OAK RIDGE
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ORNL/TM-2013/561

Additional EIPC Study Analysis: Interim Report on Medium Priority Topics

March 2014

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UT-BATTELLE

ORNL-27 (4-00)

ORNL/TM-2013/561

Electrical and Electronics Systems Research Division

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Prepared by
OAK RIDGE NATIONAL LABORATORY
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managed by
UT-BATTELLE, LLC
for the
US DEPARTMENT OF ENERGY
under contract DE-AC05-00OR22725

CONTENTS

Page

LIST OF FIGURES ... v

LIST OF TABLES ... vii

ABBREVIATIONS AND ACRONYMS ... ix

EASTERN INTERCONNECTION MEMBERS/REGIONS ... x

EXECUTIVE SUMMARY ... xi

1. INTRODUCTION ... 1

2. TOPIC 6: OPERATING AND PLANNING RESERVES ... 6
   - 2.1 RESERVES DEFINITIONS ... 6
   - 2.2 PLANNING RESERVES IN PHASE 1 ... 7
   - 2.3 OPERATING RESERVES IN PHASE 2 ... 11
   - 2.4 CONCLUSIONS ... 13

3. TOPIC 7: WIND CURTAILMENT ... 13
   - 3.1 BACKGROUND OF TOPIC ... 13
   - 3.2 ESTIMATION OF HOURLY WIND SCHEDULE AND CURTAILMENTS ... 14
   - 3.3 TIMING OF CURTAILMENTS ... 15
   - 3.4 EXPLORATION OF PEAK CURTAILMENT DAY ... 16
   - 3.5 EFFECT OF REDUCED SPIN REQUIREMENTS AND FLEXIBLE COMBINED CYCLE ... 18
   - 3.6 CURTAILMENTS VERSUS TIE LINE CAPACITY ... 20
   - 3.7 MISO MO-IL SUPPLY POCKET ... 23
   - 3.8 CONCLUSIONS ... 25

4. TOPIC 8: DEMAND RESPONSE ... 25
   - 4.1 DEMAND RESPONSE IN PHASE 1 ... 25
   - 4.2 DEMAND RESPONSE SUPPLY CURVE FOR PHASE 2 ... 26
   - 4.3 DEMAND RESPONSE DISPATCHED IN PHASE 2 ... 28
   - 4.4 SOUTHEAST DEMAND RESPONSE USE AND PRICE IMPACTS ... 30
   - 4.5 SOUTHEAST TRANSMISSION BUILD-OUTS ... 32
   - 4.6 CONCLUSIONS ... 33

5. TOPIC 9: “NO REGRETS” LINES ... 34
   - 5.1 TRANSMISSION ELEMENTS COMMON TO MULTIPLE SCENARIOS ... 34
   - 5.2 CONCLUSIONS ... 36

6. REFERENCES ... 36

APPENDIX: LINES AND TRANSFORMERS COMMON TO ALL SCENARIOS ... 1

LIST OF FIGURES

Figure **Page**

Fig. ES-1. Map of NEEM regions (EI includes the multicolored, non-gold regions)................................xi
Fig. ES-2. Phase 1 ratio of capacities to peak demand in the CO_2+ scenario. xiv
Fig. ES-3. Potential wind generation, curtailments, and actual wind generation in the CO2+ scenario. xv
Fig. ES-4. Curtailed region April 1 morning generation levels in the CO_2+ scenario and Hi Spin sensitivity..xvi
Fig. ES-5. Net transfer vs. wind curtailment in the curtailed regions in the Hi Spin sensitivity. xvi
Fig. ES-6. VACAR generation, load, and marginal price on August 1 in the CO_2+ scenario. xviii
Fig. ES-7. Marginal prices at six balancing areas versus the corresponding demand response (DR) demand for all of VACAR in the business as usual (BAU) scenario. xviii
Fig. ES-8. Locations of buses with upgrades common to all three scenarios. xix
Fig. 1. Map of NEEM regions..1
Fig. 2. Phase 1 ratio of capacities to peak demand in the CO_2+ scenario. 10
Fig. 3. Phase 1 ratio of capacities to peak demand in the RPS/R scenario. 10
Fig. 4. Phase 1 ratio of capacities to peak demand in the BAU scenario..10
Fig. 5. Potential wind generation, curtailments, and actual wind generation in the CO_2+ scenario. 15
Fig. 6. Supply and demand for major curtailed regions on April 1 in the CO_2+ scenario. 16
Fig. 7. Tie line flows on April 1 at 4:00 a.m. for the CO_2+ scenario. 16
Fig. 8. Generation and loads for PJM regions on April 1 in the CO_2+ scenario. 17
Fig. 9. Locational marginal prices for balancing areas across the EI on April 1 at 4:00 a.m. for the CO_2+ scenario...18
Fig. 10. Generation on April 1 in the curtailed regions in the Hi Spin sensitivity. 19
Fig. 11. Generation on April 1 in PJM in the Hi Spin sensitivity. 19
Fig. 12. Tie line flows on April 1 at 4:00 a.m. in the Hi Spin sensitivity. 20
Fig. 13. Net transfer vs. curtailment in the curtailed regions for the CO_2+ scenario. 21
Fig. 14. Net transfer vs. curtailment in the curtailed regions for the Hi Spin sensitivity. 21
Fig. 15. Percent of year that curtailments in curtailed regions were at different levels. 22
Fig. 16. Net transfer vs. wind curtailment in the curtailed regions in the Hi Spin sensitivity. 23
Fig. 17. Locational marginal prices on April 1 at 10:00 a.m. in the CO_2+ scenario. 24
Fig. 18. MISO MO-IL generation and load on April 1 in the CO_2+ scenario. 24
Fig. 19. ORNL NADR runs with variation in critical peak price. 27
Fig. 20. Supply curve for pricing-related DR programs in 2030. Five-tier approximation and Phase1 single tier curve also shown. 27
Fig. 21. Six-tier supply curve and model curve with allocated nonprice DR in 2030 for Phase 2. 28
Fig. 22. Capacities and peak demand for each region for the CO_2+ scenario. 29
Fig. 23. VACAR generation, load and marginal prices on August 1 under the CO_2+ scenario. 30
Fig. 24. SOCO generation, load, and marginal prices on August 1 under the CO_2+ scenario...................30
Fig. 25. Eastern Interconnection tie line loads on August 1 at 4:00 p.m. for the CO_2+ scenario. 31
Fig. 26. Marginal prices at six balancing areas versus the corresponding DR demand for all of VACAR in the BAU scenario. 32
Fig. 27. Phase 1 CO_2+ flow duration curves for the “soft” tie line between PJM ROR and VACAR. 33
Fig. 28. Locations of buses with upgrades common to all three scenarios. 35

LIST OF TABLES

Table **Page**

Table ES-1. NEEM Regions and Territories in the Eastern Interconnection ... xii
Table ES-2. Topics to Be Studied as Part of Analysis of EIPC Cases ... xiii
Table 1. NEEM Regions and Territories in the Eastern Interconnection ... 2
Table 2. Futures and Main Sensitivities Studied in Phase 1 ... 3
Table 3. Topics to Be Studied as Part of Analysis of EIPC Cases ... 5
Table 4. NERC Definitions of Reserves (NERC 2013) ... 7
Table 5. Reserve Margin Regions, Reserve Requirements, and NEEM Regions (CRA 2010) ... 8
Table 6. Intermittent Resource Contributions (CRA 2010) ... 9
Table 7. Phase 1 Reserve Requirement and 2030 Reserve Margins by Region ... 11
Table 8. Phase 2 Spinning Reserve Requirements ... 11
Table 9. Regional Average Spin Requirements and Contributions from Hydro ... 12
Table 10. Phase 2 Wind Curtailment Amounts and Percent of Potential Generation ... 14
Table 11. Curtailments and Net Transfers April 1 at 4:00 a.m. for curtailed regions ... 21
Table 12. Curtailment and Transfer Quadrants for the Hi Spin Sensitivity ... 23
Table 13. Demand Response Supply Curve as Proportion of Total DR Available in Regions for EIPC Study ... 28
Table 14. Phase 2 Demand Response Capacity (in gigawatts and percent of demand) and Generation in NEEM Regions ... 29
Table 15. Elements in Common Across All Scenarios by Region ... 34
Table 16. Overnight Capital Costs (billions of 2010 dollars) ... 35
Table 17. Elements in Common with Different Methods by Region ... 36

ABBREVIATIONS AND ACRONYMS

BA	balancing area
BAU	business as usual
CC	combined cycle
CO_2+	high CO_2 cost + aggressive EE, DR, and DG + national RPS scenario
CPP	critical peak price
CRA	Charles Rivers Associates
CT	combustion turbine
DG	distributed generation
DOE	US Department of Energy
DR	demand response
EE	energy efficiency
EI	Eastern Interconnection
EIPC	Eastern Interconnection Planning Collaborative
EISPC	Eastern Interconnection States' Planning Council
FERC	Federal Energy Regulatory Commission
GE MAPS	General Electric Multi-Area Production Simulation (software)
GW	gigawatt = 1,000 megawatts or 10^6 kilowatts
HVDC	high voltage direct current
MRN-NEEM	Multi-Region National-North American Electricity and Environment Model
NADR	*A National Assessment of Demand Response Potential* (FERC study)
NEEM	North American Electricity and Environment Model
NERC	North American Electric Reliability Corporation
ORNL	Oak Ridge National Laboratory
PSS/E	Power System Simulator for Engineering (from Siemens)
RPS	renewable portfolio standard
RPS/R	RPS, implemented regionally
RTO	Regional Transmission Operator
SCE&G	South Carolina Electric and Gas
SSC	stakeholder steering committee
SSI	Stakeholder-Specified Infrastructure
SVC	static var controller
TWh	terawatt-hour = 1,000 gigawatt-hours = 10^6 megawatt-hours = 10^9 kilowatt-hours

EASTERN INTERCONNECTION MEMBERS/REGIONS
(also referred to as NEEM regions in this report)

ENT	Entergy Corp. plus other utilities in central Missouri, Arkansas, Louisiana, Mississippi, east Texas
FRCC	Florida Reliability Coordinating Council—Florida minus the panhandle
IESO	Independent Electricity System Operator, Ontario Canada
MAPP CA	Mid-Continent Area Power Pool—Canada (Manitoba-Saskatchewan)
MAPP US	Mid-Continent Area Power Pool—US (non-MISO regions in Montana, North Dakota, South Dakota, Minnesota, Iowa)
MISO IN	Midcontinent Independent System Operator—Indiana
MISO MI	Midcontinent Independent System Operator—Michigan
MISO MO-IL	Midcontinent Independent System Operator—Missouri-Illinois (eastern Missouri, much of Illinois)
MISO W	Midcontinent Independent System Operator—West (parts of Montana, North Dakota, South Dakota, Minnesota, Iowa, Wisconsin)
MISO WUMS	Mid-continent Independent System Operator—Wisconsin-Upper Michigan
NE	Nebraska
NEISO	New England Independent System Operator
Non-RTO Midwest	Non-Regional Transmission Operator Midwest (most Kentucky, some Ohio public utilities)
NYISO A-F	New York Independent System Operator—Upstate
NYISO G-I	New York Independent System Operator—lower Hudson Valley
NYISO J-K	New York Independent System Operator—New York City-Long Island
PJM	Independent System Operator for territory from Chicago to Virginia (formerly the Pennsylvania-New Jersey-Maryland power pool)
PJM E	PJM Eastern Mid-Atlantic Area Council (New Jersey, Delaware, eastern Maryland)
PJM ROM	PJM Rest of Mid-Atlantic Area Council (eastern Pennsylvania, DC, eastern Maryland)
PJM ROR	PJM Rest of Region (northern Illinois, Ohio, western Pennsylvania, western Maryland, West Virginia, Virginia, eastern North Carolina)
SOCO	Southern Company plus other utilities in Georgia, Alabama, eastern Mississippi, western Florida
SPP N	Southwest Power Pool—North (Kansas, western Missouri)
SPP S	Southwest Power Pool—South (Oklahoma, north Texas, eastern New Mexico, western Arizona, western Louisiana)
TVA	Tennessee Valley Authority (Tennessee, northern Mississippi, northern Alabama, southern Kentucky)
VACAR	Virginia-Carolina Subregion—South Carolina, western North Carolina

EXECUTIVE SUMMARY

Between 2010 and 2012 the Eastern Interconnection Planning Collaborative (EIPC) conducted a major long-term resource and transmission study of the Eastern Interconnection (EI). With guidance from a stakeholder steering committee (SSC) that included representatives from the Eastern Interconnection States' Planning Council (EISPC) among others, the project was conducted in two phases. The first was a 2015–2040 analysis that looked at a broad array of possible future scenarios, while the second focused on a more detailed examination of the grid in 2030. The studies provided a wealth of information on possible future generation, demand, and transmission alternatives. However, at the conclusion there were still unresolved questions and issues. The US Department of Energy, which had sponsored the study, asked Oak Ridge National Laboratory researchers and others who worked on the project to conduct an additional study of the data to provide further insights for stakeholders and the industry. This report documents the second part of that follow-on study [an earlier report (Hadley 2013) covered the first part, and a subsequent report will address the last part].

