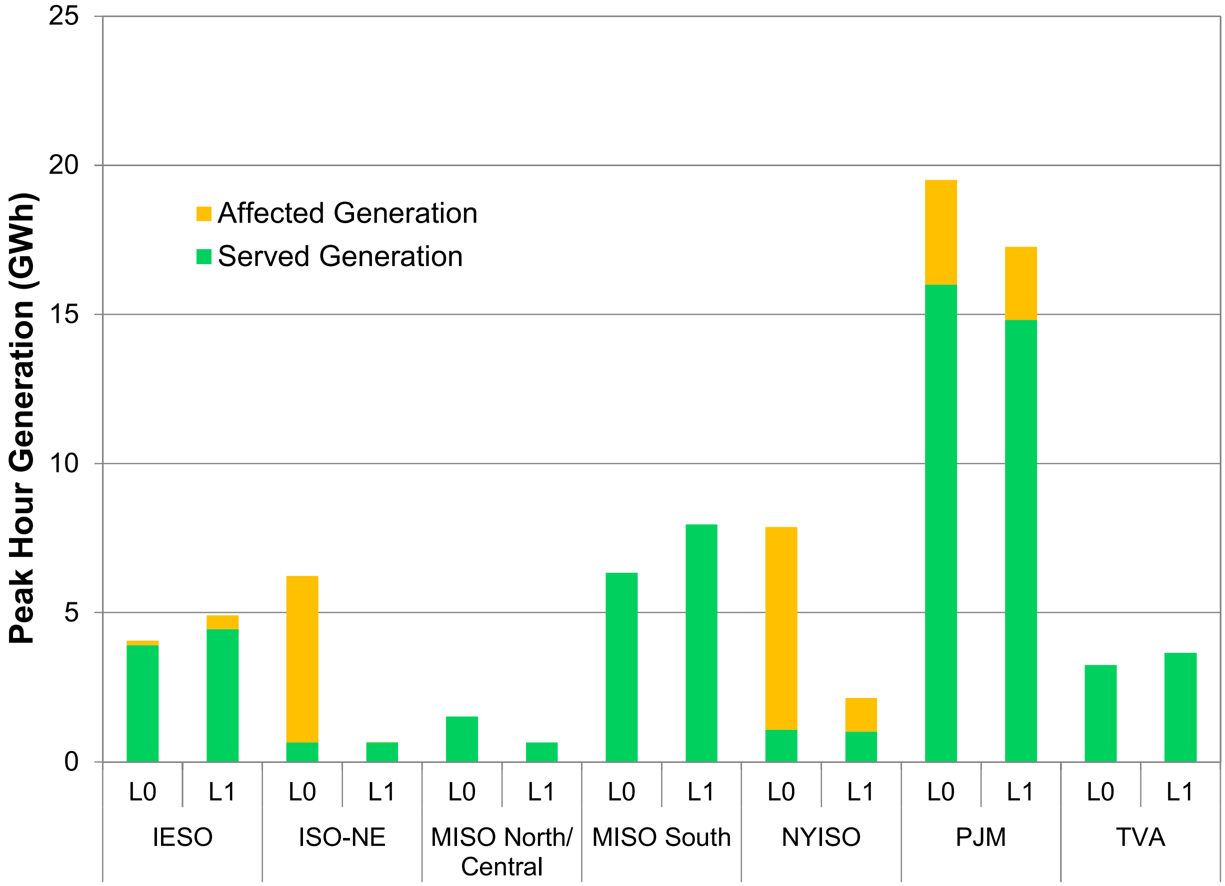


Figure 133 summarizes the unserved gas demand by GPCM location. The unserved gas demand and affected generation by location are quantified in Table 37.

Figure 133. LGDS S0 v. S1 Winter 2023: GPCM Locations with Peak Hour Affected Generation

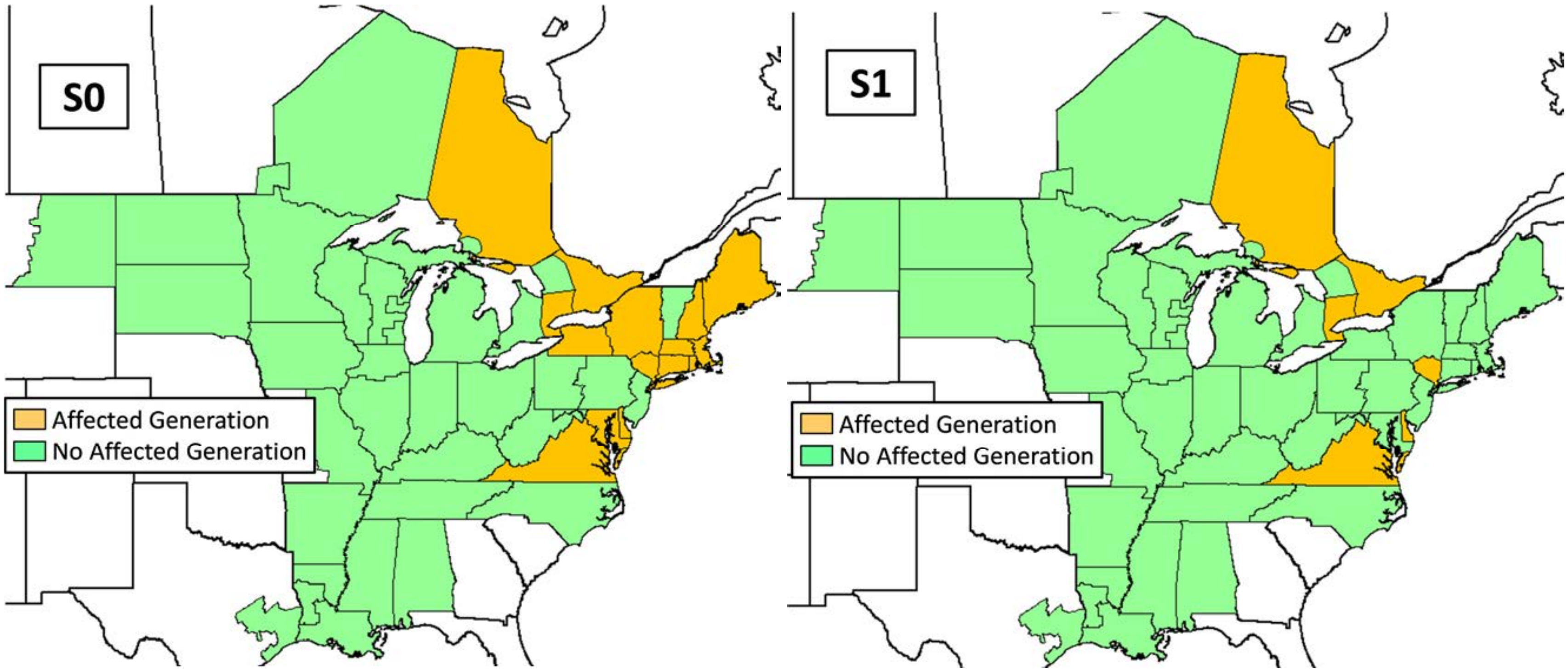


Table 37. LGDS S0 v. S1 Winter 2023: Peak Hour Unserved Generator Gas Demand and Affected Generation

GPCM Location	S0 Unserved Generation Gas Demand (MDth)	S0 Affected Generation (MWh)	S1 Unserved Generation Gas Demand (MDth)	S1 Affected Generation (MWh)
Connecticut	9.8	1,344.9	0.0	0.0
Delaware	1.4	175.4	0.1	9.1
Maine	5.5	759.2	0.0	0.0
Maryland Eastern	3.3	310.6	0.0	0.0
Massachusetts Eastern	6.5	887.7	0.0	0.0
Massachusetts Western	6.1	827.4	0.0	0.0
New Hampshire	7.5	1,002.7	0.0	0.0
New York Central Northern	18.7	2,156.4	0.0	0.0
New York City	16.1	2,103.8	0.0	0.0
New York Long Island	11.5	1,092.1	0.0	0.0
New York Southern	10.9	1,312.3	11.5	1,130.8
New York Western	1.1	125.5	0.0	0.0
Ontario – Central (CDA)	0.2	27.5	0.5	55.1
Ontario – East (EDA)	0.1	7.0	2.1	249.1
Ontario – North (NDA)	0.8	113.6	1.2	154.5
Rhode Island	5.7	756.0	0.0	0.0
Virginia	23.5	3,025.3	18.8	2,438.5

Figure 134 shows the constrained pipeline segments, in red, that result in the gas-fired affected generation shown in Figure 132 during the Winter 2023 peak hour.

Figure 134. LGDS S0 v. S1 Winter 2023: Peak Hour Constraints

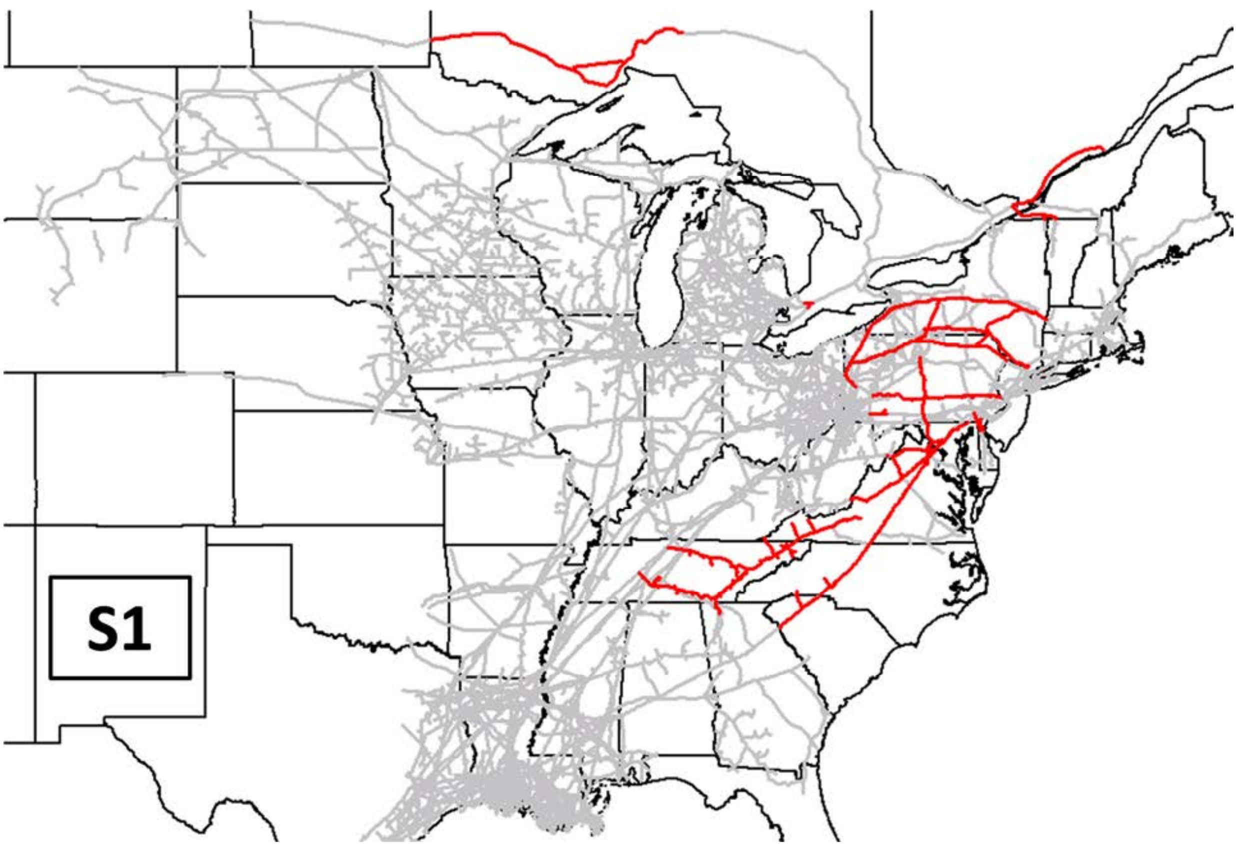


Table 38 summarizes the results of the frequency and duration analysis. For each of the constrained segments listed in Table 38, potentially affected generators are shown in Appendix D and charts illustrating the seasonal daily forecasts of RCI and generator gas demand downstream of the constrained segment relative to the capacity of the segment are included in Appendix E.

Table 38. LGDS S0 Winter 2023: Frequency and Duration of Daily Peak Hour Constraints

Constraint	# of Events	Min. Duration (Days)	Max. Duration (Days)	Total # of Days
Algonquin CT	9	1	15	54
Columbia Gas VA/MD*	7	1	52	76
Constitution*	2	31	59	90
Dominion Eastern NY	5	1	5	12
Dominion Western NY	1	4	4	4
Dominion Southeast*	5	2	12	29
East Tennessee	2	1	2	3
Eastern Shore*	14	1	9	41
Millennium*	2	31	59	90
NB/NS Supply*	2	31	59	90
Tennessee Z4 PA*	4	1	4	9
Tennessee Z5 NY*	8	1	41	81
Texas Eastern M2 PA South*	5	2	2	10
Texas Eastern M3 North*	5	1	3	8
TransCanada Ontario West*	5	1	10	15
TransCanada Quebec*	9	1	7	23
Transco Z5*	5	1	2	6
Transco Z6 Leidy to 210*	9	1	5	17
Union Gas Dawn*	2	1	2	5

6.4.4 LGDS S0 Summer 2023

Figure 135 summarizes the gas-fired affected generation during the Summer 2023 peak hour by PPA.

Figure 135. LGDS S0 Summer 2023: Peak Hour Affected Generation

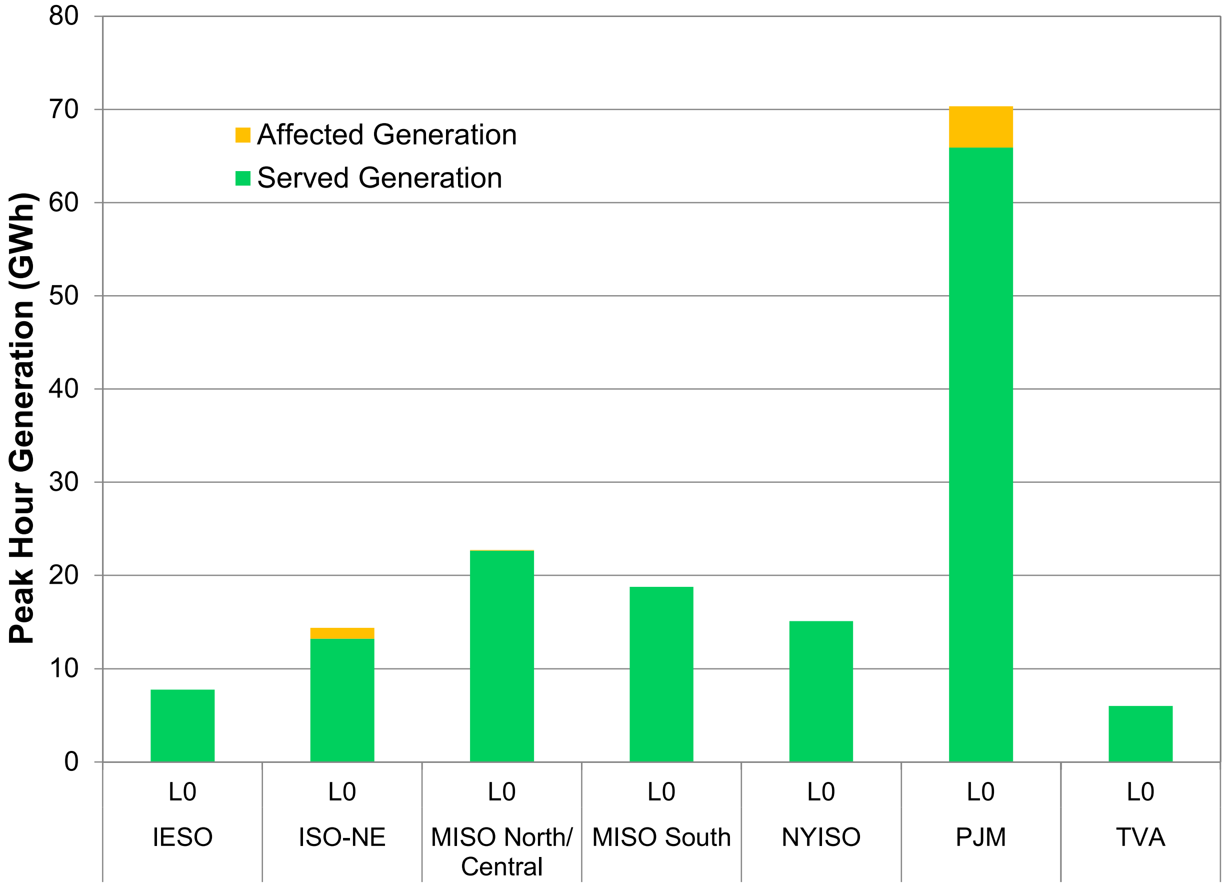


Figure 136 summarizes the unserved gas demand by GPCM location. The unserved gas demand and affected generation by location are quantified in Table 39.

Figure 136. LGDS S0 Summer 2023: GPCM Locations with Peak Hour Affected Generation

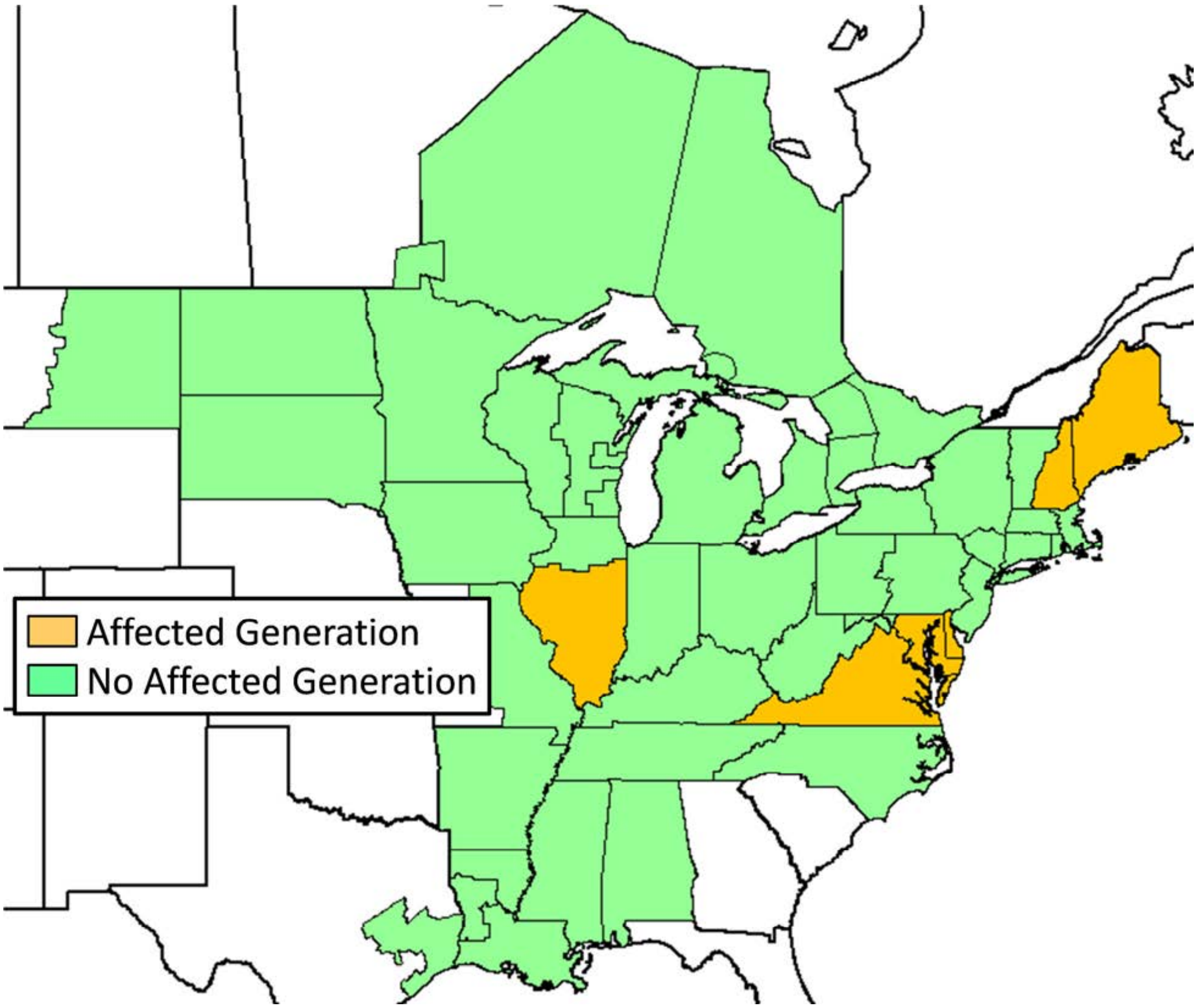


Table 39. LGDS S0 Summer 2023: Peak Hour Unserved Generator Gas Demand and Affected Generation

GPCM Location	Unserved Generator Gas Demand (MDth)	Affected Generation (MWh)
Delaware	8.0	1,119.1
Illinois Southern	0.6	66.9
Maine	4.0	540.4
Maryland Eastern	16.7	2,360.7
New Hampshire	5.8	651.6
Virginia	8.4	936.3

Figure 137 shows the constrained pipeline segments, in red, that result in the gas-fired affected generation shown in Figure 135 during the Summer 2023 peak hour.

Figure 137. LGDS S0 Summer 2023: Peak Hour Constraints

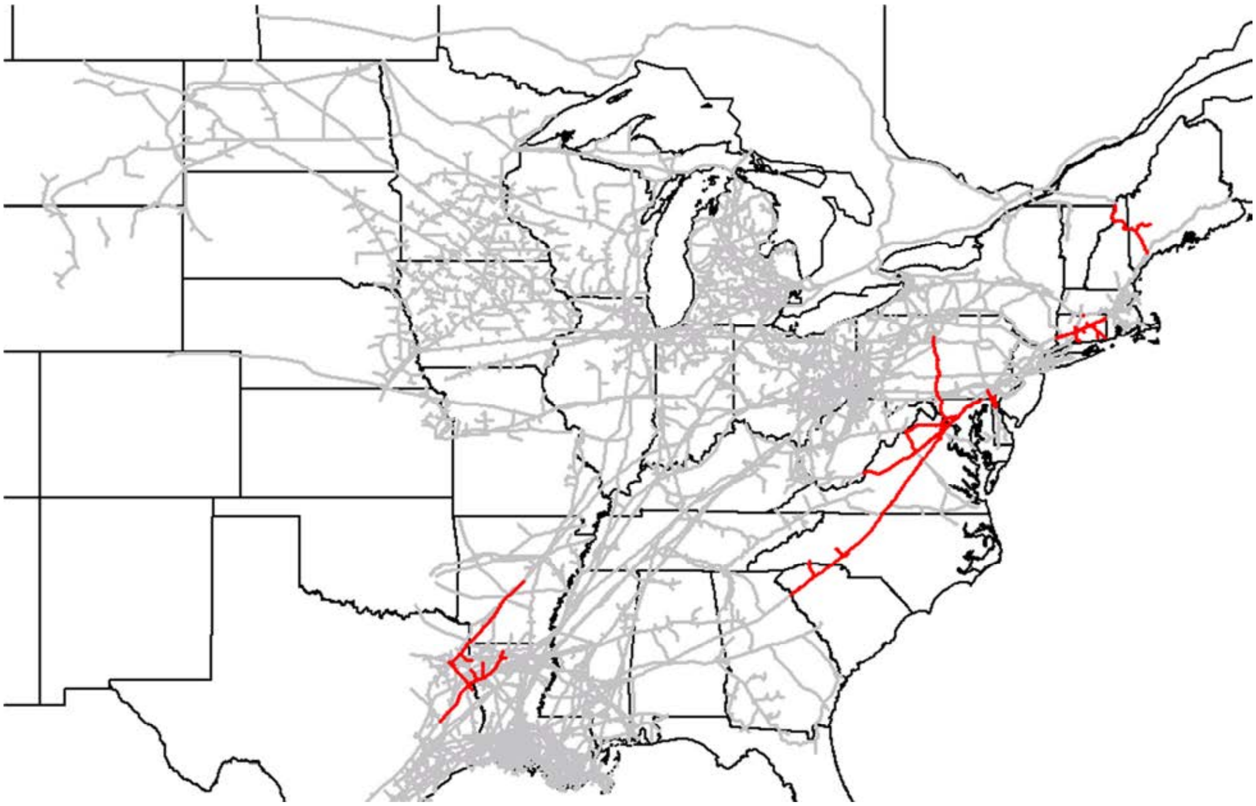


Table 40 summarizes the results of the frequency and duration analysis. For each of the constrained segments listed in Table 40, potentially affected generators are shown in Appendix D and charts illustrating the seasonal daily forecasts of RCI and generator gas demand downstream of the constrained segment relative to the capacity of the segment are included in Appendix E.

Table 40. LGDS S0 Summer 2023: Frequency and Duration of Daily Peak Hour Constraints

Constraint	# of Events	Min. Duration (Days)	Max. Duration (Days)	Total # of Days
Algonquin CT	1	2	2	2
Columbia Gas VA/MD	3	1	2	4
Dominion Southeast	5	1	3	9
Eastern Shore	7	1	3	14
NB/NS Supply	6	3	38	72
PNGTS S of Westbrook	9	1	3	17
Texas Eastern Zone ETX	5	1	3	13
Transco Z5	6	1	3	11

7 SENSITIVITY ANALYSIS

In addition to S1, 20 other sensitivities were constructed to evaluate the impact of changing one or more key variables relative to a corresponding S0 scenario: RGDS, HGDS, and/or LGDS. The list of sensitivities was developed with input from the SSC, and with the approval of the PPAs. Table 41 provides a brief description of each sensitivity, identifies the corresponding scenario, and lists the years and seasons analyzed. The abbreviation for each sensitivity case identifies the scenario that the sensitivity is based upon. For example, "HGDS S2" is Sensitivity 2 based on the HGDS. Note that in some figures, this may be further abbreviated as "H2".

Table 41. Sensitivity Cases

Sensitivity	Description	Year & Season
RGDS S1 HGDS S1 LGDS S1	Apply market gas prices for peak winter day	Winter 2018 Winter 2023
HGDS S2 LGDS S2	Remove decremental (incremental) gas price changes from the HGDS (LGDS)	Winter 2018 Summer 2018 Winter 2023 Summer 2023
RGDS S3	Significantly lower delivered gas prices	Winter 2018 Summer 2018 Winter 2023 Summer 2023
RGDS S5a	Deactivation of additional coal and nuclear resources, replaced by wind and solar resources	Winter 2018 Summer 2018 Winter 2023 Summer 2023
RGDS S5b	Deactivation of additional coal and nuclear resources, replaced by imports of Quebec hydropower	Winter 2023 Summer 2023
RGDS S5c	Deactivation of additional coal and nuclear resources, replaced by EE/DR	Winter 2018 Summer 2018 Winter 2023 Summer 2023
HGDS S9	Ontario nuclear units scheduled to be refurbished instead reach the end of life after 2018 and before 2023; Indian Point 2 & 3 retire by end of 2015	Winter 2018 Summer 2018 Winter 2023 Summer 2023
RGDS S13	Increased infrastructure to enable additional Marcellus/Utica flows to neighboring PPAs	Winter 2018 Summer 2018 Winter 2023 Summer 2023
RGDS S14	Increased gas storage availability and deliverability	Winter 2018 Summer 2018 Winter 2023 Summer 2023

Sensitivity	Description	Year & Season
RGDS S16	Increased sendout from Canaport and Distrigas LNG terminals	Winter 2018 Summer 2018 Winter 2023 Summer 2023
RGDS S18	High electric load growth	Winter 2018 Summer 2018 Winter 2023 Summer 2023
RGDS S19	High industrial gas demand	Winter 2018 Summer 2018 Winter 2023 Summer 2023
RGDS S23	Increased LNG exports from U.S. terminals	Winter 2018 Summer 2018 Winter 2023 Summer 2023
RGDS S30 HGDS S30	Bar gas use in dual fuel resources	Winter 2018 Summer 2018
RGDS S31	Very cold snap with 90/10 electric and RCI gas demands	Winter 2018 Winter 2023
RGDS S33	S31 + high forced outage rate for coal and oil units	Winter 2018 Winter 2023
RGDS S34	Maximum gas demand on electric sector	Winter 2018 Summer 2018 Winter 2023 Summer 2023
RGDS S36	S33 + Selected nuclear units unavailable	Winter 2018 Winter 2023
RGDS S37	S13 + Canaport converted to LNG export facility	Winter 2023 Summer 2023

The following subsections describe the construction of each sensitivity case, the impact on electric generation and/or RCI sector gas demand, and the affected generation determined for each sensitivity. The sensitivities have been grouped by similar variables in order to compare the relative changes. The gas demand forecasts by GPCM location for each sensitivity compared to the relevant gas demand are presented in Exhibit 18. Pipeline utilization maps for each sensitivity are included in Exhibit 16

7.1 IMPACT OF GAS PRICES: S2 AND S3

7.1.1 Description of S2 and S3

As illustrated in Figure 33 through Figure 36, there are significant differences in electric sector gas demands across the RGDS, HGDS, and LGDS. Each of three variables differs materially by scenario: electric load forecast, natural gas prices, and resource mix. S2 and S3 evaluate the impact of changing gas prices, with no change to any other variable or input factor.

Sensitivity 2 applies the RGDS mid gas price forecast to the HGDS and LGDS to isolate the impact of this variable alone.

Sensitivity 3 isolates the impact of lower natural gas prices on the RGDS. The low natural gas price forecast utilized in the HGDS was applied to construct this sensitivity. No other changes were made to the RGDS. Locational basis is the same in all scenarios, so S2 and S3 represent an across-the-board increase in gas prices in HGDS S2 relative to HGDS S0, a decrease in gas prices in LGDS S2 relative to LGDS S0, and an decrease in gas prices in RGDS S3 relative to RGDS S0, corresponding to the differences between scenarios in the AEO2013 annual Henry Hub prices.

7.1.2 Peak Hour Gas Demand in S2 and S3

Figure 138 through Figure 141 illustrate the differences in peak hour generator gas demand for HGDS S2, LGDS S2, and RGDS S3, compared to the corresponding base scenarios, HGDS S0, LGDS S0, and RGDS S0. Note that the gas demand for each sensitivity is paired in these figures with the corresponding base scenario, *e.g.*, HGDS S2 is paired with HGDS S0.

As expected, the peak hour gas demand in HGDS S2 is generally lower than in HGDS S0. There is no more than one PPA exception for any season and year case, which can be accounted for by different transmission flows and relative fuel costs by location. PJM shows the largest reduction in HGDS S2 generator gas demand relative to HGDS S0 in every season and year. Similarly, the peak hour generator gas demand in LGDS S2 is generally higher than in LGDS S0. Gas demand is reduced in every PPA in 2018 but there is one PPA with a small increase in both Winter and Summer 2023. PJM usually has the largest absolute increases in gas demand in LGDS S2, and TVA the largest increase in Summer 2018. With one exception (IESO in Summer 2018) across the four peak seasons, PPA gas demand in RGDS S3 increases relative to RGDS S0. The largest increases in peak hour gas demand are in MISO and PJM, for both winter and summer.

In all of these scenarios, the differences between the sensitivity and the corresponding base S0 scenario are less pronounced in the summer than in the winter. Electric sector gas demand increases more in winter than summer because the lower winter gas prices in RGDS S3 compared to RGDS S0, and LGDS S2 compared to LGDS S0, allow gas to be more competitive against oil and coal resources, and nearly all gas-capable generation capacity is needed to meet higher summer than winter electric loads. Conversely, higher winter gas prices in HGDS S2 compared to HGDS S0 cause more coal and oil resources to displace gas-fired resources.

Figure 138. S0, S2 and S3 Winter 2018: Electric Sector Gas Demand

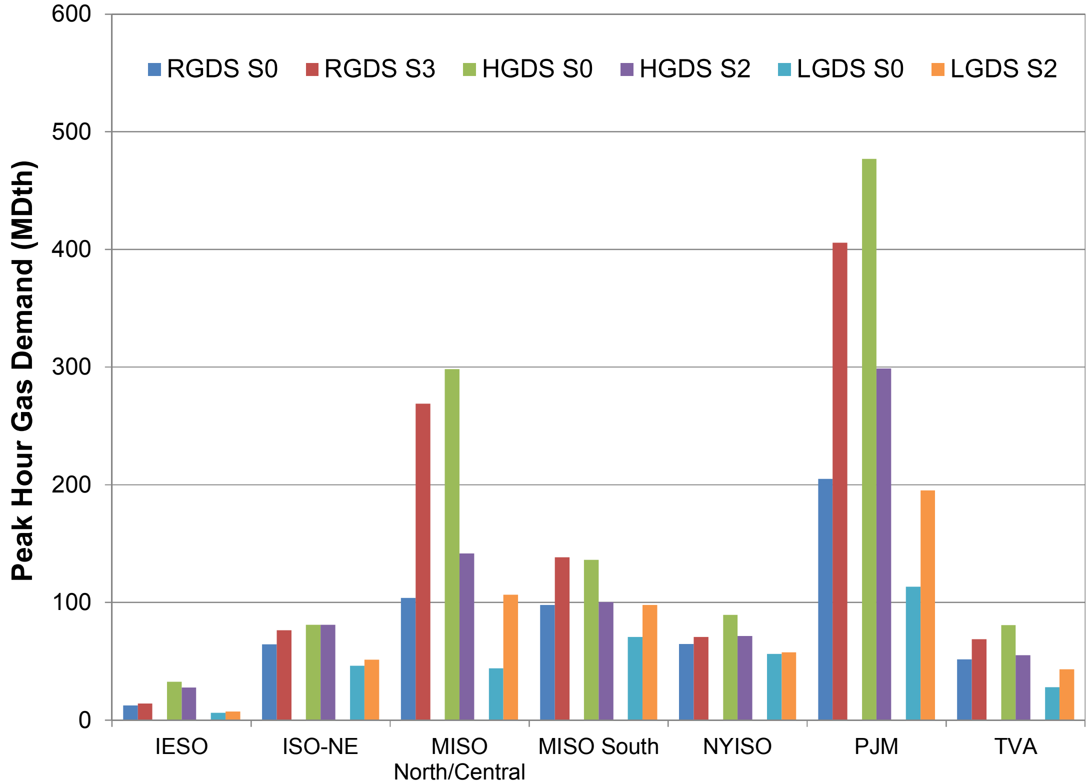


Figure 139. S0, S2 and S3 Summer 2018: Electric Sector Gas Demand

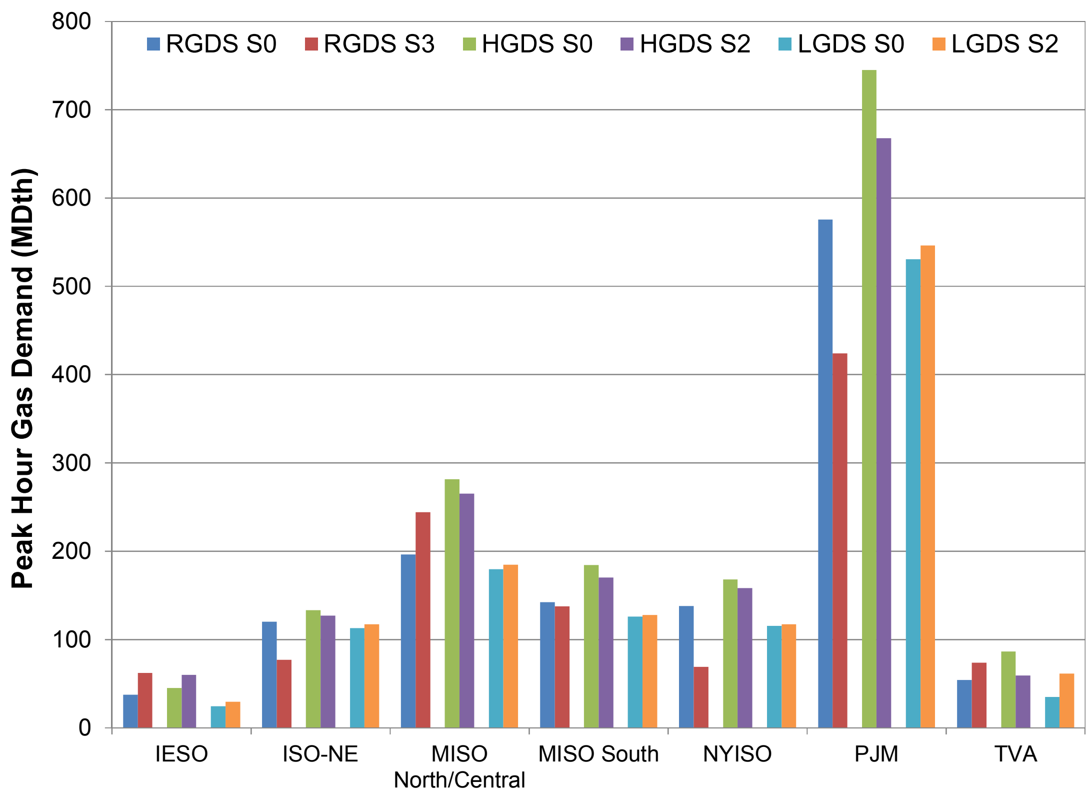


Figure 140. S0, S2 and S3 Winter 2023: Electric Sector Gas Demand

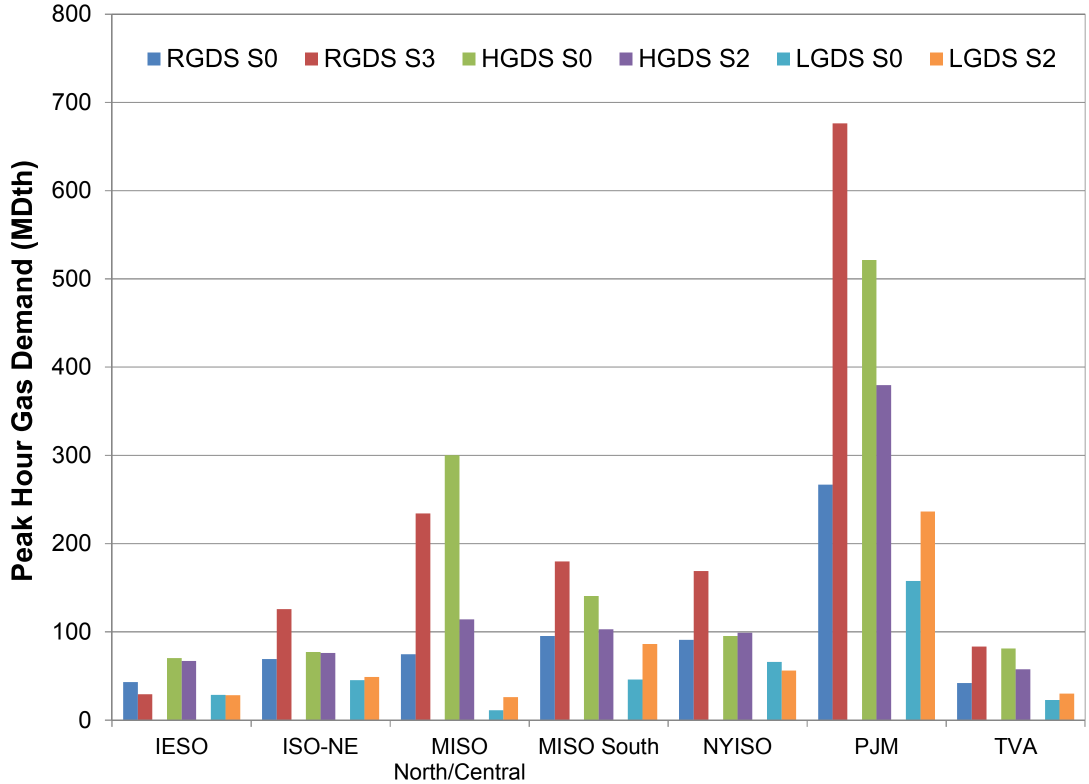
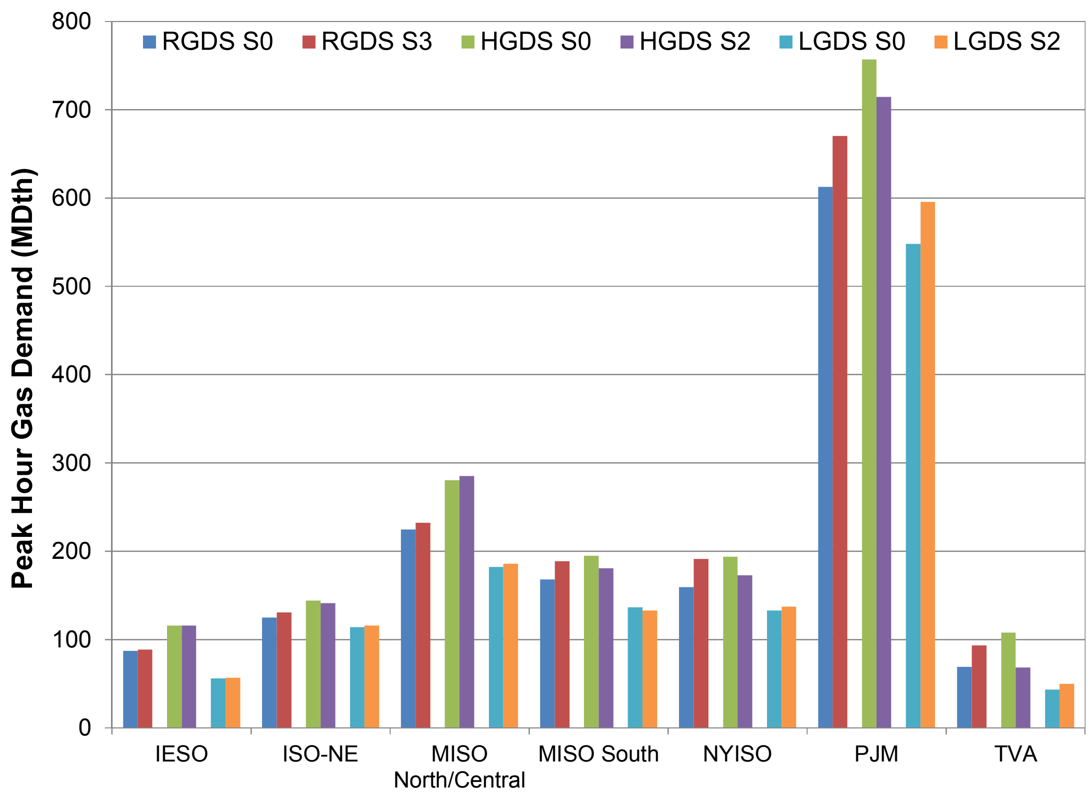


Figure 141. S0, S2 and S3 Summer 2023: Electric Sector Gas Demand



7.1.3 Peak Hour Affected Generation in S2 and S3

Figure 142 through Figure 145 compare the affected generation to served generation for S2 and S3 cases. The only variable changed in HGDS S2, LGDS S2 and RGDS S3 (relative to the corresponding S0 base scenario) is gas price. Increasing gas prices in HGDS S2 relative to HGDS S0 results in a significant decrease in gas usage and in affected generation, whereas decreasing gas prices in LGDS S2 and RGDS S3 relative to LGDS S0 and RGDS S0, respectively, increases gas usage and affected generation across nearly all PPAs. The change in gas prices can present exceptions to the general pattern of results, particularly where there is a significant amount of gas-fired generation tied to lower cost pricing points, thereby changing the level of transmission interchange between neighboring PPAs and between zones within a PPA. Appendices G and H provide further detail regarding the locations of constraints, and the unserved gas demand and affected generation by GPCM location.

