Eastern Interconnection Planning Collaborative

Phase 2 Report:

Interregional Transmission Development and Analysis for Three Stakeholder Selected Scenarios And Gas-Electric System Interface Study

DOE Award Project DE-OE0000343

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Volume 1
Executive Summary and Condensed Report

FINAL

Report Organization

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List of Acronyms

#2 FO	No. 2 Fuel Oil
#6 FO	Residual fuel oil, No. 6 Fuel Oil
AC	Alternating current
AECI	Associated Electric Cooperative, Inc.
AECO	Alberta gas pricing hub
AEK	Atmos Energy Kentucky
AEO	Annual Energy Outlook
AMA	Asset Management Agreement
ARRA	American Recovery and Reinvestment Act of 2009
BACT	Best Available Control Technology
BAU	Business as Usual
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
CBS	Customer balancing service
CC	Combined cycle
CCGT	Combined cycle gas turbine
CCT	Central clock time
CDA	Central Delivery Area
CDE	Contract demand energy
CEII	Critical Energy Infrastructure Information
CEMS	Continuous emission monitoring system
CF	Capacity factor
CHP	Combined heat and power
CO_2	Carbon dioxide
Con Edison	Consolidated Edison Co. of New York
CONE	Cost of New Entry
CP	Combined Policies
CPP	Clean Power Plan
CRA	Charles River Associates
CRSG	Contingency Reserve Sharing Group
CSAPR	Cross-State Air Pollution Rule
CT	Combustion turbine
DAM	Day-Ahead Market
Delmarva	Delmarva Power & Light
DG	Distributed Generation
DLN	Dry Low NOx
DOE	Department of Energy
DOT	Department of Transportation
DR	Demand response
Dth	Dekatherm
EA	Environmental Assessment
EBB	Electronic Bulletin Board
EDA	Eastern Delivery Area
EE	Energy efficiency
EFT	Enhanced First Transportation
EHV	Extra high voltage
EI	Eastern Interconnection
EIA	Energy Information Agency
EIPC	Eastern Interconnection Planning Collaborative
EIS	Environmental Impact Statement

EISPC	Eastern Interconnection States Planning Council
EMAAC	Eastern Mid-Atlantic Area Council
Enbridge	Enbridge Gas Distribution
EPA	Environmental Protection Agency
EPC	Engineer, Procure, Construct
EPRI	Electric Power Research Institute
ERC	Emission Reduction Credit
ERS	Electric Reliability Service
EUR	Estimated ultimate recovery
EWITS	Eastern Wind Integration and Transmission Study
F-D	Frequency-Duration
FCITC	First Contingency Incremental Transfer Capability
FERC	Federal Energy Regulatory Commission
FF	Fabric Filter
FLE	Full Load Equivalent
FLHR	Full load heat rate
FOA	Funding Opportunity Announcement
FRCC	Florida Reliability Coordinating Council
FT	Firm Transmission
FT-H	Hourly Firm Transportation Service
FT-SN	Firm Transmission-Short Notice
Gal	Gallon
GAO	Government Accountability Office
GJ	Gigajoule
GT	Gas Turbine
Gulf	Gulf of Mexico
HEU	Highly enriched uranium
HGDS	High Gas Demand Scenario
HVAC	High voltage alternating current
HVDC	High voltage direct current
IC	Internal combustion
ICAP	Installed capacity
IESO	Independent Electricity System Operator of Ontario
ILB	Illinois Basin
INGAA	Interstate Natural Gas Association of America
IRP	Integrated resource plan
ISO	Independent System Operator
ISO-NE	Independent System Operator--New England
IT	Interruptible Transportation
Keystone	Keystone Center
LAER	Lowest Achievable Emission Rate
LAI	Levitan & Associates, Inc.
LDA	Local delivery area
LDC	Local distribution company
LGDS	Low Gas Demand Scenario
LHV	Lower Hudson Valley
LIPA	Long Island Power Authority
LMP	Locational Marginal Price
LNG	Liquefied natural gas
MAAC	Mid-Atlantic Area Council
MAOP	Maximum allowable operating pressure
Marcellus	Marcellus shale natural gas producing region

MATS	Mercury and Air Toxics Standards
Mcf	Thousand cubic feet
MDQ	Maximum daily quantity
MDth	Thousand dekatherms
MDth/d	Thousand dekatherms per day
MHDO	Maximum Hourly Delivery Obligation
MISO	Midcontinent Independent System Operator
MMBtu	Million British thermal units
MMcf	Million cubic feet
MMcf/d	Million cubic feet per day
MRN	Multi-Region National
MRO	Midwest Reliability Organization
MW	Megawatt
MWG	Modeling Working Group
MWh	Megawatt hour
MWh/h	Megawatt hour per hour
NA NSR	Non-Attainment New Source Review
NAAQS	National Ambient Air Quality Standards
NADR	National Assessment of Demand Response
NAESB	North American Energy Standards Board
NAPP	Northern Appalachia
NAPSR	National Association of Pipeline Safety Representatives
NARUC	National Association of Regulatory Utility Commissions
NCDA	North Central Delivery Area
NDA	Northern Delivery Area
NEB	National Energy Board
NEEM	North American Electricity and Environment Model
NEMA	Northeast Massachusetts
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation
NGO	Non-government organization
NGrid	National Grid
NIPSCO	Northern Indiana Public Service Company
NOPR	Notice of Proposed Rulemaking
NO_x	Nitrogen oxides
NPCC	Northeast Power Coordinating Council
NPT	Northern Pass Transmission
NREL	National Renewable Energy Laboratory
NRPS/IR	National Renewable Portfolio Standard/Implemented Regionally
NSR	New Source Review
NYC	New York City
NYCA	New York Control Area
NYFS	New York Facilities System
NYISO	New York Independent System Operator
NYMEX	New York Mercantile Exchange
NYPSC	New York Public Service Commission
NYSRC	New York State Reliability Council
O&M	Operation and maintenance

OBA	Operating Balance Agreement
OEB	Ontario Energy Board
OFO	Operational Flow Order
OPS	Office of Pipeline Safety
ORNL	Oak Ridge National Laboratory
OTR	Ozone Transport Region
PA	Planning Authority
PAL	Park and Loan
Petajoule	Petajoule
PGA	Purchased gas adjustment
PHMSA	Pipeline and Hazardous Materials Safety Administration
PJ	Picojoule
PJM	PJM Interconnection
PM	Particulate matter
PPA	Participating Planning Authority
ppm	parts per million
PRB	Powder River Basin
PSD	Prevention of Significant Deterioration
PSE&G	Public Service Electric & Gas Co.
psig	pounds per square inch gauge (pressure relative to atmospheric pressure instead of relative to zero)
PSS/E	Power System Simulator for Engineering
PSS/MUST	Power System Simulator for Managing and Utilizing System Transmission
PV	Photovoltaic
RAM	Risk Alleviation Mechanism
RCI	Residential, commercial, industrial
RFO	Residual fuel oil
RGDS	Reference Gas Demand Scenario
RGGI	Regional Greenhouse Gas Initiative
ROFR	Right-of-first-refusal
ROW	Right-of-way
RPM	Reliability Pricing Model
RPS	Renewable portfolio standard
RTM	Real-Time Market
RTO	Regional Transmission Organization
SC	Simple cycle
scf	Standard cubic feet
SCGT	Simple cycle gas turbine
SCR	Selective catalytic reduction
SEMA	Southeast Massachusetts
SERC	SERC Reliability Corporation
SIP	State Implementation Plan
SNB	Short Notice Balancing
SO_2	Sulfur dioxide
SOCO	Southern Company
SOPO	Statement of Project Objectives
SPP	Southwest Power Pool
SSC	Stakeholder Steering Committee
SSI	Stakeholder Specified Infrastructure
SSMDA	Sault Ste. Marie Delivery Area
SSMLFWG	Steady State Modeling Load Flow Working Group
STEO	Short term energy outlook

STFT Short-Term Firm Transportation

STG Steam Turbine Generator

ST-SN Short-term Short Notice

SWMAAC Southwestern Mid-Atlantic Area Council

TAQ Total Authorized Quantity

Tcf Trillion cubic feet

TDF Transmission Distribution Factor

TDS Total dissolved solids

TOTF Transmission Options Task Force

TOTS Transmission Owner Transmission Solutions

TPL Transmission planning

tpy tons per year

TRR Technically recoverable resources

TSA Transportation Security Administration

TSP Transmission service provider

TVA Tennessee Valley Authority

TWh Terawatt hour

UCAP Unforced capacity

UIB Uinta Basin

ULSD Ultra-low sulfur distillate

ULSK Ultra-low sulfur kerosene

VAC Value added charge

VACAR Virginia-Carolinas

VER Variable energy resource

VOM Variable O&M

WCSB Western Canadian Sedimentary Basin

WDA Western Delivery Area

WEQ Wholesale Electric Quadrant

WGL Washington Gas Light

WGQ Wholesale Gas Quadrant

Working Group Steady State Modeling and Load Flow Working Group

WTI West Texas Intermediate

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The information and studies discussed in this report are intended to provide general information to policy-makers and stakeholders but are not a specific plan of action and are not intended to be used in any state electric facility approval or siting processes. The work of the Eastern Interconnection States Planning Council or the Stakeholder Steering Committee does not bind any state agency or Regulator in any state proceeding.

Executive Summary

In mid-2009 the Department of Energy (DOE) issued a funding opportunity announcement DE-FOA-0000068 “Resource Assessment and Interconnection-level Transmission Analysis and Planning,” directed towards the Eastern, Western, and Texas interconnections. PJM Interconnection, LLC (PJM) bid for and won the Topic A portion of this FOA for the Eastern Interconnection (EI), award DE-OE0000343, supported by nine members[1] of the Eastern Interconnection Planning Collaborative (EIPC). EIPC had been formed earlier in 2009 by 25 of the larger Planning Authorities (PA) in the EI.

This Topic A work was carried out in close interaction with the EI Topic B recipient of DOE-FOA-0000068, the National Association of Regulatory Utility Commissions (NARUC), and the state representative’s group formed through their award, the Eastern Interconnection States Planning Council (EISPC). EISPC members include regulatory representatives from the 39 states of the EI, the District of Columbia, and the City of New Orleans. While the EISPC report on their work will be published separately, this report includes input from the EISPC. DOE is additionally supporting the Interconnection-Level Transmission Planning Analysis through work at selected national laboratories on grid frequency response and on fault induced delayed voltage recovery.

The work of this funding opportunity was divided into two phases. Phase 1 began with the creation of a combined grid model for the EI (the “roll-up” case) and the formation of a diverse Stakeholder Steering Committee (SSC) with interests in public policy “futures”. Work continued with macroeconomic and generation resource allocation studies of eight futures chosen by the SSC, and the modification of the roll-up case into a Stakeholder Specified Infrastructure (SSI). Finally, the SSC chose three future scenarios as the basis for Phase 2 of the project:

1. A Nationally Implemented Federal Carbon Constraint with Increased Energy Efficiency/Demand Response, (Scenario 1: Combined Policies)

2. A Regionally Implemented National Renewable Portfolio Standard (Scenario 2: National Renewable Portfolio Standard/Implemented Regionally), and

3. Business as Usual (Scenario 3: Business as Usual).

A report describing Phase 1 studies and results was released in December, 2011. That report may be found at: http://www.eipconline.com/uploads/Phase_1_Report_Final_12-23-2011.pdf.

Phase 2 included transmission studies and production cost analyses of the three future scenarios chosen by the stakeholders. This included developing transmission options; analysis of grid reliability and production costs; and estimating generation, transmission, and selected “other” costs. A number of sensitivities were studied for the three scenarios. The sensitivities included

[1] Project participants were: Entergy, ISO-NE, MAPPCOR, MISO, NYISO, PJM, Southern Company, TVA, American Transmission Company.

four sensitivities to investigate the amount of wind curtailment in Scenario 1 which was 15% in the base run. They also included analyzing high loads and high gas prices in Scenario 3.

The initial Phase 2 work was completed and a draft report covering Phase 2 dated December 22, 2012 was submitted to DOE. On February 13, 2013 PJM received technical guidance[2] from DOE highlighting issues that require further investigation. This technical guidance requested that analyses be completed on the gas-electric system interface because it deserved a more in-depth analysis than originally envisioned. PJM accepted the technical guidance and agreed to undertake the additional analyses. The additional analysis of the interface between the natural gas delivery system and the electric generation/transmission system(s) in portions of the EI is referred to as the Gas-Electric System Interface Study.

The technical guidance requested PJM to revisit three tasks:

Task 1, Initiate Project, to adjust the process to obtain stakeholder input on the project and the structure of the SSC, because in its present form the membership emphasizes electricity stakeholders with minimal, if any, natural gas focus;

Task 11, Review of Results, to evaluate the interaction between natural gas and electricity systems; and

Task 12, Phase 2 Report, to revise the draft Phase 2 report to include the results of the gas-electric system interface analysis.

The Gas-Electric System Interface Study is of interest and importance to the entire EI, but is particularly critical in the Northeast and Midwest. Six EI PAs agreed to be participants in the analysis. These Participating Planning Authorities (PPAs) are ISO-NE; NYISO; PJM; IESO; MISO, including the Entergy system; and TVA. The combined geographic area of these PPAs is the Study Region for the Gas-Electric System Interface Study.

The Gas-Electric System Interface Study was comprised of four target areas:

Target 1: Baseline assessment and description of the natural gas-electric system interface

Target 2: Evaluation of the capability of the natural gas system to supply the fuel requirements of the electric power sector

Target 3: Analysis of selected contingencies of the gas and electric systems to determine the ability of the natural gas pipeline system to continue to provide gas service to electric generation.

Target 4: Review the availability and cost of providing dual-fuel capability at electric generating stations compared with cost the cost of obtaining firm gas transportation service.

[2] "Request for Concurrence on Technical Guidance to be Provided to PJM Interconnection L.L.C. in Response to Its Draft Phase 2 Report on the Eastern Interconnection Planning Collaborative Award, Cooperative Agreement No. DE-OE0000343 dated January 3, 2013".

This report includes the material from the initial Phase 2 report dated December 22, 2012 and has been modified to include the results for the additional gas-electric system interface analyses. With the completion of the Phase 2 work by EIPC, including the additional analyses requested in the February 13, 2013 technical guidance, the EI Topic A work scope has now met the goals defined in the Statement of Project Objectives. This report contains the complete Phase 2 studies, results, and conclusions. As was done for Phase 1, a final version will be posted at http://www.eipconline.com/.

A number of valuable conclusions were drawn from the study. While the results were not intended as a specific plan of action or for use in any state electric facility approval or siting processes, and did not include all mandatory NERC reliability planning requirements, they do provide general information to policy-makers and stakeholders, and will serve as guidelines in future EIPC activities. In addition, the study scope did not include analyses of specific current or future proposed energy policies or regulatory proceedings such as EPA's Clean Power Plan ("CPP," also known as Rule 111d). As the first interconnection-wide analysis of its kind, the work provided insights to EIPC members regarding how future studies may be performed and how future interconnections may develop. Included below in the Condensed Report and in the Full Report that follows are descriptions of the transmission system assumed as the starting point for the analysis; the transmission required to support each of the three future scenarios; the relative costs for each scenario; and the generation capacity, energy production, and emissions for each scenario.

The results of the Gas-Electric System Interface Study provide a comprehensive analysis across the region of the adequacy of the natural gas pipeline delivery system to meet the needs of the gas-fired electric generation system under various conditions over a 10-year horizon. In addition, the study identified constraints on the natural gas pipeline system that may affect the delivery of gas to specific generators following a variety of postulated gas and electric system contingencies. The study also describes a number of mitigation measures that may be considered by gas and electric system operators to alleviate the impacts on the electric system under such conditions. The results of this study provide a wealth of information for consideration by the PPAs and regional stakeholders to inform their respective operational and planning analyses.

Other benefits of the study included an interaction and development of experience between PA participants and state participants. The formation of the SSC, which represented a wide range of interests, presented challenges; however, both the EIPC and SSC found substantial advantages resulting from the study, as well as identifying opportunities for improvement in the future. The EIPC is grateful to DOE and to all the above participants for their contributions.

Condensed Report

The North American electrical power grid has developed into five separate systems: the Western, Texas, Eastern, Alaska, and Quebec Interconnections, which together serve more than 300 million people through 200,000 miles of high-voltage transmission lines. Of these five, the Eastern Interconnection (EI) in the United States covers the largest area, serves all or portions of 39 states with 70% of the U.S. population, has the largest number of utility companies, and contains six of the eight North American Electric Reliability Corporation (NERC) regions.

On June 15, 2009, the Department of Energy (DOE) released an FOA, “Resource Assessment and Interconnection-Level Transmission Analysis and Planning,” DE-FOA-0000068, funded by the American Recovery and Reinvestment Act of 2009 (ARRA). The FOA’s objective was to support development of grid capabilities in the three largest interconnections by preparing analyses of transmission requirements under a range of alternative futures and developing interconnection-wide transmission expansion plans. PJM submitted a proposal, on behalf of EIPC, for the EI Topic A portion of the FOA and it was accepted by DOE.

The EI Topic A work scope is comprised of twelve tasks, divided into two phases. The second phase includes analyses conducted as part of the Gas-Electric System Interface Study in response to technical guidance from DOE on February 13, 2013.

