2011 Economic Study

System Planning | Resource Adequacy
March 31, 2014

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Nomenclature

Nomenclature used in this report.[1]

BHE	Bangor Hydro Electric (i.e., an area in northern Maine)
CF	capacity factor
CMP	Central Maine Power
CSC	Cross-Sound Cable
DR	demand resources
EE	energy efficiency
EFOR	equivalent forced-outage rate
EMS	Energy Management System network model
FCA	Forward Capacity Auction
GADS	Generating Availability Data System
GSU	generator step-up transformer
GV	GridView
GWh	gigawatt-hours
HVDC	high-voltage direct current
IREMM	Inter Regional Electric Market Model
LMPs	locational marginal prices
LSE	load-serving entity
LSP	Local System Plan
MOD	Model-on-Demand database
MPRP	Maine Power Reliability Project
MW	megawatts
MWh	megawatt-hours
NESCOE	New England States Committee on Electricity
NEWIS	New England Wind Integration Study
NNC	Norwalk-Northport Cable
OATT	*Open-Access Transmission Tariff*
PAC	Planning Advisory Committee
PSS/E	Power System Simulation for Engineers, Siemens Energy Inc., a Transmission Planning Network Model
RENEW	Renewable Energy New England
RSP	Regional System Plans
RTEG	real-time emergency generation
RUMF	Rumford
SCC	seasonal claimed capability
SCED	security-constrained economic dispatch
SCUC	security-constrained unit commitment
SEMA/RI	Southeast Massachusetts/Rhode Island
TMNSR	10-minute non-spinning reserve
TMOR	30-minute operating reserve requirement
TMSR	10-minute spinning reserve
VAR	voltage ampere reactive

[1] Additional nomenclature used comes from the ISO's Glossary & Acronyms, http://www.iso-ne.com/support/training/glossary/.

VOM	variable operation and maintenance
WBIG	Wyman/Bigelow
WDA	wind-development subarea

Resource Technologies

CC	combined cycle
FC	fuel cell
GT	gas turbine
HY	hydro
IC	internal combustion
PS	pumped storage
PV	photovoltaic
ST	steam

Resource Fuels

SUN	sunlight
BIT	bituminous
BLQ	black liquor
DFO	distillate fuel oil
JF	jet fuel
KER	kerosene
LFG	landfill gas
MSW	municipal solid waste
NG	natural gas
NUC	nuclear
OBG	other biogas
RFO	residual fuel oil
SUB	sub-bitiminous
TDF	tire-derived fuels
WAT	water
WDS	wood

Section 1
Executive Summary

The ISO New England (ISO) *Open-Access Transmission Tariff* (OATT), Attachment K, requires the ISO to conduct economic studies arising from requests submitted through the Planning Advisory Committee (PAC).[2] To fulfill this obligation for the 2011 economic study requests, the ISO conducted a study to determine the benefits of installing wind in various locations across New England under various wind-penetration levels. The ISO presented the study's simulation results to the PAC on May 17, 2012, January 17, 2013, and March 21, 2013.[3] [4] [5] [6] [7]

The simulations were performed using both the Inter Regional Electric Market Model (IREMM) and GridView production-costing models. IREMM is a high-level production-costing model that the ISO has used for many regional system planning studies. The GridView model is capable of representing generating unit operating characteristics and detailed transmission constraints. The ISO evaluated GridView, which has the capability to supplant IREMM because GridView models security-constrained unit commitment (SCUC) and security-constrained economic dispatch (SCED) frameworks, similar to the ISO's Day-Ahead and Real-Time Energy Market operations.[8]

The ISO used the GridView model for the first time to conduct the 2011 economic studies. The GridView phase of the study began with a comparative analysis that replicated the initial IREMM analyses. The modeling capabilities of GridView were then utilized to capture a more detailed system representation. For these later phases of the study, GridView features were incorporated to include assumptions for thermal heat-rate curves, monitoring of additional 115 kilovolt (kV) lines, and simulation of

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2 ISO New England Inc. Transmission, Markets, and Services Tariff (ISO tariff), Section II, Open Access Transmission Tariff, Attachment K, "Regional System Planning Process" (January 1, 2013), http://www.iso-ne.com/regulatory/tariff/sect_2/oatt/sect_ii.pdf.

32011 Economic Studies: Draft Results, PAC presentation (May 17, 2012), http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2012/may172012/2011_eco_study.pdf .

4 Supporting Documentation (June 28, 2012), http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2012/may172012/index.html .

5 *2011 Economic Studies: GridView Simulation Results*, PAC presentation (January 17, 2013), http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2013/jan172013/a3_gridview_economic_study_011713.pdf.

6 *2011 Economic Studies—Supplemental: GridView Simulation Results—Effect of Relieving a Binding Constraint in SMEA,* Supplemental Study (January 17, 2013), http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2013/jan172013/gridview_2011_eco_supplemental.pdf.

7 *2011 Economic Studies: An Update of Gridview Simulation Results*, PAC presentation (March 21, 2013), http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2013/mar212013/a6_2011_gridview_economic_study.pdf.

8 Overview of New England's Wholesale Electricity Markets; Market Oversight (May 15, 2013), http://www.iso-ne.com/pubs/spcl_rpts/2013/markets_overview_051513_final.pdf.

contingencies in the Central Maine Power (CMP) service territory. Both IREMM and GridView analyses developed system economic and bottled-in wind energy metrics.

An analysis was performed for each of five "wind-development subareas" (WDAs) defined by export-constrained interfaces, as shown in Figure 1-1:

- WDA 1: Resources behind the Wyman/Bigelow export interface
- WDA 2: Resources behind the Rumford export interface
- WDA 3: Resources behind the Northern Maine export interface
- WDA 4: Resources behind the Northern New Hampshire export interface
- WDA 5: Resources behind the SEMA/RI export interface

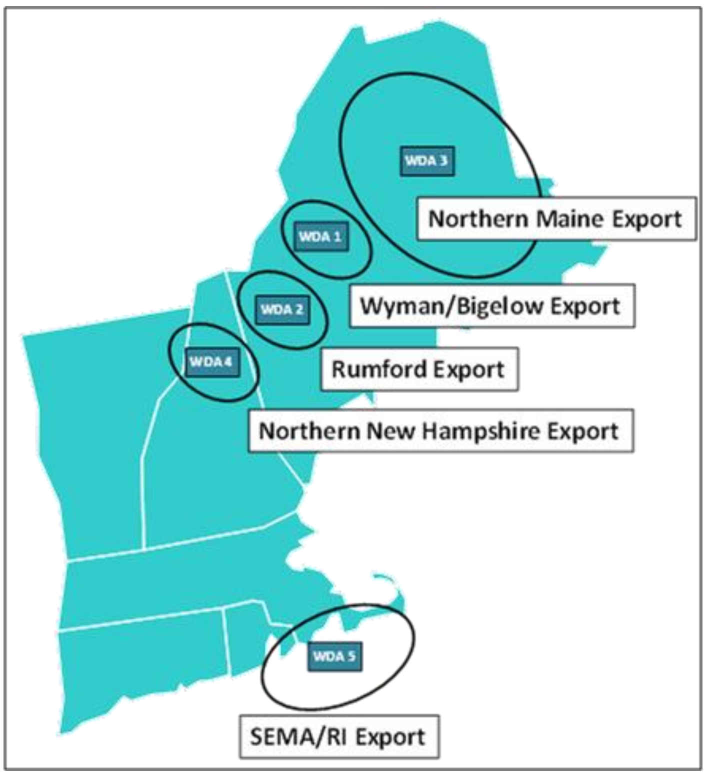

Figure 1-1: Wind Development Areas Investigated

The transmission system constraints for both IREMM and GridView included voltage and stability limits associated with defined interfaces. Other more subtle operating limitations associated with voltage and stability that affected specific wind resources, or groups of wind resources, were not included in this analysis. However, GridView was able to evaluate thermal limitations within some of the Wind Development Areas.

The 2011 economic studies focused on three different levels of wind penetration as shown in Table 1-1:

- "FCA #5"—Wind capacity purchased in the fifth Forward Capacity Auction (FCA #5) (plus some energy-only wind resources).[9]
- "Active Queue"—Wind capacity in the active ISO Generator Interconnection Queue (the queue) as of June 2011 plus wind that was commercial (Small amounts of wind in New England that preceded the queue process are included) [10].
- "All Wind"—All wind capacity registered in the queue, including wind resources that have been withdrawn.

Table 1-1
Wind Capacities in the FCA #5, Active Queue, and All-Wind Cases

	Wind Capacity (MW)		
Wind Development Areas	**FCA 5**	**Active Queue**	**All Wind**
Wyman Bigelow	281	597	990
Rumford Area	139	191	230
North Maine	109	1,257	2,834
Northern New Hampshire	100	134	460
SEMA/RI	-	1,051	7,256
Other Wind Areas	247	680	1,227
Total	**875**	**3,910**	**12,998**

This study assessed three primary groupings of simulations as summarized in Table 1-2. The first group was a series of comparison cases (IREMM vs. GridView) that illustrated the comparability of the two models using the same assumptions ("Model Comparison" cases). The second group of cases added some of the detailed transmission system conditions ("Transmission Modeling" cases). The third group of cases shows the effect of adding more detail to the network analysis ("Refined Modeling" cases). Each group of cases includes evaluations at the three wind-penetration levels.

[9] *Forward Capacity Market (FCA 5) Result Report* (June 9, 2011), http://www.iso-ne.com/markets/othrmkts_data/fcm/cal_results/ccp15/fca15/fca_5_results_report.pdf.

[10] The ISO's Generator Interconnection Queue includes the requests that generators submit to ISO New England to interconnect to the ISO-administered transmission system.

Table 1-2
GridView 2011 Economic Study—Summary of Cases Showing the Three Primary Groupings of Simulations

Level \ Scenarios	FCA 5	Active Queue	All Wind	Comments
Case 1 Unconstrained	FCA 5 – Unconstrained	Active Queue - Unconstrained	All Wind - Unconstrained	Model Comparison Cases
Case 2 Interface Constrained	FCA 5 - Interface Constrained	Active Queue - Interface Constrained	All Wind - Interface Constrained	
Case 3 Detailed Modeling	FCA 5 - Detailed System Simulation	Active Queue - Detailed System Simulation	All Wind - Detailed System Simulation	Transmission Modeling Cases
Case 4 Barnstable Relaxed	FCA 5 - Detailed System Simulation	Active Queue - Detailed System Simulation	All Wind - Detailed System Simulation	
Case 5a Detailed Resource Operating Parameters	FCA 5 - Detailed System Simulation	Active Queue - Detailed System Simulation	All Wind - Detailed System Simulation	Refined Modeling Cases
Case 5b Monitor 115 kV, and above, lines in CMP	FCA 5 - Detailed System Simulation	Active Queue - Detailed System Simulation	All Wind - Detailed System Simulation	
Case 5c Expanded Wyman/Bigelow Contingencies	FCA 5 - Detailed System Simulation	Active Queue - Detailed System Simulation	All Wind - Detailed System Simulation	
Case 5d Expanded Contingencies with New MPRP Limits	Due to Wind Penetration, Assumed Equivalent to Case 5c	Due to Wind Penetration, Assumed Equivalent to Case 5c	All Wind – Reflect MPRP Transmission Limits	

Figure 1-2 through Figure 1-4 show the production cost metrics for the three case groupings. From these figures, it can be observed that the total New England production costs decrease as more zero cost wind energy is produced. Additionally Figure 1-2 shows there is little difference between the GridView and IREMM production cost results for the Model Comparison cases. At the highest wind penetration level, the GridView case with interface constraints is slightly higher than the IREMM simulations, suggesting some additional bottled-in wind energy when using GridView.

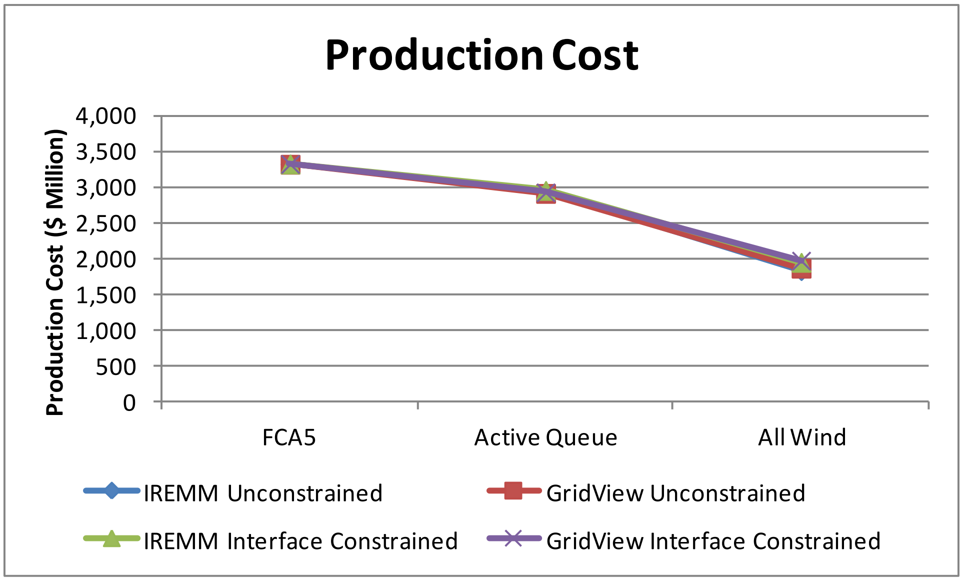

Figure 1-2: Comparison of GridView and IREMM production costs for the Unconstrained and Interface-Constrained cases.

Figure 1-3 shows the Transmission Modeling cases. At high levels of wind penetration the transmission constraints prevent some of the wind energy from displacing more expensive resources throughout New England. The GridView Barnstable Relaxed case ignores the limitations of the most congested element and shows the benefits of how a potential transmission improvement can be quantified.

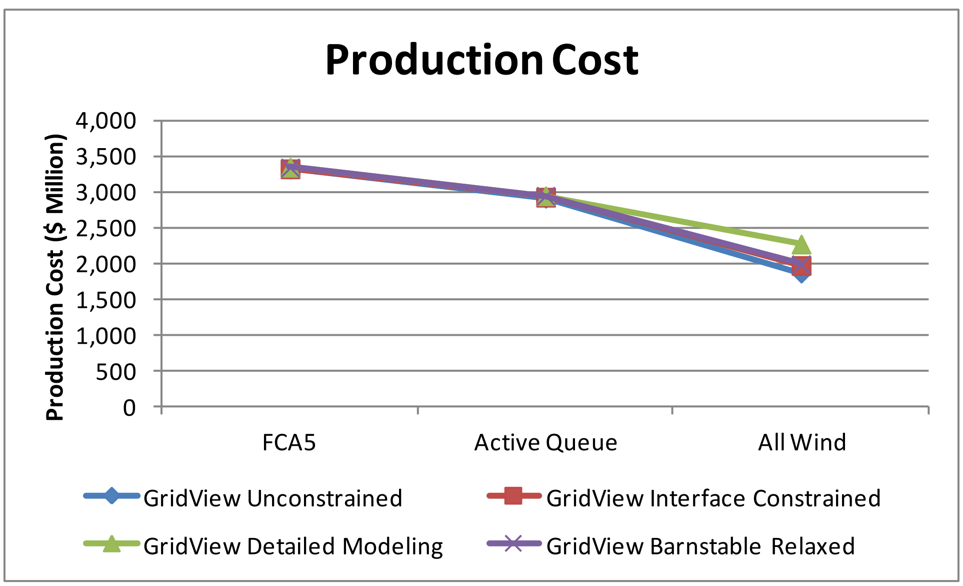

Figure 1-3: Comparison of production costs for the GridView Transmission Modeling cases.

As shown in Figure 1-4, modeling the detailed operating parameters for the generating resources raises the production costs. With the exception of the GridView Barnstable Relaxed, the other cases show little change in production cost if the modeling of the transmission system is refined in the central Maine region. The GridView Barnstable Relaxed case, which does not include start-up and no load costs, has the lowest values for the production cost metric.

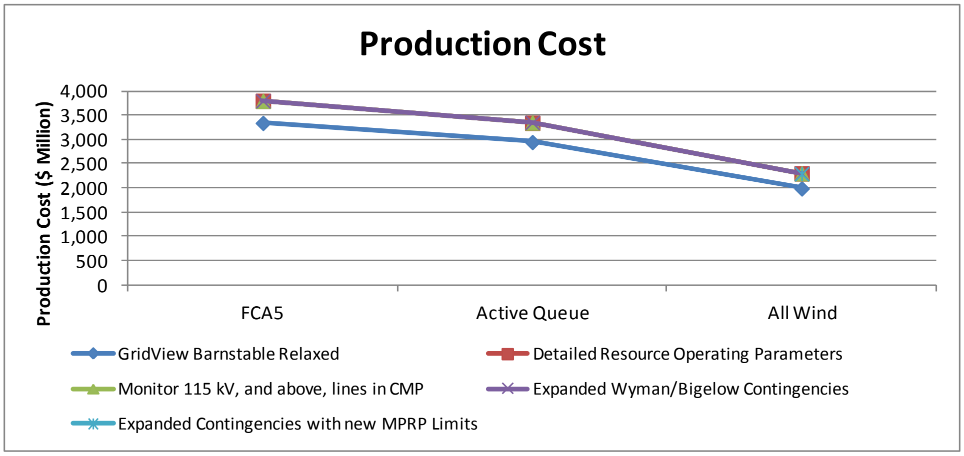

Figure 1-4: Comparison of production costs for the GridView Refined Modeling cases.

Figure 1-5 to Figure 1-7 show the average LMP metrics for the three case groupings. From these figures it can be observed that the average New England LMPs decrease as more zero cost energy is produced from wind. As shown for the Model Comparison cases in Figure 1-5, IREMM LMPs are less sensitive to wind penetration than calculated by GridView. However, the overall LMP results for both the IREMM and GridView cases are similar.

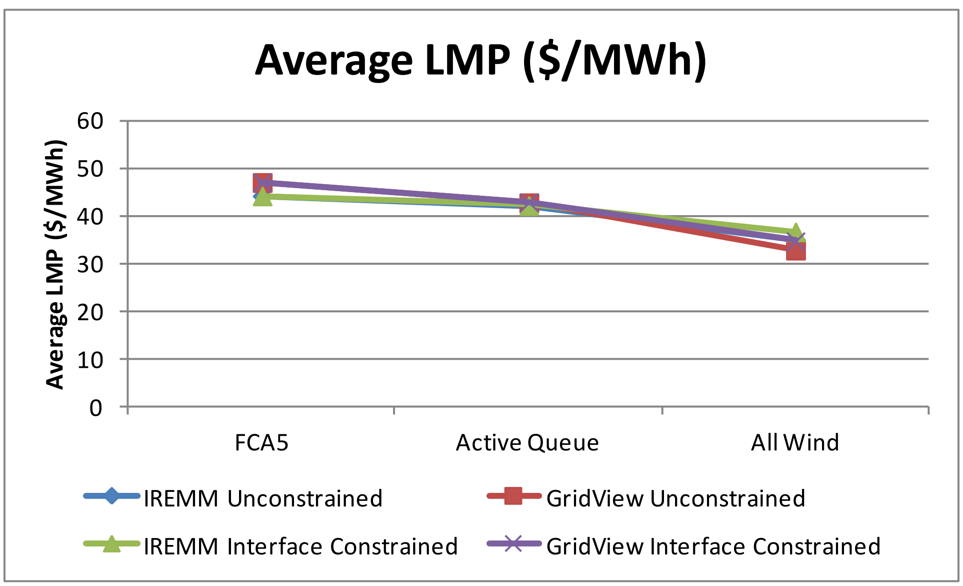

Figure 1-5: Comparison of GridView and IREMM Average LMPs for the Unconstrained and Interface-Constrained cases.

Figure 1-6 shows that for the Transmission Modeling cases, the Unconstrained and Interface Constrained cases are nearly the same. However, when contingencies and branch ratings are modeled, the average LMP increases for all three wind penetration levels. These higher LMPs are associated with increased levels of bottled-in wind energy due to transmission system limitations.

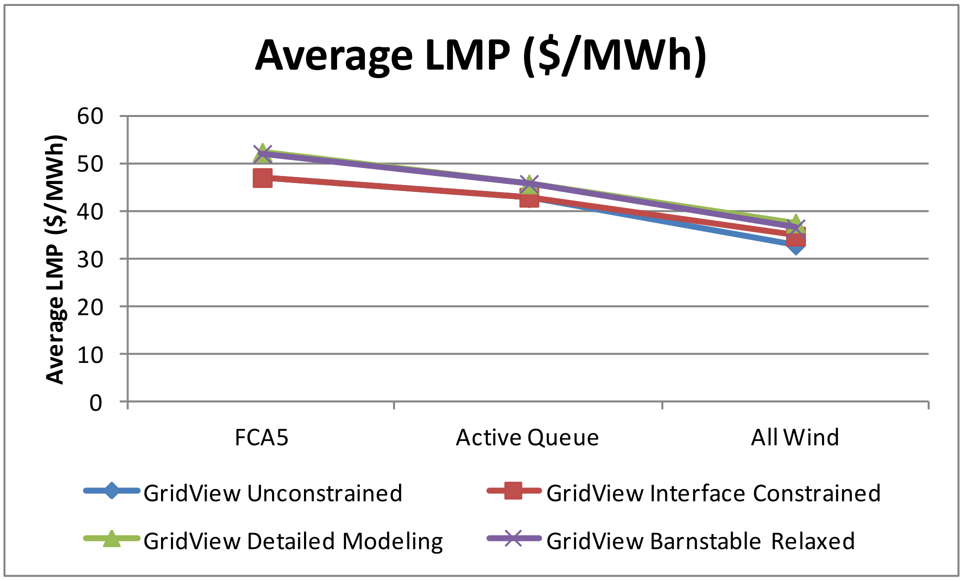

Figure 1-6 : Comparison of Average LMPs for the GridView Transmission Modeling cases.

Figure 1-7 shows that there is no significant difference in the LMPs associated with the Refined Modeling cases. Even though the GridView model includes the start-up and no load heat input costs that are important components for modeling unit commitment, this additional detail did not have an effect on the average LMPs. This suggests that the resource's marginal cost and the amount of bottled-in wind energy is approximately the same among these cases.

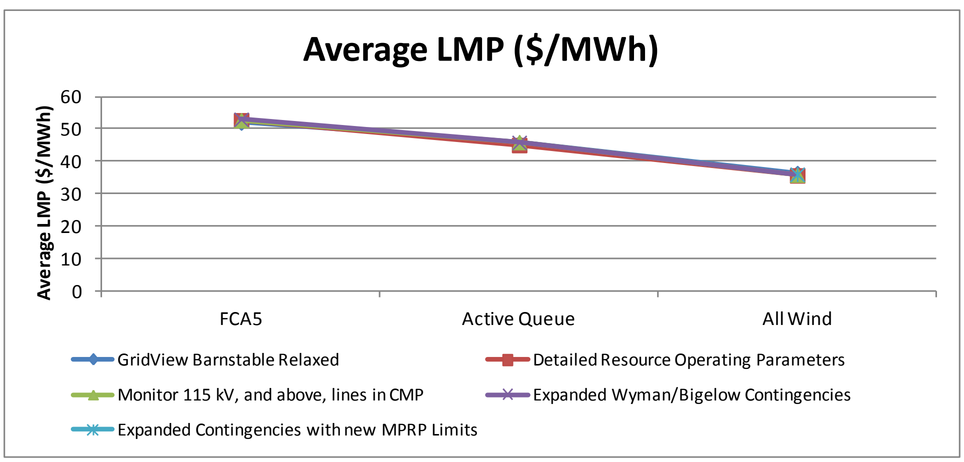

Figure 1-7: Comparison of Average LMPs for the GridView Refined Modeling cases.

The ISO made the following observations based on the simulation results:

- Under the same input assumptions and transmission modeling detail, IREMM and GridView simulations produced similar evaluation metrics, such as production costs, LSE energy expenses, annual generation, wind generation, and to a lesser degree, interface flow patterns.
- The Wyman/Bigelow subarea became export constrained with 600 MW of installed wind capacity.

- High level transmission system limitations did not bottle-in significant amounts of wind energy until over 2000 megawatts (MW) of wind resources were added in Northern Maine.
- With the modeling of more detailed generator operation limits and transmission system constraints (transmission line limits, contingencies, and phase-shifter operations), GridView simulation results showed more bottled-in wind energy and higher load-serving entity (LSE) energy expenses. This was exacerbated for scenarios with higher wind-penetration levels. [11]
- Use of detailed thermal heat-rate curve assumptions led to increased production costs while having a small effect on LSE energy expenses. This is because the detailed thermal heat rate curve included factors such as no-load and start-up costs, which do not affect the incremental costs that dominate price formation and establish LMPs.
- Modeling additional 115 kV lines in the Central Maine Power service territory and contingencies in the Wyman/Bigelow and Rumford subareas in Maine led to the following:
    - Additional curtailment of wind generation in the Wyman/Bigelow subarea, especially for the higher wind-penetration cases associated with “Active Queue” and “All-Wind” cases.
    - Slightly increased New England production costs and LSE energy expenses.
- The coordination of wind and hydro generation in the export-constrained subareas could potentially increase the aggregated wind and hydro generation located in these transmission constrained subareas.
- Comparative economic and physical metrics from GridView’s detailed transmission modeling can be useful for system planners and resource developers.

While there has been no quantification of the historical bottled-in wind energy in Maine or other Wind Development Areas, observers suggest that there have been significant amounts of bottled-in wind energy in Maine, even with wind penetration levels less than the amount considered in this study. This suggests a need to better represent the factors that cause bottled-in wind energy, such as voltage and stability limits. It may be possible to include these factors directly into either IREMM or GridView models, but the techniques and data were not available for this study. This could be a topic for additional investigation.

The remainder of this report provides the detailed modeling methodology, input assumptions, simulation results, and general observations from the IREMM and GridView phases of the study.

[11] A *load-serving entity* secures and sells electric energy, transmission service, and related services to serve the demand of its end-use customers at the distribution level.

Section 2
Introduction

As a part of the regional system planning effort, ISO New England (ISO) conducts economic planning studies each year, as specified in Attachment K of its *Open-Access Transmission Tariff* (OATT).[12] The economic studies provide information on system performance, such as estimated production costs, load-serving entity (LSE) energy expenses, estimates of transmission congestion, and environmental emissions metrics.[13] This information can assist market participants and other stakeholders in evaluating various resource and transmission options that can affect New England's wholesale electricity markets. The studies may also assist policymakers who formulate strategic visions of the future New England power system.

This report presents the *2011 ISO New England Economic Study* (2011 Economic Study), conducted in response to requests submitted by stakeholders participating in the Planning Advisory Committee (PAC). The report documents the study methodologies, data and assumptions, simulation results, and observations.

This section provides an overview of the three economic study requests the ISO received in 2011, the scopes of work for the study, the study process and the primary assumptions.

2.1 2011 Economic Study Requests

In 2011, ISO New England received and evaluated the following three economic study requests:[14]

- LS Power Transmission LLC requested that the ISO study the economic effects of adding up to 650 megawatts (MW) of wind resources in the Wyman/Bigelow subarea of Maine and relaxing the 350 MW transfer limit out of this subarea, assuming a new single-circuit 345 kV transmission project running from the Wyman subarea to the proposed Larrabee Road 345 kV substation.
- Central Maine Power (CMP) requested that the ISO evaluate the impacts on Maine and regional energy production costs and locational marginal prices (LMPs) attributable to relieving the western Maine transmission constraints identified in the *2010 ISO New England Economic Study* and in the CMP-sponsored *Western Maine Renewable Integration Study*.[15]
- Renewable Energy New England (RENEW) requested that the ISO explore the economic impacts associated with the near-term wind energy development that might occur in the region in the next five years. The request suggested that using the *New England Wind Integration Study*

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[12] *ISO New England Inc. Transmission, Markets, and Services Tariff* (ISO tariff), Section II, *Open Access Transmission Tariff,* Attachment K, "Regional System Planning Process" (January 1, 2013), http://www.iso-ne.com/regulatory/tariff/sect_2/oatt/sect_ii.pdf.

[13] A *load-serving entity* secures and sells electric energy, transmission service, and related services to serve the demand of its end-use customers at the distribution level.

[14] "Planning Advisory Committee Materials," webpage (April 24, 2011), http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2011/apr142011/index.html.

[15] NESCOE, "Request For Information—Transmission Project, Western Maine Transmission Constraint Relief, Central Maine Power Company" (February 25, 2011), http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2011/apr142011/cmp_submission_to_nescoe.pdf.

(NEWIS) "Full Queue Build-Out" scenario would be a reasonable approximation of regional wind development.[16]

2.2 2011 Economic Study Scope of Work

The ISO evaluated the three study requests and developed a single consolidated scope of work for the study. The model chosen was the Interregional Electric Market Model (IREMM), which is a simulation tool the ISO has used in past economic studies for developing hourly production costs and other summary metrics. After the ISO presented the IREMM simulation results to the PAC on May 17, 2012, it developed a scope of work for the second phase of the study that involved conducting more detailed simulations using GridView.[17] The ISO acquired GridView to supplant IREMM because it is capable of providing greater modeling detail. The study steps were presented to the PAC on January 17, 2013, and March 21, 2013.[18] [19]

2.2.1 Scope of Work for the IREMM Phase of the Study

For the IREMM portion of the study, the ISO structured simulation cases to investigate the impacts of different levels of wind penetration in the ISO's "wind-development areas" (WDAs). The study year was 2016. The WDAs investigated contained resources behind export constraints, as follows:

- WDA 1: Resources behind the Wyman/Bigelow export interface
- WDA 2: Resources behind the Rumford export interface
- WDA 3: Resources behind the Northern Maine export interface
- WDA 4: Resources behind the Northern New Hampshire export interface
- WDA 5: Resources behind the SEMA/RI export interface

Three levels of wind penetration were modeled:

- "FCA #5"—Wind capacity purchased in the fifth Forward Capacity Auction (FCA #5) (plus some energy-only wind resources)[20]

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[16] GE Applications and Systems Engineering. *New England Wind Integration Study* (December 5, 2010), http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2010/newis_report.pdf. PAC archives of NEWIS materials are available at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2010/index.html.

[17] ABB Inc., *GridView User's Manual*, Version 8. January 2012

[18] *2011 Economic Studies—Supplemental: GridView Simulation Results—Effect of Relieving a Binding Constraint in SMEA,* Supplemental Study (January 17, 2013), http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2013/jan172013/gridview_2011_eco_supplemental.pdf.

[19] *2011 Economic Studies: An Update of Gridview Simulation Results*, PAC presentation (March 21, 2013), http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2013/mar212013/a6_2011_gridview_economic_study.pdf.

[20] "Forward Capacity Market (FCA 5) Result Report" (June 9, 2011), http://www.iso-ne.com/markets/othrmkts_data/fcm/cal_results/ccp15/fca15/fca_5_results_report.pdf.

- "Active Queue"—Wind capacity in the active ISO Generator Interconnection Queue (the queue) as of June 2011 plus wind that was commercial (small amounts of wind in New England that preceded the queue process are included).[21]
- "All Wind"—All wind capacity registered in the queue, including wind resources that have been withdrawn

The primary metrics quantified in the study were as follows:

- System economics (i.e., production costs, LSE energy expenses)
- System power flow patterns
- Bottled-in wind energy

The IREMM program respects high-level interface limits *between* different Regional System Plan (RSP) areas in ISO New England. The thermal units, conventional hydro plants, and pumped storage units were modeled at a high level to reflect the units' different production costs and to mimic the ISO operations that minimizes regional production costs.

2.2.2 Scope of Work and Cases for the GridView Phase of the Study

The second phase of the study used the GridView model to investigate the economic and other system impacts of detailed generation operational limits and transmission-constraint modeling including the effects of security-constrained unit commitment (SCUC) and security-constrained economic dispatch (SCED). For the GridView simulations, the ISO conducted the following study steps:

- "Model Comparison" cases – These used the same input assumptions, similar transmission and resource representations to enable comparison of GridView and IREMM results.
- "Transmission Modeling" cases – These added detailed modeling of the transmission network to study the impacts on the system economic and bottled-in wind energy metrics.
- "Refined Modeling" cases – These cases focused on modeling that was not possible with IREMM, such as detailed modeling of thermal unit heat-rate curves, generation operational limits, and transmission constraints.
- "Hydro/Wind Coordination" cases - These cases investigated the ability of GridView to model the pondage / storage capability of hydro resource. This capability was then used to investigate the ability of hydro to coordination with variable wind energy to minimize the amount of wind that would be lost due to transmission constraints.

2.2.3 Factors Affecting Study Metrics

The economic studies used a number of assumptions for the variable factors that could affect system performance metrics:

- Generating capacity for thermal, hydro, pumped-storage, and wind units
- Load

[21] The ISO's Generator Interconnection Queue includes the requests that generators submit to ISO New England to interconnect to the ISO-administered transmission system.

- Fuel prices
- Environmental emissions
- Wind resource profiles
- Wind penetration
- Active demand resources, energy efficiency (EE), and real-time emergency generation (RTEG)
- Imports and exports

Because all the assumptions are uncertain, the modeling results indicate relative values and trends and should not be characterized as accurate projections of future transmission congestion, ultimate project economics, or resultant environmental impacts.

Section 3
Study Methodologies

This section provides an overview of the two modeling methodologies and approaches used to conduct the 2011 Economic Study. The different capabilities of the models, the data requirements, and how the data were used for simulating the power system are addressed.

3.1 Simulation Models

This section summarizes the main features of the two models used and the advantages of each one.

3.1.1 IREMM

The Inter Regional Electric Market Model (IREMM) is a simulation tool the ISO has used in past production cost studies for developing hourly production cost and other summary metrics. IREMM is a simplified production cost model with a gross representation of resource dispatch and commitment. IREMM models the region using a "pipe and bubble" representation where areas, such as RSP areas, (bubbles) are linked by representative transmission lines (pipes) that connect the areas. IREMM models the aggregated subarea load and inter-area transmission constraints represented by major interfaces.

IREMM offers the advantage of facilitating the understanding of system performance and is appropriate as a high-level screening analysis tool. The high-level data can be extracted from databases that contain granular representations, which would be suitable for use in more detailed production cost programs. Through the years, IREMM has compared well with other production cost programs.

3.1.2 GridView

GridView is a software application developed by ABB Inc. to simulate the market operation of an electric power system with a potentially constraining transmission system. It is used to analyze the operation and planning of transmission and generation assets, estimate market price signals, identify transmission system bottlenecks, and evaluate the engineering and economic impacts of changes in the configuration of the system. GridView is designed to address: changes in transmission system expansion, the addition and retirement of supply and demand resources, and the sensitivity to changes in assumptions, such as fuel prices and available resources.

GridView can be used to simulate the economic operation of a power system in hourly intervals for periods ranging from one day to many years. Typically, these simulations are performed by integrating aspects of the day-ahead market with real time data. To perform these simulations, GridView incorporates a detailed supply, demand, and transmission system model for large-scale transmission grid representation. The coordination of the day-ahead and real-time markets is handled by the security-constrained unit commitment (SCUC) and security- constrained economic dispatch (SCED) modules that mimic the operation of the ISO's energy markets. The simulation is run chronologically to capture the inter-temporal constraints by producing a realistic forecast of the power system components and energy flow patterns across the transmission grid. The output information includes transmission and generator utilization, LMPs for energy and transmission bottleneck metrics. The results can also include an assessment of system security under contingency conditions. Costs for certain ancillary services, such as operating reserve, are imputed.

3.2 Modeling of Load

The simulations were based on forecast loads in the year 2016. The monthly peak and annual energy use forecasts were obtained from the *2011–2020 Forecast Report of Capacity, Energy, Loads, and Transmission* (2011 CELT Report) data.[22] These forecasts provide an hourly profile based on the historical 2006 load shape. GridView used the same hourly load profiles as IREMM and distributed the loads to the network buses across the 13 RSP areas.

3.3 Modeling of Resources

This section summarizes how IREMM and GridView model the various types of resource characteristics, including thermal units, conventional hydro, pumped-storage hydro, wind resources, demand resources, energy efficiency, real-time emergency generation, imports and exports. The section also explains how GridView addressed operating-reserve requirements, which are not included in the IREMM analysis.