Figure 142. S0, S2 and S3 Winter 2018: Peak Hour Affected Generation

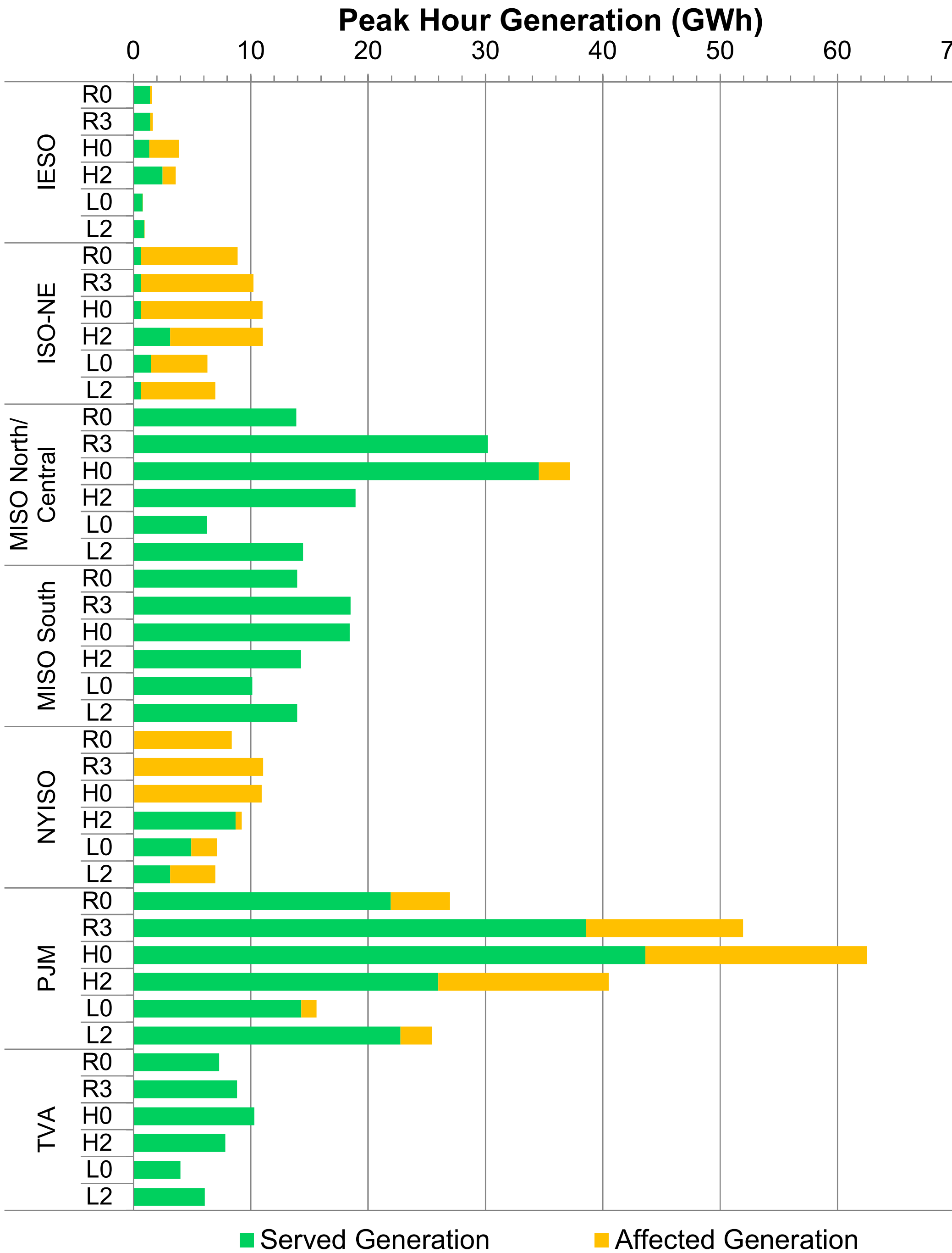


Figure 143. S0, S2 and S3 Summer 2018: Peak Hour Affected Generation

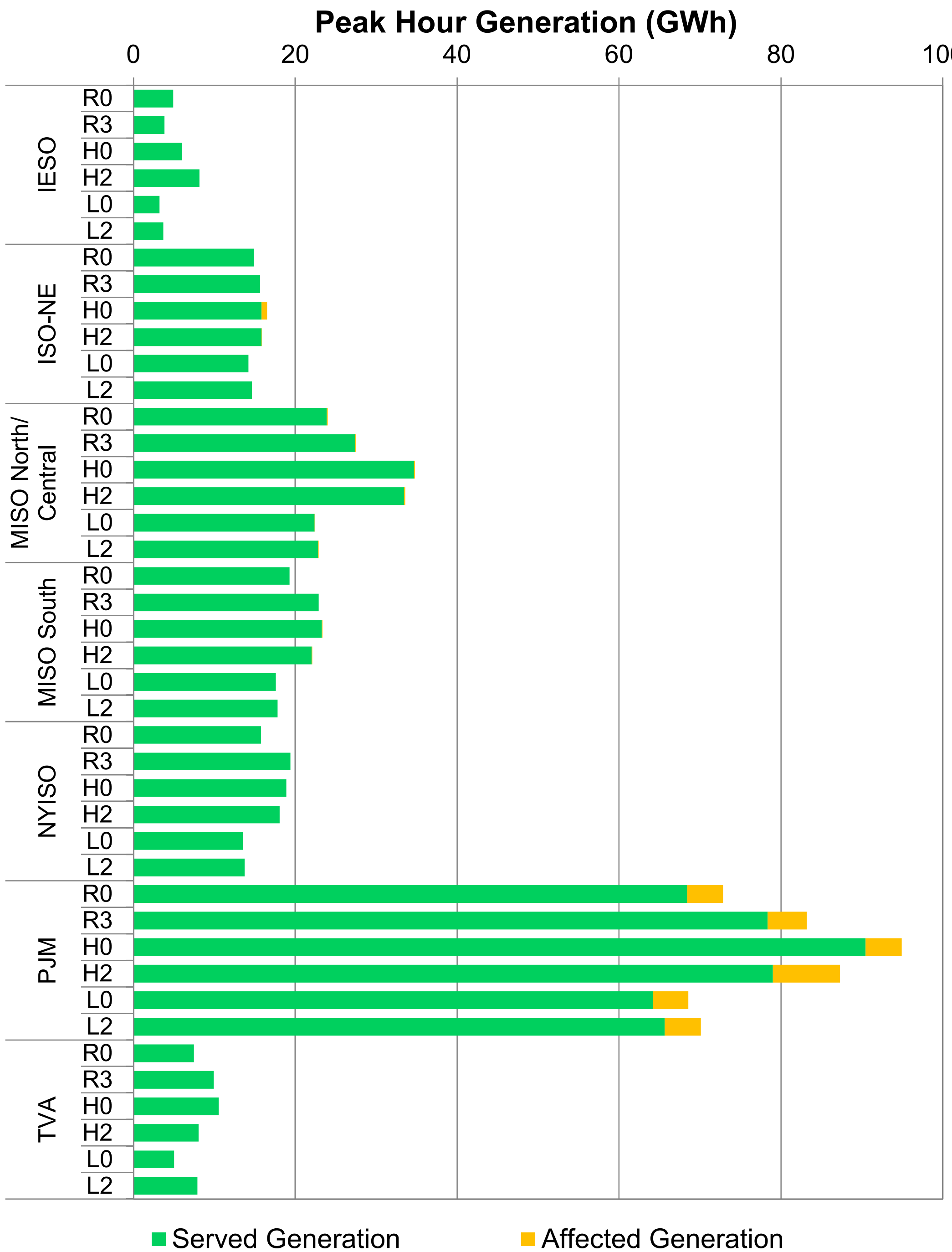


Figure 144. S0, S2 and S3 Winter 2023: Peak Hour Affected Generation

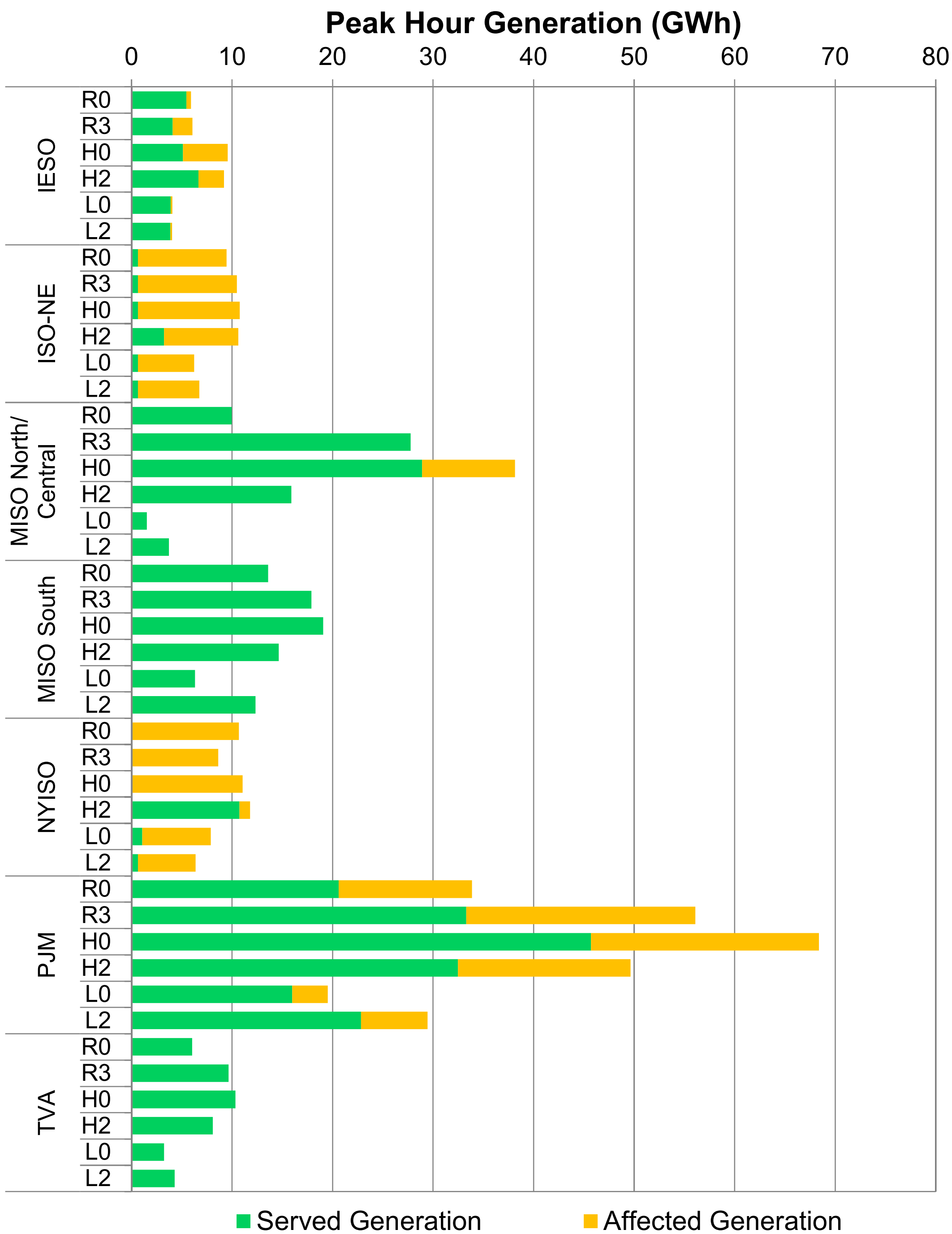
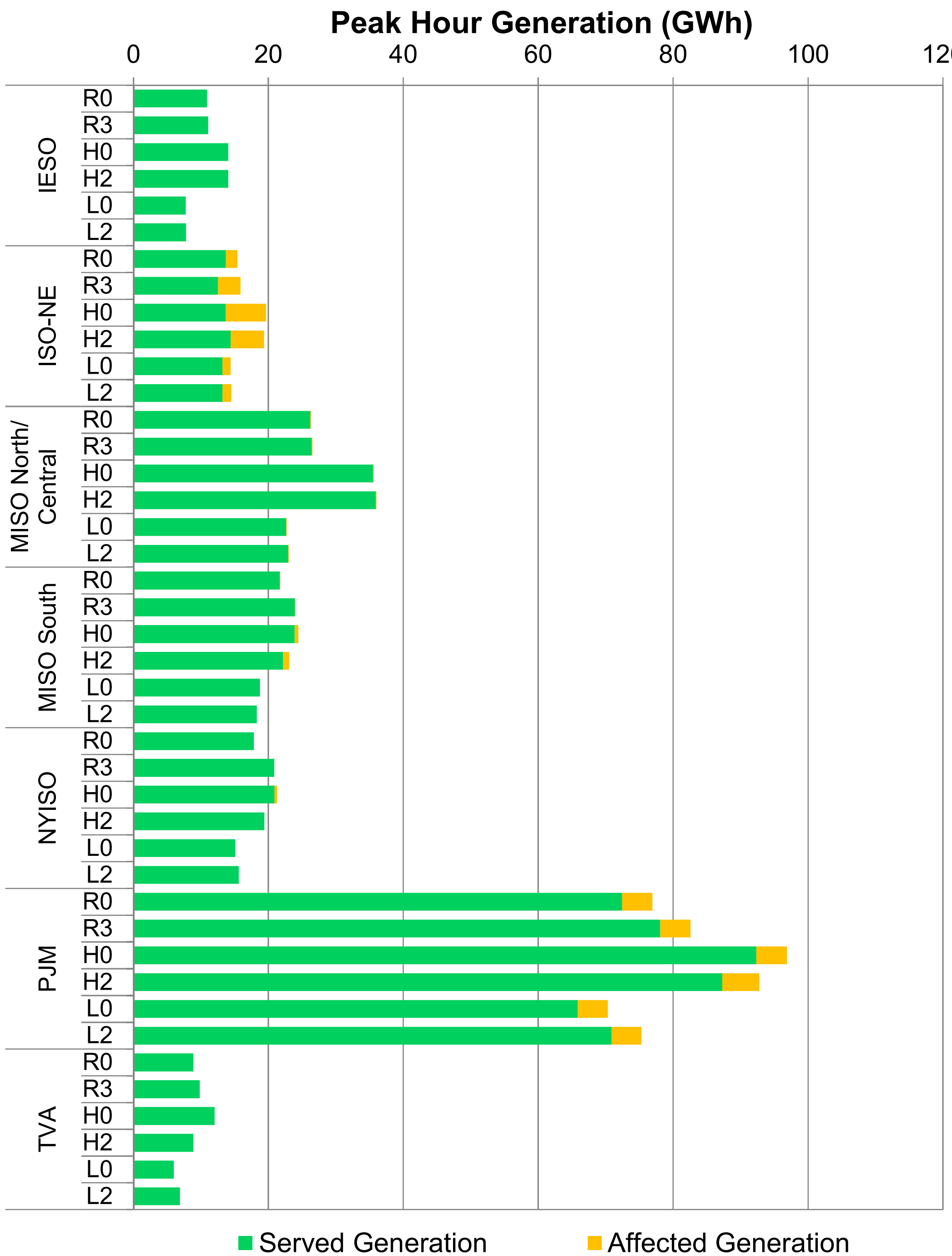


Figure 145. S0, S2 and S3 Summer 2023: Peak Hour Affected Generation



7.2 IMPACT OF COAL AND NUCLEAR PLANT DEACTIVATION: S5A, S5B, S5C, AND S9

7.2.1 Description of S5a, S5b, S5c, and S9

Sensitivities 5a, 5b, and 5c each add clean resources and deactivate coal and nuclear resources, relative to the RGDS. These three sensitivities do not incorporate any change to the gas-capable resource capacity across the PPAs, but changing other resources has an impact on the dispatch of the gas-capable resources.

Sensitivity S5a evaluates the impact of deactivating coal and nuclear resources, and replacing those resources with wind and solar resources. For RGDS S5a, the same incremental onshore wind and solar resources included in the LGDS, about 50 GW across the Study Region by 2023, were added to the resource mix. Applying a summer peak qualified capacity credit factor of 13% for wind resources and 38% for solar resources, the incremental onshore wind and solar resources are equivalent to a summer peak qualified capacity of about 8.7 GW of baseload coal and nuclear resources. To maintain approximately the same qualified capacity, coal and nuclear resources are derated on a *pro rata* basis to match the incremental wind qualified capacity.[91] Assuming that the coal capacity reductions arise from compliance with near-term environmental regulations, all coal deactivations are assumed to occur prior to 2018. The nuclear deratings are incorporated only in the 2023 study year, reflecting the fact that EPA regulations such as Clean Water Act 316(b) rules, and/or other Nuclear Regulatory Commission safety requirements applicable to nuclear units are more likely to be implemented after 2018. The resource mix for Sensitivity 5a is summarized in Exhibit 17.

Sensitivity 5b tests the impact of incremental imports from Quebec replacing deactivated coal and nuclear capacity in the Northeastern U.S. To construct RGDS S5b, the proposed 1,000 MW Champlain-Hudson Power Express project, terminating in New York City at the Astoria power plant, and the proposed 1,000 MW Clean Power Link, terminating near Ludlow, VT, near the to-be-retired Vermont Yankee plant, have been added to create additional transfer capacity from Quebec to ISO-NE and NYISO. Both projects are assumed to be in service by 2023, so only study year 2023 was analyzed for this sensitivity. The two new transmission projects are represented as virtual generators, with summer capacity factors of 100% and 75% for on-peak and off-peak hours, respectively, and winter capacity factors of 60% and 40% for on-peak and off-peak hours, respectively. By modeling these projects as direct injections of scheduled energy, it is not necessary to make specific assumptions regarding the expansion of Quebec resources to provide the additional imports. As for Sensitivity 5a, existing coal and nuclear resources have been derated on a *pro rata* basis by a total of 1,000 MW of combined coal and nuclear capacity in ISO-NE and 1,000 MW in NYISO. The resource mix for Sensitivity 5b is summarized in Exhibit 17.

Sensitivity 5c supposes a deeper level of penetration of EE and DR relative to the RGDS, allowing more deactivation of coal and nuclear capacity across the US portion of the Study Region. To emphasize the impact on electric sector gas consumption during the winter peak days, RGDS S5c is modeled as a system-wide increase in EE, rather than a mix of EE and

[91] Since the wind and solar capacity additions are not added in the same locations as coal and nuclear derating, this resource mix may not recognize local reliability impacts. This same caveat applies to Sensitivities 5b and 5c.

dispatchable DR. EE is modeled as a *pro rata* reduction to electric load across the Study Region, totaling 3,000 MW for the summer 2018 and 6,300 MW (cumulative) for the summer 2023 peak periods. Since the PPAs' forecast of EE is already included in the RGDS electric load forecast, the increment for Sensitivity 5c is intended to be a feasible "stretch" over the original forecast. Thus, the incremental EE quantity by 2018 is assumed to be 0.7% and 1.4% by 2023. The load reduction in 2023 is slightly more than the incremental EE (1.2%) projected in the NERC 2013 *Long-term Reliability Assessment*, which is in good agreement with the forecast in a 2009 Electric Power Research Institute (EPRI) report.[92]

Accounting for a 15% reserve margin, coal resources have been correspondingly derated on a *pro rata* basis for a total of 3,000 MW (+15%) across the Study Region in 2018 and 3,300 MW (+15%) of nuclear unit derates for 2023. The resource mix for Sensitivity 5c is summarized in Exhibit 17.

Sensitivity 9 tests the impact of retiring nuclear resources in IESO in lieu of refurbishment, under HGDS conditions as a further stretch of increasing electric sector gas demand. Under this sensitivity, all nuclear units in IESO will be retired by 2023 except for Bruce units 1 and 2. In NYISO, Indian Point units 2 and 3 are deactivated prior to the 2018 study year. Unlike S5a, S5b, and S5c, S9 replaces the reduced nuclear capacity with gas-fired resources. Based on information from NYISO, 1,000 MW of gas-fired combined cycle capacity was added in zone G-H-I in 2018, and additional gas-fired capacity was added in 2023 to account for load growth. In IESO, the retired nuclear capacity is replaced in the same zone by generic gas-fired combined cycle resources on a summer peak qualified capacity (UCAP) equivalent basis. The resource mix for Sensitivity 9 is summarized in Exhibit 17.

7.2.2 Peak Hour Gas Demand in S5a S5b, S5c, and S9

Figure 146through Figure 149 illustrate the differences in peak hour generator gas demand for RGDS S5a, RGDS S5b, RGDS S5c, and RGDS S9 compared to RGDS S0. S5b was not run for 2018 because new HVDC transmission lines from Quebec were assumed to not be operational by then. Except for RGDS S9, the differences are relatively small, and not in the same direction across PPAs or across the four peak seasons. For these sensitivities, inframarginal non-gas-fired resources (wind, hydropower, or EE) replace other inframarginal non-gas-capable resources (coal and nuclear) on a qualified capacity-equivalent basis. These resource mix changes impact the intra-day dispatch and interzonal energy transfers, but do not significantly change the Study Region-wide gas demand. The lack of a direct change in the gas-capable resources or their operational characteristics and costs explains why displacement of coal and nuclear capacity by inframarginal wind and hydropower capacity does not have the same directional impact on gas demand by PPA and time period. Similarly, since the EE is modeled as a load modifier rather than a dispatchable resource, it does not displace peak hour/peak day gas-fired generation.

In contrast, in RGDS S9, there is a discernible increase in gas demand in NYISO in 2018, reflecting the addition of gas-fired resources to replace Indian Point. Similarly, gas demand in IESO increases in 2023 when new gas-fired resources replace nuclear capacity. In Summer

[92] EPRI, *Assessment of Achievable Potential from Energy Efficiency and Demand response Programs in the U.S. (2010 - 2030)*, 2009.

2018, MISO North/Central has an increase in gas demand. Likewise, in Winter 2023, NYISO gas demand has little change while ISO-NE has higher gas demand and PJM has lower gas demand. The changes in resource mix in RGDS S9 impact LMPs, which in turn affect the capacity factors of coal resources, not just gas resources, which appear to explain why sometimes peak hour generator gas demand changes in a PPA other than NYISO and IESO.

Figure 146. S0, S5a, S5c, and S9 Winter 2018: Electric Sector Gas Demand

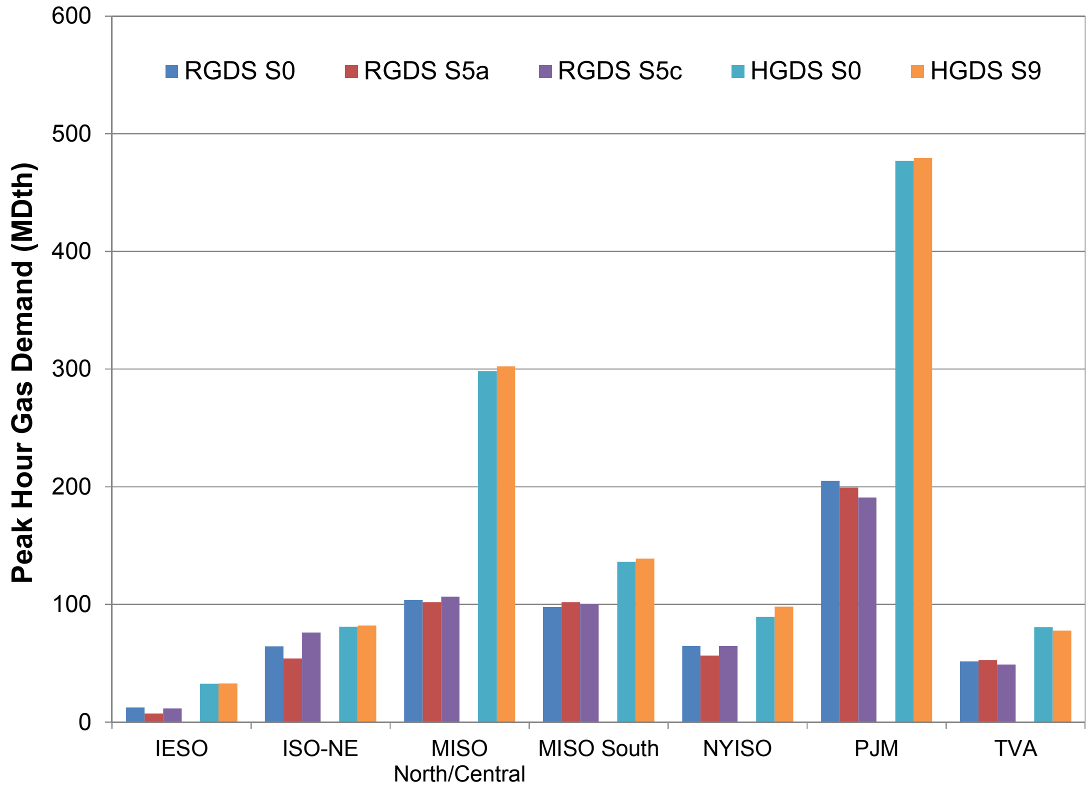


Figure 147. S0, S5a, S5c, and S9 Summer 2018: Electric Sector Gas Demand

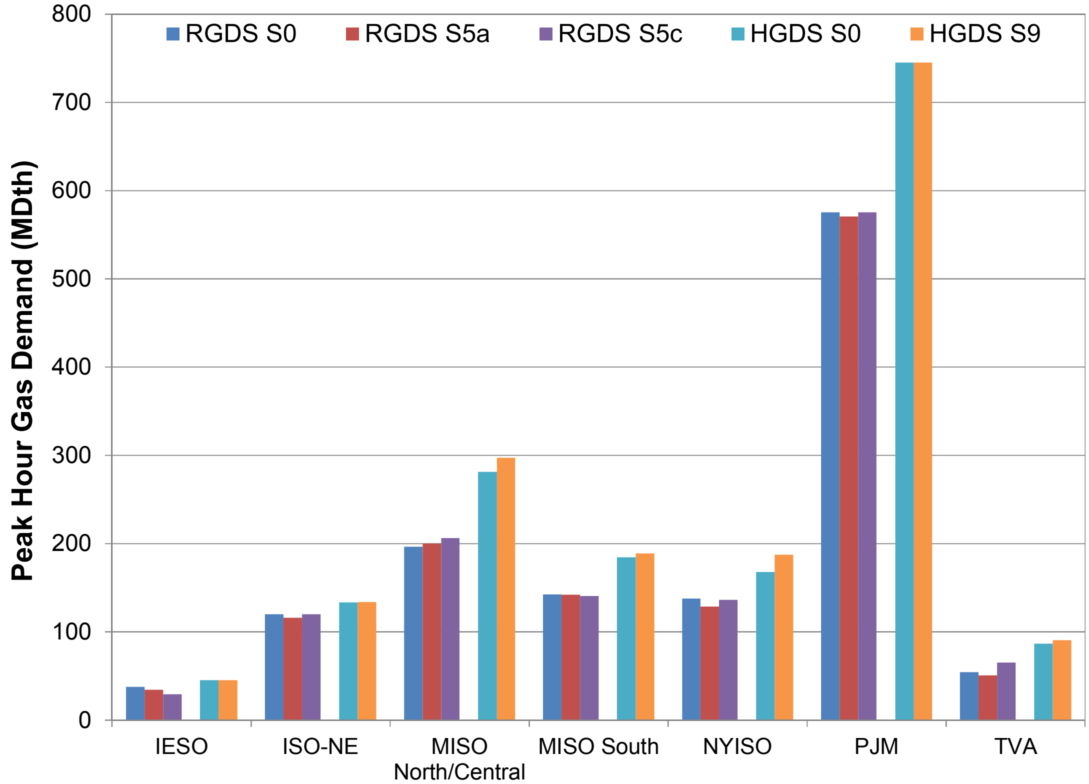


Figure 148. S0, S5a, S5b, S5c, and S9 Winter 2023: Electric Sector Gas Demand

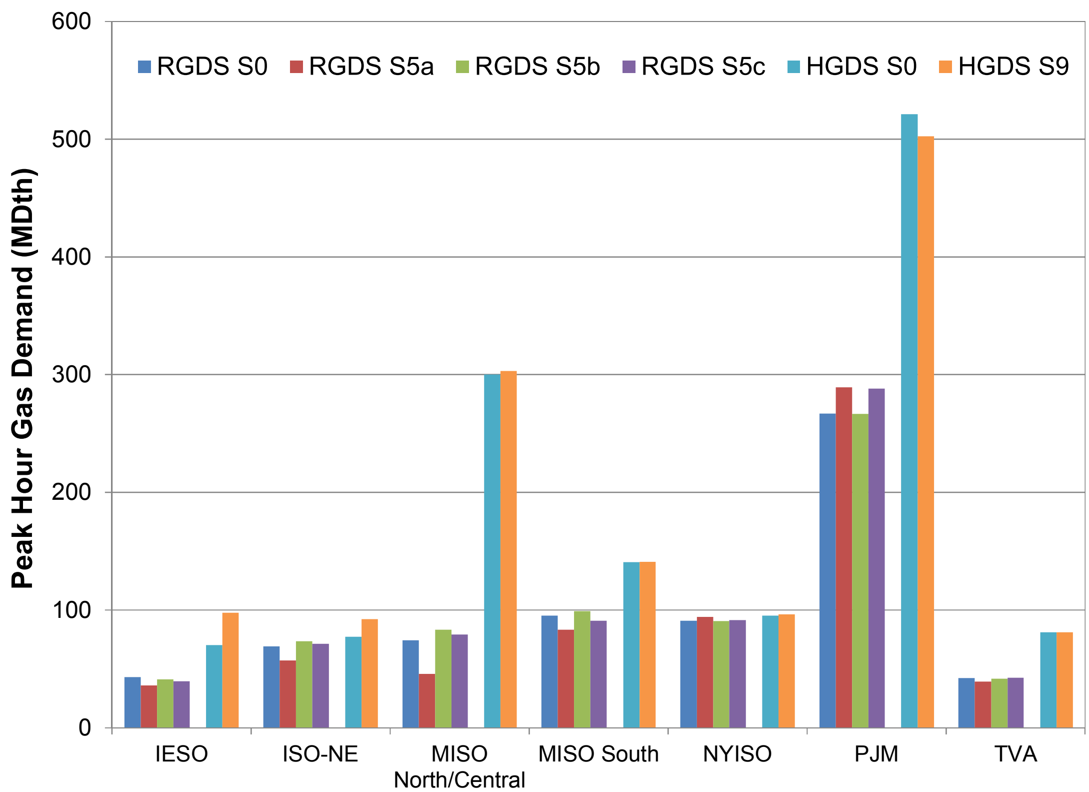
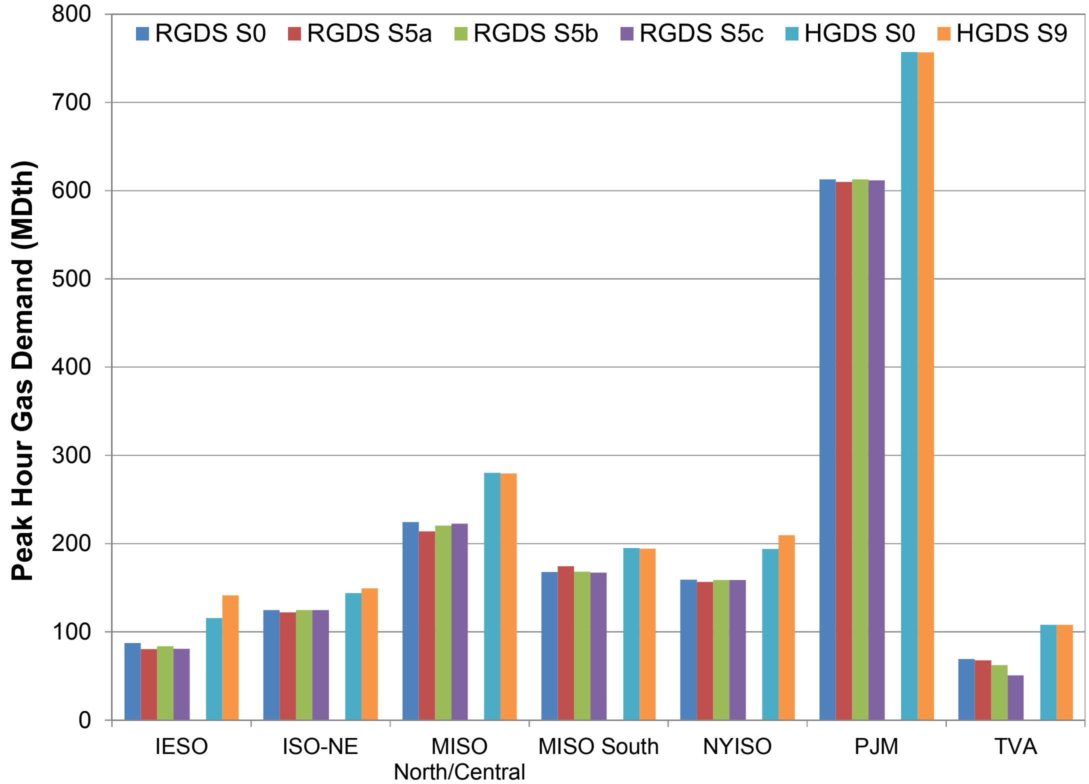


Figure 149. S0, S5a, S5b, S5c, and S9 Summer 2023: Electric Sector Gas Demand



7.2.3 Peak Hour Affected Generation in S5a, S5b, S5c and S9

Figure 150 through Figure 153 compare the affected generation to served generation for S5a, S5b, S5c, and S9. S5b was not run for 2018 because new HVDC transmission lines from Quebec were assumed to not be operational by then. RGDS S5a, RGDS S5b, RGDS S5c, and HGDS S9 involve substitution of non-gas-fired resources (coal and nuclear) for other types of non-gas-fired resources (wind, solar, hydro, and EE/DR). As for the differences in the peak gas demands observed for these sensitivities, the effect on affected generation is negligible. Appendices I and J provide further detail regarding the locations of constraints, and the unserved gas demand and affected generation by GPCM location.