Phase 1 tasks, which were completed in 2011 and documented in the Phase 1 Report released in December 2011, included:

1. Task 1: Initiate Project (Governance and Selection of Stakeholder Steering Committee [SSC]).
2. Task 2: Integrate Regional Plans (Roll-up Report).
3. Task 3: Production Cost Analysis for Roll-up Report (This task was later dropped as not necessary).
4. Task 4: Macroeconomic Futures Definition.
5. Task 5: Macroeconomic Analysis of Defined Futures.
6. Task 6: Expansion Scenario Concurrence and Phase 1 Report.

The Phase 1 Report is referenced throughout this report and can be found at: http://www.eipconline.com/uploads/Phase_1_Report_Final_12-23-2011.pdf.

This report outlines the process and results for Phase 2 of the project, including the Gas-Electric System Interface Study. Phase 2 tasks included:

7. Task 1: Initiate Project. Revisit Task 1 efforts at the beginning of the Gas-Electric System Interface Study to adjust the process to obtain stakeholder input and adjust the structure of the SSC, to add representation with natural gas system expertise.
8. Task 7: Interregional Transmission Options Development. Identify the transmission needed to provide a reliable system for each of the three scenarios.
9. Task 8: Reliability Review. Further analyze the transmission options developed in Task 7 using additional NERC reliability tests.

10. Task 9: Production Cost Analysis of Scenarios. Analyze the cost of the energy that needs to be supplied in each scenario by running a security-constrained economic dispatch model.
11. Task 10: Generation and Transmission Cost Development. Develop estimates of the cost of the supply resources and transmission in each scenario.
12. Task 11: Review of Results and Draft Report. This task includes the additional evaluation of the interaction between natural gas and electricity systems called for in the February 13, 2013 DOE guidance. Draft the final report.
13. Task 12: Phase 2 Report. Incorporate comments and finalize report for DOE approval.

Phase 1

In Phase 1, an early requirement was the formation of a Stakeholder Steering Committee (SSC) that would provide input and strategic guidance to EIPC through consensus decisions.[3] The SSC was comprised of 29 official members, ten representatives from the States, three representatives from each of six sectors and one representative from Canada. The six sectors were Transmission Owners and Developers; Generation Owners and Developers; Other Suppliers; Transmission Dependent Utilities and Public Power & Coops; End Users; and Non-Governmental Organizations.[4,5]

Eastern Interconnection Roll-Up Plan and Stakeholder-Specified Infrastructure

The first major task of Phase 1 was development of a combined grid model for the interconnection based on a roll-up of the Planning Authorities' (PAs) expansion plans for the year 2020. The PAs undertook a reliability analysis of the roll-up of the regional plans and found no significant reliability issues. Such a finding is noteworthy as it indicates the individual regional plans are not causing burdens that would manifest themselves as unsolved reliability violations elsewhere in the EI.

This model served as the basis for the EISPC and the SSC to formulate a Stakeholder Specified Infrastructure (SSI) Model as the starting point for analyses extending to 2030. The SSI infrastructure shown below in Figure CR-1 depicts only the additional transmission lines that passed the SSI screening process. A map showing the full transmission topology included in the base model is included in Appendix 2. As Phase 2 began, some changes were made in the SSI due to updates in projects that moved forward or were set aside. A list of those changes can be found at:
http://www.eipconline.com/uploads/20120314_Revised_NewFaciltitiesIncluded_SSI_model.xlsx.

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[3] The SSC developed a back-up voting structure in the event consensus could not be reached.

[4] More information on the formation and composition can be found in Section 2 of the Phase 1 report.

[5] In the Gas-Electric System Interface Study this structure was revised to include a three representative Natural Gas Sector and an eleventh State representative in order to maintain a one-third balance for the States.

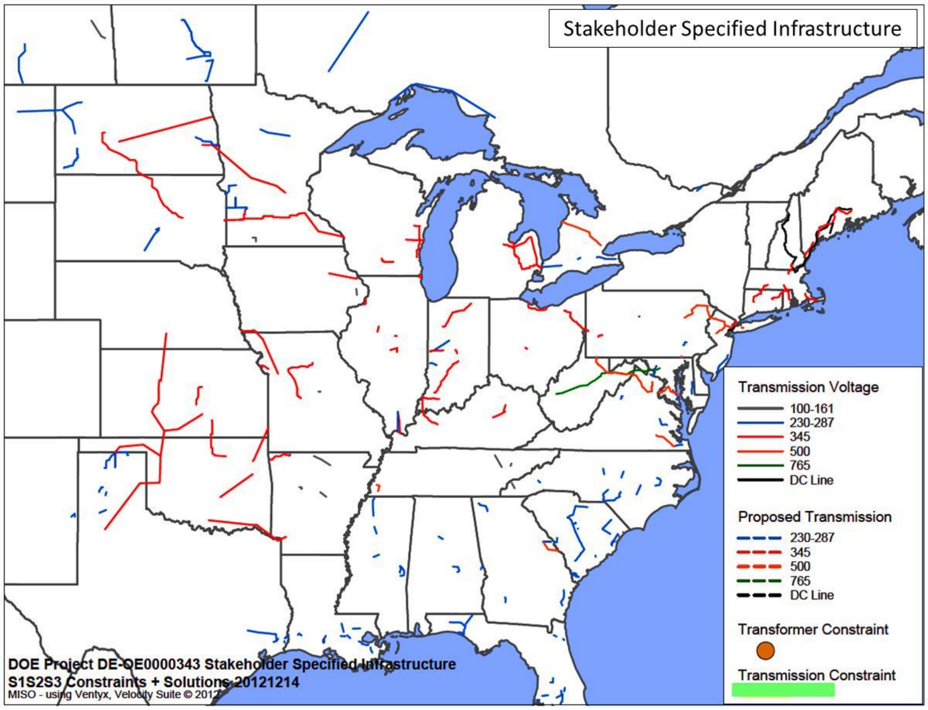


Figure CR-1. Stakeholder Specified Infrastructure

<u>Futures Development and Macroeconomic Modeling</u>

EIPC chose Charles River Associates' (CRA) Multi-Region National (MRN) macroeconomic model and their North American Electricity and Environment Model (NEEM) to develop information on resource development in eight futures, with 72 sensitivities to be allocated amongst the eight futures, for a total of 80 model runs. The NEEM model used in Phase 1 selected different types of generation based on economics, generation characteristics, and numerous input assumptions[6]. The NEEM model is a "pipe and bubble" model that placed new generation in various regions ("bubbles"), but could not automatically resize the transmission between regions (the "pipes")[7]. Thus, the Phase 1 modeling focused on economic generation additions/retirements within specific regions – using fixed transmission transfer capabilities. In the Phase 1 resource expansion model, a number of modeling runs relaxed the transmission constraints as a proxy for iterating between transmission expansion and resource expansion. The NEEM regions are shown in Figure CR-2, below. The regions outlined in blue and red are the NEEM regions that were modeled in all three scenarios. The combinations of regions outline in

[6] The NEEM model considered the expansion of the electric resource system. It was not able to capture the infrastructure interrelationships between the electric system and other infrastructures like the natural gas supply and delivery system. This limitation is highlighted in the Phase 1 report Section 4.2.1.4 *Electric-Gas Interdependencies.* The Phase 1 report includes other significant conclusions and observations.

[7] Another key assumption that impacted the Phase 2 work of the PAs is that, within the NEEM "bubbles," it was assumed that there were no transmission constraints. In Phase 2, any transmission constraints that occurred within the bubbles were identified and transmission was developed to alleviate those constraints.

black are the "Super Regions." The Super Regions were used in the futures that called for regional implementation of policies; one of these futures was chosen as Scenario 2: RPS Implemented Regionally.

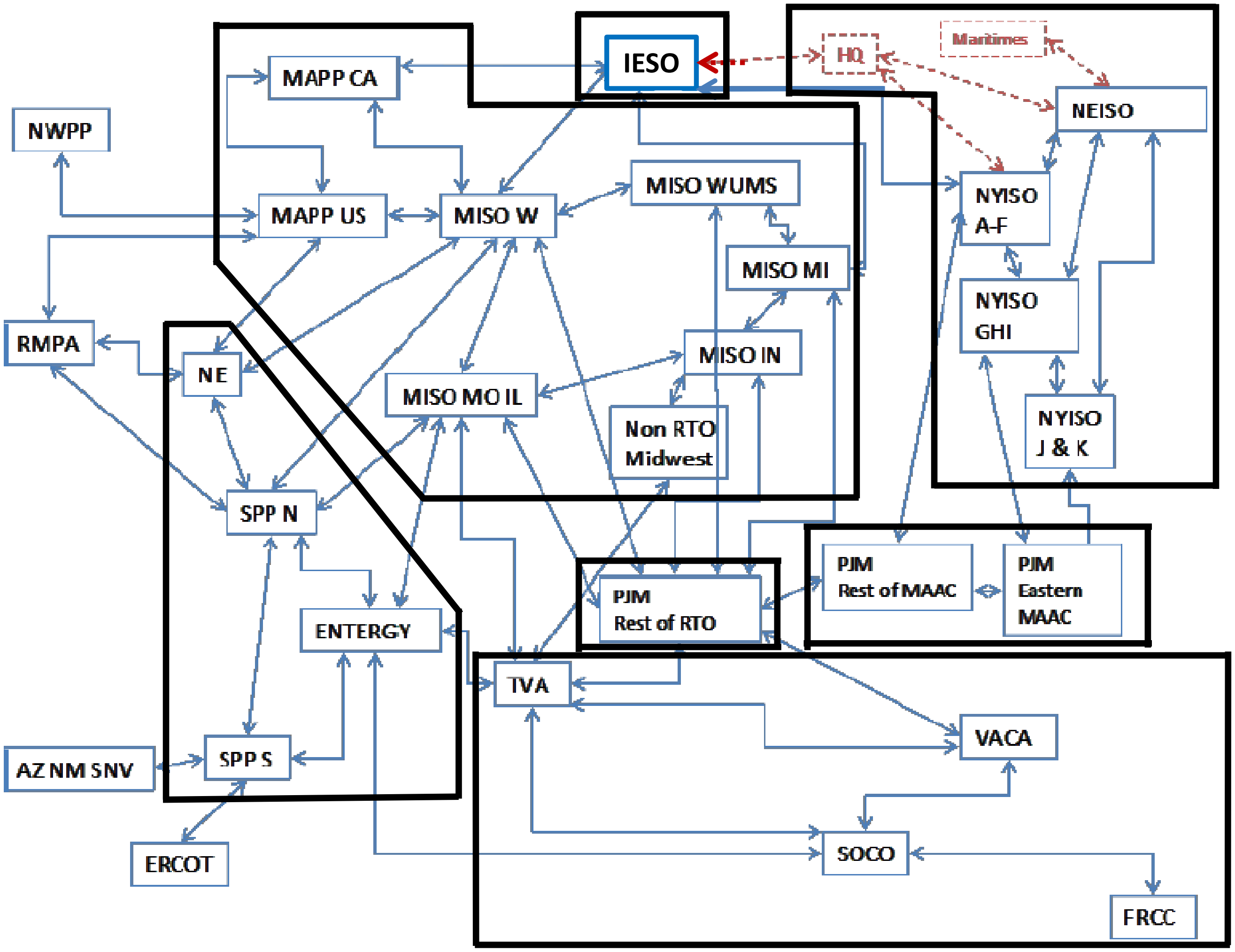


Figure CR-2. NEEM Regions (blue), Super Regions (black), and External Areas with Scheduled Tie Line Flows (red)

The eight futures analyzed as part of Phase 1 were:

1. Business as Usual with EPA regulations proposed in 2011;
2. National Carbon Constraint – National Implementation – 42% reduction by 2030;
3. National Carbon Constraint – Regional Implementation – 42% reduction by 2030;
4. Aggressive Energy Efficiency/Demand Response/Distributed Generation/Smart Grid – 20% load reductions by 2030;
5. National Renewable Portfolio Standard – National Implementation – 30% by 2030;
6. National Renewable Portfolio Standard – Regional Implementation – 30% by 2030;
7. Nuclear Resurgence – significant new nuclear facilities developed in EI; and

8. Combined Federal Climate and Energy Policy – 42% reduction in CO_2 by 2030, 30% Renewable Portfolio Standard (RPS), significant deployment of demand side measures; EI-wide implementation.

To construct computer simulations for each of these futures and sensitivities, many assumptions and data inputs were developed by the SSC Modeling Work Group (MWG), for consideration by the SSC. A detailed summary of the assumptions can be found at: http://www.eipconline.com/uploads/MWG_Recommendations_to_the_SSC_March_28__29_Revised_FINALdocx.pdf. In addition, more information is included in presentations to the SSC, which can be found at: http://www.eipconline.com/SSC_Meetings.html.

In addition to the information from the NEEM model on additional needed transmission, the SSC requested cost estimates for energy efficiency, demand response and distributed generation, as well as costs associated with maintaining higher levels of reserve generation to integrate conventional generators and renewable generators. High-level estimates of these additional costs were developed by the SSC's MWG in collaboration with Oak Ridge National Laboratory (ORNL).

Selection of Three Scenarios for Phase 2

The SSC chose three scenarios, as shown in Table CR-1, for which the EIPC was to develop full interregional transmission expansion models in the second phase of the work. These scenarios were considered by the SSC to be a diverse set of scenarios in terms of policy goals, levels of implementation, transmission build-outs, and total cost. Each of the three scenarios had specified peak demands and energy levels. They also had required additional annual average transfers between NEEM regions over and above the transfers that occurred in the base NEEM run that needed to be achieved by the Phase 2 transmission build-out. The peak demands, energy requirements and additional average transfers required are included in the descriptions below. The levels of additional average transfers required were based upon the Phase 1 NEEM analysis. More detailed maps of where the additions were required in the EI are included in Appendix 1.

Table CR-1. Scenario Descriptions for Phase 2 Studies

Scenario 1: Nationally Implemented Federal Carbon Constraint with Increased Energy Efficiency/Demand Response • Peak Demand: 565,012 MW • Total Energy: 2,979 TWh • Additional Average Transfers Required above SSI Model Limits: 37,000 MW	Reduce economy-wide carbon emissions by 42% from 2005 levels in 2030 and 80% in 2050, combined with meeting 30% of the nation's electricity requirements from renewable resources by 2030 and significant deployment of energy efficiency measures, demand response, distributed generation, smart grid and other low-carbon technologies; achieved by utilizing an EI-wide implementation strategy. The scenario has flat CO_2 prices after 2030, more wind in the MISO_W, and the MISO combined cycle plants and MISO eastern wind were dispersed throughout the MISO regions.
Scenario 2: Regionally Implemented National Renewable Portfolio Standard • Peak Demand: 673,108 MW • Total Energy: 3,621 TWh • Additional Average Transfers Required above SSI Model Limits: 3,000-4,000 MW	Meet 30% of the nation's electricity requirements from renewable resources by 2030; achieved by utilizing a regional implementation strategy.
Scenario 3: Business as Usual • Peak Demand: 690,492 MW • Total Energy: 3,687 TWh • Additional Average Transfers Required above SSI Model Limits: 0 MW	Continuation of forecasted load growth, existing RPS requirements, and Environmental Protection Agency (EPA) regulations as proposed and understood in the summer of 2011.

The results of the Topic A Phase 1 work are intended to provide information to stakeholders, including policy makers, on the combinations of generation (including type of resource and location) and transmission transfer increases needed between the NEEM regions to support those generation resources. It is important to note that any transmission expansions indicated from the macroeconomic studies do not provide a transmission plan, and the generic transmission infrastructure upgrades associated with the Phase 1 analysis were high level approximations only and do not represent likely project solutions; rather, such information was developed as information to assist the SSC in determining the three scenarios to be analyzed during the Phase 2 studies. The choice of transmission line types and voltages for expansion of the pipes was developed in the same way for all regions for the purpose of the analysis and does not necessarily reflect regionally the actual facilities that would be chosen as a result of a fully developed regional planning process.

Phase 2

In Phase 2, the EIPC performed N-1 reliability analysis on generation and transmission elements, reliability analysis on common tower outages and bus outages and used the results to develop more detailed transmission build-outs for the three selected scenarios. Phase 2 included performing production cost analysis on each of the three scenarios, using a model that provided a security constrained economic dispatch for all 8,760 hours of the year. It also included analyzing six sensitivities around them and developing capital cost estimates for the generation and transmission included in each of the scenarios.

Even with this additional detail in Phase 2, the results are indicative only and not representative of actual project solutions, which will be determined in regional level transmission planning processes as future resource requirements become more certain.

The EIPC PAs developed transmission options for the three chosen scenarios in collaboration with the Transmission Options Task Force (TOTF), a group designated by the SSC. The year chosen for the analysis was 2030. The transmission planners identified five cases for the three scenarios. Scenario 1: Combined Policies and Scenario 2: RPS Implemented Regionally required a shoulder case in addition to the traditional peak case because of their significant additions of wind generation in remote locations. Scenario 3: Business as Usual required only a peak case.