3.3.1 Thermal Units

Both the IREMM and GridView Model Comparison cases modeled all the thermal units in the ISO New England region as dispatchable units, with capacity equal to the summer seasonal claimed capability (SCC) values.[23] Most units modeled in IREMM were mapped to the GridView transmission network locations in the PSS/E transmission network model according to asset identification number (Asset ID) and plant name. However, numerous small units, whose exact interconnection points are unknown, could not be assigned to specific network buses. Their resource capacity was aggregated by fuel and technology, and were placed as aggregated units at a 345 kV bus within the appropriate RSP area.

IREMM does not model operational limits and ramp rates for thermal units. To make equivalent assumptions in the GridView Model Comparison cases, the thermal units' minimum up times, minimum down times, and start-up times were all assumed to be one hour. Additionally, the ramp rates were assumed unlimited. There were no pre-specified energy limits for thermal units.

For modeling thermal unit production costs, IREMM used a full-load average heat-rate value that neglects start-up and no load costs. IREMM then selected the primary or secondary fuel as defined in the 2011 CELT Report, depending on which had the lowest cost. In the GridView cases, the same full-load average costs (fuel types, fuel costs, and heat-rate values) were used as defined in IREMM. Because the primary objective of these simulations is to estimate the marginal cost of energy and to calculate the load-serving entity energy expense, no-load and start-up costs were excluded from the single, full-load average heat rate.

For modeling thermal unit unavailability, IREMM used the generator's equivalent forced-outage rate (EFOR) obtained from the ISO's Generating Availability Data System (GADS). IREMM derates capacity by the expected unavailability to obtain an equivalent capacity representation. GridView used the same EFOR values to derate the capacity of thermal units.

[22] 2011 CELT Report (May 2, 2011), http://www.iso-ne.com/trans/celt/report/index.html. Copies of all CELT reports are located at http://www.iso-ne.com/trans/celt/index.html.

[23] "ISO New England Seasonal Claimed Capability (SCC) Report" (as of June 1, 2011), Excel spreadsheet, http://www.iso-ne.com/genrtion_resrcs/snl_clmd_cap/2011/scc_june_2011.xls.

IREMM used the thermal unit's historical maintenance rates to schedule the planned maintenance outages for these units. The maintenance of the units were scheduled to levelize the net operating margin across the year as much as possible. This IREMM-developed maintenance schedule was then used in GridView.

In addition, GridView has modeling characteristics that differ from IREMM for the following thermal unit categories:

- *Nuclear units*—IREMM treats nuclear units the same as other thermal units. GridView models nuclear units as must-run, but dispatchable, units; they are always committed (except for outages), but the output is dispatchable. GridView can curtail the nuclear units when there is an abundance of zero-cost must run energy.
- *Fast-start unit* (i.e., available for service within 10 minutes or 30 minutes)—IREMM assumes all units are dispatchable hourly. To make an equivalent assumption, the GridView Model Comparison cases assume all units have a one-hour start-up time and a one-hour minimum-run time.
- *Combined-cycle unit*—IREMM assumes a single heat rate for the combined facility and does not model dependencies between the component generators in a combined-cycle plant. In GridView, the same method was adopted. However, because frequently the multiple generators are connected to different network busses, and because the aggregate generator output must be arbitrarily assigned to one of several generator step-up (GSU) transformers the selected transformer would not be large enough to handle all the power. Therefore, GridView must exclude the GSU transformers when monitoring for overloads.

When investigating the full capabilities of GridView for the Refined Modeling cases, GridView included the following additional detailed modeling assumptions:

- Operational assumptions
  - Start-up and variable operation and maintenance costs
  - Operating limits, such as minimum up time and minimum down time
  - Start-up times
  - Ramp rates
- 10-minute spinning reserve (TMSR) operating-reserve requirements
- Fast-start unit modeling
  - Minimum run time does not exceed one hour
  - Minimum down time does not exceed one hour
  - Time to start does not exceed 30 minutes

3.3.2 Conventional Hydro Units

IREMM schedules the dispatch of conventional hydro units with a bias toward peak hour energy production. It was assumed that some hydro energy would be generated in every hour of the month. This hydro dispatch reduces the area's net energy requirements. When the hydro capacity factor is relatively low, the maximum hydro capacity may be significantly less than its installed capability.

GridView models the hydro units as hourly resources with fixed production profiles that originated from the IREMM simulations.

3.3.3 Pumped Storage

IREMM models pumped-storage units at a 15% capacity factor in each month and 72% overall energy-storage efficiency. GridView modeled the pumped-storage units as an hourly resource whose fixed production profiles originated from the IREMM simulation.

3.3.4 Wind Units

Most wind resources included in this study were listed in the ISO's Generation Interconnection queue (although a few wind resources predate the queue process). Some wind resources were expected to have a capacity obligation in FCA #5, while some operate as energy-only resources without a capacity supply obligation.

Additional resources in the queue, both those still active and those that were withdrawn, formed the basis for the wind penetration sensitivity cases.

- "Active Queue" - Many wind resources were not part of FCA #5 because they were still actively under study.
- "All Wind" – "Active Queue" wind resources plus others that have withdrawn from the queue.

The models used the resource nameplate capacities as reported in the ISO's queue. The wind profiles used in the analysis were based on the refined regional wind models developed under NEWIS[24]. These profiles were developed for 8,760 hours and were time-synchronized with the 2006 load model used. All wind resources in the same geographical region were assigned identical wind profiles. GridView modeled the wind units as hourly resources using the same wind profiles as used in IREMM. Wind units were aggregated and connected to specific PSS/E network locations. By default, the wind was curtailed when the energy price dropped to $0/MWh.

GridView enabled "wind spillage" to respect transmission constraints. Therefore, a transmission constraint caused energy prices drop to $0/MWh causing wind generators to curtail. This curtailment value could be modified to establish a hierarchy of when the wind energy would be curtailed in relation to other resources. The last section of this study includes sensitivity cases that investigated the effect of changing the order of the wind curtailment compared with other resources.

Although the models added a large amount of wind capacity, no attempt was made to strengthen the transmission network to accommodate this wind.

3.3.5 Demand Resources, Energy Efficiency, and Real-Time Emergency Generation

Three types of demand resources were modeled—active demand resources, energy efficiency (EE), and real-time emergency generators—based on the capacity supply obligations for 2013/2014 in New

[24] "New England Wind Integration Study Executive Summary," GE Energy Applications and Systems Engineering, Enernex Corporation, AWS Truepower, http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2010/newis_es.pdf

England (including proration).[25] Each had prespecified profiles synchronized with the 2006 hourly load shape. GridView adopted the same method for modeling active demand resources, EE, and RTEG in all the simulations.

3.3.6 Imports and Exports

For the modeling of imports and exports with neighboring systems, interchange profiles based on historical import and export flows were used. Typical monthly average diurnal profiles for New York, Québec, and New Brunswick (Maritimes) were developed from three years of historical flows (2007, 2008, and 2009). For each month, all the hourly values corresponding to a specific hour were averaged together to develop 12 monthly (24-hour) profiles representing characteristic flows in each of the months. Because each month has about 30 days and because three years' worth of data was used, each hour represented a sample set of approximately 90 interchange levels. This approach captured the monthly characteristics observed within the historical data.

The profiles represented the following interconnection points:

- Hydro-Québec (HQ)
    - Highgate
    - HQ Phase II
- New York
    - Cross-Sound Cable
    - Norwalk–Northport (NNC)
    - Aggregate free-flowing AC interconnections
- New Brunswick

3.3.7 Operating Reserve Requirements

IREMM does not model operating-reserve requirements. To be consistent, the GridView Model Comparison cases did not enforce any reserve requirements.

In the Transmission Modeling and Refined Modeling cases, GridView enforced the current ISO 10-minute reserve requirement (125% of the largest contingency). Of this total 10-minute reserve, 50% must be held in committed and spinning resources (10-minute spinning reserve, or TMSR). The remaining 50% of the 10-minute reserve can be held in units that are off line but designated as fast-start-units (10-minute non-spinning reserve, or TMNSR).

The largest single-source contingency in the ISO New England area is usually the larger of HQ Phase II or Mystic units #8 and #9 combined. Assuming that this largest single-source contingency is 1,400 MW, its 125% operating reserve requirement equals 1,750 MW. Therefore, for these cases, the TMSR requirement was set at 50% of this amount, or 875 MW. The remaining TMNSR requirement could be satisfied by conventional hydro, pumped storage, and fast-start units. This requirement was not modeled because TMNSR will not affect the economic metrics unless the contingency is triggered. GridView's

[25] ISO New England, "2011 Forecast Data File," Excel file (February 17, 2012), http://www.iso-ne.com/trans/celt/fsct_detail/2011/isone_fcst_data_2011.xls.

SCUC and SCED logic ensures that the system will not violate constraints if a contingency occurs, but typically these contingencies are never activated.

For similar reasons, the 30-minute operating-reserve requirement (TMOR) is assumed to be satisfied by off-line, fast-start units; it is unlikely to affect the economic metrics and was not modeled.

3.4 Modeling the Transmission System

Both IREMM and GridView were designed to include a representation of the major transmission constraints when simulating the New England system. GridView simulations of the power system include the operating constraints caused by a physically limited transmission system and requires more detailed assumptions.

The ISO New England system is divided into 13 RSP areas with interfaces between areas or groups of areas. Within each RSP area, the transmission network is assumed adequate to handle any level of power flows. The interface limits between these areas are enforced to constrain the power transfer across New England. Figure 3-1 shows the topography of wind, biomass, demand resources and the interfaces between the 13 RSP areas.

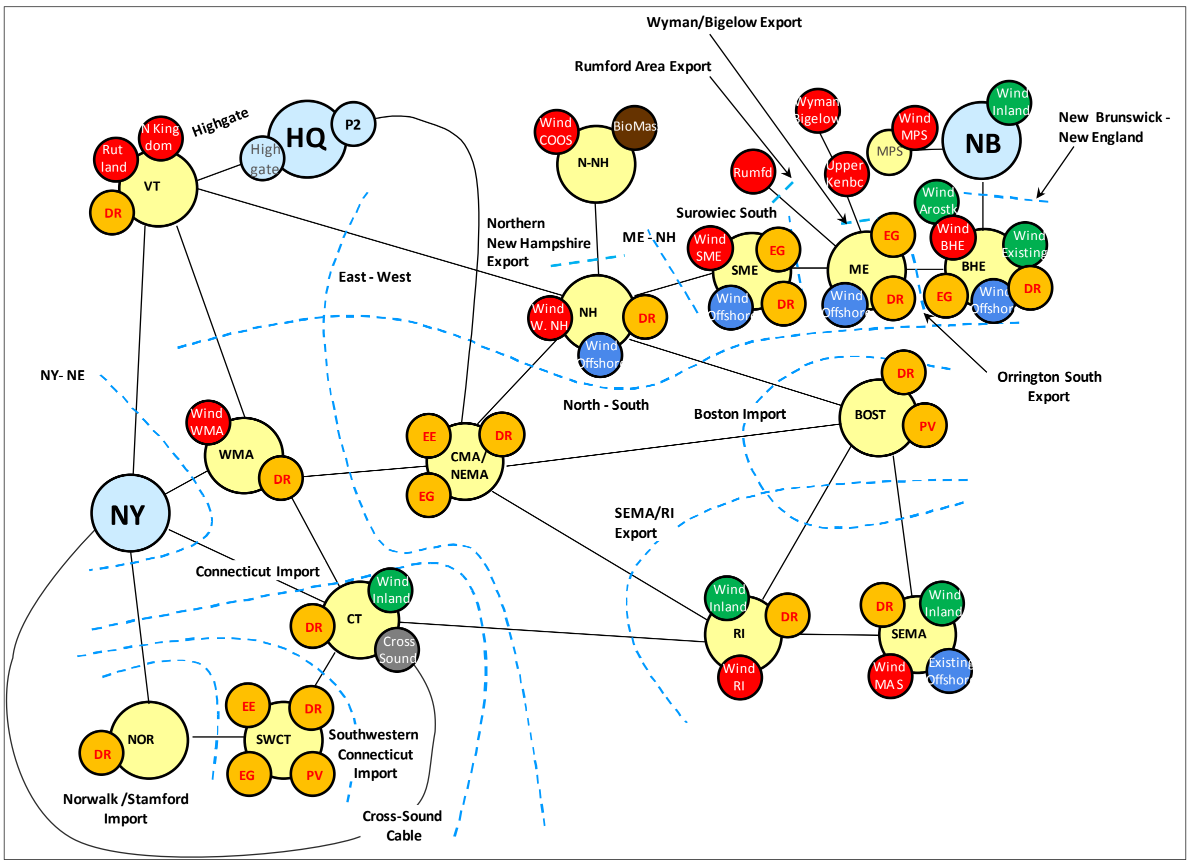

Figure 3-1: Equivalent modeling of ISO New England transmission system in IREMM.

Table 3-1 shows the interfaces defined by the ISO's Transmission Planning department and used in this study. The interface limits were assumed to remain constant throughout the year.

Table 3-1
Interface Limits for 2016 (MW)

Interface Name	Interface Limit (MW)
New Brunswick–New England	700
Orrington South Export	1,200
Surowiec South	1,150
Maine–New Hampshire	1,550
North–South	2,700
Boston Import (N-1)[(a)]	4,900
SEMA Export	No limit
SEMA/RI Export	3,300
Connecticut Import (N-1)[(a)]	3,400
SW Connecticut Import (N-1)[(a)]	3,200
Norwalk/Stamford	1,650
HQ–NE (Highgate)	200
HQ–NE (Phase II)	1,400
Cross-Sound Cable (CSC) (In)	0
CSC (Out)	346
East–West	3,500
Wyman / Bigelow Export	350
Rumford Export	519
Northern New Hampshire Export	140

(a) N-1 refers to a system's first contingency—when the power element (facility) with the largest impact on system reliability is lost.

3.4.2 Model Comparison Cases

For GridView, the detailed 2016 ISO New England transmission network was obtained from the ISO's Model on Demand (MOD) database.[26] For the "Unconstrained" cases, transmission branches (lines and transformers) and interface limits were not monitored. For the "Interface-Constrained" cases, only the major interfaces shown in Table 3-1 were monitored.

3.4.3 Transmission Modeling Cases

The Transmission Modeling cases monitored 268 branches operated at 230 kV and above throughout New England. Because of the combined-cycle modeling issues described in Section 3.3.1, GSU transformer

[26] Siemens, "Model on Demand," flyer (2009), http://w3.usa.siemens.com/smartgrid/us/en/transmission-grid/products/grid-analysis-tools/model-on-demand/Documents/SWMD01_EN_MOD_S4.pdf.

branches were not monitored to prevent a GSU transformer from artificially limiting a combined-cycle plant.

3.4.3.1 Contingency Modeling

The Transmission Modeling cases used the contingencies developed for the 2010 Benchmark study case. These contingencies were derived from frequently occurring binding contingencies, which are defined as those that occurred in the past three years. A total of 160 contingencies meet these criteria, and with the current level of effort, 100 of them were converted from the ISO Operations' (EMS) network model to the PSS/E network model used in GridView.

The 2010 Benchmark study case contingencies were based on an historical network and did not include future transmission infrastructure due in service by 2016. To evaluate the effect of new transmission lines in the Wyman/Bigelow subarea, the GridView Refined Modeling cases included additional contingency cases. These cases included additional monitoring and contingencies in the CMP service territory associated with all transmission lines rated 115 kV and above.

3.4.3.2 RSP and LSP Projects Modeled in GridView

The 2016 transmission network model obtained from MOD included many RSP and Local System Plan (LSP) transmission projects. The following key RSP and LSP projects were included:

- RSP projects
  - New England East–West Solution (NEEWS)
  - Maine Power Reliability Project (MPRP)
  - Greater Rhode Island
  - Central Maine Power Local System Plan
  - National Grid—Close E1–M1 Loop
  - Auburn Area Transmission System
  - Central–Western Massachusetts
  - Boston 15 kV Enhancement
- LSP projects
  - National Grid's East Main St.
  - National Grid's Monroe VAR Support
  - National Grid's Carpenter Hill 115/69 kV Transformer
  - National Grid's Bird Road Substation
  - Vermont Electric Power Company's Essex CB 230 Closing
  - Merrimack Scrubber Loads

3.4.3.3 Phase-Shifter Modeling

The Model Comparison cases did not respect phase-shifter megawatt ratings and angle limits. The GridView Transmission Modeling and Refined Modeling cases monitored two aspects of phase shifters:

- Angle and megawatt limits defined in MOD

- Enforcement of the parallel phase-shifter operation at Baker Street and Waltham substations

3.4.4 Refined Modeling Cases

The Refined Modeling cases are sensitivity cases that used detailed resource modeling that was not available in IREMM. This allowed the study of the combined effect of modeling more detailed thermal unit heat-rate curves and transmission constraints. The additional cases developed were categorized as follows:

- Detailed modeling of thermal unit heat-rate curves and transmission constraints
- Sensitivity study using latest MPRP interface-transfer limits
- Modeling of wind/hydro coordination

3.4.4.1 Detailed Modeling of Thermal Unit Heat-Rate Curves and Transmission Constraints

GridView has the ability to reflect generating unit operational constraints, such as start-up costs, no-load costs, and incremental heat-rate curves, along with operating limits, including minimum up time, minimum down time, start-up time. These Refined Modeling cases added this level of modeling detail to allow estimating the marginal costs of supplying energy more accurately.

3.4.4.2 Sensitivity Study Using the December 2012MPRP Interface-Transfer Limits[27]

The interface limits associated with latest MPRP interface limits were investigated.

3.4.4.3 Modeling of Wind/Hydro Coordination

One of the questions that arose at the PAC during the study was the ability to better coordinate wind and hydro generation within WDAs, such as within the Wyman/Bigelow and Rumford Wind subareas. A series of cases was developed to quantify the ability to increase the energy output through an export limited interface from these two technologies. This series of cases only analyzed the wind and hydro units in Wyman/Bigelow and Rumford areas, under the All-Wind wind-penetration cases. This scenario modeled 1,200 MW of wind capacity (990 MW in Wyman/Bigelow and 230 MW in Rumford), 200 MW of hydro capacity, and 350 MW of export capability from the Wyman/Bigelow subarea.

The hydro energy was assumed to be banked (stored when the LMP dropped to, or below, a hydro threshold price), while the wind energy was assumed to be curtailed (lost when the LMP dropped to, or below a wind threshold price).

Threshold LMP values of slightly less than $0, $5, and $10/MWh were evaluated for the wind generation.

Unlike a wind unit, a hydro unit can conserve the hydro energy that cannot be used so that it could be generated at a later hour[28]. LMP threshold values of $0, $11, and $20/MWh were studied for the hydro energy banking.

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27 *Maine Power Reliability Program (MPRP): Transfer Capability Study Results*, (December 13, 2012), http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2012/dec132012/index.html.

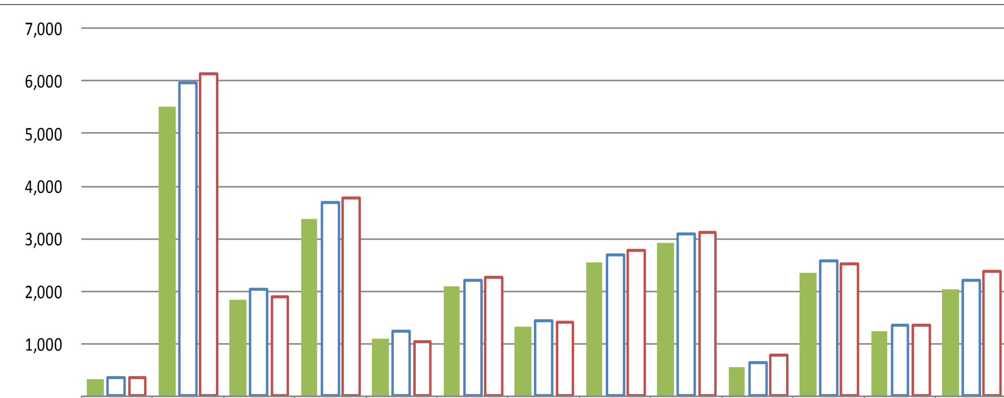
28 The amount of peaking and ponding is dependent on the restrictions of the utilization of the water resource.

Section 4
Data and Assumptions

The data and assumptions used in the two simulation models are reviewed in this section. The figures presented use descriptive statistics to illustrate the data.

4.1 Load

A production-costing model requires an hourly chronological load profile to use as the basis for simulation. The hourly profile for the 2016 load was based on the historical 2006 load shape due to the availability of time-synchronized intermittent resource data in 2006. To allocate these loads to the busses across the New England network, historical distribution factors from 2006 were used. These distribution factors resulted in slight shifts in the relative peak loads among RSP areas compared with the 2011 CELT Report. The red and blue “hollow” bars in Figure 4-1 provide a comparison of the peak loads defined in each RSP area compared with CELT values. The solid green bar shows the effect of deducting active demand resources, energy efficiency, and real-time emergency generation from the IREMM loads to get the input to GridView.

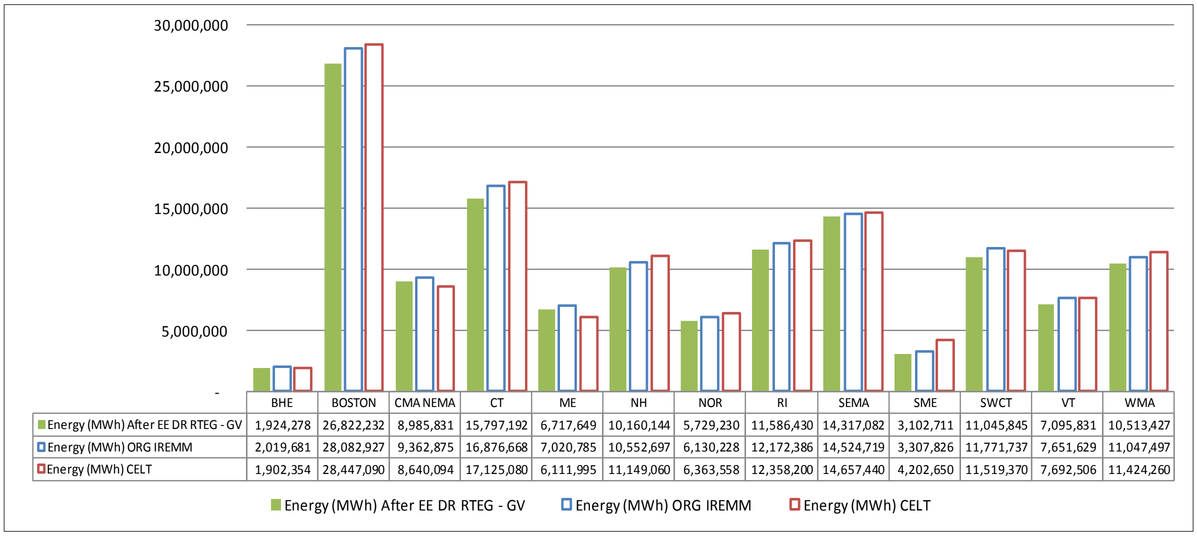


	BHE	BOSTON	CMA NEMA	CT	ME	NH	NOR	RI	SEMA	SME	SWCT	VT	WMA
Peak Load (MW) After EE DR RTEG - GV	318	5,525	1,832	3,389	1,095	2,095	1,312	2,542	2,928	545	2,362	1,226	2,041
Peak (MW) Org IREMM	350	5,970	2,035	3,695	1,235	2,200	1,425	2,700	3,100	631	2,570	1,350	2,205
Peak (MW) CELT	340	6,145	1,900	3,780	1,050	2,250	1,410	2,790	3,105	775	2,515	1,350	2,370

Peak Load (MW) After EE DR RTEG - GV   Peak (MW) Org IREMM   Peak (MW) CELT

Figure 4-1: Comparison of peak load input in GridView and CELT forecasted load for 2016.

Similarly, Figure 4-2 compares the annual energy represented in IREMM and GridView to the CELT values.



	BHE	BOSTON	CMA NEMA	CT	ME	NH	NOR	RI	SEMA	SME	SWCT	VT	WMA
Energy (MWh) After EE DR RTEG - GV	1,924,278	26,822,232	8,985,831	15,797,192	6,717,649	10,160,144	5,729,230	11,586,430	14,317,082	3,102,711	11,045,845	7,095,831	10,513,427
Energy (MWh) ORG IREMM	2,019,681	28,082,927	9,362,875	16,876,668	7,020,785	10,552,697	6,130,228	12,172,386	14,524,719	3,307,826	11,771,737	7,651,629	11,047,497
Energy (MWh) CELT	1,902,354	28,447,090	8,640,094	17,125,080	6,111,995	11,149,060	6,363,558	12,358,200	14,657,440	4,202,650	11,519,370	7,692,506	11,424,260

Figure 4-2: Comparison of energy definition in GridView and CELT forecasted load for 2016.

4.2 Fuel Prices

Fuel prices were assumed constant across all months in a year, with the exception of natural gas. Figure 4-3 shows the monthly fuel prices used for 2016. IREMM and GridView cases used the same prices.

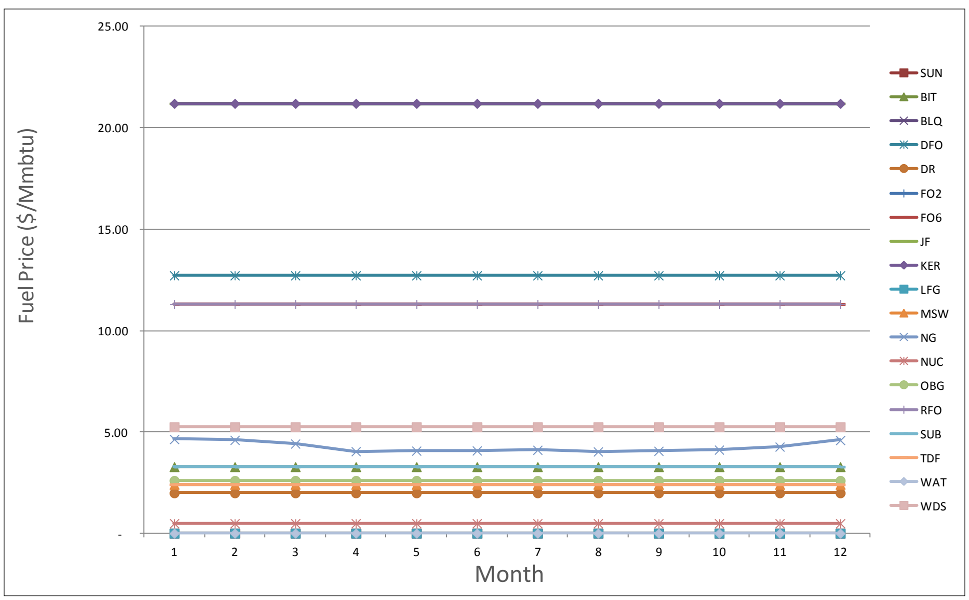


Figure 4-3: Fuel-price assumptions in GridView and IREMM 2016 cases.

Natural gas prices were assumed to vary by month over the year to reflect the seasonal trends resulting from shifts in supply and demand. Historical trends have shown that prices are higher for natural gas during the high heating winter months and lower during the low demand associated with the nonheating months. Figure 4-4 details the monthly natural gas price multiplier assumptions for the natural gas price.

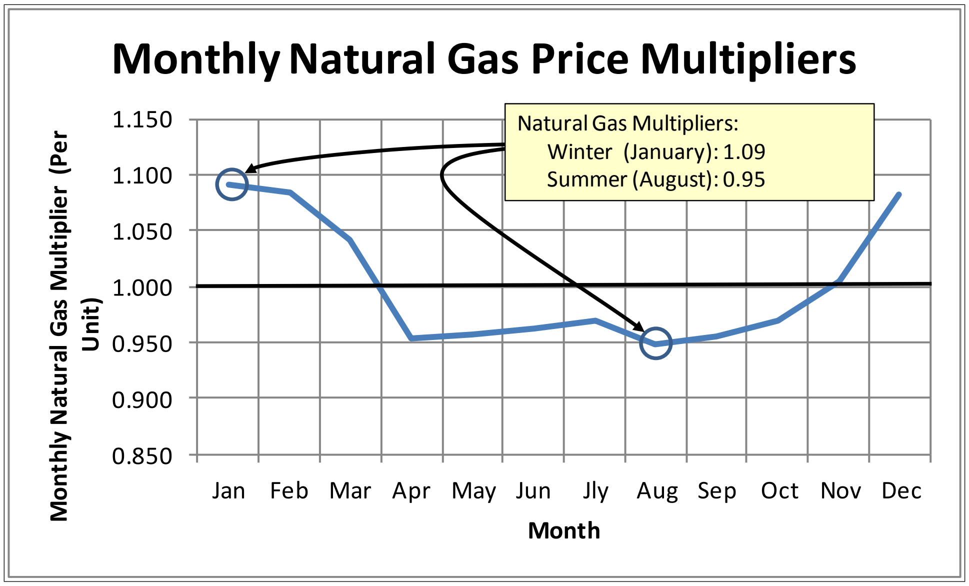


Figure 4-4: Assumed monthly natural gas multipliers.

4.3 Environmental Emissions

GridView and IREMM both based the value of emissions on the cost of emission allowances, as follows:[29]

- CO_2—$10/ton
- SO_2—$302/ton
- NO_X—$700/ton

In the simulations, the CO_2 allowance values are the most significant. While the dollar-per-ton allowance values for SO_2 and NO_X allowance values are greater than the CO_2 value, the emission rates for SO_2 and NOx are much smaller than the CO_2 emission rate.

4.4 Resource Availability

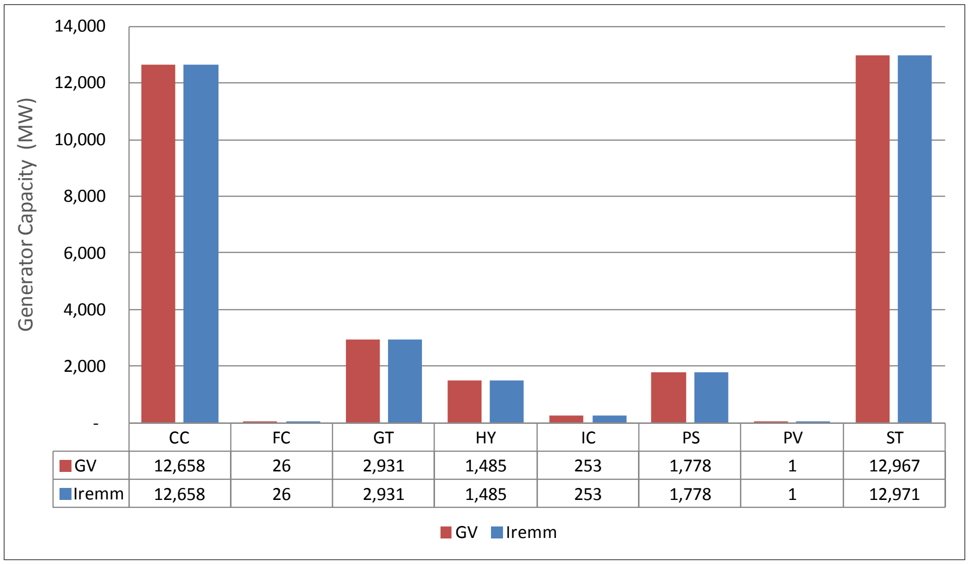
The New England equivalent availability factors for these resources were based on the assumptions used in establishing New England's Installed Capability Requirements.[30]

4.5 Thermal, Hydro, and Pumped-Storage Capacity

Figure 4-5, Figure 4-6, and Figure 4-7 present the capacities of the generating units in the GridView and IREMM cases. The wind units were reviewed separately and are not included in these comparisons.

[29] Emission allowance values do not include the effect of regulatory changes, which have greatly reduced the value of SO_2 and NO_X emission allowances.

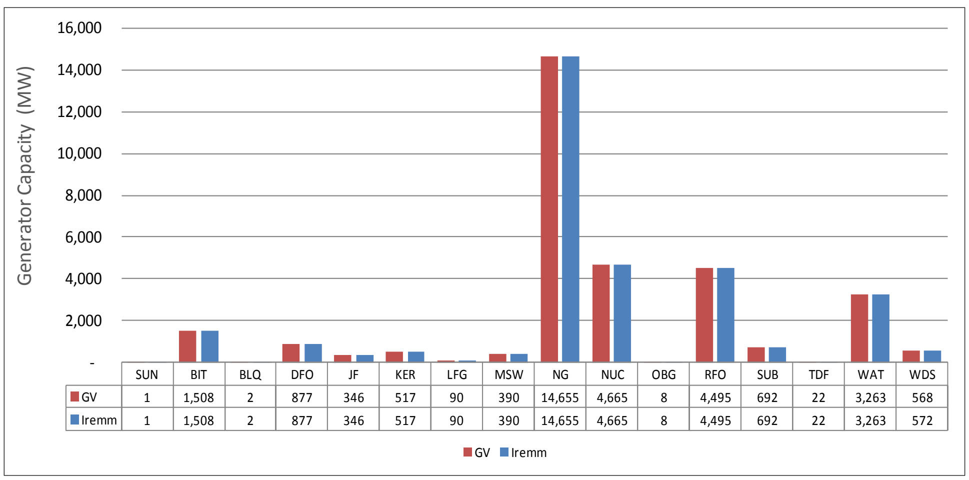
[30] *Assumptions for the Installed Capacity Requirement (ICR) for the 2013/14 Forward Capacity Auction (FCA #4)*,Power Supply Planning Committee presentation (February 18, 2010), http://www.iso-ne.com/committees/comm_wkgrps/relblty_comm/pwrsuppln_comm/mtrls/2010/feb182010/icr1314_assumptions_02_18_10.pdf.



	CC	FC	GT	HY	IC	PS	PV	ST
GV	12,658	26	2,931	1,485	253	1,778	1	12,967
Iremm	12,658	26	2,931	1,485	253	1,778	1	12,971

Figure 4-5: Comparison of GridView and IREMM generating unit capacities, by generator type (excluding wind).

Note: The Nomenclature section defines the abbreviations for generator types.



	SUN	BIT	BLQ	DFO	JF	KER	LFG	MSW	NG	NUC	OBG	RFO	SUB	TDF	WAT	WDS
GV	1	1,508	2	877	346	517	90	390	14,655	4,665	8	4,495	692	22	3,263	568
Iremm	1	1,508	2	877	346	517	90	390	14,655	4,665	8	4,495	692	22	3,263	572

Figure 4-6: Comparison of GridView and IREMM generating unit capacities, by fuel type (excluding wind).

Notes: The Nomenclature section defines the abbreviations for fuel types.

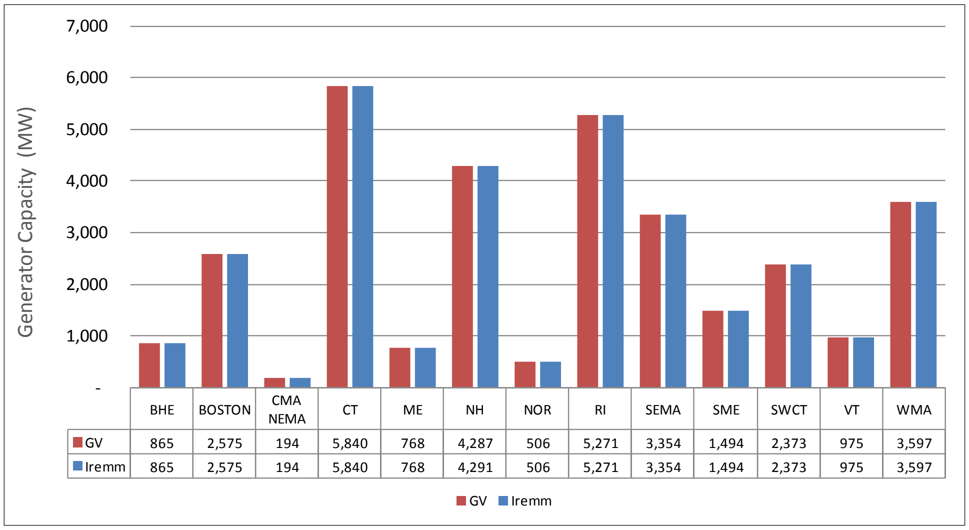


Figure 4-7: Comparison of GridView and IREMM generating unit capacities, per RSP areas (excluding wind).