Figure 150. S0, S5a, S5c, and S9 Winter 2018: Peak Hour Affected Generation

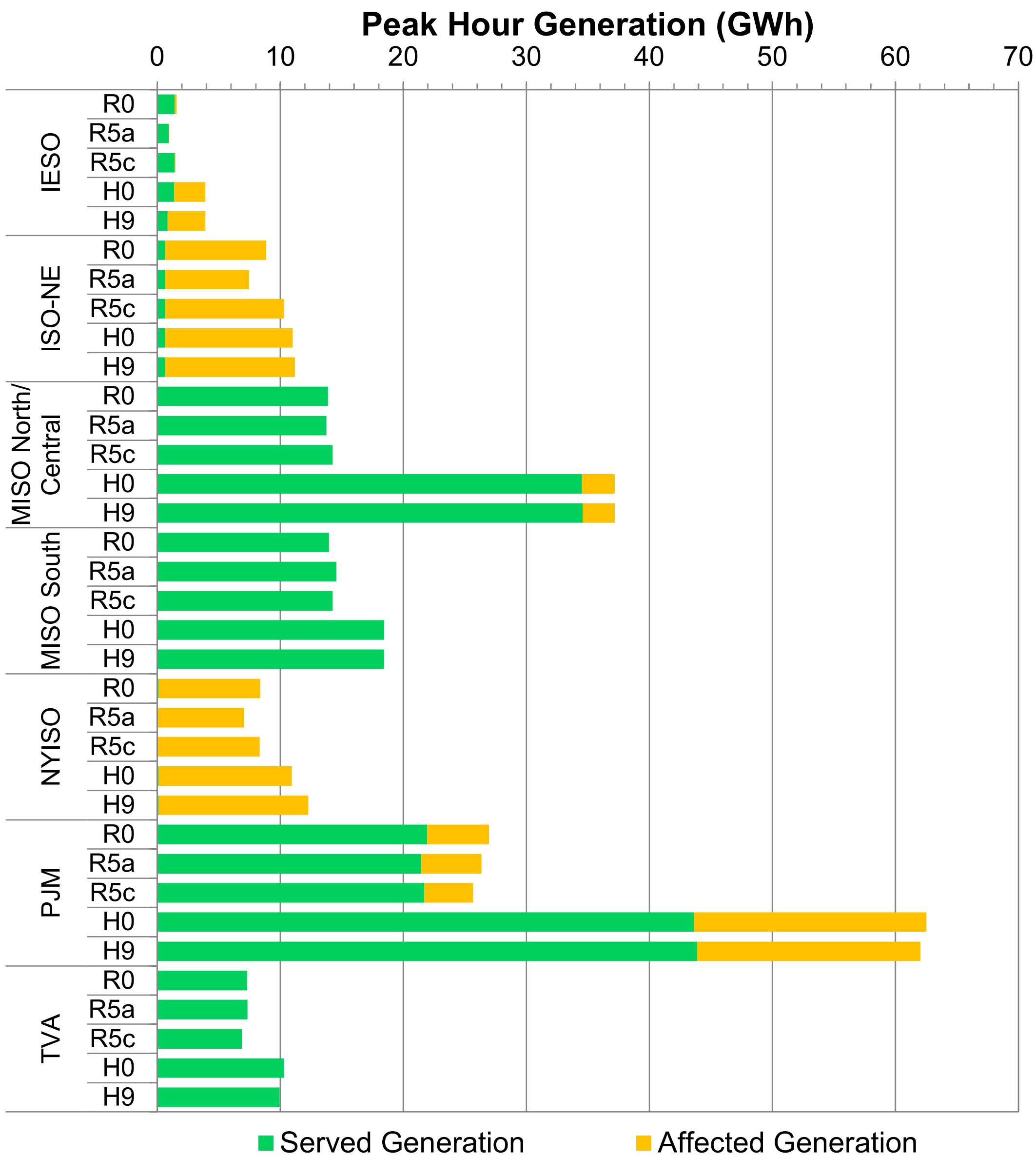


Figure 151. S0, S5a, S5c, and S9 Summer 2018: Peak Hour Affected Generation

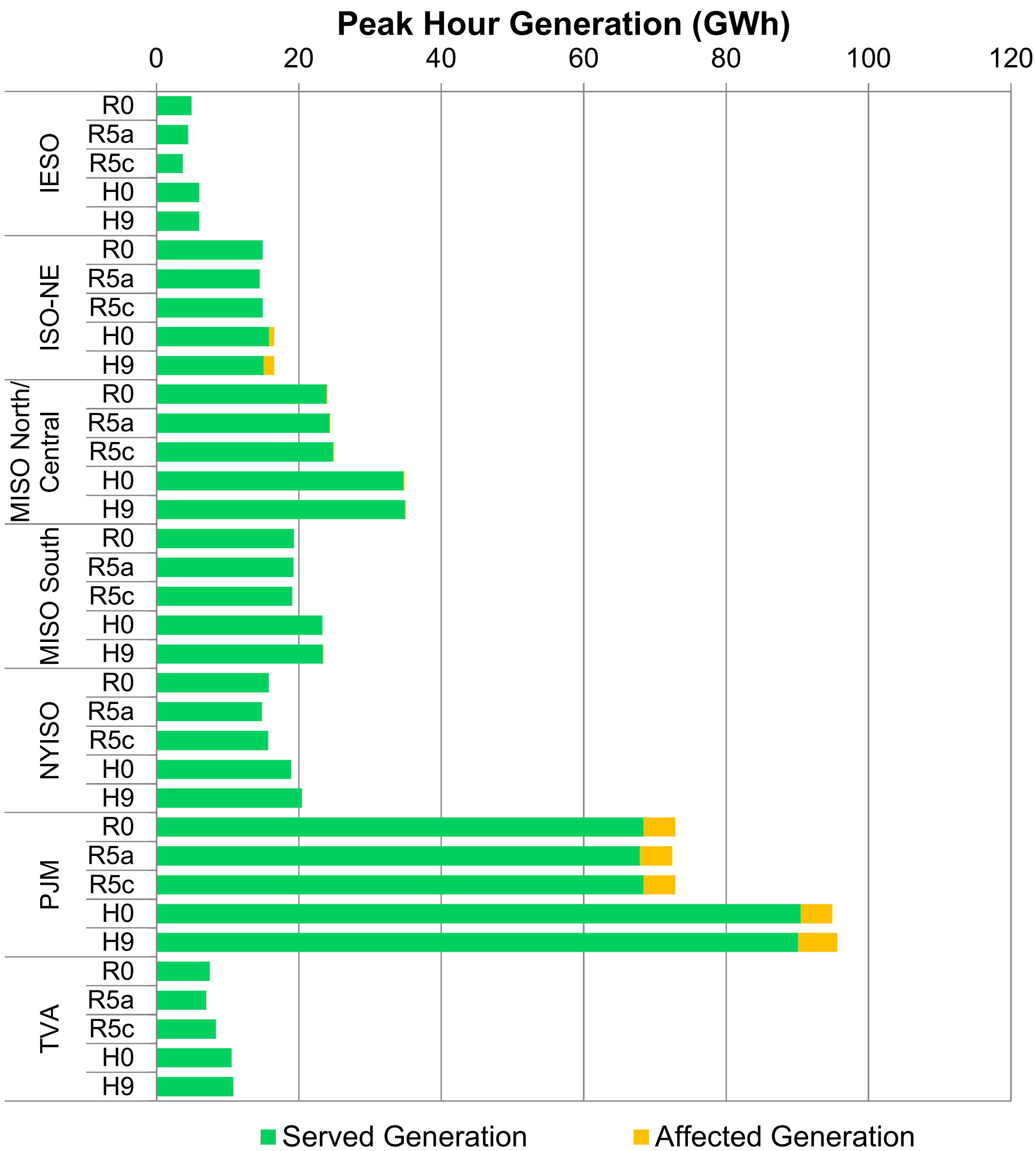


Figure 152. S0, S5a, S5b, S5c, and S9 Winter 2023: Peak Hour Affected Generation

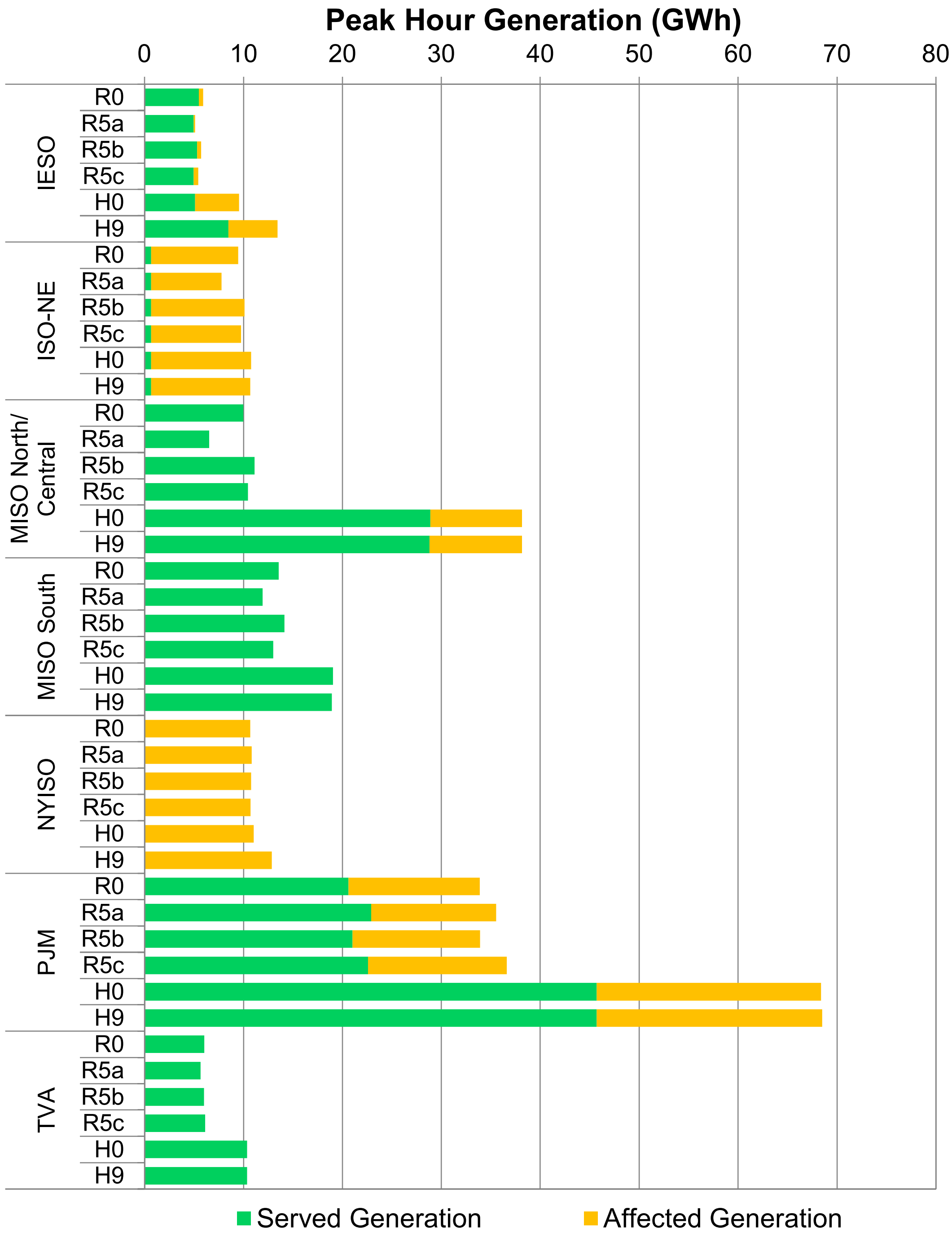
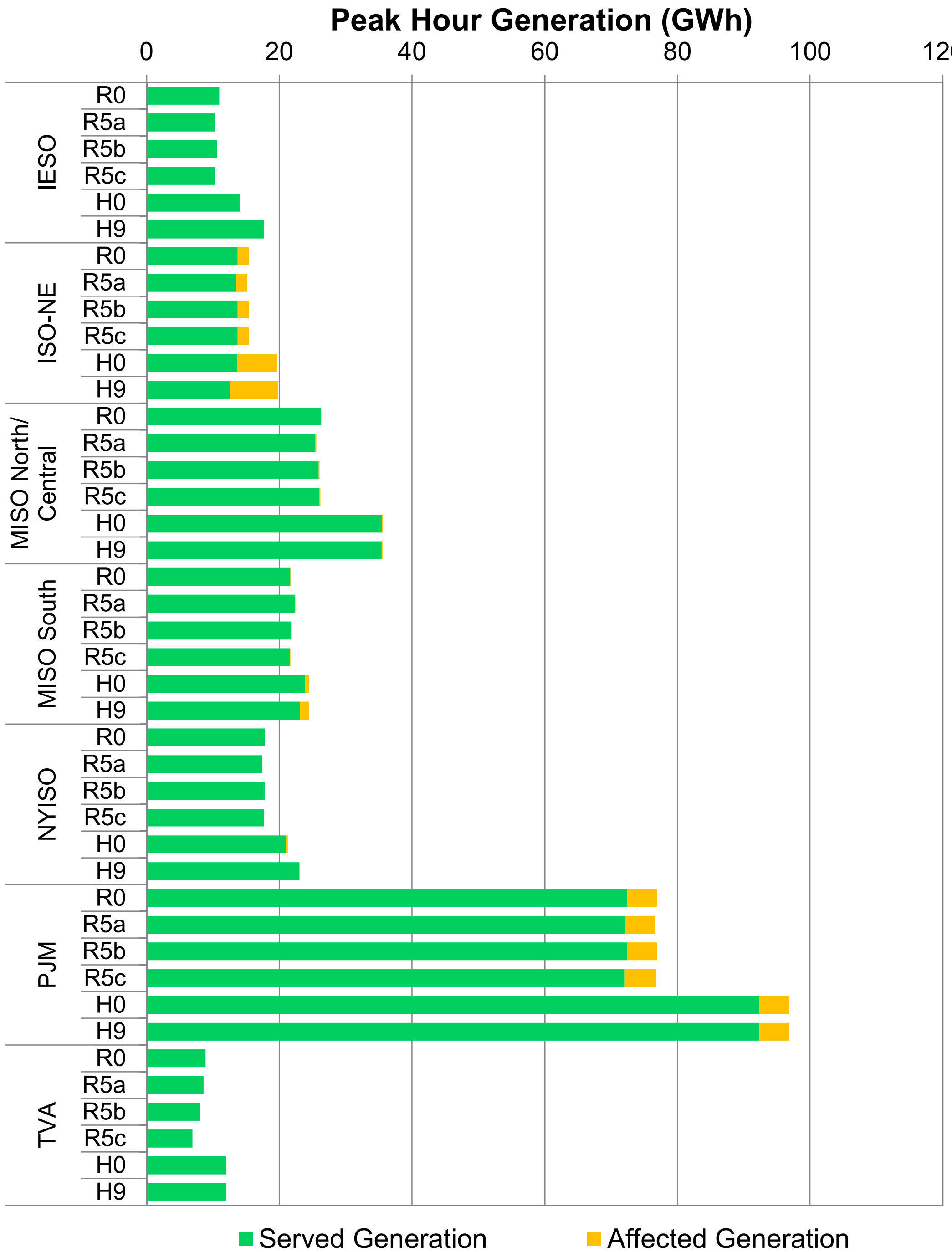


Figure 153. S0, S5a, S5b, S5c, and S9 Summer 2023: Peak Hour Affected Generation



7.3 Impact of Gas Infrastructure Expansions: S13, S14, and S16

7.3.1 Description of S13, S14, and S16

This group of sensitivities tests the impact of expanding natural gas infrastructure at specific locations within the Study Region. No change to the dispatch of generation resources was modeled. These sensitivities were run against the RGDS only.

Sensitivity 13 supposes a material increase in gas production, infrastructure and flows from Marcellus and Utica formations to neighboring PPAs. This impact is modeled by adding pipeline infrastructure projects which had been announced prior to April 22, 2014, but did not met the criteria for inclusion in the RGDS of demonstrating committed market support. The incremental pipeline infrastructure projects, listed in Table 42, impact all PPAs in the Study Region. Detailed descriptions of these projects are presented in Appendix F.[93]

Table 42. Incremental Infrastructure Projects Included in S13

Pipeline	Project	Delivery PPA(s)
Algonquin	Atlantic Bridge[94]	ISO-NE
CNYOG (Stagecoach)	Northern Expansion	NYISO
Columbia Gas	Leach Xpress	PJM
	QuickLink	PJM
Columbia Gulf	Rayne Xpress	MISO, TVA
Dominion[95]	Lebanon West	PJM
	New Market	NYISO
Empire	Central Tioga County Extension	IESO, NYISO
	Northern Access 2016	IESO
Equitrans	Ohio Valley Connector	PJM
Iroquois	South to North	IESO, ISO-NE
NFG	Clermont to Transco	PJM
NGPL	Gulf Coast Market Expansion	MISO
NEXUS	NEXUS Gas Transmission	IESO, MISO, PJM
Northern Border	Bakken Header[96]	MISO
PNGTS	Continent to Coast	ISO-NE
Tennessee	Northeast Energy Direct	ISO-NE, NYISO, PJM
Texas Eastern	Natrium Lateral	PJM
	Renaissance	TVA
Texas Gas	Northern Supply Access	MISO
	Southern Indiana Market Lateral	MISO
TransCanada	Eastern Mainline Project	IESO
Transco	Gulf Trace	MISO
Union	Hamilton-Milton	IESO
	Lobo Compressor Station Expansion	IESO
	Parkway E	IESO
WBI	Dakota Pipeline	MISO

[93] Projects which have been announced since April 22, 2014 have been referenced in Appendix F as well.

[94] The first 100 MDth/d of incremental capacity associated with the Atlantic Bridge Project has been included in the primary *Gas Demand Scenarios*. An additional 500 MDth/d of capacity is included in Sensitivity 13.

[95] The WV West Project is not listed here because when it was filed at FERC as the Clarington Project in Docket No. CP14-496, it did not include the project components targeted for Sensitivity 13.

[96] This project transports gas from the Bakken shale.

Sensitivity14 supposes a 10% increase in deliverability and associated pipe header capacity to all existing underground storage facilities in the Study Region by 2018. The increased gas storage deliverability applies to both FERC jurisdictional and state/provincial facilities. No other changes to either electric load or RCI gas demand are incorporated in this sensitivity.

Sensitivity 16 evaluates the deliverability impacts on a peak day ascribable to the more complete utilization of the Distrigas and Canaport LNG import terminals. For Distrigas, the 251 MDth/d peak day sendout input to the RGDS is maintained, representing contractual deliveries to Mystic 8&9 and NGrid. In addition, we assume that 242 MDth/d and 116 MDth/d will be gasified and delivered to Algonquin and Tennessee, respectively. These values are based on observations of pipeline flows from February 22, 2011, the peak Distrigas sendout day since October 2010, as reported on the Algonquin and Tennessee electronic bulletin boards (EBBs). For Canaport, we assume that regasified LNG will be made available from Canaport to use fully Repsol's pipeline entitlement on M&N into northern New England, *i.e.*, 850 MDth/d. A portion of this north-to-south flow on a Winter Peak Day would include production from Deep Panuke and Sable Island not otherwise used by RCI and generator loads in the Maritimes.

7.3.2 Peak Hour Affected Generation in S13, S14, and S16

Figure 154 through Figure 157 compare the affected generation to served generation for S13, S14, and S16. Each of these sensitivities involves an expansion of the gas infrastructure.

Sensitivity 13 involves increased infrastructure to transport incremental volumes from the Marcellus and Utica shale production area to neighboring PPAs. The difference in affected generation in PJM is comparatively small as the affected generators in Delaware, Maryland, and Virginia are located downstream of delivery constraints identified in RGDS S0 on Columbia Gas, Dominion, Eastern Shore, and Transco. Even with more gas emanating from shale gas formations, unless the entire supply chain is expanded to accommodate the incremental production, downstream constraints are not alleviated. Affected generation in NYISO and ISO-NE is reduced in Winter 2018 because greater volumes of gas can move west to east as a result of the assumed infrastructure improvements. Affected generation in PJM, NYISO and ISO-NE is further reduced in Winter 2023 following the addition of Tennessee's Northeast Direct Project, which is assumed to be commercialized in Q4-2018, not in time to ameliorate constraints on the peak hour of the peak day in 2018.

Sensitivity 14 involves a 10% increase in conventional storage capacity and daily withdrawal capability at storage facilities across the Study Region. In most cases, storage facilities are located upstream of the pipeline constraints identified in RGDS S0. Therefore, expanding withdrawal capability does not have a commensurate impact on deliverability to gas-fired generators.

Sensitivity 16 involves the reenergization of the Distrigas and Canaport LNG import terminals. Assumed utilization of the regasification capability at both import terminals revitalizes the operational flexibility on Tennessee's high pressure system around Boston, Algonquin's medium pressure system around Boston, and M&N's high pressure system into Northern New England. Gas-fired affected generation in ISO-NE is significantly reduced as a result of east-end gas supply availability. However, the import volumes are not sufficient to reduce affected generation in NYISO or PJM.

Appendices K and L provides further detail regarding the locations of constraints, and the unserved gas demand and affected generation by GPCM location.

Figure 154. S0, S13, S14 and S16 Winter 2018: Peak Hour Affected Generation

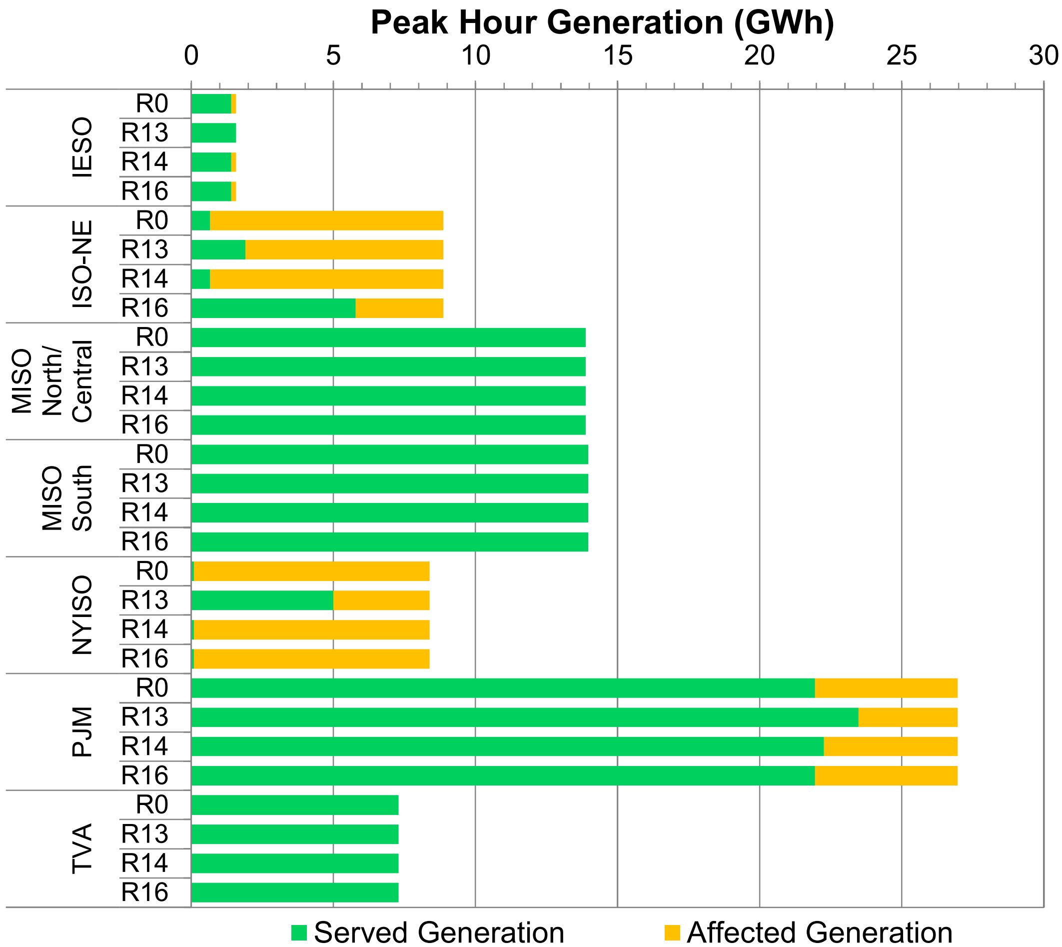


Figure 155. S0, S13, S14 and S16 Summer 2018: Peak Hour Affected Generation

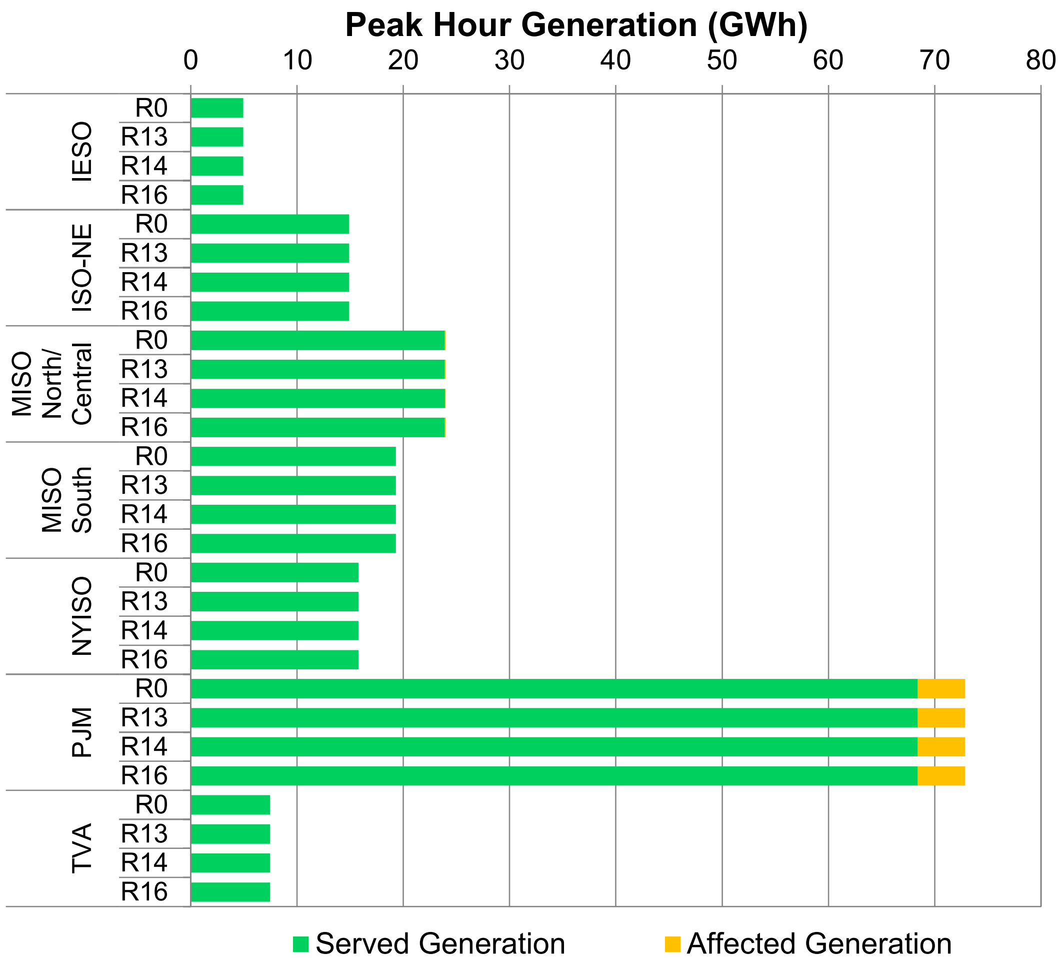


Figure 156. S0, S13, S14 and S16 Winter 2023: Peak Hour Affected Generation

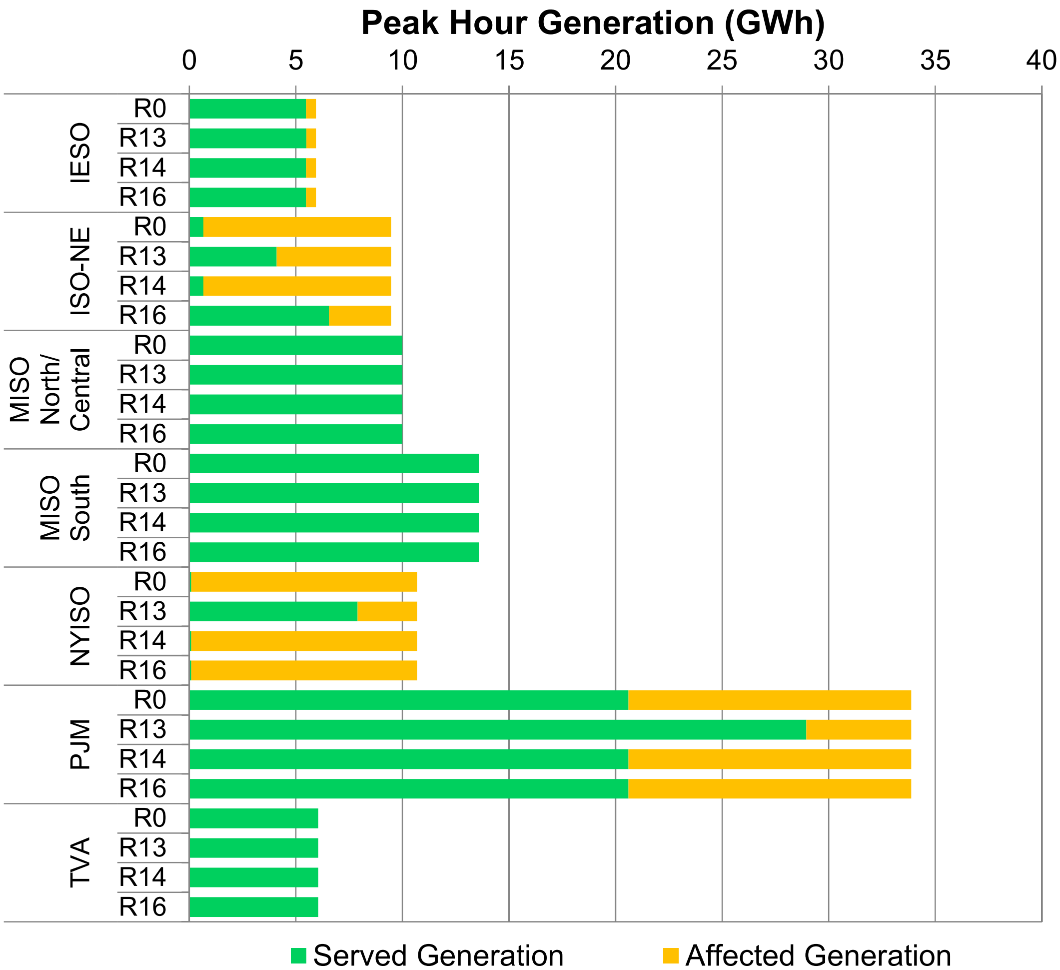
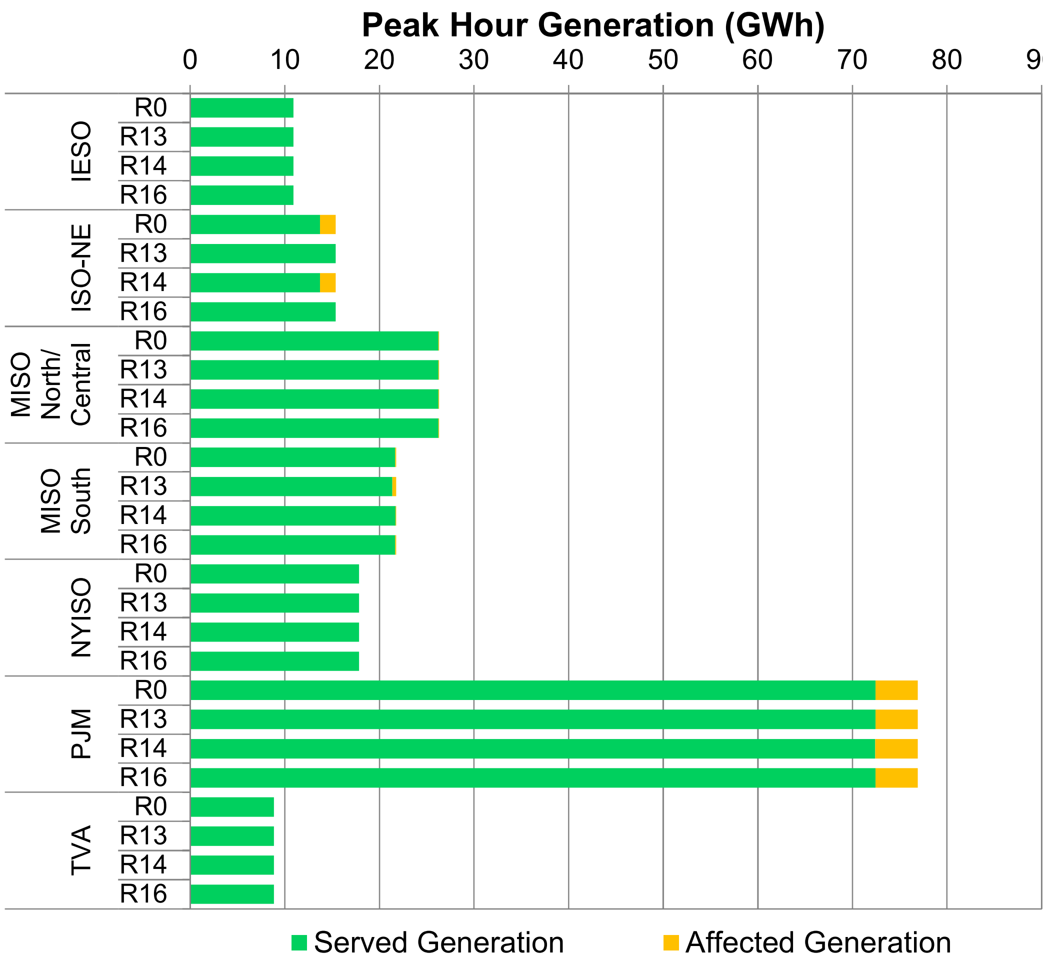


Figure 157. S0, S13, S14 and S16 Summer 2023: Peak Hour Affected Generation



7.4 IMPACT OF INCREASED ELECTRIC LOAD OR RCI DEMAND: S18 AND S19

7.4.1 Description of S18 and S19

Sensitivity 18 substitutes the higher load forecast used in the HGDS for the base load forecast in the RGDS. The gas-fired resources that were added in the HGDS to maintain reserve margins were also added to the resource mix for RGDS S18. The resource mix for RGDS S18 is summarized in Exhibit 17. No other changes were made to model inputs.

Sensitivity 19 analyzes the impact of higher industrial demand based on the industrial gas demand forecast taken from the AEO2013 High Economic Case. The portion of each GPCM RCI customer's demand that is classified as industrial has been scaled based on the census region industrial growth rates in the AEO2013 forecast, shown in Table 43. Differentiation of each LDC's demand between Residential/Commercial and Industrial is based on sector factors included in RBAC's GPCM base case database, and differentiation of non LDC customers' demand is based on historical pipeline EBB data.

Table 43. S19 Industrial Load Growth Rates

Census Division	2018 Total Growth Rel. to 2013	2018 Annual Growth Rate	2023 Total Growth Rel. to 2018	2023 Annual Growth Rate
New England (CT, ME, MA, NH, RI, VT)	18.35%	3.67%	11.06%	2.21%
Middle Atlantic (NJ, NY, PA)	26.2%	5.24%	10.14%	2.03%
East North Central[97] (IL, IN, MI, OH, WI)	14.76%	2.95%	4.57%	0.91%
West North Central[98] (IA, MN, MO, ND, SD)	12.41%	2.48%	3.29%	0.66%
South Atlantic (DC, DE, GA, MD, NC, VA, WV)	15.18%	3.04%	5.35%	1.07%
East South Central (AL, KY, MS, TN)	10.84%	2.17%	5.49%	1.10%
West South Central (AR, LA, TX)	12.81%	2.56%	5.75%	1.15%
Mountain (MT)	22.23%	4.45%	6.77%	1.35%

7.4.2 Peak Hour Gas Demand in S18 and S19

Figure 158 through Figure 161 illustrate the differences in peak hour generator gas demand for RGDS S18 compared to RGDS S0. Gas demand generally increases across the Study Region, but declines somewhat in TVA in Winter 2018 and Summer 2023, and in MISO South in Winter 2023. Generally, the PPAs that have larger electric load increases in RGDS S18 have larger increases in gas demand. As for other sensitivities, there may be occasional PPA level exceptions to the expected directional impact as a result of changes in LMPs, generating capacity technology or fuel mix, and power flows.

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[97] For the East North Central census division, AEO2013's Reference Case forecasts a decrease in residential demand from 1.195 Tcf in 2018 to 1.126 in 2023, a decrease in commercial demand from 0.713 Tcf in 2018 to 0.709 Tcf in 2023, an increase in industrial demand from 1.257 Tcf in 2018 to 1.287 Tcf in 2023, and an increase in transportation demand from 0.009 Tcf in 2018 to 0.011 Tcf in 2023, resulting in a net decrease in total gas demand from 3.174 Tcf in 2018 to 3.135 in 2023.