As part of the original project team EIPC chose CRA to perform the production cost modeling using the GE MAPS model. In contrast to the NEEM model used in Phase 1, GE MAPS is a detailed economic dispatch and production cost model that simulates the operation for the electric power system, taking into account transmission topology. Analysis of the three scenarios and six sensitivities was performed using the transmission expansion options developed in the reliability analysis. The GE MAPS model forecasted energy production costs, constraints limiting dispatch and interregional transactions, anticipated emissions, renewable energy production, and other pertinent factors.

<u>Reliability Analysis Results – Constraints</u>

Below are three maps (Figure CR-3, Figure CR-4, and Figure CR-5) showing the overload and voltage constraints identified by the PAs during the reliability analysis conducted for the entire EI for each of the three scenarios. These constraints occurred in the model after the generation interconnection projects were included in the model. Without the generation interconnection projects, the models would not have solved.

The transmission options developed by the group are designed to reliably serve the load specified in each scenario and to meet the interchange between NEEM regions that was specified in the scenario. In Phase 1, the NEEM model assumed that each of the NEEM regions had enough internal capacity to allow power to move without constraint within each region. In Phase 2, the PAs performed transmission reliability analysis to determine where constraints would arise <u>within</u> the regions as well as between the regions. For these analyses, all constraints 200 kV and above were addressed by the PAs. In selected cases, at a PA's discretion, lower voltages were addressed if the issues were severely affecting the 200 kV and above system and/or the area did not have the necessary supporting 200 kV and above infrastructure.

The results of this analysis comply with selected NERC reliability standards that are described in the report; however, because of the long-term nature of the analysis, it did not include all requirements for full compliance with all NERC standards. One example of a NERC standard that was not included was testing for transient stability for generators. This is a very detailed requirement that would not be addressed in a strategic analysis such as this.

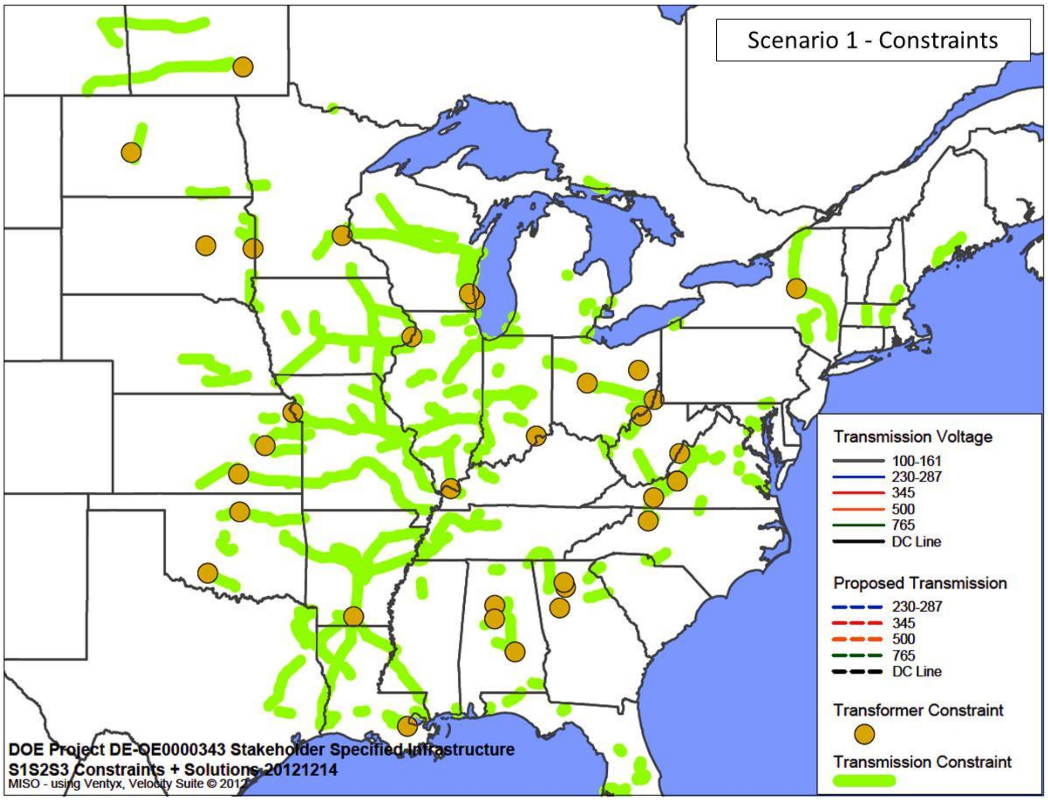


Figure CR-3. Scenario 1 – Constraints

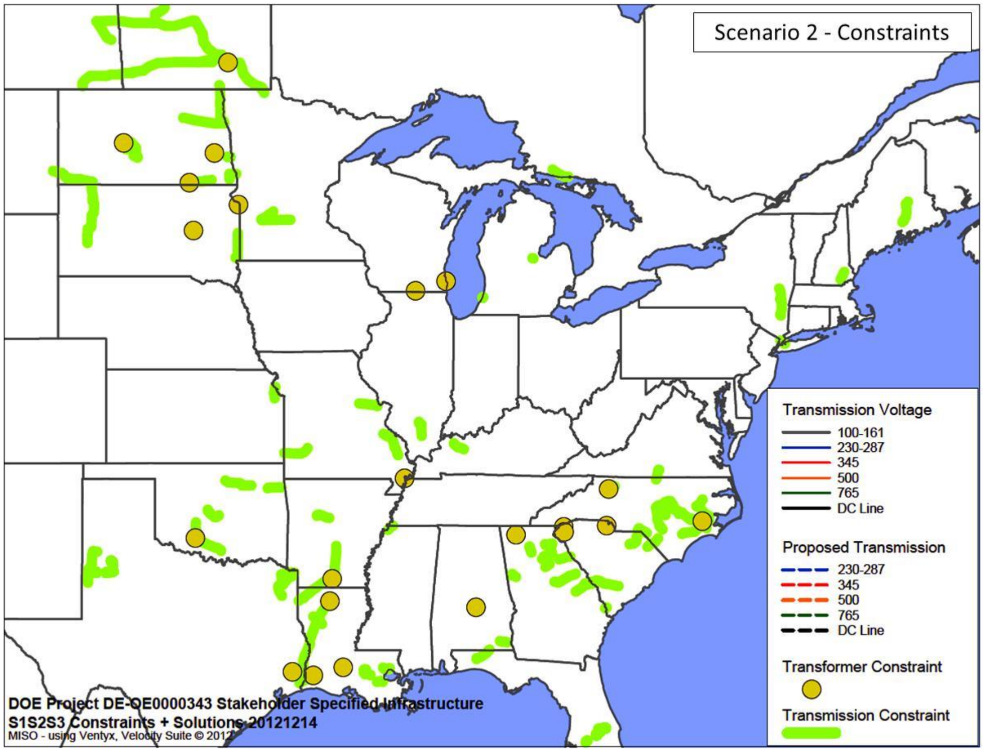


Figure CR-4. Scenario 2 – Constraints

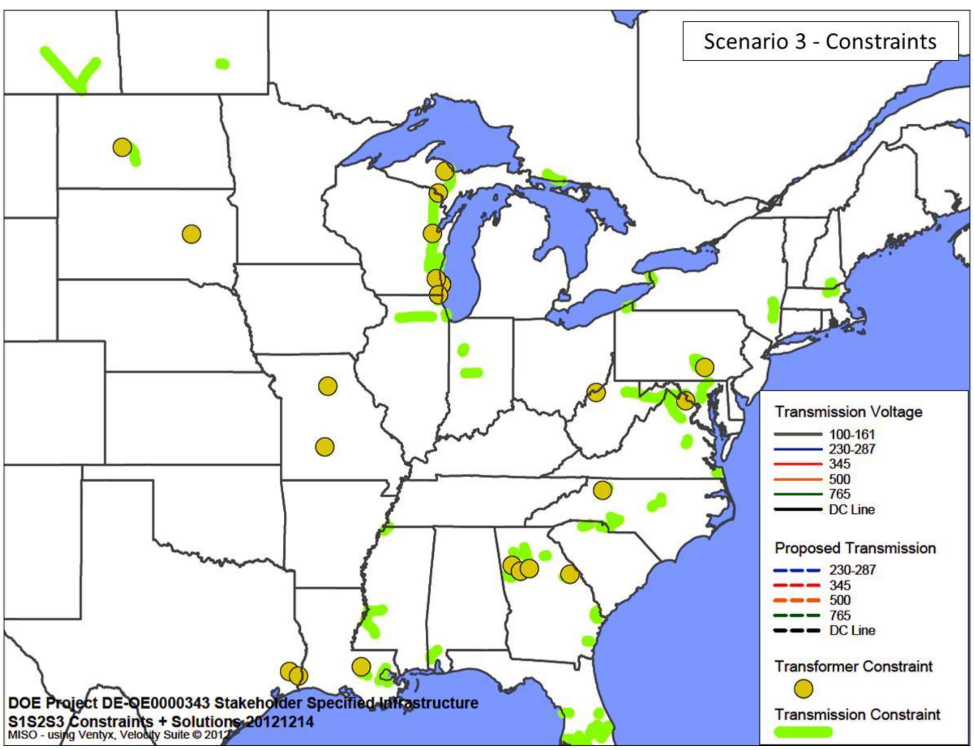


Figure CR-5. Scenario 3 – Constraints

Scenario 1 was the most challenging from a transmission planning perspective because of the large amount of additional transfers that needed to occur in the scenario, particularly from

MISO-West to PJM and from Southwest Power Pool (SPP) to PJM. In Scenario 2, the bulk of the constraints occur in the MISO and SPP regions due to the amount of wind being sited in those areas. Some constraints also occur in the southeast states. Scenario 3 has scattered constraints in Canada and a number of states. In all three scenarios it was assumed that new natural gas plants would be placed at the site of deactivated coal plants, reducing the need for transmission; the locations and capacities of natural gas pipelines were not taken into account.

Reliability Analysis Results – Additional Transmission

The constraints identified were eliminated with the addition of transmission elements. These elements range from transformers to high voltage direct current (HVDC) and extra high voltage alternating current (AC) transmission lines that are hundreds of miles long.

Below are maps (Figure CR-6, Figure CR-7, and Figure CR-8) of the transmission build-outs that were identified by the PAs for each of the three scenarios.

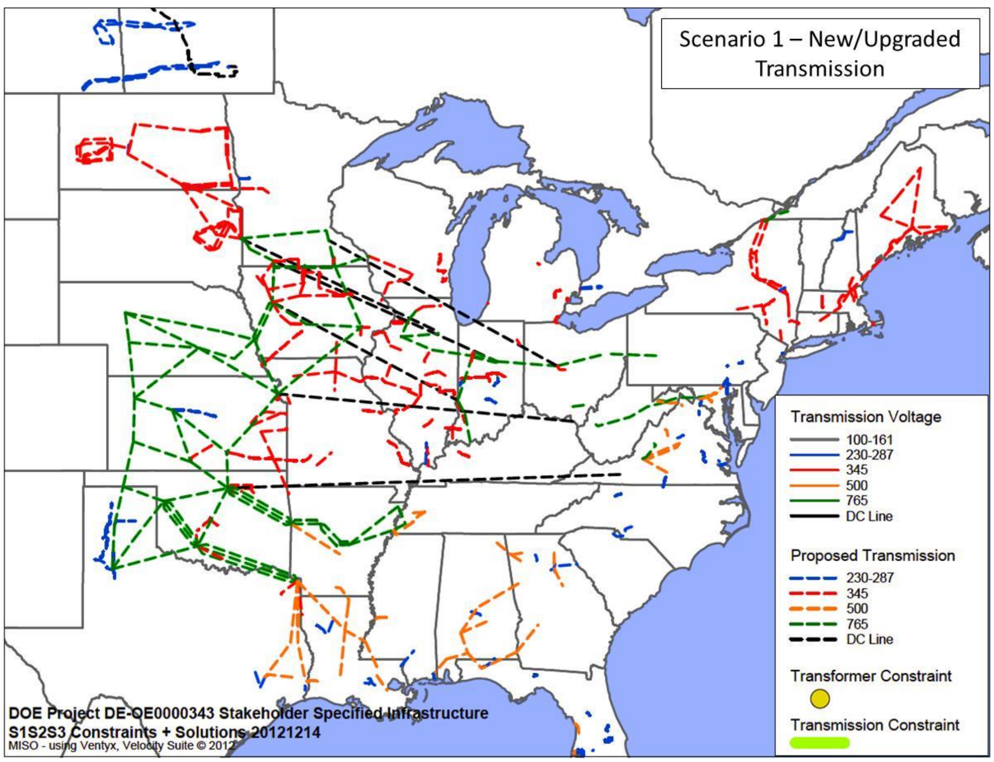


Figure CR-6. Scenario 1 – New/Upgraded Transmission

In solving the significant constraints that occurred in the model for Scenario 1, the PAs found that building a larger AC system was not sufficient. New 500 kV HVDC lines were added until the most significant constraints were solved. Six 500 kV HVDC lines, each capable of carrying 3,500 MW, were needed to reliably achieve the required transfers. In addition, there were still significant amounts of 765 kV, 500 kV and 345 kV AC lines that were needed to maintain reliability. The map above shows new and reconductored/upgraded facilities added to the system for Scenario 1. Over 4,300 miles of existing transmission lines, ranging from 115 kV to 345 kV, needed to be reconductored or upgraded.

In Scenario 1, the required additional average transfers specified by the SSC in Phase 1 were 37,000 MW.

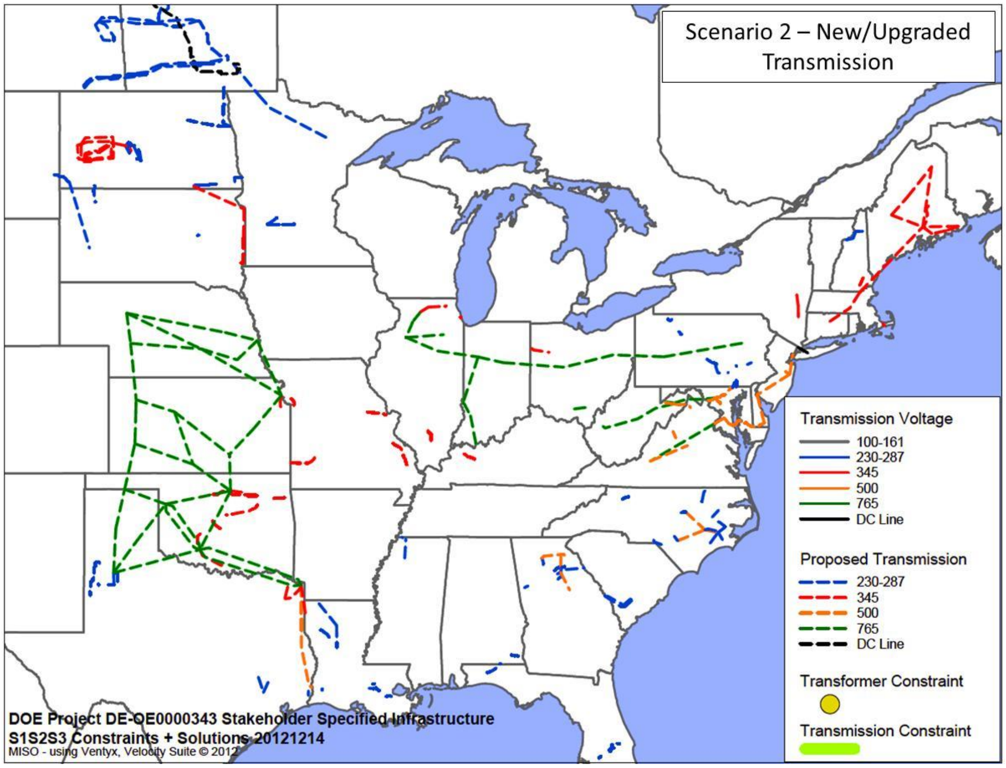


Figure CR-7. Scenario 2 – New/Upgraded Transmission

For Scenario 2, the largest amount of transmission added is from Illinois going east to Ohio and Pennsylvania. This 765 kV transmission was developed to move renewable wind power from the western to the eastern side of the PJM – Rest of Region NEEM region. Other additions involved wind collector systems and some additional transmission in other areas. In addition to the new lines, over 2,600 miles of lines needed to be reconductored or upgraded. Both the new and reconductored/upgraded lines are depicted in the map above.