4.6 Wind Generators

This section provides a statistical overview of the data for wind generators that are the focus of this study. The primary descriptive statistic is the amount and location of installed capacity in each of the three wind penetration levels, which is expressed in megawatts (MW). Supplemental statistics provide information about the amounts of energy that can be produced and whem that energy might be produced over the course of the year. The ratio of the average amount of energy that a generator can produce over the course of a year, compared to its maximum capability, is called capacity factor and is expressed as a percentage.

4.6.1 Wind Unit Capacity

Comparing the wind capacity for the three wind-penetration scenarios (FCA #5, Active Queue, and All Wind) shows the increasing wind-penetration levels. Figure 4-8 shows the installed wind capacity of each wind-development area and under each wind-penetration level. The values underlying Figure 4-8 are shown in Table 4-1.

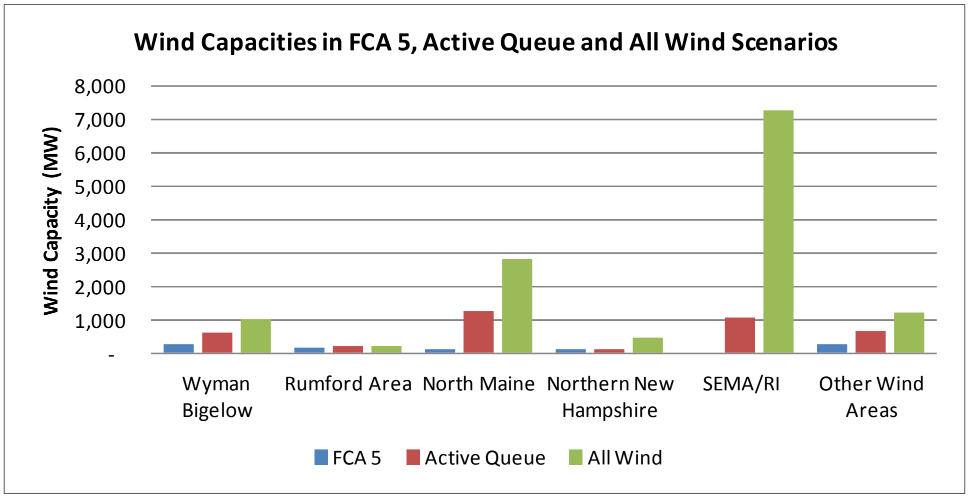


Figure 4-8: Wind capacities in FCA #5, Active Queue, and All-Wind wind-penetration cases.

Table 4-1
Wind Capacities in the FCA #5, Active Queue, and All-Wind Cases Defined in GridView

	Wind Capacity (MW)		
Wind Development Areas	**FCA 5**	**Active Queue**	**All Wind**
Wyman Bigelow	281	597	990
Rumford Area	139	191	230
North Maine	109	1,257	2,834
Northern New Hampshire	100	134	460
SEMA/RI	-	1,051	7,256
Other Wind Areas	247	680	1,227
Total	**875**	**3,910**	**12,998**

4.6.2 Wind Resource Profiles

The wind profiles used in the analysis were based on the refined regional wind models developed for NEWIS. These profiles consisted of estimated wind energy production for all 8,760 hours of the year, which is time-synchronized with the 2006 load model. This synchronization was desirable to reflect the wind conditions that occurred simultaneously with the loads and to recognize that the ramp rates of the generating units could become constraining if wind increased while loads decreased suddenly, or if wind decreased while loads increased suddenly

Table 4-2 presents the capacity factors of the wind resources at different locations. The resources within the same wind-development areas shared the same profile.

Table 4-2
Capacity Factor of Wind Resources of Various Wind Locations

Wind Area	Wind Regime	Profile	Capacity Factor	Wind Profile Type
WBHE	Northern Maine	BHE	31.50%	Inland
WBIG	Central Maine	CMP	34.00%	Inland
WIME	Central Maine	CMP	34.00%	Inland
WSME	Central Maine	CMP	34.00%	Inland
WINH	Northern NH	North NH	34.40%	Inland
NONH	Northern NH	North NH	34.40%	Inland
WIVT	Vermont	VT	34.20%	Inland
WIMA	Western Mass	WMA	34.10%	Inland
WOMA	Offshore Mass	SEMA	41.90%	Offshore
WORI	Offshore RI	RI	42.30%	Offshore

Figure 4-9 and Figure 4-10 present two wind profiles to illustrate the offshore and onshore wind profiles. Figure 4-9 shows an offshore profile (SEMA/RI) for both a chronological profile and an average profile for a rolling 24-hour window. The rolling window profile is presented to provide a clearer view of the wind trends. Figure 4-10 shows a similar pair of profiles for Northern Maine (WBHE).

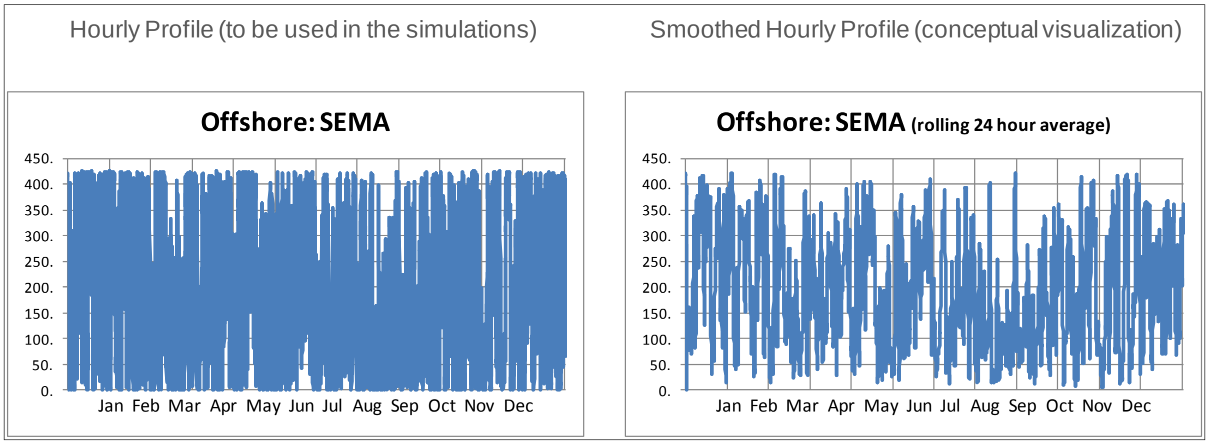


Figure 4-9: SEMA/RI offshore wind profiles based on NEWIS profiles.

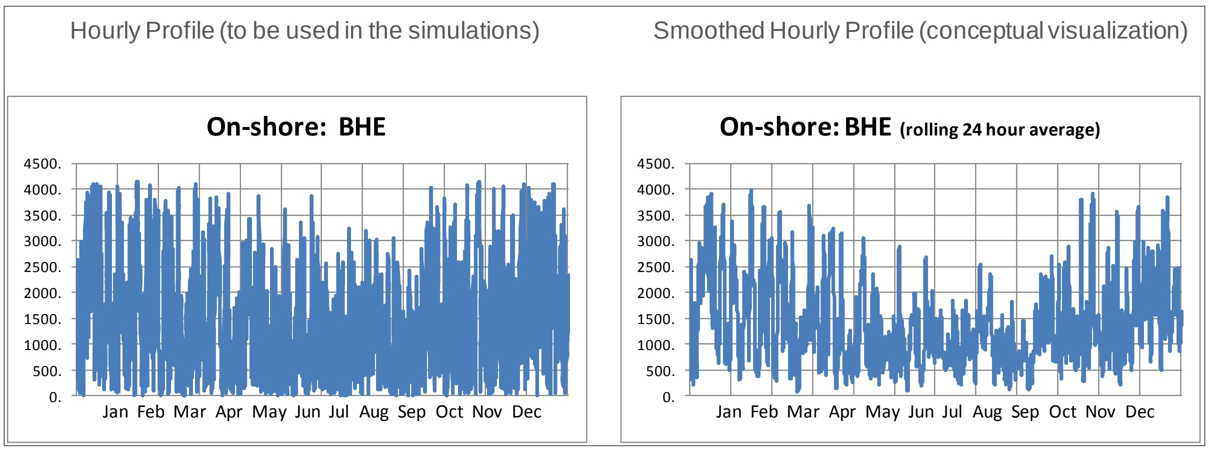


Figure 4-10: BHE onshore wind profiles based on NEWIS profiles.

4.7 Active Demand Response, Energy Efficiency, and Real-Time Emergency Generation

The demand resources modeled in New England were based on the 2013/2014 capacity supply obligations (including proration) as shown in Table 4-3.

Table 4-3
Amount and Type of Demand Resources in New England (MW, 2016)

Resource Type	Megawatts with Obligations
Real-time demand-response	1,172
Energy efficiency (seasonal and on peak)	1,148
Real-time emergency generation (activated in OP #4, Action 6[31])	683

For these economic studies, the ISO explicitly modeled the energy efficiency and demand response by developing a profile for each of the three components. These profiles underscore the ISO's expectation that active demand-response and real-time emergency generators will be called and must be ready to respond.[32] Figure 4-11 presents the hourly values of active demand response, energy efficiency, and emergency generation, which were used to modify the hourly load. This modified load was satisfied in both the IREMM and GridView simulations.

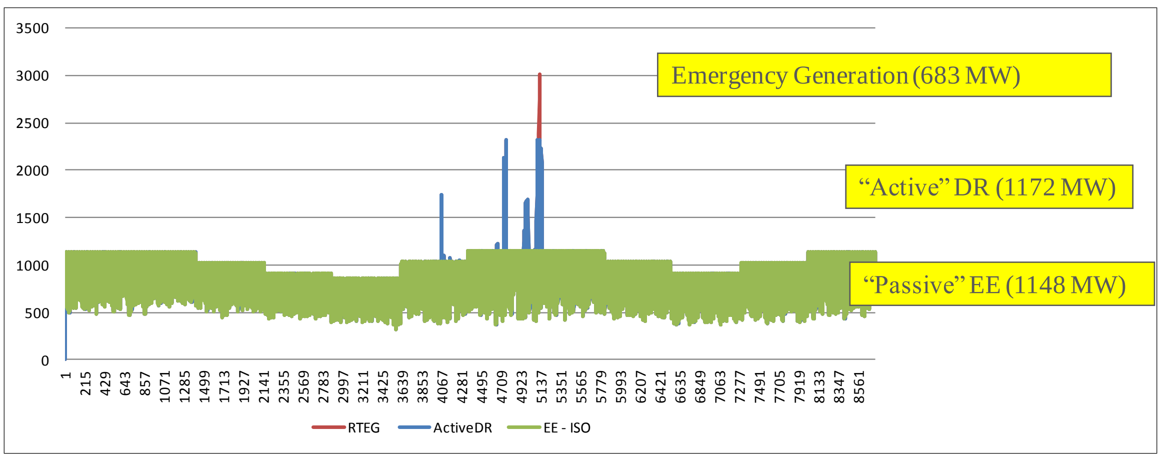


Figure 4-11: Chronological curve of energy efficiency, active demand resources, and real-time emergency generation values.

Table 4-4 shows the capacity of energy efficiency, active demand response, and real-time emergency generators by RSP area included in the simulations.

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31 OP 4 actions include allowing the depletion of the 30-minute and partial depletion of the 10-minute reserves (1,000 MW), scheduling market participants' submitted emergency transactions and arranging emergency purchases between balancing authority areas (1,600 to 2,000 MW), and implementing 5% voltage reductions (400 to 450 MW). Operating Procedure No. 4, *Action during a Capacity Deficiency* (December 9, 2011), http://www.iso-ne.com/rules_proceds/operating/isone/op4/index.html.

32 This approach to modeling demand response is preferable to modeling a "pseudo-generator" with a high, fixed dispatch price because they are rarely "dispatched" in production simulation models. This is because production cost models are mostly "expected-value" models and typically underestimate the times when active demand response (and peaking units) will be called. Publishing a profile with unrealistically low estimates of how often active demand resource would be needed is thought to provide an erroneous market signal.

Table 4-4
Energy Efficiency, Active Demand Response, and Real-Time Emergency Generation Capacities (MW) by RSP Areas

	Energy Efficiency			Active Demand Response				Real-Time Emergency Generation			
RSP Area	2010	2011	2012	2010	2011	2012	2013	2010	2011	2012	2013
BHE	4	9	15	33	36	37	39	3	3	5	5
BOST	133	172	204	84	83	205	241				
CMAN	40	52	62	42	58	50	61	211	212	297	312
CT	144	153	173	137	103	113	133				
ME	14	28	47	100	109	111	117	10	9	16	16
NH	41	55	62	34	39	35	43				
NOR	53	57	64	51	38	42	49				
RI	62	81	95	33	79	43	63				
SEMA	68	88	104	57	62	136	137				
SME	10	20	35	76	83	84	88	8	7	12	12
SWCT	96	102	115	91	68	74	87	389	347	294	338
VT	55	72	89	30	53	29	35				
WMA	55	70	83	56	77	66	81				
Total	775	959	1148	824	888	1025	1174	621	578	624	683

4.8 Imports and Exports

One of the key assumptions was New England's import/export interchange flows with New York, Quebec, and New Brunswick (Maritimes). The diurnal flows across these external interfaces are presented in Figure 4-12 to Figure 4-16. These graphs show the profiles for each of the three years with the three-year average shown as a thick blue line.

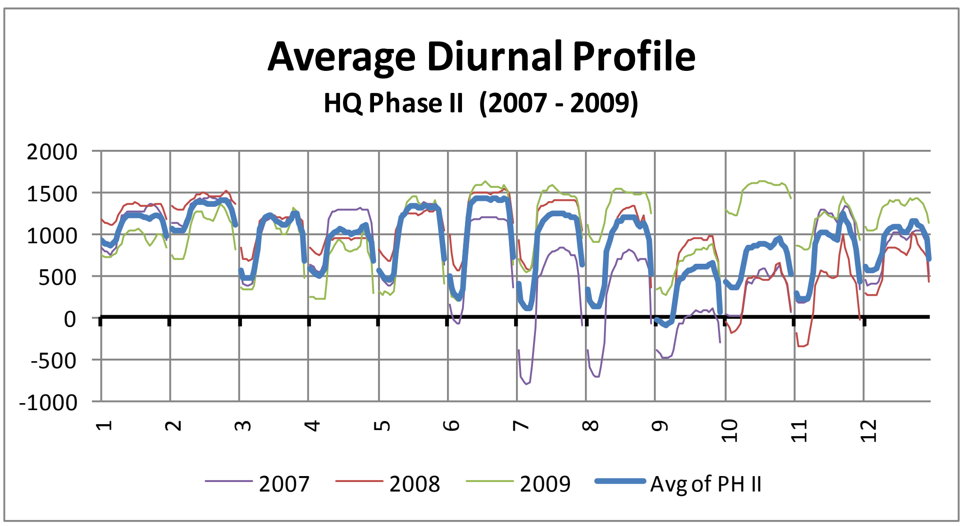

Figure 4-12: Average diurnal flows by month, representing net energy injections into New England at HQ Phase II (MW).

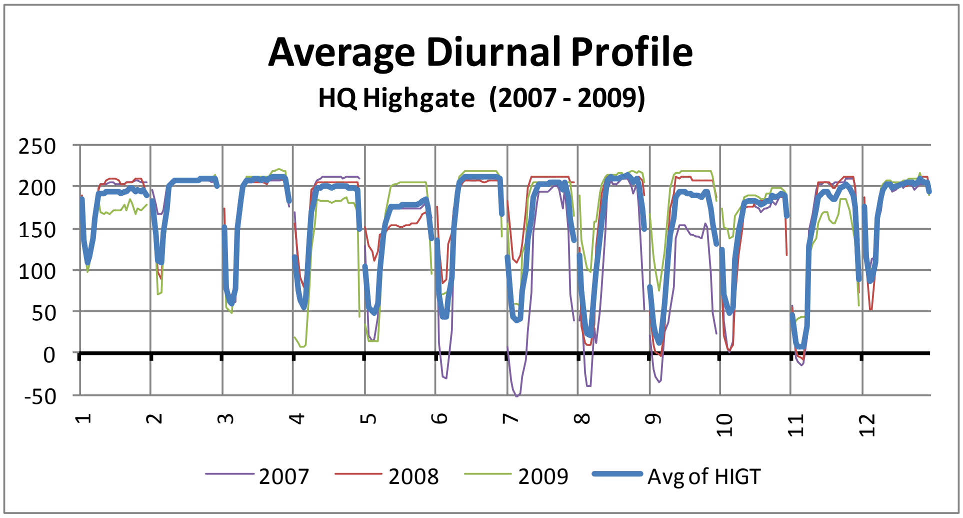

Figure 4-13: Average diurnal flows by month, representing net energy injections into New England at Highgate (MW).

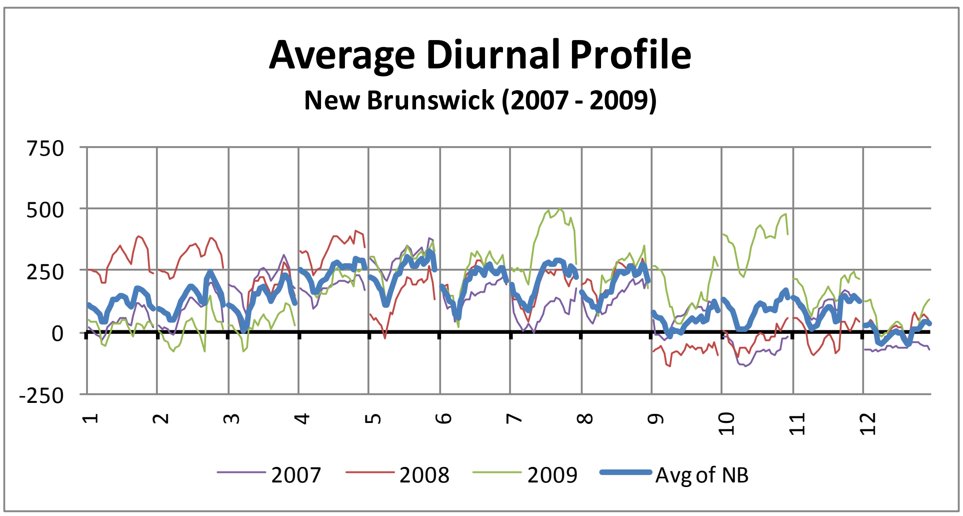

Figure 4-14: Average diurnal flows by month, representing net energy injections into New England at New Brunswick (MW).

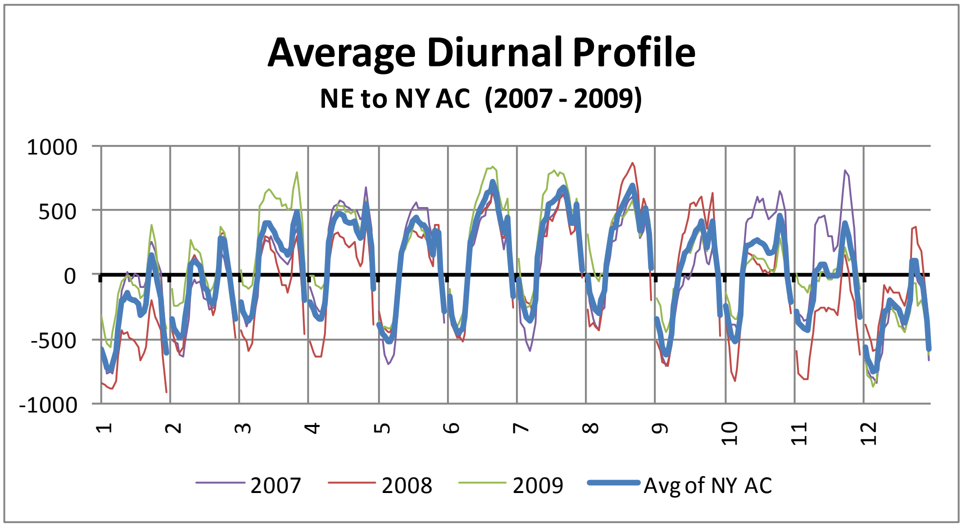

Figure 4-15: Average diurnal flows by month, representing net energy injections into New England at the NY AC tie (MW).

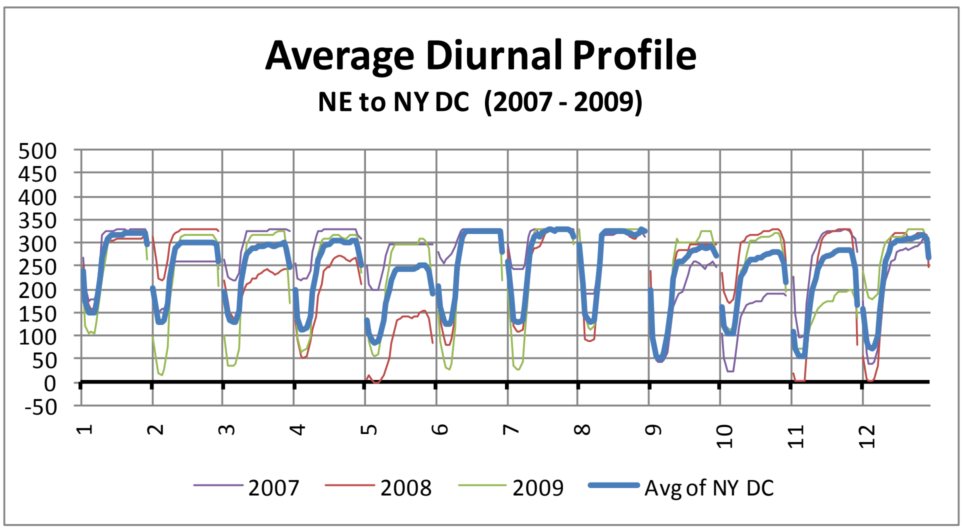

Figure 4-16: Average diurnal flows by month, representing net energy injections into New England at Cross-Sound Cable (MW).

Figure 4-17 shows the annual chronological hourly representation and the annual flow-duration curves for each of the interfaces, assuming the monthly diurnal profiles.

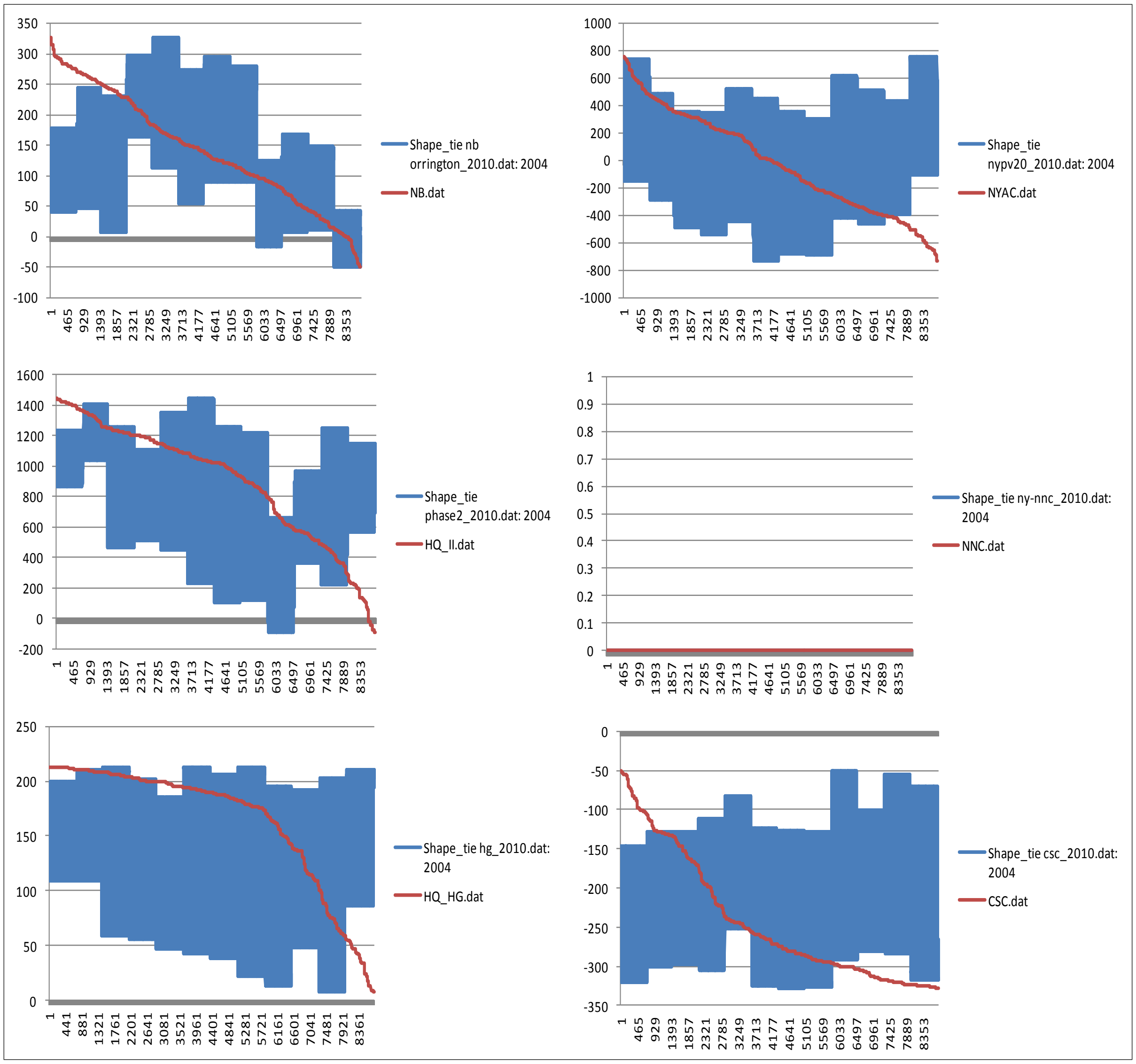

Figure 4-17: Chronological and duration curves of imports/exports with neighboring systems (MW).

Section 5
Study Cases

This study assessed four categories of cases that began with the model comparison cases (IREMM vis-à-vis GridView) followed by more detailed analyses by GridView. The remainder of this report groups the discussion and results of the underlying cases by these four major case categories. The cases include evaluations at the three wind-penetration levels: wind resources from FCA #5, the Active Queue, and All Wind.

- "Model Comparison" cases (six cases each for IREMM and GridView)
- "Transmission Modeling" cases (six GridView cases only)
- "Refined Modeling" cases (ten GridView cases only)
- "Hydro/Wind Coordination" cases (nine GridView cases only)

5.1 Model Comparison Cases (IREMM and GridView)

Six major cases were investigated during the model comparison phase of the study, developed from two transmission representations and three different outlooks for the penetration of wind capacity. Table 5-1 shows the case matrix for this phase of the study. The IREMM results were compared with the GridView results for these six cases, which are highlighted by a green dashed line in the table. The horizontal direction in the table shows the scenarios with increasing wind penetrations from FCA #5 to the All-Wind cases. The vertical direction shows the two levels of transmission modeling: Unconstrained and Interface-Constrained.

Table 5-1
GridView 2011 Economic Study—Model Comparison Cases

Scenarios / Level	FCA 5	Active Queue	All Wind	Comments
Case 1 Unconstrained	FCA 5 – Unconstrained	Active Queue - Unconstrained	All Wind - Unconstrained	Benchmark with IREMM
Case 2 Interface Constrained	FCA 5 - Interface Constrained	Active Queue - Interface Constrained	All Wind - Interface Constrained	Benchmark with IREMM

5.2 Transmission Modeling Cases (GridView)

Table 5-2 adds the GridView Transmission Modeling cases to the matrix of cases shown in Table 5-1. Two additional sensitivities were included in this second phase of the study, which only used GridView, adding six detailed transmission network model cases. These are highlighted by a brown dashed line in Table 5-2. These cases include additional monitored elements, reflecting 268 lines and associated transformers at or above 230 kV. These cases also include 100 contingencies obtained from the 2010 Benchmark case. Of these 100 contingencies, four were in the CMP subarea.

Table 5-2
GridView 2011 Economic Study—Transmission Modeling Cases

Level \ Scenarios	FCA 5	Active Queue	All Wind	Comments
Case 1 Unconstrained	FCA 5 – Unconstrained	Active Queue - Unconstrained	All Wind - Unconstrained	Benchmark with IREMM
Case 2 Interface Constrained	FCA 5 - Interface Constrained	Active Queue - Interface Constrained	All Wind - Interface Constrained	Benchmark with IREMM
Case 3 Detailed Modeling	FCA 5 - Detailed System Simulation	Active Queue - Detailed System Simulation	All Wind - Detailed System Simulation	Transmission Modeled in Detail
Case 4 Barnstable Relaxed	FCA 5 - Detailed System Simulation	Active Queue - Detailed System Simulation	All Wind - Detailed System Simulation	Barnstable Autotransformer Not monitored

Upon reviewing the results of these GridView Transmission Modeling cases, the ISO observed a large amount of bottled-in wind in the All-Wind wind-penetration cases and that the SEMA/RI export interface was congested in only a few hours. Because this was an unexpected result, the ISO investigated the reasons for the large amount of bottled-in energy. This case resulted in a new Case 4 referred to as the "Barnstable Relaxed" case, where the Barnstable autotransformer is not monitored.

5.3 Refined Modeling Cases (GridView)

The next level of detail was included in the third phase of the study, the "Refined Modeling" cases. These cases include detailed modeling of heat-rate curves for thermal units and continued investigation of more detailed modeling of transmission constraints. Four additional sensitivities, comprising 10 additional cases, were included in the Refined Modeling cases. Table 5-3 shows the case matrix with these supplemental cases highlighted within the dotted brown lines. These cases were compared to Case 4, the Barnstable Relaxed case.

Table 5-3
GridView 2011 Economic Study—Refined Modeling Cases

Level \ Scenarios	FCA 5	Active Queue	All Wind	Comments
Case 1 Unconstrained	FCA 5 – Unconstrained	Active Queue - Unconstrained	All Wind - Unconstrained	Benchmark with IREMM
Case 2 Interface Constrained	FCA 5 - Interface Constrained	Active Queue - Interface Constrained	All Wind - Interface Constrained	Benchmark with IREMM
Case 3 Detailed Modeling	FCA 5 - Detailed System Simulation	Active Queue - Detailed System Simulation	All Wind - Detailed System Simulation	
Case 4 Barnstable Relaxed	FCA 5 - Detailed System Simulation	Active Queue - Detailed System Simulation	All Wind - Detailed System Simulation	Barnstable Autotransformer Not monitored
Case 5a Detailed Resource Operating Parameters	FCA 5 - Detailed System Simulation	Active Queue - Detailed System Simulation	All Wind - Detailed System Simulation	Based on Case 4
Case 5b Monitor 115 kV, and above, lines in CMP	FCA 5 - Detailed System Simulation	Active Queue - Detailed System Simulation	All Wind - Detailed System Simulation	Based on Case 5a
Case 5c Expanded Wyman/Bigelow Contingencies	FCA 5 - Detailed System Simulation	Active Queue - Detailed System Simulation	All Wind - Detailed System Simulation	Based on Case 5b
Case 5d Expanded Contingencies with New MPRP Limits	Due to Wind Penetration, Assumed Equivalent to Case 5c	Due to Wind Penetration, Assumed Equivalent to Case 5c	All Wind – Reflect MPRP Transmission Limits	Based on Case 5c

The Refined Modeling cases were developed with these modeling assumptions:

- **Case 5a: Detailed Resource Operating Parameters—**the detailed operating performance parameters for thermal units were obtained from the 2010 Benchmark Study case. This data allowed the use of multiple-block heat-rate curves instead of a single-block heat-rate value that IREMM used, and which GridView also used, in the Model Comparison cases discussed above. For example, in the GridView Model Comparison cases, the minimum operating level was assumed to be 10%of the unit capacity rating to allow GridView to mimic the IREMM modeling, which allowed a zero output level and had no unit-commitment logic. GSU transformers remained excluded from the list of monitored elements.
- **Case 5b: Monitor 115 kV Lines, and Above, in CMP—**Case 5a was used as the starting point for this case. All 115 kV lines and above in the Central Maine Power service territory were

monitored for thermal overloads under "all-lines-in" conditions. In the Transmission Modeling cases, 268 lines were monitored, all of which were 230 kV and above. In this case, an additional 163 115 kV lines were monitored to identify the binding constraints that may limit the wind output in this area. The interface limits shown in Table 3-1 are the only voltage and stability constraints modeled because these constraints require external studies to establish the limits.

- **Case 5c: Expanded Wyman/Bigelow Contingencies—**Case 5c was based on Case 5b with 15 additional N-1 contingencies modeled. These additional contingencies are associated with the loss of each 115 kV line in the Wyman/Bigelow and Rumford subareas. After the loss of any 115 kV line, all remaining 115 kV lines in this area were monitored for thermal overloads.
- Case 5d: Expanded Contingencies with New MPRP Limits—this sensitivity case evaluated the impact of the most recent estimate of the Maine Power Reliability Project interface voltage and stability limits. These are shown in **Error! Reference source not found.** for the three affected nterfaces. The transmission network obtained from MOD contained the MPRP infrastructure additions.

Table 5-4 MPRP Interface Limit Values Used in MPRP Sensitivity Case

Interface Name	Initial Value (MW)	Value from the latest MPRP studies (MW)
Orrington South	1,200	1,325
Surowiec South	1,150	1,500
ME - NH	1,450	1,900

5.4 Hydro/Wind Coordination (GridView)

The ISO developed a series of cases to investigate the potential benefits of coordinating wind and hydro generation in the Wyman/Bigelow and Rumford subareas. Wind cannot be stored, but within limits, hydro energy can be. This analysis focused on the ability to model and quantify the benefits of storing hydro energy during periods of high wind production. This is in contrast to dispatching the hydro energy and not being able to use the wind energy. The metric used to evaluate performance was the combined wind plus hydro generation, without violating any constraints on the transmission network.

Table 5-5 shows the additional cases and how they were used to investigate the use of storing hydro energy to accommodate the production of more energy from wind. In Case 6a1, where both hydro and wind curtailed at an LMP of $0/MWh, the simulations assume the hydro energy would be stored before the wind energy was curtailed (i.e., wind was curtailed when the LMP was slightly less than $0/MWh).

Table 5-5
GridView 2011 Economic Study—Hydro/Wind Coordination Cases

Scenarios / Level	Wind Curtails at < $0/MWh	Wind Curtails at $5/MWh	Wind Curtails at $10/MWh
Case 6a Hydro Banks at $ 0/MWh	6a1) Wind Curtails before Hydro Banks	6a2) Wind Curtails before Hydro Banks	6a3) Wind Curtails before Hydro Banks
Case 6b Hydro Banks at $11/MWh	6b1) Hydro Banks Before Wind Curtails	6b2) Hydro Banks Before Wind Curtails	6b3) Hydro Banks Before Wind Curtails
Case 6c Hydro Banks at $20/MWh	6c1) Hydro Banks Before Wind Curtails	6c2) Hydro Banks Before Wind Curtails	6c3) Hydro Banks Before Wind Curtails

These cases must be compared to each other and cannot be directly compared to any of the previous cases. This is because GridView dispatched the hydro using an optimization algorithm whereas the other cases used fixed input profiles.

Section 6
Simulation Results

This section presents the simulation results and observations from the many cases investigated. For the Model Comparison cases, IREMM and GridView simulation results are presented together for comparison. All other cases simulated with GridView are presented in groups of sensitivity cases to illustrate the model's response to different assumptions and modeling techniques.

One of the key aspects of this study was to investigate how much wind was produced in each wind-development area and how transmission constraints affected wind production. The study also discusses which issues could, and could not, be factored into this analysis. The GridView simulations include perfect foresight. This ability to accurately look ahead minimizes the impacts of constraints that result from shortages of flexible resources.

6.1 Model Comparison Cases (Cases 1 and 2)—Effect of Wind Penetration

For the Model Comparison cases, the IREMM results were compared to the GridView cases. Table 6-1 presents the results of the economic metrics for production cost and LSE energy expense.

Table 6-1
IREMM and GridView Results for LSE Expense and Production Cost (Million $)

	Production Cost			LSE Energy Expense		
	FCA5	Active Queue	All Wind	FCA5	Active Queue	All Wind
IREMM Unconstrained	3324	2936	1833	6635	6319	5257
GridView Unconstrained	3321	2913	1867	7056	6418	4930
IREMM Interface Constrained	3324	2955	1949	6635	6333	5503
GridView Interface Constrained	3324	2928	1973	7056	6436	5211

6.1.1 Economic Metrics—Production Cost

Figure 6-1 shows a comparison of the production cost metric for each of the IREMM and GridView Model Comparison cases. This figure shows the following results:

- For Case 1, the Unconstrained cases, the GridView results are very close to the IREMM results.
- For Case 2, the Interface-Constrained cases, the GridView results and the IREMM results are close in all three scenarios because the interface limits caused little bottled-in wind energy.
- At higher penetration levels of wind, the production cost was reduced significantly.
- The two models produced similar results for production costs.