[98] For the West North Central census division, AEO2013's Reference Case forecasts a decrease in residential demand from 0.398 Tcf in 2018 to 0.383 in 2023, a decrease in commercial demand from 0.3043 Tcf in 2018 to 0.299 Tcf in 2023, an increase in industrial demand from 0.681 Tcf in 2018 to 0.693 Tcf in 2023, and an increase in transportation demand from 0.004 Tcf in 2018 to 0.006 Tcf in 2023, resulting in a net decrease in total gas demand from 1.388 Tcf in 2018 to 1.381 in 2023.

Figure 158. RGDS S18 vs. RGDS S0 Winter 2018: Electric Sector Gas Demand

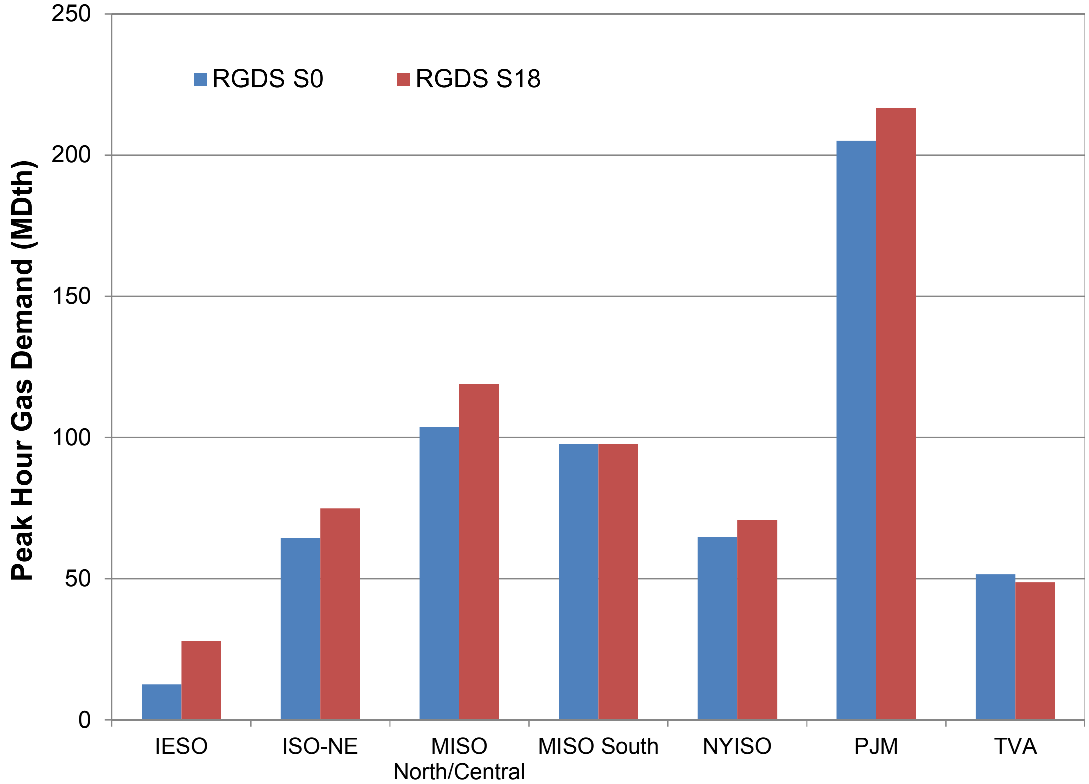


Figure 159. RGDS S18 vs. RGDS S0 Summer 2018: Electric Sector Gas Demand

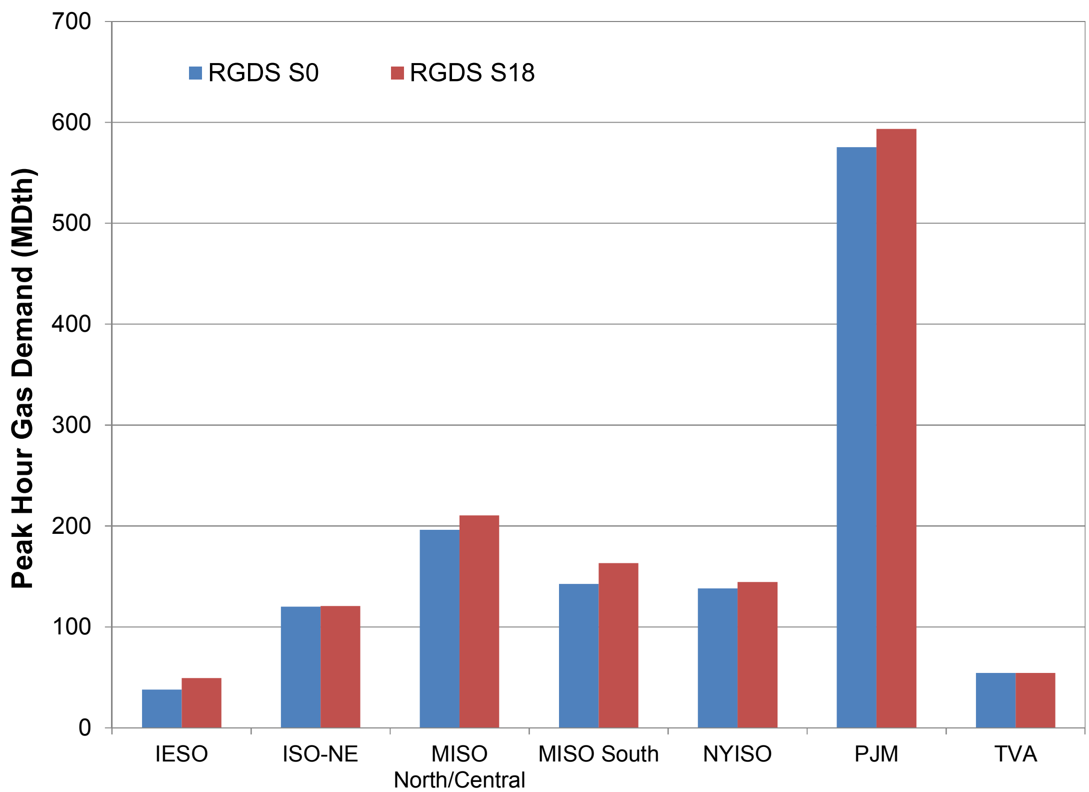


Figure 160. RGDS S18 vs. RGDS S0 Winter 2023: Electric Sector Gas Demand

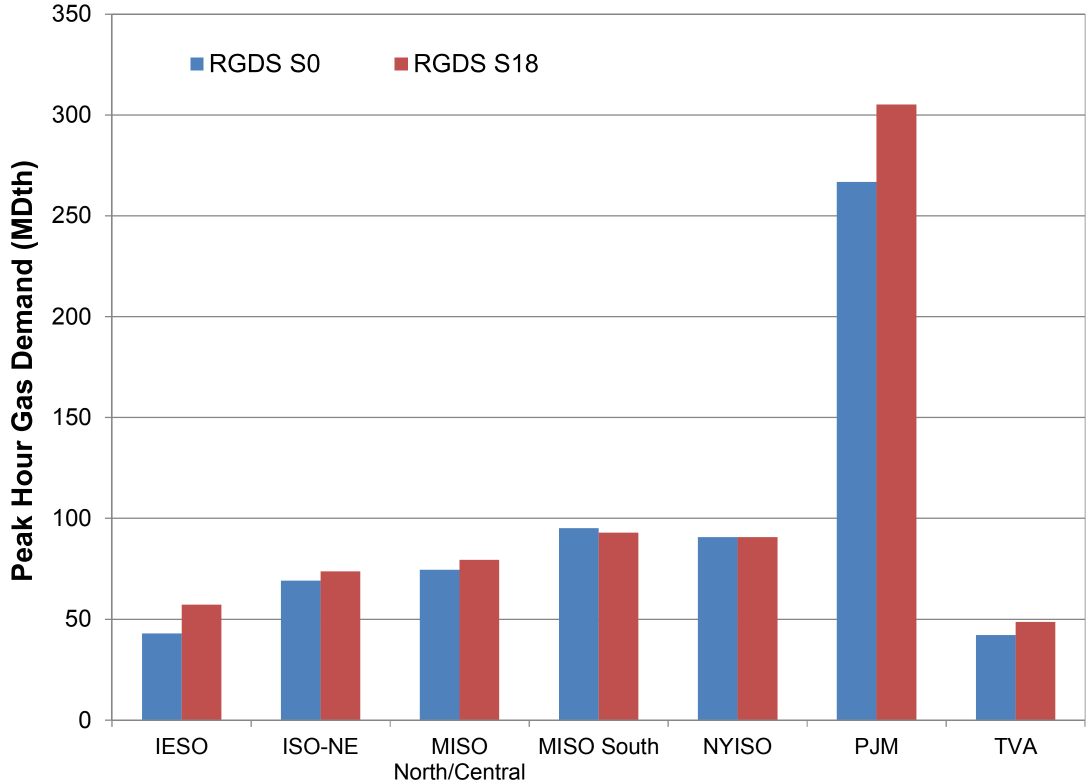
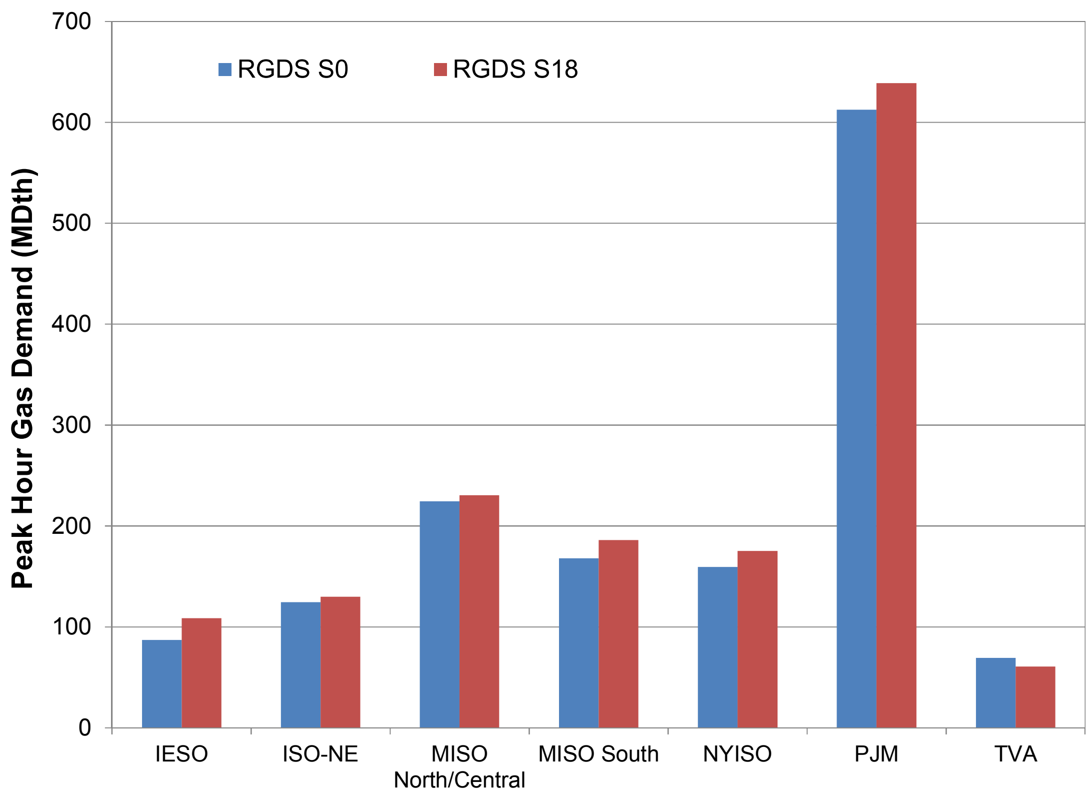


Figure 161. RGDS S18 vs. RGDS S0 Summer 2023: Electric Sector Gas Demand



The increases in total RCI demand in RGDS S19 relative to RGDS S0 are shown in Figure 162 through Figure 165. Compared to the base RGDS S0 RCI gas demand, the increase is relatively small, but it is significant compared to the electric sector gas demand in the winter heating season.

Figure 162. RGDS S19 vs. RGDS S0 Winter 2018: RCI Gas Demand

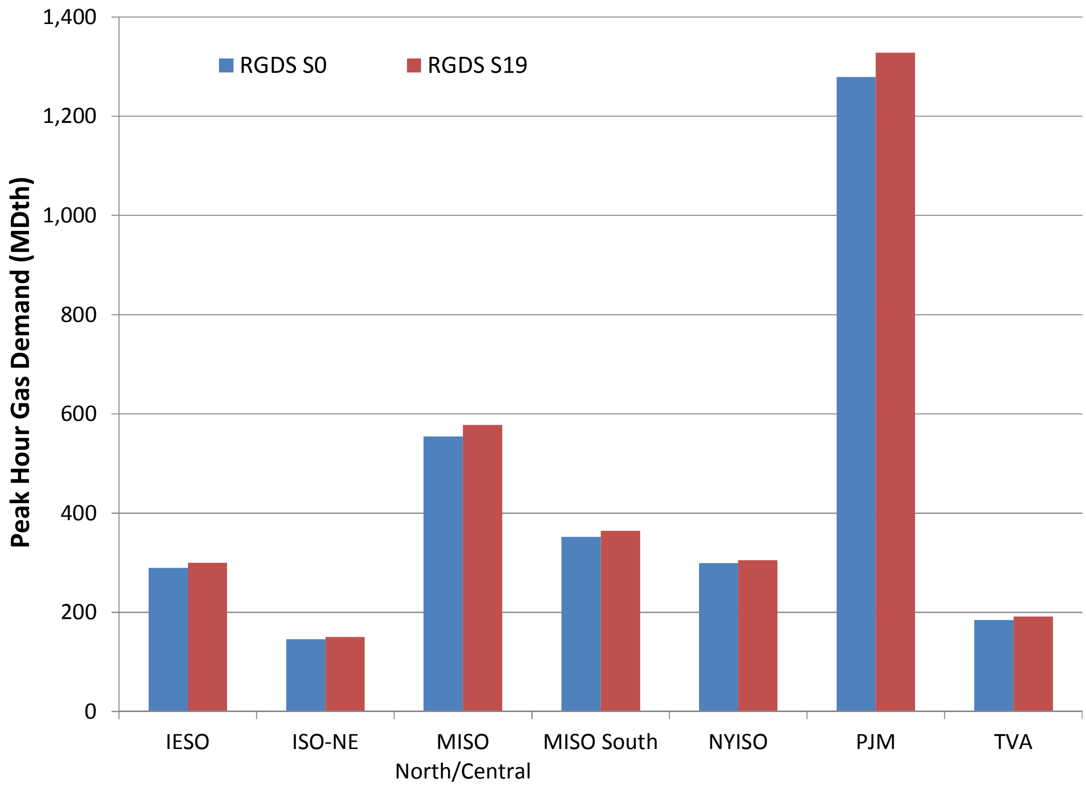


Figure 163. RGDS S19 vs. RGDS S0 Summer 2018: RCI Gas Demand

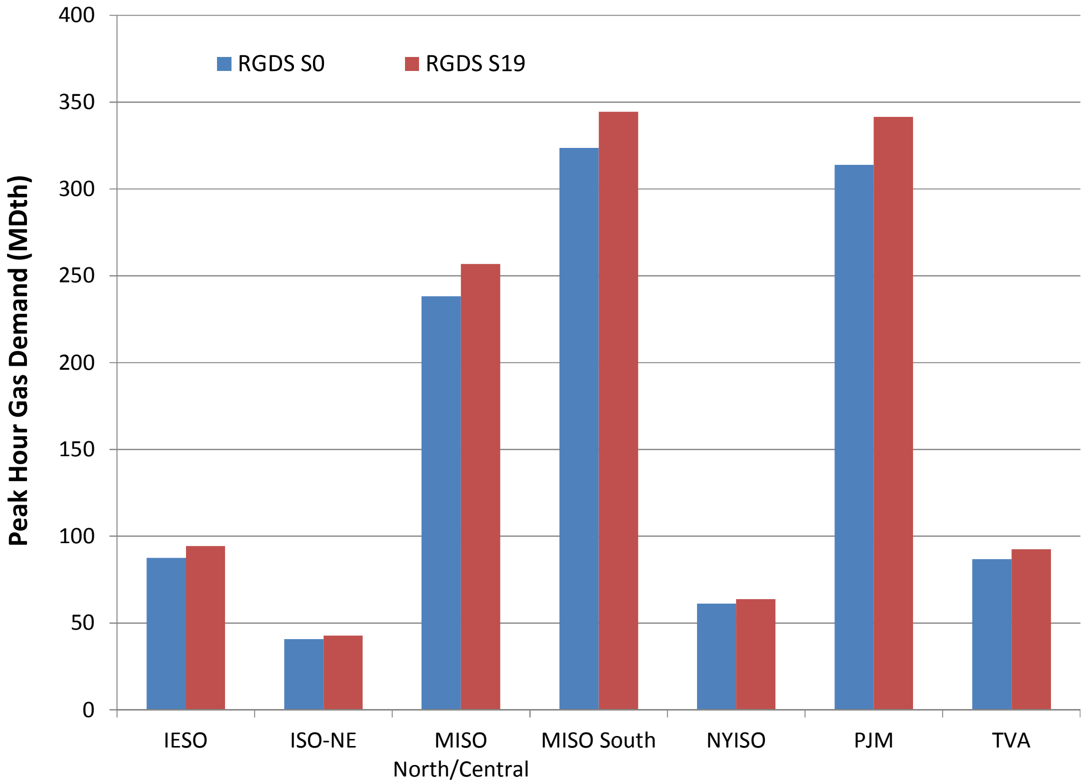


Figure 164. RGDS S19 vs. RGDS S0 Winter 2023: RCI Gas Demand

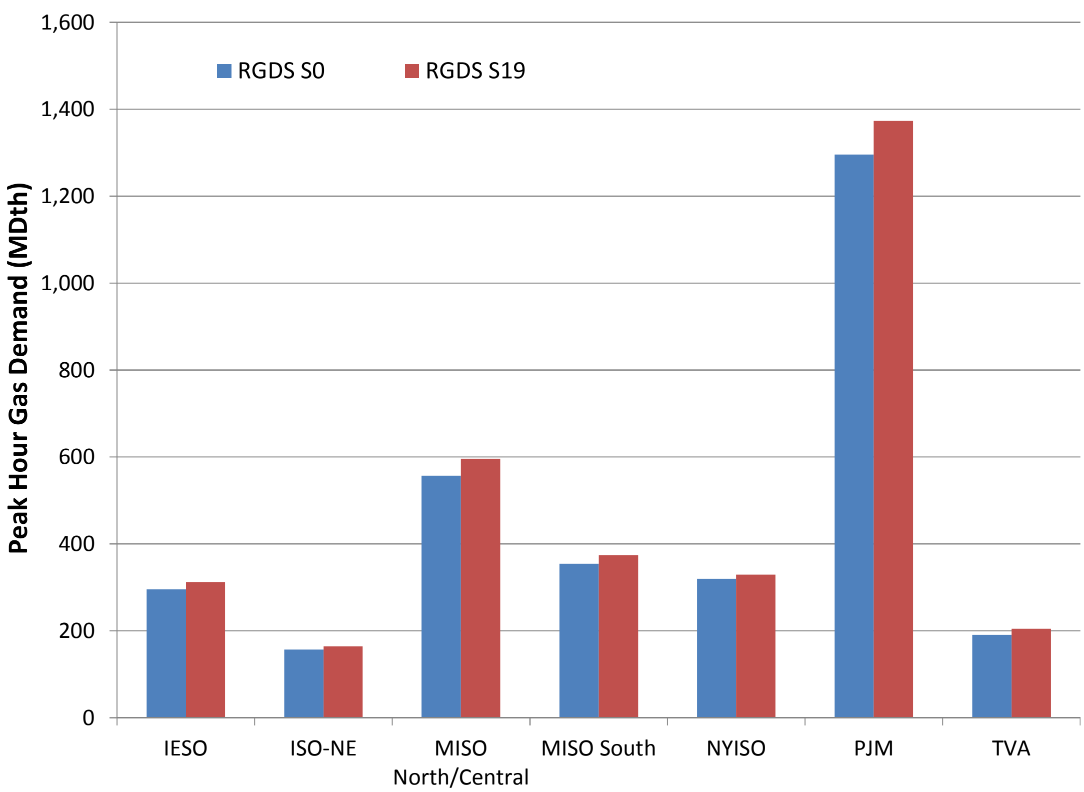
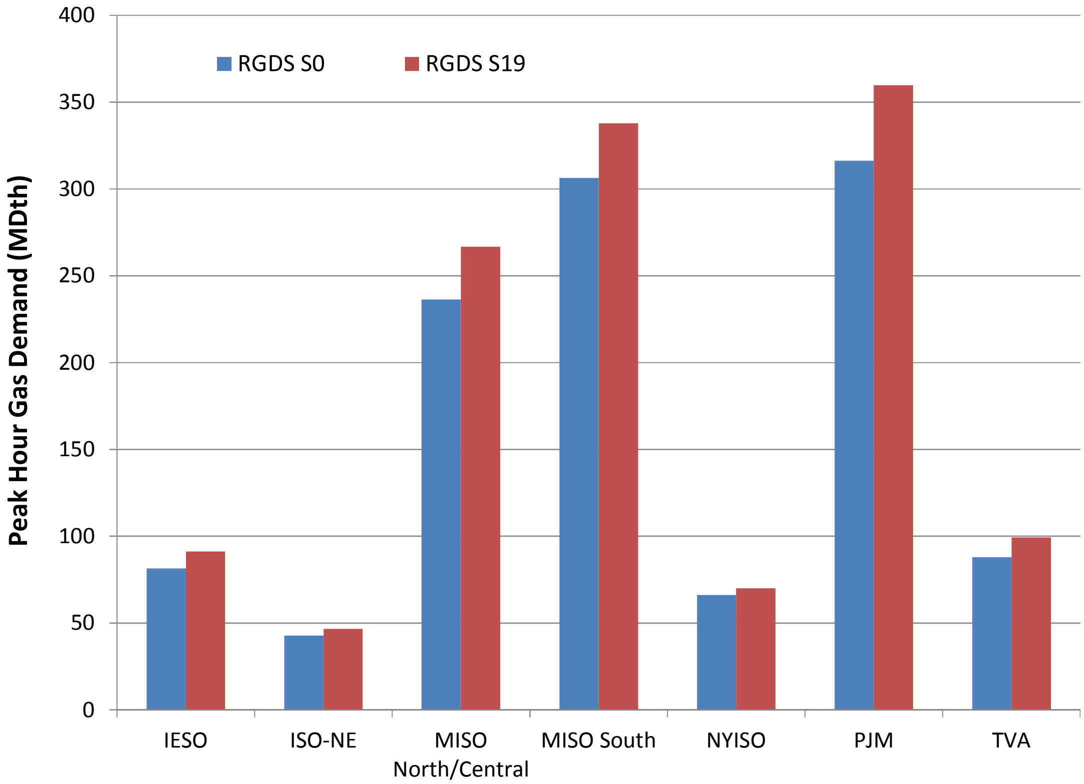


Figure 165. RGDS S19 vs. RGDS S0 Summer 2023: RCI Gas Demand



7.4.3 Peak Hour Affected Generation in S18 and S19

Figure 166 through Figure 169 compare the affected generation to served generation for S18 and S19. As expected, the amount of affected generation in RGDS S18 generally increases relative to RGDS S0, commensurate with the increase in load and consequent gas demand. The small changes for TVA and MISO South in S18 appear to be due to relatively low gas prices in those areas and relatively small electric load increase. The only significant change in the amount of affected generation is for PJM in S19 for Winter 2018. Other PPAs are either nearly or entirely unconstrained, or nearly or entirely constrained, so the change in RCI gas demand has no impact. Appendices M and N provide further detail regarding the locations of constraints, and the unserved gas demand and affected generation by GPCM location.

Figure 166. S0, S18 and S19 Winter 2018: Peak Hour Affected Generation

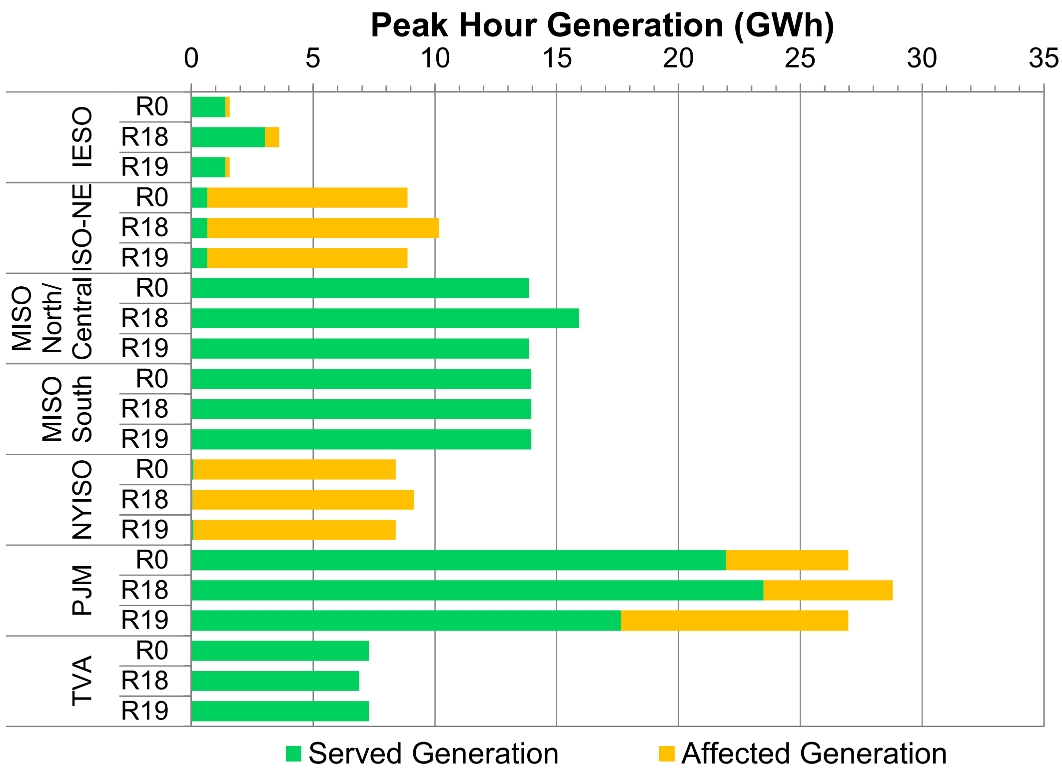


Figure 167. S0, S18 and S19 Summer 2018: Peak Hour Affected Generation

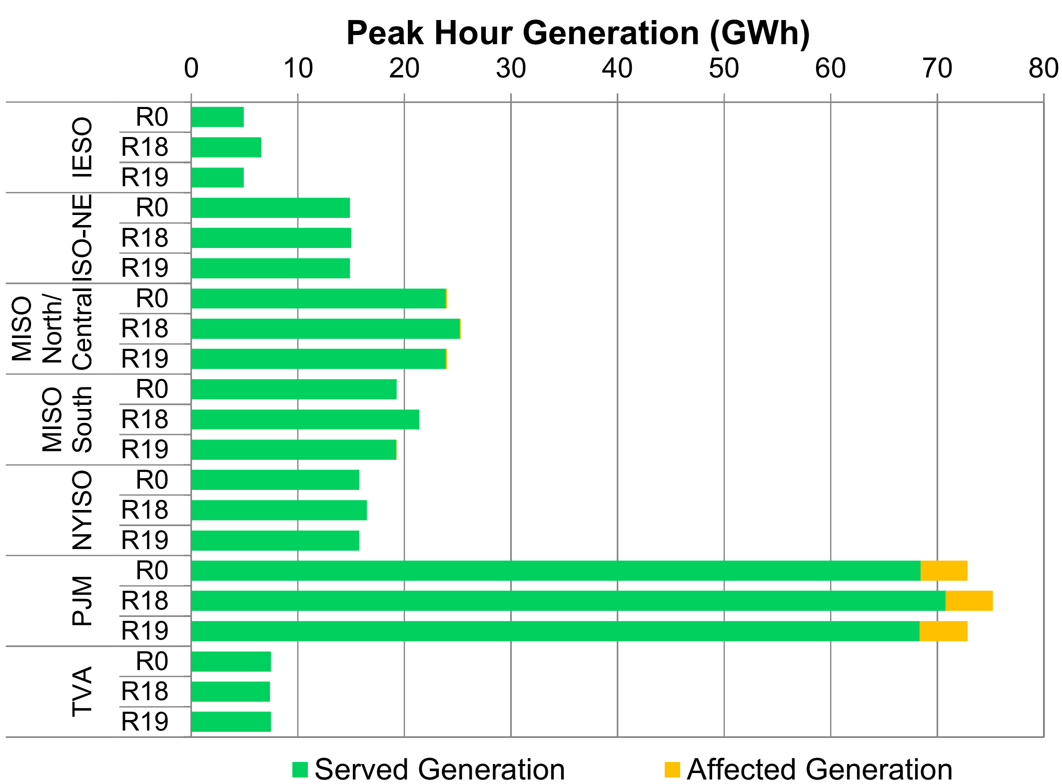


Figure 168. S0, S18 and S19 Winter 2023: Peak Hour Affected Generation

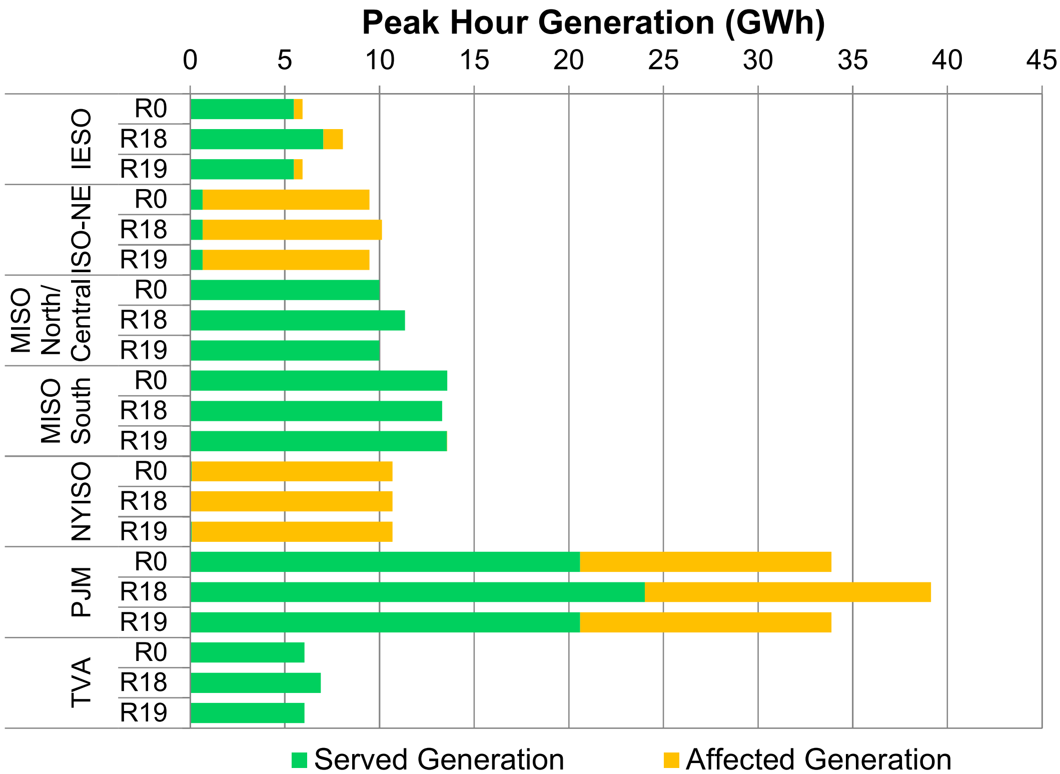
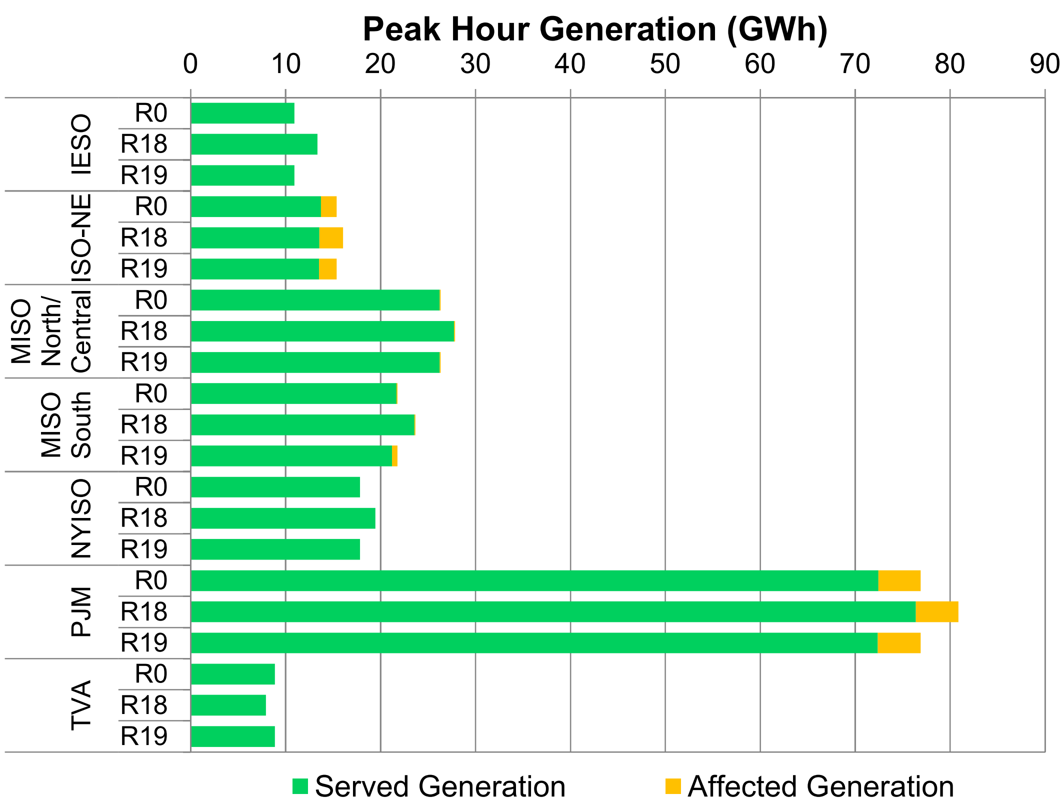


Figure 169. S0, S18 and S19 Summer 2023: Peak Hour Affected Generation



7.5 IMPACT OF LNG EXPORTS: S23 AND S37

7.5.1 Description of S23 and S37

This pair of sensitivities envisions expansions to the LNG export capability in the U.S. These sensitivities were run against the RGDS only.

Sensitivity 23 analyzes the impact of including additional LNG export facilities along the Gulf of Mexico and the Pacific Northwest, and tripling LNG exports relative to the RGDS by 2023, consistent with the LNG export forecast in the AEO2014 Reference Case. AEO2014 forecasts total U.S. LNG exports will be 3.45 Bcf/d in 2018 and 6.9 Bcf/d in 2023, reflecting an average capacity factor for the LNG export terminals of 73%. Six export terminals are assumed to be operating by 2022 with the first, Sabine Pass (2.2 Bcf/d capacity), starting operations in 2015, one year ahead of the RGDS forecast. In addition to Cove Point, MD (1.0 Bcf/d) in 2018 and Freeport, TX (1.4 Bcf/d) in 2017 in the RGDS, the other terminals included in this sensitivity are Lake Charles, LA (2.0 Bcf/d) in 2019, Cameron, LA (1.7 Bcf/d) in 2020, and Jordon Cove, OR (1.2 Bcf/d) in 2022. The proposed LNG export facilities outside of the Study Region are included in the GPCM model. GPCM models supply and demand across North America, and changes to levels of gas exports outside the Study Region can affect gas flows and basis within it. For the peak day analysis in GPCM, all of the LNG export terminals have been assumed to operate at full capacity.

Sensitivity 37 evaluates the capacity of the gas pipeline infrastructure assuming that the existing Canaport LNG import terminal in New Brunswick is converted to an export facility by 2023. While Repsol has released a preliminary announcement of a plan to convert Canaport to an export facility, no information is public regarding the details of Repsol's export regime, liquefaction capability, system-wide improvements to ensure deliverability, or external commitments with LNG offtakers. Therefore, LAI modeled an assumed Canaport export facility with a maximum daily liquefaction capability of 1.0 Bcf/d, similar to Cove Point. All new pipeline projects modeled in S13 were included to facilitate gas delivery from Marcellus and Utica to Canaport. Additional upgrades were added to the pipeline infrastructure in S37 to facilitate incremental transport volumes between the Tennessee / M&N interconnection at Dracut and the Canaport facility. In light of the regulatory and commercial / market milestones associated with developing Canaport as an LNG export facility, this sensitivity was run only for 2023.

7.5.2 Peak Hour Affected Generation in S23 and S37

Figure 170 through Figure 173 compare the affected generation to served generation for S23 and S37. In RGDS S23 the addition of LNG export facilities in MISO South does not materially affect gas-fired affected generation across the Study Region. The advancement of the Dominion Cove Point export facility does result in approximately 1 GWh of incremental affected generation in PJM relative to RGDS S0 during the Summer 2018 seasonal peak hour due to the increase in exports from 400 MDth/d to 1,000 MDth/d and the assumed prioritization of export volumes, based on the firm transportation contracts held by the LNG export customers, which are transported via the constrained Columbia Gas, Dominion, and Transco pipeline segments in Virginia and Maryland. Were export volumes not to be prioritized, the affected generation would be unchanged from RGDS S0, with unserved liquefaction demand during the seasonal peak hour.

Like the turnaround of the Dominion LNG facility, in RGDS S37 the Canaport LNG import terminal is switched around for daily liquefaction to export up to 1.0 Bcf/d. Tennessee's Northeast Energy Direct Project, which is assumed to expand transportation capacity from Marcellus to Dracut by 2.2 Bcf/d, and Algonquin's Atlantic Bridge Project, which is assumed to be commercialized with volumes of 600 MDth/d in RGDS S13, an increase of 500 MDth/d from RGDS S0, are supplemented by incremental capacity on M&N from eastern Massachusetts to Canaport. These improvements would enable gas to flow south to north on M&N for export without any denigration of RCI customers' entitlements. Affected generation in ISO-NE is unchanged in RGDS S37 relative to RGDS S0, but reduced relative to RGDS S13 because gas from Marcellus that is available for delivery to generators following additional infrastructure improvements is instead allocated to exports in RGDS S37.