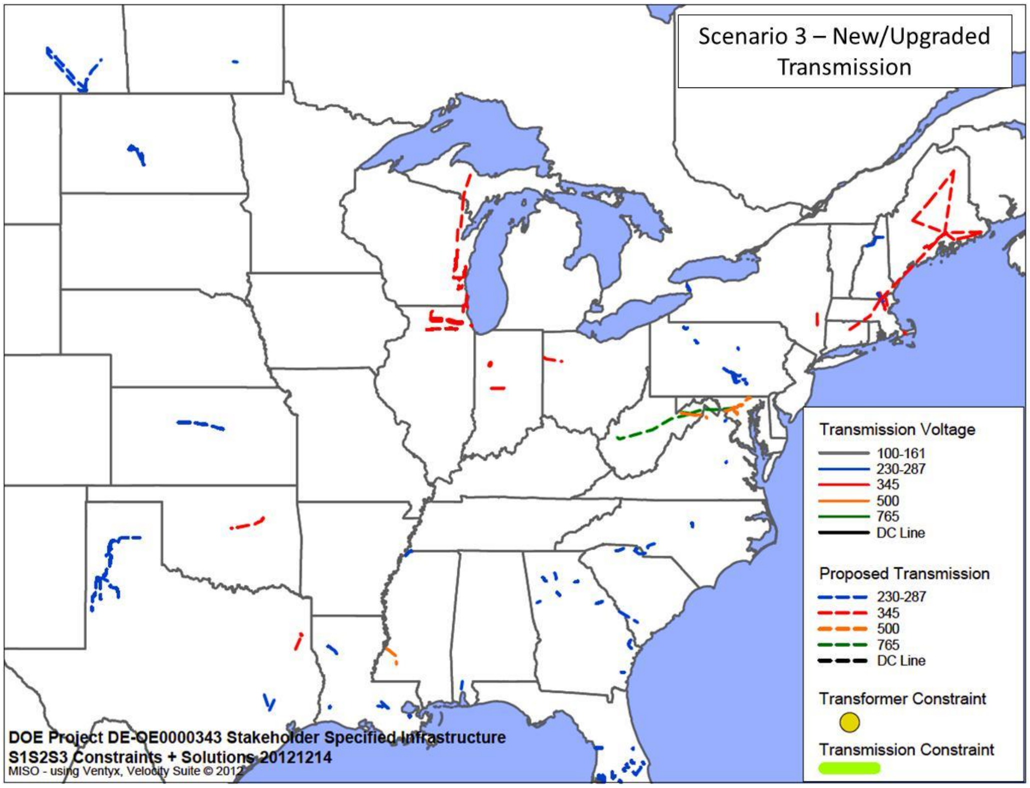


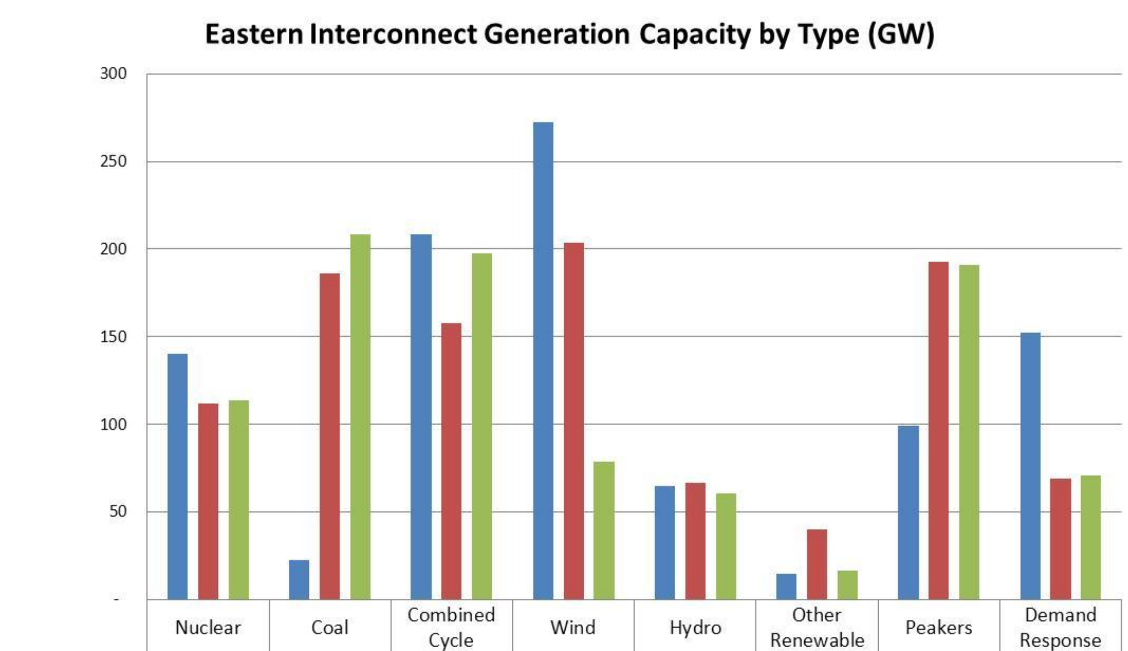
Figure CR-8. Scenario 3 – New/Upgraded Transmission

Because Scenario 3 had no required additional transfers above the limits in the SSI model between NEEM regions and new generation was placed first on brownfield sites where generation had been deactivated in the model, the scenario required very few transmission upgrades to support the new generation interconnections. An additional 765 kV line was needed in Virginia/West Virginia and 345 kV lines were needed in a few regions. In addition to the new lines, over 2,500 miles of existing transmission lines needed to be reconductored or upgraded. Both the new lines and the reconductored/upgraded lines are depicted in Figure CR-8.

A comparison of the additional transmission transfers between Phase 1 results and Phase 2 results shows the additional transmission facilities in Phase 2 provided for additional transfer capability in approximately the amounts anticipated by the NEEM model in Phase 1.

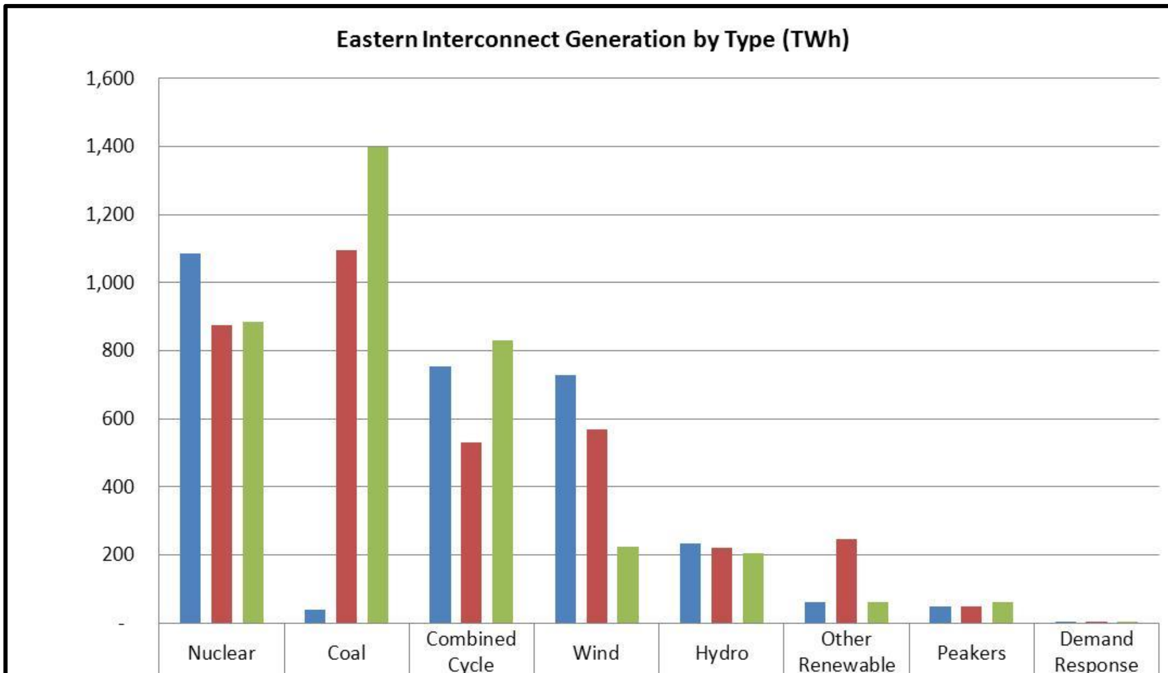
Production Cost Results

The following figures (Figure CR-9 and Figure CR-10) show the installed capacity and total energy for each of the three scenarios from the GE MAPS base runs.



	Nuclear	Coal	Combined Cycle	Wind	Hydro	Other Renewable	Peakers	Demand Response
Scenario 1	140	23	208	272	65	15	99	152
Scenario 2	112	186	158	203	67	40	192	69
Scenario 3	113	208	197	79	61	16	191	71

Figure CR-9. EI Generation Capacity



	Nuclear	Coal	Combined Cycle	Wind	Hydro	Other Renewable	Peakers	Demand Response
Scenario 1	1,087	40	755	728	235	61	50	4
Scenario 2	875	1,095	532	568	222	248	50	0
Scenario 3	886	1,399	831	223	205	63	60	1

Figure CR-10. EI Energy

For Scenario 1: Combined Policy, the largest amount of installed capacity in the EI is wind capacity, followed by combined cycle and demand response. Together, these three generation types comprise 64% of the total capacity in the EI. While wind, combined cycle and demand response make up the largest amount of installed capacity, the largest amount of generation comes from nuclear power plants, combined cycle and wind. Together, they produce 87% of the energy needed for the EI.

For Scenario 2: RPS Implemented Regionally, the largest amount of installed capacity in the EI is wind capacity, followed by peakers and coal. Together, these three generation types comprise 57% of the total capacity in the EI. While wind, peakers and coal make up the largest amount of installed capacity, the largest amount of generation comes from coal plants, nuclear and wind. Together, they produce 70% of the energy needed for the EI. Scenario 2 has a more diverse supply-fuel mix in its portfolio than Scenario 1, both in terms of capacity and energy.

For Scenario 3: Business as Usual, the largest amount of installed capacity in the EI is coal, followed by combined cycle and peakers. Together, these three generation types comprise 64% of the total capacity in the EI. While coal, combined cycle and peakers make up the largest amount of installed capacity, the largest amount of generation comes from coal plants, nuclear and combined cycle. Together, they produce 85% of the energy needed for the EI.

For Scenario 3, the energy produced by the top three generation types is roughly equal to Scenario 1 with coal replacing wind in Scenario 3. Combined cycle and nuclear energy show up in the top three energy sources in both Scenarios 1 and 3, producing 50% and 47% of total energy, respectively.

Production Costs and Emissions Results

Table CR-2 shows the production costs, CO_2 emissions costs and emissions levels for each of the three scenarios.

Table CR-2. Annual Costs, Emissions, Demand and Energy

	Scenario 1 Base - Combined Policies	Scenario 2 Base - RPS Implemented Regionally	Scenario 3 Base - Business as Usual
Annual Production Costs ($M)			
Fuel	40,802	73,789	85,057
Variable O&M	6,430	15,502	18,411
Total Production Costs ($M)	47,231	89,291	103,469
CO2 Costs ($M)	45,340	126	154
Total w/CO2	92,571	89,416	103,622
Emissions (short tons)			
SO2 (000)	93	873	1,122
NOx (000)	21	1,300	1,771
CO2 (millions)	358	1,391	1,792
Peak Demand (MW)	565,012	673,108	690,492
Energy (TWh)	2,979	3,621	3,687

CO_2, SO_x and NO_x emissions in Scenario 1 are significantly lower than in Scenarios 2 and 3, due to the policies that are being modeled. Production costs (fuel and variable operation and maintenance (VOM)) are also significantly lower than in Scenarios 2 and 3. In this scenario, EI-wide CO_2 costs are explicitly modeled based on an underlying CO_2 price determined in the Phase 1 NEEM runs and the quantity of emissions from fossil-fueled resources. Those costs are shown in the "Total w/ CO_2" entry in the table above. The peak demand and energy for Scenario 1 are lower than for Scenarios 2 and 3 because of the aggressive energy efficiency/demand response assumptions made in Scenario 1.

Emissions in Scenario 2 are significantly higher than in Scenario 1, resulting from a generation portfolio that is more dependent on fossil fuel generation. Production costs are also significantly higher than Scenario 1 also due more reliance on fossil-fuel generation. EI-wide CO_2 costs were assumed at current levels; i.e., only those costs incurred in Regional Greenhouse Gas Initiative (RGGI) states in Scenario 2. Thus, the CO_2 costs shown in the summary above are small.

Emissions in Scenario 3 are the highest of the three scenarios, with no additional environmental policies assumed other than implementation of the EPA regulations as they were proposed in 2011. There are significant CO_2 emissions but, as with Scenario 2, the SSC assumed costs were at existing levels for RGGI states. The very low costs in Scenario 3 resulted from these assumptions. Overall production costs for Scenario 3 are the highest of the three scenarios, in part due to the additional demand and energy served in this scenario, roughly $56 billion/year higher than Scenario 1, and $14 billion/year higher than Scenario 2.

Production Cost Results – Transfers

In Phase 1, the EIPC and SSC agreed upon an expansion of the transmission inter-regional capacity of 37 GW in Future 8 Sensitivity 7, which became Scenario 1 in Phase 2. During the process of developing the build-out transmission systems in Phase 2, both AC and DC lines were added to the grid in order to meet reliability constraints during one peak hour and off-peak hour of 2030, while approximating the power generation and loads from Phase 1. The transmission system for the business as usual (BAU) case was similarly built-out for the peak hour in 2030.

These transmissions systems were then modeled in GE MAPS for all 8,760 hours. The results from GE MAPS show greater tie line flows between the regions in the scenarios than were in Phase 1. Peak inter-regional flows are higher by a combined total of 117 GW; average flows over the 8,760 hours are higher by 58 GW. The build-out transmission systems (from Phase 2 used in GE MAPS) ended up requiring more transmission capacity (than shown in Phase 1 by NEEM) to meet reliability constraints, and the production cost simulation used that capacity to the maximum extent possible.

Scenario Cost Results

The three scenarios were intentionally chosen by the SSC to represent "bookend" scenarios; scenarios that were very different in the amount of transmission that would be needed to support them. Below is a table showing the quantified costs for each of the three scenarios. Costs are represented in two ways, annual costs for the year 2030 and "overnight" capital costs for all transmission and generation installed through 2030. For summary purposes, mid-level costs are presented. All costs are represented in $2010 Billions.

The production costs shown are for a single year – 2030. Production costs occur each year, and will vary each year depending on the supply mix and demand; in Phase 2 of the EIPC process, only a single year's production costs (2030) were computed. The capital costs presented below are "overnight" capital costs. As the name implies, "overnight" capital costs represent the capital cost of a project if it could be built overnight - they do not include the interest costs of funds used during construction.

Table CR-3. Quantified Operation and Maintenance (O&M) and Capital Costs

2030 O&M Costs - ($2010 Billions)			
Costs	**Scenario 1: Combined Policy**	**Scenario 2: RPS Implemented Regionally**	**Scenario 3: Business as Usual**
Production Costs - Fuel	$ 40.8	$ 73.8	$ 85.1
Production Costs - Variable O&M	$ 6.4	$ 15.5	$ 18.4
CO2 Costs	$ 45.3	$ 0.1	$ 0.2
Policy Driven Energy Efficiency	$ 8.9	$ 1.5	$ 1.5
CO2 Price Driven Energy Efficiency	$ 10.0	$ -	$ -
Demand Response	$ 0.6	$ 0.3	$ 0.3
Variable Resource Integration	$ 2.9	$ 2.5	$ 1.0
Thermal Contingency	$ 3.8	$ 5.0	$ 6.2
Fixed O&M	$ 34.7	$ 52.1	$ 48.1
Total O&M Costs	**$ 153.4**	**$ 150.9**	**$ 160.7**
Overnight Capital Costs for Capital through 2030 ($2010 Billions)			
Costs	**Scenario 1**	**Scenario 2**	**Scenario 3**
Transmission - Generation Interconnection	$ 49.6	$ 54.3	$ 7.3
Transmission - Constraint Relief	$ 48.4	$ 13.0	$ 7.9
Transmission - Voltage Support	$ 0.5	$ 0.1	$ 0.2
Generation	$ 868.1	$ 679.4	$ 242.3
Nuclear Uprates	$ 4.9	$ 4.9	$ 4.9
Pollution Retrofit Costs	$ 6.8	$ 20.2	$ 22.0
Distributed Generation	$ -	$ -	$ -
Total Capital Costs	$ 978.2	$ 771.9	$ 284.6

The analysis did not include social benefits and costs that would arise from the different policies modeled. Also not included in the above are costs for:

1. Lower voltage transmission projects;
2. SSI generation and transmission projects (common to all three scenarios);
3. Generation interconnection costs not included in the overlays; i.e., the generator step-up and the lead lines to the first breaker – the costs for the generator interconnection overlays are included;
4. Generation deactivation/decommissioning;
5. Capital costs for existing units;
6. Tax credits and incentives; and
7. Transmission O&M.

Sensitivity Analysis and Results

Six stakeholder-specified sensitivity analyses were performed using the GE MAPS model. A significant concern of many stakeholders was the level of wind curtailment (15% over the EI and rising as high as 25-40% in some regions) in Scenario 1: Combined Policies. The sensitivities performed are described below. The first four sensitivities listed were intended to address the wind curtailment issue.

1. Scenario 1: Combined Policy – Loads were increased by 5%.
2. Scenario 1: Combined Policy – Increased flexibility and availability of spinning reserves.
3. Scenario 1: Combined Policy, Flowgate Relief – Increase flowgate capacity on top 25 binding flowgates by 50%. These flowgates involved seven transmission elements. These changes were applied to the High Spin sensitivity case rather than to the Scenario 1 Base model.
4. Scenario 1: Combined Policy, Reduced Wind – Reduce the wind build-out in the highly constrained wind regions. Reduction amount was based on how much wind reduction occurred in the top four curtailed regions in the base run and totaled 35 GW.
5. Scenario 3: Business as Usual, High Gas Prices – Gas prices were increased by 25% across all seasons.
6. Scenario 3: Business as Usual, Higher Loads – Loads were increased by 5% across all regions and time periods.