The EI covers most of the electricity grid east of the Rockies. High voltage transmission lines interconnect the regions in the EI so power can be transferred readily between them. The EI consists of the multicolored (non-gold) regions in the map in Fig. 1. The regions used in the EIPC study (both EI and non-EI) are referred to as NEEM regions throughout this report because of the model (the North American Electricity and Environment Model) used for analysis in Phase 1 of the study. These NEEM regions are based on the boundaries of organizations such as utilities, regional transmission operators, coordinating authorities, independent system operators, and other natural groupings of the grid. Table ES-1 gives a more detailed description of each region in the EI.

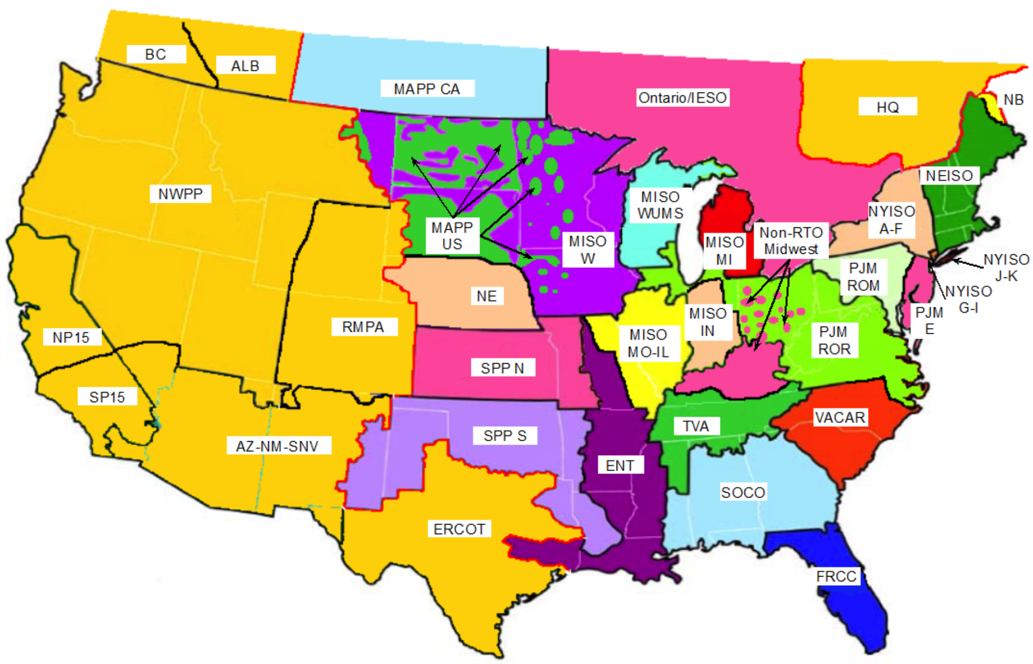

Fig. ES-1. Map of NEEM regions (EI includes the multicolored, non-gold regions).

For this report, results are presented at the level of the entire EI, the individual NEEM regions, or collections of NEEM regions into larger "territories" based on similar characteristics or transmission relationships.

Table ES-1. NEEM Regions and Territories in the Eastern Interconnection

Region	Description	Territory
MAPP CA	Mid-Continent Area Power Pool (MAPP) Canada (Manitoba-Saskatchewan)	Northwest
MAPP US	MAPP US (non-MISO regions in MT, ND, SD, MN, IA)	Northwest
MISO W	Midcontinent Independent System Operator (MISO) in Michigan	Northwest
MISO MO-IL	MISO Missouri-Illinois (eastern MO, much of IL)	Northwest
MISO WUMS	MISO Wisconsin-Upper Michigan	Northwest
MISO IN	MISO Indiana	Northwest
MISO MI	MISO West (parts of MT, ND, SD, MN, IA, MN, WI)	Northwest
Non-RTO Midwest	Non-Regional Transmission Operator (RTO) in Midwest (most KY, some OH)	Central
PJM ROR	PJM Rest of Region (north IL, OH, west PA, west MD, WV, VA, east NC)	Central
PJM ROM	PJM Rest of Mid-Atlantic Area Council (MAAC) (east PA, DC, east MD)	Central
PJM E	PJM Eastern MAAC (NJ, DE, east MD)	Central
IESO	Independent Electricity System Operator in Ontario	Northeast
NYISO A-F	New York Independent System Operator in Upstate NY	Northeast
NYISO G-I	New York Independent System Operator in lower Hudson Valley	Northeast
NYISO J-K	New York Independent System Operator in New York City-Long Island	Northeast
NEISO	New England Independent System Operator	Northeast
NE	Nebraska	Southwest
SPP N	Southwest Power Pool (SPP) North (Kansas, western Missouri)	Southwest
SPP S	SPP South (Oklahoma, north TX, east NM, west AR, west LA)	Southwest
ENT	Entergy Corp. + other utilities in central MO, AR, LA, MS, east TX	Southwest
TVA	Tennessee Valley Authority (TN, north MS, north AL, south KY)	Southeast
SOCO	Southern Company + other utilities in GA, AL, east MS, west FL	Southeast
VACAR	South Carolina, west North Carolina	Southeast
FRCC	Florida minus panhandle	Southeast

The Phase 1 analysis used a capacity expansion model belonging to Charles Rivers Associates (CRA) called MRN-NEEM (Multi-Region National-North American Electricity and Environment Model). A capacity expansion model evaluates energy supply and demand over multiple decades and will build or retire capacity as needed or economic. The MRN-NEEM document on the EIPC website provides more detail on the models used (CRA 2010).

In Phase 1 of the study, the term "futures" was used to define a consistent set of input assumptions on technologies, policies, and costs. Eight futures were defined by the SSC in an attempt to cover a wide range of possible policies. A set of sensitivities was defined for each future, but first a base case using the general equilibrium economic model MRN had to be run to establish economy-wide, energy-related demands and prices. The results of these base cases could then be used to expand the transmission system between regions. Following that, other sensitivities allowed the EIPC and SSC to explore a variety of changes to technologies, costs, demands, or policies.

Three scenarios representing transmission needs under a broad array of hypothetical futures were selected for more extensive transmission-focused evaluation in Phase 2: a business as usual scenario (labeled BAU in this report); a scenario with a national renewable portfolio standard that is implemented on a regional basis (labeled RPS/R here); and a combined policies scenario with a high CO_2 cost, a national renewable portfolio standard, and aggressive energy efficiency/demand response/distributed generation (labeled CO_2+ here).

In Phase 2 the EI was modeled at a very detailed level (70,000 buses, 9,900 generators) using the Power System Simulator for Engineering (PSS/E) model for a peak hour and off-peak hour in each case (only the peak hour in the BAU case.) Transmission lines and other upgrades were added to ensure reliability criteria were met in those hours. The resulting build-outs of the transmission system in these scenarios were then used as inputs in the General Electric Multi-Area Production Simulation software (GE MAPS) model run by CRA. GE MAPS is a detailed economic dispatch and production cost model that simulates electric power system operation, taking into account transmission topology. The GE MAPS model projected energy production costs, constraints limiting dispatch and interregional transactions, anticipated emissions, renewable energy production, and other pertinent factors.

Additional information regarding the EIPC modeling can be found in Sect. 1 of this report, the EIPC Phase 1 Report (EIPC 2011), and the EIPC Phase 2 Report (EIPC 2012).

The results from Phases 1 and 2 provided a wealth of data that could be examined further to address energy-related questions. In January 2013, a small group of members of the EIPC, EISPC, and SSC were contacted to determine the need for additional analysis and topics of interest. Based on this, a list of 13 possible study topics was developed and ranked by the group in terms of relative priority (Table ES-2). The topics are ranked by priority (high, medium, low) and arranged such that the lower numbered/higher ranked items in each category contribute to the later items within the same category.

Table ES-2. Topics to Be Studied as Part of Analysis of EIPC Cases

	Description
	High Priority Topics
1	How do Phase 2 results compare to Phase 1
2	Were there significant changes in earlier years within various regions?
3	When all costs are integrated, how do results compare between scenarios?
4	Do some regions face over-reliance on certain fuels or technologies?
5	What are the gas sector Interrelationships in the different regions?
	Medium Priority Topics
6	How did regional operating and planning reserves definitions affect the results?
7	Why was there so much wind curtailment in the RPS/R and CO_2+ scenarios?
8	How much did Demand Response as defined in the models affect results?
9	What transmission lines were of value in all scenarios?
	Low Priority Topics
10	Regional vs national implementation of policies
11	Load growth sensitivities on resource mix and cost
12	Environmental Policy sensitivity impacts
13	Technology sensitivity impacts

The first five topics were discussed in the report *Additional EIPC Study Analysis: Interim Report on High Priority Topics* (Hadley 2013). The second set of topics is covered in this report.

Topic 6: How did regional operating and planning reserves definitions affect the results?

Reserves represent an amount of capacity above demand available to provide adequate electricity at the correct voltage and frequency to maintain the grid under unusual or abnormal circumstances. There are two main types of reserves used in the EIPC study: planning reserves and operating reserves. Planning reserves are used for long-term resource planning, while operating reserves are used for day-to-day operations.

Phase 1 of the study used planning reserves, with values between 12–18% for the various regions. All generating capacity could be used to meet the reserve margin, including DR. However, the EIPC derated intermittent (solar and wind) technologies by applying a fractional “resource contribution credit.” The installed capacity of the technology was multiplied by this fraction to represent the amount of capacity that would be available during peak hours. This credit ranged from 11% to 30% depending on the region and technology. Because the capacity factors for these technologies were higher than the credit, there was often a large amount of extra generation from these intermittent sources, which affected the curtailment quantities discussed under Topic 7. Even after the credit was applied, the modeling in Phase 1 built capacity in excess of the reserve margin in some regions to lower the overall cost of generation through export to others.

Fig. ES-2 presents the capacities in each region as a fraction of their peak demands in the CO_2+ scenario. It shows both the technologies that qualify for the reserve calculation plus the intermittent capacity that is not credited. All regions meet their minimum reserve margins, but those with high wind capacity have significant capacity above internal reserve requirements and will have this capacity available for export to other regions when wind production is high. Another observation is that the CO_2+ scenario included significant DR. Because the DR fully qualified for the reserve margin calculation, it lowered the amount of traditional generation required. Many regions required DR to meet their peak demand (the 100% line crosses DR in the chart) unless they could import from the regions with excess production. In Phase 1, only the southeast regions, notably VACAR* and FRCC,* called on DR for a small portion of their needs.

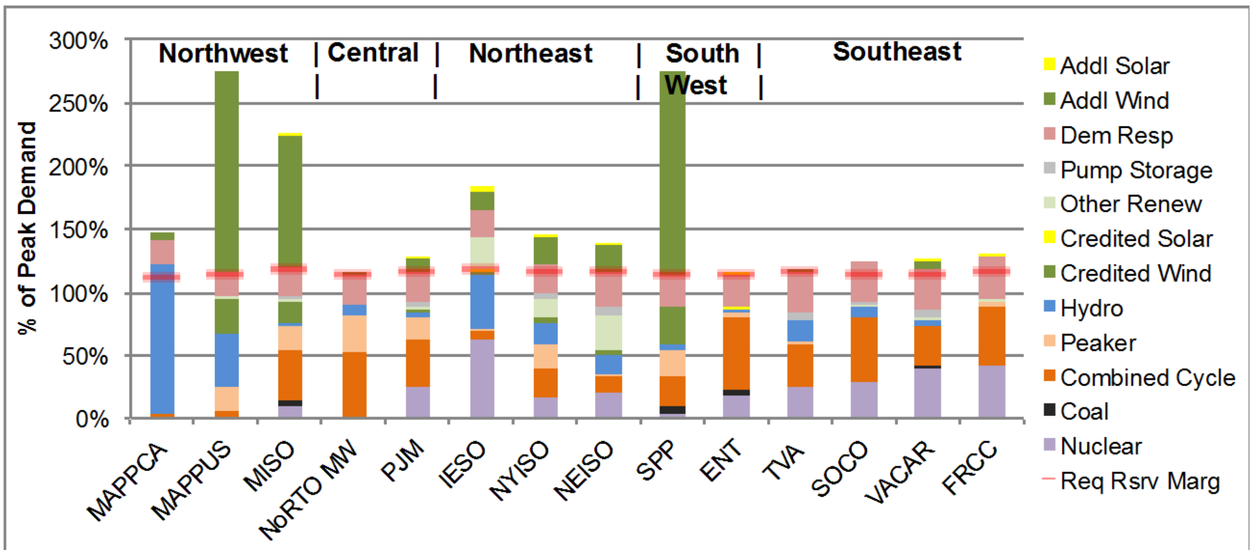

Fig. ES-2. Phase 1 ratio of capacities to peak demand in the CO_2+ scenario.