Appendices O and P provide further detail regarding the locations of constraints, and the unserved gas demand and affected generation by GPCM location.

Figure 170. S0 and S23 Winter 2018: Peak Hour Affected Generation

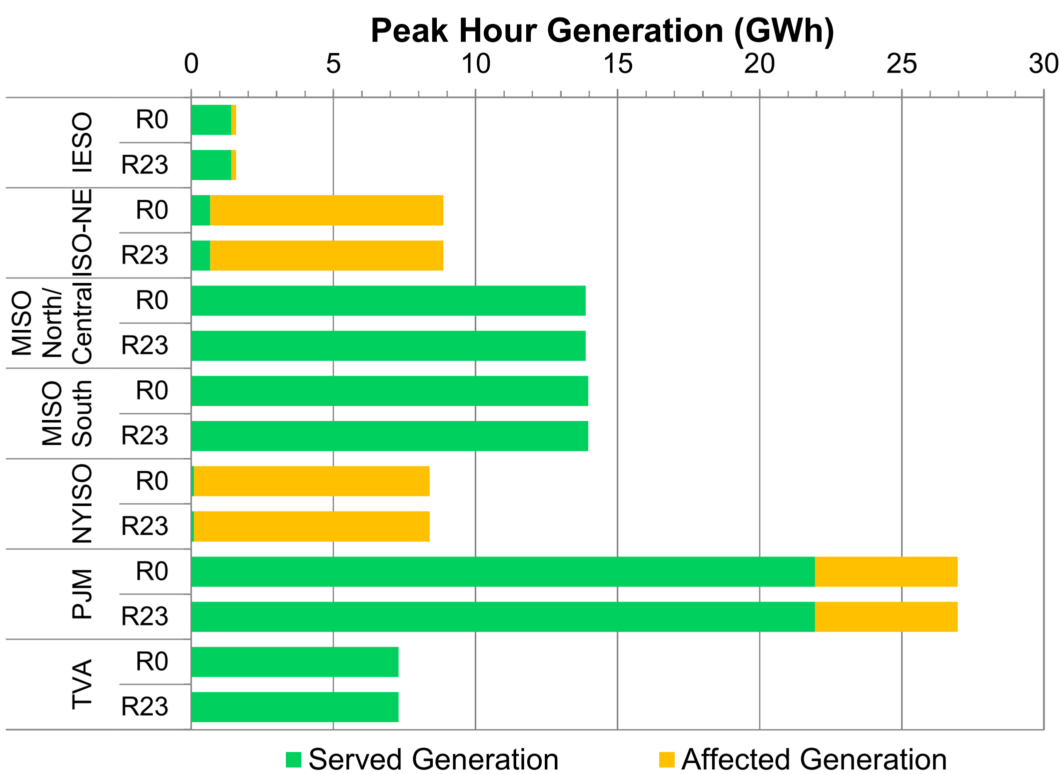


Figure 171. S0 and S23 Summer 2018: Peak Hour Affected Generation

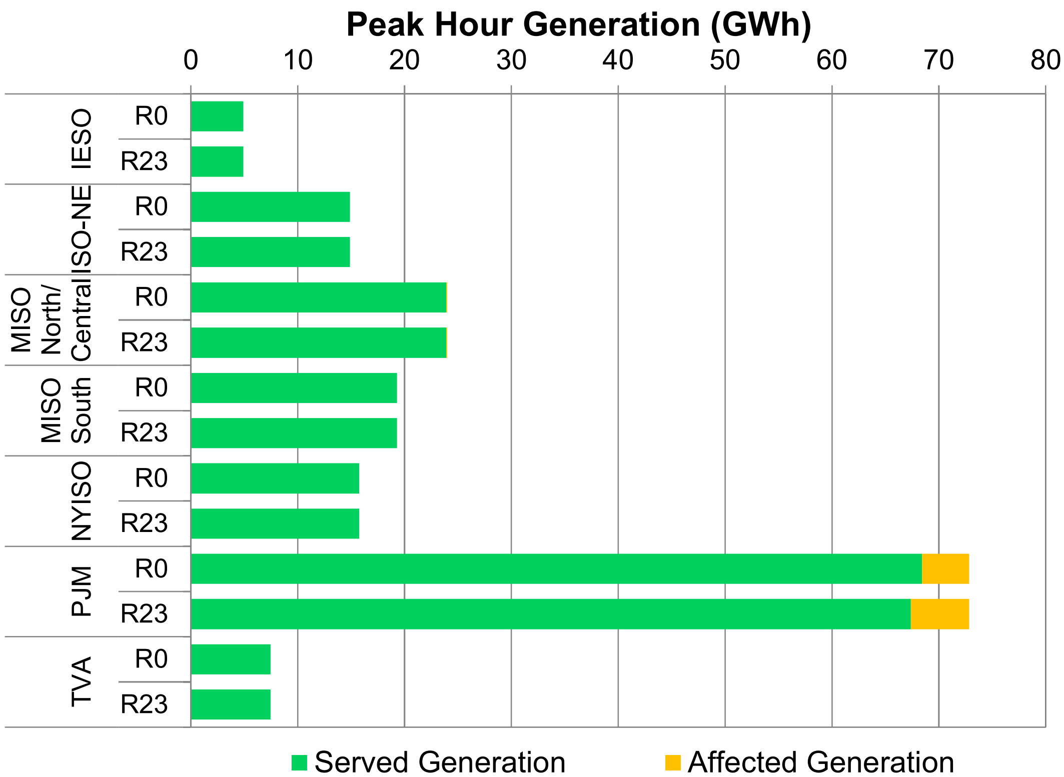


Figure 172. S0, S23 and S37 Winter 2023: Peak Hour Affected Generation

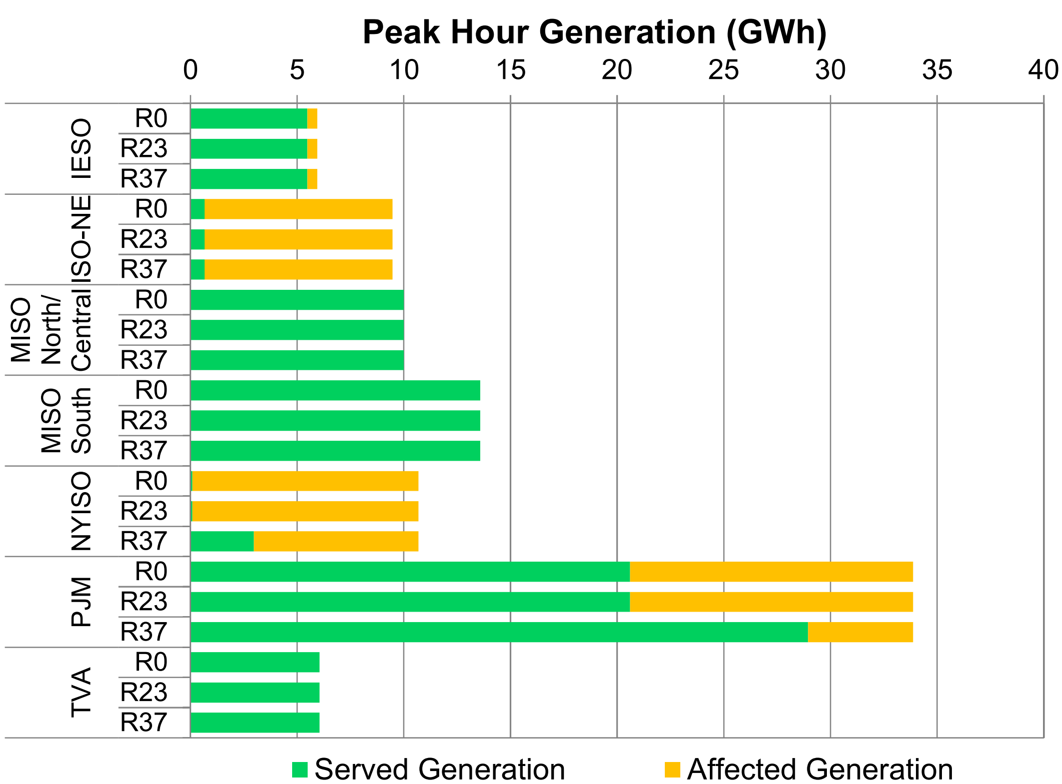
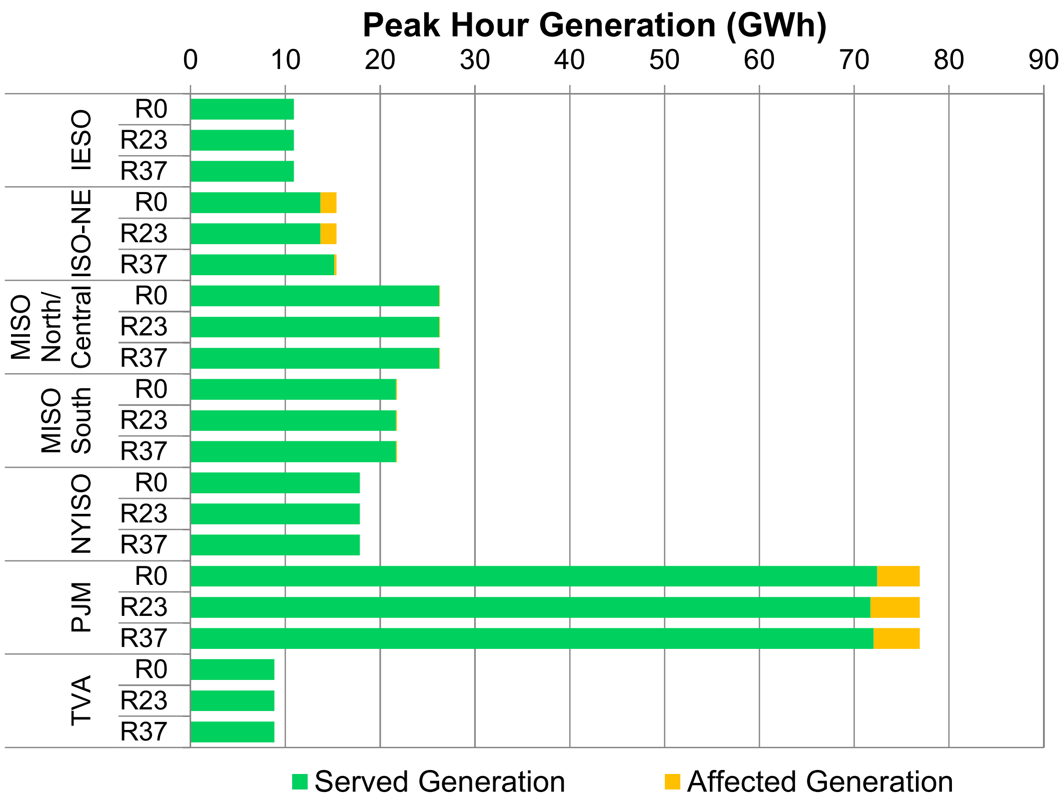


Figure 173. S0, S23 and S37 Summer 2023: Peak Hour Affected Generation



7.6 Impact of Forcing Fuel Type: S30 and S34

7.6.1 Description of S30 and S34

Sensitivity 30 supposes that all of the dual fuel capable resources in the Study Region are unable to schedule and burn gas on winter and summer days in 2018. To simulate this condition, all of the resources capable of burning oil and/or gas, as well as coal-fired units capable of co-firing gas, are restricted in the AURORAxmp model to burn only oil or coal, respectively. The dual-fuel oil/gas resources include units that burn RFO and distillate oils (fuel oil, ULSD, kerosene, jet fuel) along with gas. This sensitivity was run against the RGDS and the HGDS, for 2018 only.

Sensitivity 34 evaluates the maximum gas demand by all gas-fired generation in the Study Region. To induce maximum gas demand in the electric sector, LAI made the simplifying assumption that the delivered price of natural gas is $0/MMBtu, thus ensuring that gas-capable units run flat out, or near flat out, over the forecast period. Non-fuel, variable O&M (VOM) costs applicable to gas-fired generators remained unchanged relative to VOM costs used in the RGDS. The RCI demand was assumed to be the same as in S0. This sensitivity was run against the RGDS only.

7.6.2 Peak Hour Gas Demand in S30 and S34

Figure 174 through Figure 177 illustrate the differences in peak hour gas demand for RGDS S30 and RGDS S34 compared to RGDS S0, and HGDS S30 compared to HGDS S0. For both S30 cases, IESO and TVA peak hour gas demands change little. IESO has a relatively small amount of dual fuel capacity, and TVA has coal resources that can operate at higher capacity factors in S30. Gas demand reductions for MISO, NYISO, and PJM are much larger during the summer than the winter season. For those three PPAs, nearly all gas-capable capacity is needed to meet the higher summer peak load. During the winter season, gas-only generators can substitute for dual fuel resources that have higher dispatch costs. ISO-NE and MISO South gas demands increase in the Winter 2018 RGDS comparison and show little decrease in the Winter 2018 HGDS comparison. This result appears to be related to increases in LMPs resulting from the increase in dispatch costs of dual fuel units. For MISO overall, gas demand decreases in the Winter 2018 RGDS comparison as well as the Winter 2018 HGDS comparison.

For RGDS S34, peak hour gas demand more than triples in PJM and more than doubles in MISO and TVA in both winter seasons, and increases by smaller amounts in the other PPAs. Gas demand in the winter is able to increase substantially in PJM, MISO, and TVA because they have large amounts of coal and other low cost resources that can be displaced by gas-fired generation. In the summer seasons, peak hour gas demand increases the most in the same three PPAs, but by smaller relative amounts. The relative increases in the summer seasons are smaller because most gas-capable capacity is utilized in S0 to meet the higher summer peak loads.

Figure 174. S0, S30 and S34 Winter 2018: Electric Sector Gas Demand

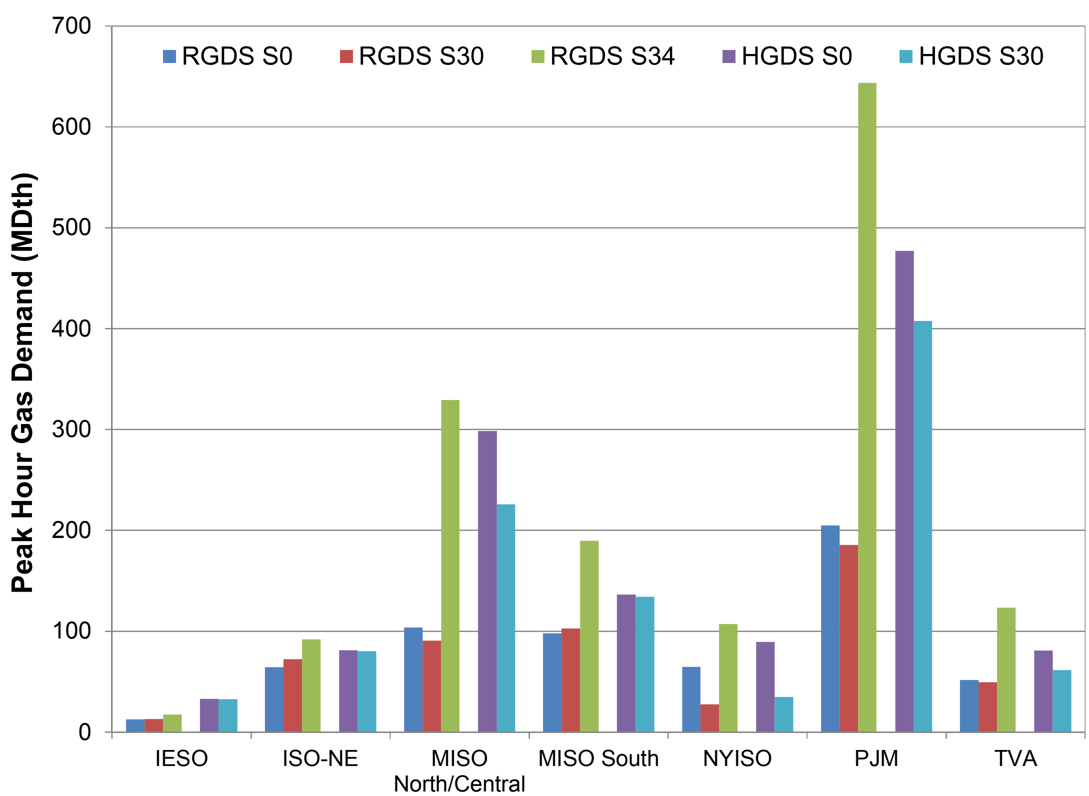


Figure 175. S0, S30 and S34 Summer 2018: Electric Sector Gas Demand

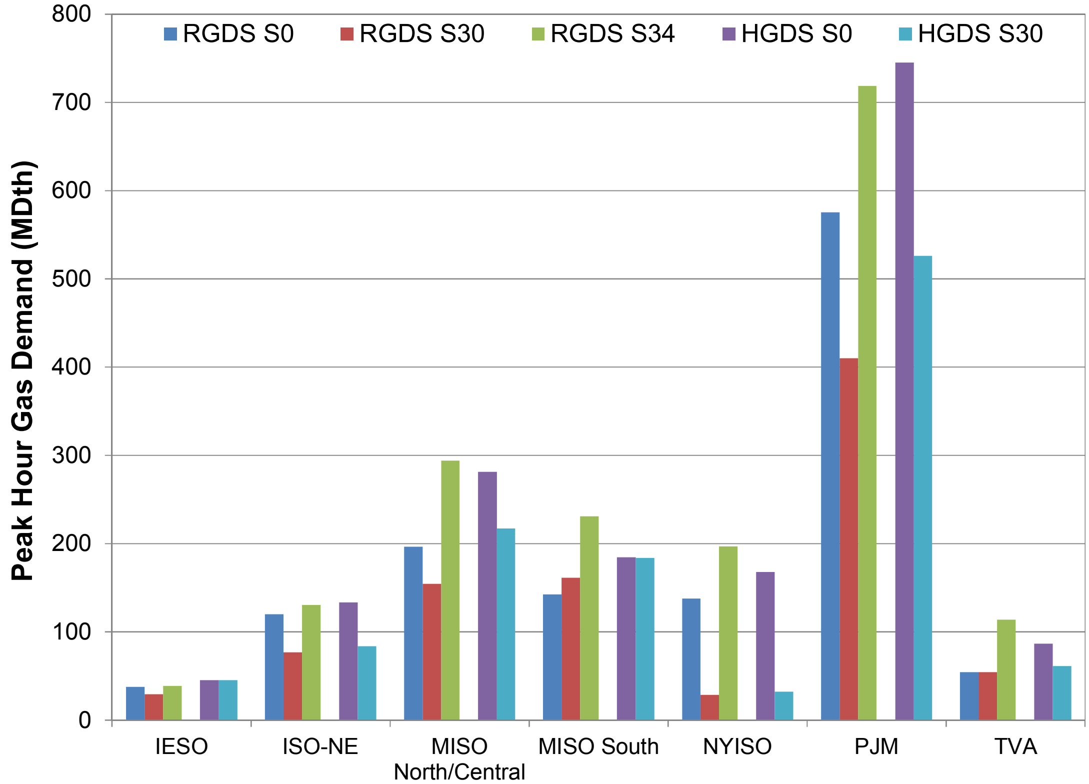


Figure 176. S0 and S34 Winter 2023: Electric Sector Gas Demand

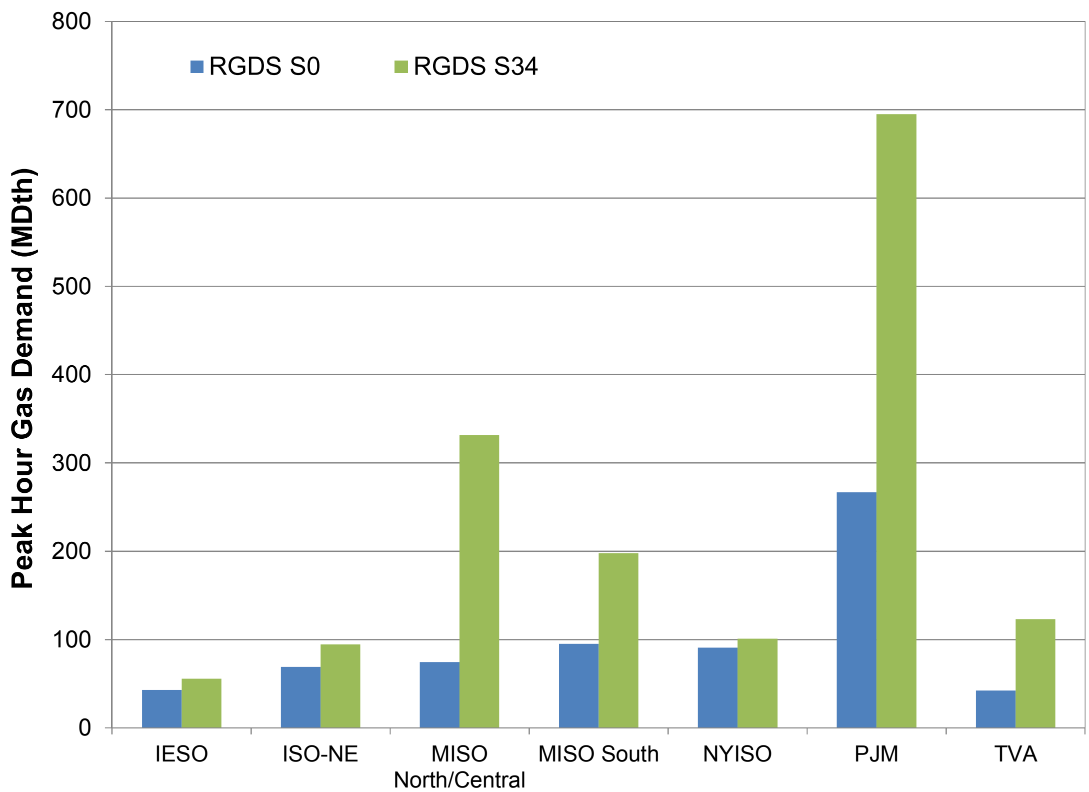
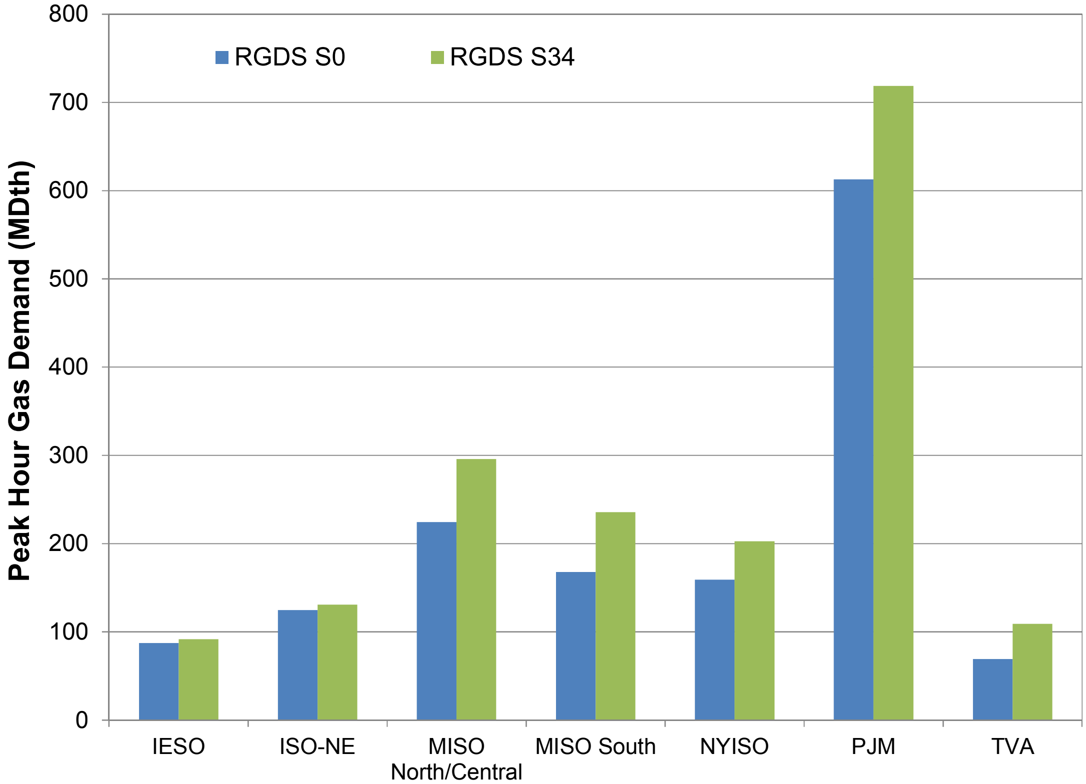


Figure 177. S0 and S34 Summer 2023: Electric Sector Gas Demand



7.6.3 Peak Hour Affected Generation in S30 and S34

Figure 178 and Figure 179 compare the affected generation to served generation for S30 and S34. Prohibiting gas burn for dual fuel units has only a small impact on the quantity of affected generation in RGDS S30, except in NYISO, where there is a significant amount of dual fuel resources. However, the impact is significant across the Study Region in HGDS S30, with affected generation eliminated completely in MISO North/Central in winter 2018, and in ISO-NE in summer 2018. In PJM, NYISO, and ISO-NE, the total amount of gas-fired generation in winter 2018 is reduced in response to barring gas use at dual fuel units, but affected generation is not eliminated.

In RGDS S34, the amount of affected generation significantly increases in PJM, NYISO, and ISO-NE under a maximum gas demand condition. In IESO and TVA a small amount of affected generation is seen under maximum gas demand, but no affected generation is seen in MISO South. Appendices Q and R provide further detail regarding the locations of constraints, and the unserved gas demand and affected generation by GPCM location.

Figure 178. S0, S30 and S34 Winter 2018: Peak Hour Affected Generation

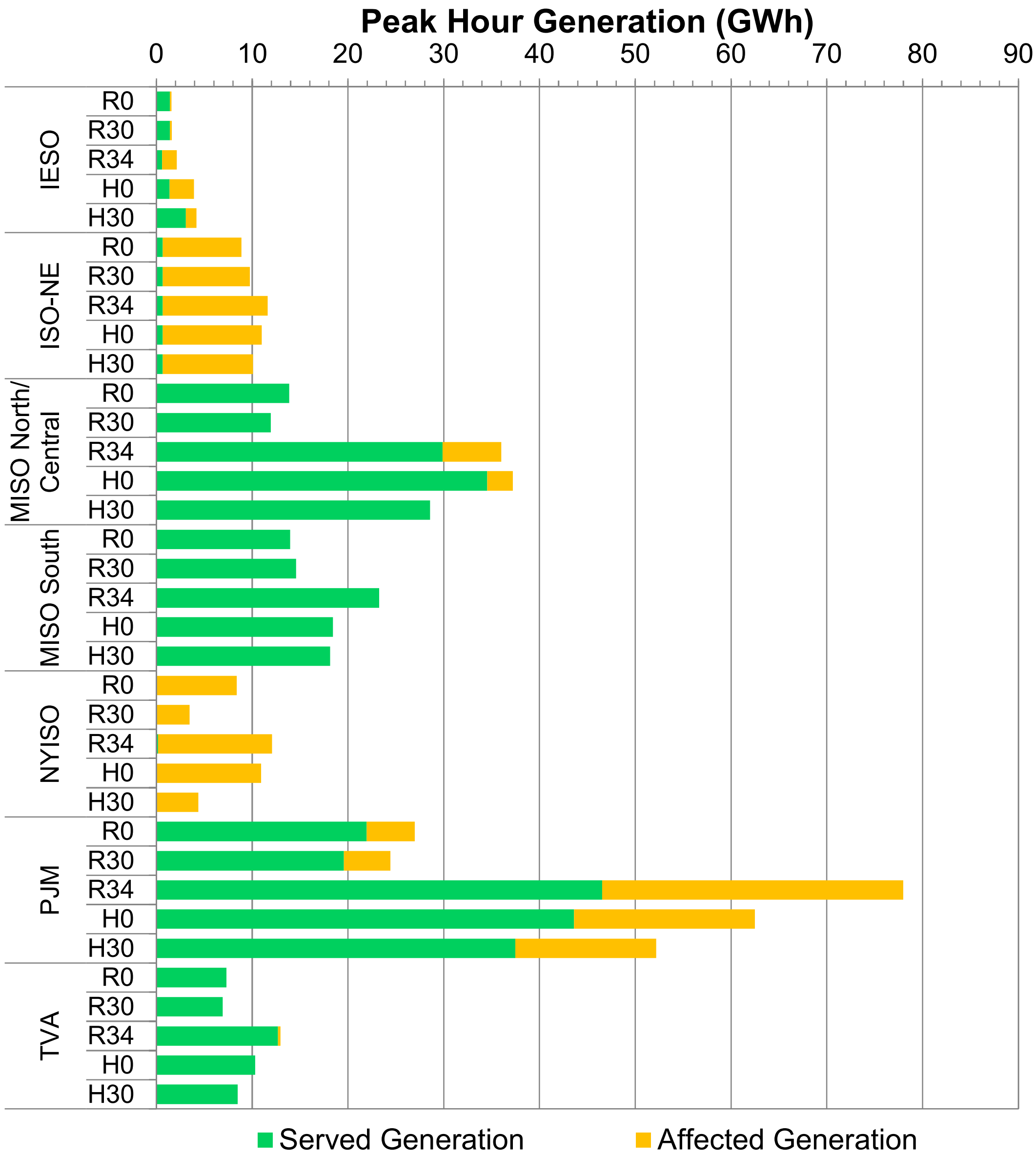


Figure 179. S0, S30 and S34 Summer 2018: Peak Hour Affected Generation

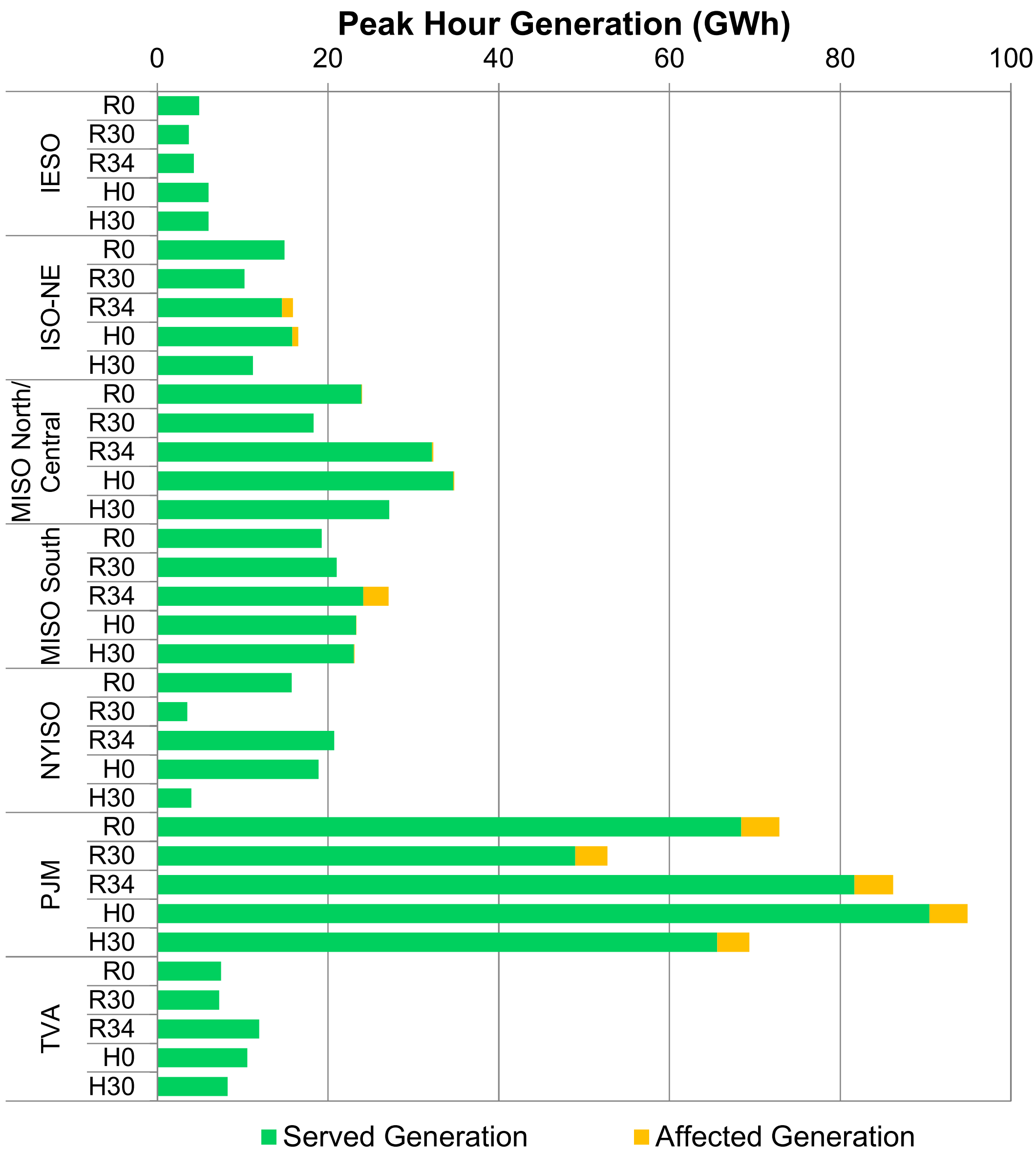


Figure 180. S0 and S34 Winter 2023: Peak Hour Affected Generation

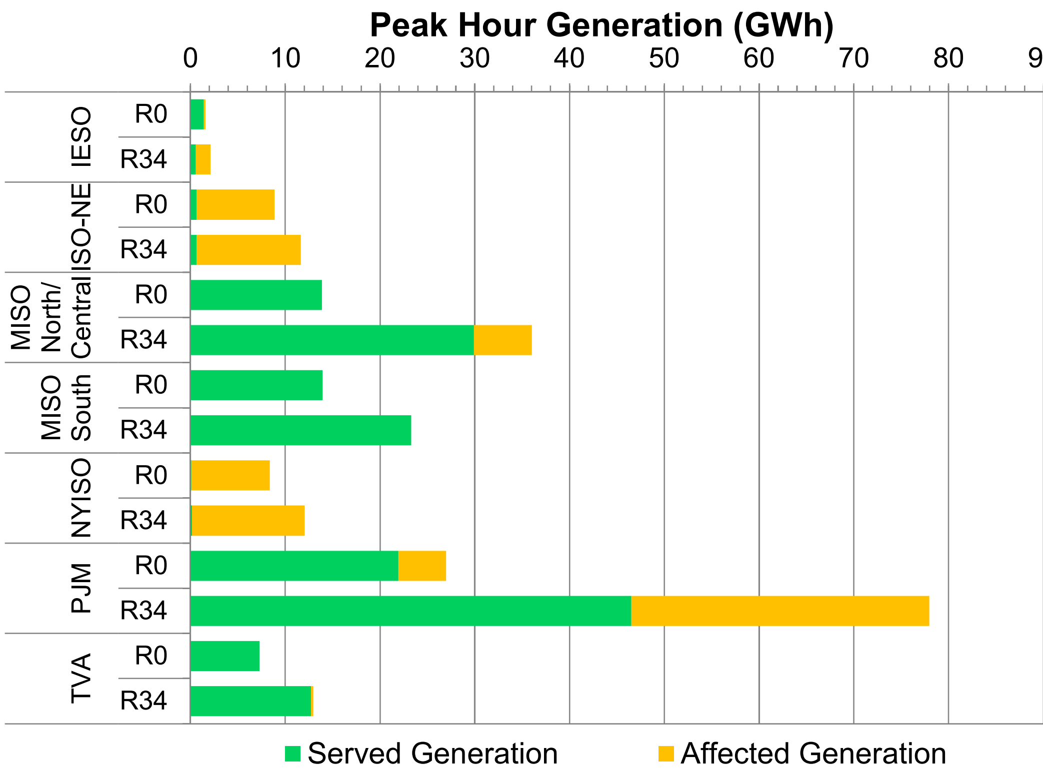
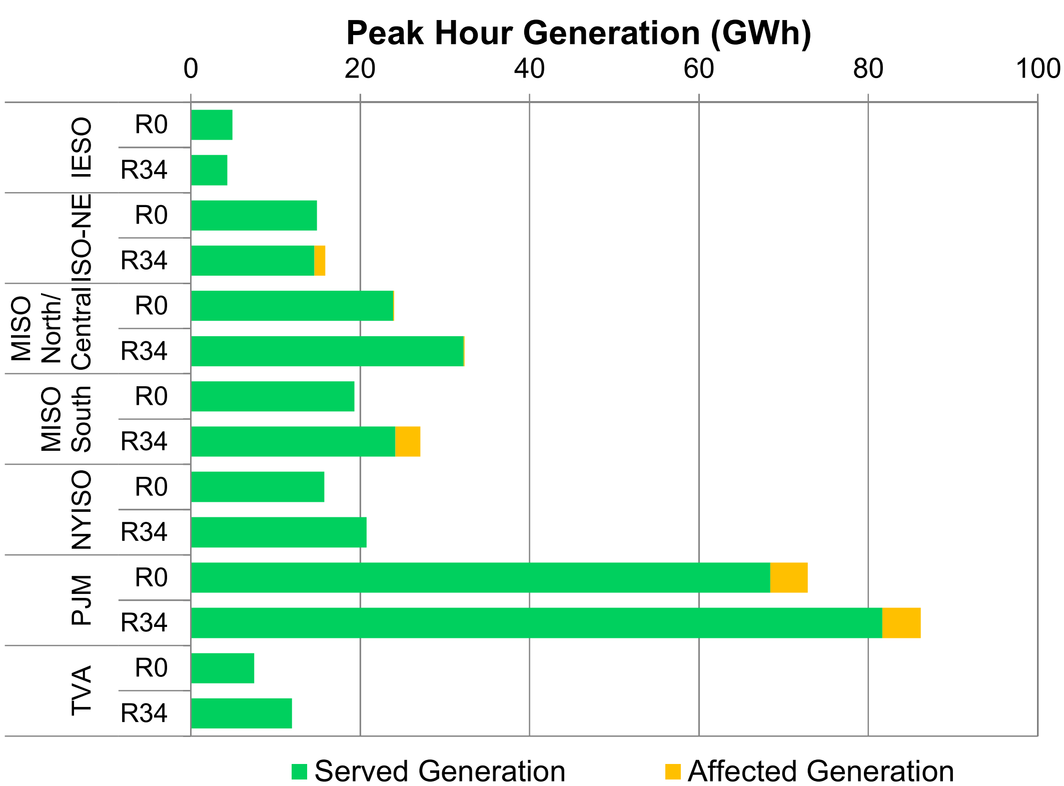


Figure 181. S0 and S34 Summer 2023: Peak Hour Affected Generation



7.7 IMPACT OF EXTREME COLD CONDITIONS: S31, S33, AND S36

7.7.1 Description of S31, S33, and S36

Sensitivity 31 envisions a Study Region-wide cold-weather event when all PPAs coincidently experience an extreme winter peak electric load and RCI gas demand. Peak electric winter loads have been represented by each PPA's "90/10" extreme load forecasts, *i.e.*, for a probabilistic distribution of electric loads, the winter peak event at the 90th percentile of probable load. Extreme load forecasts for NYISO, ISO-NE, and PJM were obtained from published planning documents.[99] The other PPAs furnished estimates of 90/10 peak load forecasts directly to LAI. All PPAs except for PJM provided total peak loads for the entire PPA. The PPA-wide loads were distributed over the load zones in proportion to the 50/50 loads for each zone. For PJM, the load zones in the published forecast were not identical to the Aurora load zones, so for those zones the extreme peak loads were adjusted so that the ratio of the 90/10 to 50/50 peak loads was the same as for the entire PPA. This sensitivity was run against the RGDS only.