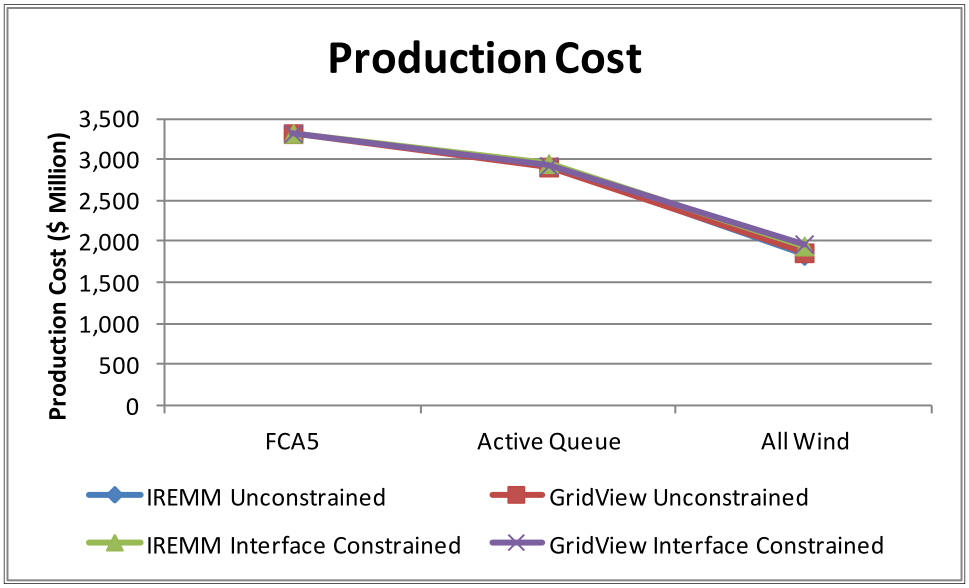

Figure 6-1: Comparison of GridView and IREMM production costs for the Unconstrained and Interface-Constrained cases.

6.1.2 Economic Metrics—LSE Energy Expense

The LSE energy expense metric is influenced by many factors and has some peculiar characteristics. For example, the aggregate New England LSE energy expense metric may increase or decrease if excess wind causes an export-constrained area, or areas, to experience very low LMPs while other areas have very high LMPs due to congestion. This is because the energy that cannot be exported may set very low local clearing prices (decreases LSE energy expense in the area), while the high-marginal-cost resources set the clearing prices in import-constrained areas (increases LSE energy expense). These divergent LMPs have the potential to distort the trend for the LSE energy-expense metric. The net increase or decrease of the aggregate LSE energy expense would be affected by the magnitude and geographic scope of the areas with increased LMPs vis-a-vis the geographic scope of the areas with decreased LMPs.

Figure 6-2 shows the LSE energy expense for the IREMM and GridView Model Comparison cases. This figure shows the following results:

- For Case 1, the Unconstrained case, the GridView results are very close to the IREMM results.
- For Case 2, the Interface-Constrained case, the GridView results and the IREMM results are close. However, in the All Wind GridView cases, the interface limits slightly increased the amount of system congestion, and the system congestion drove up the LSE energy expense.
- The IREMM results are the same for the Unconstrained and Interface-Constrained cases.

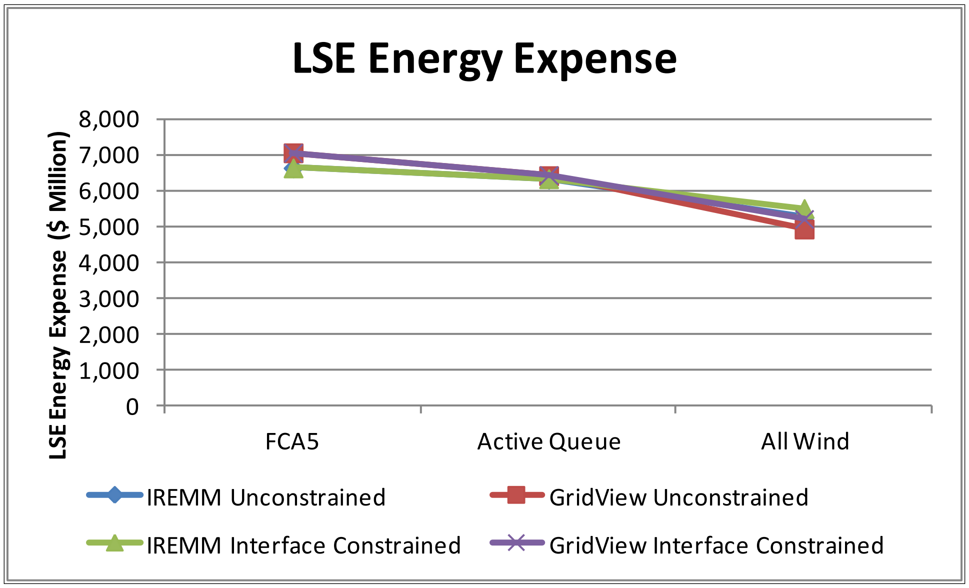

Figure 6-2: Comparison of GridView and IREMM LSE energy expenses for the Unconstrained and Interface-Constrained cases.

The Interface-Constrained cases for both models are nearly identical for the FCA #5 and Active Queue cases.

The IREMM and GridView All-Wind wind-penetration cases both show about $250 Million increase in LSE Energy Expense due to congestion. GridView shows the same trends, although wind penetration had a slightly greater effect on LSE energy expense. GridView tended to have lower LSE Energy Expense that IREMM. This is attributed to some coal units that set lower LMPs in GridView than in IREMM for the All-Wind cases.

6.1.3 Generation by Fuel Types

Because both IREMM and GridView used many of the same high-level inputs for these cases, the results from the two models were expected to be similar. This can be seen in Table 6-2, which shows the energy generated by fuel type for these cases:

- The IREMM and GridView results were not significantly affected by the presence of the interface constraints.
- The IREMM and GridView results differ somewhat in the amount of energy produced by coal, which affected the amount of gas generation. This difference is attributed to the lower cost of two coal units in GridView that did not reflect the units' CO_2 emission allowance costs. The lower dispatch price led to the coal units in GridView, being dispatched more often and occasionally setting a lower clearing price than IREMM.

Table 6-2
Generation by Fuel Type—Model Comparison Cases (GWh)

	Coal	Gas	Hyd/Oth	Nuclear	Oil	Wind	Biomass
FCA5							
IREMM Unconstrained	5,029	77,284	19,520	37,760	49	2,590	5,859
GridView Unconstrained	6,885	74,338	21,319	37,770	583	2,635	4,561
IREMM Interface Constrained	5,029	77,308	19,515	37,760	49	2,590	5,859
GridView Interface Constrained	6,890	74,397	21,318	37,770	778	2,587	4,545
Active Queue							
IREMM Unconstrained	3,257	69,806	19,462	37,760	7	12,140	5,859
GridView Unconstrained	6,245	67,631	21,181	37,770	548	12,187	4,560
IREMM Interface Constrained	3,264	70,232	19,205	37,760	7	12,001	5,859
GridView Interface Constrained	6,268	67,731	21,185	37,770	562	12,087	4,517
All Wind							
IREMM Unconstrained	973	43,474	19,236	36,359	-	43,376	5,246
GridView Unconstrained	4,024	41,882	20,698	36,048	149	43,381	3,940
IREMM Interface Constrained	1,185	46,318	18,526	36,857	-	40,884	4,718
GridView Interface Constrained	4,168	44,069	20,098	36,640	215	40,948	3,984

From a high-level perspective, as the wind penetration increased, the wind energy generated increased and thermal generation decreased. Natural gas generation decreased the most. The results for both the IREMM and GridView models show that the nuclear generation was affected when wind penetration was high because nuclear units were dispatchable and could be displaced by wind.

Comparing the wind energy generation across the cases shows that some wind was bottled-in when the interfaces were constrained. This effect was most pronounced in the All-Wind wind penetration case where approximately 2,500 GWh of wind energy was constrained behind interfaces, and natural gas largely replaced this energy.

6.1.3.1 FCA #5

Figure 6-3 compares the GridView and IREMM generation results by fuel type for the Unconstrained cases. This figure shows that the GridView simulation produced slightly less energy from natural gas and slightly more from coal. For the Interface-Constrained case, Figure 6-4 shows the same trend, which is to be expected, because there was little congestion in these cases. These Model Comparison cases for FCA #5 wind penetration show that the GridView results are close to the IREMM results.

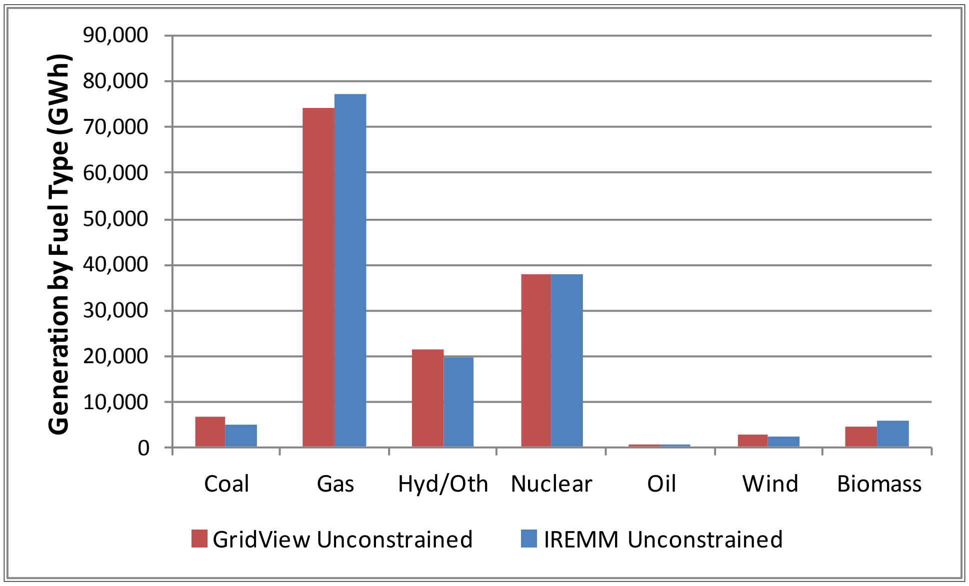

Figure 6-3: Comparison of GridView and IREMM results for generation by energy sources—Case 1 (Unconstrained) under FCA #5 wind penetration.

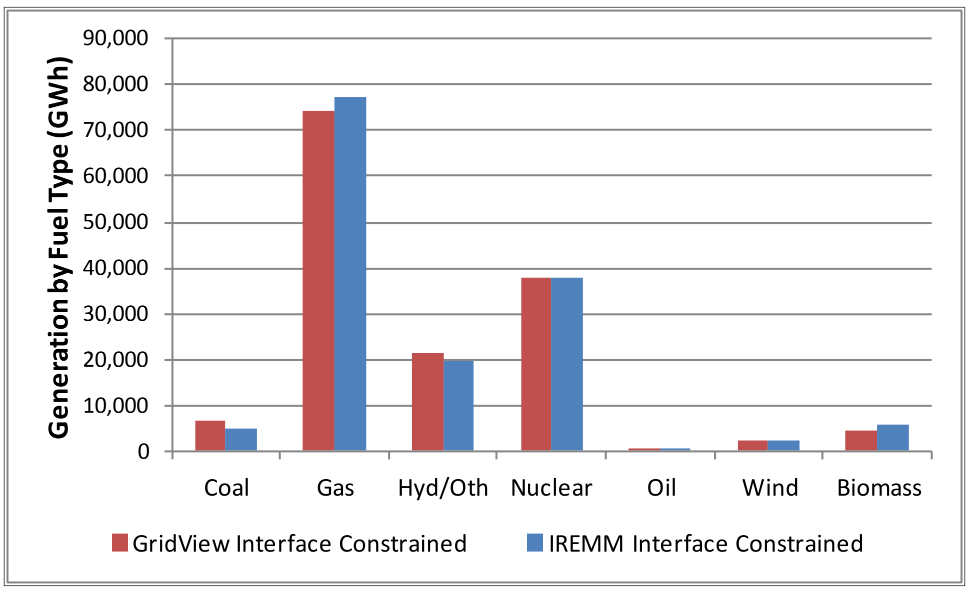

Figure 6-4: Comparison of GridView and IREMM results for generation by energy sources—Case 2 (Interface Constrained) under FCA #5 wind penetration.

6.1.3.2 Active Queue

For the Active Queue wind-penetration cases, Figure 6-5 and Figure 6-6 present the generation by fuel types for the Unconstrained and Interface-Constrained cases. The results of the two models broadly agree. The increase in wind from the FCA #5 case displaced mostly natural gas generation and some coal. The GridView cases continue to show more coal-based generation than IREMM.

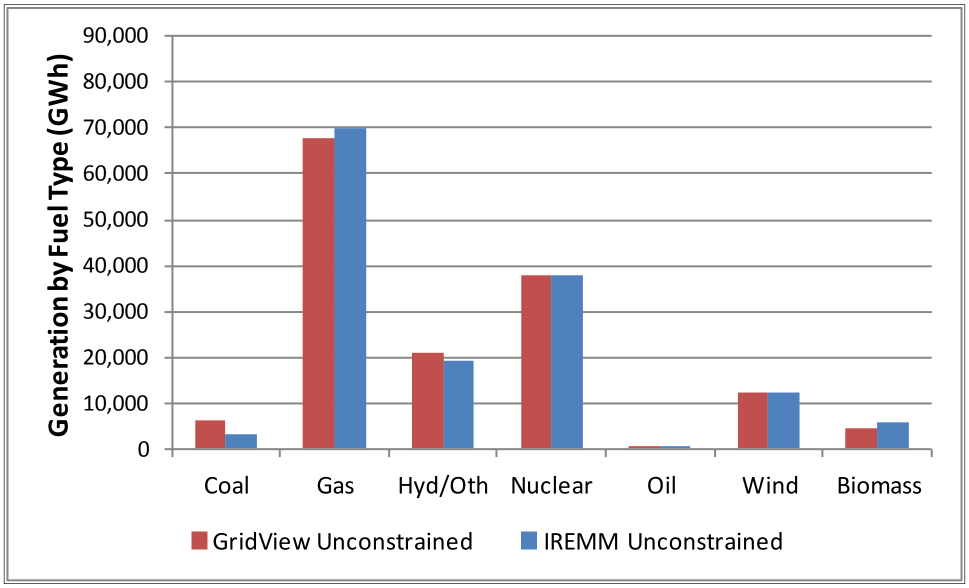

Figure 6-5: Comparison of GridView and IREMM results for generation by energy sources—Case 1 (Unconstrained) under Active Queue wind penetration.

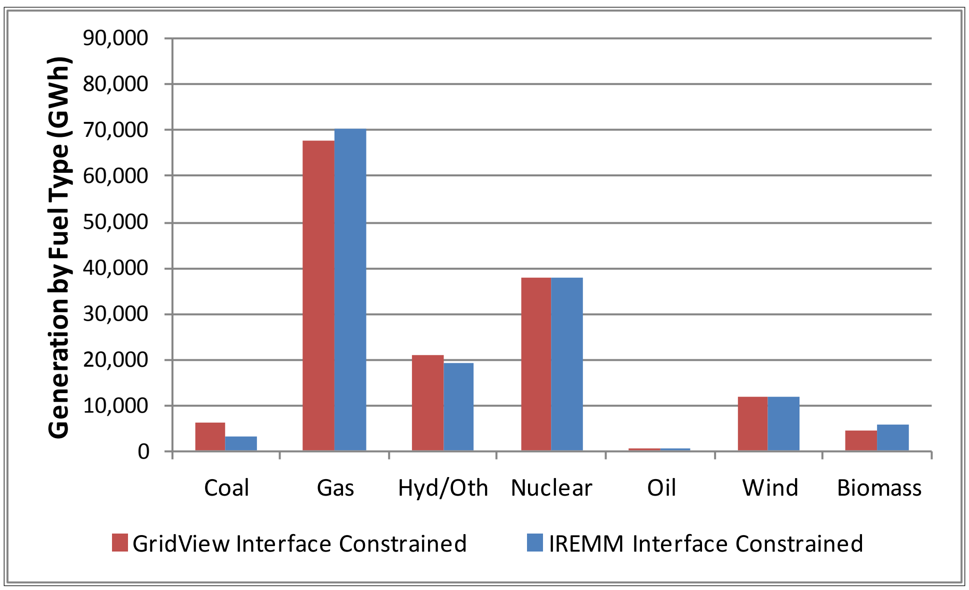

Figure 6-6: Comparison of GridView and IREMM results for generation by energy sources—Case 2 (Interface Constrained) under Active Queue wind penetration.

6.1.3.3 All Wind

For the All-Wind wind-penetration cases, Figure 6-7 and Figure 6-8 present the generation by fuel type for the Unconstrained and Interface-Constrained cases. Again, the results for the two models broadly agree, which shows increasing wind penetration from the Active Queue case displaced mostly natural gas generation and some coal. The results show more coal energy with GridView than with IREMM.

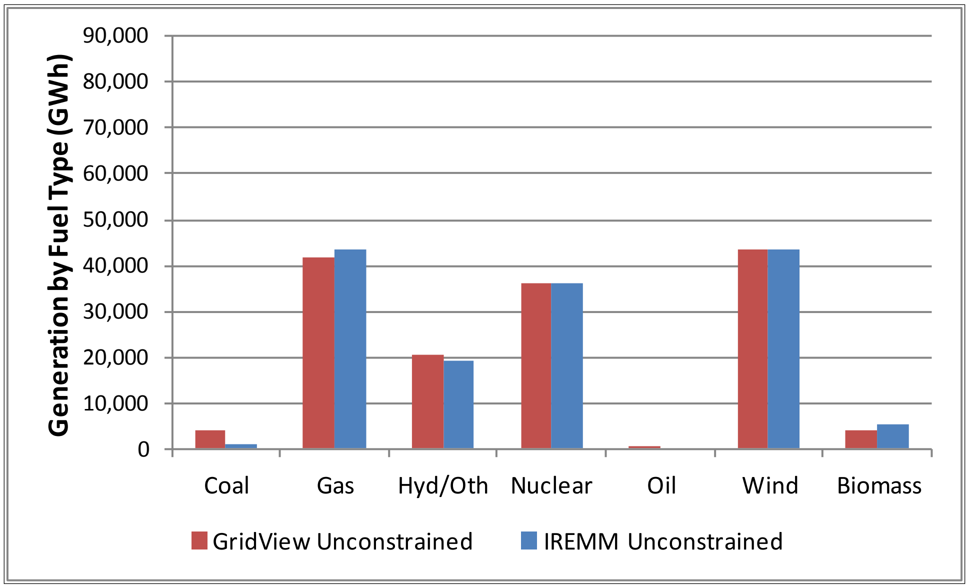

Figure 6-7: Comparison of the GridView and IREMM results for generation by energy sources—Case 1 (Unconstrained) under All-Wind wind penetration.

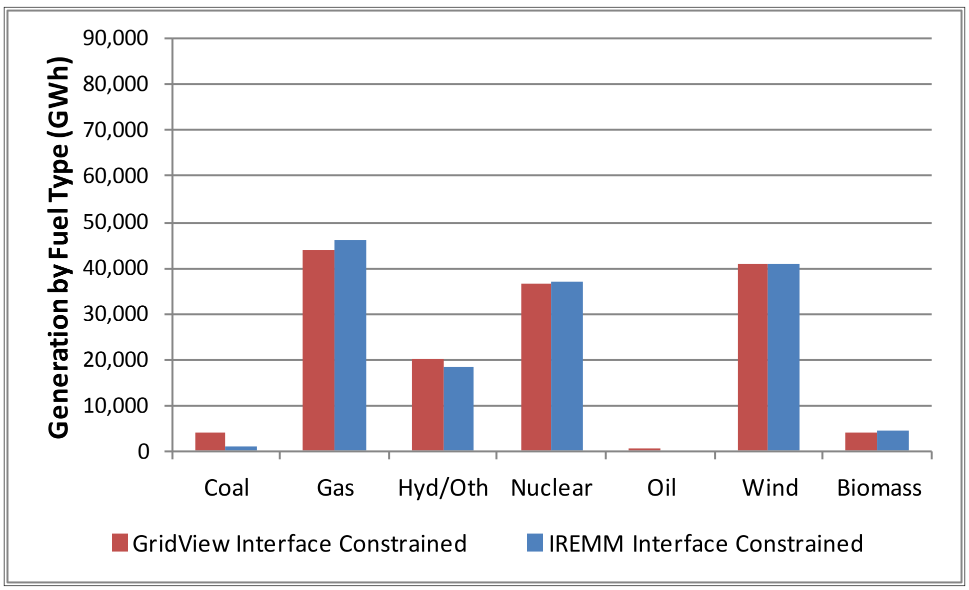

Figure 6-8: Comparison of GridView and IREMM results for generation by energy sources—Case 2 (Interface Constrained) under All-Wind wind penetration.

6.1.4 Wind Generation

For the Model Comparison cases, the amount of wind generation is relatively consistent between the IREMM and the GridView cases because both models relied on input hourly profiles and assumed the energy was injected into each region at zero cost. Thus, the amount of energy available was identical prior to the models deciding between wind energy and other resources when faced with constraints.

Table 6-3 shows the wind generation by wind-development area for the Model Comparison cases. As expected, more wind energy was generated in the higher wind-penetration cases. The very large growth of wind in SEMA/RI for the All-Wind cases is clearly the most prominent feature of the wind-generation data. Even with this large amount of energy in SEMA/RI, the Unconstrained and Interface-Constrained cases differed very little, suggesting that the SEMA/RI interface limit reduced the dispatch of other resources within the SEMA/RI region that had a higher dispatch cost than wind. This resulted in curtailing only small amounts of wind generation.

The results suggest that some wind curtailment occurred in the Wyman/Bigelow subarea for the Active Queue and the All-Wind cases. For the All-Wind cases, a small amount of bottled-in wind energy was observed in Northern Maine. The results from IREMM showed a small amount of bottled-in wind in northern New Hampshire.

Table 6-3
Wind Generation by Wind Development Area for the Model Comparison Cases (GWh)

	Wyman / Bigelow	Rumford Area	Northern Maine	Northern New Hampshire	SEMA/RI	Other Wind Areas
FCA5						
IREMM Unconstrained	834	411	300	301	-	791
GridView Unconstrained	835	413	300	301	-	740
IREMM Interface Constrained	835	413	301	300	-	791
GridView Interface Constrained	787	413	300	301	-	740
Active Queue						
IREMM Unconstrained	1,777	569	3,470	404	3,858	2,087
GridView Unconstrained	1,777	569	3,469	404	3,883	2,039
IREMM Interface Constrained	1,638	569	3,469	404	3,895	2,087
GridView Interface Constrained	1,680	569	3,466	404	3,883	2,039
All Wind						
IREMM Unconstrained	2,949	684	7,960	1,384	26,720	3,725
GridView Unconstrained	2,949	687	7,930	1,384	26,711	3,675
IREMM Interface Constrained	2,104	677	6,977	981	26,466	3,725
GridView Interface Constrained	2,018	685	6,629	1,384	26,445	3,678

6.1.4.1 FCA #5

Figure 6-9 shows that GridView and IREMM wind generation were effectively the same; only small differences were seen in areas with relatively low concentrations of wind resources, which are referred to as “Other Wind Areas.” The 50 GWh difference was due to approximately 17 MW of “older wind” that was not part of the queue process. This small amount of wind capacity was included in IREMM but not in GridView. Because wind in the dispersed regions of the New England system is outside of the scope of this study, this small difference was neglected.

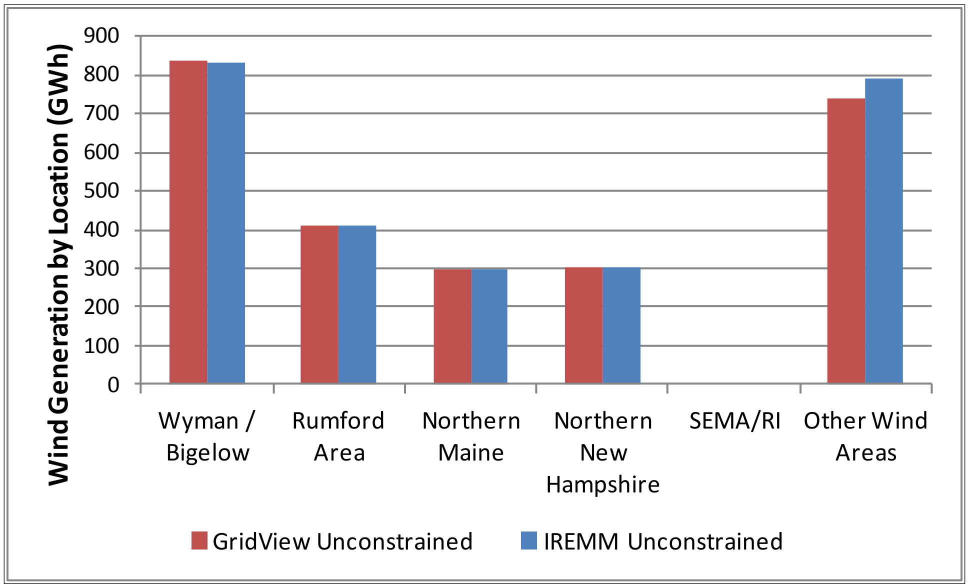

Figure 6-9: Comparison of GridView and IREMM results for wind generation by location—Case 1 (Unconstrained) under FCA #5 wind penetration.

For the cases with interface constraints, shown in Figure 6-10, the amount of wind energy was only affected in the Wyman/Bigelow export constraint.

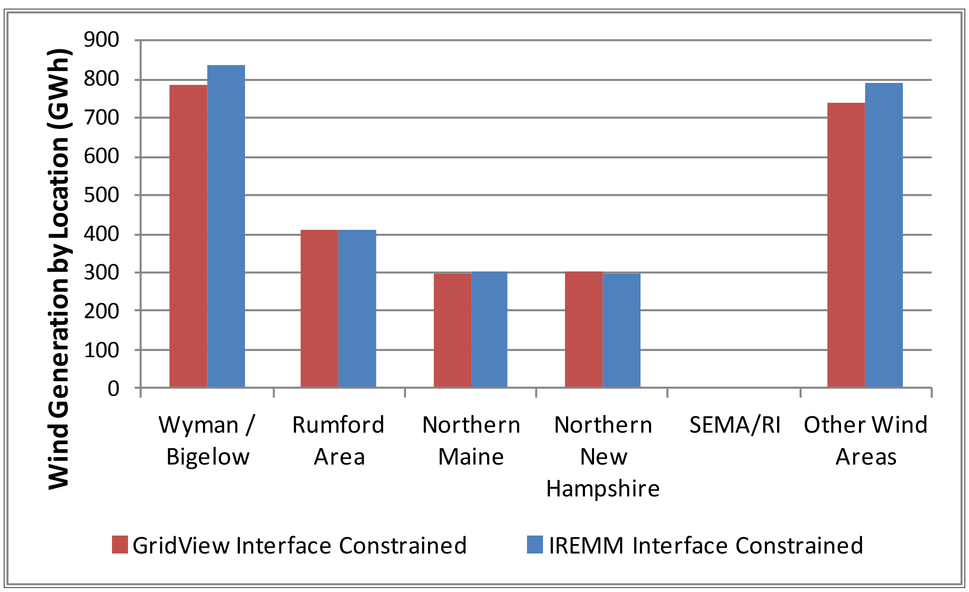

Figure 6-10: Comparison of GridView and IREMM results for wind generation by location—Case 2 (Interface Constrained) under FCA #5 wind penetration.

6.1.4.2 Active Queue

Figure 6-11 and Figure 6-12 show the IREMM and GridView wind generation for each of the WDAs, for the Unconstrained and Interface-Constrained cases. The figures show that the GridView and IREMM simulation results are close. Both models showed approximately 100 GWh of bottled-in wind in the Wyman/Bigelow subarea.

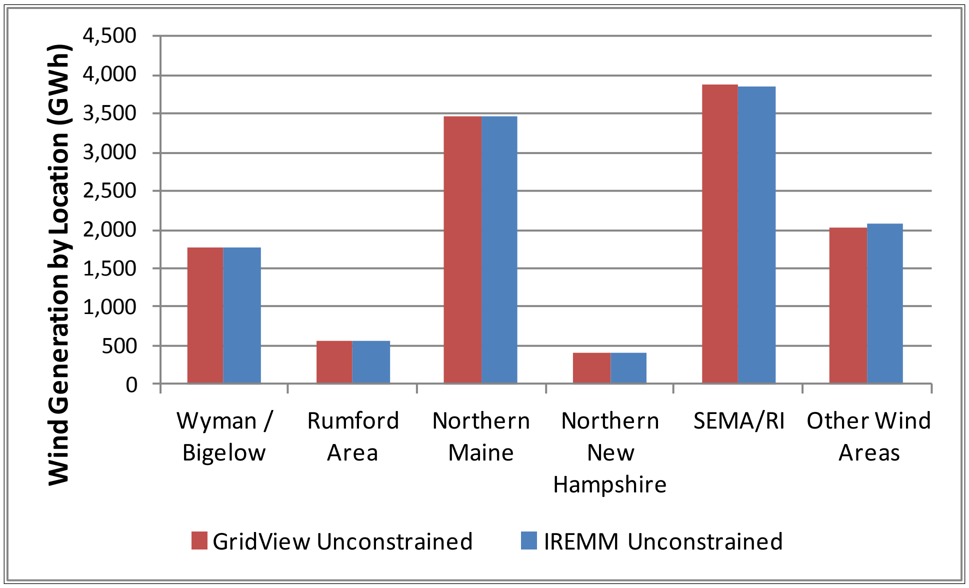

Figure 6-11: Comparison of GridView and IREMM results for wind generation by location—Case 1 (Unconstrained) under Active Queue wind penetration.

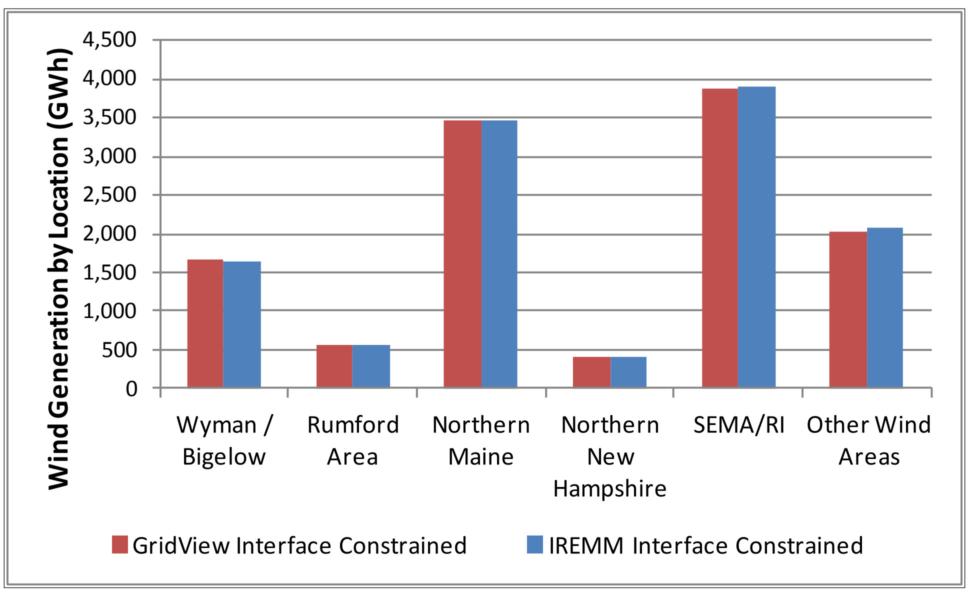

Figure 6-12: Comparison of GridView and IREMM results for wind generation by location—Case 2 (Interface Constrained) under Active Queue wind penetration.

6.1.4.3 All Wind

Figure 6-13 and Figure 6-14 show IREMM and GridView wind generation for each of the wind-development areas for both the Unconstrained and Interface-Constrained cases. These figures show that the GridView and IREMM simulation results are close, with the SEMA/RI offshore wind responsible for the majority of wind energy in both models. The All-Wind wind-penetration case combined with the interface constraints, bottled-in approximately 900 GWh of wind (comparing Figure 6-13 with Figure 6-14) when using either the IREMM or GridView models. This reflects the bottled in energy that could not be exported to the rest of New England from the Wyman/Bigelow subarea.

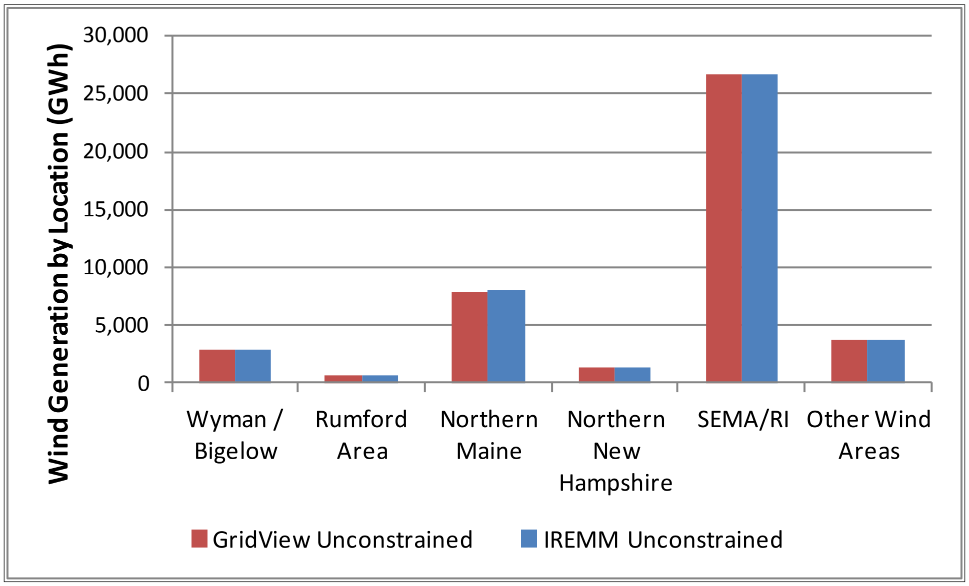

Figure 6-13: Comparison of GridView and IREMM wind generation by location—Case 1 (Unconstrained) under All-wind wind penetration.

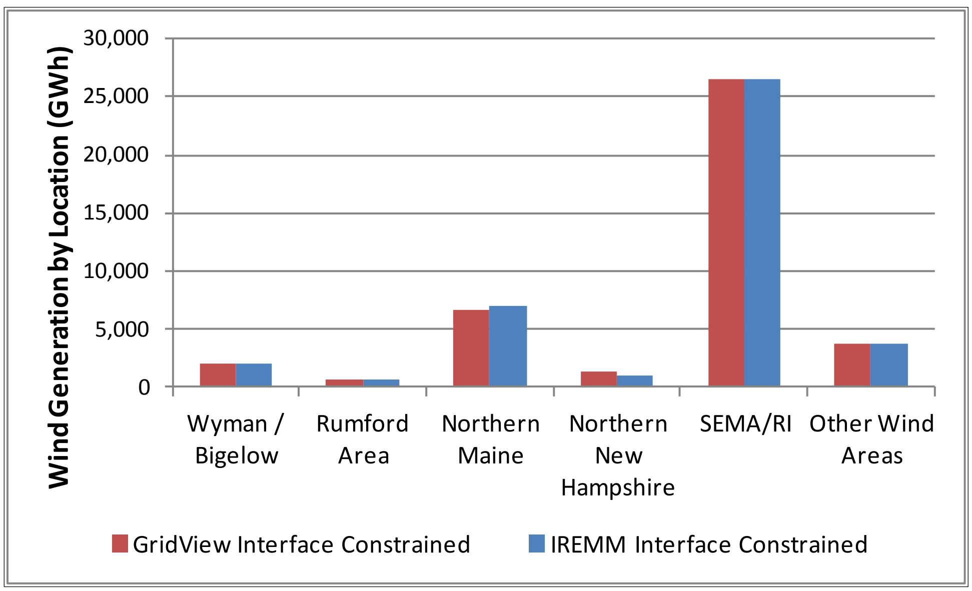

Figure 6-14: Comparison of GridView and IREMM wind generation by location—Case 2 (Interface Constrained) under All-Wind wind penetration.