Scenario 1 Sensitivity Results: Wind Curtailment

The following table summarizes the results of the four sensitivities designed to investigate the wind curtailment issue.

Table CR-4. Sensitivity Results – Production Costs, Emissions and Wind Curtailment

	Scenario 1 - Combined Policies				
	Base	High Load	High Spin Availability	+Flowgate Relief	Reduced Wind
Annual Production Costs ($M)					
Fuel	40,802	45,805	39,552	39385	42630
Variable O&M	6,430	6,932	6,457	6443	6536
Total Production Costs ($M)	47,231	52,737	46,010	45828	49165
CO2 Costs ($M)	45,340	52,360	43,153	42825	47586
Total w/CO2	92,571	105,097	89,163	88654	96751
% Increase	-	14%	-4%	-4%	5%
Emissions (short tons)					
SO2 (000)	93	113	92	92	99
NOx (000)	21	25	21	21	23
CO2 (millions)	358	413	340	338	375
% Increase in CO2	-	15%	5%	6%	5%
Wind Curtailment					
Wind Curtailment (TWh)	131	119	120	110	64
Percentage Curtailed	0.15	0.14	0.14	0.13	0.09
% Change in Curtailment	-	-10%	-9%	-16%	-51%

In the High Load sensitivity, production costs increased by 14% and CO_2 emissions by 15%. Wind curtailment was reduced from 131 TWhs to 119 TWhs, or approximately 10%.

The High Spin Availability sensitivity reduced production costs by 4% and CO_2 emissions by 5%. Wind curtailment was reduced from 131 TWhs to 120 TWhs or approximately 9%.

The Flowgate Relief sensitivity decreased the production costs and CO_2 emissions slightly from the High Spin Availability results. It does, however, decrease the wind curtailment from 120 TWhs in the High Spin Availability to 110 TWhs, reducing the overall wind curtailment by 16% when compared to the Scenario 1 Base Case.

The Reduced Wind sensitivity increases both production costs and CO_2 emissions by 5% and reduces the wind curtailment to 64 TWhs. If compared on an absolute value basis to the wind curtailment in the Scenario 1 Base Case, this represents a 51% reduction. Comparing on a percentage basis, because of the reduced wind potential in the sensitivity, this still represents a wind curtailment reduction of approximately 43%.

The relative sizes of the impacts from Flowgate Relief and Reduced Wind cannot be compared because the relative changes that were made are very dissimilar. Although the Flowgate Relief sensitivity increased flows by 50% on the affected elements, only seven transmission elements in three regions were adjusted. In the Reduced Wind case, wind generation in four of the largest wind producing regions in the EI were reduced significantly.

Scenario 3 Sensitivity Results: Natural Gas Price and Load Increases

The final two sensitivities involved increasing load and gas prices in Scenario 3. Increasing gas prices by 25% in all seasons reduced the use of combined cycle plants and increased the use of coal. This resulted in production costs increasing by 10% overall and emissions increasing from 2% to 12%, depending on the emission type. Increasing load by 5% increased the use of combined cycle plants and, to a lesser extent, combustion turbines and coal. This resulted in increased production costs of 9% overall, and increased emissions in the 5-6% range.

Table CR-5. Sensitivity Results –Production Costs, Emissions, Load and Gas Prices

	Production Costs ($2010 Millions)			Change from the Base (%)	
	S3 Base	S3 Hi Gas	S3 Hi Load	S3 Hi Gas	S3 Hi Load
Fuel	$ 85,057	$ 94,326	$ 93,317	11%	10%
Variable O&M	$ 18,411	$ 19,072	$ 19,407	4%	5%
Total	$ 103,469	$ 113,398	$ 112,724	10%	9%
CO2	$ 154	$ 150	$ 178	-3%	16%
Total w/ CO2	$ 103,623	$ 113,548	$ 112,902	10%	9%
	Emissions (short tons)			Change from the Base (%)	
	S3 Base	S3 Hi Gas	S3 Hi Load	S3 Hi Gas	S3 Hi Load
NOx (000)	1,122	1,171	1,184	4%	6%
SO2 (000)	1,771	1,988	1,880	12%	6%
CO2 (millions)	1,792	1,833	1,889	2%	5%

Gas-Electric System Interface Study

In 2013, the PPAs in the EI commissioned a multi-target inquiry into natural gas-electric system interfaces to determine the adequacy and adaptability of the gas delivery infrastructure to supply the needs of gas-fired electric generation across the Study Region. The six PPAs include IESO, ISO-NE, MISO, NYISO, PJM, and TVA. The Study Region consists of the combined footprint of the six PPAs, including MISO-South. The growing reliance on natural gas as a fuel for electricity generation throughout North America has brought the interaction between natural gas infrastructure and the power grid into sharp focus as noted in the initial stages of the EIPC work under the DOE cooperative agreement. The recent and anticipated growth in gas-fired generation is driven by abundant domestic natural gas supplies and a sharp decline in the cost of natural gas relevant to other fuels for electric generation, as well as more stringent environmental regulations that are expected to cause additional generation retirements of coal and oil-fired capacity across the EI. The increase in gas demand for electric generation coupled with the lack of infrastructure expansions to serve gas-fired generators in certain PPAs raises strategic concerns over pipeline and storage companies' ability to keep pace with the coincident requirements of gas utilities serving residential, commercial and industrial (RCI) customers as well as the needs of gas-fired generation plants on peak demand days. In some PPA regions, such concerns persist throughout the heating season as well, November through March.

The purpose of the Target 1 analysis is to describe the natural gas system infrastructure, operations, and commercial services across the Study Region, including the operational arrangements among interstate/interprovincial pipelines, storage facilities, and local distribution company (LDC) systems. The purpose of the Target 2 analysis is to evaluate the adequacy of the interstate gas pipeline network to meet the coincident peak demands of RCI customers and gas-capable generators across the Study Region. The majority of these gas-capable generators do not have firm, or uninterruptible, transportation entitlements for regional pipeline or storage capacity. Hence, central to the Target 2 paradigm is computation of the frequency and duration of pipeline bottlenecks affecting scheduled gas-fired generation under three distinct market scenarios, as well as a broad array of case sensitivities associated with individual changes to primary market or regulatory assumptions. The purpose of the Target 3 analysis is to quantify the consequences of postulated gas or electric-side contingencies under various scenarios for both winter and summer peak day conditions in 2018 and 2023.[8] The purpose of the Target 4 analysis is to assess how the cost of dual-fuel capability compares to the cost of developing incremental firm pipeline transportation capability to meet the scheduling requirements of gas-fired generators across the Study Region, including an assessment of the costs of these options as well as oil replenishment logistics by location across the Study Region.

Target 1 Summary

Summary statistics regarding generating capacity and connectivity to pipelines and LDCs are presented in Table CR-6. If a generator has both an interstate/interprovincial connection and an intrastate/LDC connection, it is counted in the interstate/interprovincial total. Figure CR-11 shows the network complexity of the multitude of interstate pipelines operating in the Study Region.

Table CR-6. Generator Statistics by PPA

PPA	Total Capacity (GW)	Gas-Capable Capacity[9] (GW)	% of Total	Interstate/ Interprovincial-Served Capacity[9] (GW)	Intrastate/LDC-Served Capacity[9] (GW)
PJM	185	80.0	43%	40.3	38.7
MISO	177	69.0	39%	44.6	24.4
NYISO	38	21.0	55%	4.3	16.7
ISO-NE	35	18.6	54%	14.3	4.3
TVA	34	12.2	36%	9.9	2.3
IESO	33	9.9	28%	1.2	8.7
Total	502	210.7	42%	114.6	95.1

[8] For purposes of the Gas-Electric System Interface Study, winter includes the January, February and December while summer includes June, July and August of the specified calendar year.

[9] Includes coal plants that utilize natural gas for start-up.

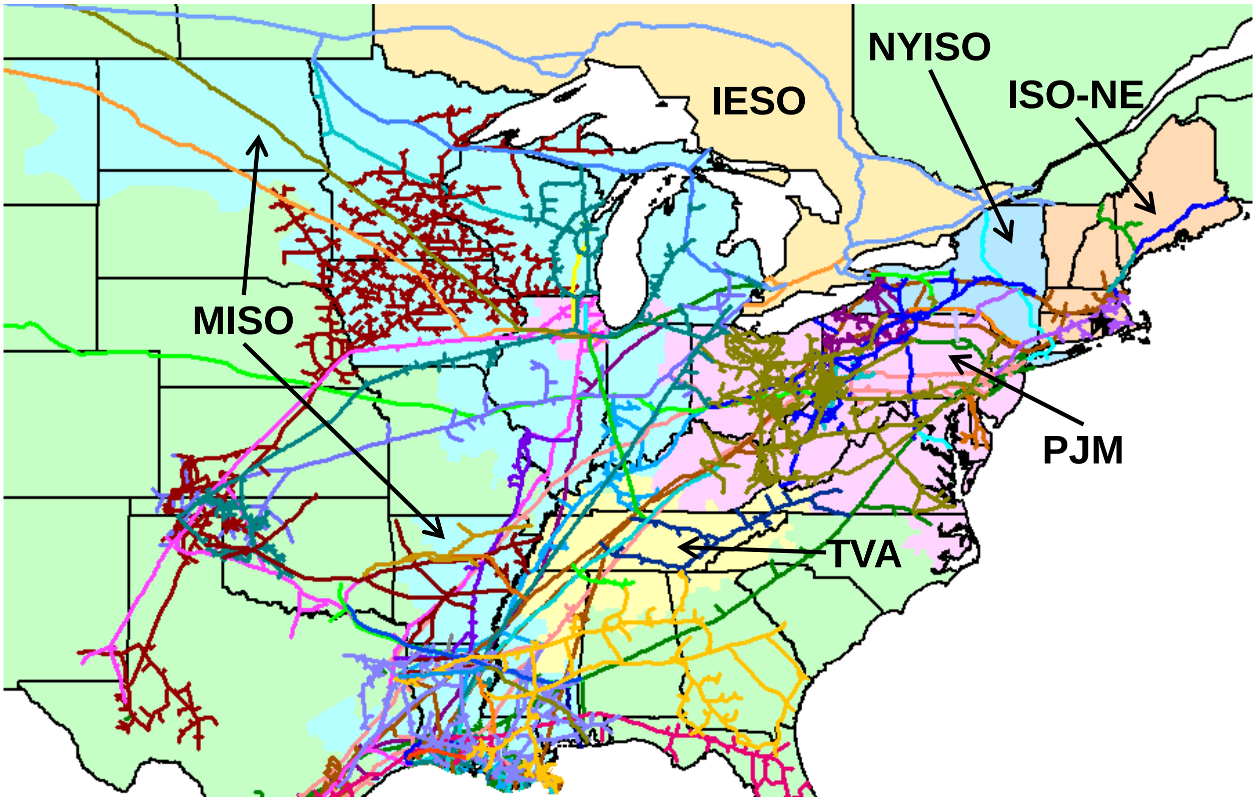


Figure CR-11. Interstate and Interprovincial Pipelines Operating in the Study Region

Interstate/interprovincial pipeline and storage companies offer two basic services: firm transportation and/or storage, and interruptible transportation and/or storage. Across the Study Region, pipeline and storage infrastructure capacity is sized to meet the contractual demand of firm customers during peak demand conditions, with little or no reserve capacity.[10] This is in contrast to the bulk electric system design basis, which ensures grid reliability by including a reserve margin to mitigate the impact of low-probability contingency events. The firm shippers are those entitlement holders who pay the FERC-authorized cost of service rate on a fixed monthly basis over the duration of a long-term contract to guarantee deliverability under all circumstances, except *force majeure*. In contrast, non-firm or interruptible transportation shippers contract for a lower priority service usually payable on a volumetric basis that depends on the availability of capacity. A lower priority service may be scheduled when there is slack deliverability across a pipeline or a pipeline segment, or it may be curtailed or interrupted when a pipeline's throughput is at or near its certificated capability. Because the pipelines are sized to accommodate the peak period needs of firm shippers, which for the most part are the LDCs' obligations to serve RCI customers, many pipelines are fully subscribed. But they are not always fully utilized throughout the heating season or on a summer peak day. Hence, for a generator to contract for firm transportation in its own name, the pipeline would need to expand its delivery capability to accommodate the incremental demand in order to assure no service degradation to other firm customers during periods of peak demand.

[10] Natural gas transportation customers are also referred to as "shippers." These terms are used interchangeably in this report.

Except in Ontario and, to a lesser extent, TVA, one noteworthy trend common across the Study Region is the limited direct participation of gas-fired generators in the primary or secondary market for pipeline capacity entitlements. Target 1 research shows that most gas-fired generators in the Study Region do not possess firm transportation rights from a liquid sourcing point to the plant gate, at least not in their own name. With one noteworthy exception, the majority of gas-fired generation located behind LDC citygates is supplied on a non-firm basis. The exceptions are in Ontario where the majority of gas-fired generators are located at the local level and have firm transportation entitlements for all or the majority of their respective daily fuel requirements, and in TVA where the PPA holds firm transportation entitlements for many of its generators. Elsewhere across the Study Region, a generator's reliance on non-firm transportation arrangements exposes the generator to the risk of not being scheduled, being interrupted, or being otherwise curtailed during cold snaps or outage contingencies. Across most of the Study Region, a generator's reluctance to enter into firm transportation arrangements can be explained by complex and evolving market dynamics, including financial credit constraints required by the pipelines, squeezed profit margins from energy sales, and gas-fired generators' risk aversion under the PPAs' existing wholesale market designs. The limited number of merchant generators holding primary firm transportation entitlements also reflects the absence of an explicit PPA requirement for generators to hold firm transportation rights in MISO, PJM, NYISO, and ISO-NE.

Rather than acquiring firm primary or secondary firm transportation capacity through pipeline contracts and released capacity, generators often obtain their commodity supply, transportation arrangements, and daily scheduling flexibility through transactions with gas marketers or other third-party suppliers. These third parties rely heavily on the robust secondary market to contract for released capacity and then market that capacity to generators.[11] While these transactions between generators and third parties are not centralized or transparent, they are a major source of capacity for generators. Many gas-fired generators also have the ability to burn oil to bridge the fuel supply gap when pipeline or deliverability constraints arise at the local level. On a short-term basis, the gas commodity supply can typically be bundled just-in-time to meet a generator's scheduling requirements in the day-ahead market (DAM) or real-time market (RTM). On a long-term basis, generators can contract for firm supply with marketers that hold firm transportation rights. Some merchant generators across the Study Region do actively participate directly on their own behalf in the secondary market for a portion of their daily fuel requirements, but this is much more the exception than the rule.

Pipelines and LDCs utilize the North American Energy Standards Board's (NAESB) standard nomination, confirmation and scheduling process. The NAESB gas day runs from 9:00 am to 9:00 am Central Clock Time (CCT). By contrast, the electric operating day runs from midnight to midnight, generally according to each time zone. This timing, along with the variation in PPA dispatch posting schedules, results in an operational and planning gap between the gas and electric days, with initial gas nominations generally due before the day-ahead electric market schedules are available. In Order No. 809, FERC approved changing the deadline for Timely Cycle nominations from 11:30 am to 1:00 pm CCT, and added a third intraday cycle with nominations due at 7:00 pm CCT.[12] These changes are designed to improve coordination

[11] Released capacity is recallable, but is used to provide capacity even during winter periods.

[12] Order No. 809 was issued by FERC on April 16, 2015 in Docket No. RM14-2-000.

between the electric and gas operating schedules, and to increase scheduling flexibility for all pipeline shippers. Order No. 809 also requires pipelines to make multi-party firm transportation contracts available if requested by a shipper, which will provide shippers, including gas-fired generators, with greater flexibility and facilitate more efficient use of pipeline capacity.

Table CR-7 provides a qualitative assessment of the gas-electric interface capability by PPA. The color coding is relational, based on the gas-electric interface attributes observed in the six PPAs. Green represents favorable gas-electric interface conditions relative to the other PPAs, that is, the absence of pressing concerns regarding the operational and commercial infrastructure available to generation companies. Yellow represents neutral conditions, that is, conditions not clearly favorable or unfavorable to generation companies. Red represents comparatively unfavorable conditions.