The extreme winter peak load used in S31, as well as S33 and S36, compared to the expected (50/50) peak winter loads used in the RGDS is shown in Table 44.

Table 44. Extreme (90/10) Winter Peak Demand

		2018		2023	
PPA	**Zone**	**50/50 Winter Peak Load (GW)**	**90/10 Winter Peak Load (GW)**	**50/50 Winter Peak Load (GW)**	**90/10 Winter Peak Load (GW)**
IESO	ON_C	9.0	9.7	9.4	10.1
	ON_E	3.0	3.3	3.1	3.3
	ON_N	2.5	2.7	2.6	2.8
	ON_W	6.8	7.3	6.9	7.4
-	*TOTAL*	**21.3**	**22.9**	**22.1**	**23.5**
ISO-NE	ISONE_CT	5.5	5.9	5.8	5.9
	ISONE_BOSTN	4.5	4.8	4.8	4.9
	ISONE_ME	2.0	2.1	1.9	2.0
	ISONE_ROS	10.3	11.0	11.3	11.6
-	*TOTAL*	**22.3**	**23.8**	**23.8**	**24.4**

[99] NYISO 2014 Load & Capacity Data "Gold Book" Table I-2d; ISO-NE, 2014-2023 Forecast Report of Capacity, Energy, Loads and Transmission "CELT Report" Table 1.6; PJM, Load Forecast Report, January 2014 (Rev. February 2014), Table D-2.

PPA	Zone	2018 50/50 Winter Peak Load (GW)	2018 90/10 Winter Peak Load (GW)	2023 50/50 Winter Peak Load (GW)	2023 90/10 Winter Peak Load (GW)
MISO	MISO_ARK	4.6	5.5	4.8	5.7
	MISO_IA	7.0	8.3	7.4	8.7
	MISO_IL	7.9	9.3	8.8	10.3
	MISO_IN	13.6	16.0	14.0	16.4
	MISO_MI	13.7	16.2	13.9	16.2
	MISO_MN_ND	14.7	17.3	15.5	18.2
	MISO_MO	6.4	7.5	6.5	7.7
	MISO_SOUTH	17.4	20.5	18.2	21.3
	MISO_WUMS	10.0	11.7	10.3	12.0
-	*TOTAL*	**95.3**	**112.3**	**99.5**	**116.3**
NYISO	NY_A-E	8.2	8.9	8.3	9.0
	NY_GHI	2.8	3.1	2.9	3.1
	NY_Cap	2.0	2.1	2.0	2.2
	NY_NY	7.8	8.5	8.1	8.7
	NY_LI	3.6	3.9	3.8	4.1
-	*TOTAL*	**24.4**	**26.5**	**25.1**	**27.0**
PJM	PJM_ATSI	7.1	7.5	6.9	7.6
	PJM_CLEV	3.6	3.8	3.4	3.8
	PJM_EMAAC	15.9	17.7	14.8	18.3
	PJM_MAAC	13.2	14.6	13.6	15.3
	PJM_PSEG	3.5	3.8	3.2	3.8
	PJM_PSEG_N	3.3	3.6	3.0	3.6
	PJM_RTO	78.1	86.7	77.4	90.3
	PJM_SWMAAC	11.1	12.5	10.9	12.9
-	*TOTAL*	**135.8**	**150.1**	**133.2**	**155.7**
TVA	TVA_C	18.6	20.9	19.3	23.1
	TVA_NE	1.8	2.0	1.9	2.2
	TVA_NW	0.8	0.9	0.9	1.0
	TVA_S	7.6	8.5	7.9	9.4
	TOTAL	**28.9**	**32.3**	**30.0**	**35.8**
	STUDY REGION TOTAL	**328.0**	**368.0**	**333.7**	**382.7**

For LDC forecasts that include both a "Normal Day" condition and a "Design Day" condition, the "Design Day" forecasts have been used to represent a 90th percentile RCI forecast. For customers where such a forecast is not available, deliveries on the Study Region-coincident peak

RCI demand day from January 2014 were escalated at the AEO2013 Reference Case growth rates used in the RGDS, applied by census region. If an LDC has a forecast in the public domain that does not include a "Design Day" condition, then the January 2014 demand was used as the applicable basis, escalated at the growth rate included in the published forecast.

The non-coincident maximum spot "next day" gas price index observed in January 2014 for each gas pricing point was used to simulate the peak winter day event. Seven of the 35 locational maximum spot prices are higher than those incorporated in S1, which used the spot prices on the date when the average of six pricing points representing the key pricing point for each PPA was the highest.

Sensitivity 33 is intended to mirror the extreme weather events in January 2014, when several PPAs experienced a high average forced outage rate (FOR) for their respective fleets of coal-fired units, and, in some PPAs, for oil-fueled units as well. This sensitivity tested the ability of the gas network to compensate for unavailable coal and oil-fired capacity during extreme weather events. The 90/10 electric and RCI loads and the peak day fuel prices from S31 were applied.

The forced outages were modeled deterministically, with all coal and oil units derated by the maximum FOR percentage that was experienced by each PPA in January 2014 on the day when the total unavailable capacity was the greatest for each PPA. The FORs applied to the coal and oil units in each PPA are shown in Table 45. Ontario does not have any coal-fired units and only one oil-fired plant, so it is not shown in the table. For modeling purposes, LAI assumed that the maximum coal and oil-fueled unit outages across the Study Region are coincident. In order to isolate the effect of higher FORs for oil and coal units, the FORs of gas-capable units remained unchanged. This sensitivity was run against the RGDS only.

Table 45. Assumed Forced Outage Rates for Extreme Winter Event

	Coal Capacity (GW)	Coal Forced Outage (GW)	Coal Forced Outage Rate	Oil Capacity (GW)	Oil Forced Outage (GW)	Oil Forced Outage Rate
ISO-NE	2.3	1.0	0.44	5.8	2.3	0.40
MISO	61.2	2.5	0.04	2.4	0.0	0.00
NYISO	1.5	0.0	0.03	2.6	0.4	0.16
PJM	75.5	13.7	0.18	11.3	2.8	0.24
TVA	12.6	1.3	0.10	0.1	0.0	0.00

The purpose of Sensitivity 36 is to test the gas network capability under the 90/10 winter weather conditions if selected nuclear units experience forced outages, in addition to the increased FORs on the coal and oil-fired units modeled in S33. Based on information provided by the PPAs, the following nuclear unit outages were modeled:

- In TVA, Sequoyah #2 is assumed to be forced out of service during the winter peak day in 2018 and 2023.

- In IESO, one Bruce unit and two Pickering units are assumed to be forced out of service for the winter peak day in 2018, and one Bruce unit and one Darlington unit are assumed to be forced out of service during the winter peak day of 2023.
- In PJM, all of Byron and Quad Cities are assumed to be forced out of service during the winter peak days in 2018 and 2023.

All other input assumptions remained unchanged from those of S33. This sensitivity was run against the RGDS only.

7.7.2 Peak Hour Gas Demand in S31, S33, and S36

The increases in RCI demand in RGDS S31 relative to RGDS S0 are shown in Figure 182 and Figure 183. Note that RGDS S31, RGDS S33 and RGDS S36 all assumed the same RCI gas demand.

Figure 182. RGDS S31 vs. RGDS S0 Winter 2018: RCI Gas Demand

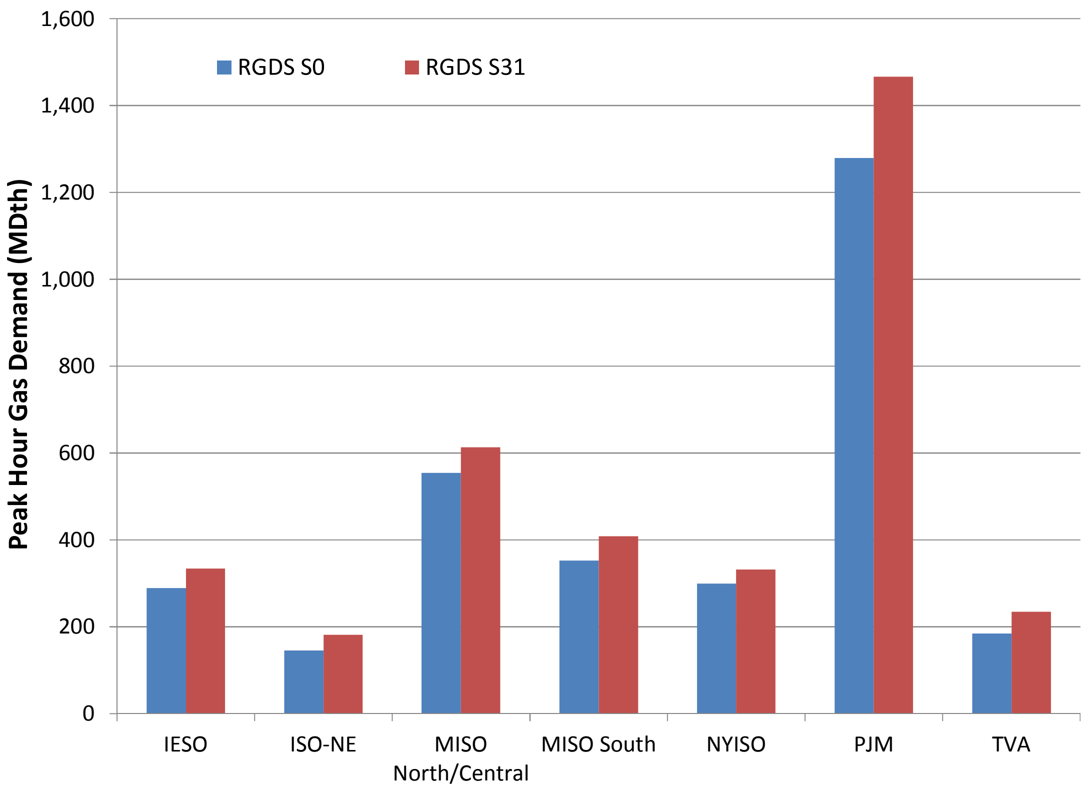


Figure 183. RGDS S31 vs. RGDS S0 Winter 2023: RCI Gas Demand

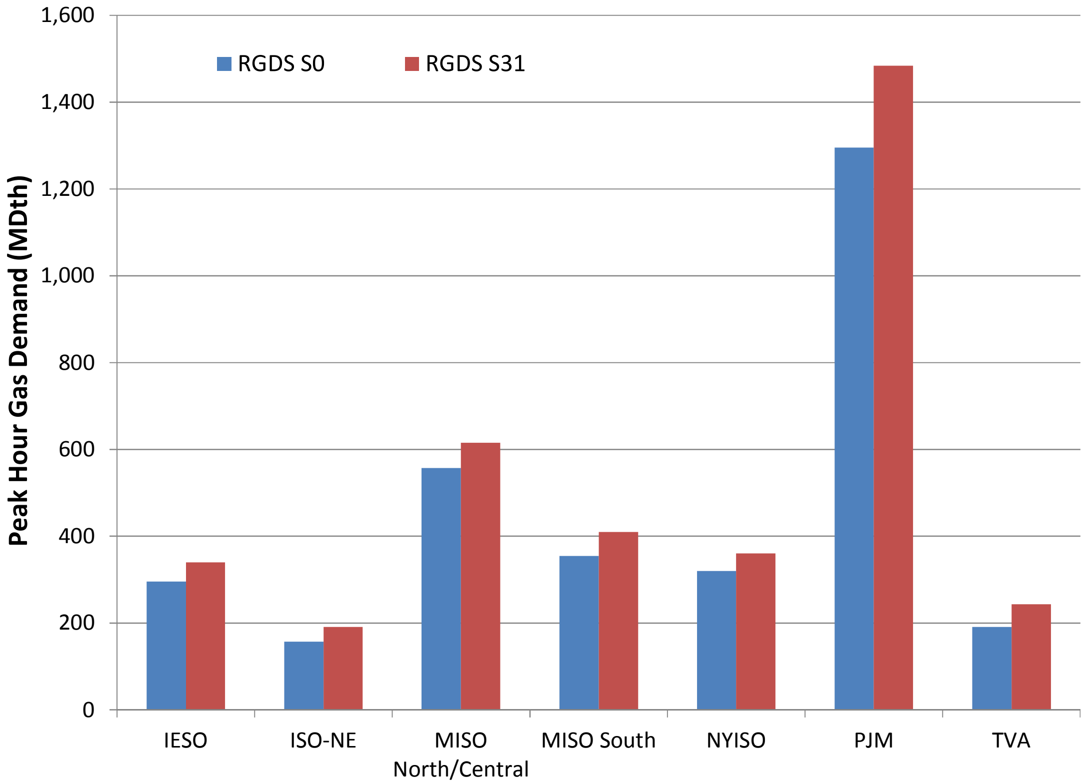


Figure 184 and Figure 185 illustrate the differences in peak hour electric sector gas demand for RGDS S31, RGDS S33, and RGDS S35 compared to RGDS S0. Across all these sensitivities, winter peak day gas demands decrease in ISO-NE, MISO North/Central, and NYISO, which all experienced very high delivered gas prices in January 2014. In ISO-NE and NYISO, there was also considerable capability for dual gas/oil resources to switch to burning oil when faced with higher dispatch costs by burning gas. IESO, MISO South, PJM, and TVA have either little change or an increase in gas demand under extreme weather conditions. This result is explained by the fact that the January 2014 maximum daily spot prices rose very little at AECO, for many IESO generators, or at Henry Hub and other Gulf locations, for MISO South and many TVA generators, and on Dominion South and Columbia Appalachia for many PJM generators.

The incremental impacts of the higher FORs are significant in PJM, ISO-NE, and MISO South. The increase in PJM is related to the high (18%) forced outage assumed for its considerable coal unit capacity. The increase in gas demand in MISO South appears to be linked to higher LMPs because S33 did not assume high coal or oil FORs in MISO. While a very high coal resource FOR was assumed for ISO-NE, it has a relatively small coal plant capacity, so its gas demand in S33 does not increase much in comparison to S31.

Comparing RGDS S36 to S33, gas demand increases substantially in IESO, PJM, and TVA in both Winter 2018 and Winter 2023 as a direct result of assuming the nuclear unit outages. MISO South also has an increase in gas demand in RGDS S36 compared to RGDS S33, which is likely the result of changes in LMPs.

Figure 184. S0, S31, S33 and S36 Winter 2018: Electric Sector Gas Demand

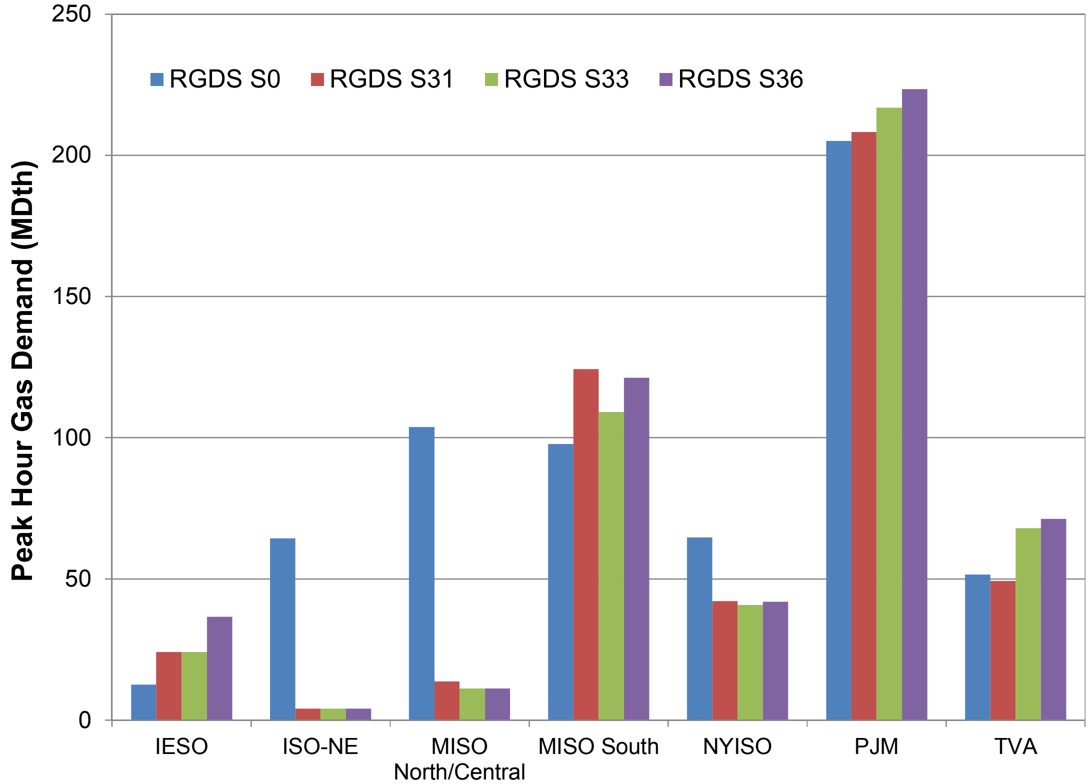
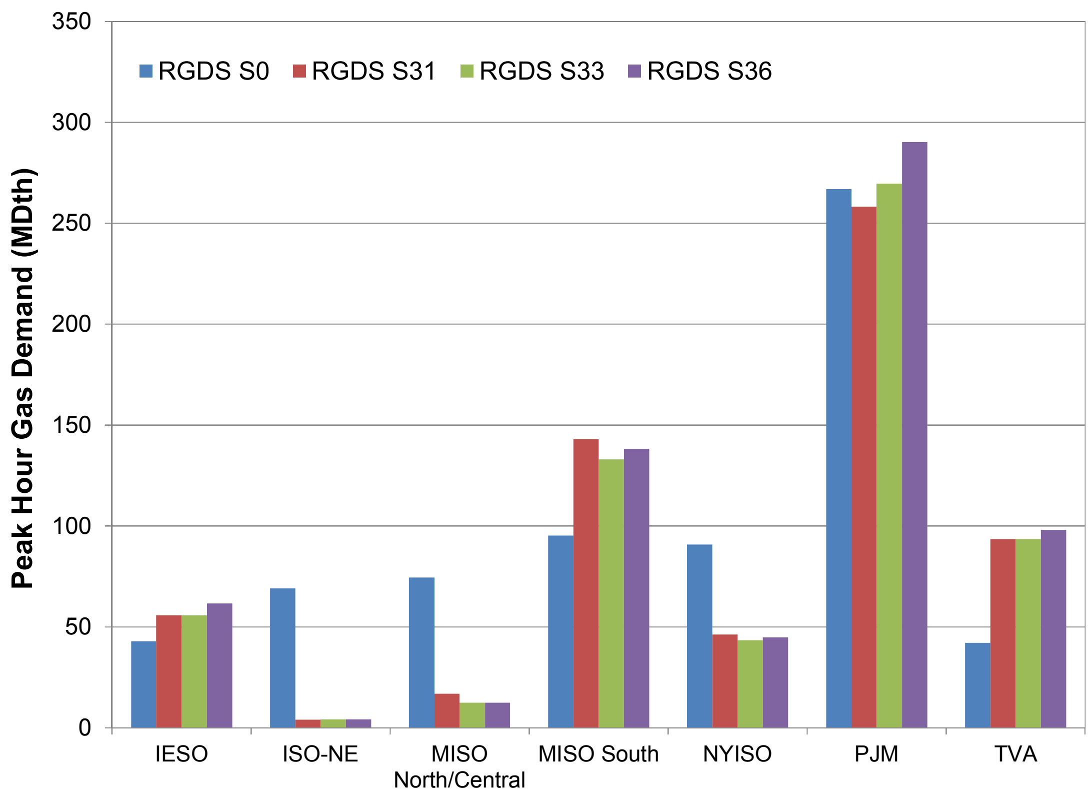


Figure 185. S0, S31, S33 and S36 Winter 2023: Electric Sector Gas Demand



7.7.3 Peak Hour Affected Generation in S31, S33, and S36

Figure 186 and Figure 187 compare affected generation to served generation for S31, S33, and S36. These sensitivities were run for winter only. The amount of affected generation decreases significantly in these sensitivities in NYISO and is eliminated entirely in ISO-NE, as oil and coal are in merit and substitute for gas-fired generation. In PJM, increases in gas demand resulting from forced outages and higher electric load were roughly offset by substitution of oil and coal-fired generation in response to higher gas prices. In IESO, generation gas demand and affected generation increased because gas prices for Ontario generators did not increase much and energy exports to other PPAs were higher. Appendix S provides further detail regarding the locations of constraints, and the unserved gas demand and affected generation by GPCM location.

Figure 186. S0, S31, S33 and S36 Winter 2018: Peak Hour Affected Generation

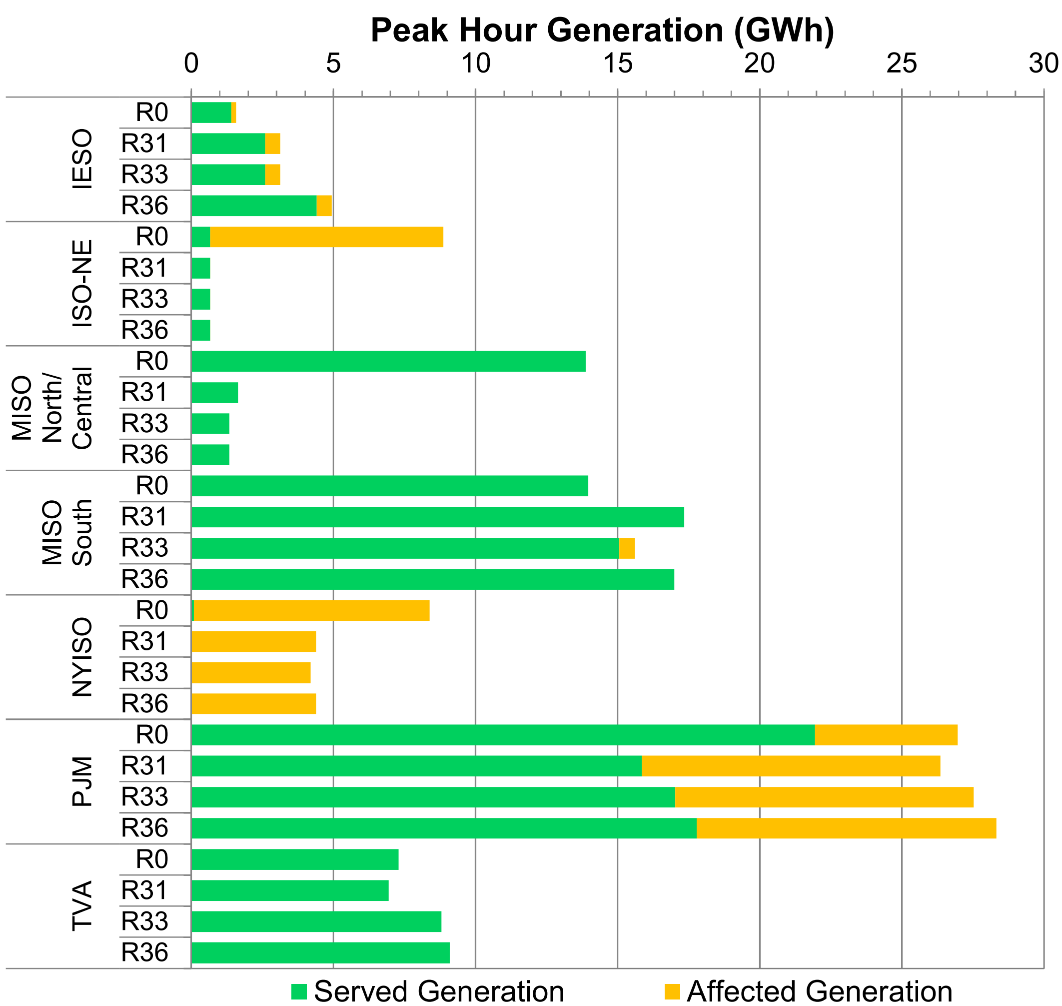
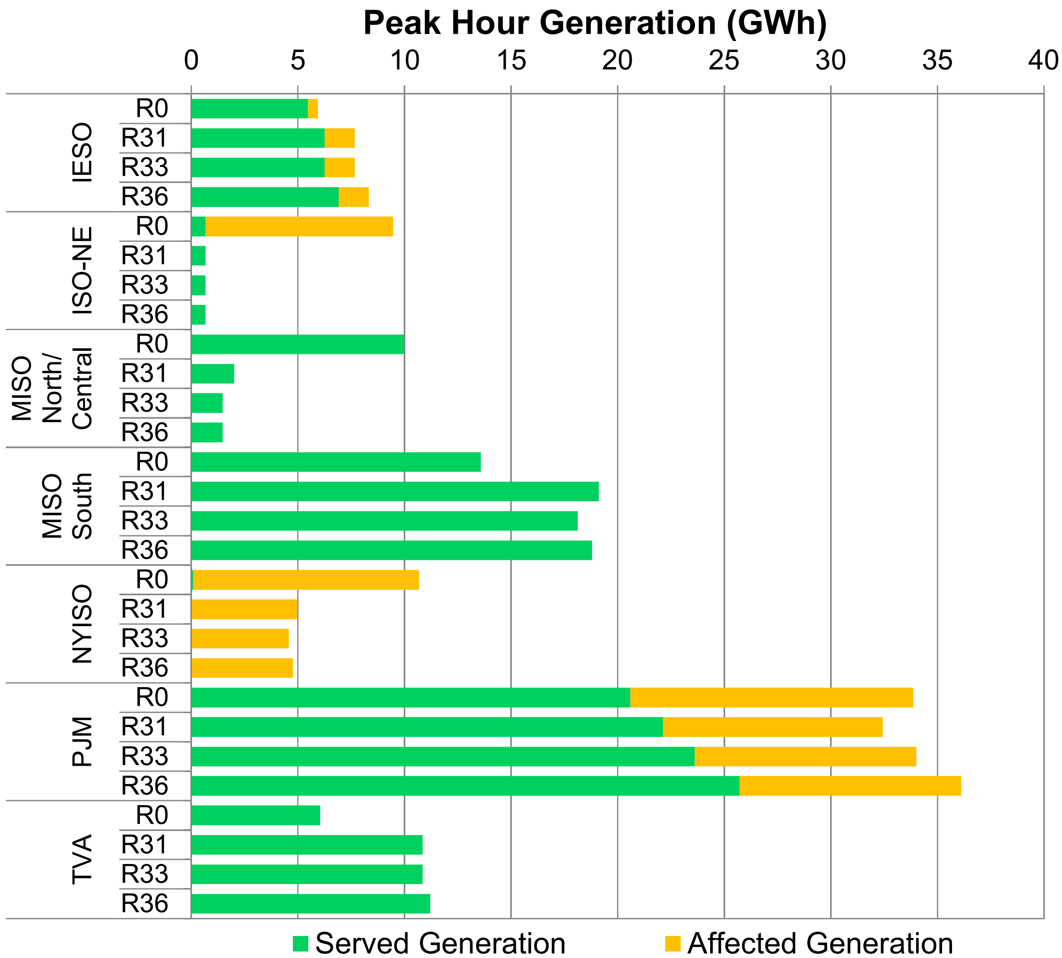


Figure 187. S0, S31, S33 and S36 Winter 2023: Peak Hour Affected Generation



8 CONSTRAINT MITIGATION

8.1 POTENTIAL MITIGATION MEASURES

8.1.1 Characterization of Constraints

The constraints on delivery of natural gas to generators identified in Section 6 are characterized by the amount of unmet generator gas demand (Dth) in the peak hour of the peak day (winter or summer), and by the number of days in the relevant season that the constraint materializes, potentially giving rise to peak hour affected generation (GWh). Additional measures include the frequency and duration of consecutive day peak hour constraints. The identification of affected generation in a given location does not indicate that electric system reliability in that location is in jeopardy. The reported affected generation represents a seasonal peak hour condition under a fixed dispatch pattern. As such, although dual-fuel capability has been identified, iterative redispatching has not been performed to investigate the availability of gas-fired generation at other locations, or other mitigation measures ascribable to non-gas fired generation resources.

The most economical means of mitigating a specific constraint are highly dependent on the unique characteristics of the pipeline and of the affected generators. Unserved peak hour demand is an indicator that there is insufficient pipeline deliverability to meet the gas demands of gas-fired generators under a defined scenario or sensitivity. Mitigation of the constraint therefore involves one or more physical infrastructure improvements and/or leveraging of dual fuel infrastructure to ensure that supply and demand are in balance not only on the peak hour of the peak day in Winter 2018 or Winter 2023, but also throughout the three-month heating season, January, February and December. In delineating the potential mitigation measures applicable to reduce or eliminate constraints across the Study Region, LAI has focused on the Winter 2018 results. This is because additional producer, marketer, and generator-sponsored projects may be expected to materialize before Winter 2023 based on projects currently under development that would further expand transportation capacity, particularly in the northeast, beyond what has been included in the RGDS.[100]

Identification of one or more mitigation measures to alleviate the transportation constraint is the primary objective of this analysis. The delineation of the viable mitigation measure is based on LAI's assessment of the results of the frequency and duration analysis presented in Section 6. It does not incorporate independent engineering economic or environmental analysis, however. [101]

There are a number of mitigation measures available to pipeline companies, generation companies, fuel suppliers, and/or PPAs to alleviate a pipeline constraint affecting gas-fired generators. *For high frequency, long duration constraints* resulting in the non-scheduling or

[100] See Appendix F for the identification of incremental pipeline expansion projects that have been included in Sensitivity 13 or announced since the project lists for the RGDS and Sensitivity 13 were set.

[101] The economics of alternative mitigation measures to reduce or eliminate pipeline constraints is outside the scope of the Target 2 analysis. In Target 4, Task 5, LAI will conduct engineering economic analysis of the tradeoffs between incremental firm transportation versus investment in dual fuel capability where selected pipeline locations are constrained. The economics of alternative mitigation measures delineated in this section are not part of the Target 4 study, however.

interruption of gas-fired generation in one or more PPAs, the most economic mitigation measure may be the installation of additional pipeline capacity that is available throughout the winter, in particular, but more generally throughout the year to support gas-fired generation. Incremental pipeline capacity can be realized a variety of ways. In order to install additional capacity, a pipeline would need to demonstrate market support in the form of a service agreement for firm transportation or firm storage as part of a Certificate of Public Convenience and Necessity filing at FERC. From high cost to low cost: [102]

- a pipeline company may develop a new pipeline from a liquid sourcing point to the market center to support incremental gas-fired generation;
- a pipeline may install additional loopline and/or compression along the constrained segment, subject to maximum allowable operating pressure (MAOP) limitations;
- a rival pipeline company may install a lateral from an underutilized pipeline to the generator, including the installation of new metering and instrumentation.

For low frequency, short duration constraints resulting in the non-scheduling or interruption of gas-fired generation in one or more PPAs, the most economic mitigation measure may be the use of liquid fuel. This may require modifications to fuel handling and burner systems and environmental controls. Storage may be available from existing oil tanks, or it may require the installation of new oil tanks to accommodate the drawdown of distillate fuel oil for combined cycle and/or simple cycle units. To the extent the low frequency, short duration constraints occur during a substantial portion of the winter and there is idled LNG import capacity available from one or more existing pipelines, one mitigation measure would incorporate a financial approach. Such a financial approach would involve bringing additional cargoes to an existing LNG import facility through a seasonal service from an LNG supplier or marketer, which may be a viable mitigation measure in ISO-NE for either the Distrigas terminal in Massachusetts or the Canaport terminal in New Brunswick. In PJM, the Cove Point terminal is assumed to convert to an export facility, but a potential mitigation measure would be to contract with shippers holding firm transportation and/or storage rights on the Cove Point system to redeploy gas otherwise bound to the liquefaction plant for brief duration during cold snaps or short term operating contingencies, and utilize the existing LNG storage infrastructure at to maintain timely export shipments. In considering LNG mitigation measures, LAI has made the simplifying assumption that construction of a new LNG import terminal or satellite LNG tank either on a pipeline or behind and LDC citygate is not feasible for purposes of ameliorating a low frequency, short duration constraint. Another mitigation measure relates to the use of surge capacity at an LNG export terminal or reenergization of an LNG import terminal. Finally, another mitigation measure relates to the use of industrial DR at the local level. From high cost to low cost:

- a PPA, fuel supplier, or marketer could arrange for a seasonal LNG peaking service requiring the commitment of one or more destination flexible cargoes to the Repsol Canaport and/or Suez Distrigas import facilities, or by contracting for short-term flow

[102] Delineation of cost duration curves for alternative mitigation measures is outside the scope of the Target 2 analysis. Estimation of the costs associated with fuel assurance is included in the Target 4 analysis.

diversions with shippers holding firm service at the Dominion Cove Point LNG export terminal;

- a generator could add dual-fuel capability by modifying equipment and constructing on-site oil tank capacity, while lining up oil inventory to assure adequate fuel deliverability during one or more cold snaps throughout the winter;[103]

- an LDC could activate industrial gas DR to deliver via displacement to one or more generators otherwise unscheduled; or

- a generator could use existing oil inventory held in storage to supplant pipeline rendered supply.

Between the range of technology remedies associated with high frequency, long duration constraints and low frequency, short duration constraints are mitigation measures that reasonably fit moderate frequency, moderate duration constraints, or high frequency, short duration constraints, or low frequency, long duration constraints. In identifying applicable mitigation measures, LAI has utilized the frequency and duration results for RGDS S0 and, where applicable, HGDS S0. Unless otherwise noted, all mitigation measures are oriented around the peak hour transportation constraints that are reported in the frequency and duration results for RGDS S0.[104]

The relative viability of alternative mitigation measures depends on location-specific conditions. Many of these mitigation measures have the potential for costs to be "socialized" since a number of benefitted shippers in one PPA would bear responsibility for joint fixed costs. The relative economics of one approach versus another are uniquely dependent on a pipeline's operating conditions, in particular, the available "headroom" that can be used to accommodate increased compression with or without additional loopline. Environmental, siting, and permitting considerations affecting the use of oil at a particular site are also unique to the individual generation company's location, state and local environmental review, and commercial considerations. It should be noted that all of the potential mitigation measures involve investment decisions by multiple parties, including pipelines, generators, storage operators, *etc*. The best mitigation measures for different generators on the same constrained pipeline segment might be different, as well, depending on technology type (*e.g*., peakers versus combined cycle plants) and other factors.

8.1.2 Interpretation of Frequency and Duration Analyses

The figures illustrating the frequency and duration analyses in Section 6.2.1 and 6.2.2 show the peak hour gas demand, including electric generation and RCI demand, compared to the pipeline segment capacity for each day of the Winter 2018 and Summer 2018 respectively, for RGDS S0.

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[103] The scope and cost of providing dual-fuel capability for new simple cycle and combined cycle units is discussed in the Target 4 report.

[104] LAI has exercised its professional judgment in identifying the preliminary recommended mitigation measure. The best fit solution for a given transportation deficit in the Study Region requires much technical analysis by the pipeline and/or generation company, the performance of which has not been conducted in this Target 2 report.

As discussed in Section 6.1, the magnitude of a constraint is related to the level of the potentially affected generation. LAI has categorized constraints in terms of three measures:

- Persistency – the total number of days in the winter and summer in which there is potentially affected generation during the peak hour),
- Significance – the ratio of the potentially affected generation to total generation demand on the peak hour of the peak day, and
- Depth – the ratio of the average peak hour potentially affected generation over all days when affected generation occurs, to the affected generation on the peak hour of the peak day

We have interpreted the pattern of constraints and then characterized them as "Low", "Moderate", and "High" for each of these measures to support a reasonably consistent basis to assign mitigation measures for the various constrained sections under Winter and Summer conditions. The mitigation measures generally fall into two broad categories: pipeline capacity expansion and alternative peak supply.

8.2 Mitigation Measures Applicable to Identified Constraints

8.2.1 RGDS S0 Winter and Summer 2018 Constraints

Relevant characteristics for each of the 22 constrained segments identified under this scenario in Sections 6.2.1 and 6.2.2 are summarized in Table 46. The potentially applicable mitigation measure(s) for each constraint are discussed in the following subsections. Mitigation measures involving capacity additions would require a counterparty to execute a service agreement for firm service.