6.1.5 Bottled-In Wind Energy

Table 6-4 shows the amounts of bottled-in wind energy in each wind-development area that resulted from applying the interface constraints. The table shows that the IREMM and GridView models both estimated approximately the same amounts of bottled-in energy. For the Wyman/Bigelow subarea, some amount of wind energy was bottled-in at each level of wind penetration and the amount of undeliverable energy increased from 50 GWh in the FCA #5 case to about 900 GWh under the All-Wind wind-penetration case. As expected, the All-Wind wind-penetration cases showed the most bottled-in wind energy.

Table 6-4
GridView and IREMM Bottled-In Wind Energy by Wind Development Subarea (GWh)

	Wyman / Bigelow	Rumford Area	Northern Maine	Northern New Hampshire	SEMA/RI	Other Wind Areas
FCA5						
IREMM Bottled-In	0	0	0	1	0	0
GridView Bottled-In	48	0	0	0	0	0
Active Queue						
IREMM Bottled-In	139	0	1	0	0	0
GridView Bottled-In	97	0	3	0	0	0
All Wind						
IREMM Bottled-In	845	7	983	403	254	0
GridView Bottled-In	931	2	1301	0	266	0

6.1.5.1 FCA #5

Figure 6-15 shows that as a result of the interface constraints, the Wyman/Bigelow WDA had a small amount of bottled-in wind energy with GridView, but not with IREMM.

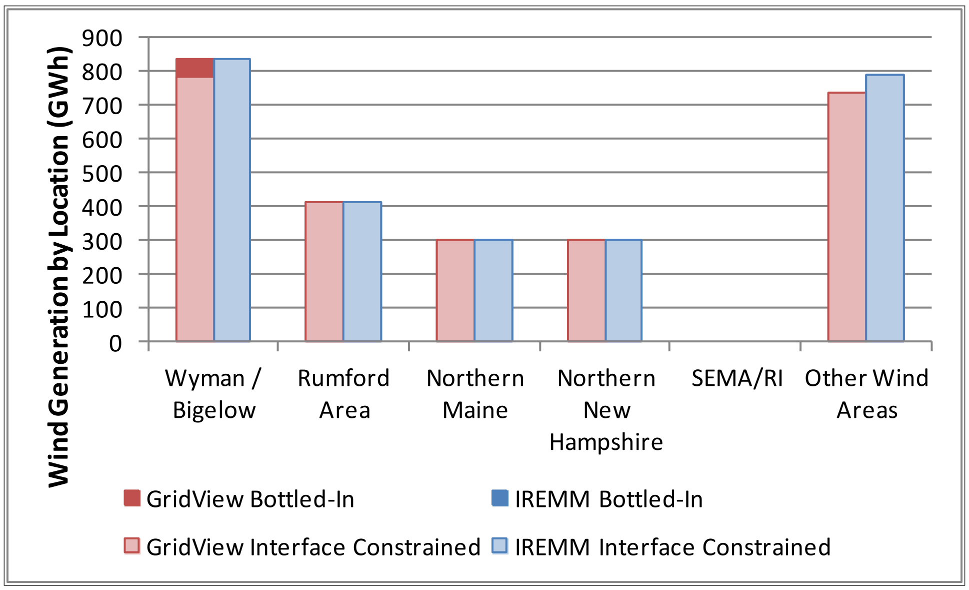

Figure 6-15: Effects of interface constraints under the FCA #5 wind-penetration cases.

6.1.5.2 Active Queue

Figure 6-16 shows that the Interface-Constrained case for the Wyman/Bigelow WDA had some bottled-in wind. IREMM and GridView estimated approximately the same amount of bottled-in wind energy (97 to 137 GWh).

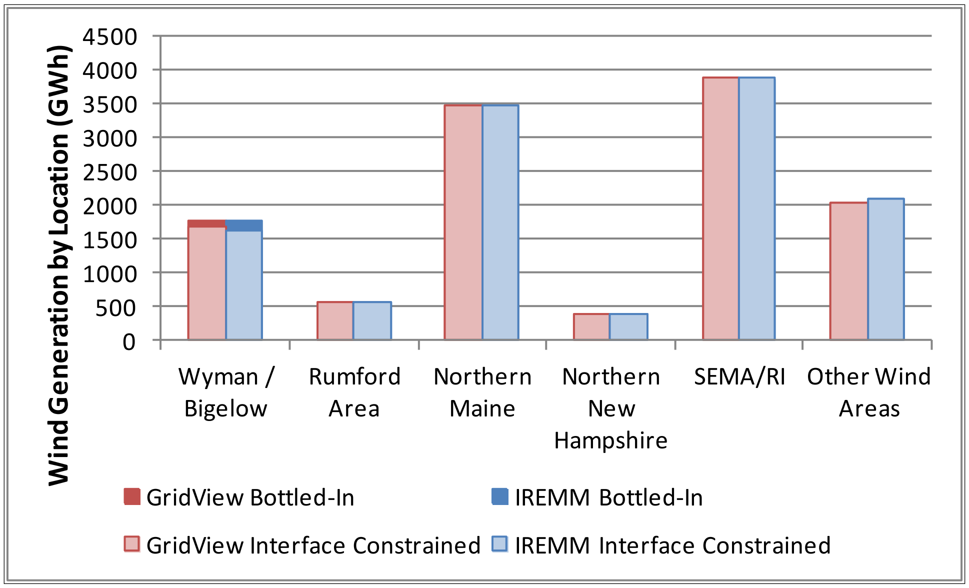

Figure 6-16: Effects of interface constraints under the Active Queue wind-penetration cases.

6.1.5.3 All Wind

Figure 6-17 shows that under the All-Wind wind-penetration scenarios, the Wyman/Bigelow, Northern Maine, and SEMA/RI wind development areas have some bottled-in wind as a result of the interface constraints. IREMM and GridView estimated approximately the same amount of bottled-in wind energy, except in northern New Hampshire where GridView did not identify any bottled-in wind energy.

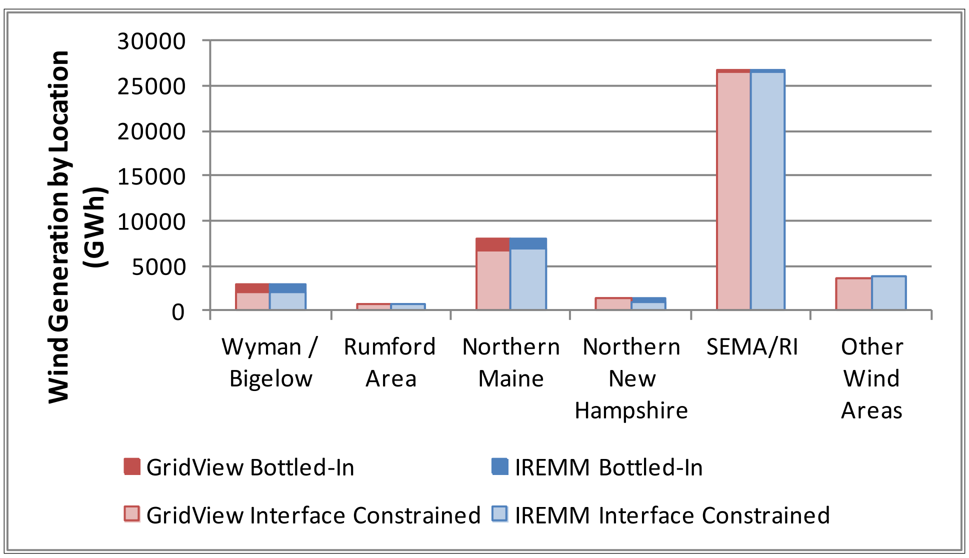

Figure 6-17: Effects of interface constraints under the All-Wind wind-penetration cases.

6.1.6 Interface Flow-Duration Curves

Wind energy injected into wind-development areas across New England flowed from where it was generated to where it was consumed, which caused potential stresses on the transmission system. This section provides an overview of the energy flows on a number of key interfaces for the Model Comparison cases. The flows simulated by GridView were approximately the same as IREMM. The primary interfaces compared are as follows:

- Wyman/Bigelow Export Interface
- Rumford Export Interface
- Orrington South
- Northern New Hampshire Export Interface
- SEMA/RI Export Interface
- Surowiec South

6.1.6.1 FCA #5

Figure 6-18 shows six flow-duration curves that compare four IREMM and GridView Model Comparison cases. The figures show that the trend and shape of the curves from both models are approximately the same for all these cases. For this wind penetration level, only Wyman/Bigelow and Northern New Hampshire showed any signs of being constrained. The Wyman/Bigelow interface resulted in bottled-in wind energy, while the Northern New Hampshire interface did not result in any lost wind energy, even though other types of generation could not be exported from this area.

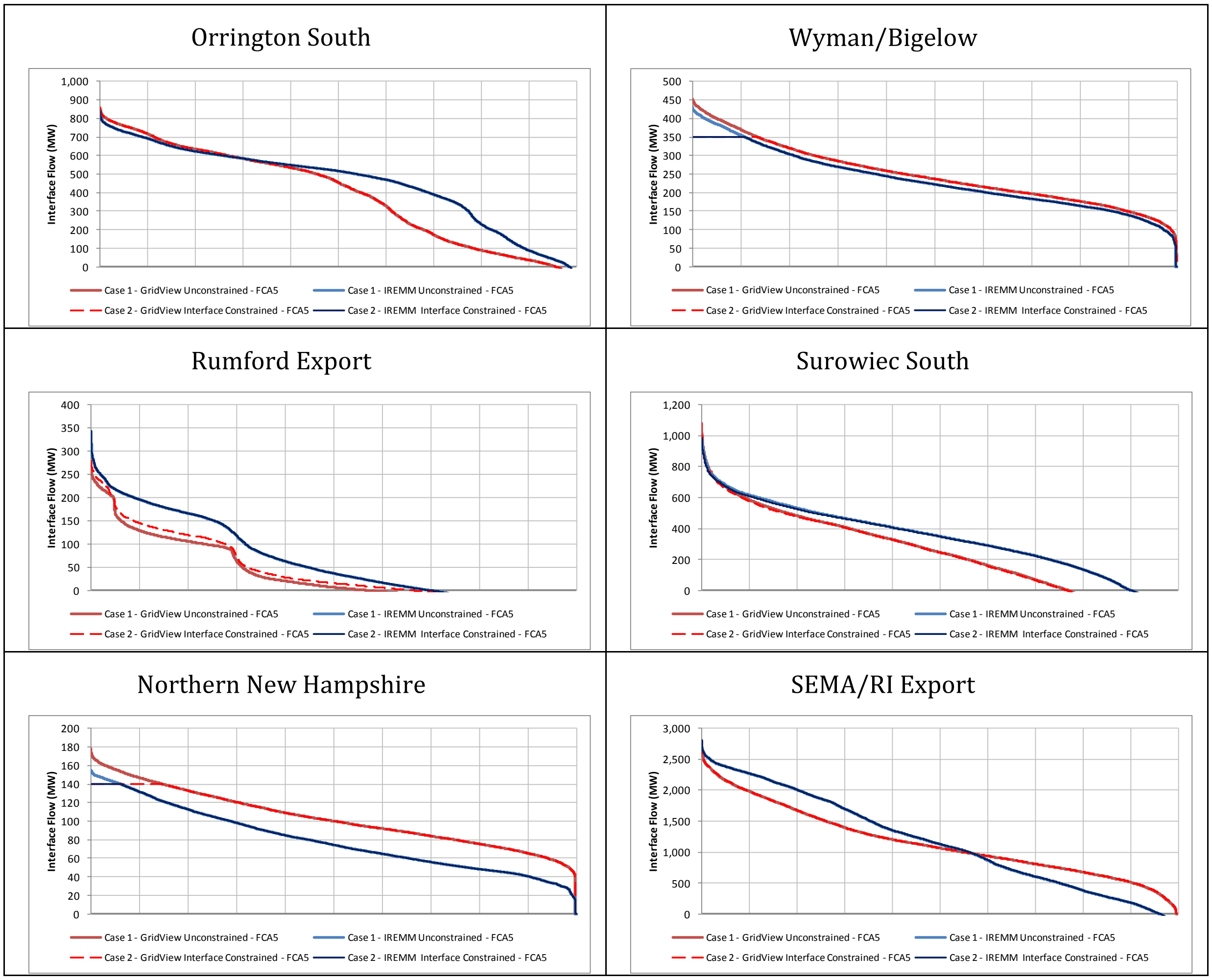

Figure 6-18: GridView and IREMM internal-interface flow-duration curves—Cases 1 and 2 (Unconstrained and Interface Constrained) for FCA #5 wind penetration.

The need to identify all the smaller generators and assign them to an appropriate bus is an ongoing modeling refinement. Some of the differences in the flows can be explained by GridView and IREMM assigning smaller generators to aggregated resources that are located on different sides of an interface. A second reason for the differences in the flows was the potential difference in the dispatch of specific units that had very similar costs. For example, one model might have dispatched a gas-fired combined-cycle resource in Connecticut before a resource in Maine with an equal dispatch cost, while the other model may have switched the dispatch order. This would not have a significant effect on economic metrics but could make a difference on unconstrained interface flows.

6.1.6.2 Active Queue

Figure 6-19 shows the flow-duration curves for the Active Queue wind-penetration cases. The figure shows that the trend and shape of the curves from both models are approximately the same for these four cases. The largest differences were for the highest generation hours in the Wyman/Bigelow subarea. GridView output was lower than IREMM for approximately 10% of the hours.

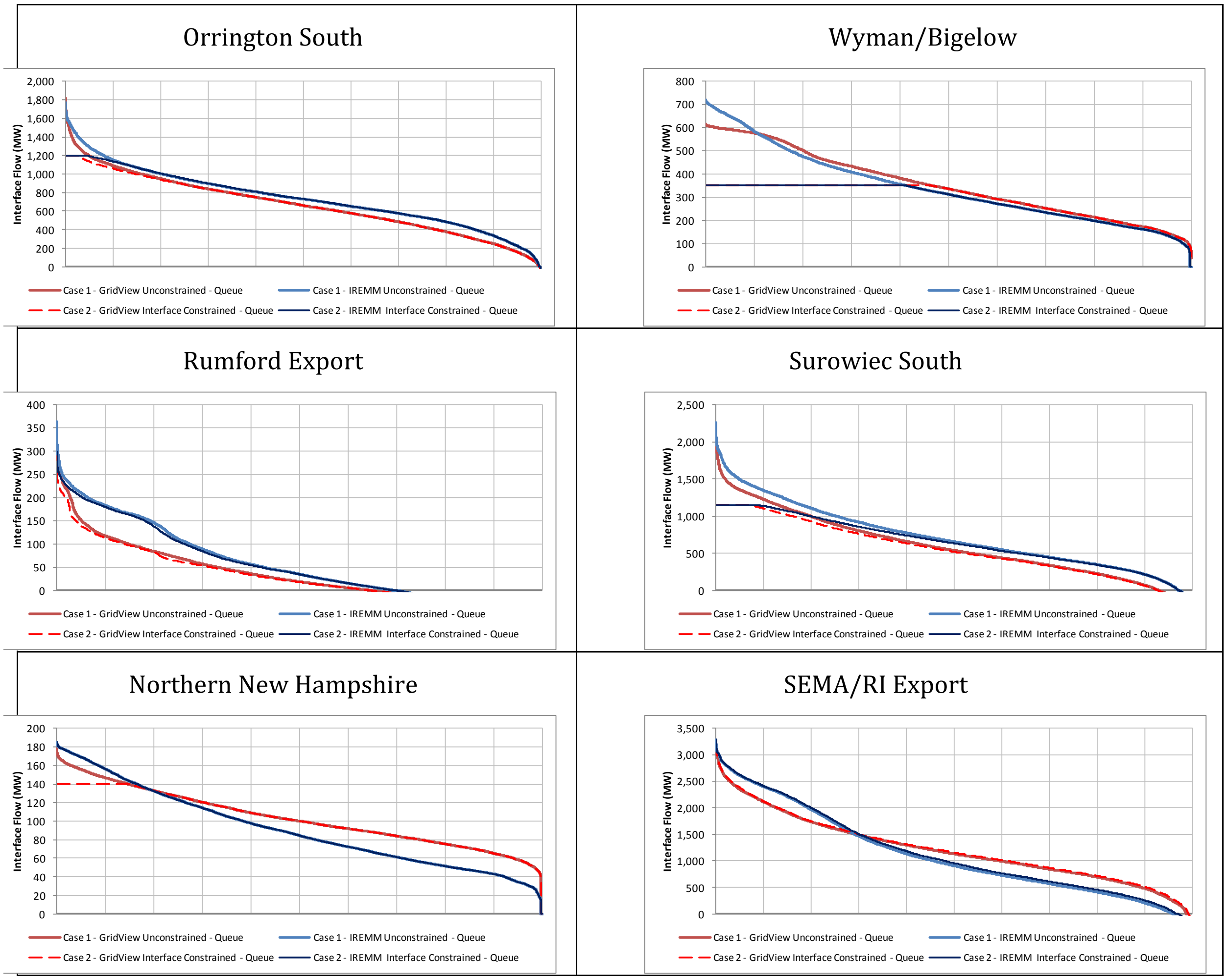

Figure 6-19: GridView and IREMM internal interface flow-duration curves—Cases 1 and 2 (Unconstrained and Interface Constrained) for Active Queue wind penetration.

Orrington South, Wyman/Bigelow, Northern New Hampshire, and Surowiec South interfaces showed signs of being constrained. The Wyman/Bigelow interface resulted in bottled-in wind energy, while the Northern New Hampshire interface did not result in any lost wind, even though other types of generation could not be exported to the rest of New England.

These flow-duration curves show that four of the interfaces were binding:

- Wyman/Bigelow: binding approximately 42% of the time
- Rumford Export: not binding
- Orrington South: binding about 10% of the time
- Northern New Hampshire: binding about 18% of the time in the GridView case but not in the IREMM case
- SEMA/RI Export: not binding
- Surowiec South: binding about 10% of the time

6.1.6.3 All Wind

Figure 6-20 shows the flow-duration curves for the All-Wind wind-penetration cases. The figures show that for the Unconstrained case, the trend and shape of the curves from both models are approximately the same; the interfaces were constrained for a significant amount of time. However, a constrained interface would not necessarily result in bottled-in wind energy if other energy resources with higher dispatch prices could have their output reduced due to the export constraint.

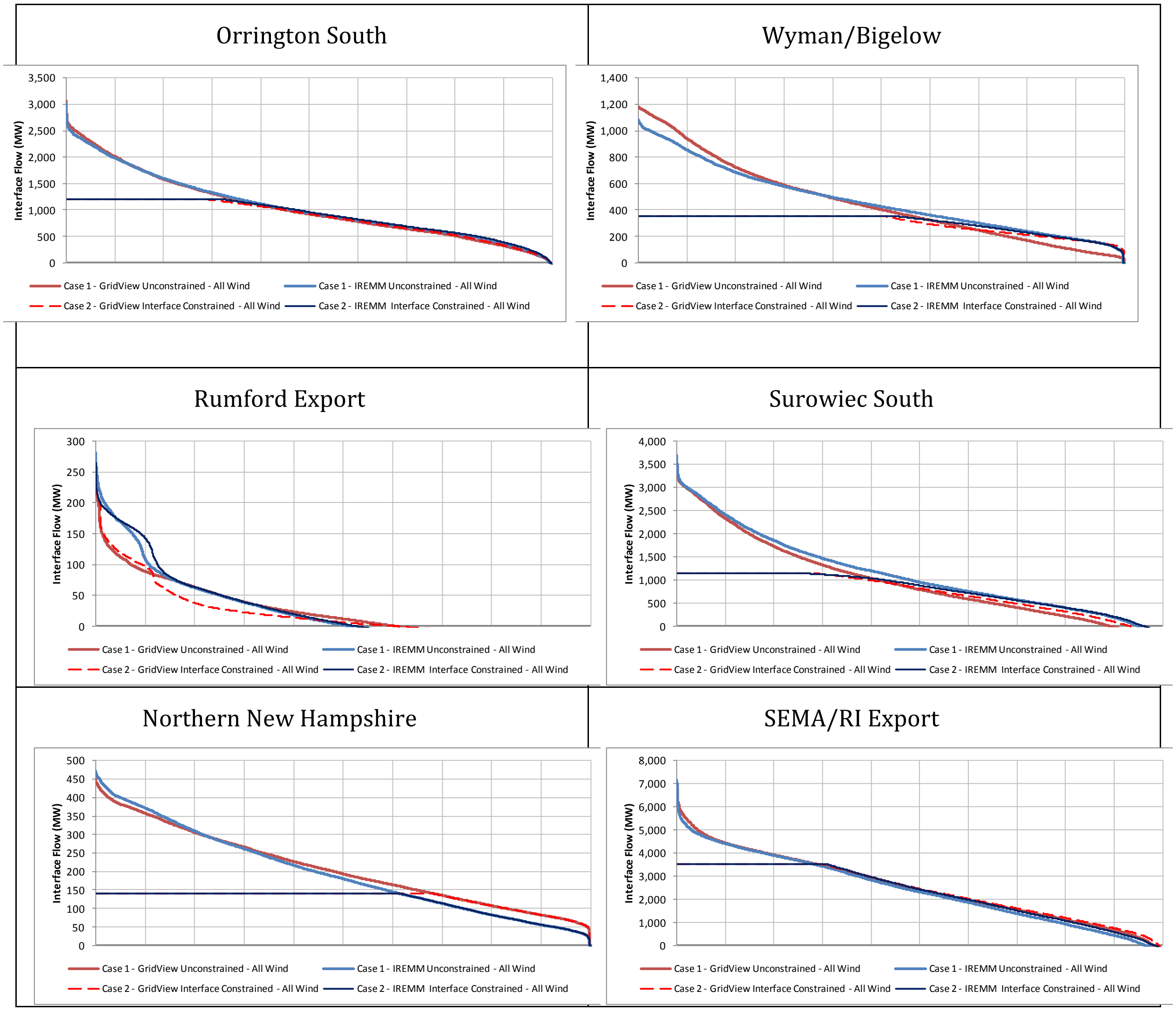

Figure 6-20: GridView and IREMM internal interface flow-duration curves—Cases 1 and 2 (Unconstrained and Interface Constrained) for All-wind wind penetration.

These flow-duration curves show that five of the interfaces are binding:

- Wyman/Bigelow: binding approximately 55% of the time
- Rumford Export: not binding
- Orrington South: binding about 35% of the time
- Northern New Hampshire: binding about 60% of the time

- SEMA/RI Export: binding about 30% of the time
- Surowiec South: binding less than 40% of the time

6.2 GridView Transmission Modeling (Cases 1 to 4): Effect of Wind Penetration

The Transmission Modeling cases only compared the results of the GridView cases. Table 6-5 presents the economic metrics for Cases 1 to 4 (Unconstrained, Interface Constrained, Detailed Modeling and Barnstable Relaxed). The following sections discuss these results in more detail. In Case 3, the Detailed Modeling case, a binding transmission constraint resulted in a significant amount of congestion. Because the Detailed Modeling case provides an opportunity to show how a problematic transmission constraint can be identified, it is discussed in more detail. The Barnstable Relaxed case showed the effect of relieving that particular problematic transmission constraint.

Table 6-5
GridView Transmission Modeling Cases: LSE Expense and Production Cost (Million $)

	Production Cost			LSE Energy Expense		
	FCA5	Active Queue	All Wind	FCA5	Active Queue	All Wind
GridView Unconstrained	3321	2913	1867	7056	6418	4930
GridView Interface Constrained	3324	2928	1973	7056	6436	5211
GridView Detailed Modeling	3346	2948	2273	7854	6858	5627
GridView Barnstable Relaxed	3343	2948	1991	7803	6858	5460

6.2.1 Economic Metrics—Production Cost

Figure 6-21 shows a comparison of the production cost metric for each of the Transmission Modeling cases. This figure shows the following:

- For the Transmission Modeling cases, the production cost values are close for all the FCA #5 and Active Queue cases.
- For the All-Wind wind-penetration cases, the costs for the Detailed Modeling case are significantly higher than the previous Interface-Constrained case.
- The Detailed Modeling All-Wind wind-penetration case is higher because there is significantly more bottled-in wind, which caused an increase in generation from fuel-consuming thermal units and raised the production cost.
- For Case 4, the Barnstable Relaxed case, the production cost for the All-Wind case realigns with the Unconstrained (Case 1) and Interface-Constrained (Case 2) cases.

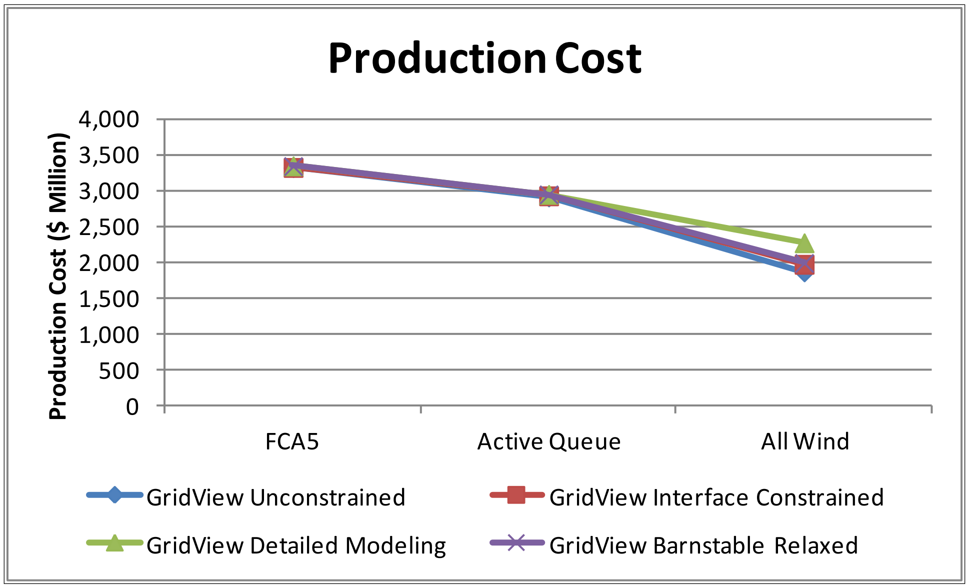

Figure 6-21: Comparison of production costs for the GridView Transmission Modeling cases.

6.2.2 Economic Metrics—LSE Energy Expense

Figure 6-22 shows the LSE energy expense for each of the GridView Transmission Modeling cases. The LSE energy expense metric can be influenced by the factors that increase the marginal costs in one area and decrease the marginal costs in other areas. For example, excess wind could cause an entire RSP area, or group of RSP areas, to value the energy at zero, while other areas could have high prices because the low marginal cost energy cannot be imported into the higher-priced, import-constrained areas. Figure 6-22 shows the following:

- The results for the GridView Unconstrained and Interface-Constrained cases are very close.
- Compared to the Unconstrained case, the results for the Interface-Constrained case is slightly higher under the All-Wind wind-penetration scenario.
- For the Unconstrained case (Case 1), as the amount of wind energy exported to southern New England increased, the LSE energy expense decreased.
- The addition of transmission contingencies in the Detailed Modeling case resulted in more bottled-in energy than in the interface-constrained cases. This increased LSE energy expense for all wind penetration levels.
- Relieving the binding constraint, Barnstable Relaxed (Case 4), did not have a significant impact on the aggregate New England LSE energy-expense metric compared to the Detailed Modeling case. The removal of the constraint in the Barnstable Relaxed case allowed the energy to flow into SEMA where some of it became bottled-in behind the SEMA/RI interface and was unable to reduce LMPs across New England. The net effect was a small decrease in the aggregate New England LSE energy expense.

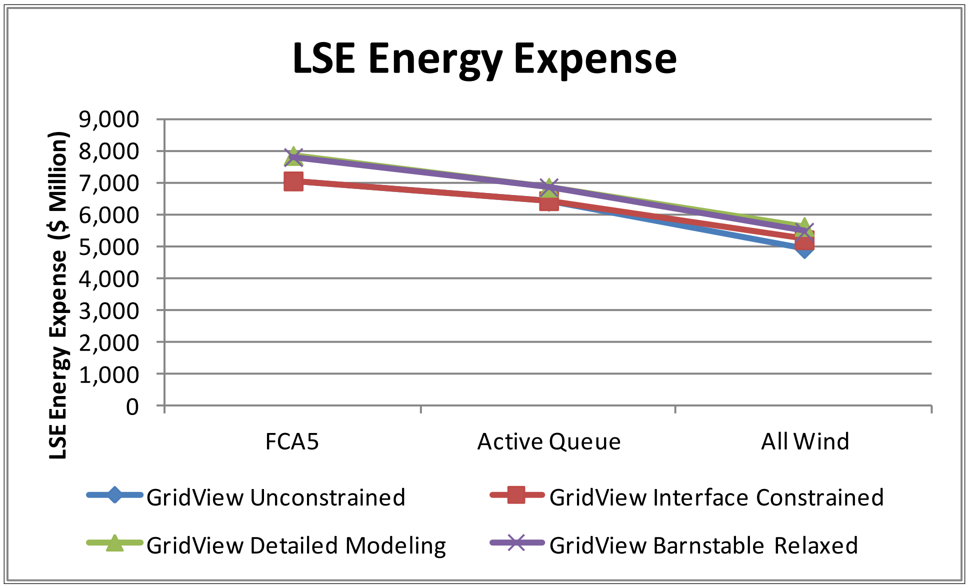

Figure 6-22: Comparison of LSE energy expenses for the GridView Transmission Modeling cases.

6.2.3 Generation by Fuel Types

Table 6-6 shows the generation by fuel type and how fuel consumption changed as the amount of wind energy increased. The table shows the impact of four different levels of transmission-constraint modeling. The most obvious trend in this table is that as the wind-generation gigawatt-hours increased, natural-gas-based generation decreased. Case 4, Barnstable Relaxed, allowed more bottled-in wind to be produced than the Detailed Modeling case (Barnstable constraint not relaxed).

Table 6-6
Generation by Fuel Type for the GridView Transmission Modeling Cases (GWh)

	Coal	Gas	Hyd/Oth	Nuclear	Oil	Wind	Biomass
FCA5							
GridView Unconstrained	6,885	74,338	23,353	37,770	583	2,635	4,561
GridView Interface Constrained	6,890	74,397	23,158	37,770	778	2,587	4,545
GridView Detailed Modeling	6,918	74,345	23,163	37,770	870	2,514	4,545
GridView Barnstable Relaxed	6,918	74,345	23,163	37,770	870	2,514	4,545
Active Queue							
GridView Unconstrained	6,245	67,631	21,184	37,770	548	12,187	4,560
GridView Interface Constrained	6,268	67,731	21,190	37,770	562	12,087	4,517
GridView Detailed Modeling	6,161	66,388	23,003	37,770	584	11,724	4,495
GridView Barnstable Relaxed	6,161	66,388	23,003	37,770	584	11,724	4,495
All Wind							
GridView Unconstrained	4,024	41,882	20,701	36,048	149	43,381	3,940
GridView Interface Constrained	4,168	44,069	20,101	36,640	215	40,948	3,984
GridView Detailed Modeling	5,187	51,428	22,672	37,739	224	29,081	3,794
GridView Barnstable Relaxed	4,398	44,341	22,513	36,055	240	38,949	3,629

6.2.3.1 FCA #5

Figure 6-23 shows the generation by fuel type for the GridView Transmission Modeling cases (Case 1 to Case 4). At the FCA #5 level of wind penetration, the additional transmission system modeling detail produced very little change in generation by fuel type.

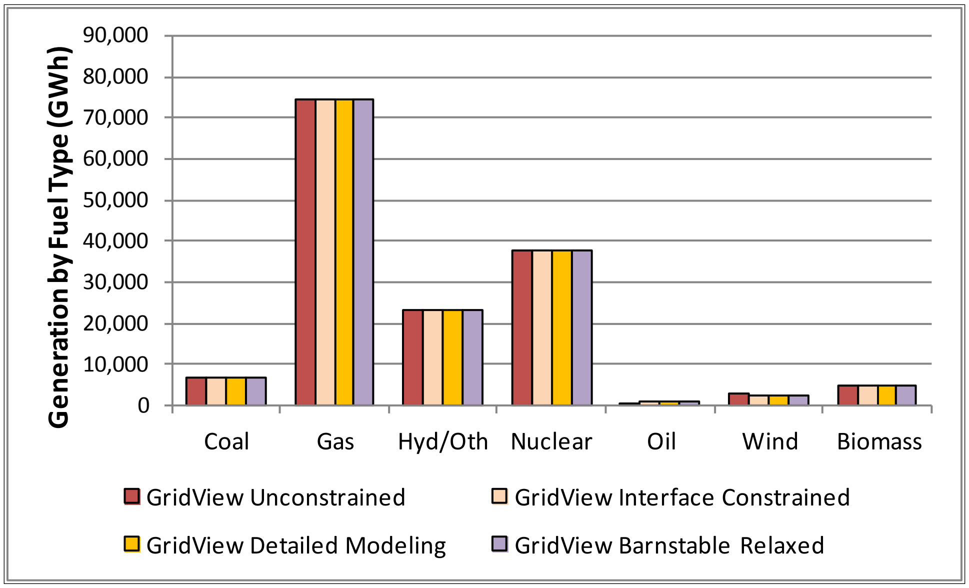

Figure 6-23: Energy generation by fuel type under FCA #5 wind penetration for the GridView Transmission Modeling cases.

6.2.3.2 Active Queue

Figure 6-24 shows the generation by fuel type for the Active Queue wind penetration cases. This figure shows that the additional transmission contingencies and respecting the pre and post contingency thermal limits of the transmission elements decreases natural gas and wind based generation while slightly increasing pumped storage and imports.

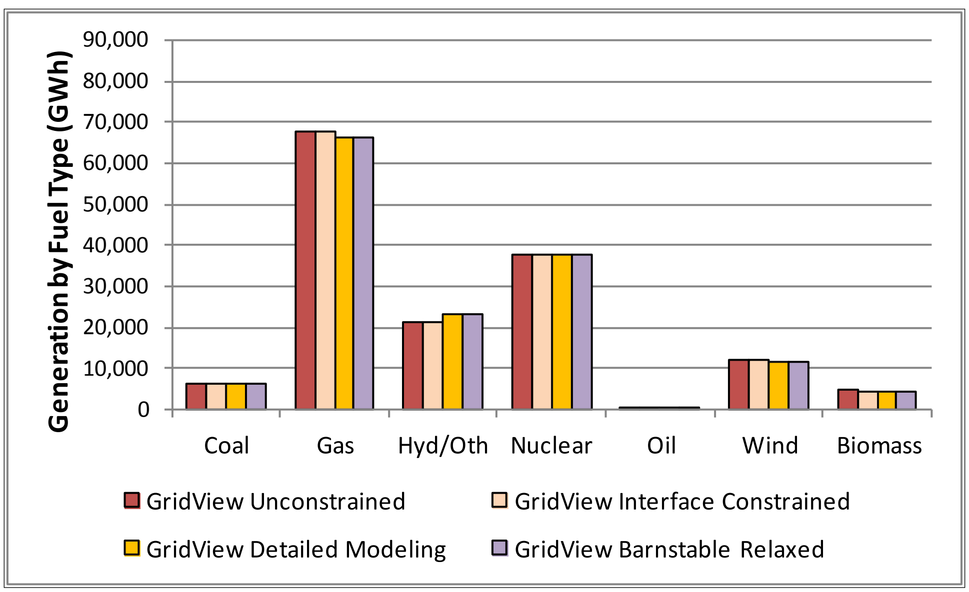

Figure 6-24: Energy generation by fuel type under Active Queue wind penetration for the GridView Transmission Modeling cases.

6.2.3.3 All Wind

For the All-Wind wind-penetration cases, Figure 6-25 presents the generation by fuel type for the four Transmission Modeling cases. Case 3, the Detailed Modeling case that included transmission contingencies and thermal limits resulted in a decrease in wind generation and an increase in gas, coal, pumped storage, imports, and to some extent, nuclear generation.