The Phase 2 calculations used operating reserves in their calculations. The required reserve quantities varied greatly by region, with PJM having the largest requirements both in megawatts and as a percentage of demand. In the modeling, only thermal fossil plants [coal, gas steam, and combined cycle (CC)] and hydroelectric plants could provide reserves; these plants had to be running at least at their minimum dispatch points and could only provide limited quantities based on their ramp rates. While many regions had sufficient hydro to cover most of their reserves requirement, other regions were forced by their reserves requirements to increase output from the committed thermal units while other lower-cost units (most notably wind) were curtailed. A sensitivity was run that cut the reserves requirement in half (to represent DR supply of reserves in some of the regions) and enhanced CC flexibility (minimum power levels, minimum up/down times, and ramp rates). This led to a reduction in the amount of low cost power curtailed, and is more fully discussed under Topic 7. During peak times, some regions had to back down their more efficient CC plants to provide reserves and call on more expensive CT units and DR to provide energy, as discussed under Topic 8.

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*Note: Refer to Table ES-1 or the Eastern Interconnection regions list at the front for complete definitions of region identifiers used in the text.

Topic 7: Why was there so much wind curtailment in the RPS/R and CO_2+ scenarios?

Wind power is a resource that can provide large amounts of electrical power at very low marginal cost. The variable operating cost is near zero, and when production tax credits are available the net variable cost to wind producers is actually negative. Generally, it is most economic for the sector to take all generation provided from wind. However, there are various reasons why at times the system cannot accept all the wind power available, and some wind farms have to reduce power levels. There can be multiple contributing factors to curtailment: there is simply more production than consumers demand at the time; there is insufficient transmission to carry the power to other regions where there is demand; and/or there are other factors such as local reserve requirements, transmission impedance, ramping limitations, environmental regulations, or other low cost resources are available. These factors become more of an issue as the fraction of power from wind increases.

In Phase 1 of the study there was little issue with curtailment, primarily for two reasons. First, the wind generation and loads were aggregated and averaged into just 20 periods to cover each year, rather than the 8,760 hours used in Phase 2. Extremes of high wind generation and/or very low demand, when curtailment would be most pronounced, were not evaluated. Phase 2 provided a more detailed view, resulting in large curtailments, most notably in the high wind regions of MISO and SPP, especially in the CO_2+ scenario. Second, operating reserves, which could force higher cost generators to run instead of the wind generators, were not modeled in Phase 1 of the study.

The results from the GE MAPS model included the annual total curtailments by region but did not include the hourly amounts, which are necessary to evaluate the causes. We used the results from multiple scenarios with differing amounts of curtailment to create a close approximation of the hourly curtailments for the five regions with the highest levels of curtailment (MISO_MO-IL, MISO_W, NE, SPP_N, and SPP_S). These regions accounted for 122 out of 131 TWh of curtailment in the EI for the CO_2+ scenario. Our first analysis showed that curtailments were highest in the morning hours for each region (Fig. ES-3), which indicates that low demand levels played an important role in curtailments.

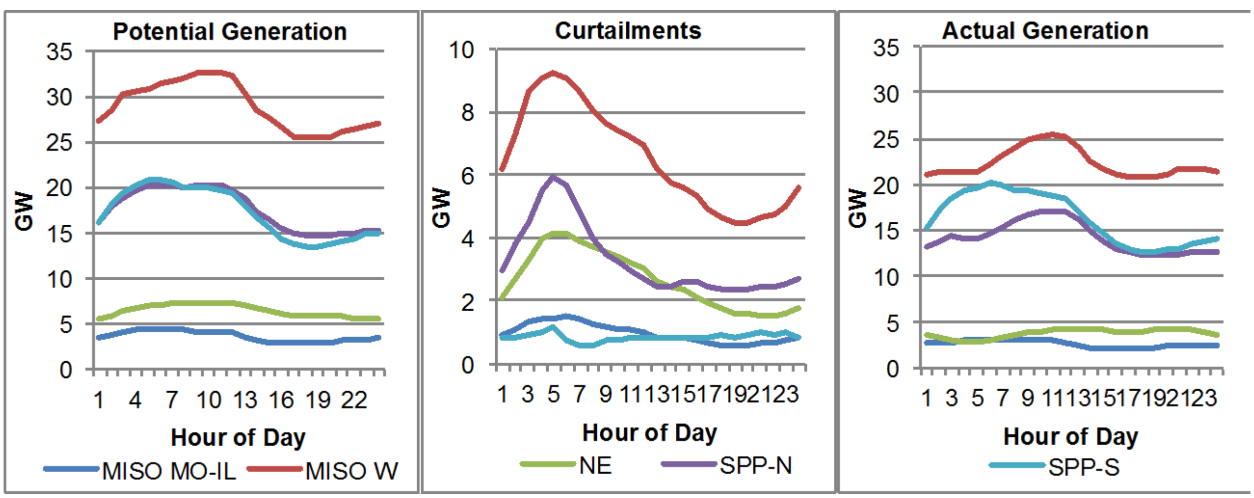

Fig. ES-3. Potential wind generation, curtailments, and actual wind generation in the CO2+ scenario. (Refer to Table ES-1 or the acronym list for region explanations.)

The peak curtailment day of April 1 was analyzed in depth (Fig. ES-4). The high curtailments at 4 a.m. occurred even though interregional tie lines were not heavily loaded, so low demand must have played a role. Another factor was that CC production occurred, especially in PJM, despite prices below cost of production. When the ramp rates were increased for CCs and minimum up/down times were reduced to increase the flexibility of these units in the "Hi Spin" sensitivity, CC production was greatly reduced in the early hours, resulting in more transfers from the windy regions and less curtailment.

The modifications in the Hi Spin sensitivity reduced curtailments significantly in some hours, but there were still many hours with large curtailments. Plotting the level of curtailments versus the net exports from the curtailed regions shows that most of the curtailments, especially the high levels of curtailment, occurred when transfers from the region were near their peak amounts (Fig. ES-5). The red lines in Fig. ES-5 indicate the median values for net transfers and curtailments. Each point represents a different hour in the year. Most points reside in quadrants I and III, where both transfers and curtailments are either high or low together.

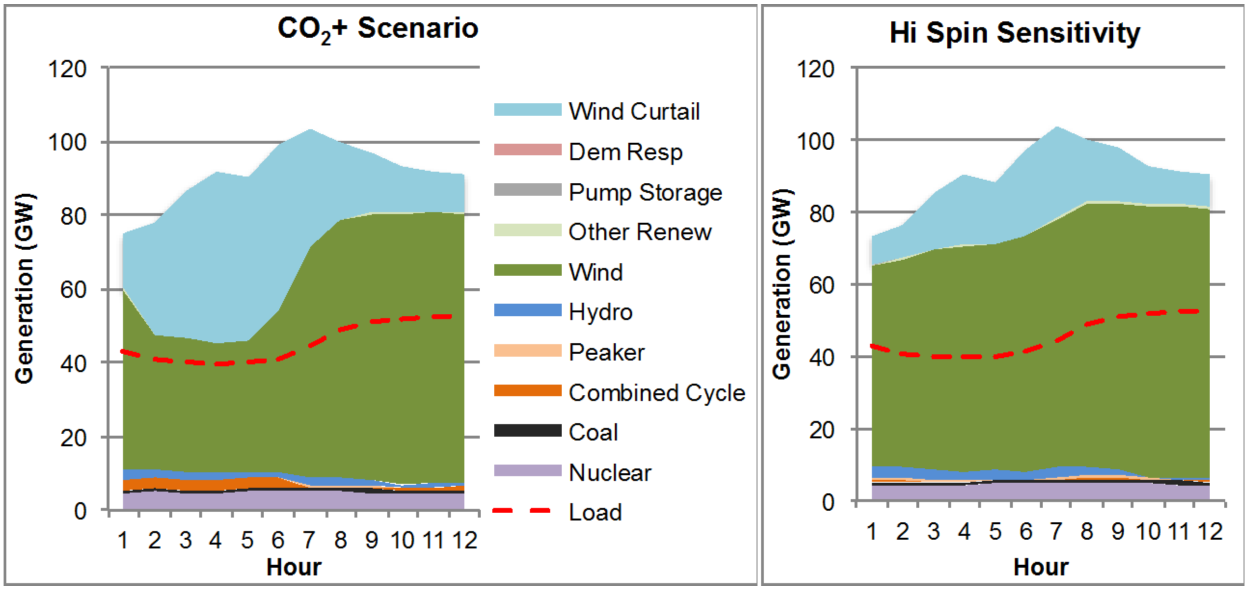

Fig. ES-4. Curtailed region April 1 morning generation levels in the CO_2+ scenario and Hi Spin sensitivity.

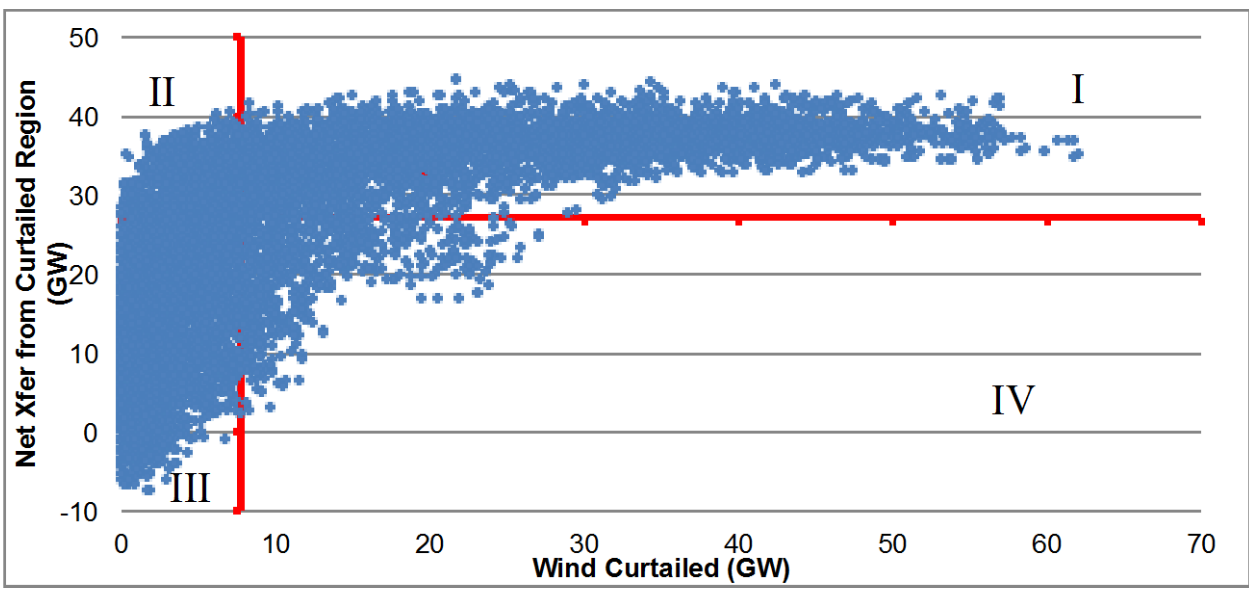

Fig. ES-5. Net transfer vs. wind curtailment in the curtailed regions in the Hi Spin sensitivity.

A final point is that the vast majority of curtailed energy occurs in quadrant I when both curtailments and transfers are above the median. More than 96 TWh of curtailment from these five regions occurred in quadrant I in the Hi Spin sensitivity. In the CO_2+ scenario, quadrant I contained more than 101 TWh. The Hi Spin sensitivity only reduced curtailment by 9 TWh overall, so clearly, the dominant reason for the curtailments was the transfer limitations. However, it would require more than 60 GW of additional transfer capacity (more than 17 high voltage direct current lines) to ease the peak amount of curtailment shown in Fig. ES-5. There did appear to be some generation pockets such as in MISO_MO-IL, MAPP_US, and VACAR where wind was curtailed because nearby transmission elements were not sufficiently built out.

Topic 8: How much did Demand Response as defined in the models affect results?

DR is a complex collection of programs and technologies that allows demand to respond to supply, mainly through reduction of demand in the face of supply shortages. In June 2009, the Federal Energy Regulatory Commission (FERC) released a study on DR, *A National Assessment of Demand Response Potential* (FERC 2009), referred to in this report as the NADR. The amount of DR for each region was calculated using the state-by-state projections of DR from the FERC NADR model. The model projects both future DR and future peak demand through 2019 for four different scenarios: BAU, expanded BAU, achievable amounts, and full participation. The state-weighted average ratio of DR amounts to peak demand were found for each region in the study.