Table 46. Summary of RGDS S0 2018 and HGDS S0 2018 Constrained Segments

	RGDS S0 Winter 2018				RGDS S0 Summer 2018				HGDS S0 2018		Characterization		
Constrained Segment	Events	Min Duration (Days)	Max Duration (Days)	Total Days	Events	Min Duration (Days)	Max Duration (Days)	Total Days	Winter Days	Summer Days	Persistence	Severity	Depth
Columbia Gas VA/MD	12	1	5	23	1	1	1	1	57	21	Mod	Mod	Mod
Columbia Gas W PA/NY	11	1	5	21					17		Mod	High	Low
Constitution	5	1	12	25					90		Mod	Mod	High
Dominion Eastern NY	6	1	6	15					21		Mod	High	Low
Dominion Western NY	1	4	4	4					34		Low	High	Low
Dominion Southeast	7	1	12	22	3	1	2	5	22	37	Mod	High	Mod
East Tennessee Mainline	7	1	2	9					26		Low	Low	High
Eastern Shore	11	1	10	51	7	1	6	19	20	45	High	High	Mod
Empire Mainline	5	1	12	21					60		Mod	High	Low
Millennium	4	1	59	83					27		High	High	Mod
NB/NS Supply	13	1	20	58					56	28	High	High	Mod
TransCanada Ontario West	5	1	5	12					8		Mod	High	Low
TransCanada Quebec	9	1	14	30					29		Mod	High	Mod
Tennessee Z4 PA	10	1	7	30					76		High	High	Mod
Tennessee Z5 NY	2	31	59	90					90		High	High	High
Transco Leidy Atlantic	8	2	23	59					90		High	High	Mod
Transco Z5	3	1	7	9	7	2	6	18	21	16	Low	High	Low
Transco Z6 Leidy to 210	5	1	3	8					90		Low	Low	Mod
Texas Eastern ETX					4	1	6	12		24	Mod	High	Mod
Texas Eastern M2 PA South	10	1	15	50					90		High	High	Mod
Texas Eastern M3 North	10	2	7	39					82		High	High	Mod
Union Gas Dawn	2	1	3	4					6		Low	High	High

8.2.1.1 Columbia Gas VA/MD

This constraint on the Columbia Gas system is described in Sections 6.2.1.1 and 6.2.2.1, and results in a gas transportation deficit affecting generators in Maryland and Virginia on the peak hour of the peak day in the winter and also on the peak day in the summer. As shown in Figure C1, Figure C2, Figure C43, and Figure C44, some amount of gas transportation deficit is expected during the peak hour on 23 days during the winter, with the magnitudes of the shortfalls expected to drop off roughly linearly. The 23 days are distributed over 12 events, with a maximum of 5 days of consecutive constrained peak hour delivery. In the summer, there is a single day of constrained peak hour delivery. The constraints along the Columbia Gas VA/MD segment can be characterized as being of moderate frequency and duration, but on the peak winter day it affects a substantial portion (about 75%) of unconstrained generation demand. Dominion's recently announced 1.5 Bcf/d Atlantic Coast Pipeline project would also serve the Virginia markets currently served by the Columbia VA/MD segment, and could therefore help to mitigate this constraint beginning in late 2018. Other potential mitigation measures include financial arrangements for the utilization of LNG storage at the Cove Point LNG terminal (see Section 8.2.1.6), utilization of existing dual fuel capability at generation sites in SWMAAC and Virginia, installation of new dual-fuel capability at appropriate generating units in SWMAAC and/or Virginia, and activation of industrial DR through one or more LDCs doing business in Maryland and Virginia.

8.2.1.2 Columbia Gas Western PA/NY

This constraint on the Columbia Gas system is described in Section 6.2.1.2, and results in a gas transportation deficit affecting generators in Pennsylvania, New Jersey, Virginia, Maryland, and Delaware on the peak hour of the winter peak day. As shown in Figure C3 and Figure C4, some amount of transportation deficit is expected during the peak hour on 21 days during the winter, with the magnitudes of the shortfalls expected to drop off roughly linearly. The 21 days are distributed over 11 events, with a maximum of 5 days of consecutive peak hour constraint. This constraint can be characterized as being of moderate frequency and duration, but on the peak day it affects a substantial portion (about 90%) of unconstrained generation demand. The mitigation measure most likely to be economical is utilization of existing dual fuel capability at generation sites in Pennsylvania, New Jersey, Virginia, Maryland, Delaware and New York. Another mitigation measure that has the potential to reduce transportation deficits allocable to generators would be activation of industrial DR with many of the LDCs doing business in the many states affected by constraints on Columbia Gas Western PA/NY.

8.2.1.3 Constitution Pipeline

This constraint on the Constitution Pipeline is described in Section 6.2.1.3, and results in a gas transportation deficit affecting generators in New York and Connecticut on the peak hour of the peak day. As shown in Figure C5 and Figure C6, some amount of shortfall is expected during the peak hour on 25 days during the winter, with the magnitudes of the shortfalls expected to drop off roughly linearly. The 25 days are distributed over 5 events, with a maximum of 12 days of consecutive peak hour constraint. This constraint can be characterized as being of moderate to high frequency and duration, but on the peak day nearly one-half of generation demand is unmet. Because Constitution is expected to be commercialized in 2017[105], it is reasonable to expect initial pressures and flows along the Constitution mainline to Wright, New York, to be substantially under the certificated MAOP of the new route system. Therefore all incremental deliverability to alleviate the constraints in Winter 2018 and, for that matter, Winter 2023, can be realized by adding one or two compression stations in southeastern Pennsylvania and/or southern New York. No other mitigation measures would likely be required.

8.2.1.4 Dominion Eastern NY

This constraint along Dominion Eastern NY is described in Section 6.2.1.4, and results in a gas transportation deficit affecting generators in NYISO on the peak hour of the peak day in Winter 2018. As shown in Figure C7 and Figure C8, some amount of shortfall is expected during the peak hour on 15 days during the winter. The magnitude of the shortfall is substantial in relation to total gas-fired generation scheduled along this route segment during the three months. The 15 days are distributed over 6 events. This constraint can be characterized as being of moderate

[105] When the assumptions for this study were defined in the first quarter of 2014, the assumed in-service date for the proposed Constitution Pipeline was 2017. On December 2, 2014 FERC certificated Constitution. According to Constitution, the expected in-service date is second half 2016.

frequency and duration, but on the peak hour of the peak day no gas-fired generation can be served. Dominion's 112 MDth/d New Market Project, which is included in Sensitivity 13 and currently undergoing FERC review for a planned 2016 in-service date, will increase the capacity of this segment and alleviate the constraint.

8.2.1.5 Dominion Western NY

This constraint along Dominion Western NY is described in Section 6.2.1.5, and results in a gas transportation deficit affecting generators in NYISO on the peak hour of the peak day in the Winter 2018. As shown in Figure C9 and Figure C10, the duration of the shortfall is low, occurring on 4 days over 1 event during the winter. The magnitude of the shortfalls is insignificant in relation to total gas-fired generation scheduled along this route segment during the winter. This constraint can be characterized as being of low frequency and duration. Like Dominion Eastern NY, on the peak day no gas-fired generation can be scheduled. During nearly all of the winter, Dominion would be expected to schedule all or nearly all gas-fired generation across Dominion Western NY. The addition or more complete utilization of existing compression capability on the system would be expected to alleviate the constraint. Again, coordination with one or more LDCs to activate industrial DR could also mitigate the constraint as well as use of existing dual fuel capability.

8.2.1.6 Dominion Southeast

This constraint along Dominion Southeast, described in Sections 6.2.1.6 and 6.2.2.2, results in a gas transportation deficit affecting generators in PJM on the peak hour of the peak day in the Winter 2018. As shown in Figure C11, Figure C12, Figure C45, and Figure C46, the shortfall is substantial, occurring during the peak hour on 22 days during the peak winter month. The magnitude of the shortfall is substantial in relation to total gas-fired generation scheduled along this route segment in Maryland and Virginia during the winter. The 22 days are distributed over 7 events, the majority of which occur in January, the peak month. This constraint can be characterized as being of high frequency and duration. During the 22 days of mainline constraints on Dominion Southeast, the transportation deficit results in the majority of gas-fired generation potentially being affected. In summer, the affected generation on the peak hour of the peak day is also significant.

The Cove Point pipeline has firm transportation capacity of 1.8 Bcf/d, and connects the LNG terminal to the major mid-Atlantic gas transmission systems of Transco, Columbia and Dominion. One potentially viable mitigation measure on Dominion would be implementation of a flow day diversion or seasonal peaking service from Dominion Cove Point, thereby reducing Dominion Cove Point's utilization of the Dominion Southeast mainline for purposes of supporting the anticipated export regime of the Cove Point LNG facility.[106] This mitigation measure leverages Cove Point's existing storage capacity, the size of which could potentially enable orderly year-round shipments to export markets in Asia and India. A flow day diversion on peak winter days when constraints arise would facilitate the redeployment of Dominion

[106] Cove Point seeks to export about 1 Bcf/d, or about 7.82 million metric tons per annum over a 25-year term. Dominion Cove Point's customers are Tokyo's Sumitomo Corporation and New Delhi-based GAIL India.

Southeast capacity to serve gas-fired generation.[107] Therefore implementation of this mitigation measure would necessitate commercial arrangements with Sumitomo and/or GAIL. Precisely how this is paid for is outside the scope of this analysis.

Absent the ability to utilize LNG storage at Cove Point through a flow day diversion or seasonal peaking service with Dominion Cove Point's customers in Japan and India, additional capacity along the Dominion Southeast mainline would be required to alleviate the constraint. A combination of loopline and/or compression may be expected to alleviate the constraint. Other mitigation measures associated with the addition of storage withdrawal capacity at Oakford or mobilization of industrial DR do not appear viable.

8.2.1.7 East Tennessee Mainline

This constraint along the East Tennessee Mainline is described in Section 6.2.1.7, and results in a negligible gas transportation deficit affecting generators in PJM on the peak hour of the peak day in Winter 2018.[108] As shown in Figure C13 and Figure C14, the magnitude of the shortfall is insignificant in relation to the total amount of gas-fired generation that can be served along the East Tennessee mainline. This constraint occurs during the peak hour of nine days during two of three peak winter months. The constraint can be characterized as low frequency and duration, resulting in relatively small amounts of affected generation in Virginia. The constraint may be alleviated through the addition of compression, the more complete utilization of existing compression, use of liquid fuel capability, or, perhaps, mobilization of industrial DR.

8.2.1.8 Eastern Shore

This constraint along the Eastern Shore is described in Sections 6.2.1.8 and 6.2.2.3, and results in a gas transportation deficit affecting generators in PJM on the peak hour of the peak day in Winter 2018. As shown in Figure C15, Figure C16, Figure C47, and Figure C48, the duration of the shortfall is substantial, occurring during the peak hour on 51 days throughout the winter. The magnitude of the shortfall is substantial in relation to total gas-fired generation scheduled along this route segment in Delaware during the winter. The 51 days are distributed over 11 events. The constraint also results in a significant deliverability shortfall in summer, with a total of 19 days of constrained delivery. This constraint can be characterized as being of high frequency and duration.

Working in conjunction with Texas Eastern, the constraint may be alleviated by boosting receipt point capability by means of incremental horsepower at the Daleville compressor station on the northern segment of the Eastern Shore system, coupled with requisite downstream horsepower additions at the existing Delaware City or Bridgeville compressor stations. Absent sufficient MAOP headroom along the Eastern Shore mainline serving gas-fired generators on the Delmarva Peninsula, Eastern Shore would need to add loopline back to the Texas Eastern interconnect on the Delmarva Peninsula.

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[107] Total LNG storage capacity at the existing Cove Point facility is 14.6 Bcf.

[108] The TVA generator served by East Tennessee holds firm transportation capacity.

8.2.1.9 Empire Mainline

Flow on the western portion of Empire mainline has been reversed since prolific gas production from Marcellus has rationalized the reversal-of-flow on Millennium and the Empire Connector and the Empire mainline to upstate New York, while the eastern portion of the Empire mainline continues to flow west to east. This constraint along the Empire Mainline is described in Section 6.2.1.9, and results in a gas transportation deficit affecting generators in NYISO on the peak hour of the peak day in Winter 2018. As shown in Figure C17 and Figure C18, the shortfall in NYISO is significant, occurring on 21 days throughout the winter. The magnitude of the shortfall is significant in relation to total gas-fired generation scheduled along this route segment during the winter. The 21 days are distributed over 5 events. However, with the exception of only three days in January, most of the generator demand is served. This constraint can be characterized as being of moderate frequency and duration.

To alleviate the constraint, one potential mitigation measure would be the addition of liquid fuel capability at the 1,040 MW Sithe Independence combined cycle plant in Scriba, New York. If, for whatever reason, the addition of liquid fuel capability at Sithe Independence could not be permitted or otherwise implemented, alleviating the constraint would require the addition of compression along the Empire mainline, or the more complete utilization of existing compression. Incremental additions to Empire that are currently under development are designed primarily to increase delivery capability to TransCanada at Chippawa, and therefore may not directly affect mainline capacity east of the Empire Connector.

8.2.1.10 Millennium

This constraint on Millennium is described in Section 6.2.1.10, and results in a gas transportation deficit affecting generators in New York and New England on the peak hour of the peak day. As shown in Figure C19 and Figure C20, a substantial shortfall is expected on 83 days during the winter. The 83 days are distributed over 59 events. This constraint can be characterized as being of high frequency and duration. Given the nature of the constraint, new pipeline capacity would be required accommodate additional flow to premium markets in NYISO, ISO-NE and IESO.

Millennium has received FERC certification to expand system capacity through compression additions at Hancock and Minisink. Whether or not there is still more expansibility through additional horsepower improvements is unknown. Therefore the mitigation measure needed to alleviate transportation constraints would likely involve a combination of additional compression plus loopline additions along the Millennium mainline from the Bluestone, Laser, and/or Stagecoach receipt points to Ramapo. Storage additions at the Stagecoach high deliverability storage fields may also contribute to the reduction of the transportation constraint, but would not likely be adequate without loopline additions to increase the transportation capacity of Millennium. Millennium is currently studying the addition of approximately 30 miles of new 24-inch, or, perhaps, larger mainline that would connect the existing Millennium system to Dominion near Cortland, NY, but this project would not alleviate the mainline constraint.

8.2.1.11 New Brunswick / Nova Scotia

The decline in Atlanta Canada gas production reflects the reduction in gas production in Sable Island and the high cost of replacing gas supply in Deep Panuke. Boundary flow into New England is exacerbated by the assumed low capacity factor of Repsol's regasification of LNG at the Canaport LNG import facility in New Brunswick. This constraint on New Brunswick / Nova Scotia supply is described in Section 6.2.1.11, and results in a gas transportation deficit affecting generators in ISO-NE on the peak hour of the peak day. As shown in Figure C21 and Figure C22, a substantial shortfall is expected during the peak hour on 58 days during the winter. These constraints are distributed over 13 events. This constraint can be characterized as being of high frequency and duration.

Given the high frequency and duration of the constraint, the mitigation measure is revitalization of north-to-south flows on Maritimes & Northeast into Northern New England. A fuel supplier, marketer, or ISO-NE may be positioned to reenergize the Repsol LNG import facility by committing a number of destination flexible cargoes to Canaport during the winter. How this would be paid for is outside the scope of this analysis.

Absent reenergization of the Canaport LNG import facility, another potential mitigation measure is a large new pipeline into New England, such as Kinder Morgan's Northeast Energy Direct project. The Northeast Energy Direct, as currently designed, would substantially increase Tennessee's delivery capacity to M&N at Dracut, MA, thereby alleviating the boundary flow constraint affects gas-fired generation in New England.[109] Finally, another mitigation measure would be continued reliance on the region's liquid fuel capability for generation in northern New England, in particular. Other mitigation measures associated with storage, increased compression, or industrial DR are not of sufficient scale to alleviate the constraints.

8.2.1.12 TransCanada Ontario West

The changes along the TransCanada mainline into Ontario do not endanger TransCanada's ability to serve its RCI customers throughout the province. A comparatively small amount of potentially affected generation does materialize as a result of the TransCanada Ontario West constraint on several days throughout the winter. This constraint is described in Section 6.2.1.16. The constraint results in a gas transportation deficit affecting generators in IESO on the peak hour of the peak day. As shown in Figure C31, a significant shortfall is expected during the peak hour on 12 days during the winter. These constraints are distributed over 5 events. This constraint can be characterized as being of comparatively low frequency and duration in relation to the total firm transportation that is scheduled to serve Enbridge, Union, and direct connected gas-fired generators.

TransCanada has undertaken a variety of system improvements within the province to reinforce deliverability to gate stations across the system. The Eastern Mainline Project, which is included in Sensitivity 13, will alleviate this constraint by enabling increased gas flows from upstate New York into southern Ontario and along the southern line of the Eastern Triangle. No other mitigation measures are likely required to alleviate constraints in Ontario West.

[109] See Appendix F for a detailed description of the Northeast Energy Direct project.

8.2.1.13 TransCanada Quebec

The changes along the TransCanada Quebec segment do not endanger TransCanada's ability to serve its RCI customers throughout the province. However, a comparatively significant amount of affected generation does materialize in ISO-NE on many days throughout the winter. This constraint is described in Section 6.2.1.17. The constraint results in a gas transportation deficit affecting generators in New England on the peak hour of the peak day. As shown in Figure C33 and Figure C34, a significant shortfall is expected during the peak hour on 30 days during the winter. These constraints are distributed over 9 events. This constraint can be characterized as being of comparatively moderate frequency and duration.

To mitigate the constraint, it would be necessary for TransCanada to make system improvements in southern Ontario to boost pressure and flow into the PNGTS receipt point at East Hereford. This would require customers to underpin any requested facilities with long-term firm contractual commitments. PNGTS's certificated capacity is 168 MDth/d, but the pipeline is capable of transporting roughly two times this volume when pressures are adequate in southern Ontario on TransCanada Quebec. Through its Eastern Mainline Project, TransCanada is taking affirmative steps to add facilities along its mainline to Quebec to meet firm demand. This initiative coupled with comparatively minor system improvements on PNGTS may alleviate the affected generation in New England attributable to operational constraints in southern Ontario. Therefore the constraints identified on TransCanada Quebec are likely mitigated through known pipeline improvements along the Eastern Triangle.[110]

8.2.1.14 Tennessee Z4 PA

This constraint on Tennessee is described in Section 6.2.1.12, and results in a gas transportation deficit affecting generators in PJM, NYISO and ISO-NE on the peak hour of the peak day in 2018. As shown in Figure C23 and Figure C24, a substantial shortfall is expected during the peak hour on 30 days in the winter. The 30 days are distributed over 10 events. Explained by the demand for shale gas along the Tennessee mainline and downstream pipelines in New York and New England, this constraint can be characterized as being of high frequency and duration. On the peak day it potentially affects a substantial portion of unconstrained generation demand. Given the high frequency, high duration nature of the constraint, new pipeline capacity would be required along the Z4 segment to accommodate additional flow and downstream Z5/Z6 segments.

Kinder Morgan's Northeast Energy Direct Project, described in Appendix F, is designed to move up to 2.2 Bcf/d into New York and New England from shale production in central Pennsylvania. The actual incremental capacity is purportedly scalable to match firm customer commitments. If built, this project would alleviate the Tennessee Z4 PA constraint.

[110] LAI did not add the TransCanada Eastern Mainline Project to the topology of the Study Region in the RGDS, HGDS or LGDS. The impact of this project expansion is addressed in S13.

8.2.1.15 Tennessee Z5 NY

This constraint on Tennessee is described in Section 6.2.1.13, and results in a substantial transportation deficit affecting generators in PJM, NYISO and ISO-NE on the peak hour of the peak day in 2018. As shown in Figure C25 and Figure C26, a substantial shortfall is expected on all 90 days of the winter, reflecting continuous deliverability constraints along this primary pathway out of Marcellus. The 90 days are distributed over 59 events. Explained by the demand for shale gas along the Tennessee mainline and other downstream pipelines such as Texas Eastern, Millennium and Iroquois that receive gas from Tennessee, this constraint can be characterized as being of high frequency and duration. Hence, the mitigation measure is a major new pipeline facility from Marcellus to end use markets in PJM, NYISO and ISO-NE.

Tennessee's Northeast Energy Direct Project, discussed in Section 8.2.1.14 above, would also alleviate this constraint.

8.2.1.16 Texas Eastern ETX

This constraint on Texas Eastern affects generation only in the summer, as discussed in Section 6.2.2.4 and depicted in Figure C49 and Figure C50. Shortfalls occur during the peak hour on 12 days in the summer. This can be characterized as low frequency low duration. Viable mitigation measures include more complete utilization of existing compression, potential addition of new compression at the Donaldson station, and/or more complete utilization of interconnect flows with various intrastate and interstate pipelines along the Texas Eastern M1-West segment.

8.2.1.17 Texas Eastern M2 PA South

The Texas Eastern M2 PA Southern Branch is often fully utilized throughout the winter, as discussed in Section 6.2.1.14. This constraint results in a gas transportation deficit affecting generators in PJM on the peak hour of the peak day in 2018, and occurs during the peak hour. 50 days during Winter 2018 over 10 events. As shown in Figure C27 and Figure C28, this constraint can be characterized as high frequency and duration.

Texas Eastern recently conducted an open season for the proposed Appalachia to Market Project, also known as the A2M Project, which would provide up to 1 Bcf/d of incremental firm transportation capacity from the Marcellus and Utica shale production areas to markets in the Northeast for a November 2018 in-service date. By expanding Texas Eastern's capacity to move gas from west to east across Pennsylvania, this project would potentially alleviate both this constraint and the Texas Eastern M3 Northern Line constraint discussed in the following section. Because many of the generators affected by this constraint are located downstream of Lambertville, where the M3 northern and southern lines re-join, mitigation of either this constraint or the Texas Eastern M3 North constraint, which is addressed in the following section, would relieve the congestion.

8.2.1.18 Texas Eastern M3 Northern

The Texas Eastern M3 Northern line is often fully utilized throughout the winter. These constraints result in a gas transportation deficit affecting generators in PJM and NYISO on the peak hour of the peak day in 2018. This constraint along Texas Eastern's Northern line is discussed in Section 6.2.1.15. As shown in Figure C29 and Figure C30, constraints arise during the peak hour on 39 days throughout the winter and are distributed over 10 days. This constraint can be characterized as high frequency and duration. Because Texas Eastern interconnects with Algonquin in Lambertville, NJ and Hanover, NJ downstream deliveries to generators in New England may also be impacted.

As noted in the previous section, Texas Eastern's A2M Project would also mitigate this constraint.

8.2.1.19 Transco Leidy Atlantic

The Transco Leidy Atlantic segment is frequently constrained reflecting the demand for shale gas and the lack of sufficient take away capacity across a large portion of the Study Region. This constraint on Transco Leidy Atlantic is described in Section 6.2.1.18, and results in a gas transportation deficit affecting generators in PJM on the peak hour of the peak day in 2018. As shown in Figure C35 and Figure C36, a substantial shortfall is expected during the peak hour on 59 days distributed over 8 events throughout the winter. Explained by the unmet demand for shale gas along this critical route segment, this constraint can be characterized as high frequency and duration.

Transco's Diamond East Project, discussed in Section 8.2.1.21 below, would, by incrementing the takeaway capacity from the Leidy Line, also reduce the demand on the Leidy Atlantic segment, alleviating the constraint.

8.2.1.20 Transco Z5

The Transco Zone 5 segment is seldom constrained. Constraints along Transco Zone 5 result in a significant amount of potentially affected gas fired generation in Virginia and Eastern Maryland on the Transco Z5 segment, but only during the peak hours of 9 days, as shown in Figure C37 and Figure C38.[111] This constraint along Transco's Zone 5 segment is described in Sections 6.2.3.19 and 6.2.2.5, and results in a gas transportation deficit affecting generators in PJM on the peak hour of the peak day in 2018. The 9 days are distributed over 3 events. In the summer, there are 18 days of some affected generation load. Summer loads are shown in Figure C51 and Figure C52. This constraint can be characterized as being of low frequency and duration.

Given the magnitude of the constraint and the comparatively low dispatch of the gas-fired generators located in the Transco Z5 location, alleviation of the constraints along Transco Z5 warrants increased reliance of existing generators' dual fuel capability in Maryland and Virginia. As discussed in the Columbia VA/MD constraint mitigation section above, Dominion's New Atlantic Coast Pipeline could also alleviate this constraint by providing a new gas supply path from West Virginia into Virginia and North Carolina and reducing demand on Transco.

[111] A gas transportation deficit in North Carolina and South Carolina is also expected, but not reported herein as the Carolinas are outside the definition of the Study Region.

8.2.1.21 Transco Z6 Leidy to Station 210

This constraint on Transco Z6 Leidy to Station 210 is described in Section 6.2.1.20, and results in a negligible gas transportation deficit affecting generators in PJM on the peak hour of the peak day in 2018. As shown in Figure C39 and Figure C40, an insignificant shortfall is expected during the peak hour on 8 days during the winter. The shortfall is characterized as low frequency and duration, resulting in an insignificant amount of affected generation over the 8 days that are distributed over 5 events. The Transco Z6 Leidy to Station 210 segment is a relatively short path constraint in southeast PA. This constraint has almost no impact on the scheduling of gas-fired generation in EMAAC and downstate New York.

Transco recently announced the 1 Bcf/d Diamond East Project, consisting of incremental compression and pipeline looping along the Leidy Line into Station 210 for a proposed mid-2018 in-service date, which would alleviate this constraint. In addition, the PennEast Pipeline, sponsored by a cohort of Pennsylvania and New Jersey LDCs, would add a new 1 Bcf/d transportation path from an interconnection with Transco's Leidy Line to central New Jersey, potentially reducing demand on this constrained segment.

8.2.1.22 Union Gas Dawn

The Dawn storage hub is often used fully during the winter, thereby constraining a small amount of transportation delivery capability for generation behind the Union system. As discussed in Section 6.2.1.21, the constraint can be characterized as low frequency and duration, resulting in a negligible amount of affected generation at the local level. In light of the dispatch profile of gas-fired generators, character of service associated with most generators' transportation portfolios, and underutilized gas-fired generation capability throughout the province during the winter, the Union Gas Dawn constraint may not warrant mitigation.

8.2.2 Constraints Applicable Only to HGDS S0

Constraints under HGDS are generally more severe and numerous than under RGDS conditions. Twelve additional constrained segments were identified under the HGDS winter and summer analyses. The relevant characteristics of these constrained segments are summarized in Table 47. Constraint descriptions and charts showing daily peak-hour conditions are provided in Appendix D and Appendix E. The following subsections discuss possible mitigation measures for these constraints.[112]

[112] Note that HGDS Winter and Summer total constraint days are provided in Table 47 for the segments which are also constrained under RGDS.

Table 47. Summary of Constrained Segments Unique to HGDS 2018

	HGDS Winter 2018				HGDS Summer 2018				Characterization		
Constrained Segment	Events	Min Duration (Days)	Max Duration (Days)	Total Days	Events	Min Duration (Days)	Max Duration (Days)	Total Days	Persistance	Severity	Depth
Algonquin Connecticut					8	1	5	21	Mod	Mod	Mod
Alliance	4	1	6	10					Mod	High	High
ANR Northern Illinois	10	1	35	60					High	Mod	Mod
Great Lakes East	12	1	30	66					High	High	Mod
Midwestern	19	1	10	55					High	Mod	Mod
NGPL IA/IL North	11	1	20	51					High	Mod	Mod
NGPL IA/ILSouth	12	1	11	48					High	High	Mod
Northern Border Chicago	14	1	10	46					High	High	Mod
Northern Natural D	4	1	4	8					Low	Mod	Mod
PNGTS N of Westbrook					11	1	7	28	Mod	Low	Mod
PNGTS S of Westbrook					12	1	8	48	High	Low	High
Viking Zone 1	11	1	10	24					Mod	High	Mod

8.2.2.1 Algonquin Connecticut

This constraint on Algonquin is described in Appendix D, Section 1.2.1. While delivery capacity along the Algonquin Connecticut route segment allows for the scheduling of gas-fired generation throughout southern New England, as shown in Figures E61 and E62, there are 21 days covering 8 events during Summer 2018 when there is a significant gas transportation deficit potentially affecting generators in ISO-NE during the peak hour. The constraints arise in each of the three summer months. The incremental 500 MDth/d of Atlantic Bridge Project capacity that is included in Sensitivity 13 and Spectra's recently-announced 1 Bcf/d Access Northeast Project are currently in development and would mitigate this constraint.

8.2.2.2 Alliance

This constraint on Alliance is described in Appendix D, Section 1.1.1. As shown in Figures E1 and E2, there are 10 days covering 4 events when there is a significant gas transportation deficit during the winter in Chicago. The impact on gas-fired generators in MISO North/Central and PJM can be characterized as low frequency and duration. Mitigation of the constraint may be realized through more complete utilization of existing compression as well as more complete use of interconnect flows with neighboring pipelines.

8.2.2.3 ANR Northern Illinois

This constraint on ANR Northern Illinois is described in Appendix D, Section 1.1.2. As shown in Figures E3 and E4, there are 60 days covering 10 events when there is a significant gas transportation deficit in northern Illinois during all three winter months. The impact on gas-fired generators in PJM can be characterized as high frequency and duration. Alleviation of the constraint may require the installation of loopline and compression to accommodate gas-fired generators.

8.2.2.4 Great Lakes East

This constraint on Great Lakes East is described in Appendix D, Section 1.1.12. As shown in Figures E23 and E24, there are 66 days covering 12 events when there is a significant gas transportation deficit in MISO North/Central during the peak hour, including days during all three winter months. The impact on gas-fired generators in MISO North/Central can be characterized as high frequency and duration. Mitigation of the constraint may require either the installation of loopline and / or compression to accommodate the additional demand for natural gas-fired generation, or the addition of storage withdrawal capability in Michigan to strengthen Great Lakes' ability along its Eastern segment to keep pace with increased gas demand under HGDS S0.

8.2.2.5 Midwestern

This constraint on Midwestern is described in Appendix D, Section 1.1.13. As shown in Figures E25 and E26, there are 55 days covering 19 events when there is a significant gas transportation deficit in MISO North/Central during the peak hour, including days during all three winter months. The impact on gas-fired generators in MISO North/Central can be characterized as high frequency and duration. Mitigation of the constraint may require either the installation of loopline and / or compression to accommodate the additional demand for natural gas-fired generation.

8.2.2.6 NGPL IA/IL North

This constraint on NGPL IA/IL North is described in Appendix D, Section 1.1.16. As shown in Figures E31 and E32, there are 51 days covering 11 events in Iowa and Illinois when there is a significant gas transportation deficit in MISO North/Central during the peak hour, including days during all three winter months. While NGPL would still be able to accommodate gas-fired generators across the IA/IL North segment, the impact on gas-fired generators in MISO North/Central can be characterized as high frequency and duration. Mitigation of the constraint may require either the installation of loopline and/or compression to accommodate the additional demand for natural gas-fired generation.

8.2.2.7 NGPL IA/IL South

This constraint on NGPL IL/IA South is described in Appendix D, Section 1.1.17. As shown in Figures E33 and E34, there are 48 days covering 12 events when there is a significant gas transportation deficit along the Southern segment of the NGPL route system during the peak hour, including days during all three months of the winter, particularly in December. Again, NGPL would still be able to accommodate gas-fired generators across the IA/IL South segment, but constraints in Iowa and Illinois South can be characterized as high frequency and duration. Mitigation of the constraint may require more complete utilization of existing compression, new compression, or the installation of loopline.

8.2.2.8 Northern Border Chicago

This constraint on Northern Border Chicago is described in Appendix D, Section 1.1.18. As shown in Figures E35 and E36, there are 46 days covering 14 events in and around Chicago when there is a significant peak hour gas transportation deficit along the Chicago route segment of the Northern Border mainline. Constraints arise during all three months of the winter. While Northern Border would be able to accommodate gas-fired generators in PJM, constraints can be characterized as high frequency and duration. Mitigation of the constraint may require more complete utilization of existing compression, new compression, or the installation of loopline.

8.2.2.9 Northern Natural Zone D

This constraint on Northern Natural is described in Appendix D, Section 1.1.19. As shown in Figures E37 and E38, there are 8 days covering 4 events in Zone D with a peak hour constraint, resulting in a comparatively negligible gas transportation deficit. Northern Natural's vast field and market area storage deliverability and mainline flexibility, including interconnects with many pipelines in MISO North/Central may be leveraged to mitigate the constraints in Zone D without any other infrastructure improvements.

8.2.2.10 PNGTS North of Westbrook

This constraint on PNGTS is described in Appendix D, Section 1.2.6. As shown in Figures E71 and E72, there are 28 days covering 11 events during the summer when there is a peak hour gas transportation deficit, but none in the winter. In relation to PNGTS's ability to schedule gas-fired generation in northern New England throughout the summer, this constraint can be characterized as low frequency and duration. In light of improvements TransCanada is making in southern Ontario, and in light of growing customer interest in obtaining increased firm capacity on the TransCanada system to deliver to the PNGTS system – although no new incremental contracts have been executed as of yet – in conjunction with PNGTS's proposed Continent to Coast Project, no additional mitigation measures would likely be required to alleviate the constraint.

8.2.2.11 PNGTS South of Westbrook

This constraint on PNGTS is described in Appendix D, Section 1.2.7. As shown in Figures E73 and E74, there are 48 days covering 12 events during the summer when there is a peak hour gas transportation deficit, but none in the winter. Again, in light of improvements TransCanada is making to its system in Ontario and potential increases to Quebec capacity in the future, along with the Continent to Coast Project, which would reduce demand for the southern segment of PNGTS to deliver gas to Westbrook, no additional mitigation measures would likely be required to alleviate the constraint south of Westbrook.

8.2.2.12 Viking Zone 1

This constraint on Viking is described in Appendix D, Section 1.1.30. As shown in Figures E59 and E60, there are 24 days covering 11 events during the winter when there is a potential peak hour gas transportation deficit affecting generators in MISO North/Central, specifically Wisconsin. This constraint can be characterized as moderate frequency and duration. Mitigation of the constraint may be achievable through implementation of bi-directional flow on the pipeline, reducing throughput demand on Zone 1. Many of the generators potentially affected by this constraint are served by downstream pipelines, as shown in Figure D9, which may offer additional mitigation opportunities.

9 IDENTIFICATION OF UNCONSTRAINED LOCATIONS

In this section, pipeline segments with utilization rates less than 90% and less than 80% are highlighted in blue on maps of each PPA to support identification of locations with unconstrained paths from supply points. The pipeline utilization rates illustrated in this section do not indicate the availability of primary firm transportation on less utilized paths, and the identification on unconstrained locations assumes that generators would rely on interruptible service, capacity release, or a third-party agreement with a current pipeline customer. Because many paths are fully subscribed, regardless of forecasted peak hour utilization, in order to contract for firm transportation service on a given segment or path, incremental capacity additions may be required.

9.1 IESO

Figure 190 and Figure 191 show the pipeline segments in IESO that are utilized at less than 90% and less than 80% in RGDS S0 Winter 2018.

Figure 188. RGDS S0 Winter 2018 – IESO – Segments Less Than 90% Utilized

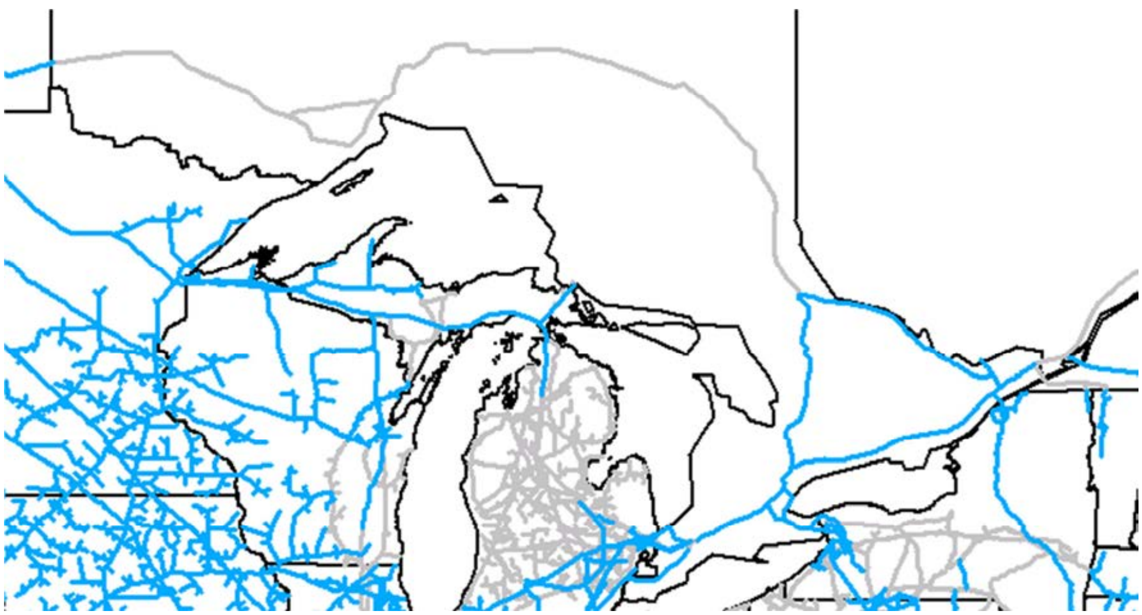
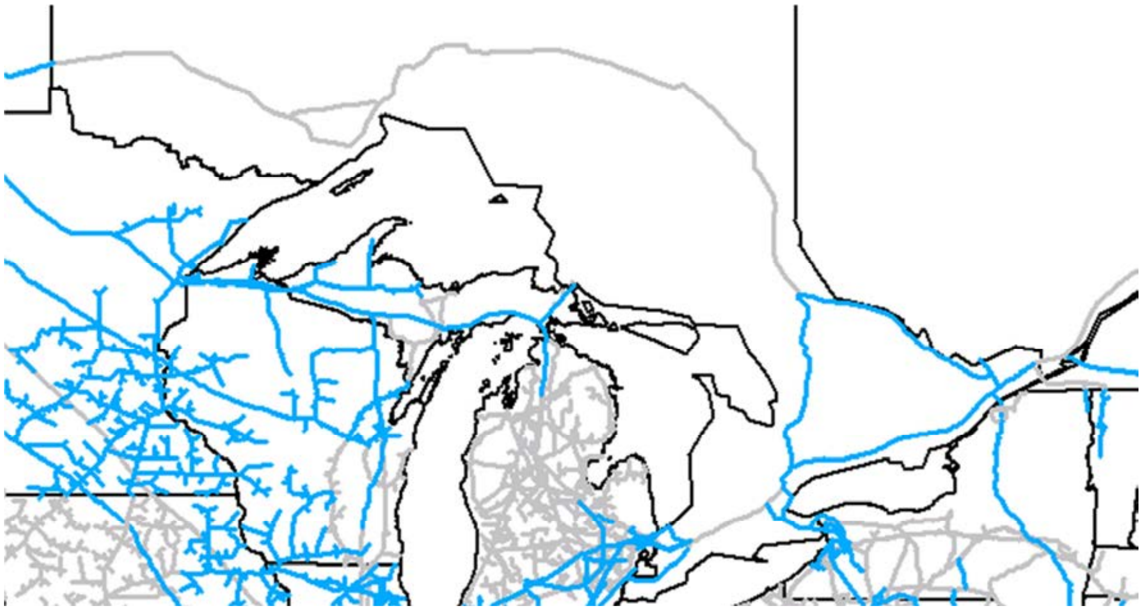


Figure 189. RGDS S0 Winter 2018 – IESO – Segments Less Than 80% Utilized



TransCanada's and Union's mainlines in Ontario are affected by upstream supply constraints in the RGDS, which will be relieved by infrastructure expansions modeled in Sensitivity #13. Absent or pending these modifications, the primary unconstrained location in Ontario is shown in the St. Clair area, where gas can flow into the via Panhandle Eastern and Vector. The path to the Sault Ste. Marie area via Great Lakes is also unconstrained.