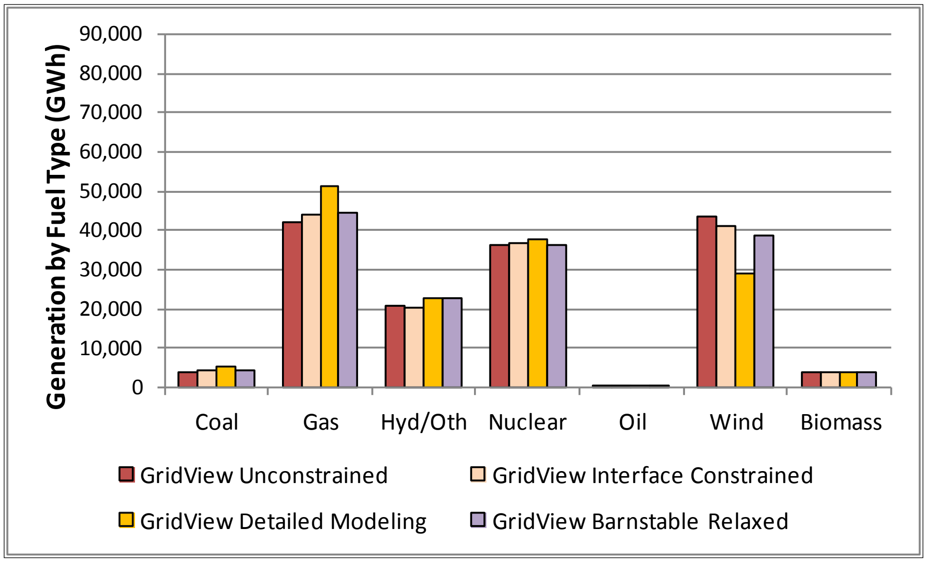

Figure 6-25: Energy generation by fuel type under All-Wind wind penetration for the GridView Transmission Modeling cases.

These cases illustrate that for the All-Wind wind-penetration cases, transmission constraints may exist that would not have been identified if only major interfaces were represented. Using the available analytical tools, GridView was able to identify the binding transmission elements, allowing the effect of relieving the constraints to be quantified.

Comparing Case 3, the Detailed Modeling case, with Case 4, the Barnstable Relaxed case, shows that by relieving a binding constraint, wind generation increased and the amount of bottled-in energy from the SEMA/RI area decreased. Consequently, fewer gigawatt-hours from thermal generation were produced.

6.2.4 Wind Generation by Wind-Development Areas

Table 6-7 shows the amount of wind energy produced in each wind development area. A comparison of the Interface-Constrained case to the Detailed Modeling case shows that the detailed modeling of the transmission network decreased the wind generation in all areas. This result was most noticeable in the higher wind-penetration cases.

Under the All-Wind wind-penetration case, wind generation in the Wyman/Bigelow areas decreased 25 percent when transmission contingencies and thermal limits were represented in the Detailed Modeling case. The SEMA/RI wind output decreased 40 percent. In the Barnstable Relaxed case, much of this bottled-in SEMA/RI wind energy was able to be generated and only about 3 percent was constrained in.

Table 6-7
Wind Generation by Wind-Development Areas
for the GridView Transmission Modeling Cases (GWh)

	Wyman / Bigelow	Rumford Area	Northern Maine	Northern New Hampshire	SEMA/RI	Other Wind Areas
FCA5						
GridView Unconstrained	835	413	300	301	0	740
GridView Interface Constrained	787	413	300	301	0	740
GridView Detailed Modeling	714	413	300	301	0	740
GridView Barnstable Relaxed	714	413	300	301	0	740
Active Queue						
GridView Unconstrained	1777	569	3469	404	3883	2039
GridView Interface Constrained	1680	569	3466	404	3883	2039
GridView Detailed Modeling	1325	569	3459	403	3883	2038
GridView Barnstable Relaxed	1325	569	3459	403	3883	2038
All Wind						
GridView Unconstrained	2949	687	7930	1384	26711	3675
GridView Interface Constrained	2018	685	6629	1384	26445	3678
GridView Detailed Modeling	1511	619	6365	994	15869	3678
GridView Barnstable Relaxed	1473	660	6444	994	25656	3678

6.2.4.1 FCA #5

Figure 6-26 shows that modeling the transmission network in detail, as shown in Cases 3 and 4, resulted in a slight decrease in wind generation in the Wyman/Bigelow subarea compared to the Interface-Constrained case. The more granular transmission modeling did not have an impact on the results for the other wind-development areas.

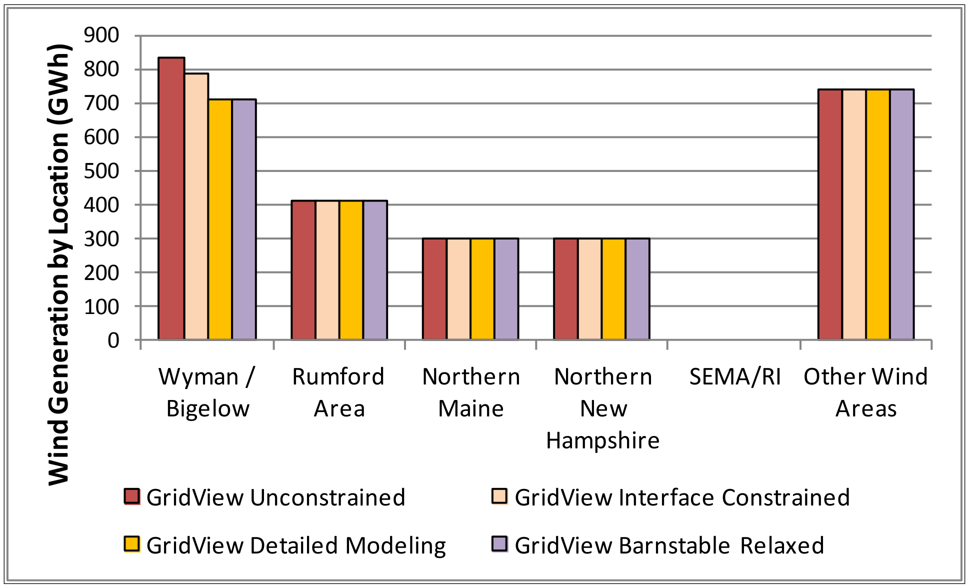

Figure 6-26: Energy generation by fuel type under FCA #5 wind penetration for the GridView Transmission Modeling cases.

6.2.4.2 Active Queue

Figure 6-27 repeats the same trend observed for the FCA #5 wind-penetration scenarios with a slight decrease in wind generation in the Wyman/Bigelow subarea compared to the Interface-Constrained case. The more granular transmission modeling did not have an impact on the results for the other wind development areas.

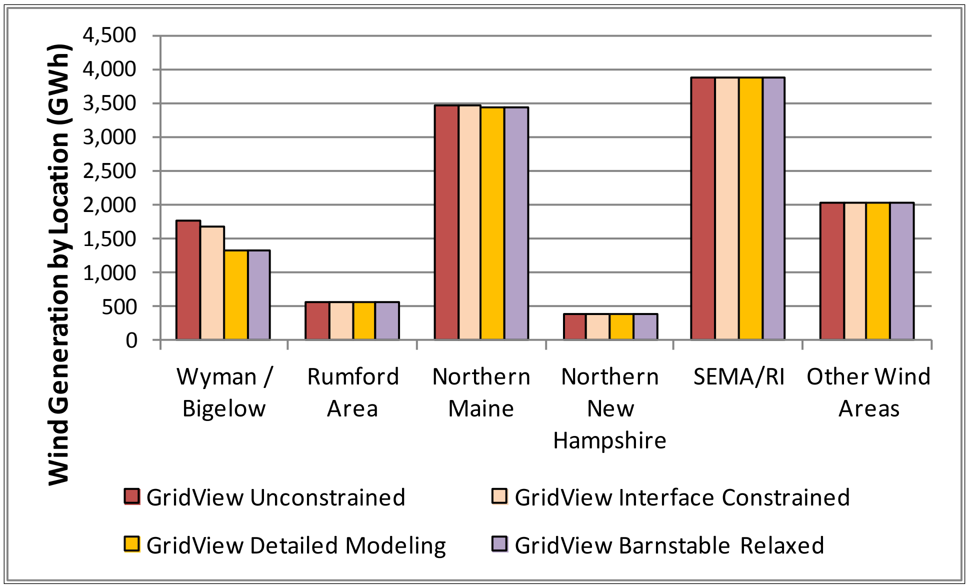

Figure 6-27: Energy generation by fuel type under Active Queue wind penetration for the GridView Transmission Modeling cases.

6.2.4.3 All Wind

Figure 6-28 shows that for the All-Wind wind-penetration level, the Detailed Modeling case resulted in bottled-in wind energy requiring increased generation from natural gas and coal, as shown in Figure 6-25. In the Barnstable Relaxed case, eliminating the constraint allowed wind generation in the SEMA/RI area to increase to levels that aligned with the Interface-Constrained case.

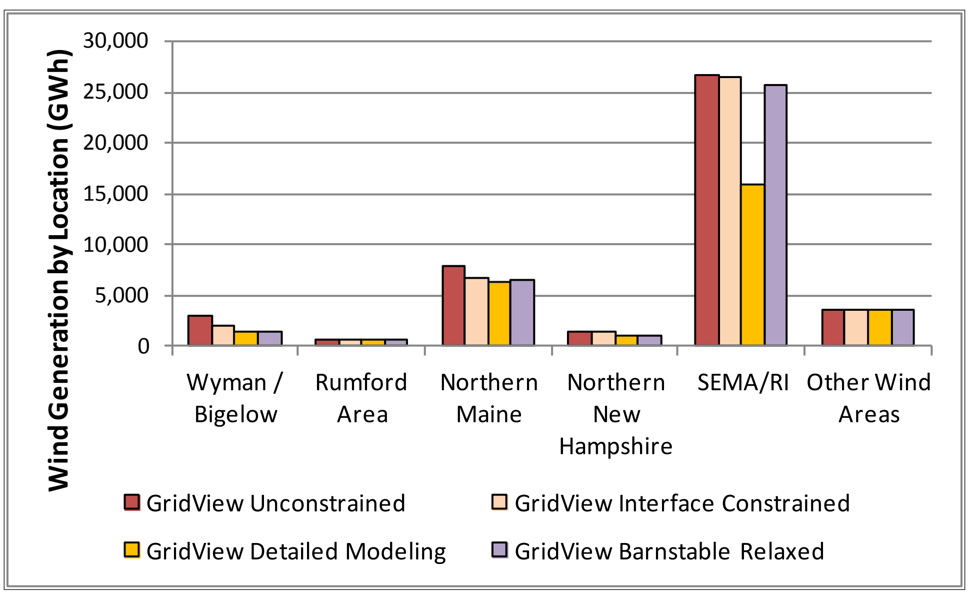

Figure 6-28: Energy generation by fuel type under All-Wind wind penetration for the GridView Transmission Modeling cases.

6.2.5 Bottled-In Wind

Table 6-8 shows the wind production of each of the WDAs from the perspective of bottled-in wind. The gigawatt-hours of bottled-in wind energy was referenced to the Unconstrained case. Most of the bottled-in wind energy is mostly in the Wyman/Bigelow subarea under FCA #5 and the Active Queue wind-penetration cases. Bottled-in wind occurred in all the wind development areas for the All-Wind wind penetration cases.

Table 6-8
Bottled-In Wind Energy by Wind Development Area for Transmission Modeling Cases (GWh)

	Wyman / Bigelow	Rumford Area	Northern Maine	Northern New Hampshire	SEMA/RI	Other Wind Areas
FCA5						
GridView Interface Constrained	48	0	0	0	0	0
GridView Detailed Modeling	121	0	0	0	0	0
GridView Barnstable Relaxed	121	0	0	0	0	0
Active Queue						
GridView Interface Constrained	97	0	3	0	0	0
GridView Detailed Modeling	452	0	10	1	0	1
GridView Barnstable Relaxed	452	0	10	1	0	1
All Wind						
GridView Interface Constrained	931	2	1301	0	266	(3)
GridView Detailed Modeling	1438	68	1565	390	10842	(3)
GridView Barnstable Relaxed	1476	27	1486	390	1055	(3)

6.2.5.1 FCA #5

Figure 6-29 shows that for the FCA #5 wind-penetration cases, the bottled-in wind occurred in the Wyman/Bigelow subarea only. Compared to the Interface-Constrained case, the Detailed Modeling case created an additional 80 GWh of bottled-in wind. The post-contingency thermal limitations from the additional contingencies modeled in the Wyman/Bigelow subarea restricted the export of wind energy.

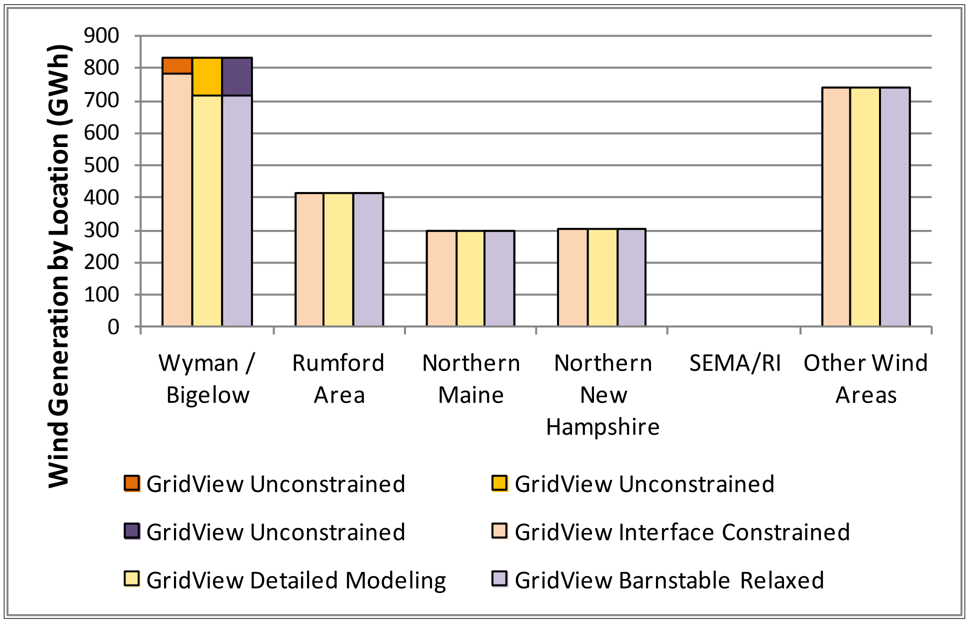

Figure 6-29: Energy generation by fuel type under FCA #5 wind penetration for the GridView Transmission Modeling cases.

6.2.5.2 Active Queue

Figure 6-30 shows that only in the Wyman/Bigelow subarea was the bottled in wind energy significant. The wind production in other wind development areas was not affected.

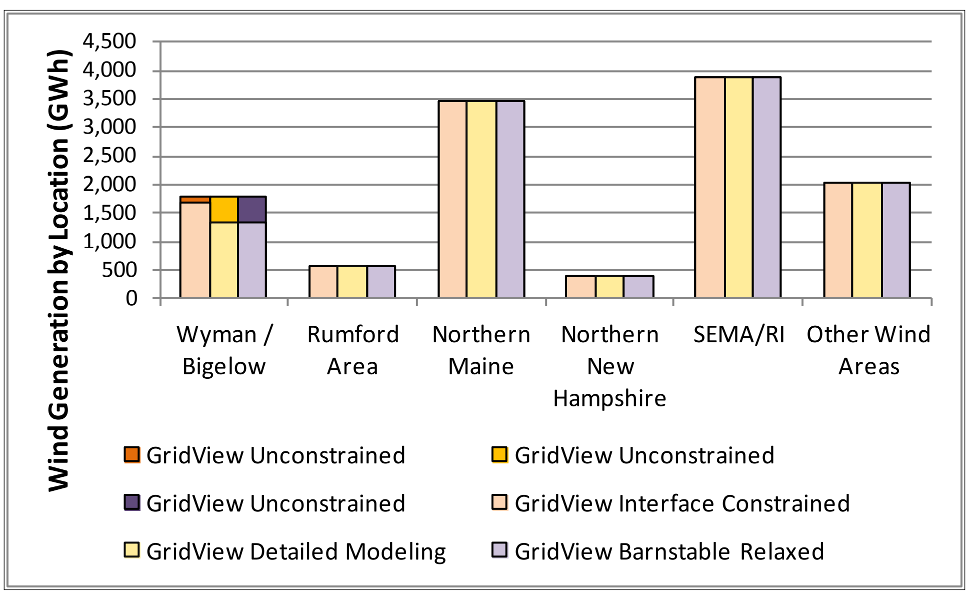

Figure 6-30 Energy generation by fuel type under Active Queue wind penetration for the GridView Transmission Modeling cases.

6.2.5.3 All Wind

Figure 6-31 shows the bottled-in wind energy for the All-Wind wind-penetration case. This shows that about 40% of the potential wind energy in SEMA/RI was bottled-in under the Detailed Modeling case.

When the Barnstable Constraint was relaxed, the amount of bottled-in wind energy dropped to only about 3% of the potential wind energy.

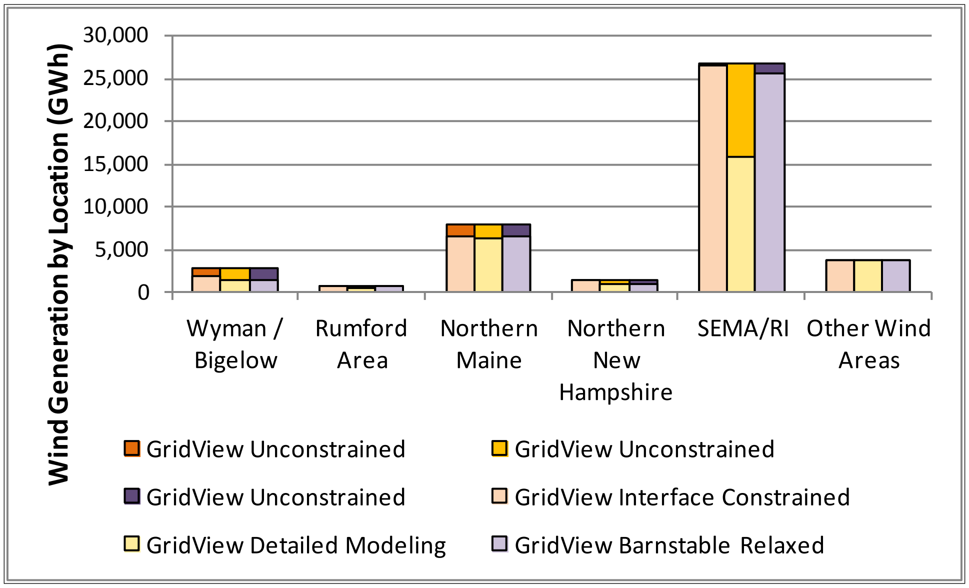

Figure 6-31: Energy generation by fuel type under All-Wind wind penetration for the GridView Transmission Modeling cases.

6.2.6 Flow-Duration Curves—FCA #5

This section provides more detail on the interface flow-duration curves for the Transmission Modeling cases.

6.2.6.1 FCA #5

Figure 6-32 through

Figure 6-37 show GridView flow-duration curves from the four Transmission Modeling cases with the FCA #5 wind-penetration levels. Figure 6-32 shows that Orrington South is unconstrained and has the same flows in all three cases.

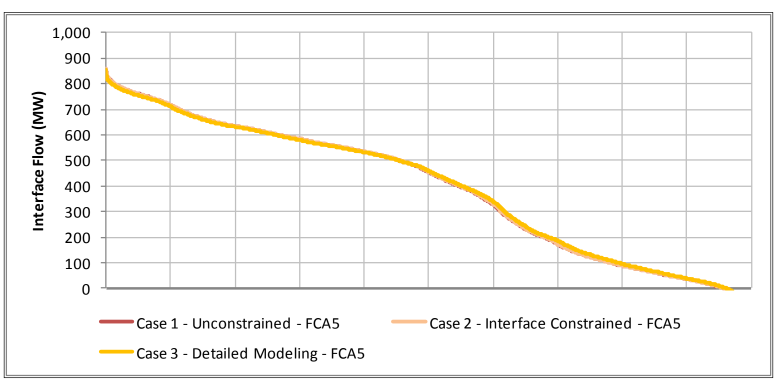

Figure 6-32: Flow-duration curves for the Orrington South Interface (Cases 1 to 3) under FCA #5 wind penetration for the GridView Transmission Modeling cases.

Figure 6-33, the Wyman/Bigelow interface, shows that the Interface-Constrained case limit was reached about 14% of the hours. In the Detailed Modeling case, the Wyman/Bigelow interface did not reach the

350 MW export limit. This indicates that before the interface limits were reached, more restrictive local binding constraints limited the wind output.

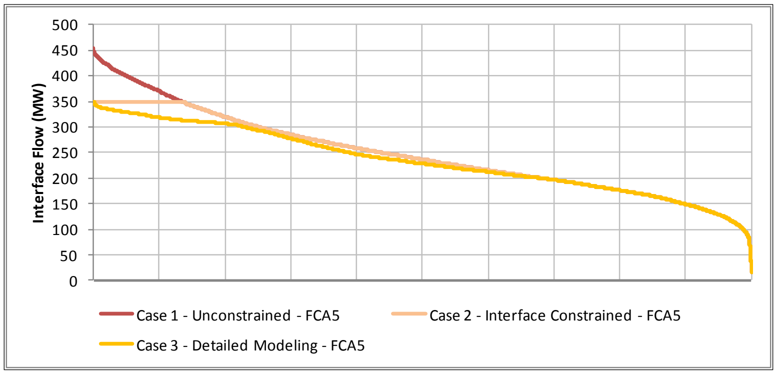

Figure 6-33: Flow-duration curves for the Wyman/Bigelow subarea export interface (Cases 1 to 3) under FCA #5 wind penetration for the GridView Transmission Modeling cases.

Figure 6-34 shows that in the Interface Constrained case where Wyman/Bigelow output is limited, more energy is produced within the Rumford area which then flows across that interface.

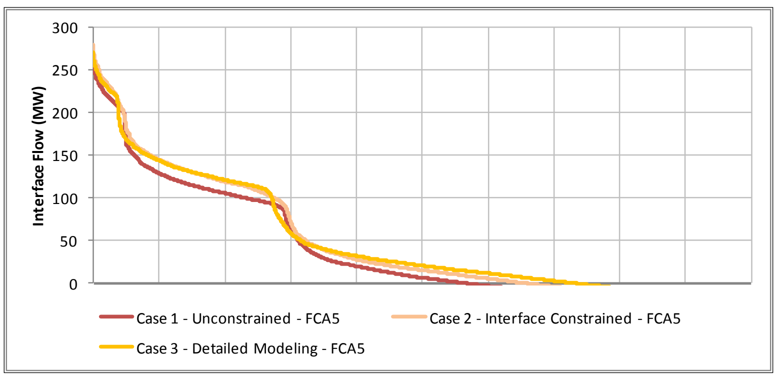

Figure 6-34: Flow-duration curves for the Rumford subarea (Cases 1 to 3) under FCA #5 wind penetration for the GridView Transmission Modeling cases.

Figure 6-35 shows the effect of reduced Wyman/Bigelow wind production as the flows across Surowiec South were reduced by corresponding amounts.

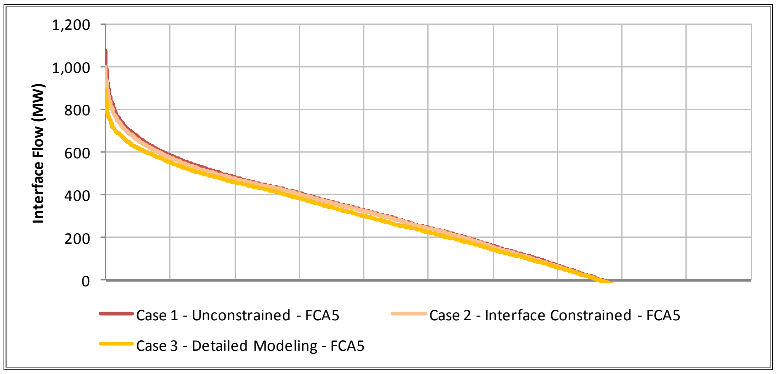

Figure 6-35 Flow-duration curves for the Surowiec South subarea (Cases 1 to 3) under FCA #5 wind penetration for the GridView Transmission Modeling cases.

Figure 6-36 shows Northern New Hampshire WDA exports were limited. This did not result in a reduction in wind energy because other resource types were constrained down.

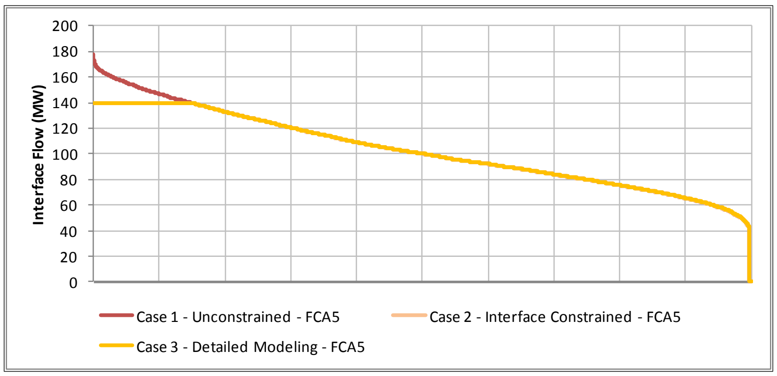

Figure 6-36: Flow-duration curves for the Northern New Hampshire subarea (Cases 1 to 3) under FCA #5 wind penetration for the GridView Transmission Modeling cases.

Figure 6-37 shows that the SEMA/RI area was not affected by additional transmission modeling when only the FCA #5 resources were added.

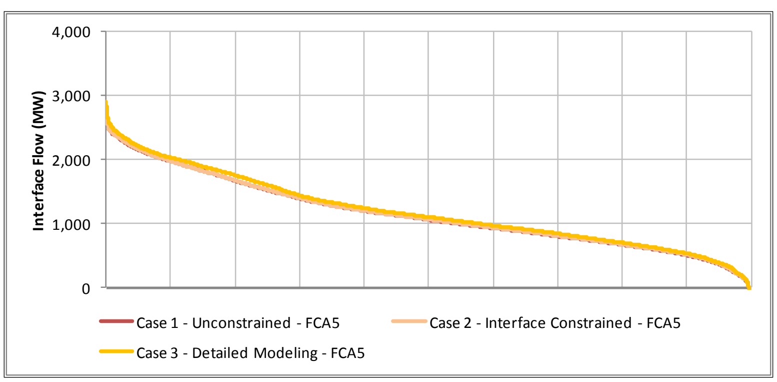

Figure 6-37: Flow-duration curves for the SEMA/RI Export Interfaces (Cases 1 to 3) under FCA #5 wind penetration for the GridView Transmission Modeling cases.

6.2.6.2 Active Queue

For the Active Queue wind-penetration cases, Figure 6-38 to Figure 6-43 show the flow-duration curves for the Transmission Modeling cases. In this case, four interfaces were binding; Orrington South , Wyman/Bigelow, Surowiec South and Northern New Hampshire.

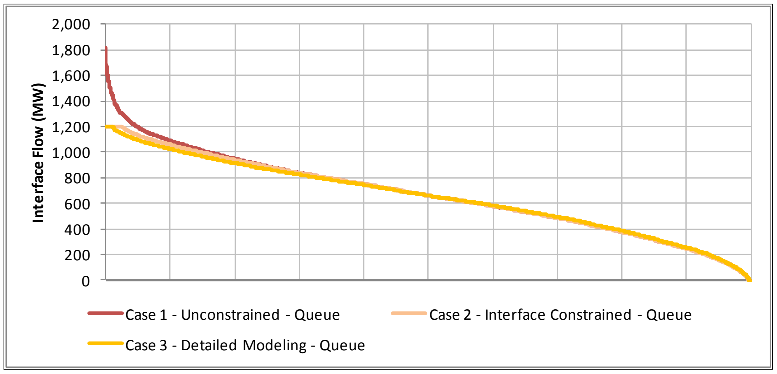

Figure 6-38: Flow-duration curves for the Orrington South export interface (Cases 1 to 3) under Active Queue wind penetration for the GridView Transmission Modeling cases.

As shown in Figure 6-39 the Wyman/Bigelow export interface was binding about 45% of the time in the Interface-Constrained case but only about 20% of the time in the Detailed Modeling case. This suggests that a contingency in the Wyman/Bigelow subarea tends to be more restrictive than the export interface.

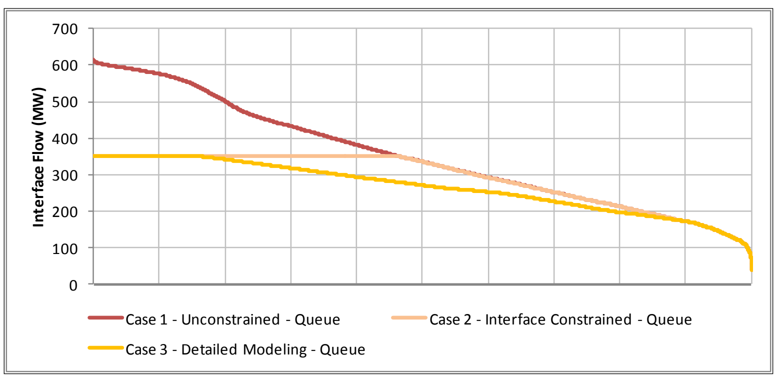

Figure 6-39 Flow-duration curves for the Wyman/Bigelow export interface (Cases 1 to 3) under Active Queue wind penetration for the GridView Transmission Modeling cases.

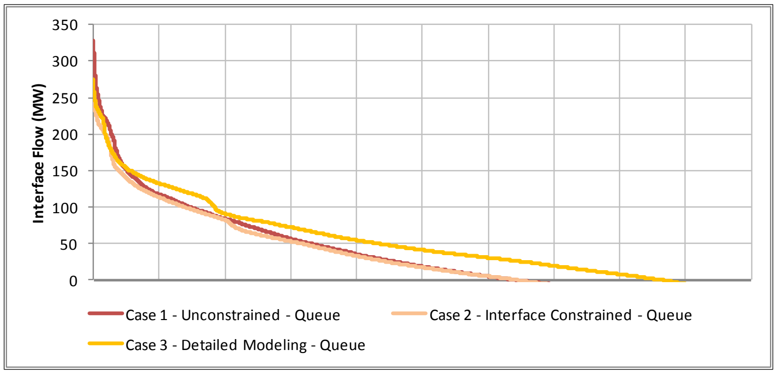

Figure 6-40: Flow-duration curves for the Rumford export interface (Cases 1 to 3) under Active Queue wind penetration for the GridView Transmission Modeling cases.

As shown in Figure 6-41, the Surowiec South interface was binding in nearly 10% of the hours in both these cases.

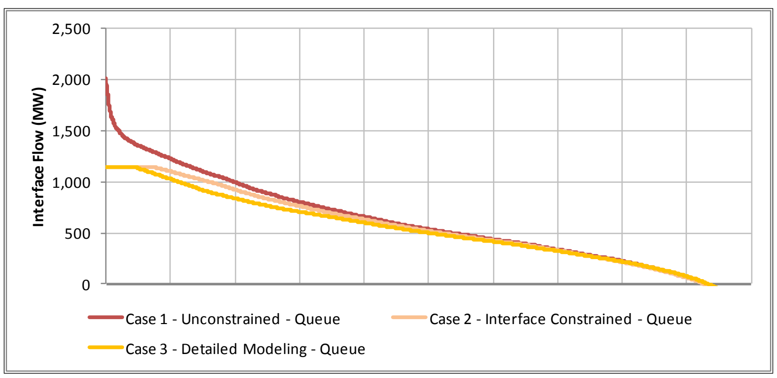

Figure 6-41: Flow-duration curves for the Surowiec South export interface (Cases 1 to 3) under Active Queue wind penetration for the GridView Transmission Modeling cases.

Likewise, as shown in Figure 6-42 for northern New Hampshire, the interface was constrained approximately 15% of the time in the Interface-Constrained and Detailed Modeling cases.

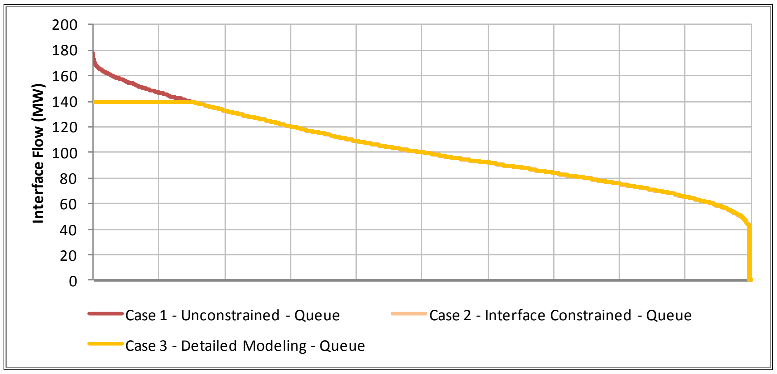

Figure 6-42: Flow-duration curves for the Northern New Hampshire export interface (Cases 1 to 3) under Active Queue wind penetration for the GridView Transmission Modeling cases.

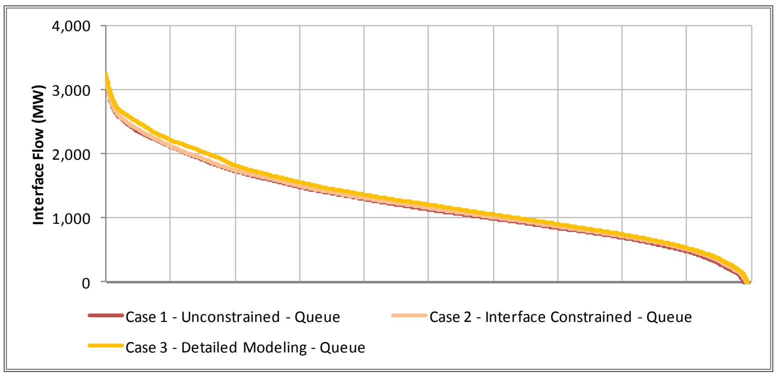

Figure 6-43: Flow-duration curves for the SEMA/RI are (Cases 1 to 3) under Active Queue wind penetration for the GridView Transmission Modeling cases.

6.2.6.3 All Wind

For the All-Wind wind-penetration cases, Figure 6-44 to Figure 6-49 show the flow-duration curves for the Transmission Modeling cases. Figure 6-44 shows that under the Interface-Constrained case, the Orrington South interface is constrained approximately 20% of the time. Another 15% of the time, the interface flow was lower than the unconstrained flows. In those hours, Orrington South may not have been constrained because the downstream constraints, primarily Surowiec South, bound first. However, detailed transmission modeling had little impact on the interface flows along the Maine corridor.

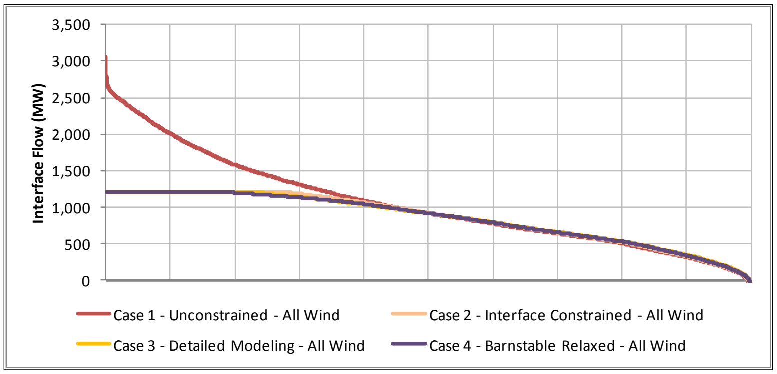

Figure 6-44: Flow-duration curves for the Orrington South export interface (Cases 1 to 4) under All-Wind wind penetration for the GridView Transmission Modeling cases.

Figure 6-45 shows the Wyman/Bigelow interface was constrained approximately 50% of the time under the Interface-Constrained case and only about 15% under the Detailed Modeling case. This is also suggestive of the downstream constraint, Surowiec South, binding first.