The SSC assumed a DR growth rate based on a combination of these scenarios. In the models used, this amount of DR capacity was forced in as pseudo power plants at relatively high variable costs (price) to generate. In Phase 1 only a single cost could be used so it was set at $750/MWh, roughly the maximum amount from the FERC study. DR energy was dispatched in just the VACAR and FRCC regions, but DR capacity reduced the quantity of ordinary capacity needed to meet reserve requirements in all regions.

In Phase 2, the SSC created a DR supply curve for each region based on the amounts used in Phase 1 and the FERC model. DR was used more frequently because variations in demands and supplies were greater than in Phase 1, along with reserve requirements limiting CC production, similar rationales to the wind curtailments described above. Load pockets in MISO_MO-IL and MAPP_US led to frequent, but low levels of, DR dispatch in the CO_2+ scenario.

DR use was more extensive in the Southeast: SOCO, VACAR, and FRCC. Lack of surplus renewables meant little cushion during peak times, as for example in the August 1 scenario depicted in Fig. ES-6. Operating reserve requirements also contributed as CC capacity had to be reduced during periods of peak demand to provide needed spinning reserves. If DR was allowed to provide reserves, the CC may have provided more power and reduced the need to call on DR energy. The figure also shows the price impact as DR gets dispatched. If DR had been allowed to qualify for reserves, then less would have been dispatched and prices would have been lower.

The DR capacity was scattered across a region in line with the demands. Transmission congestion issues both within a region and between regions could cause DR to be called upon in some parts of a region but not in others. This can be seen in the different marginal prices reported by the balancing areas. Within VACAR, the areas within the southern part of South Carolina (Santee Cooper, Central Electric Coop, and SC Electric & Gas) called upon DR more often at higher levels, resulting in higher marginal prices than other areas in the region (in Fig. ES-7).

One question was why the Southeast did not build out more transmission capacity if it was going to be faced with more capacity issues than other regions. This can be partly explained because in the Phase 1 modeling the potential added transmission was only used during peak times, less than 20% of the year, and so did not meet the SSC usage criteria for these lines to be built. There could be several reasons why they were only used during peak times, including hurdle rates between regions or the “peakiness” in the Southeast, with higher summer demands.

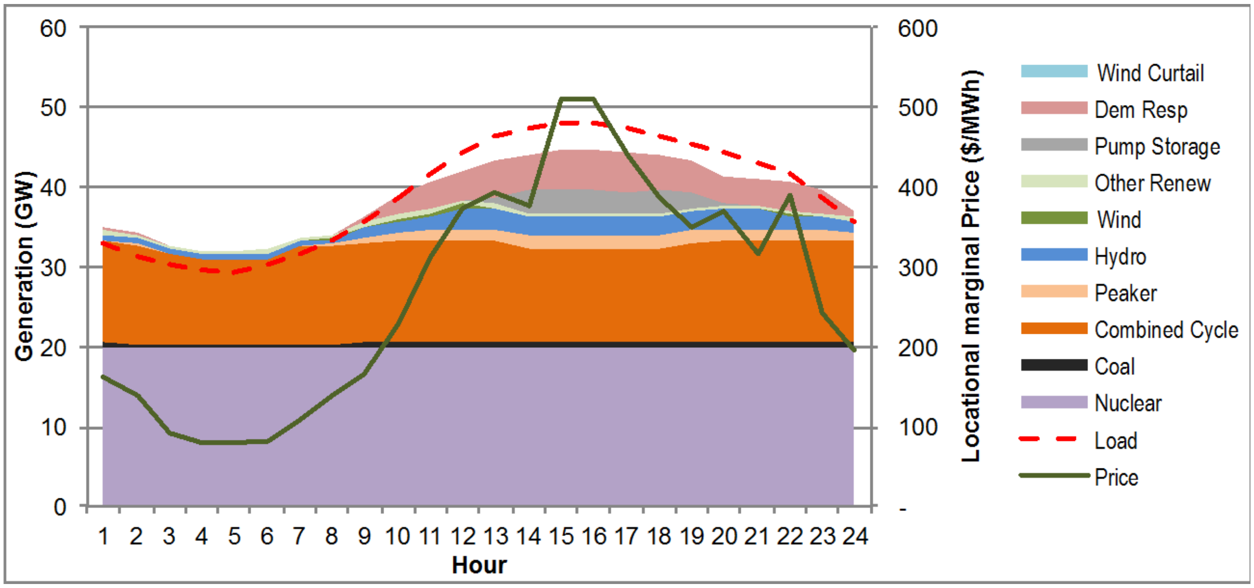

Fig. ES-6. VACAR generation, load, and marginal price on August 1 in the CO_2+ scenario.

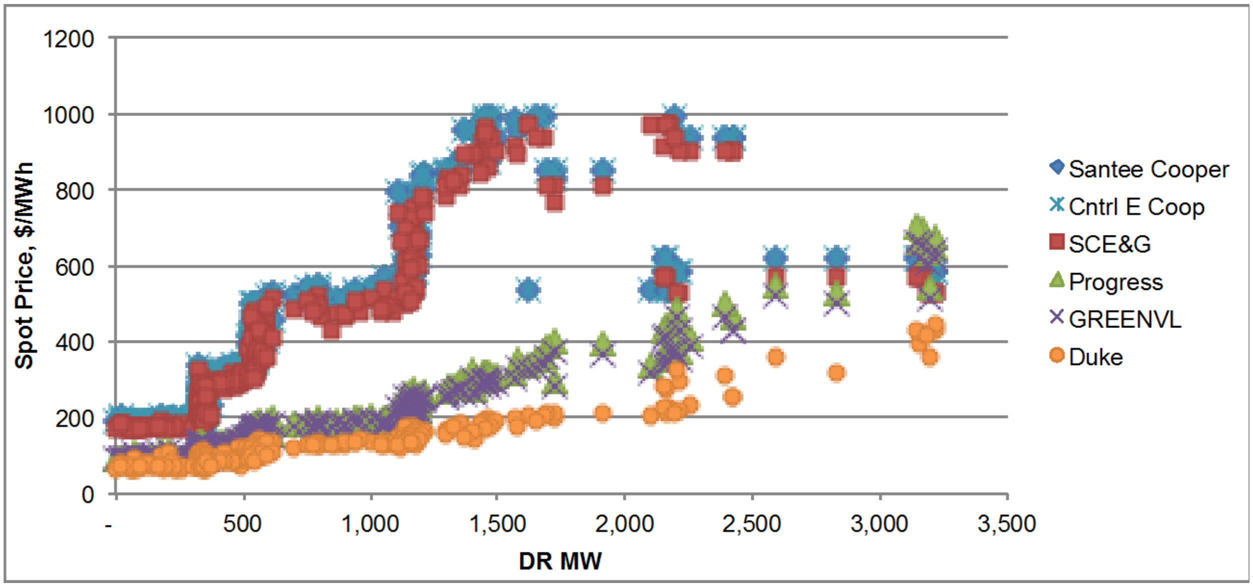

Fig. ES-7. Marginal prices at six balancing areas versus the corresponding demand response (DR) demand for all of VACAR in the business as usual (BAU) scenario.

DR can be a vital contributor to balancing supply and demand, but modeling efforts for this study were rough approximations. The resource had to be modeled as a pseudo generator with a price set high to model its limited availability. In Phase 1, only a single price for all DR could be applied, and so it was set at roughly what the available models represented for the total potential supply. In Phase 2, a more complex supply curve with six price steps provided a more nuanced approach. Because DR was used in meeting the minimum planning reserve margin, some regions relied on it to meet their peak demand. In the CO_2+ scenario DR capacity was highest and those regions without access to surplus wind (most notably VACAR) used higher levels of DR at consequent high prices. Some of this was due to the differences in the geographic, transmission, and time step detail in Phase 1 and Phase 2 modeling. At times, DR was called on because of transmission constraints that limited the availability to import power from other regions or elsewhere within a region.

Topic 9: What transmission lines were of value in all scenarios?

Before any scenarios were run, a base transmission grid was defined, including both existing elements and new elements proposed by the EIPC and approved by the SSC. Each scenario then had elements (transmission lines, transformers, autotransformers, reactive support devices, or other upgrades) added as needed to interconnect new generation, prevent overloads, or prevent low voltage situations. Of these added elements, 89 were common to all three scenarios (Fig. ES-8). Many of these additions were in the NEISO region to support new wind farms that were added in the SSC process. In addition to these, there were 26 elements that were modified in all three scenarios, but in different ways (e.g., added circuit, re-conductoring, or higher rating on new equipment).

Fig. ES-8. Locations of buses with upgrades common to all three scenarios.

1. INTRODUCTION

Between 2010 and 2012 the Eastern Interconnection Planning Collaborative (EIPC) conducted a major long-term resource and transmission study of the Eastern Interconnection (EI). With guidance from a stakeholder steering committee (SSC) that included representatives from the Eastern Interconnection States' Planning Council (EISPC) among others, the project was conducted in two phases. The first was a 2015-2040 analysis that looked at a broad array of possible future scenarios, while the second focused on a more detailed examination of the grid in 2030. The studies provided a wealth of information on possible future generation, demand, and transmission alternatives; however, at the conclusion there were still unresolved questions and issues. The US Department of Energy (DOE), which had sponsored the study, asked Oak Ridge National Laboratory (ORNL) researchers and others who had worked on the project to conduct an additional study of the data to provide further insights for stakeholders and the industry. This report documents the second part of that follow-on study [an earlier report (Hadley 2013) covered the first part, and a subsequent report will address the last part].

The EI covers most of the electricity grid east of the Rockies. High voltage transmission lines interconnect the regions in the EI so power can be transferred readily between them. The EI consists of the multicolored (non-gold) regions in the map in Fig. 1. The regions used in the EIPC study (both EI and non-EI) are referred to as NEEM regions throughout this report because of the model (the North American Electricity and Environment Model) used for analysis in Phase 1 of the study. These NEEM regions are based on the boundaries of organizations such as utilities, regional transmission operators, coordinating authorities, independent system operators, and other natural groupings based on the structure of the grid. Table 1 gives a more detailed description of each region in the EI.

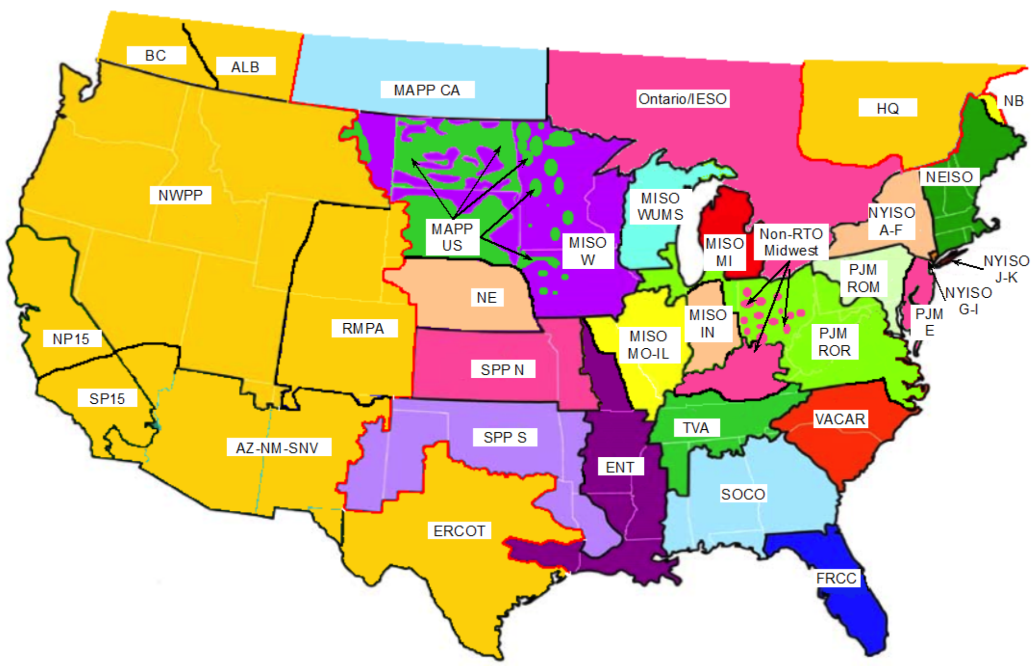

Fig. 1. Map of NEEM regions (EI includes the multicolored, non-gold regions).

For this report, results are presented at the level of the entire EI, the individual NEEM regions, or collections of NEEM regions into larger "territories" based on transmission relationships.