Table CR-7. Qualitative Assessment of Gas – Electric Interface Attributes

	Criterion	IESO	ISO-NE	MISO	NYISO	PJM	TVA
Natural Gas Supply	Gas Supply Portfolio Diversity	Green	Red	Green	Green	Green	Yellow
	Pipeline Connectivity	Yellow	Red	Green	Green	Green	Yellow
	Conventional Storage Deliverability	Green	Red	Green	Yellow	Green	Yellow
	LNG Storage Capability	Yellow	Green	Yellow	Yellow	Yellow	Yellow
Electric-Gas Interface	Firm Transportation Entitlements	Green	Red	Yellow	Yellow	Yellow	Green
	Direct Pipeline Connectivity	Green	Green	Green	Yellow	Green	Green
Electric/Gas Tariff	Pipeline or LDC Penalties	Green	Red	Red	Red	Red	Red
	LDC Provision of Flexible Service	Green	Yellow	Yellow	Green	Green	Yellow
	Active Secondary Market	Red	Green	Green	Green	Green	Yellow

In terms of portfolio diversity and pipeline connectivity, PJM, MISO and NYISO are benefited by improved access to new sources of gas supply from shale formations, while substantial existing pipeline and storage infrastructure supports flow from conventional producing basins in the Gulf of Mexico, Rocky Mountains, and western Canada. A building boom from Marcellus into downstate New York has improved gas supply diversity into PJM and NYISO. New England; with access to supply sources in eastern Canada, western Canada, liquefied natural gas (LNG) imports, Marcellus gas, and the Gulf Coast; ostensibly has adequate supply portfolio diversity. However, declining production from eastern Canada, the cost disadvantages associated with long-haul transportation from western Canada, and the potential for high prices for LNG in global markets limit the level of portfolio diversity in New England relative to the other PPAs. Flow reversals on the major pipelines serving TVA will increase supply diversity by moving more Marcellus gas north-to-south. Supply diversity into Ontario has improved with the onset of new transportation services on the TransCanada pipeline and the reversal-of-flow on pipelines in New York, thereby providing much improved access to Marcellus. MISO benefits from the well-developed pipeline and storage infrastructure that provides access to diverse supply sources across North America. There are significant conventional and, to a lesser extent, high deliverability storage resources in PJM and MISO. In contrast to conventional storage resources, high deliverability facilities are capable of multiple injection and withdrawal cycles each year. Ontario's storage infrastructure is also favorable to LDC and gas-fired generator operations with large storage facilities and access around the Dawn storage hub in southern Ontario. Storage connectivity levels for TVA are also favorable, with good access to the storage facilities along the Gulf Coast. Absent conventional storage resources in New England, there is significant LNG import terminal capacity around Boston and New Brunswick, as well as satellite storage capacity earmarked exclusively for LDC use.

As previously noted, gas-fired generators predominantly rely on non-firm transportation arrangements, except in TVA and Ontario. In ISO-NE, interruptible service is increasingly unavailable on Algonquin and Tennessee gas pipelines, the primary pathways into New England, due to congestion patterns emanating from Marcellus. While primary and secondary firm pipeline services are available to generators in PJM, NYISO, MISO and ISO-NE, the cost associated with this service coupled with the availability of firm and non-firm services from gas marketers at the plant gate has resulted in generation companies' general reliance on gas marketers for an aggregated delivery service. The majority of new combined-cycle plants and peakers are directly connected to interstate pipelines, thereby exploiting higher delivery pressures to supplement heat rate efficiency, while avoiding local transportation costs. Again, Ontario is the exception where the majority of new generation facilities are located behind citygates throughout the province. New generation on the New York Facilities System depends on local service from either Consolidated Edison Co. of New York (Con Edison) or National Grid (NGrid). While the provision of such service is non-firm, LDC tariffs and New York State Reliability Council (NYSRC) Reliability Rules require generators on the New York Facilities System to have backup fuel capability throughout the year.

Both pipelines and LDCs have provisions memorialized in their respective tariffs to safeguard against scheduling conduct that degrades service to firm customers. Pipeline and LDC tariffs typically require shippers to schedule and take gas ratably, that is, approximately 1/24th of their daily quantity each hour, while generator hourly gas demand profiles often call for non-ratable gas deliveries to meet early morning and late afternoon ramping requirements. A pipeline or LDC may allow a gas-fired generator to exceed these limits if it does not interfere with the provision of service to other firm customers.[13] Pipelines and LDCs can, however, assess significant and punitive penalties during extreme operating conditions when Critical Notices, particularly Operational Flow Orders, are in effect, and a shipper's non-ratable takes or unauthorized overpulls threaten to harm pipeline operational integrity. A broad array of tariff

[13] Generators are more likely to have this operational flexibility during the non-heating season, when slack pipeline deliverability conditions are much more likely to occur. In light of heightened pressure on gas-fired generators to obtain natural gas on a timely basis in accord with the PPAs' scheduling requirements in the DAM and RTM, some pipelines in the Study Region have implemented greater scheduling flexibility in the form of specific additional nomination cycles, or hourly scheduling flexibility, allowing the shipper to consume gas during an 8 to 12-hour period rather than a 24-hour period to coincide with electric usage.

provisions oriented around generation service are offered by LDCs in PJM and NYISO. Because generation companies in Ontario have firm transportation rights, operational issues pertaining to daily imbalances and non-ratable takes are rarely problematic. Moreover, LDC tariff provisions in Ontario afford generation companies substantially similar rights and privileges as other firm customers. The secondary market in Ontario, however, appears moribund in relation to trading activity elsewhere in the Study Region.

Target 2 Summary

The Target 2 analysis identified the quantities of "affected generation" across the Study Region. Affected generation is the MWh of scheduled gas-fired generation that could not be served on the peak hour of the seasonal peak days in 2018 and 2023 as a result of pipeline congestion. Three gas demand scenarios were evaluated – the Reference Gas Demand Scenario (RGDS), the High Gas Demand Scenario (HGDS), and the Low Gas Demand Scenario (LGDS). In addition, a range of sensitivity cases were defined by the PPAs, the SSC and regional stakeholder groups to explain the relative importance of key variables tested in the three gas demand scenarios. Affected generation was quantified by pipeline segment across the Study Region. The frequency and duration of pipeline constraints was also analyzed on the peak hour of each day during the three summer and three winter months in order to delineate the amount of gas-fired generation that could be served by location across the Study Region after all RCI load has been satisfied. To analyze the coincident peak demands of LDCs serving firm RCI customers, as well as gas-capable electric generators across the Study Region, and to identify the affected generation, a six-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 for each scenario.

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. Quantify the frequency and duration of pipeline constraints during the peak hour of each day during the three winter and summer months for each year.

5. Identify the gas transportation constraints causing the unserved peak hour demand.

6. Identify potential mitigation measures to reduce or eliminate transportation constraints affecting generation.

Figure CR-12 shows the proportion of served and affected generation in each PPA for the Reference, High and Low scenarios during the winter 2018 peak hour, based on average seasonal gas prices. The identification of affected generation in a given location does not indicate that electric system reliability in that location is in jeopardy. Redispatching the system utilizing dual-fuel resources and other mitigation measures ascribable to non-gas fired resources are available to electric system operators but were not explicitly analyzed as part of the study objectives. The "adequate" and "constrained" characterizations are used to describe the ability of the gas pipeline network to meet electric generator gas demand under the scheduled dispatch regime revealed in the electric simulation model. Importantly, characterizations of pipeline infrastructure adequacy do not reflect the pipelines' ability to serve firm customers, as that is a given under the study paradigm.

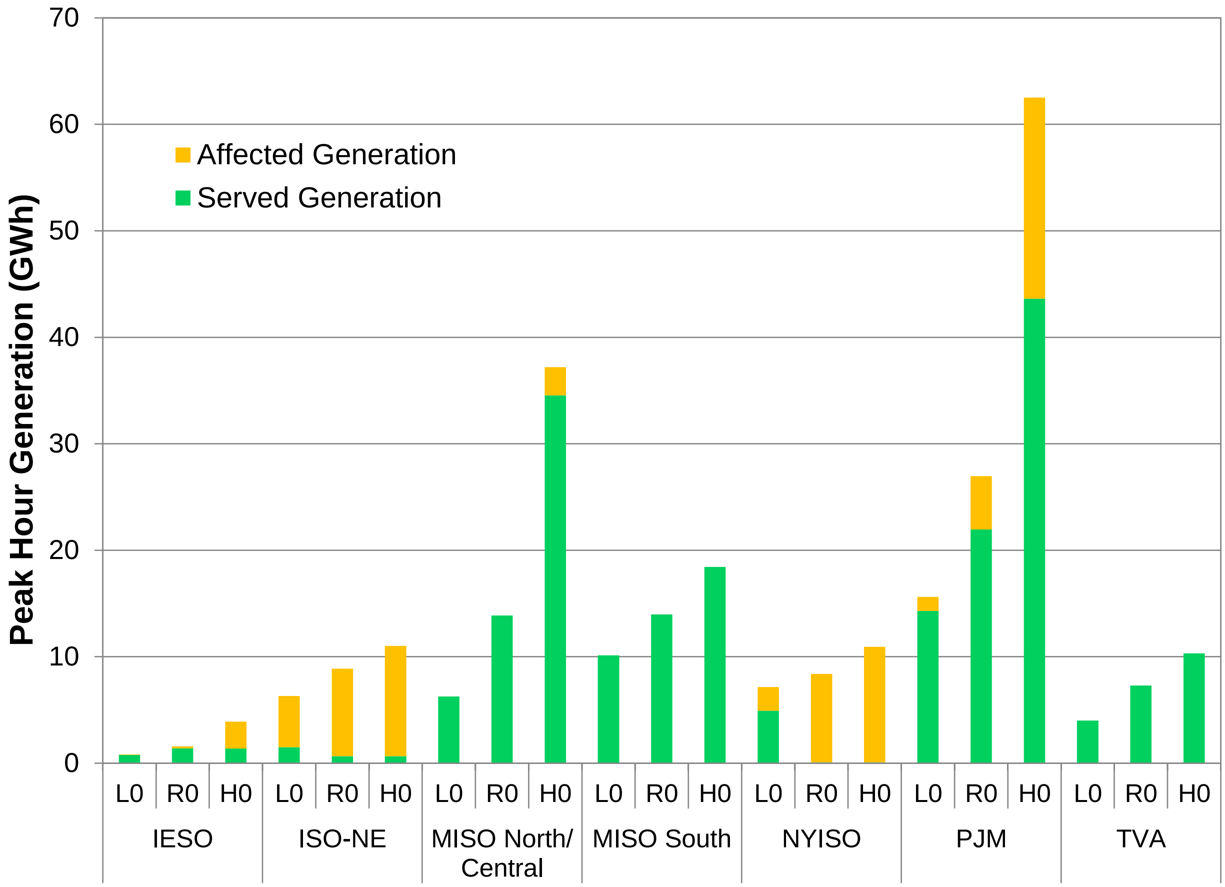


Figure CR-12. Summary of Affected Generation (Winter 2018)

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. The only significant risk factor affecting the scheduling of gas-fired generation in any of the sensitivities pertains to nuclear availability as a result of the possible retirement or delayed restart of selected units. 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 100% utilization of the TransCanada mainline in western Ontario and of withdrawal capacity from Union's Dawn storage facility 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 back to a liquid sourcing point, 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. In each of the three gas demand scenarios, limiting receipts at the LNG import facilities in New Brunswick and Massachusetts increase 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; comparatively moderate and small pipeline expansions, respectively; have been incorporated in the scenarios due to the development status of the projects at the time analysis 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. The primary risk factor affecting MISO North/Central is heightened attrition of coal-fired capacity due to environmental regulations. Coupled with low gas prices and high load, the resultant increased reliance on gas-fired resources across the PPA causes certain of the pipelines serving MISO North/Central to be 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 of 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 EI. 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 New York 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 is in Eastern MAAC, Southwest MAAC and Virginia and located behind LDCs. Therefore delivery is constrained during the peak heating season. Like generators in ISO-NE, NYISO, and MISO, the majority of generators in PJM do not hold firm transportation entitlements. 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, although several significant pipeline expansion projects have been announced since the analysis inputs were set that may help alleviate some of these constraints. 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. Uncertainties surrounding the continued operation of selected PJM nuclear plants may result in transportation constraints as gas-fired generation supplants lost nuclear energy production. 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 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.

Table CR-8 summarizes the risk factors and market dynamics affecting gas infrastructure adequacy in each of the six PPAs during winter 2018.

Table CR-8. Risk Factors and Market Dynamics Affecting Gas Infrastructure Adequacy (Winter 2018)

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

Target 3 Summary

In the Target 3 analysis, the PPAs and Levitan & Associates, Inc. (LAI) formulated gas- and electric-side contingencies in order to gauge the resiliency of the pipeline system in each PPA region to continue to provide gas service to scheduled generation following a postulated contingency event. Gas-side contingencies included mainline ruptures, the loss of strategically located compression stations, or the loss of major storage deliverability. Electric-side contingencies included outages of large non-gas generators or the loss of large transmission lines. The contingency events were postulated to occur on a winter peak day and a summer peak day in 2018 or 2023. The modeled peak days for the RGDS cover 2018 and 2023, but only 2018 peak days were assessed for the HGDS.

Steady state and transient hydraulic simulation analyses were performed in order to test the resiliency of the consolidated network of gas pipeline and storage facilities when gas or electric equipment failures are postulated in the vicinity of gas-fired generators in each PPA region. Target 3 results identify gas-fired plants that might trip off line due to declining gas pressure at the plant gate, and the time interval between the commencement of the event and the resultant loss of gas supply to the generation plant. This time interval is referred to as the "time-to-trip." A delivery pressure of 485 psig was applied across the Study Region as the threshold below which gas-fired generators cannot continue to operate at full power output. Emphasis is placed on the physical capability of the consolidated network of pipeline and storage infrastructure across the Study Region to maintain service to RCI and gas-fired generation customers following the postulated gas-side contingency. Hence, a pipeline's contractual obligations are not explicitly recognized in the study approach. In accordance with their tariffs, pipelines would limit deliveries to non-firm customers following occurrence of a contingency event if necessary to preserve their ability to meet contractual firm customer demands.

In order to determine the probable outer bound of how long service to an affected gas-fired generator could potentially be maintained following a specific contingency, a physical analysis was conducted that did not differentiate between the character of service of RCI and generation customers. This approach examines (i) post-contingency pressures and flows in the event that system conditions do not require pipelines to limit generator deliveries in order to protect service to RCI customers; (ii) potential service duration to gas-fired generators in the event that they are relying on firm transportation either through third-party arrangements or an entitlement held in their own name; and (iii) how much time a PPA may have to redispatch other generators, both gas fired and non-gas fired, to replace affected gas-fired generation. The results of the study support the PPAs' awareness of the adaptability and resiliency of the consolidated network of pipeline infrastructure after a contingency, and allow PPAs and generators to assess the risks of interruption from contingencies even if firm service were purchased and gas-fired generation were treated on par with RCI load for purpose of curtailment.

The amount of generation that may not be able to be dispatched on natural gas due to pipeline and/or LDC infrastructure constraints following the postulated event is referred to as affected generation. This is consistent with the definition of affected generation in the Target 2 effort. Insofar as affected generation is not tantamount to unserved electric energy, it is important to note that additional non-gas fueled resources or other gas generation in non-constrained locations may be dispatched or ramped up to replace the energy from the affected gas fired units. The hydraulic models do not incorporate all of the individual pipeline operators' remedial actions following the contingency, as such remedial actions are unique to each pipeline. Moreover, a pipeline's contractual obligations, and its scheduling and curtailment priorities based on the firmness of transportation service, are not explicitly modeled in the hydraulic analysis. Since the multitude of the pipelines' contractual obligations are not embedded in the model, the study's conclusions may differ from how a pipeline would need to act, pursuant to its tariff, in an actual contingency event. The PPAs may consider the results of this analysis, as appropriate, in their respective reliability analyses. Lacking access to pipeline and LDC operational data in Ontario, the deliverability assessments in IESO were performed by the pipeline company and the LDCs based on input from LAI.

In the pre-contingency baseline for the 2018 winter peak day, generator gas demands are undeliverable at several plants in ISO-NE, MISO, NYISO and PJM, as shown in Figure CR-13. In ISO-NE, NYISO and PJM, these undeliverable volumes are due to (i) prioritization of RCI customer deliveries and (ii) delivery pressures below 485 psig to affected generators. In MISO, the undeliverable volumes are due to delivery pressures below 485 psig to affected generators served by Northern Natural. In the pre-contingency baseline for the 2018 summer peak day, MISO and NYISO have less undeliverable generation than on the winter peak day, although low pressures continue to limit gas deliveries to some plants. ISO-NE has more undeliverable generation than on the winter peak day due to delivery pressures below 485 psig on Algonquin in southeastern Massachusetts. PJM has more undeliverable generation than on the winter peak day due to greater total deliveries on Eastern Shore and Texas Eastern's Philadelphia Lateral that result in delivery pressures below 485-psig to affected plants.