9.2 ISO-NE

Figure 190 and Figure 191 show the pipeline segments in ISO-NE that are utilized at less than 90% and less than 80% in RGDS S0 Winter 2018.

Figure 190. RGDS S0 Winter 2018 – ISO-NE – Segments Less Than 90% Utilized

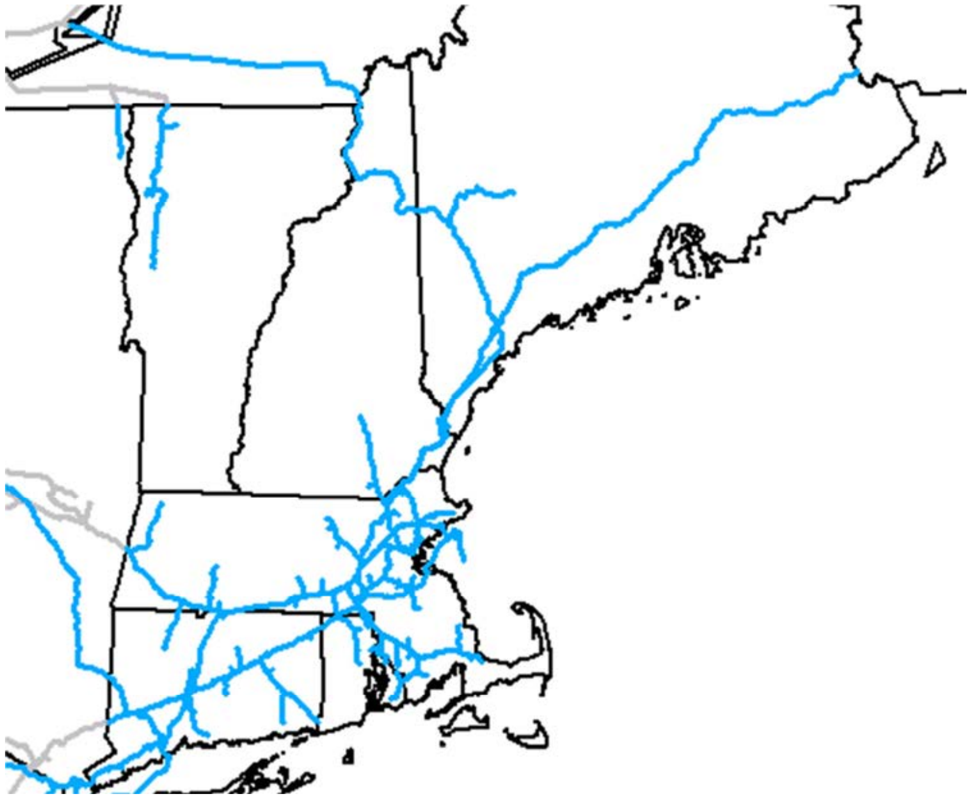
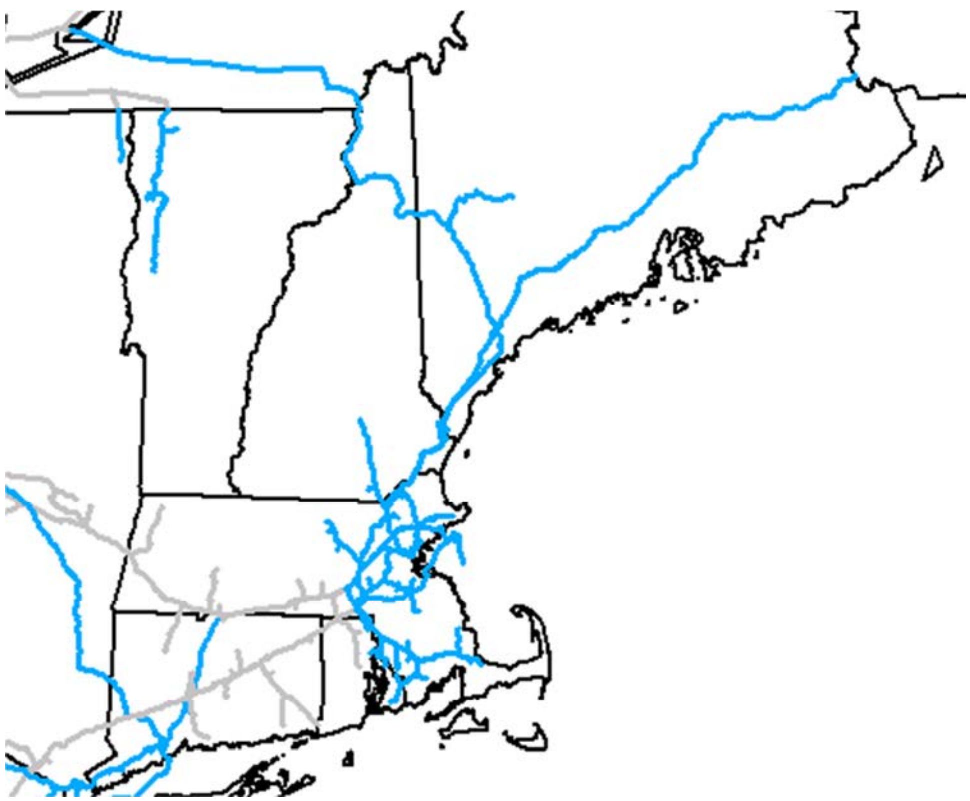


Figure 191. RGDS S0 Winter 2018 – ISO-NE – Segments Less Than 80% Utilized



Although these maps indicate that the natural gas infrastructure in ISO-NE is generally not fully utilized, upstream constraints limit the delivery of gas into the region. Because ISO-NE does not have gas supply sources within its boundaries, there are no locations with unconstrained paths from a supply point. One exception would be for generation directly connected to the Distrigas LNG import terminal, but ensuring fuel availability would most likely require a firm supply contract. Commitment of destination flexible LNG cargoes to the Suez Distrigas LNG import facility would be required in order to more fully utilize the Tennessee and/or Algonquin mainlines in Northeast Massachusetts and Boston. Use of satellite LNG tanks behind various LDCs' citygates in New England is not considered a viable resource option to meet the demand of gas fired generation in ISO-NE.

9.3 MISO

Figure 190 and Figure 191 show the pipeline segments in MISO North/Central that are utilized at less than 90% and less than 80% in RGDS S0 Winter 2018.

Figure 192. RGDS S0 Winter 2018 – MISO North/Central – Segments Less Than 90% Utilized

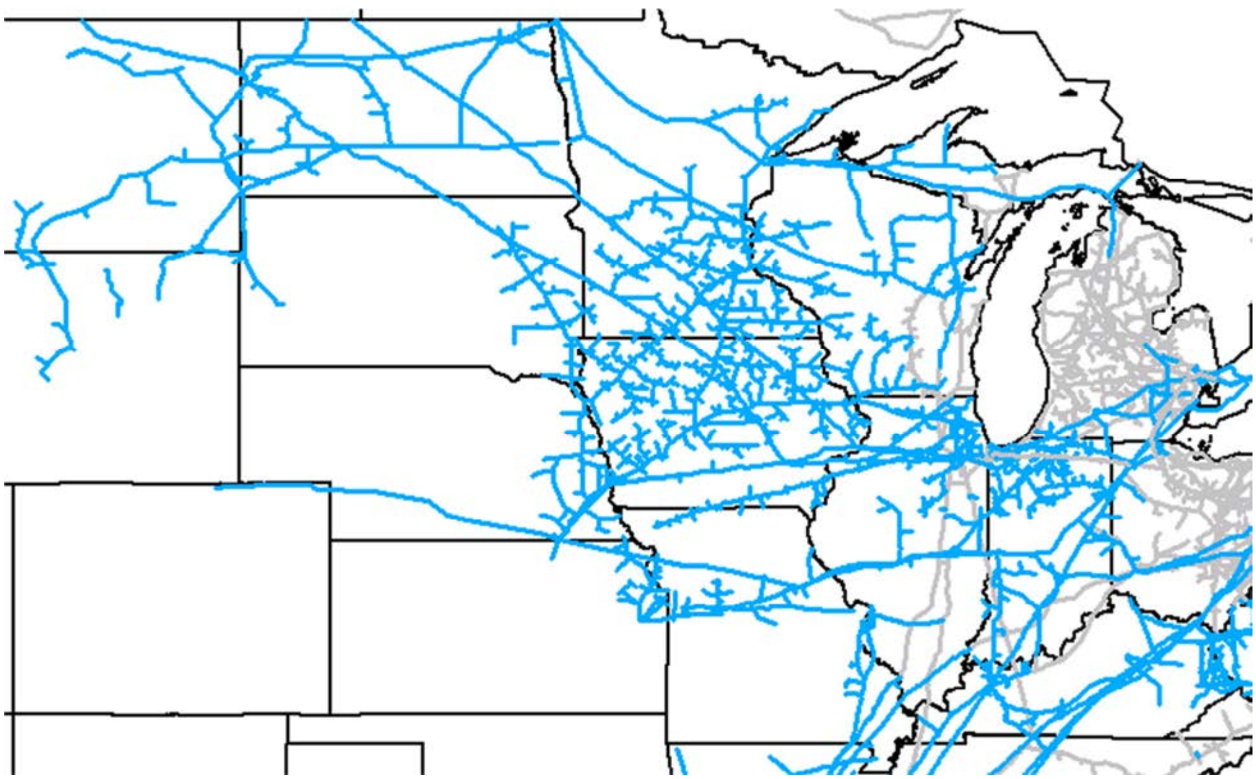
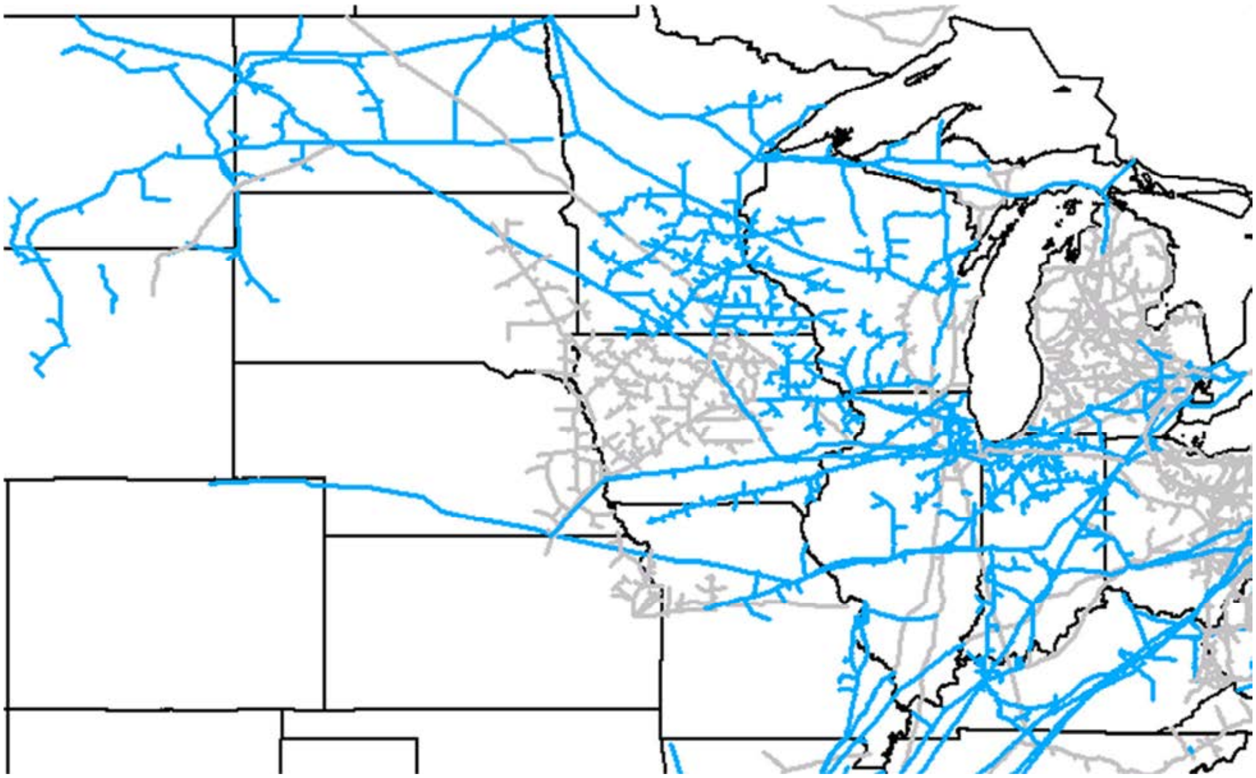


Figure 193. RGDS S0 Winter 2018 – MISO North/Central – Segments Less Than 80% Utilized



The WBI Energy system has available capacity to serve incremental generator gas demand in Montana and North Dakota from the Bakken shale and Williston Basin. WBI can also deliver gas to Northern Border to serve incremental demand along its mainline in South Dakota, Minnesota and Iowa, and to Great Lakes and Viking (via Northern Border) to serve demand in Minnesota, Wisconsin and Michigan. Great Lakes and Viking can subsequently deliver gas to ANR in northern Wisconsin. ANR can also deliver incremental gas from the Gulf Coast to Indiana. Rockies Express can transport gas from Colorado and Wyoming to meet demand in Missouri, southern Illinois and Indiana. NGPL's Amarillo mainline can transport additional gas from the Permian Basin to generators in Iowa. Mississippi River and Panhandle Eastern can transport incremental gas from the Gulf Coast to southern Illinois and from the Anadarko Basin / Woodford shale to southern Illinois, Indiana and southern Michigan, respectively.

Figure 190 and Figure 191 show the pipeline segments in MISO South that are utilized at less than 90% and less than 80% in RGDS S0 Winter 2018.

Figure 194. RGDS S0 Winter 2018 – MISO South – Segments Less Than 90% Utilized

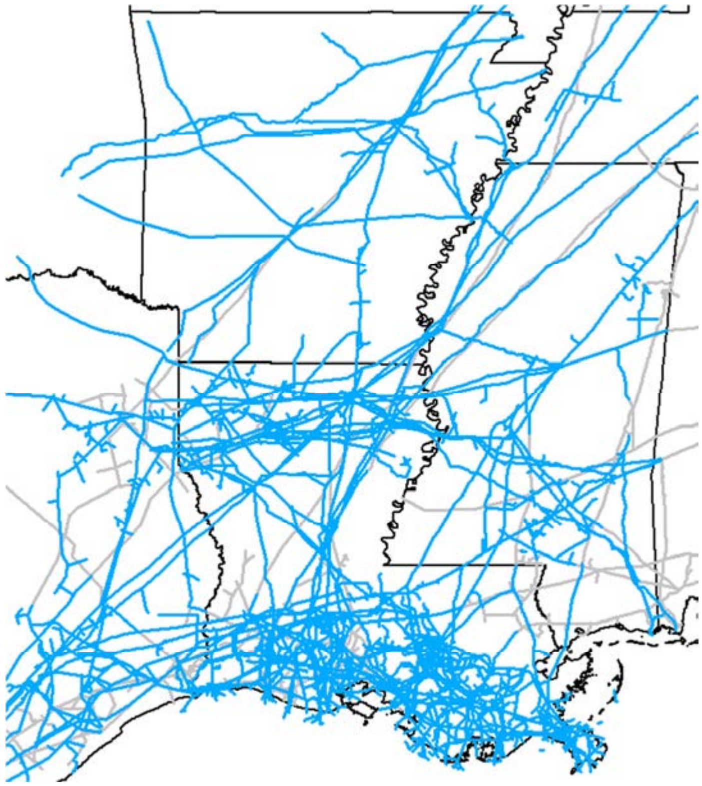
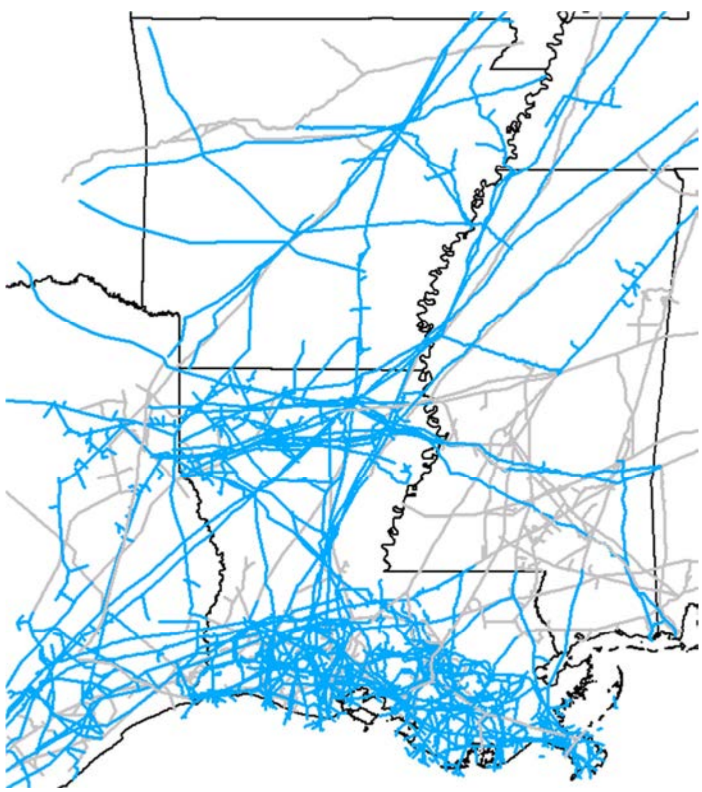


Figure 195. RGDS S0 Winter 2018 – MISO South – Segments Less Than 80% Utilized



The majority of pipeline segments in MISO South are not highly utilized during the seasonal peak hour, and are therefore able to deliver incremental gas to generators in MISO South. This deliverability reflects adequate supply from conventional onshore and offshore production resources in Louisiana, East Texas and the Gulf of Mexico. Massive gas gathering and pipeline infrastructure in MISO South result in the underutilization of gas pipeline infrastructure in the PPA, but there are specific pipelines that are constrained, largely due to high demand in downstream locations. Exceptions include Gulf South, NGPL, Ozark, Southern Natural, Tennessee Legs 500 and 800, Texas Eastern and Trunkline, along with the Acadian, KM Tejas and KM Texas intrastate systems.

9.4 NYISO

Figure 190 and Figure 191 show the pipeline segments in NYISO that are utilized at less than 90% and less than 80% in RGDS S0 Winter 2018.

Figure 196. RGDS S0 Winter 2018 – NYISO – Segments Less Than 90% Utilized

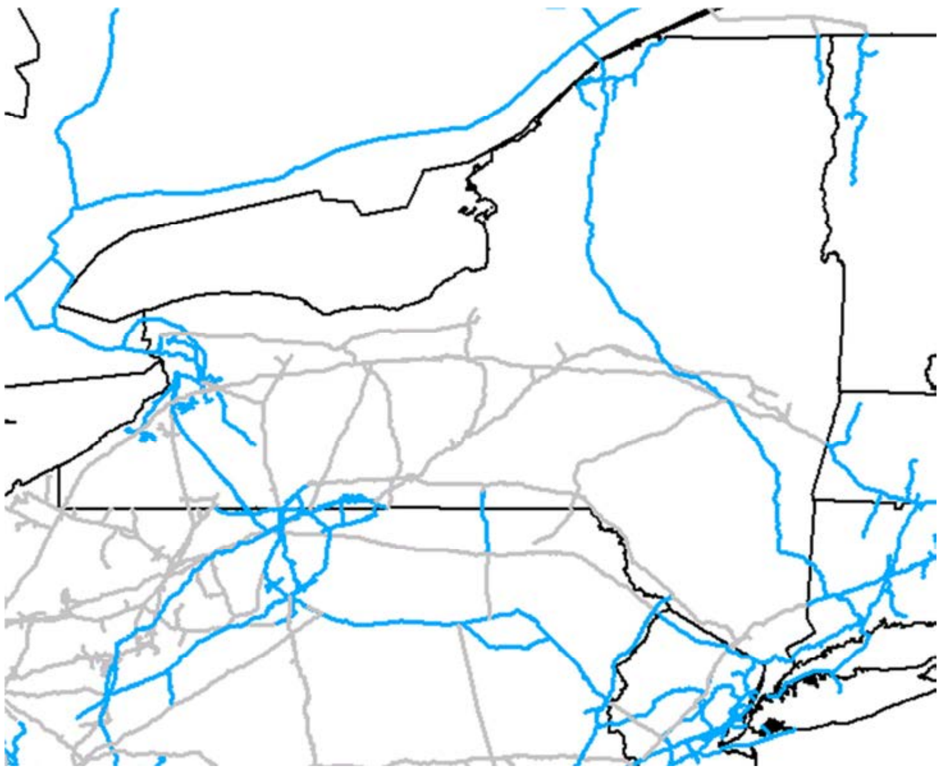
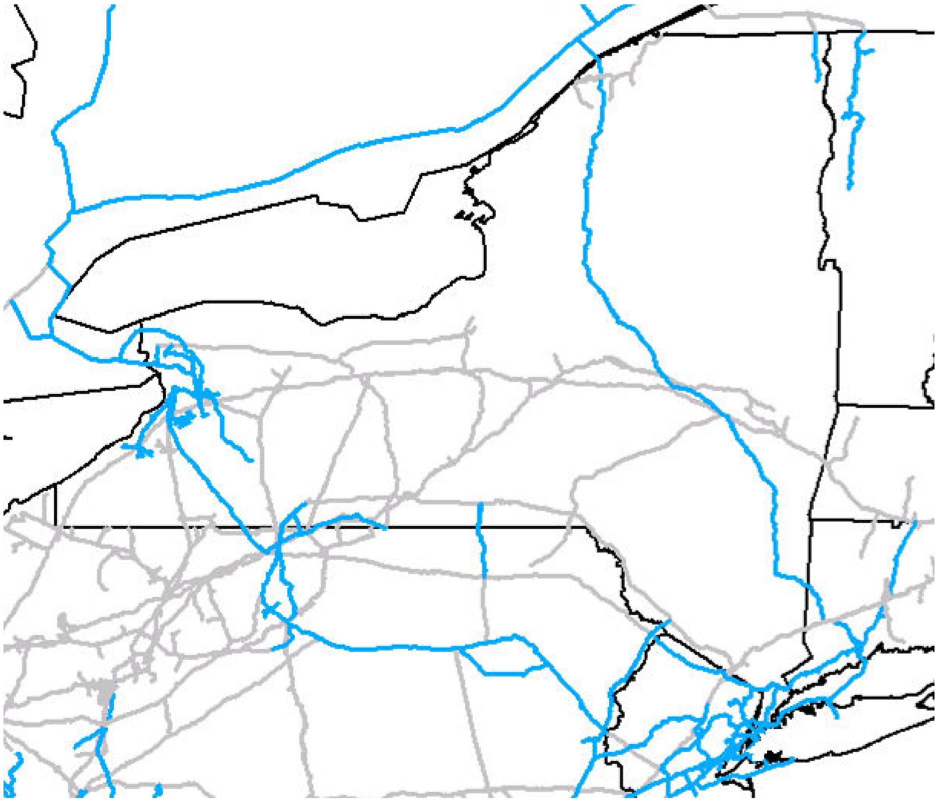


Figure 197. RGDS S0 Winter 2018 – NYISO – Segments Less Than 80% Utilized



Major new pipeline additions into the New York Facilities System have greatly expanded total receipt point capability in downstate New York, in particular, into Manhattan. Underutilization of total receipt point capability into the New York Facilities System reflects upstream constraints on the primary pipelines linking Marcellus with the market center in New York City and Long Island. While Iroquois is not fully utilized, upstream constraints on Constitution and in Ontario limit incremental supplies to meet new generator gas demand.

Connections to the Stagecoach storage facility's north lateral, also known as part of the Central New York Oil & Gas pipeline, represent an unconstrained location. The Stagecoach lateral system allows gas to be moved between Transco and Tennessee in Pennsylvania and Millennium in New York. Although the Millennium and Tennessee segments connected to the Stagecoach system are highly utilized, relative to conventional storage facilities this storage facility has a high deliverability, multi-cycle operating regime, allowing gas to be injected into storage when the supply pipelines are less utilized and withdrawn during congested periods. A generator connected directly to the Stagecoach system could therefore potentially have access to unconstrained supply.

In western New York, the NFG pipeline has an unconstrained path back to the Leidy storage network and adjacent Marcellus production area, and could serve incremental generation connected to its system or to Tennessee's Niagara line via interconnect.

9.5 PJM

Figure 190 and Figure 191 show the pipeline segments in PJM that are utilized at less than 90% and less than 80% in RGDS S0 Winter 2018.

Figure 198. RGDS S0 Winter 2018 – PJM – Segments Less Than 90% Utilized

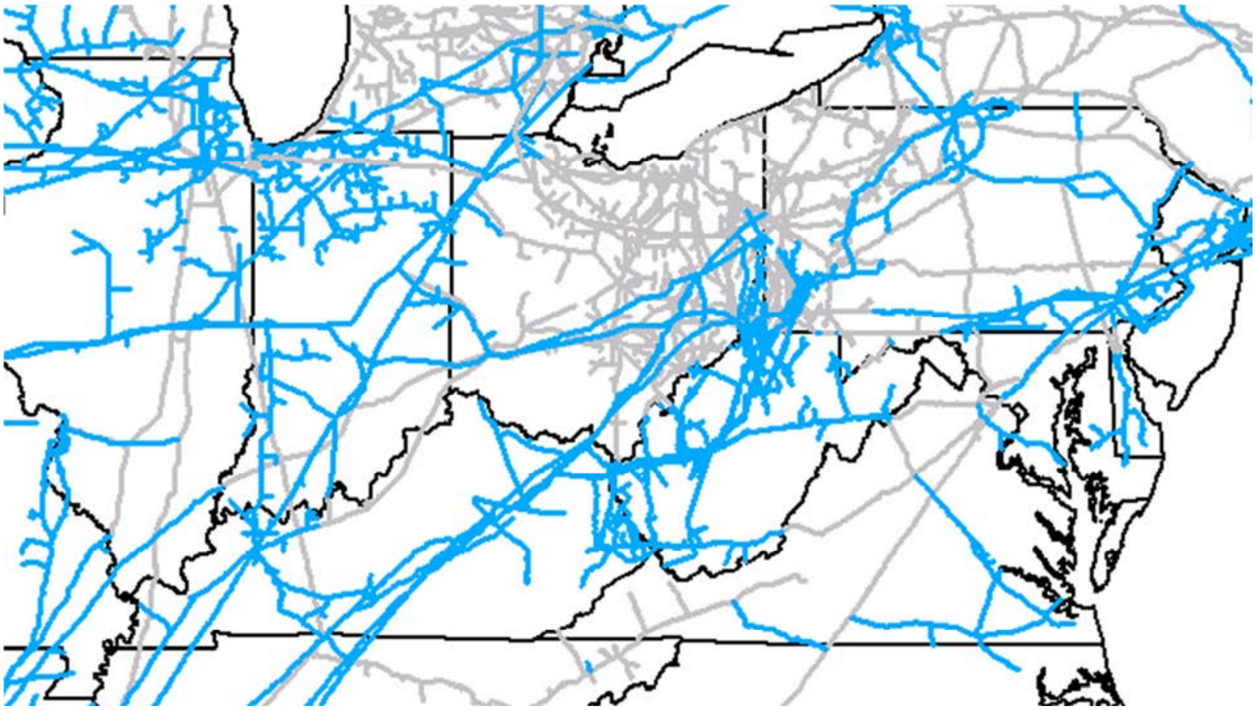
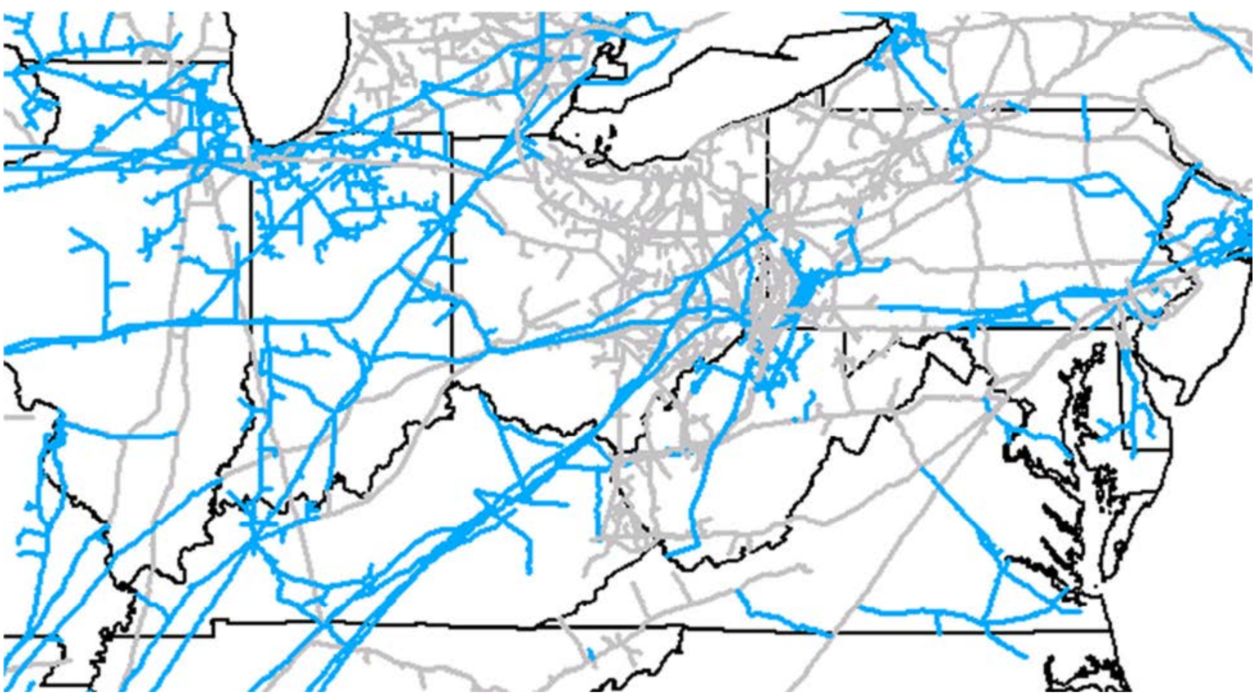


Figure 199. RGDS S0 Winter 2018 – PJM – Segments Less Than 80% Utilized



Segment utilization rates in PJM indicate that incremental generators in Pennsylvania could connect to Transco's Leidy Line, NFG and Equitrans to access shale gas. Equitrans could also deliver incremental shale gas in West Virginia. Although the study parameters assume no imports at Cove Point, the Dominion Cove Point pipeline could serve incremental generator gas demand if Dominion Cove Point's large storage capability could be leveraged to accommodate Cove Point's customers' shipment schedule. Generators in Ohio could access Utica shale gas via Dominion or Tennessee, with Tennessee also able to deliver incremental gas from the Gulf Coast, while generators could directly connect to Rockies Express to access gas from conventional sources in Colorado and Wyoming. ANR could also deliver incremental gas to northeastern Ohio from the Gulf Coast. Finally, generators in northern Illinois could access incremental gas supplies from the Permian Basin via NGPL's Amarillo mainline or from the Bakken shale and Williston Basin via Northern Border.

9.6 TVA

Figure 190 and Figure 191 show the pipeline segments in TVA that are utilized at less than 90% and less than 80% in RGDS S0 Winter 2018.

Figure 200. RGDS S0 Winter 2018 – TVA – Segments Less Than 90% Utilized

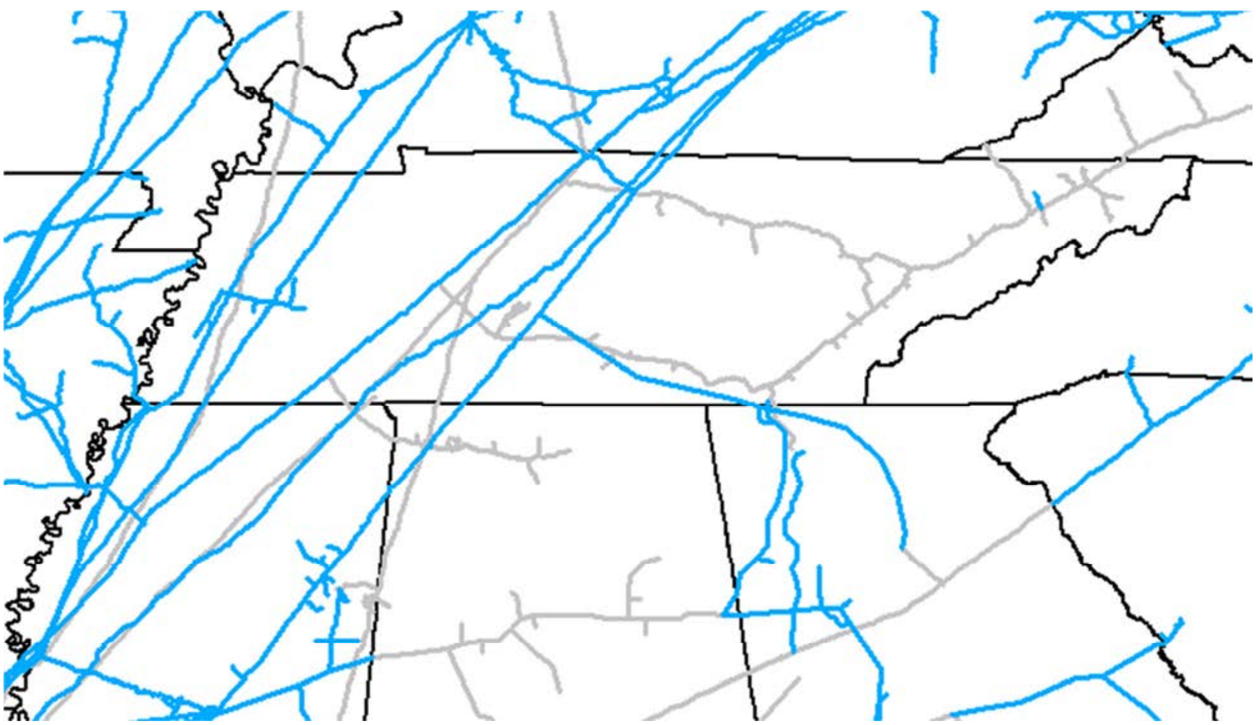
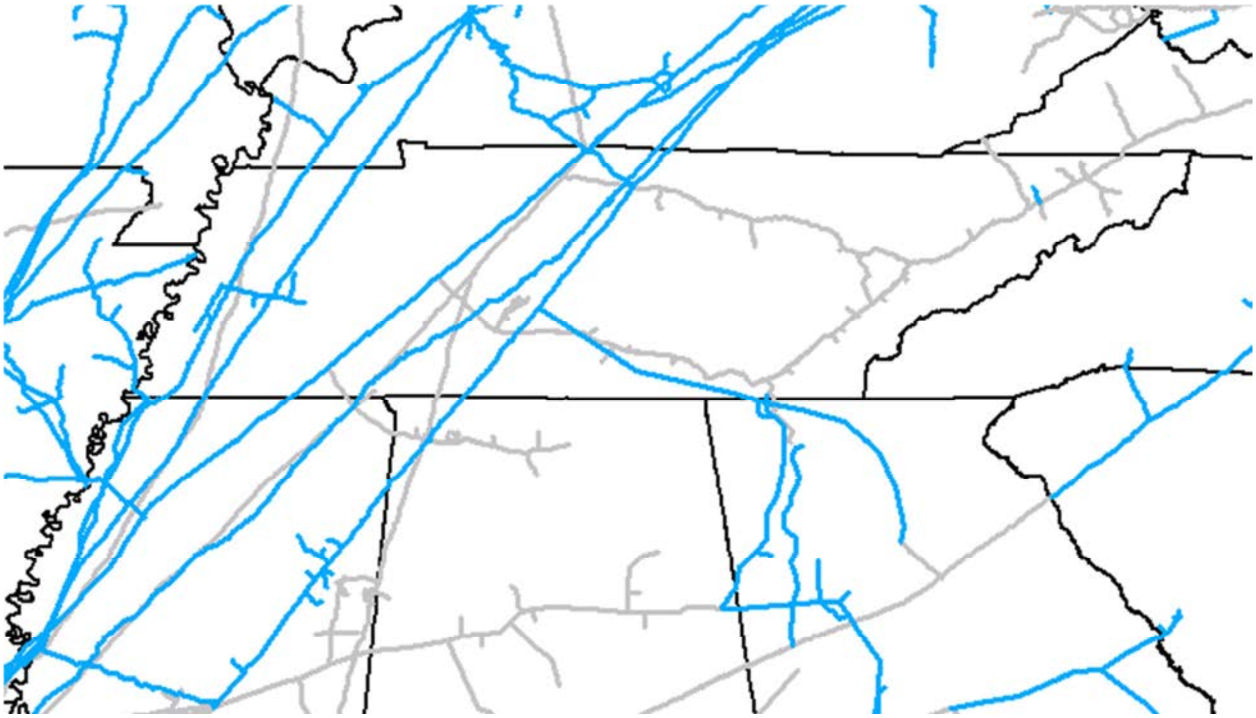


Figure 201. RGDS S0 Winter 2018 – TVA – Segments Less Than 80% Utilized



Several of the trunklines serving TVA are less than 80% utilized during the seasonal peak hour, including ANR, Columbia Gulf, Tennessee's 100 Leg, Texas Eastern and Texas Gas. Upstream of TVA, assuming traditional south-to-north flow patterns, each of these pipelines, with the exception of Texas Eastern, has an unconstrained path to Gulf production. As flow reversal from shale formations develops, the supply options for these paths will be expanded, which will also expand the potential deliverability to generators in TVA, as downstream / northern customers will be less dependent on flows through TVA.