Table 1. NEEM Regions and Territories in the Eastern Interconnection

Region	Description	Territory
MAPP CA	Mid-Continent Area Power Pool (MAPP) Canada (Manitoba-Saskatchewan)	Northwest
MAPP US	MAPP US (non-MISO regions in MT, ND, SD, MN, IA)	Northwest
MISO W	Midcontinent Independent System Operator (MISO) in Michigan	Northwest
MISO MO-IL	MISO Missouri-Illinois (eastern MO, much of IL)	Northwest
MISO WUMS	MISO Wisconsin-Upper Michigan	Northwest
MISO IN	MISO Indiana	Northwest
MISO MI	MISO West (parts of MT, ND, SD, MN, IA, MN, WI)	Northwest
Non-RTO Midwest	Non-Regional Transmission Operator (RTO) in Midwest (most KY, some OH)	Central
PJM ROR	PJM Rest of Region (north IL, OH, west PA, west MD, WV, VA, east NC)	Central
PJM ROM	PJM Rest of Mid-Atlantic Area Council (MAAC) (east PA, DC, east MD)	Central
PJM E	PJM Eastern MAAC (NJ, DE, east MD)	Central
IESO	Independent Electricity System Operator in Ontario	Northeast
NYISO A-F	New York Independent System Operator in Upstate NY	Northeast
NYISO G-I	New York Independent System Operator in lower Hudson Valley	Northeast
NYISO J-K	New York Independent System Operator in New York City-Long Island	Northeast
NEISO	New England Independent System Operator	Northeast
NE	Nebraska	Southwest
SPP N	Southwest Power Pool (SPP) North (Kansas, western Missouri)	Southwest
SPP S	SPP South (Oklahoma, north TX, east NM, west AR, west LA)	Southwest
ENT	Entergy Corp. + other utilities in central MO, AR, LA, MS, east TX	Southwest
TVA	Tennessee Valley Authority (TN, north MS, north AL, south KY)	Southeast
SOCO	Southern Company + other utilities in GA, AL, east MS, west FL	Southeast
VACAR	South Carolina, west North Carolina	Southeast
FRCC	Florida minus panhandle	Southeast

The Phase 1 analysis used a capacity expansion model belonging to Charles Rivers Associates (CRA) called MRN-NEEM (Multi-Region National-North American Electricity and Environment Model). A capacity expansion model evaluates energy supply and demand over multiple decades and will build or retire capacity as needed or economic. The MRN-NEEM document on the EIPC website provides more detail on the models used (CRA 2010). The following are some of the key characteristics of the Phase 1 modeling.

- Each region was treated as a single point or "bubble," with no transmission modeled internally.
- Each region was connected to other regions by single "pipes" for transferring electricity rather than physical transmission lines operating at different voltages.
- Transfer capacities between regions were initially calculated by the EIPC; however, a method was created to use model results to determine how much to expand the capacity in the different scenarios.
- The model calculated the supply, demand, and consequent generation capacity needed for each 5-year point between 2010 and 2050; however, only results for 2015–2040 were reported.
- The model attempted to minimize costs over the period, taking into account various reliability and policy constraints such as minimum reserve margins and environmental regulations.
- The hours of each year were aggregated into 20 "blocks" of different durations: 10 blocks covered the summer hours, while five blocks each covered the winter and "shoulder" seasons.

CRA and the EIPC members formulated some of the initial inputs for the model, with final values determined by the SSC. This group pulled in information from utilities, DOE sources, and others to establish such factors as growth rates, cost projections, technology changes, etc. The inputs used and outputs from the model are available on the EIPC website (http://www.eipconline.com/). In addition, the EIPC prepared preliminary estimates of the cost of transmission expansion under each of the scenarios. Results of the Phase 1 analysis are in the EIPC Phase 1 Report (EIPC 2011).

In Phase 1 of the study, the term "futures" was used to define a consistent set of input assumptions on technologies, policies, and costs. Eight futures were defined by the SSC in an attempt to cover a wide range of possible policies. A set of sensitivities was defined for each future, but first a base case using the general equilibrium economic model MRN had to be run to establish economy-wide energy-related demands and prices for each of the futures. The results of these base cases could then be used to expand the transmission system between regions. Following that, other sensitivities allowed the EIPC and SSC to explore a variety of changes to technologies, costs, demands, or policies. Table 2 summarizes the different futures and sensitivities analyzed.

Table 2. Futures and Main Sensitivities Studied in Phase 1

Sensitivities	Future 1: BAU	Future 2: CO_2 Cost /National Implement	Future 3: CO_2 Cost /Regional Implement	Future 4: Aggressive EE/DR/DG	Future 5: National RPS/National Implement	Future 6: National RPS/Regional Implement	Future 7: Nuclear Resurgence	Future 8: CO_2 Cost + RPS + EE/DR/DG
Expand transmission	√	√	√		√	√	√	√
Load growth	√	√	√		√	√	√	
+/-Gas or Renewable $	√	√	√		√	√		√
Delay Regulations	√							
CO2 Cost Adjust		√	√				√	√
PHEV variations				√				
Extra EE savings				√				
Clean Energy Standard					√	√		
Small Modular Reactors							√	
Higher RPS limits								√

Future 1 was the business as usual (BAU) scenario. It had 17 sensitivities run that were used to establish the transmission build-out and explore the effects of gas prices, renewable costs, delayed environmental policies, and other factors. The final scenario, Future 1, Scenario 17 or F1S17, was used as the basis for the BAU scenario in Phase 2. Futures 2 and 3 examined the impact of raising the cost of CO_2 to lower the level of CO_2 emissions to 20% of 2005 levels by 2050. The distinction between them was the amount of interregional cooperation and transfer capacity within the EI. Future 4 examined the effect of more aggressive energy efficiency (EE), demand response (DR), and distributed generation (DG). Because it reduced demand, there was no need to expand the transmission grid.

Futures 5 and 6 examined a national renewable portfolio standard (RPS) with different levels of interregional cooperation. The second, Future 6, had only regional implementation, meaning each territory (roughly) was responsible for meeting their RPS requirements, and transmission capacity was not expanded between territories to assist. There were 10 sensitivities in this future and the final one, F6S10, was used for Phase 2. Future 7 examined the potential for a nuclear resurgence based on lower costs for nuclear and other factors; a base and four sensitivities were examined. Future 8 was the final future of Phase 1 and combined both the CO_2 costs from Future 2 with the aggressive EE-DR-DG expansion from Future 4 and the RPS from Future 5. There were seven sensitivities run, so it is referred to in this report as the F8S7 scenario.

Three scenarios, representing transmission needs under a broad array of hypothetical futures were selected for more extensive transmission-focused evaluation in Phase 2. The EI was modeled at a very detailed level (70,000 buses, 9,900 generators) using the Power System Simulator for Engineering (PSS/E) model for a peak hour and off-peak hour in each case (only the peak hour in the BAU case). Transmission lines and other upgrades were added to ensure reliability criteria were met in those hours. The resulting build-outs of the transmission system in these scenarios were then used to model the EI in the General Electric Multi-Area Production Simulation software (GE MAPS) model run by CRA. GE MAPS is a detailed economic dispatch and production cost model that simulates electric power system operation, taking into account transmission topology, to predict energy production costs, constraints limiting dispatch and interregional transactions, anticipated emissions, renewable energy production, and other pertinent factors. Results from the GE MAPS cases (hourly and annual results for the year 2030) were released to stakeholders. In addition, separate cost calculations were done by the EIPC and others for transmission and generation capital costs and other costs not calculated in GE MAPS. Following are some of the key characteristics of the Phase 2 modeling phase.

- The transmission build-out with PSS/E used an hour from Block 1 (peak summer) and an hour from Block 13 (mid-shoulder), using the average expected wind generation for each block.
- Transmission lines and substations were added during the build-out primarily to meet reliability concerns; cost optimization was not a factor except indirectly through engineering judgment on line placement.
- GE MAPS modeled the system chronologically for the 8,760 hours of 2030, incorporating CRA estimates of wind patterns for the different regions.
- Operating reserves rather than planning reserves were modeled; technologies to meet reserve requirements were more restrictive than in Phase 1, limiting them to coal, combined cycle (CC), and hydro units.

In Phase 2, the nomenclature for cases changed. The EIPC focused first on building out the transmission for the combined CO_2 + RPS + EE-DR-DG scenario. Consequently, it was called Scenario 1. Four sensitivities were run on the scenario to examine questions surrounding the amount of wind curtailment that occurred in the base case. The RPS with regional implementation scenario was chosen as the second future to examine in Phase 2 and so was called Scenario 2, with no sensitivities run for it. The BAU scenario was the last to be examined and so was called Scenario 3. Two sensitivities were run for it: higher gas prices and higher demands.

The mixture of futures, sensitivities, and scenarios, with different nomenclature, has caused some confusion during the process. While many cases and scenarios were analyzed, the final results discussed in this report were derived based on three main scenarios. Brief descriptions of the three follow, including the names of the cases from the two different phases and the labels used in this report.

- **Business as Usual**
  - Labeled BAU
  - Future 1, Sensitivity 17 (F1S17) in Phase 1
  - Scenario 3 (S3) in Phase 2
  - A continuation of current trends, policies, laws, and regulations
- **National Renewable Portfolio Standard Implemented Regionally**
  - Labeled RPS/R
  - Future 6, Sensitivity 10 (F6S10) in Phase 1
  - Scenario 2 (S2) in Phase 2
  - A national RPS of 30% by 2030, with regional implementation
- **Combined CO_2 + RPS + EE-DR-DG**
  - Labeled **CO_2+**
  - Future 8, Sensitivity 7 (F8S7) in Phase 1
  - Scenario 1 (S1) in Phase 2

— Also called “Combined Policies” in some reporting
— A combination of a high CO_2 cost ~$150/metric Ton CO_2; national RPS of 30%; and aggressive energy efficiency, demand response, and distributed generation expansion

The results from Phase 1 and 2 provided a wealth of data that could be examined further to address energy-related questions. In January 2013, a small group of members of the EIPC, EISPC, and SSC were contacted about possible additional analyses and what topics would be of most interest. Based on feedback from this group, a list of 13 potential study topics was developed, which the group categorized as high, medium, or low priority and then ranked within these categories (Table 3). Order in the ranking was determined in such a way that earlier, lower numbered, items contribute to later items within the same category.

Table 3. Topics to Be Studied as Part of Analysis of EIPC Cases

	Description
	High Priority Topics
1	How do Phase 2 results compare to Phase 1
2	Were there significant changes in earlier years within various regions?
3	When all costs are integrated, how do results compare between scenarios?
4	Do some regions face over-reliance on certain fuels or technologies?
5	What are the gas sector Interrelationships in the different regions?
	Medium Priority Topics
6	How did regional operating and planning reserves definitions affect the results?
7	Why was there so much wind curtailment in the RPS/R and CO_2+ scenarios?
8	How much did demand response as defined in the models affect results?
9	What transmission lines were of value in all scenarios?
	Low Priority Topics
10	Regional vs. national implementation of policies
11	Load growth sensitivities on resource mix and cost
12	Environmental policy sensitivity impacts
13	Technology sensitivity impacts

The first five topics were discussed in the report *Additional EIPC Study Analysis: Interim Report on High Priority Topics* (Hadley 2013). The second set of topics is covered in this report.

Section 2 (Topic 6) begins with a discussion of the different definitions for reserve margins used in the study and how their application varied between regions. Reserves represent an amount of capacity above demand available to continue to provide adequate electricity at the correct voltage and frequency to maintain the grid during abnormal occurrences. There are two main types of reserves that were used in the EIPC study: planning reserves and operating reserves. They each have different purposes and definitions, but the distinctions are often lost in discussions.

The regional planning reserve requirement, given the demand forecast and the amount of existing resources, determines the need for new resources. In the RPS/R and CO_2+ scenarios, a significant amount of wind resources was added. Because of the way the model is structured, wind resources contribute only a fraction of their nameplate capacity (related to the coincidence of wind production at the time of peak system loads) toward meeting the regional planning reserve requirement. Thus, the potential for a large amount of wind energy exists, which leads to curtailments that are explored in Section 3 (Topic 7).

The rules determining how operating reserves are provided, both the amounts by region and the requirements for the units that provide them, also contribute to the wind energy curtailments examined in

Section 3 because they require commitment of units that must be running at least at a minimum operating point. The output from these committed units means that there is less demand that would be supplied by wind energy. In some cases, wind is curtailed as a result.

Demand response (DR) is a complex collection of programs and technologies that let demand respond to supply, mainly through reduction of demand in the face of supply shortages. While DR was modeled as a viable option to supply planning reserves in Phase 1, it could not supply operating reserves in Phase 2. Additionally, the costs associated with calling on DR were modeled differently in the two models. Section 4 (Topic 8) looks at the different ways in which DR was modeled in Phase 1 and Phase 2 and how the modeling affected the results.

In Phase 2 a number of transmission components were included in the build outs of each of the three scenarios to meet reliability concerns. Because the scenarios capture significantly different outlooks for the future, there may be value in examining the components that show up in all three scenarios as they potentially represent elements that will be needed under a wide variety of future circumstances. If they were to be constructed, it would not be at the expense of other opportunities or more advantageous outcomes as it appears they will be needed regardless of what happens in the future. Section 5 (Topic 9) identifies and discusses these transmission components.