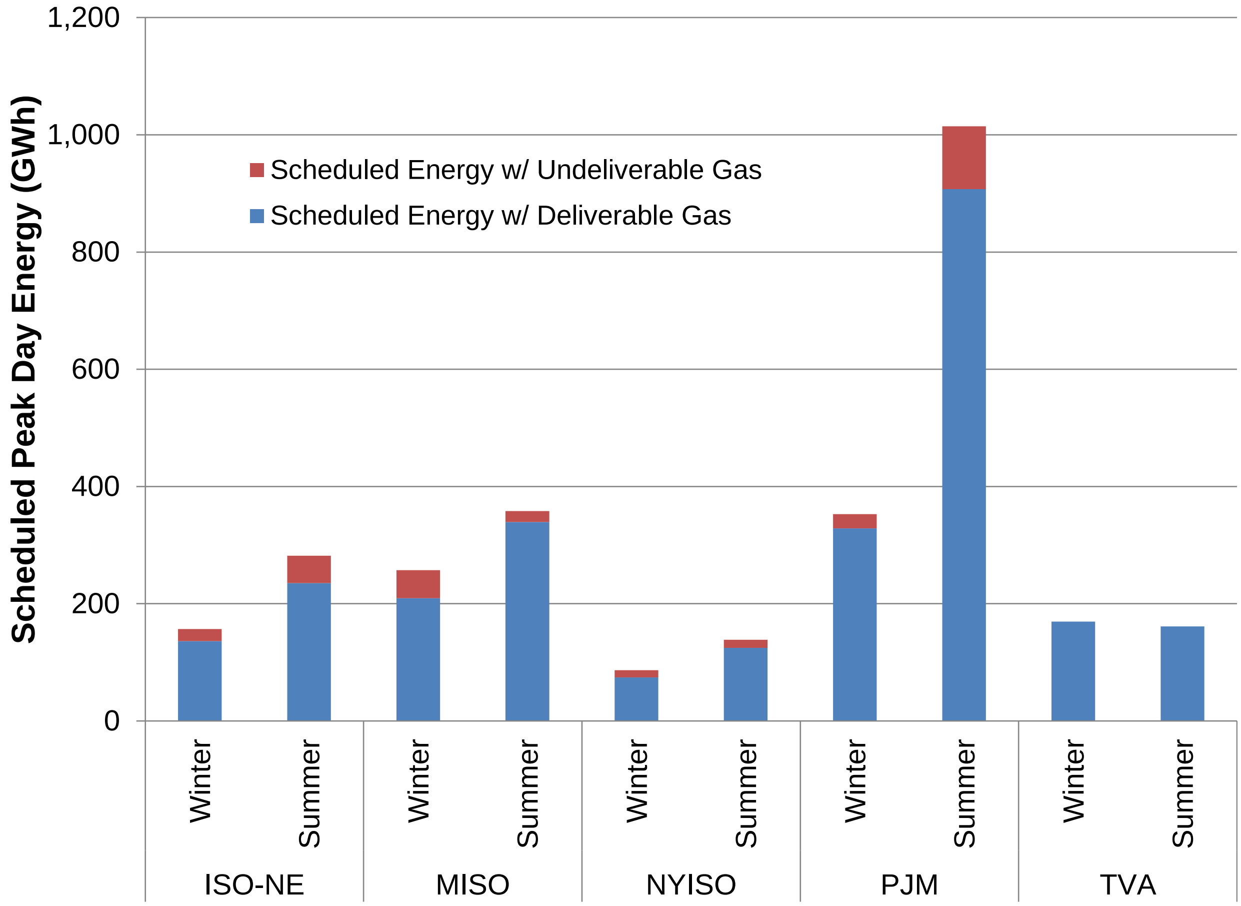


Figure CR-13. Baseline Energy Deliverability (2018 Reference Scenario)

With respect to the gas-side contingencies tested, the most resilient and adaptable segments of the consolidated gas network across the Study Region are located in MISO North/Central, the rest of RTO area of PJM, TVA, and IESO. The pipeline system in MISO South appears to be highly resilient and adaptable, but was not hydraulically tested due to the quantity of pipe, access to storage, and the highly interconnected and expansive pipeline infrastructure network configuration of regional infrastructure emanating from the Gulf of Mexico and East Texas. Across the Study Region, the consolidated network of pipeline infrastructure is highly resilient in response to postulated gas-side contingencies during the summer when RCI demand is low, thus resulting in negligible affected generation, except for line break contingencies which limit or eliminate deliveries to downstream generators and cannot be mitigated. Figure CR-14 presents a summary of the winter 2018 RGDS gas contingency results, showing which types of events are most impactful in each of the PPAs.

PPA	Type	# Tested	Shortest Time to Trip (h:m:s)
ISO-NE	Compression	3	3:52:47
	Line Break	3	0:11:03
	Supply	2	0:00:00
MISO	Compression	3	9:17:42
	Line Break	3	18:53:42
NYISO	Compression	3	12:22:51
	Line Break	3	0:54:20
PJM	Compression	1	None
	Line Break	6	0:03:00
	Storage	1	None
TVA	Compression	3	None
	Line Break	3	4:21:49

* Scheduled energy with undeliverable gas

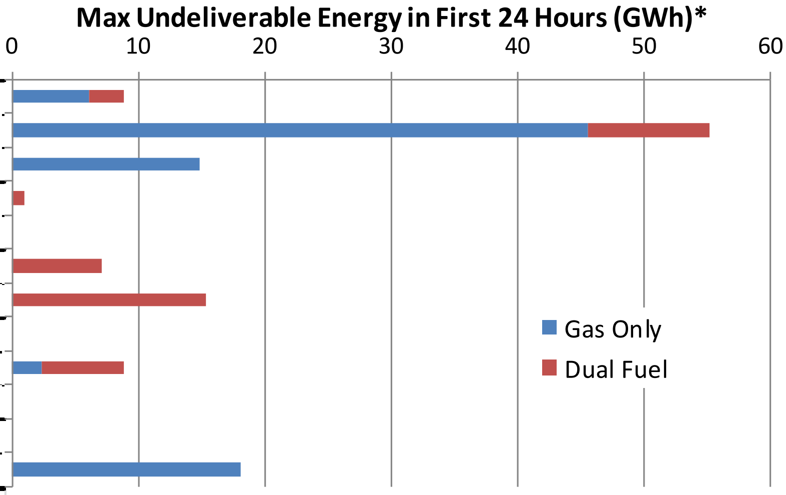
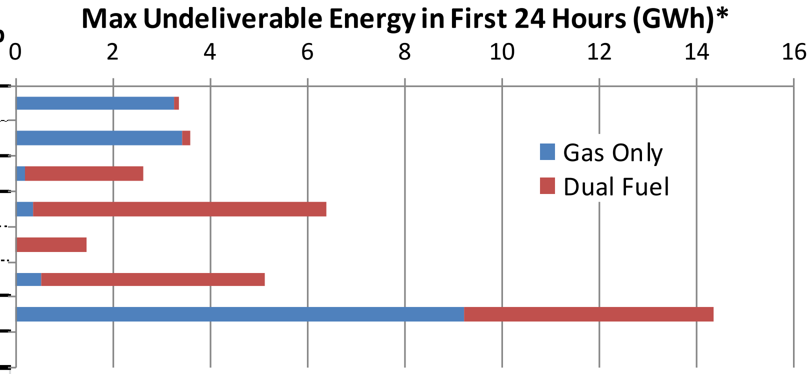


Figure CR-14. Summary of Gas Contingency Results (Reference Gas Demand Scenario, Winter 2018)

During the winter, the less resilient and less adaptable segments of the gas pipeline network, which are less able to sustain gas-fired generation, are found in the MAAC area of PJM (both SWMAAC and EMAAC), the Lower Hudson Valley and Capital District zones in NYISO, and ISO-NE. The most severe gas-side impacts, measured in terms of time-to-trip intervals and total affected generation, happen in ISO-NE, reflecting the region's critical dependence on west-to-east flows on Algonquin and Tennessee and the assumed limitations on use of LNG. While PJM and NYISO also experience affected generation following gas-side contingencies, generators are spread across more pipelines, and individual contingencies are therefore less impactful than in ISO-NE. Moreover, much of the affected generation in the MAAC area of PJM and in NYISO that is potentially impacted by the postulated gas-side contingencies is dual-fuel capable, whereas the majority of affected generation in ISO-NE lacks dual-fuel capability.

In terms of the array of PPA-specific electric-side contingencies tested, the gas constraints varied significantly by PPA. None of the ISO-NE or MISO contingencies resulted in the diminution of gas pressure below the threshold for gas-fired generators. However, there was some incremental undeliverable gas for energy at plants that could not be scheduled to burn gas in the baseline. Generation contingencies in NYISO and PJM resulted in delivery pressures dropping below the threshold for generator operation, although the time before the first plants trip offline is likely sufficient for control room operators to take remedial action. Nearly all of the affected generation in NYISO is at plants with dual-fuel capability. No constraints were observed for the TVA and IESO contingencies. Figure CR-15 presents a summary of the winter 2018 RGDS electric contingency results, showing which types of events are most impactful in each of the PPAs.

PPA	Type	# Tested	Shortest Time to Trip (h:m:s)
ISO-NE	Generation	3	None
	Transmission	2	None
MISO	Generation	8	None
NYISO	Generation	3	10:48:17
	Transmission	2	None
	Gen + Trans	1	10:50:37
PJM	Generation	3	2:45:10
TVA	Generation	5	None



* Scheduled energy with undeliverable gas

Figure CR-15. Summary of Electric Contingency Results (Reference Gas Demand Scenario, Winter 2018)

<u>Target 4 Summary</u>

Target 4 research identified the dual-fuel capable generators in the Study Region, the on-site storage capacities for back-up fuel at these facilities, and the resupply modes employed to replenish back-up fuel supplies. The operating issues and costs for developing dual-fuel capability at new simple cycle (SC) and combined cycle (CC) generating units were examined, along with the operational considerations involved with switching from natural gas to ultra-low sulfur diesel (ULSD) fuel. Dual-fuel capable units have utilized a range of distillate fuel oils as back-up fuel, including #2 fuel oil, ULSD, kerosene, and ultra-low sulfur kerosene. Going forward, new gas-fired plants are expected to utilize ULSD as the primary back-up fuel. The anticipated heavy reliance on ULSD constitutes a major change in the distillate oil market, resulting in a conversion of the majority of the transportation fleet, distribution systems, and storage facilities from higher sulfur distillate fuel oils to ULSD. Consequently, the ULSD supply chain is capable of meeting dual-fuel generators' back-up fuels needs. Importantly, improvements in the liquidity and availability of ULSD have little or no bearing on the availability and deliverability on short notice of residual fuel oil ("RFO" or "#6 FO") for the old-style steam turbine generators in many parts of the Study Region, in particular, ISO-NE, downstate New York and the MAAC portion of PJM.

A total of 561 dual-fuel capable units were identified in the Study Region, including dual-fuel steam units usually burning RFO as the alternate to natural gas, as well as existing SC and CC units that typically burn distillate fuel oil as back-up. Data regarding on-site fuel storage and resupply modes were developed for 48 representative plants across the Study Region, using publicly available sources such as air permits and regulatory filings. The plants in the database have a wide range of on-site storage capacities with the average for on-site distillate fuel oil storage equivalent to 96 hours at full load operation.

The ability to utilize back-up fuel for each plant is determined by the conditions of air permits and local zoning approvals that govern the delivery, on-site storage and combustion of back-up fuel. Permits for new dual-fuel plants typically limit the number of hours that a plant can operate on back-up fuel in any 365-day period, since operation on ULSD has higher nitrogen oxides

(NO_x), carbon dioxide (CO_2) and particulate matter (PM) emissions than on natural gas.[14] The most common limit is 720 hours, but some recent permits have established lower annual hourly limits. Converting an existing gas-only plant to dual-fuel capability will require an air permit modification. If the use of ULSD will cause a significant net increase in NO_x and PM emissions, the permit modification may require that existing pollution controls be upgraded. In addition, retrofitting a gas-only plant to burn ULSD may require local zoning authorizations to allow construction of on-site storage tanks and to allow changes in local traffic patterns to accommodate increased truck traffic. Additional costs will be incurred in order to upgrade pollution controls, add storage tanks and back-up fuel handling equipment, modify fuel combustors, and upgrade plant control systems. The cost to retrofit an existing gas-only plant to burn back-up fuel is usually higher than the cost to incorporate dual-fuel capability in new construction.

To analyze comparative costs for dual-fuel plants, SC and CC configurations and equipment were identified that are representative of recently constructed and planned dual-fueled plants across the Study Region. Performance and operating characteristics of the tested combustion turbine (CT) models were obtained from the manufacturers. Cost estimates were obtained from CT manufacturers, recent Cost of New Entry (CONE) studies, and Federal Energy Regulatory Commission (FERC) filings, and the cost model provides for locational variations. Dual-fuel capable SC and CC plants also incur higher fixed O&M costs for maintaining additional equipment, incremental property taxes and insurance, periodic liquid fuel tests, and carrying costs of back-up fuel inventory.

Equipment vendors of heavy-frame dual-fuel CTs claim that their units can switch between fuels "on-the-fly," or while operating at up to 80% to 85% of full load. The transfer can take place in under a minute provided that liquid fuel is available and recirculating at the required pressure and temperature. Initiation of recirculation can take several minutes and requires operator intervention. Vendors of some aeroderivative CTs claim that fuel switching can be achieved at full load if liquid fuel recirculation is in operation, but the switch itself requires operator intervention. Plant owners generally prefer to switch fuel at less than the maximum load to reduce the risk of spikes in NO_x or PM emissions. The switchover to liquid fuel may result in the loss of operating flexibility in light of generators' preference to operate at a uniform output level on oil to reduce the risk of emissions excursions.

A set of location-specific cost comparisons between dual-fuel capability and firm transportation service as a means of achieving fuel assurance was undertaken. For each of 27 locations selected across the Study Region, inputs to the dual-fuel cost model such as a labor cost factor, tax rates, and permit restrictions were identified. Particular attention was paid to those characteristics which would affect the liquid fuel inventory level and storage tank size, such as location of a source of liquid fuel and delivery logistics. For each location, a net cost of firm transportation for natural gas was established, based on the reservation cost for incremental capacity on the most likely pipeline path from a source (such as Marcellus) to the location. Adjustments were made for locations likely to be served by an LDC. Firm transportation rates were then netted

[14] Because sulfur-containing compounds; e.g., mercaptan, are added as a safety odorizer to natural gas, switching to ULSD actually decreases SO_2 emissions.

against the avoided cost of non-firm transportation over the same path adjusted for pipeline limitations during the peak heating season observed in the Target 2 analysis.

All costs were ultimately expressed as an annual levelized cost per kW over a 20-year time frame beginning in 2018 for comparison sake. Levelized annual cost per kW of installed capacity was chosen because it allows for a relative comparison of fuel assurance cost among plants of different capacities and heat rates.

At most of the PPA-selected locations, dual-fuel capability has a much lower cost for a new combined cycle plant than firm transportation, as shown in Figure CR-16. For simple cycle plants, the difference is even more pronounced, as shown in Figure CR-17. The cost of dual-fuel capability is generally similar across the range of locations, with the most significant variations arising from the inventory levels and tank volumes for locations with barge delivery, relative to those locations that can be replenished via truck. Firm transportation for the New England locations tends to be very expensive because of constraints on pipeline capacity serving the region. Notably, whether or not a seasonal LNG service leveraged from the existing Suez Distrigas and/or Repsol Canaport LNG import facilities is a good substitute for oil-based dual-fuel capability was not tested in Target 4. Locations in MISO, TVA, and some in PJM show relatively low cost for firm transportation, since recent expansion capacity has been constructed at the system rate, or in some instances, where existing capacity may not be fully subscribed due to decontracting.