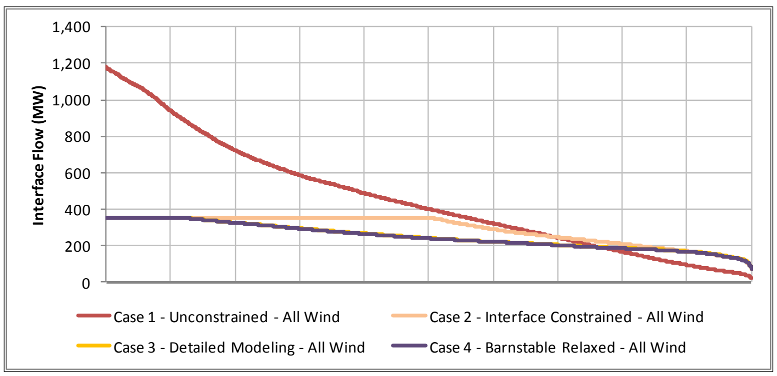

Figure 6-45: Flow-duration curves for the Wyman/Bigelow Export Interface (Cases 1 to 4) under All-Wind wind penetration for the GridView Transmission Modeling cases.

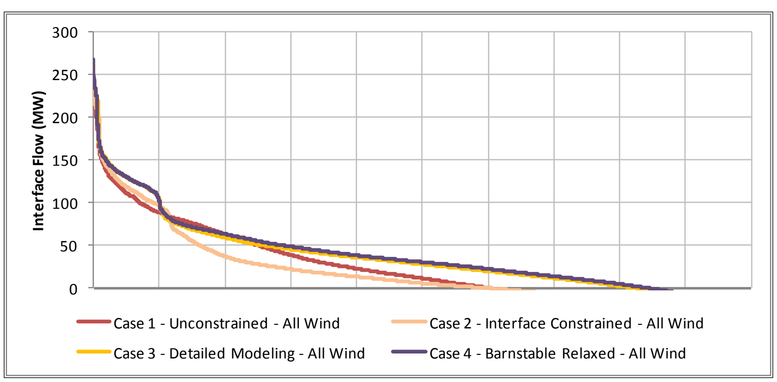

Figure 6-46: Flow-duration curves for the Rumford Export Interface (Cases 1 to 4) under All-Wind wind penetration for the GridView Transmission Modeling cases.

The Surowiec South interface, shown in Figure 6-47, was constrained over 20% of the hours; this would have limited flows across other upstream interfaces.

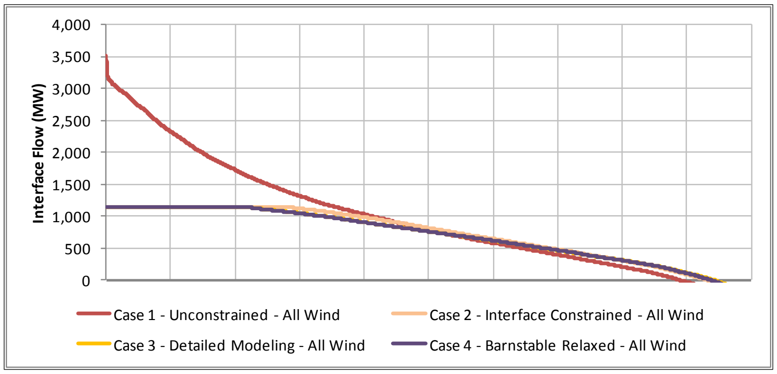

Figure 6-47: Flow-duration curves for the Surowiec South Export Interface (Cases 1 to 4) under All-Wind wind penetration for the GridView Transmission Modeling cases.

Figure 6-48 shows that the transmission interface associated with wind generation in the Northern New Hampshire WDA reached its limit the nearly 70% of the time.

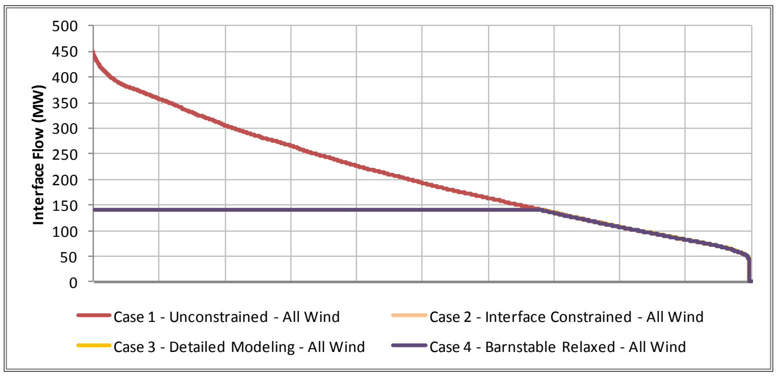

Figure 6-48: Flow-duration curves for the Northern New Hampshire Export Interface (Cases 1 to 4) under All-Wind wind penetration for the GridView Transmission Modeling Cases.

From Figure 6-49 for the Detailed Modeling case, the flow-duration curve of the SEMA/RI export interface, the interface was binding only about 5% of hours compared to 25% for the Interface-Constrained case. This indicates that other binding constraints limited the wind generation upstream from the SEMA/RI interface.

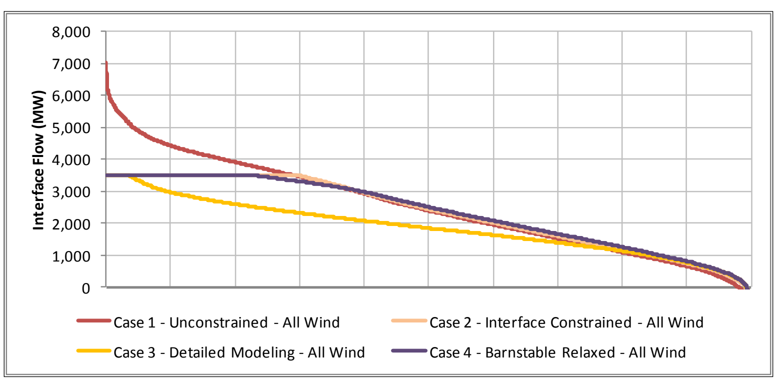

Figure 6-49: Flow-duration curves for the SEMA/RI Export Interface (Cases 1 to 4) under All-Wind wind penetration for the GridView Transmission Modeling cases.

6.2.7 Investigation of Wind Curtailment and Binding Constraints

To explain how a binding constraint can be identified, the SEMA/RI interface for the All-Wind wind-penetration level was investigated. Figure 6-49 shows that the Detailed Modeling case resulted in the SEMA/RI interface binding in only 5% of the hours. However, the comparable Interface-Constrained case shows that the same wind-penetration level caused the SEMA/RI interface to be binding about 25% of the time. The likely cause was one or more individual transmission elements within SEMA/RI area restricting export flow, which can studied using GridView.

A useful tool for identifying congestion is a list of binding constraints and the associated annual congestion cost. This metric quantifies the contribution of each binding constraint towards the total New England congestion cost.

Table 6-9 shows a sorted list of binding constraints that contributed the most to New England's total congestion cost. The results for the All-Wind wind-penetration case show that the branch labeled as "Barnstable Transformer" was the source of $208.7 million in annual congestion.

Table 6-9
Comparison of Binding Constraints Sorted by Total Congestion Cost

No.	*Item*	*Type*	*Total Congestion Cost (M$)*
1	Barnstable Transformer	Branch Rating	208.7
2	SURW_SOUTH	Interface	67.8
	Contingency	Contingency	49.7
4	ORR_SOUTH	Interface	44.1
5	NORTHERN NH/VT	Interface	28.8
6	SEMA/RI	Interface	22.6
7	Contingency	Contingency	21.0
8	Contingency	Contingency	7.4
9	WYMAN BIGELOW EXPORT	Interface	6.9
10	Contingency	Contingency	5.8

The Detailed Modeling results showed very volatile LMP prices and high values for congestion at several buses in the SEMA area. The Barnstable bus, which interconnected about 5,000 MW of offshore wind, was the most volatile bus in SEMA. This suggested that the Barnstable bus was close to the constraint, and it was chosen as the starting point.

Figure 6-50 shows three graphs on a chronological scale for all 744 hours in January. The red line shows the data for the Detailed Modeling case, and the blue line shows the comparable data for the Interface-Constrained case. These graphs provide a time-synchronized comparison of key metrics such as:

- Wind generation
- LMP
- Congestion component of the LMP

The top graph shows that the maximum wind output in the Detailed Modeling case was limited to approximately 30% of the maximum output of the wind in the Interface-Constrained case. Closer inspection shows that when the wind generation in the Detailed Modeling case (red) was less than the wind generation in the Interface-Constrained case (blue), a local constraint existed and the LMP in the middle graph dropped to zero. The lower graph shows that when the LMP dropped to zero, the congestion component became negative, confirming that the zero LMP was due to transmission constraints. To investigate the binding elements, a specific hour was chosen for further evaluation.

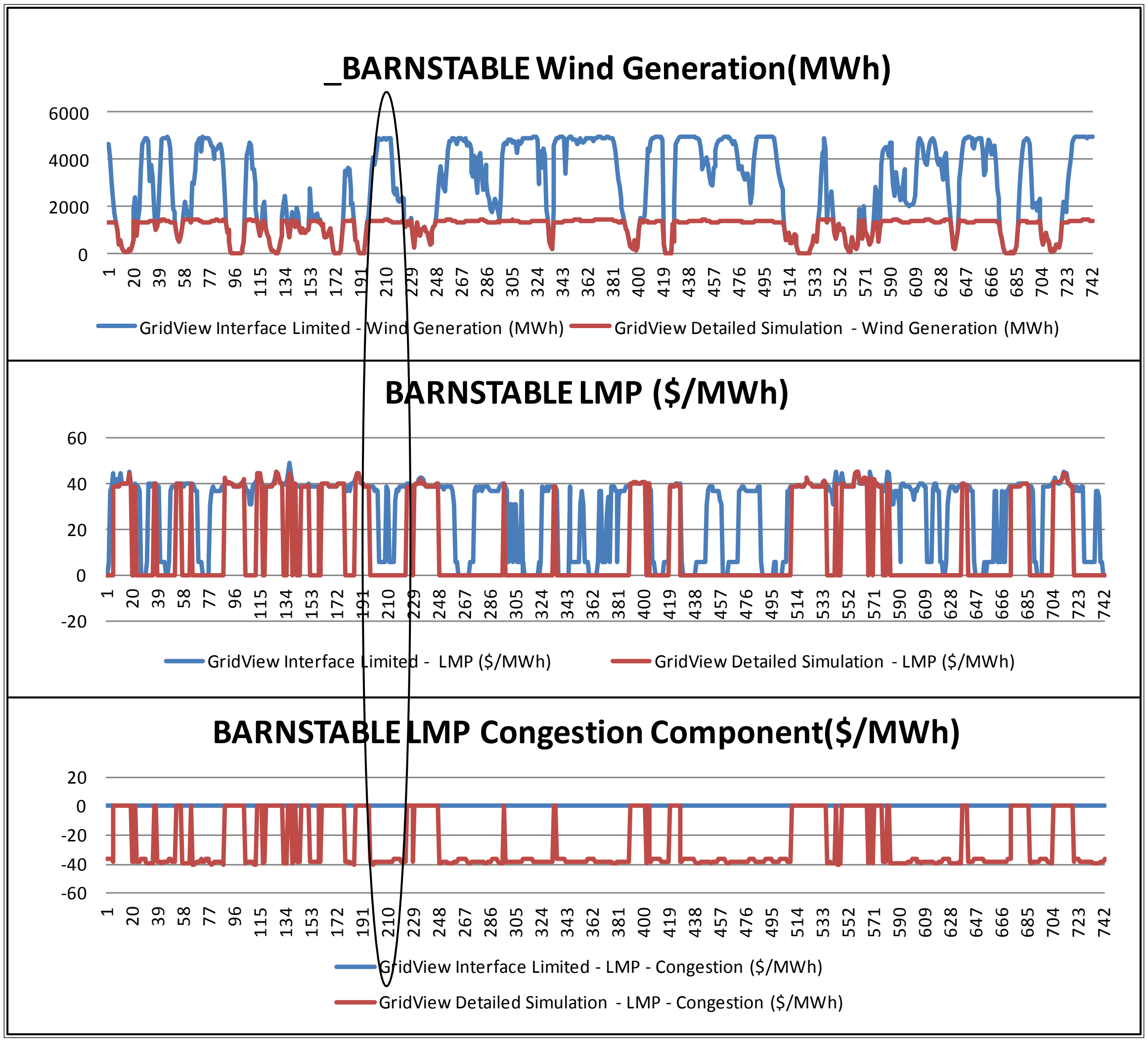

Figure 6-50: GridView-simulated hourly LMP congestion at a major bus in the SEMA/RI area.

6.2.8 Relieving a Binding Constraint Modeling

To find the cause of bottled-in wind energy, an hour with a $0/MWh LMP was selected for further analysis (hour 210) as shown in Figure 6-50. Analysis of this hour allowed the constraints with the largest congestion components to be identified. The "Barnstable transformer," a 115 to 345 KV transformer, was shown to be the largest source of congestion. It provided a path for large offshore wind farms to deliver energy into the ISO New England 345 kV system.

The purpose of the study was to quantify the ability of the transmission system, as planned, to accept and deliver various amounts of wind energy. Therefore no modification of the transmission network was assumed. The transmission system used for this study was obtained from the 2016 MOD case, which was not designed to accept and transmit 13 GW of wind energy across New England.

Therefore, the Barnstable transformer was removed from the list of monitored elements so that the constraint could be relaxed.

6.2.8.1 Flow Duration Curve—Relieving a Binding Constraint

Figure 6-51 presents the SEMA/RI interface flow-duration curve, before and after relieving the Barnstable transformer constraint. This figure shows that after relieving this constraint, the SEMA/RI export interface carried higher flows, reaching its limit in about 25% of the hours.

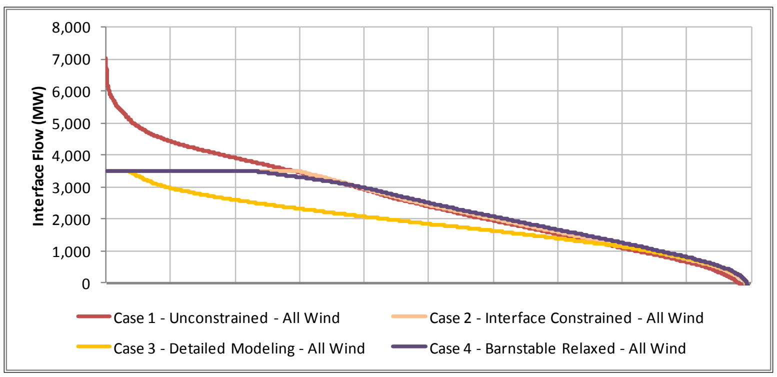

Figure 6-51: GridView-simulated internal flow-duration curve for the Unconstrained case under the All-Wind wind-penetration cases.

6.3 GridView Refined Modeling Cases (Case 4 and Cases 5a to d)–Effect of Wind Penetration

For the GridView Refined Modeling cases, each of the sensitivity cases was compared to the Barnstable Relaxed case. Four additional sensitivity cases were investigated as follows:

- **Barnstable Relaxed** – used as a reference for comparison
- **Detailed Resource Operating Parameters—**used a more complete representation of the units' heat rate and operating parameters.
- **Monitor 115 kV and above transmission lines in CMP—**monitored these lines for overloads under normal system operations.
- **Expanded Wyman/Bigelow contingencies—**monitored 115 kV transmission lines and above in CMP for overloads under normal system operations, and under additional contingencies on the 115 kV line in CMP.
- **Expanded contingencies with new MPRP limits—**increased the voltage and stability limits on Orrington South, Surowiec South, and Maine–New Hampshire interfaces to reflect the likely limits with the reinforced transmission infrastructure.

Table 6-10 presents the economic results of these cases in tabular format for easy comparison. The following sections discuss these results further.

Table 6-10
LSE Expense and Production Costs for the GridView Refined Modeling Cases (Million $)

	Production Cost			LSE Energy Expense		
	FCA5	Active Queue	All Wind	FCA5	Active Queue	All Wind
GridView Barnstable Relaxed	3343	2948	1991	7803	6858	5460
Detailed Resource Operating Parameters	3800	3346	2302	7910	6759	5350
Monitor 115 kV, and above, lines in CMP	3800	3353	2304	7911	6897	5381
Expanded Wyman/Bigelow Contingencies	3800	3354	2303	7955	6881	5403
Expanded Contingencies with new MPRP Limits	na	na	2293	na	na	5398

6.3.1 Economic Metrics—Production Cost

Figure 6-52 shows a comparison of the production cost metric for Barnstable Relaxed with each of the Refined Modeling cases. The production costs of the sensitivity cases are all relatively close to each other. This suggests that the additional monitored transmission lines and constraints in the Wyman/Bigelow and CMP areas did not result in significant amounts of bottled-in wind energy. Otherwise, more energy from fossil-fueled resources would be generated and the cost of producing this energy would increase the production cost metric.

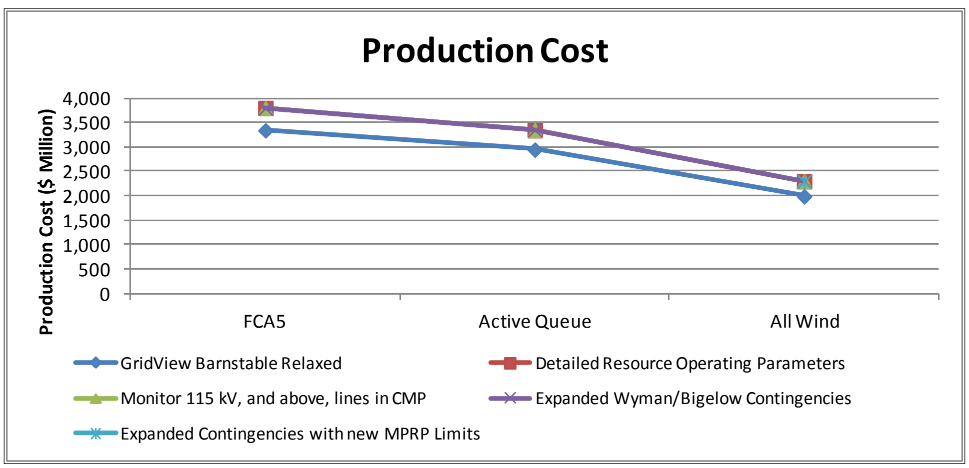

Figure 6-52: Comparison of production costs for the GridView Refined Modeling cases.

This figure shows that, compared to Barnstable Relaxed case, all the sensitivity cases with detailed resource operating parameters, such as heat rate and operating limits, had higher production costs. This is largely a result of the explicit inclusion of no-load and start-up costs that were not part of the Model Comparison and Transmission Modeling cases.

6.3.2 Economic Metrics—LSE Energy Expense

Figure 6-53 shows the LSE energy expenses for the Barnstable Relaxed case and the sensitivity cases. While many factors influenced the LSE energy expense metric, the effects of the transmission constraints were not significant, and the LSE energy expenses of all these cases were nearly identical.

As shown in the analysis of the LSE energy expense metric, the marginal cost of energy for the sensitivity cases was comparable to the Barnstable Relaxed case. This suggests that the change in production cost did not affect the cost at which the marginal units were dispatched.

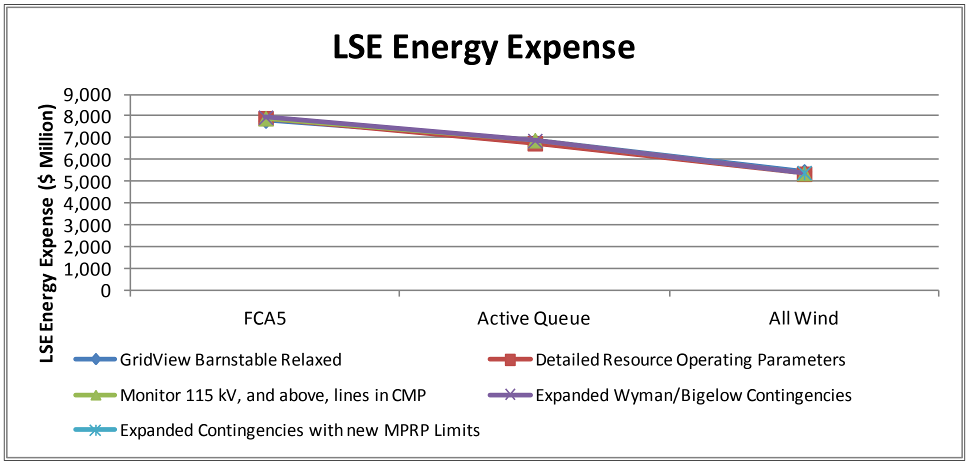

Figure 6-53: Comparison of LSE energy expense for the GridView Refined Modeling cases.

6.3.3 Generation by Fuel Types

Table 6-11 shows that compared with the Barnstable Relaxed case, the Detailed Resource Operating Parameters case increased the amount of coal (+2,600 GWh) and oil (+600 GWh) energy production and decreased the amount of natural gas (−4,000 GWh) production.

Table 6-11
Generation by Fuel Type for the GridView Refined Modeling Cases (GWh)

	Coal	Gas	Hyd/Oth	Nuclear	Oil	Wind	Biomass
FCA5							
GridView Barnstable Relaxed	6,919	74,346	23,159	37,771	871	2,514	4,546
Detailed Resource Operating Parameters	9,373	70,112	24,345	37,802	1,437	2,509	4,547
Monitor 115 kV, and above, lines in CMP	9,394	70,084	24,343	37,802	1,445	2,510	4,547
Expanded Wyman/Bigelow Contingencies	9,396	70,083	24,342	37,802	1,445	2,510	4,547
Expanded Contingencies with new MPRP Limits	9,396	70,083	24,342	37,802	1,445	2,510	4,547
Active Queue							
GridView Barnstable Relaxed	6,162	66,388	22,999	37,771	584	11,725	4,496
Detailed Resource Operating Parameters	8,519	62,359	24,160	37,802	1,092	11,707	4,486
Monitor 115 kV, and above, lines in CMP	8,504	62,613	24,163	37,802	1,039	11,565	4,439
Expanded Wyman/Bigelow Contingencies	8,503	62,606	24,163	37,802	1,046	11,565	4,439
Expanded Contingencies with new MPRP Limits	8,503	62,606	24,163	37,802	1,046	11,565	4,439
All Wind							
GridView Barnstable Relaxed	4,398	44,342	22,510	36,055	241	38,949	3,630
Detailed Resource Operating Parameters	5,575	42,358	23,328	36,455	608	38,219	3,583
Monitor 115 kV, and above, lines in CMP	5,600	42,413	23,361	36,461	601	38,116	3,573
Expanded Wyman/Bigelow Contingencies	5,603	42,427	23,358	36,460	589	38,114	3,573
Expanded Contingencies with new MPRP Limits	5,566	42,089	23,399	36,369	620	38,479	3,601

As the wind penetration increased, the wind energy generation increased and the thermal generation decreased. In these cases, high wind penetration resulted in a slight decrease in nuclear generation while natural gas decreased the most.

A comparison of the wind generation values across Active Queue cases shows little change in wind generation, even with the additional contingencies in the CMP service territory. The All-Wind wind-penetration sensitivity case with the most recent MPRP interface limits shows a 350 GWh increase in wind generation and a corresponding decrease in natural gas generation.

6.3.3.1 FCA #5

Figure 6-54 shows the generation by fuel type for these cases. This figure shows less energy production from natural gas and slightly more from coal in all the cases with the detailed resource operating parameters modeled.

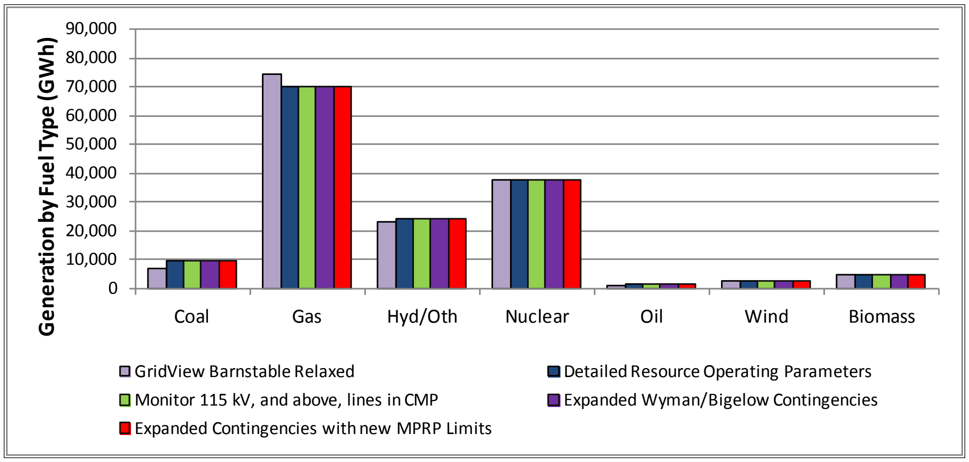

Figure 6-54: Generation by fuel type under FCA #5 wind penetration for the GridView Refined Modeling cases.

6.3.3.2 Active Queue

Figure 6-55 presents the generation by fuel type for the Refined Modeling cases under the Active Queue wind-penetration cases. The results are similar to those shown previously for the lower FCA #5 wind penetration, where the Refined Modeling sensitivities show a small difference in aggregate fuel consumption resulting from the additional transmission constraints modeled.

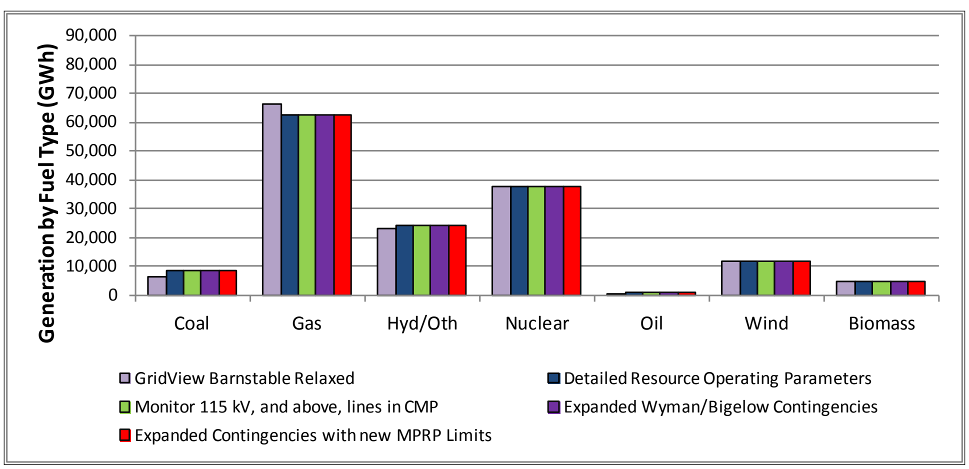

Figure 6-55: Generation by fuel type under Active Queue wind penetration for the GridView Refined Modeling cases.

6.3.3.3 All Wind

For the All-Wind wind-penetration cases, Figure 6-56 presents the generation by fuel type for the Refined Modeling cases. With the Expanded Contingencies with New MPRP Limits, there is a slight increase in wind energy and a corresponding decrease in natural gas generation.

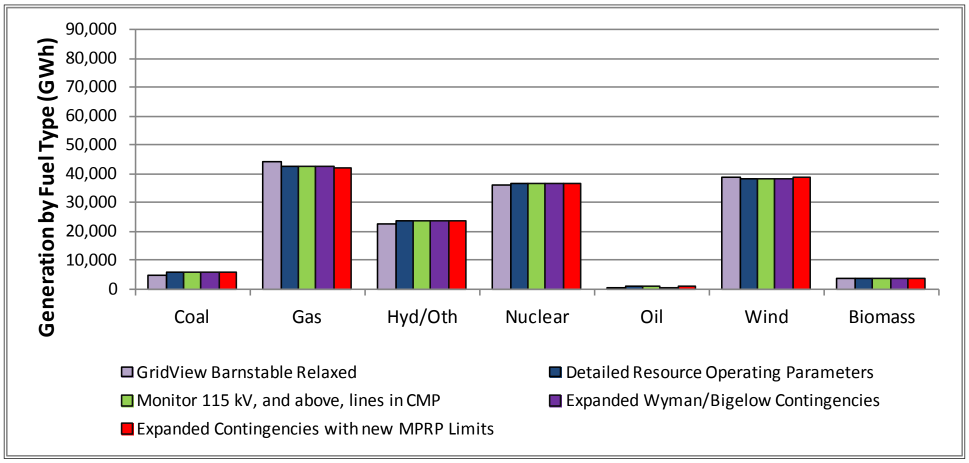

Figure 6-56: IREMM generation fuel type under All-Wind wind penetration for the GridView Refined Modeling cases.

6.3.4 Wind Generation by Wind-Development Areas

Table 6-12 shows the wind generation by wind-development area for the Refined Modeling cases. As expected, higher wind-penetration cases resulted in more wind energy generation. Though not many differences were observed when varying the limits and contingencies.

Table 6-12
Wind Generation by Wind Development Area for the GridView Refined Modeling Cases (GWh)

	Wyman / Bigelow	Rumford Area	Northern Maine	Northern New Hampshire	SEMA/RI	Other Wind Areas
FCA5						
GridView Barnstable Relaxed	714	413	300	301	-	740
Detailed Resource Operating Parameters	709	413	300	301	-	740
Monitor 115 kV, and above, lines in CMP	709	413	300	301	-	740
Expanded Wyman/Bigelow Contingencies	709	413	300	301	-	740
Expanded Contingencies with new MPRP Limits	709	413	300	301	-	740
Active Queue						
GridView Barnstable Relaxed	1,325	569	3,459	403	3,883	2,039
Detailed Resource Operating Parameters	1,318	569	3,447	403	3,884	2,039
Monitor 115 kV, and above, lines in CMP	1,172	569	3,451	403	3,884	2,039
Expanded Wyman/Bigelow Contingencies	1,172	569	3,451	403	3,884	2,039
Expanded Contingencies with new MPRP Limits	1,172	569	3,451	403	3,884	2,039
All Wind						
GridView Barnstable Relaxed	1,473	660	6,444	994	25,656	3,678
Detailed Resource Operating Parameters	1,460	656	6,350	996	25,037	3,678
Monitor 115 kV, and above, lines in CMP	1,344	658	6,362	996	25,036	3,677
Expanded Wyman/Bigelow Contingencies	1,345	659	6,360	996	25,035	3,677
Expanded Contingencies with new MPRP Limits	1,373	687	6,672	996	25,032	3,675

The very large growth of wind in SEMA/RI for the All-Wind cases is clearly the most salient factor in terms of wind generation.

6.3.4.1 FCA #5

Figure 6-57 shows that for the FCA #5 wind-penetration cases, the wind generation was slightly affected by the additional monitoring of 115 kV transmission lines in the CMP region. The expanded Wyman/Bigelow contingencies did not create any additional bottled-in wind energy, which suggests that the initial list of contingencies already included the most-limiting contingencies.

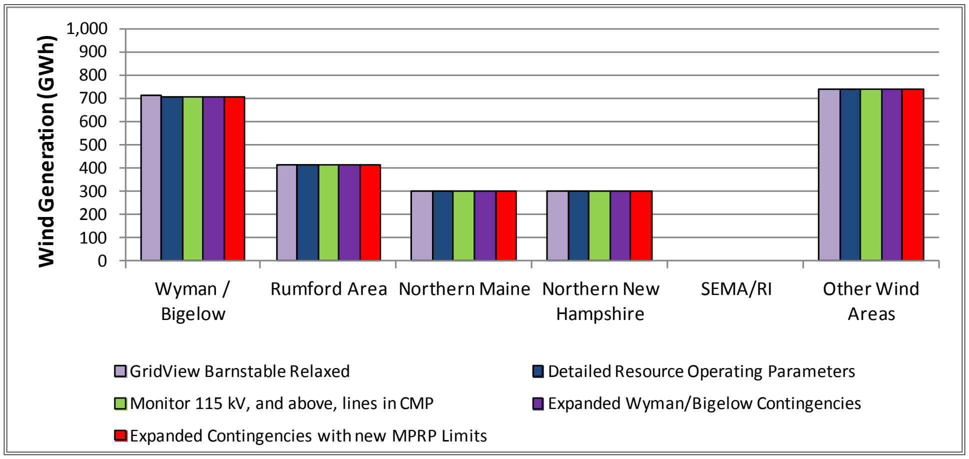

Figure 6-57: Wind generation by location—Cases 5a to d under FCA #5 wind penetration for the GridView Refined Modeling cases.

6.3.4.2 Active Queue

For the Active Queue wind-penetration cases, Figure 6-58 shows that the Refined Transmission monitoring and contingency sensitivity cases had little effect on the wind generation. The wind generation behind the Wyman/Bigelow interface is reduced by 150 GWh due to these additional transmission constraints.

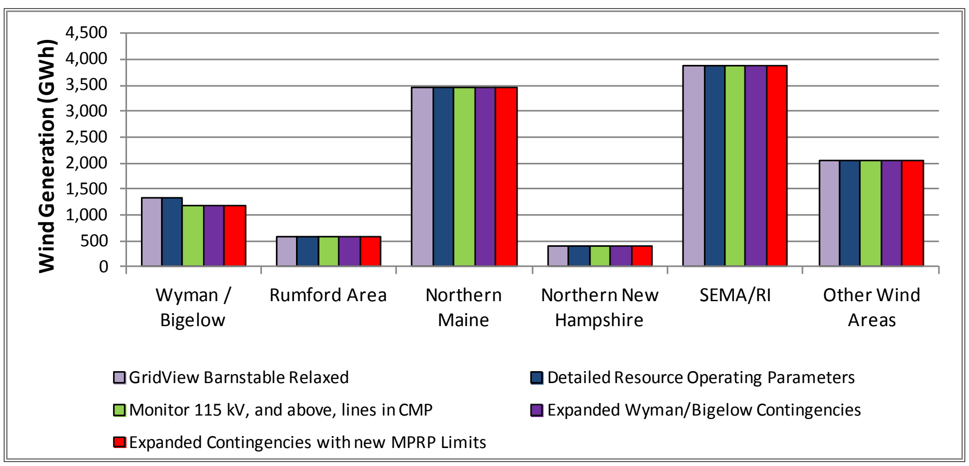

Figure 6-58: Wind generation by location—Cases 5a to d under Active Queue wind penetration for the GridView Refined Modeling cases.

6.3.4.3 All Wind

For the All-Wind wind-penetration cases, Figure 6-59 shows that the additional monitoring and contingency cases had little effect on wind energy generation. For the Northern Maine and Rumford wind development areas, the new MPRP limits slightly increased the wind generation.

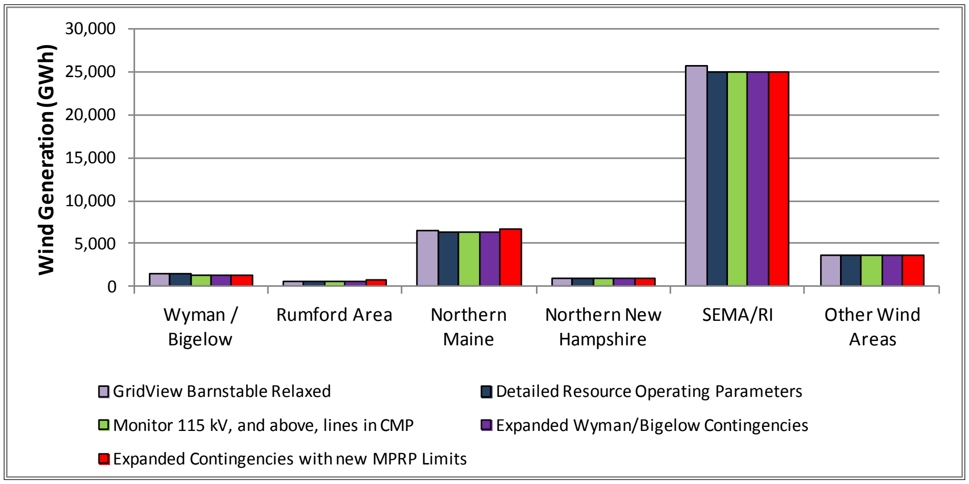

Figure 6-59: Wind generation by location—Case 5a to d under All-Wind wind penetration for the GridView Refined Modeling cases.