2. TOPIC 6: OPERATING AND PLANNING RESERVES

2.1 RESERVES DEFINITIONS

Reserves represent an amount of capacity above demand available to provide adequate electricity at the correct voltage and frequency to maintain the grid under unusual or abnormal circumstances. Two main types of reserves were used in the EIPC study: planning reserves and operating reserves. They each have different purposes and definitions, but the distinctions are often lost in discussions.

Planning reserves are used for long-term resource planning and defining regional planning reserve margins. These were discussed at length in the EISPC-sponsored white paper *The Economic Ramifications of Resource Adequacy White Paper* (Astrape 2013). The North American Electric Corporation (NERC) publishes the standards for all regions on its website (NERC 2013). Most regions begin with a reliability criterion such as 1 day of outages in 10 years, but there are a number of variations on how this is calculated. The regions then determine the reserve margin required to meet that criterion. For example, the Reliability*First* Corporation region includes the following requirements (among others), as listed in Standard BAL-502-RFC-02 of the NERC reliability standards.

R1 The Planning Coordinator shall perform and document a Resource Adequacy analysis annually. The Resource Adequacy analysis shall [Violation Risk Factor: Medium]:

- R1.1 Calculate a planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year analyzed (per R1.2) being equal to 0.1. (This is comparable to a "one day in 10 year" criterion).
  - R1.1.1 The utilization of Direct Control Load Management or curtailment of Interruptible Demand shall not contribute to the loss of Load probability.
  - R1.1.2 The planning reserve margin developed from R1.1 shall be expressed as a percentage of the median forecast peak Net Internal Demand (planning reserve margin). (NERC 2013)

In this example, the planning reserve margin is to meet the 1-day-in-10-year loss of load probability; load lost through utility-controlled DR (direct load control and interruptible rates) will not be counted as loss of load for the probability, and the reserve margin is applied to the median forecast peak load to determine the number of megawatts needed for the region. Planning reserve margins were included in NEEM in Phase 1.

In Phase 2, the GE MAPS model used operating reserves or its subset spinning reserves as a key variable. These reserves are needed on an ongoing basis and vary as demand and other factors come into play. The NERC "Glossary of Terms" in the NERC reliability standards (NERC 2013) defines the different reserves, shown in Table 4. Note that the terms include two definitions for spinning reserves. In one, only unloaded generation is included, but in the second, load fully removable from the system is included as well. This distinction plays a role in the results from Phase 2.

As a complement to operating reserves, the NERC standards also define "contingency reserves" (Standard BAL-002-1). These reserves "may be supplied from generation, controllable load resources, or coordinated adjustments to interchange schedules." (R1). The contingency reserves are a mix of the operating reserves—spinning and the operating reserves—supplemental, as defined in Table 4. Both of these must be capable of being synchronized to the grid within the "disturbance recovery period." Elsewhere in the standards the default value for the period is set at 15 min, although individual interconnections are allowed to set alternatives with approval of the NERC Operating Committee.

Table 4. NERC Definitions of Reserves (NERC 2013)

NERC Term	Definition
Operating Reserve	That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection. It consists of spinning and non-spinning reserve.
Non-Spinning Reserve	1. That generating reserve not connected to the system but capable of serving demand within a specified time. 2. Interruptible load that can be removed from the system in a specified time.
Spinning Reserve	Unloaded generation that is synchronized and ready to serve additional demand.
Contingency Reserve	The provision of capacity deployed by the Balancing Authority to meet the Disturbance Control Standard (DCS) and other NERC and Regional Reliability Organization contingency requirements.
Operating Reserve—Spinning	The portion of Operating Reserve consisting of: • Generation synchronized to the system and fully available to serve load within the Disturbance Recovery Period following the contingency event; or • Load fully removable from the system within the Disturbance Recovery Period following the contingency event.
Operating Reserve—Supplemental	The portion of Operating Reserve consisting of: • Generation (synchronized or capable of being synchronized to the system) that is fully available to serve load within the Disturbance Recovery Period following the contingency event; or • Load fully removable from the system within the Disturbance Recovery Period following the contingency event.

2.2 PLANNING RESERVES IN PHASE 1

Phase 1 of the EIPC study used planning reserve margins, with each region supplying its requirement (Table 5). MRN-NEEM took into account reserve margins for individual regions and for collections of regions into larger regions, such as MISO[*] and NYISO. MRN-NEEM covers all of the United States and Canada, so reserve margins were defined for regions inside and outside of the EI.

Table 5. Reserve Margin Regions, Reserve Requirements, and NEEM Regions (CRA 2010)

Reserve Margin Area	Reserve Requirement	NEEM Regions
ALB	18.0%	ALB
AZ-NM-SNV	15.7%	AZ-NM-SNV
BC	18.0%	BC
CA	16.6%	NP15
		SP15
ENT	14.0%	ENT
ERCOT	NA	ERCOT
FRCC	16.0%	FRCC
MAPP US	14.0%	MAPP US
MAPP CA	12.0%	MAPP CA
MISO	17.4%*	MISO IN
		MISO MI
		MISO MO-IL
		MISO W
		MISO WUMS
NEISO	16.0%	NEISO
Non-RTO Midwest	14.0%	Non-RTO Midwest
NWPP	18.0%	NWPP
NYISO	16.5%*	NYISO A-F
		NYISO GHI
		NYISO JK
NYISO GHI JK	-5.0%	NYISO GHI
		NYISO JK
NYISO JK	-8.0%	NYISO JK
OH (IESO)	17.0%	OH
PJM	15.3%*	PJM E
		PJM ROM
		PJM ROR
PJM E	-2.2%	PJM E**
RMPA	14.0%	RMPA
SOCO	14.0%	SOCO
SPP	13.6%	NE
		SPP N
		SPP S
TVA	15.0%	TVA
VACAR	14.0%	VACAR
**** Based on coincident peak in reserve margin area. For PJM, CRA applied a diversity factor to the noncoincident peaks.***		
***** For purposes of the study, set equal to actual 2010 Reserve Margin***		

For planning reserve margin calculations, all generating capacity qualified to meet the reserve margin, including DR. However, the EIPC applied a fractional resource contribution credit to intermittent generation (wind and solar). The installed capacity of the technology is multiplied by this fraction to

[*]Note: Refer to Table 1 or the Eastern Interconnection regions list at the front for complete definitions of region identifiers used in the figures, tables, and text.

represent the amount of capacity that will be available during the peak period. The amount can vary depending on the type of technology and quality of resources in the region. Solar generation is set at 30% to reflect that the peak time is likely on a hot, sunny day, but often later in the day when the sun is not at full strength. Offshore wind is set similarly based on expectations for future installations. Onshore wind generation is set lower to reflect that its generation during the peak can be lower than its average generation because winds are often calmer on the hottest, highest demand days. Table 6 lists the credit factors for each region as used in Phase 1 of the study.

Table 6. Intermittent Resource Contributions (CRA 2010)

NEEM Region	Technology	Reserve Contribution
All Regions	Photovoltaic	30%
All Regions	Solar Thermal	30%
All Regions	Offshore Wind	30%
California	Wind	25%
Canada	Wind	20%
ERCOT	Wind	9%
New York	Wind	15%
PJM (-E, -ROM, -ROR)	Wind	13%
SPP	Wind	15%
TVA	Wind	12%
IESO	Wind	11%
MAPP CA	Wind	11%
All Other Regions	Wind	15%

An important consequence of the capacity credit is that wind generation on average is higher than its credit, yet a region will build its combined total capacity to meet the reserve margin using the lower value. This means that there will be significant generation capacity above what is needed, and even with the low capacity factors of intermittent renewables (25%–40%) there should be a number of hours in which there is substantial low or zero variable cost renewable power being generated. If this power cannot be absorbed within its own region, it will be exported if tie line capacity is available. In Fig. 2 the CO_2+ scenario generating capacities for each major region are shown as a fraction of the region's peak demand. In it, the intermittent generation (solar, wind) have been split into two categories; the amount credited toward the reserve margin is shown immediately above the hydro capacity, while the remaining wind and solar capacity are shown on the top of each column. MAPP US, MISO, and SPP have significant amounts of capacity above the required amounts. This power is available for internal use or export if it is being produced and transmission capacity is available. If the production cannot be used then the plants must be curtailed, with loss of revenues to plant owners and loss of low-cost power to users. This was a significant issue in the CO_2+ scenario, as described in Sect. 3.

Another note of interest is that, at least for the CO_2+ scenario (Fig. 2), the line representing 100% of peak demand passes through the capacity from DR. While many regions will import from the wind-rich areas to avoid use of DR, those regions far from wind sources (e.g., VACAR, FRCC) need to use DR for some of their peak hours. This does not occur in the BAU or RPS/R scenarios as DR is not as significant a fraction of the capacity contribution to the reserve margin for these two scenarios.

The RPS/R and BAU scenarios also do not have the large surpluses of wind that were in the CO_2+ scenario (Fig. 3 and Fig. 4). In the RPS/R scenario, MAPP US continues a high proportion of wind to demand to supply the rest of the Northwest. MISO and SPP have much lower surplus wind capacity because they do not have the transmission capability to export to the east. PJM and VACAR increase their surplus wind capacity to help meet RPS requirements for their regions. The BAU scenario has relatively little excess capacity because RPS requirements are not expanded beyond current state regulations.

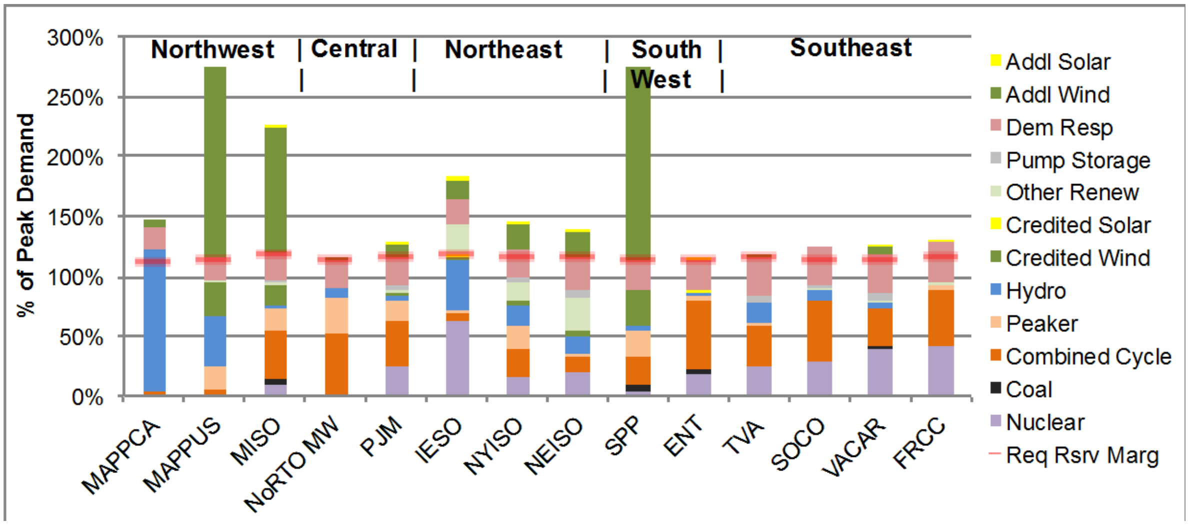

Fig. 2. Phase 1 ratio of capacities to peak demand in the CO_2+ scenario.

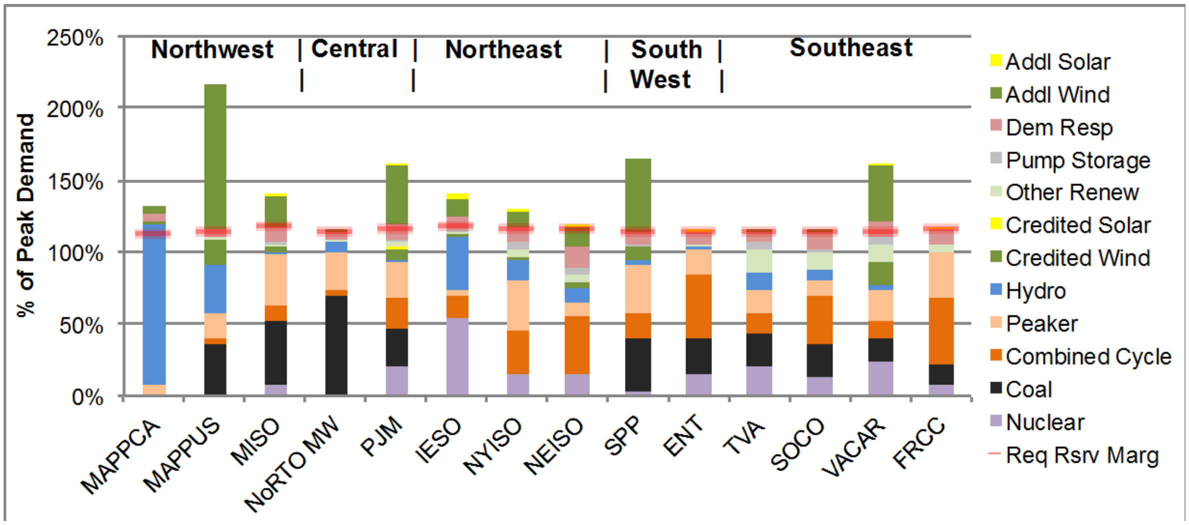

Fig. 3. Phase 1 ratio of capacities to peak demand in the RPS/R scenario.