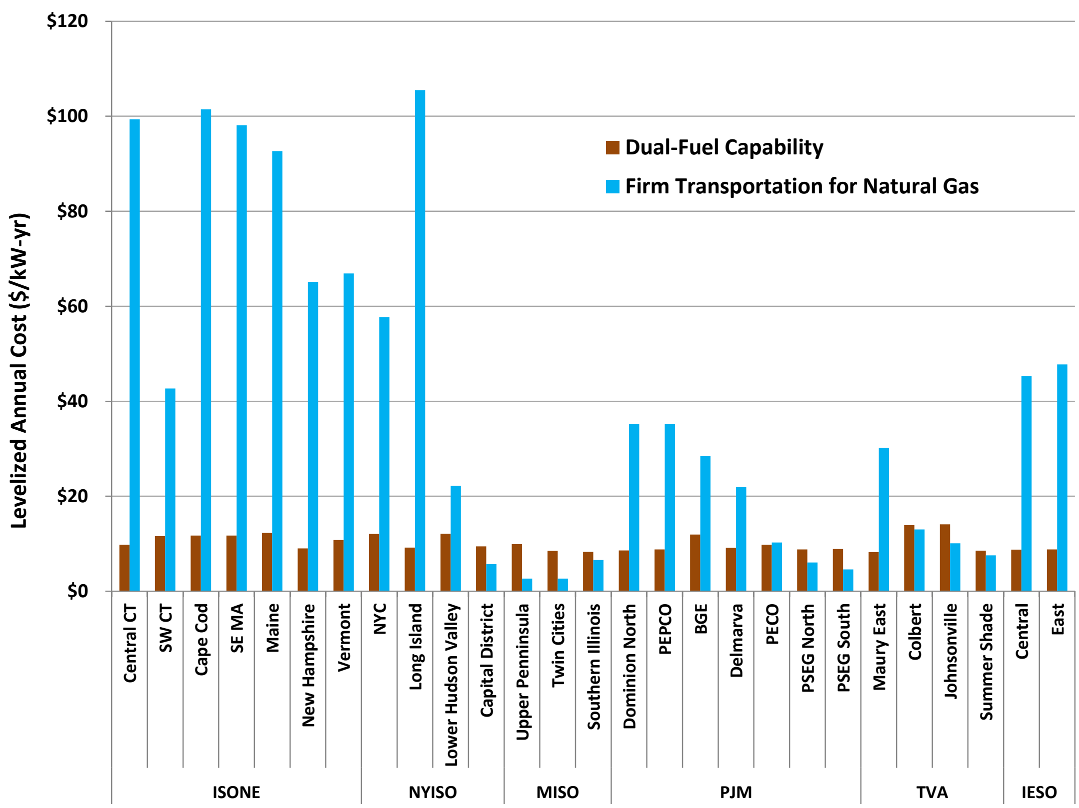


Figure CR-16. Levelized Annual Cost Comparison for Combined Cycle Plant

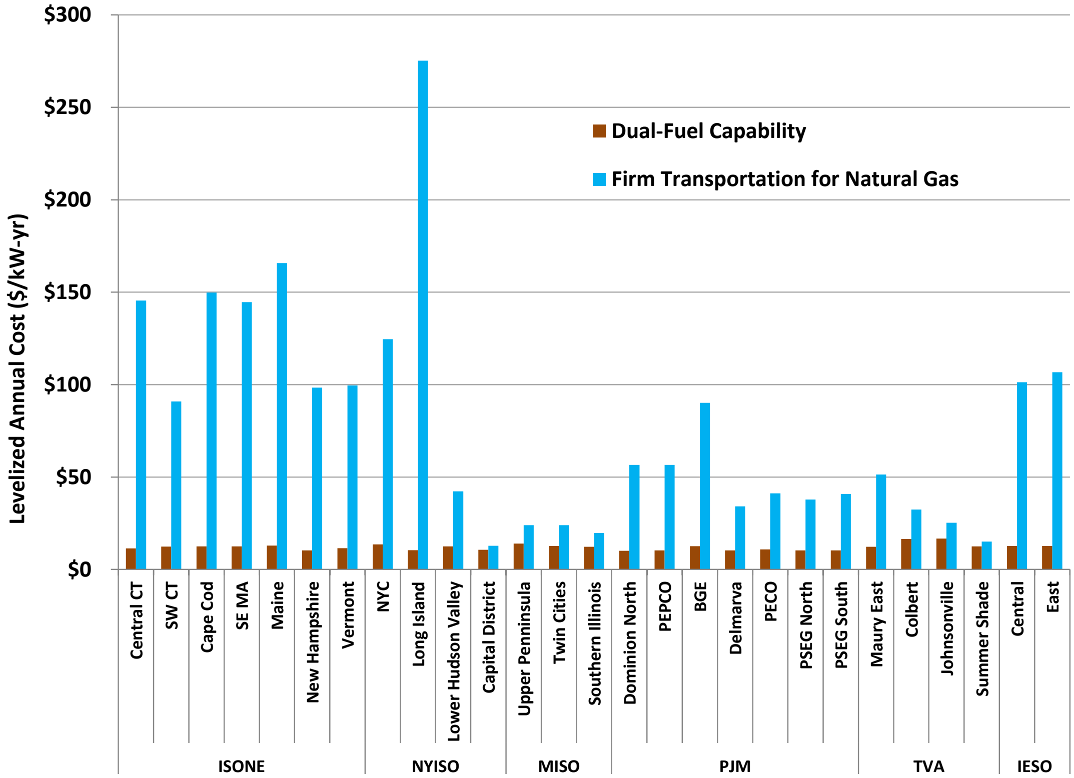


Figure CR-17. Levelized Annual Cost Comparison for Simple Cycle Plant

With few exceptions, dual-fuel capability appears to be much less costly with respect to reducing the direct cost as a strategy to achieve fuel assurance. The primary reasons supporting these results are five-fold: (i) existing pipelines in constrained locations are typically fully subscribed, thereby requiring a pipeline to add expensive new facilities to serve a gas-fired generation plant; (ii) generators behind LDC gate stations would be expected to bear the high cost of local facility improvements to ensure year-round service in addition to mainline improvements from the producing basin to the local system; (iii) the avoided cost of non-firm transportation is not sufficiently high in most constrained locations to significantly reduce the net cost of incremental firm transportation service; (iv) the capital charges, inventory carrying charges and incremental fixed O&M associated with dual-fuel capability are comparatively low; and (v) structural change in the distillate oil market has and will continue to improve the logistics of ULSD replenishment during cold snaps or outage contingencies.

Despite the ostensible economic superiority of the dual-fuel capable solution to the challenge of maintaining fuel assurance for electric reliability, there may be other commercial reasons that otherwise induce generators to invest in firm transportation.

Observations and Guidance

Phase 1 and Analysis of Three Scenarios in Phase 2

Following the completion of Phase 1 of the project, some initial observations were drawn by stakeholders as follows:

- This project represents a unique dialogue with many different stakeholder groups on public policy and interconnection-wide transmission analyses to increase understanding of alternative policy futures and the generation and transmission that might be needed to support them. It does not require one size fits all projects or solutions, nor does it make any conclusions regarding market driven versus vertically integrated utility models. It does, however, show potential ways to accommodate differing stakeholder-chosen policy futures. The EIPC analysis will continue to be a valuable contributor to both the utility and the regulatory functions in their efforts to efficiently advance the electricity industry.
- Although previous experience of the participants has been in transmission planning exercises that are generally more limited in geographic scope and involving fewer participants than the analyses conducted by EIPC, the Topic A project work involving a larger team over the full EI proceeded well.
- The interaction between PAs and state participants also developed a communication capability that will serve the nation well in the future.
- It is expected that the participants will use the experience for continuing and enhancing future coordination efforts and that all of these efforts will help guide the U.S. in considering and establishing potential national goals for energy.

The Phase 2 analyses of three transmission buildout scenarios continued the open and productive dialogue between the EIPC, states and stakeholders. Because of the nature of this work, the discussions were focused on traditional transmission planning and production cost analysis and were somewhat more technical in nature.

General Observations from Analysis of Three Scenarios in Phase 2 include:

- The goal of the DOE's Funding Opportunity Announcement, "to prepare analyses of transmission requirements under a broad range of alternative futures…" has been met. The project is not intended to supplant existing regional planning processes.
- The project was very helpful in understanding the complexity of interconnection-wide transmission planning.
- The futures developed represent significantly different policy drivers and the project has provided a great deal of information on these three scenarios.
- The results of Phase 2 serve as indicative transmission build-outs that present options that could be considered as part of a more traditional planning process that involves analyzing more model years, considering all NERC mandatory compliance criteria and evaluating the economic benefits of specific transmission projects or groups of projects as resource plans become more certain.

- Transmission reinforcements presented in this report are not an absolute indication of the required transmission reinforcements since the scope of this project was limited to evaluate specified alternatives and considered only higher voltage level additions and constraints and did not consider all mandatory NERC planning requirements. In addition, necessary simplifying assumptions used for this analysis regarding the choices of how transmission facilities are configured, the impact of fuel supply variations on resource availability, and other factors would be taken into account in the final determination of required transmission reinforcements.
- Much more detailed analysis, iteration and optimization than was possible in the project would be needed to develop actual detailed transmission plans.

In the last quarter of 2012, The Keystone Center, the facilitator of the EIPC stakeholder process, conducted a number of interviews with various members of the stakeholder process and EIPC PAs to gather input about whether these goals were met.

Stakeholders found the overall process to be extremely worthwhile, and they are pleased to have participated. Stakeholders across the board agreed that the EIPC process had great value and elements of EIPC should continue in the future. Stakeholders in general developed more trust of the PAs' process and over time relied more heavily on their input and judgment. Stakeholders particularly saw value in:

- The openness, inclusiveness and transparency of the process.
- The opportunity to learn more about transmission planning and have input into the process.
- The structure and balance of the SSC.
- The independence of the Chair, Vice-Chair and facilitators.
- The willingness and ability of the chairs to develop straw proposals when the group faced difficult or contentious issues.
- The relationships and understanding that developed over time.
- The working groups' ability to delve into the details and make recommendations to the SSC.
- The access to data and information on the web site.
- The DOE requirement to come to consensus; at first, stakeholders were concerned about this requirement but believed it ultimately led to a better understanding of others' positions and more creative ideas to achieve consensus.

Stakeholders also identified the following challenges/opportunities:

- Understanding the transmission planning process and the models used.
- The inability to iterate the analysis more frequently; i.e., to review the results from a smaller set of analysis before determining next steps.
- More time was needed to consider the results of the analyses and the voluminous data generated.
- The stakeholder balance designed into the SSC structure did not always materialize in the process.

In addition to process Observations and Guidance, there were also Observations and Guidance on the analytical process undertaken. These are listed below:

- The transmission option analysis presented here represents a single snapshot in time for each of three very different scenarios. It focuses on a snapshot of a specific year – 2030. Traditional transmission planning analyzes interim years typically utilizing models for one, five, and ten years out rather than "jumping" out twenty years. The results of this transmission analysis might be very different if it were done in a more incremental fashion. Future studies may wish to look at smaller time intervals – e.g., 5, 10 and 15 years.

- The interrelationships of various energy related infrastructures may need to be considered further to better understand how these relationships might impact the broad range of alternative futures. One example is the relationship between the natural gas supply and delivery infrastructure and the electric transmission system highlighted in Phase 1 of the project. This relationship was subsequently analyzed in the Gas-Electric System Interface Study and is further discussed below.

- There are many ways to implement a given policy initiative and different forms of implementation may require different generation and transmission.

- The cost estimates in the project are based on a variety of generalized assumptions and are only broadly indicative on a relative basis between the futures. A number of potentially significant costs were not included.

- Future interconnection-wide studies may wish to consider a more iterative process, allowing for opportunities to review the analysis results before making decisions on the next part of the analysis.

- Many PAs are already doing transmission expansion planning that considers economic criteria in addition to reliability criteria. Future interconnection-wide transmission planning exercises should consider doing so as well.

At the final SSC meeting of the Phase 2 work analyzing the three scenarios, the Chairs proposed and the SSC accepted, with revisions, a document outlining their observations and guidance for the use of the report. This memo is included in its entirety in Section 7.0 - Observations and Guidance of this report.

<u>Phase 2 Gas-Electric System Interface Study</u>

The Gas-Electric Infrastructure Study represents a first of its kind comprehensive analysis of the gas infrastructure's capability to serve future needs of electric generation over a region that encompasses over 1.7 million square miles, 35 states and the province of Ontario, and serves roughly 165 million people in the U.S. and Canada. Although individual regional and inter-regional analyses have been undertaken in the past, an analysis that examines all of the LDC and generation demands on the gas system simultaneously across this vast footprint in the EI has not been previously undertaken. The PPAs and the stakeholders of the EIPC are grateful to the DOE for its support of this phase of the EIPC project.

By definition, a project of this magnitude reveals both notable observations and needed additional work. Although specific observations resulting from each of the four targets are identified in the narrative accompanying that specific target, the PPAs provide these higher level observations for consideration. These do not express the views of some stakeholders from the natural gas industry.

- The increasing number of generation facilities which depend on the natural gas infrastructure (e.g., single fuel gas-only units and dual-fuel units) underscores the importance of the findings in this report. The consolidated network of gas infrastructure – the pipeline, storage, and LDC systems – was historically built and operated to serve RCI customers, predominantly for heating and process loads. From an historical perspective, the use of the consolidated network to serve gas-fired generation load was an adjunct opportunity for additional off-season sales. Consistent with the LDCs' traditional obligation to serve RCI load, pipeline and storage infrastructure was largely paid for by LDC customers who then enjoy the benefits of year-round deliverability and first priority to delivery infrastructure to serve their needs. As part of the regulatory compact, the LDCs' RCI customers bore the cost responsibility associated with the highly capital-intensive gas infrastructure through rates ultimately set by FERC, the National Energy Board (NEB), and the state or provincial regulatory commissions.
    - In light of fundamental changes in the electricity market over the last two decades, gas-fired generation has become a large and increasingly critical portion of total gas load. Hence, many aspects as to how this "obligation to serve" the RCI load (and the concomitant pipeline/LDC financing structures for the construction of new infrastructure) may need to be rethought. As this analysis notes, the traditional model of long-term commitments is a less than ideal fit for merchant power generators competing within wholesale markets or operating in vertically integrated systems owing to their highly variable load profiles. In the organized markets, these gas-fired units are often the margin units setting price in both the DAM and RTM where their obligations to deliver power are not known with certainty more than a day ahead, and are subject to competitive pressures on both a daily and intra-day basis.
- The Target 1 analysis focused on definition of gas infrastructure, including contracting preferences and market structure affecting the scheduling of gas and the secondary market. The Target 2 analysis focused on the physical ability of the pipeline system to serve gas generation assuming that the majority of the gas-fired generation across the Study Region was subordinate to the gas demands associated with the LDCs who retain the obligation to serve RCI load. The Target 3 analysis focused on the physical ability of the pipeline system to serve gas-fired generation following postulated gas- or electric-side contingencies across the Study Region when gas-fired generation is assumed to be on par with RCI load in terms of scheduling priority. By placing the gas-fired generation demands on par with RCI loads following a postulated contingency event, the PPAs and stakeholders could see the potential operational risks under a set of assumptions associated with location-specific events that may limit the amount of time that scheduled

gas-fired generation could continue to operate, particularly at full power output levels *even if* the affected generators were obtaining the same priority of service from pipelines and LDCs as RCI load. The Target 4 analysis examined the tradeoffs between dual-fuel capability and incremental firm transportation to serve the daily fuel requirements of new peakers or combined cycle plants at many different locations across the Study Region. Part of the Target 4 analysis also included operational and environmental considerations related to the restocking of liquid fuel via truck or barge from existing oil terminals to various generation sites across the Study Region.

- When asked to comment on each of the four target findings and observations, the pipelines sometimes cited a host of tariff requirements and negotiated arrangements which would likely cause a departure in practice from the results of that physical analysis, including contract arrangements or the pipeline's obligations to serve the needs of their firm entitlement holders. The Target 3 analysis clearly demonstrates a level of infrastructure resiliency or "robustness" that is embedded in the consolidated network of pipeline and storage infrastructure following a postulated contingency. Such resiliency may not be available to generators due to the present priority of service paradigm and the binary firm/non-firm view of transportation service to generators.

    - Many of these same issues were faced by the electric transmission system some years ago. Nevertheless, the transmission system was able to evolve from a pure physical system with long-term reservations of physical capacity to a system which today maximizes the efficiency of the infrastructure by, in a number of PPAs, treating all load as network service and establishing a dynamic pricing system to assign the costs of constraints to the cost causers in an efficient and equitable manner. The net effect is that users of the electric transmission system in wholesale market regions pay only for the value of the service that they receive. Although the electric transmission model may not be completely transferable in total to the pipeline industry, the evolution of congestion management on the electric grid is illustrative of the progress that can be made when similar issues to those being faced by the gas pipeline industry are addressed using new paradigms. Going forward, as policymakers work to determine the most appropriate gas pipeline and LDC tariff structure for gas-fired generation, they are going to have to grapple with these marked differences between the physical capability of the system and the priority rights and levels of services provided by pipelines and LDCs in order to arrive at a new paradigm, one that strives to find a fair and efficient balancing point among different stakeholder interests; i.e., RCI customers, gas-fired generators, investors and ultimate consumers who depend on reliable supplies of both electricity and natural gas. All four target analyses, in particular, Targets 2 and 3 can provide useful information on how best to begin to identify, analyze, and prioritize these issues.

- This study used existing models such as the AURORAxmp model for electricity dispatch and the GPCM and WinFlow/Win Tran models to analyze the flow of natural gas from the producing areas to the market areas across the Study Region. At times, there was difficulty in combining the results of the various modeling systems to ensure that the results were compatible. The time-intensive nature of this effort underscores the need for additional modeling development in this area in order to improve the tools available for performing the type of integrated analysis of the electric and gas systems undertaken in this study.

- Although pipeline and LDC services are federally and state regulated respectively, as the report points out, there are a great deal of unique bilateral arrangements which make it difficult to determine the full picture of how natural gas delivery service is provided to generators to meet the uncertain daily scheduling requirements in the DAM or RTM. Moreover, the limited regulation affecting secondary market transactions has resulted in market liquidity among buyers and sellers for released capacity rights, but less than desirable transparency regarding the overall amount of spare capacity as well as applicable commercial terms and price discovery. As the importance of gas-fired generation to serve electric consumers' reliability needs across the Study Region increases, policymakers will need to balance the need for continuing to encourage "tailored" bilateral arrangements with the costs in terms of rational price formation that facilitate the goals of fuel assurance at a reasonable cost under a less than fully transparent system.

- With few exceptions across the Study Region, the Target 4 analysis proves that using ULSD in a dual-fuel capable generator is a superior choice from a cost standpoint than contracting for additional firm pipeline capacity from a liquid sourcing point to the generator's plant gate. This analysis raises two issues:

  First, should these results be considered by the pipeline industry as proof that more flexible services should be developed by pipelines if they wish to capture any of the discretionary load that otherwise would migrate to ULSD at peak time periods?

  Second, on the flip side, although ULSD seems a more cost effective alternative across most of the footprint evaluated in the Study Region, the permitting issues associated with increased reliance on this product could prove limiting. Policymakers will need to balance the need for electric system reliability through use of ULSD given its relative cost-effectiveness, with the environmental regulations that often put strict permitting limitations on burning of fuel oil, even ULSD.

- Finally, the impacts of EPA's CPP were beyond the scope of this report. Any analysis of the CPP will need to await issuance of the Final Rule and work with the states as they seek to develop their individual plans. Nevertheless, the 2023 analysis should be instructive as to the demands that will be placed on gas infrastructure in the Study Region. In this regard, the analysis results, particularly for 2023 as described in each of the target results, can serve as a reference point for future work which PAs will need to undertake to analyze the CPP impacts as state plans are being developed.