6.3.5 Bottled-In Wind Energy

Table 6-13 shows the amounts of bottled-in wind energy for each of the Refined Modeling cases compared to the Barnstable Relaxed case. The Wyman/Bigelow area had some bottled-in wind energy at each level of wind penetration. The amount of bottled-in wind energy in the Wyman/Bigelow subarea increased about 150 GWh in the Active Queue and the All-Wind wind-penetration cases as a result of the refined GridView transmission representation.

Table 6-13
Bottled-In Wind Energy by Wind Development Subarea for the GridView Refined Modeling Cases (GWh)

	Wyman / Bigelow	Rumford Area	Northern Maine	Northern New Hampshire	SEMA/RI	Other Wind Areas
FCA5						
GridView Barnstable Relaxed	121	-	-	-	-	-
Detailed Resource Operating Parameters	126	-	-	-	-	-
Monitor 115 kV, and above, lines in CMP	126	-	-	-	-	-
Expanded Wyman/Bigelow Contingencies	126	-	-	-	-	-
Expanded Contingencies with new MPRP Limits	126	-	-	-	-	-
Active Queue						
GridView Barnstable Relaxed	452	-	10	1	-	-
Detailed Resource Operating Parameters	459	-	22	1	(1)	-
Monitor 115 kV, and above, lines in CMP	605	-	18	1	(1)	-
Expanded Wyman/Bigelow Contingencies	605	-	18	1	(1)	-
Expanded Contingencies with new MPRP Limits	605	-	18	1	(1)	-
All Wind						
GridView Barnstable Relaxed	1,476	27	1,486	390	1,055	(3)
Detailed Resource Operating Parameters	1,489	31	1,580	388	1,674	(3)
Monitor 115 kV, and above, lines in CMP	1,605	29	1,568	388	1,675	(2)
Expanded Wyman/Bigelow Contingencies	1,604	28	1,570	388	1,676	(2)
Expanded Contingencies with new MPRP Limits	1,576	-	1,258	388	1,679	-

6.3.5.1 FCA #5

Figure 6-60 shows that some bottled-in wind was in the Wyman/Bigelow wind-development area. The sensitivity cases with more detailed resource operating parameters and additional modeling of contingencies in the CMP region was negligible and resulted in only a 0.4% increase in bottled-in energy (from 14.5% to 15.0%).

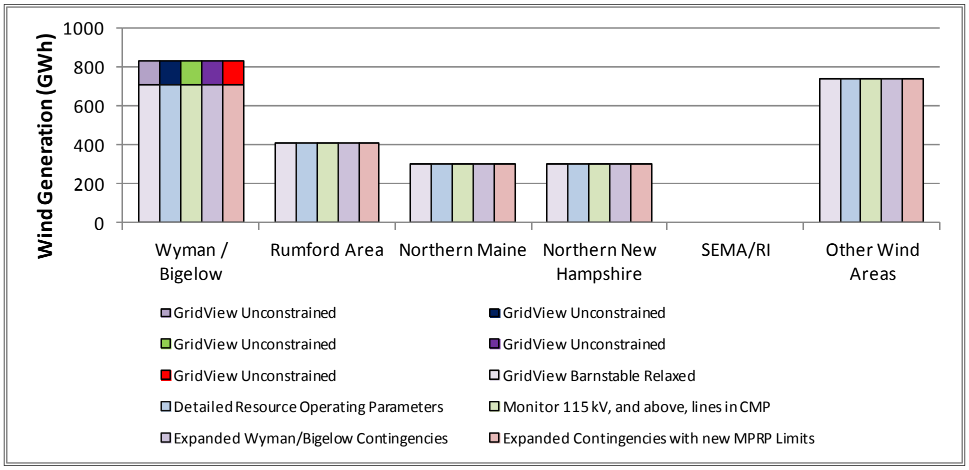

Figure 6-60: Effect of interface constraints under FCA #5 wind penetration for the GridView Refined Modeling cases.

6.3.5.2 Active Queue

Figure 6-61 shows some bottled-in wind energy in the Wyman/Bigelow WDA as a result of the monitoring of 115 kV lines. Additionally, modeling of the contingencies increased the amount of bottled-in wind energy in the Wyman/Bigelow subarea by about 33% (from 25.5% to 34.0%).

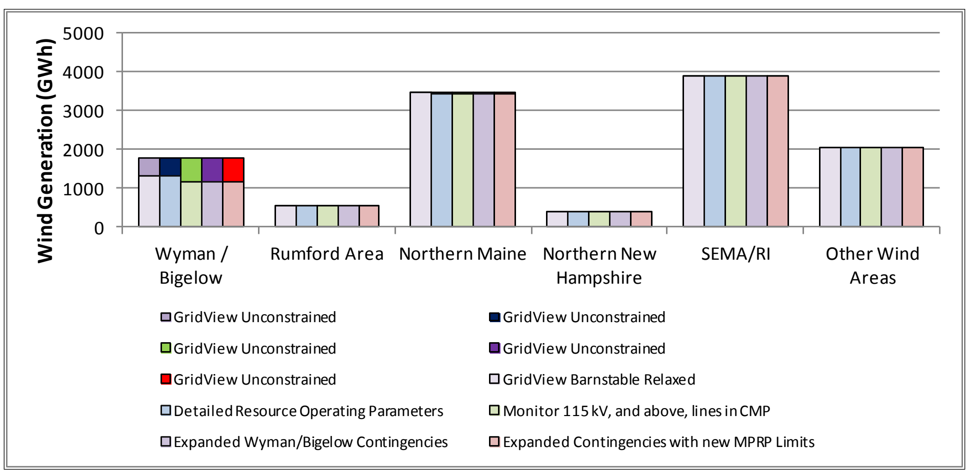

Figure 6-61: Effect of interface constraints under Active Queue wind penetration for the GridView Refined Modeling cases.

6.3.5.3 All Wind

Figure 6-62 shows that under the All-Wind wind-penetration scenarios, some bottled-in wind energy resulted in Wyman/Bigelow, Northern Maine, and SEMA/RI wind-development areas. However, the amounts did not change with the additional monitoring or contingencies associated with 115 kV lines in the CMP region. These results also show that using the latest MPRP interface limit increased the wind generation in Northern Maine and Rumford subareas by about 300 GWh, while having no significant offsetting impact on the wind generation in other wind-development areas.

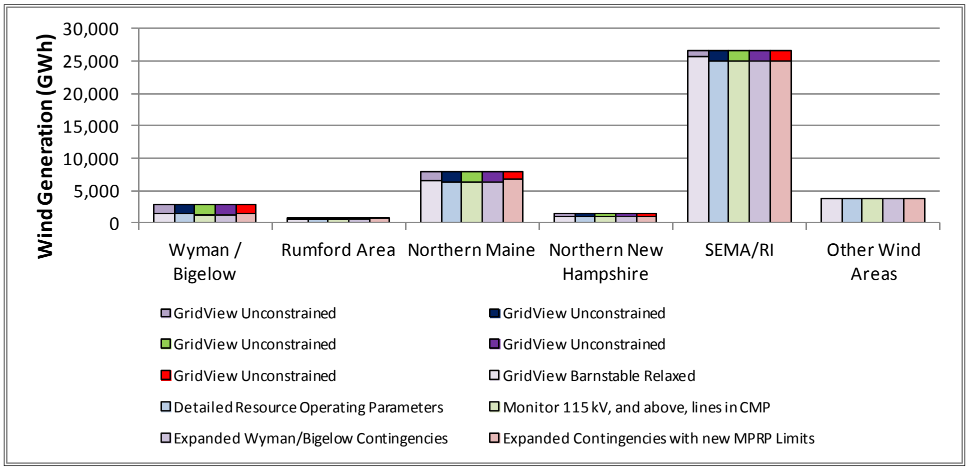

Figure 6-62: Effect of interface-constraints under All-Wind wind penetration for the GridView Refined Modeling cases.

6.3.6 Interface Flow-Duration Curves

The following section presents the key interface flow-duration curves under the Refined Modeling cases for the three wind-penetration levels. A graphical overview of the energy flows on a number of major interfaces is provided.

These results show that there were increased flows across the Orrington South and Surowiec South interfaces for the cases with detailed modeling of thermal unit heat-rate curves. The addition of modeling transmission constraints in central Maine produced relatively small changes in the energy flows across these interfaces.

6.3.6.1 FCA #5

The Orrington South and Surowiec South interfaces exhibit the largest difference between cases, as shown in Figure 6-63 and Figure 6-65, respectively. For the FCA #5 wind scenario, the addition of detailed heat rate curves increased the flows through the Maine corridor. Little impact is seen in Figure 6-64 for Wyman/Bigelow. The monitoring of additional lines and contingencies did not have a noticeable impact in any case.

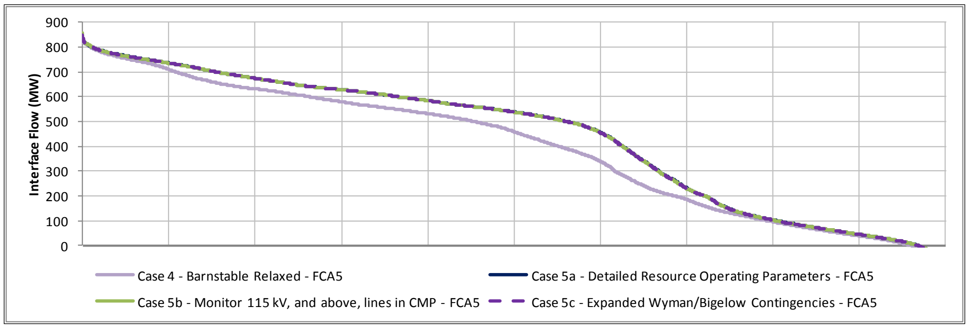

Figure 6-63: Orrington South (Case 4, 5a to c) under All-Wind wind penetration for the GridView Refined Modeling cases.

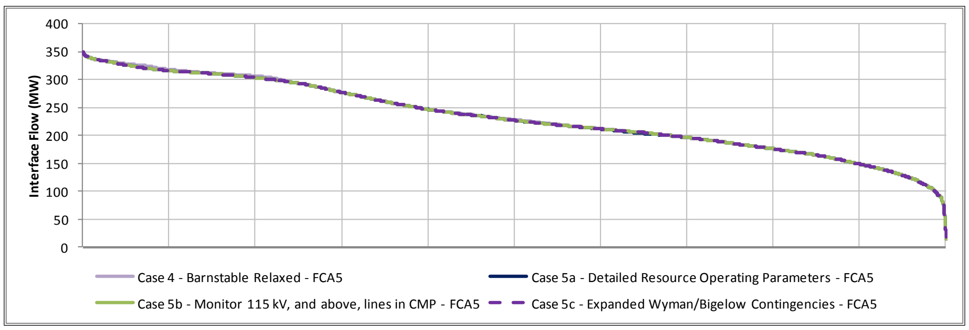

Figure 6-64: Wyman/Bigelow (Case 4, 5a to c) under FCA #5 wind penetration for the GridView Refined Modeling cases.

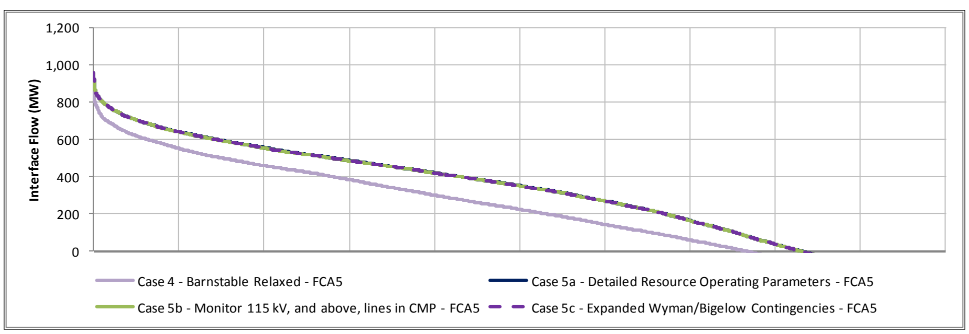

Figure 6-65: Surowiec South (Case 4, 5a to c) under FCA #5 wind penetration for the GridView Refined Modeling cases.

6.3.6.2 Active Queue

The Orrington South and Surowiec South interfaces exhibit the largest difference between cases, as shown in Figure 6-66 and Figure 6-68. All the sensitivity cases with the more detailed resource operating parameters showed increased flows through the Maine corridor. For the Surowiec South interface, the sensitivity case, that monitored the 115 kV lines and above in the CMP area, showed a slight decrease in the flow. For other interfaces, the monitoring of additional lines and contingencies did not have a noticeable impact.

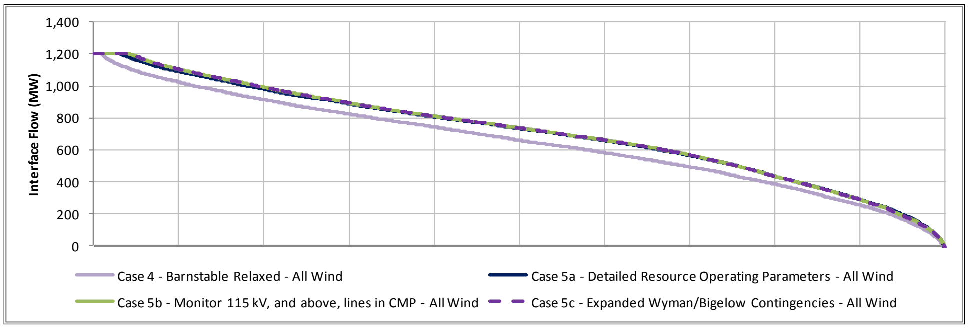

Figure 6-66: Orrington South interface (Case 4, 5a to c) under Active Queue wind penetration for the GridView Refined Modeling cases.

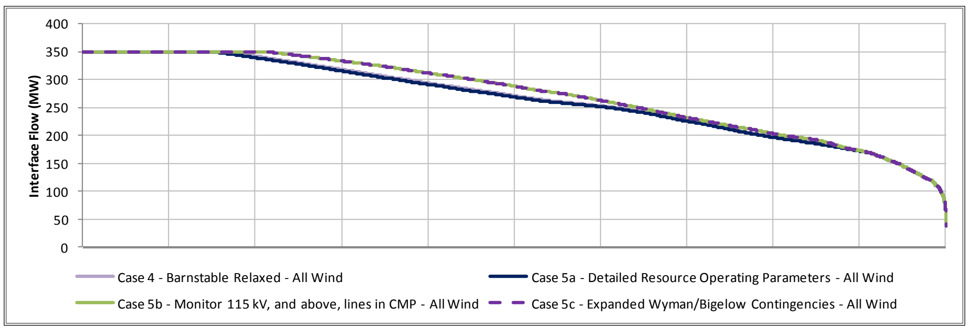

Figure 6-67: Wyman/Bigelow interface (Case 4, 5a o c) under Active Queue wind penetration for the GridView Refined Modeling cases.

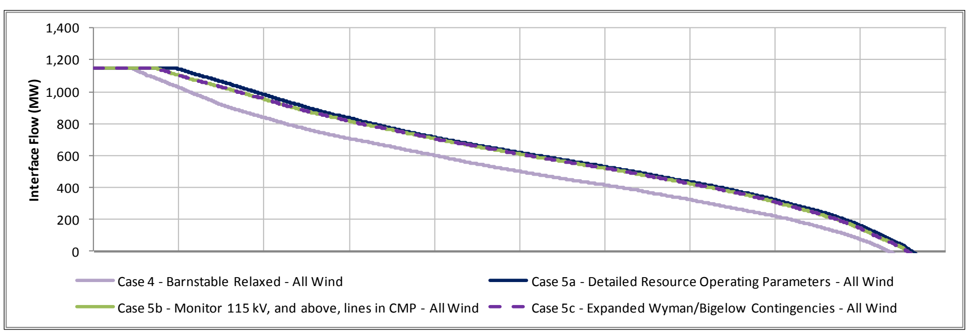

Figure 6-68: Surowiec South interface (Case 4, 5a to c) under Active Queue wind penetration for the GridView Refined Modeling cases.

6.3.6.3 All Wind

The Orrington South and Surowiec South interfaces exhibited some difference between cases, as shown in Figure 6-69 to Figure 6-71. The addition of detailed heat-rate curves produced small increases in the flows through the Maine corridor. The monitoring of additional lines and contingencies did not have a noticeable impact. The largest difference in flows was associated with the revised MPRP limits. As expected, the revised MPRP limits did not affect the flows across the Wyman/Bigelow interface because the limit for that interface was not increased by the MPRP.

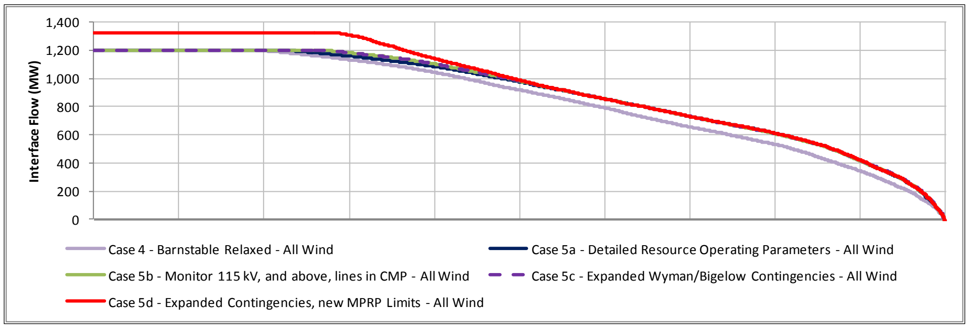

Figure 6-69: Orrington South interface (Case 4, 5a to d) under All-Wind wind penetration for the GridView Refined Modeling cases.

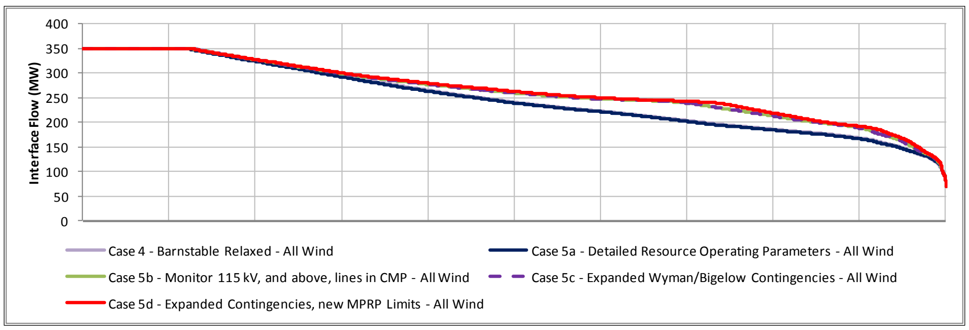

Figure 6-70: Wyman/Bigelow interface (Case 4, 5a to d) under All-Wind wind penetration for the GridView Refined Modeling cases.

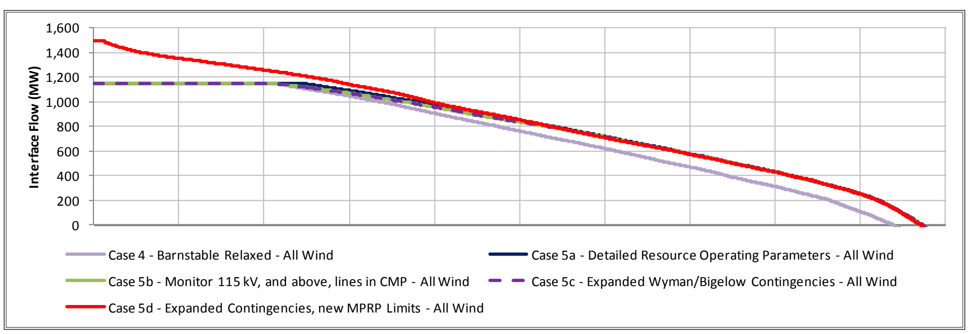

Figure 6-71: Surowiec South interface (Case 4, 5a to d) under All-Wind wind penetration for the GridView Refined Modeling cases.

6.4 GridView Wind/Hydro Coordination Cases (Case 6a1, 6a2 and 6a3)

One of the questions that arose during the PAC discussions was the ability to coordinate variable wind generation output with potential energy storage available at hydroelectric facilities within an export-constrained area. To evaluate this coordination, a GridView model simulated the assumed capability of hydro to store the variable wind energy, that otherwise would have been lost because of transmission constraints. This evaluation used the All-Wind wind-penetration case for illustration.

6.4.1 Maximizing Generation from Behind a Constraint

To evaluate the extent to which GridView could maximize the combined output of wind and hydro generation in an export-constrained area, nine cases were developed. These cases investigated different

LMP based strategies for deciding whether to store or spill hydro compared to wind. The system's ability to maximize the combined hydro and wind generation comes from the ability to retain hydro energy in a reservoir, which can be used for generation at a later time. In contrast, wind energy that would be curtailed to avoid violating export limits cannot be stored.

As a point of reference, Table 6-14 shows the total wind energy from the Wyman/Bigelow and Rumford subareas for the cases presented in the previous sections. The first four cases in the table used the IREMM-developed hourly profile for hydro generator. These input profiles did not respond to simulated price signals. Rather, this fixed-hydro profile, in conjunction with the NEWIS wind profiles, resulted in the significant amounts of bottled-in wind energy for the All-Wind wind-penetration cases.

Table 6-14
Wind and Hydro Generation for Selected Cases: Wyman/Bigelow (GWh)

	Wyman / Bigelow		
Case	Wind	Hydro	Total
GridView Unconstrained	2949	na	na
GridView Interface Constrained	2018	na	na
Detailed Resource Operating Parameters	1460	na	na
Expanded Wyman/Bigelow Contingencies	1345	na	na
6a1 Hydro Banks at $ 0/MWh - Wind Curtails at <$0/MWh	1,809	947	2,756
6a2 Hydro Banks at $ 0/MWh - Wind Curtails at $ 5/MWh	1,590	944	2,534
6a3 Hydro Banks at $ 0/MWh - Wind Curtails at $10/MWh	1,604	947	2,551
6a1 Hydro Banks at $11/MWh - Wind Curtails at <$0/MWh	1,991	767	2,758
6a2 Hydro Banks at $11/MWh - Wind Curtails at $5/MWh	1,835	768	2,603
6a3 Hydro Banks at $11/MWh - Wind Curtails at $10/MWh	1,804	768	2,572
6a1 Hydro Banks at $20/MWh - Wind Curtails at <$0/MWh	2,045	685	2,730
6a2 Hydro Banks at $20/MWh - Wind Curtails at $5/MWh	1,858	737	2,595
6a3 Hydro Banks at $20/MWh - Wind Curtails at $10/MWh	1,810	758	2,568

In this section, GridView modeled two hydro resources in the Wyman/Bigelow subarea as dispatchable hydro that responded to price. In the unconstrained cases, these hydro resources were able to produce 993 GWh. Under the Interface-Constrained cases, the fixed-hydro profile was only able to produce about 500 GWh. By allowing GridView to coordinate the dispatch of the hydro and wind, the amount of hydro generation increased at least 150 GWh, and the wind generation increased at least 250 GWh.

Table 6-14 shows that the hydro generation for these cases ranged from a low of 685 GWh to a high of 947 GWh. Additionally, the wind generation for these cases ranged from a low of 1,590 GWh to a high of 2,045 GWh. To better visualize the results, these values are plotted in Figure 6-72.

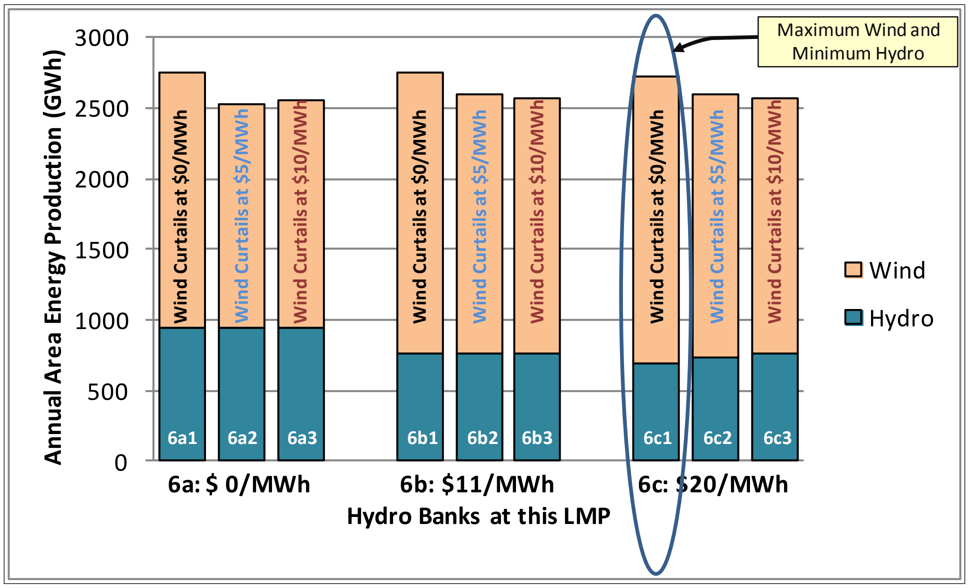

Figure 6-72: Graphical comparison of wind and hydro coordination cases.

Figure 6-72 and Table 6-14 show that tradeoffs exist and that maximum wind and maximum hydro generation occurred under different threshold prices. The maximum hydro generation occurred when hydro continued to operate until the LMP dropped to $0/MWh (cases 6a1, 6a2, and 6a3). However, this decreased the amount of wind energy that could be generated.

The maximum wind generation occurred in case 6c1, which stored hydro when the LMP dropped to $20/MWh or lower and continued wind production until the LMP dropped under $0/MWh. This case produced the lowest amount of hydro generation.

As shown in Figure 6-72, the maximum generation from both wind and hydro occurred when wind curtailed at $0/MWh (cases 6a1, 6b1, and 6c1). This indicates that by varying the wind-curtailment LMP and the hydro-banking LMP, the total generation from wind and hydro can be increased further.

6.4.2 Potential Increase of Wyman/Bigelow Wind and Hydro Generation through Coordination in an Export-Constrained Area

To better illustrate the GridView optimization, Figure 6-73 shows the monthly wind and hydro generation as cumulative monthly curves for the Wyman/Bigelow resources. This figure includes curves for each month showing cumulative energy production from hydro generation (lower set of curves) and wind generation (upper set of curves). Each set of hydro or wind monthly generation curves show the effect of the model making different selections between wind and hydro energy. Because the total hydro energy at the end of the month is unchanged, the ability to use hydro storage within a daily/monthly window is demonstrated. The differences in the wind generation highlight the months in which hydro storage was the most useful.

For each of the hydro wind-coordination cases, almost all the hydro generation was produced by the end of each month. However, for many of the cases, the total wind generation was higher. The upper line for each month shown on Figure 6-73 (purple) is associated with wind curtailed at under $0/MWh, while hydro was banked at $20/MWh.

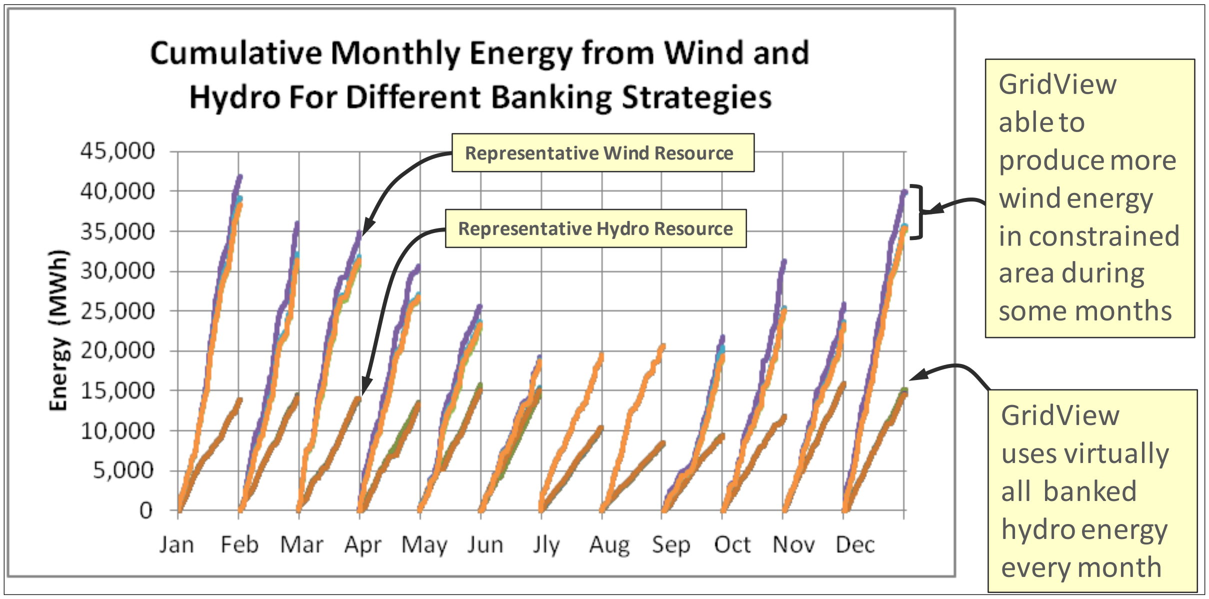

Figure 6-73: Cumulative monthly energy from wind and hydro for different banking strategies.

One of the reasons for the increased wind generation may be due to the wind in the Wyman/Bigelow subarea "undercutting" other zero-cost energy, such as other hydro, wind, and imports valued at $0/MWh or greater. This is suggested by the observations where the combined output of wind and hydro was approximately equal, whenever the wind was curtailed at under $0/MWh. Furthermore, hydro and Wind generation was not maximized for the cases where wind was curtailed at a lower LMP than the hydro. It was maximized only in the cases when wind was curtailed; last when the LMP was less than $0/MWh.

6.4.3 Flow-Duration Curves

Figure 6-74 shows a series of flow duration curves for the Wyman/Bigelow export interface. The maximum flows out of the export-constrained subarea occurred in cases 6a1, 6b1, and 6c1 when wind was curtailed under $0/MWh and hydro was stored at $20/MWh. The figure indicates that the different wind- and hydro-curtailment strategies would have an impact on the flow on the Wyman/Bigelow export interface.

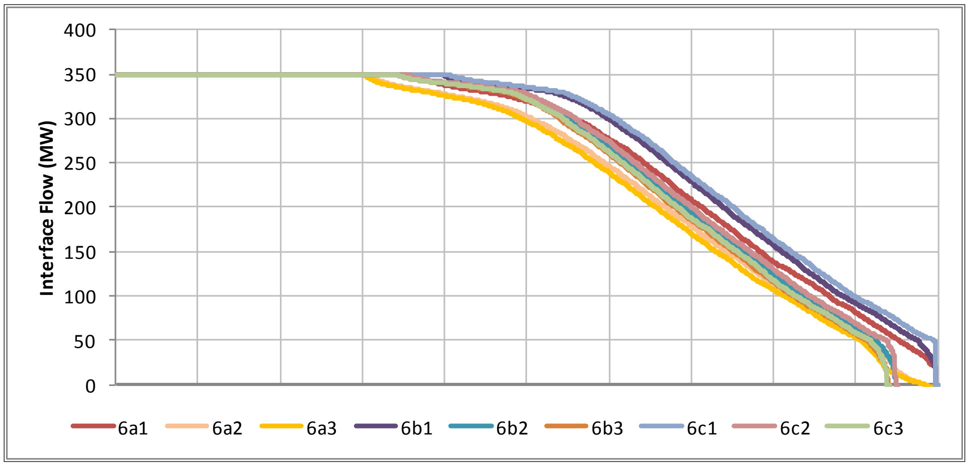

Figure 6-74: Flow-duration curves for the nine sensitivity cases defined in Table 6-14 cases for Wyman/Bigelow All-Wind wind penetration under the wind/hydro coordination scenarios.

Section 7
Observations and Recommendations

The 2011 economic studies investigated the impact of various levels of wind penetration on the New England system from different modeling perspectives: the IREMM high-level production-costing model and the GridView greater detail model. GridView allows the impacts of a granular transmission model to be analyzed in conjunction with detailed generation operational limits within a security-constrained unit commitment and security-constrained economic dispatch framework.

7.1.1 Model Comparison Cases

In the first grouping of cases, the replication of the IREMM results using GridView suggests that both models performed equally well. The use of both the IREMM and GridView models to perform the 2011 economic studies has provided greater confidence that both models produce the same results given the same inputs. This phase of the analysis investigated the following parameters for both an unconstrained system and interface-constrained case:

- Production cost
- LSE electric energy expense
- Annual by fuel type generation
- Wind generation
- Interface flow patterns

The following observations were drawn from these cases:

- The high level interface constraints defined between RSP areas do not exhibit much congestion under FCA#5 and the Active Queue cases.
- Under the All-Wind wind penetration cases the Orrington South, Surowiec South and SEMA/RI interfaces were binding.
- Higher LSE energy expense for the interface constrained cases, compared to the unconstrained cases, were the result of bottled-in wind energy in the Wyman/Bigelow WDA.
- In the All-Wind wind penetration case, the interfaces associated with Northern New Hampshire and Northern Maine also created bottled-in wind that increased LSE energy expense.

7.1.2 Transmission Modeling Cases

In the second phase of the study, the effect of additional transmission modeling detail was investigated. These cases showed that using a detailed transmission model that includes contingencies could result in additional bottled-in wind and a different dispatch of system resources. Additionally, constraining transmission elements can be identified through GridView, and the implications of relaxing or eliminating these constraints can be investigated. The following observations were drawn from these cases:

- When more detailed generation parameters, operating limits, and transmission system constraints were modeled, GridView simulation results showed more bottled-in wind and higher LSE energy expenses, especially in the scenarios where the wind penetration levels were higher.

- High level transmission system limitations did not bottle-in significant amounts of wind energy until over 2000 megawatts (MW) of wind resources were added in Northern Maine.
- The Wyman/Bigelow subarea, also in Maine, became export constrained with 600 MW of wind development.

7.1.3 Refined Modeling Cases

The Refined Modeling cases investigated detailed thermal heat-rate curve assumptions, monitoring of additional 115 kV lines, and contingencies in Central Maine Power areas. The following observations were drawn from these cases:

- Detailed modeling of thermal heat-rate curves and use of other operating parameters led to an elevated production cost metric, with the LSE energy expense metric unaffected.
    - The Detailed Resource Operating Parameters decreased the Wyman/Bigelow wind generation slightly.
- The modeling of thermal constraints on additional 115 kV lines in central and southern Maine and additional contingencies in Wyman/Bigelow and Rumford subareas led to the following observations:
    - Curtailments of wind generation in the Wyman/Bigelow subarea was about 10% of the amount in both the Active Queue and All-Wind wind-penetration cases.
    - The addition of the contingencies throughout central Maine did not have a significant impact on the wind generation.
    - New England production costs and LSE energy expenses were slightly increased due to the additional no-load and start-up costs reflected the Detailed Resource Operating Parameters.
- The detailed interface binding constraints obtained from these cases can provide useful information for system planners and resource developers.
- The recognition of the December 2012 MPRP interface limits allowed a slight increase in wind generation from the Northern Maine wind-development subarea.

7.1.4 Hydro/Wind Coordination

The coordination of wind and hydro generation in the export-constrained subareas could potentially increase the total generation from the aggregated wind and hydro plants located in these subareas.

7.1.5 Future Modeling Recommendations

The overall results have shown that the GridView model, with its additional capabilities, can replicate and extend the analysis that could be performed using IREMM. The following improvements in the modeling process can now be included in economic studies:

- Expand the current catalog of 100 contingencies to include more of the transmission contingencies that have occurred in the last few years.
- Continue to refine the detailed resource operating parameters to better reflect resource operating characteristics.
- Identify the network bus locations of smaller resources typically not included in the transmission planning models to model them as explicit resources.

- Improve the representation of combined-cycle resources to allow their generator step-up transformers to be included.
- Investigate the robustness of dispatch under uncertainty. The GridView model has simulated the New England system with "perfect foresight" in unit commitment and dispatch.
- Develop additional modeling techniques to represent wind resources:
    - The results of this analysis suggest relatively little bottled-in wind energy based on the thermal limitations that GridView is designed to address. Observations by others suggest that historical bottled-in wind energy in Maine is higher than either the IREMM or GridView models estimated, even though the wind penetration is lower.
    - Additional research is needed to understand how to better represent these constraining factors, which may include representations for voltage and stability limits.
    - Stakeholders suggested investigating a method to reflect the impact of low short-circuit capability in remote areas of the system, because this physical parameter affects resource stability.