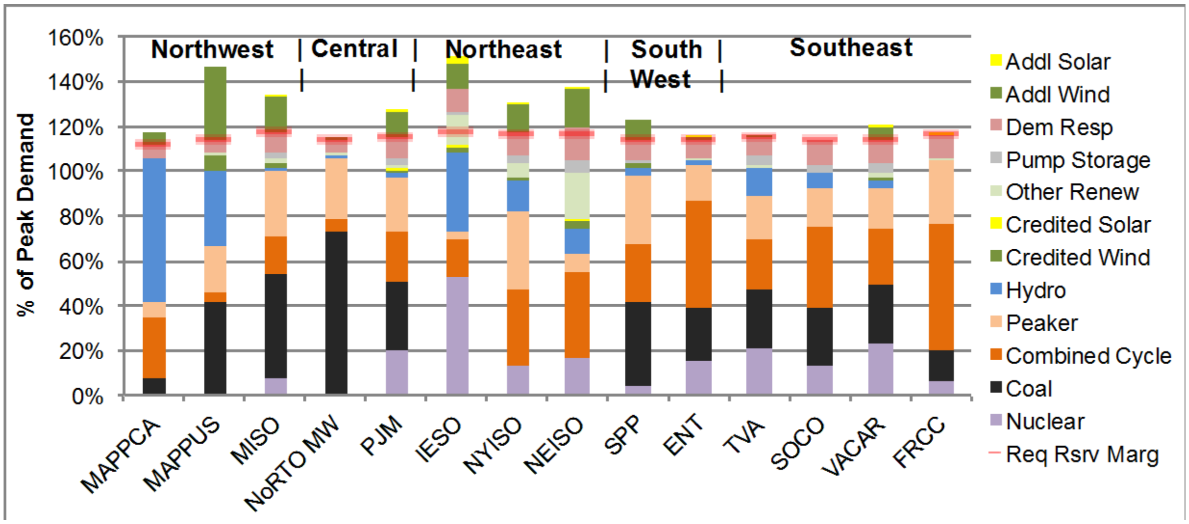

Fig. 4. Phase 1 ratio of capacities to peak demand in the BAU scenario.

Figures 2, 3 and 4 include lines on each column showing the planning reserve margin for each region. One question raised early in the EIPC study was whether NEEM would force capacity down to the reserve margin in each year or would leave capacity higher than the minimum if it was cost-effective overall. This could happen if one region had a lower cost resource that it could use for export to other regions. At the same time, the importing regions still must have sufficient capacity to meet their internal reserve margins unless they have formal reserve sharing agreements. The CO_2+ scenario allowed reserve sharing between the southwest and southeast territories and between the northwest and central territories. In the RPS/R scenario a more regional condition was set, with each territory required to meet its requirements internally. (Hydro Quebec power could be counted for NYISO and NEISO in all cases.)

Examining the results, it is clear that NEEM did allow capacity to be higher. Table 7 shows the reserve requirement in 2030 for each consolidated region and the actual reserve margin for each of the three final cases studied. In the BAU scenario, almost all regions were at their minimum requirement, but in the subsequent scenarios some regions had higher margins as needed for minimizing costs.

Table 7. Phase 1 Reserve Requirement and 2030 Reserve Margins by Region

Reserve Margin Area	Reserve Requirement	2030 Reserve Margin		
		BAU	RPS/R	CO_2+
MAPP CA	12.0%	12.0%	26.2%	40.8%
MAPP US	14.0%	14.0%	15.9%	15.5%
MISO	17.4%	17.4%	17.4%	20.1%
Non-RTO Midwest	14.0%	14.0%	14.0%	14.0%
PJM	15.3%	15.3%	19.9%	15.3%
IESO	17.0%	23.7%	25.5%	43.3%
NYISO	16.5%	16.5%	16.5%	18.9%
NEISO	16.0%	19.3%	20.4%	16.0%
SPP	13.6%	13.6%	13.6%	13.6%
ENT	14.0%	14.0%	14.0%	14.0%
TVA	15.0%	15.0%	15.0%	15.0%
SOCO	14.0%	14.0%	14.9%	23.5%
VACAR	14.0%	14.0%	21.0%	17.3%
FRCC	16.0%	16.0%	16.0%	28.1%

2.3 OPERATING RESERVES IN PHASE 2

In Phase 2, the focus in the GE MAPS modeling was on spinning reserves rather than planning reserves. The amounts for each region were based on the EIPC members' stated requirements for each, taking into account loss of the single largest generator, largest generator plus half of the second largest, or percentage of demand. Table 8 is from the Phase 2 final report (EIPC 2012). NYISO includes requirements both for the region as a whole (600 MW) and for subregions (300 MW for zone J-K, 0 MW for zone K). PJM similarly has requirements both for the mid-Atlantic region and the full region. Note that the PJM region has the largest reserve requirement. With a peak demand of 137 GW, its spinning reserve at peak is 11.8 GW, 7.6 times that of SOCO, the next largest, at its peak.

Table 8. Phase 2 Spinning Reserve Requirements

GE MAPS Commitment Pool	GE MAPS Operating Reserve Group	Spinning Reserve Requirement	Spinning Reserve Amount at Peak
NEISO	NEISO	530 MW	530 MW
NYISO	Long Island	0 MW for NYISO-K (Long Island)	0 MW
NYISO	East NY	300 MW for NYISO-G ~ NYISO-K	300 MW
NYISO	NYISO	600 MW for NYISO-A ~ NYISO-K	600 MW
PJM	PJM Mid Atlantic	1150 MW + 7.5% of load	4,844 MW
PJM	PJM RTO	1509 MW + 7.5% of load	11,785 MW

Table 8 (continued)

GE MAPS Commitment Pool	GE MAPS Operating Reserve Group	Spinning Reserve Requirement	Spinning Reserve Amount at Peak
Midwest	MISO	800 MW	800 MW
TVA	TVA	625 MW	625 MW
SPP	SPP	983 MW	983 MW
VACAR	VACAR	2% of hourly load	958 MW
SOCO	SOCO	3% of hourly load	1,542 MW
FRCC	FRCC	350 MW	350 MW
IESO	IESO	225 MW	225 MW

Another factor was the technologies that qualified as spinning reserve and the quantity available from them. According to the Phase 2 documentation (EIPC 2012), only coal, gas/oil steam, CC, and hydro units were available to provide spin. The amount of spin available was calculated on a unit-by-unit basis. The maximum spin from thermal plants was limited to the lesser of the amount of capacity above their minimum amount and 10 times their per minute ramp rate (to reflect a 10 min response.) Because the ramp rates used were 3 MW/min for coal, 6 MW/min for oil/gas steam, and 10 MW/min for CC, the maximum spin was 30 MW from coal units, 60 MW from oil/gas steam, and 100 MW from CC. Also, the reserves were limited to 50% of the unit's capacity.

As an example, a 600 MW CC plant has a minimum capacity of 300 MW. So to provide the maximum 100 MW of spin it must operate at a minimum of 300 MW. To provide 10,000 MW of spin for PJM, assuming 600 MW CC plants, there would need to be 30 GW of CC plants operating. Using this formula, smaller units of 200 MW could run at their minimum of just 100 MW and still provide 100 MW of spinning reserve. (Note: The capacity and operations of specific plants are not available from the results reported, so it is not possible to determine which plants provided spinning reserves.)

Besides thermal plants, hydro plants could provide spinning reserves equal to 50% of the difference between the plant's capacity and the month's average generation. So for example, a 300 MW hydro plant operating at 100 MW on average for a given month could provide 100 MW of spin. For many of the regions, hydro capacity could provide a large portion of the spin requirement. Table 9 shows the amount of spin required and available by month for the CO_2+ scenario. Six of the regions have sufficient hydro to provide all of their spinning reserve; two others have more than half provided by hydro. Only PJM and FRCC require significant spinning reserve from thermal resources.

Table 9. Regional Average Spin Requirements and Contributions from Hydro

	NEISO	NYISO	PJM	MISO	TVA	SPP	VACA	SOCO	FRCC	IESO
Average Spin Required	530	600	7,665	800	625	983	520	889	350	225
Average Spin from Hydro	1,303	652	1,621	632	1,507	527	596	1,324	24	2,320
Ratio	246%	109%	21%	79%	241%	54%	115%	151%	7%	1031%

One sensitivity was run on the CO_2+ scenario that relaxed several variables relative to reserve requirements. The "Hi-Spin" sensitivity implementation included the following.

- Reduce spinning reserve requirements in MISO, SPP, PJM and Ontario by 50%.
- All CC units were modeled with a 100 MW/min ramp rate, turndown 14% of base load, minimum runtime, and downtime of 2 h.

Ontario already met all spin requirements from hydro, so the changes had no effect on it. MISO, SPP, and PJM received some of their spin requirements from thermal plants, so a change in their generation was expected because of these modifications. The second step in the sensitivity greatly increased the flexibility and amount of spin from CC plants. Plants could provide up to 1,000 MW of spin based on the new ramp rate, which effectively eliminated that restriction. The earlier example of a 600 MW CC plant could operate as low as 84 MW while providing 300 MW of spin (half of its capacity), so 10,000 MW of spin would only need 2,800 MW of CC operating at minimum power. This is less than 1/10 of the amount needed under the original specification. Furthermore, the minimum runtime and downtime of 2 h are much less than the base case values of 6 h and 8 h for minimum runtime and downtime. These combined changes reduced the need for CC plants and also allowed for their shut down when not needed much more frequently. This resulted in less forced curtailment of wind generation, as discussed in the next section.

2.4 CONCLUSIONS

In Phase 1, the regional planning reserve requirement, given a demand forecast and schedule of plant retirements, determines the need for new resource builds. Planning reserves include all generation technologies in the calculation but reduce the capacities of wind and solar to reflect their limited availability during peak demands. Some scenarios (the CO_2+ scenario especially) included large amounts of wind, which contributed only a small fraction toward meeting the planning reserve requirement. Because generation from these sources was often much larger than the reduced amount included in the reserves requirement, there was extra generation for export to other regions if transmission was available but curtailments were necessary (as noted in Phase 2) if not. This is discussed further in Sect. 3.

The Phase 2 calculations used operating reserves in their calculations. The required reserve quantities varied greatly by region, with PJM having the greatest requirements, both in megawatts and as a percentage of demand. In the modeling, only thermal fossil plants (coal, gas steam, and CC) and hydroelectric plants could provide reserves; these plants had to be running at least at their minimum dispatch points and could only provide limited quantities based on their ramp rates. While many regions had sufficient hydro to cover most of their reserves requirement, other regions were forced by their reserves requirements to increase output from the committed thermal units while other lower cost units (most notably wind) were curtailed. A sensitivity was run that reduced the reserves requirement by 50% (to represent DR supply of reserves in some of the regions) and enhanced CC flexibility (minimum power levels, minimum up/down times, and ramp rates). This led to a reduction in the amount of low cost power curtailed, more fully discussed in Sect. 3. During peak times, some regions had to back down their more efficient CC plants to provide reserves and call on more expensive combustion turbine (CT) units and DR to provide energy, as discussed in Sect. 4.

3. TOPIC 7: WIND CURTAILMENT

3.1 BACKGROUND OF TOPIC

Wind power is a resource that can provide large amounts of electrical power at very low marginal cost. The variable operating cost is near zero, and with production tax credits the final cost to producers is actually negative. Generally, it is most economic for the sector to take all generation provided from wind. However, there are various reasons why at times the system cannot accept all the wind power available and some wind farms have to reduce power levels. There can be multiple contributing factors to curtailment: there is simply more production than consumers demand at the time; there is insufficient transmission to carry the power to other regions where there is demand; and/or there are other factors such as local reserve requirements, transmission impedance, ramping limitations, environmental regulations, or other low cost resources available. These factors become more of an issue as the fraction of power from wind increases.

In Phase 1 of the EIPC study, there was a brief question about whether any curtailment would occur. An analysis showed that even in the CO_2+ scenario, the level of curtailment was less than 2% in all of the regions. However, in Phase 2 there was a significant amount of wind curtailment in the CO_2+ scenario from the GE MAPS runs, along with some in the RP/R scenario as well. CRA released data that showed the amount curtailed over the course of the year for each region (Table 10).

Table 10. Phase 2 Wind Curtailment Amounts and Percent of Potential Generation

	BAU		RPS/R		CO2+	
	GWh	% Potential	GWh	% Potential	GWh	% Potential
ENT	0	0%	0	0%	237	30%
MAPP US	1	0%	393	2%	3,894	12%
MISO IN	0	0%	0	0%	521	2%
MISO MI	1	0%	1	0%	35	0%
MISO MO-IL	1	0%	1	0%	8,426	26%
MISO W	123	0%	4,553	5%	65,463	25%
MISO WUMS	0	0%	0	0%	52	1%
NE	0	0%	119	1%	22,417	40%
NEISO	49	0%	2	0%	439	2%
NYISO A-F	11	0%	3	0%	985	5%
PJM E	0	0%	14	0%	47	1%
PJM ROM	3	0%	3	0%	2	0%
PJM ROR	5	0%	444	0%	504	1%
SPP N	1	0%	1,053	3%	21,271	15%
SPP S	1	0%	3,713	4%	4,910	3%
TVA	0	0%	1	0%	-	0%
VACAR	4	0%	19,162	24%	11	0%
IESO	865	5%	528	3%	2,192	13%
MAPP CA	0	0%	25	2%	5	0%
EI	1,066	0%	30,015	5%	131,412	15%

The CO_2+ scenario had the most widespread curtailments and so was the subject of the most scrutiny. The western plains regions had the largest amount of curtailment, although there were pockets of curtailments in other regions as well. In the RPS/R scenario, the largest curtailments occurred in VACAR. These were likely offshore wind curtailments and possibly due to inadequate transmission build-out.

3.2 ESTIMATION OF HOURLY WIND SCHEDULE AND CURTAILMENTS

To explore the various reasons for the curtailments it was necessary to determine when the curtailments happened and what the demands and production requirements were across the EI. The Phase 2 reports included hourly output for all types of generation, including wind, for each NEEM region. The reports also included the amount of wind energy curtailed for the year by NEEM region (Table 10). Neither wind curtailments nor wind energy available (also referred to here as potential wind generation) were provided on an hourly basis. Thus, we had to estimate the amount of wind energy available in each hour based on the data available. We created a heuristic and applied it to five specific regions that had high levels of curtailment (MISO MO-IL, MISO W, NE, SPP N, and SPP S). These regions are highlighted in Table 10. MISO MO-IL, MISO W, NE, and SPP N all experienced high levels of wind curtailments in the CO_2+ scenario. SPP S experienced high levels of wind curtailments in the RPS/R scenario. While VACAR also experienced high levels of wind curtailments in RPS/R, an estimated hourly wind availability schedule could not be produced for that region due to inconsistencies in the reported data for wind output and capacity. A comparison of the estimated wind availability to the wind output from the model provided an estimate of hourly curtailments.

Hourly wind availability was estimated using the hourly wind generation information from the CO_2+ and RPS/R scenarios and their sensitivities. Because the CO_2+ and RPS/R scenarios and the CO_2+ sensitivity that had reduced wind capacity have different amounts of wind capacity installed, the hourly wind generation was normalized based on the amount of capacity for each scenario or sensitivity. Thus, the hourly wind generation data were converted from a megawatt basis to a fraction of wind capacity basis. This placed the various scenarios and sensitivities on an equal footing for a direct comparison. The estimated wind availability for a particular hour was determined by taking the maximum of the normalized wind generation levels across the scenarios/sensitivities for that hour. This operation was performed for all hours of the year to find the estimated wind availability schedule.

The estimated hourly wind availability schedule was then converted back to a megawatt basis for the various scenarios and sensitivities. The hourly curtailments were then estimated by subtracting the hourly wind generation from the hourly wind availability.

The estimation method does not capture all of the curtailments but does significantly reduce the amount of unaccounted for energy for all of the regions except MISO MO-IL. (MISO MO-IL experienced significant local congestion in the production costing model that likely caused curtailments across all the sensitivities.) While the estimation method does not exactly recreate the hourly wind availability, it is sufficient to identify specific hours of the year with large curtailment levels. The transmission interchange levels and generation levels of other generation sources can then be examined for these hours to provide insight into the causes of the wind curtailments.

3.3 TIMING OF CURTAILMENTS

A first analysis compares the potential wind generation, wind curtailments, and wind generation by hour of day (Fig. 5). These curves show the average values for all 365 days of the year. Curtailments were highest in the early morning hours, peaking around 5:00 a.m. Because demands are lowest at these times, there is clearly a connection between level of curtailments and demand. While it is also true that potential wind generation is also highest before noon, a clear suppression of demand in the early hours can be seen for most regions examined. SPP-S has a relatively flat and low level of curtailment, so its actual generation stays about the same shape as the potential generation.

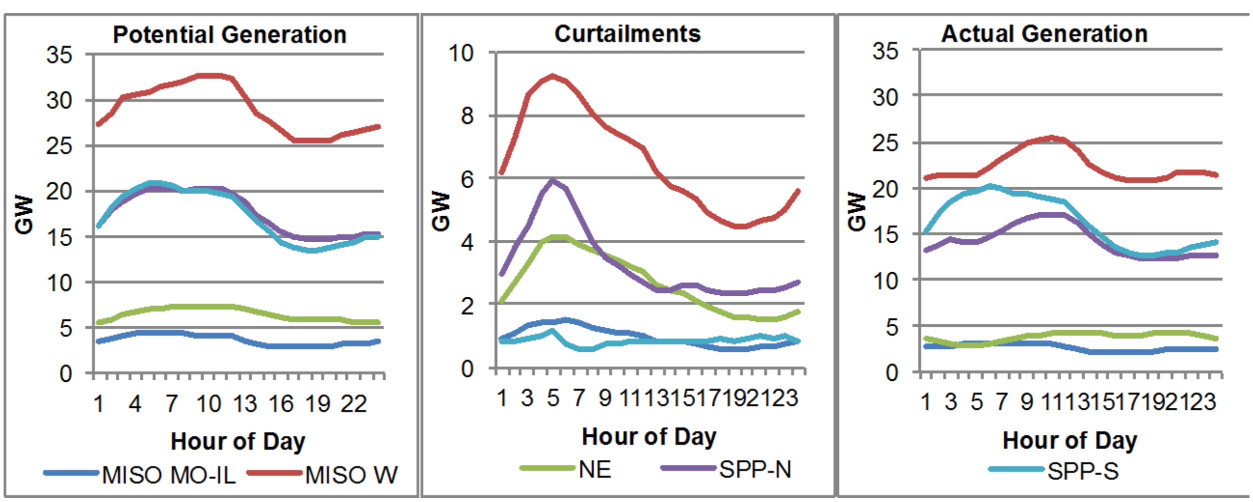

Fig. 5. Potential wind generation, curtailments, and actual wind generation in the CO_2+ scenario.

3.4 EXPLORATION OF PEAK CURTAILMENT DAY

Another avenue of exploration is to examine the transmission flows during an hour of high curtailment to see whether regional transfer capacities are being strained. As an example, April 1 had the highest level of curtailment for the year for those regions in which we calculated hourly curtailments (Fig. 6). There was major curtailment in the early hours and supply was only slightly above the region's demands, so little was exported.

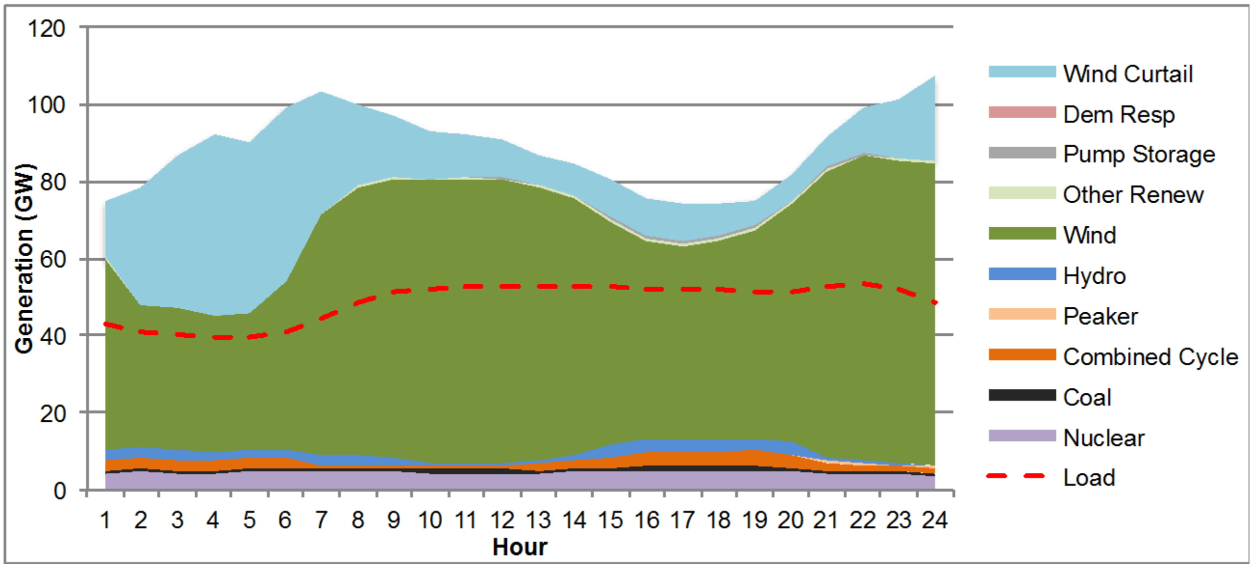

Fig. 6. Supply and demand for major curtailed regions on April 1 in the CO_2+ scenario.

The lack of export is verified by looking at the tie line flows at 4:00 a.m. for the scenario (Fig. 7). Even the high voltage direct current (HVDC) lines from SPP N and MISO W to PJM were only lightly loaded. (In the detailed reports, one of the four HVDC lines between MISO W and PJM ROR was actually flowing back into MISO W.) PJM and other regions were not able to absorb the extra wind power in this hour.

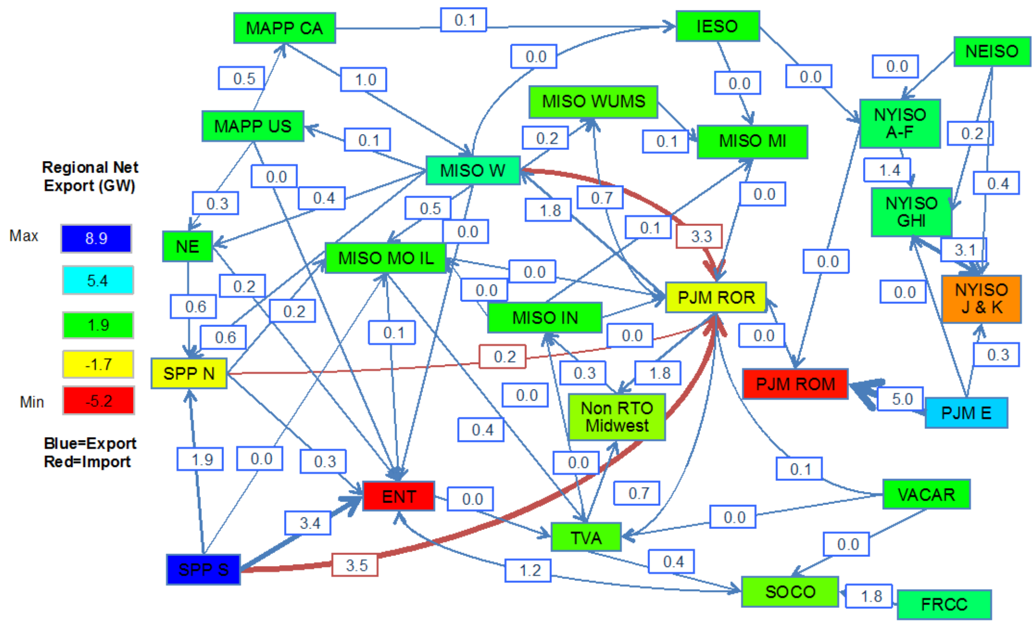

Fig. 7. Tie line flows on April 1 at 4:00 a.m. for the CO_2+ scenario.

The PJM region could not take additional power because its plants were running at the minimum levels or had to be running to be available in later hours. In Fig. 8, the generation levels by technology are shown for the three PJM regions combined. Note that the CC plants are running at 17,300 MW constantly through the morning. If these were all 750 MW plants running at their minimum of 50% of capacity, then there would be 50 plants running, and they would provide 5,000 MW of reserves. Based on the equation for required reserves, PJM needs 6,200 MW of reserves in that hour. Subtracting 1,400 MW supplied by hydro leaves 4,800 MW of reserves needed, about the same amount as provided by the CCs. So for this hour, it appears that the main cause of the curtailed wind was the reserves requirements and other operating constraints, not lack of transmission.

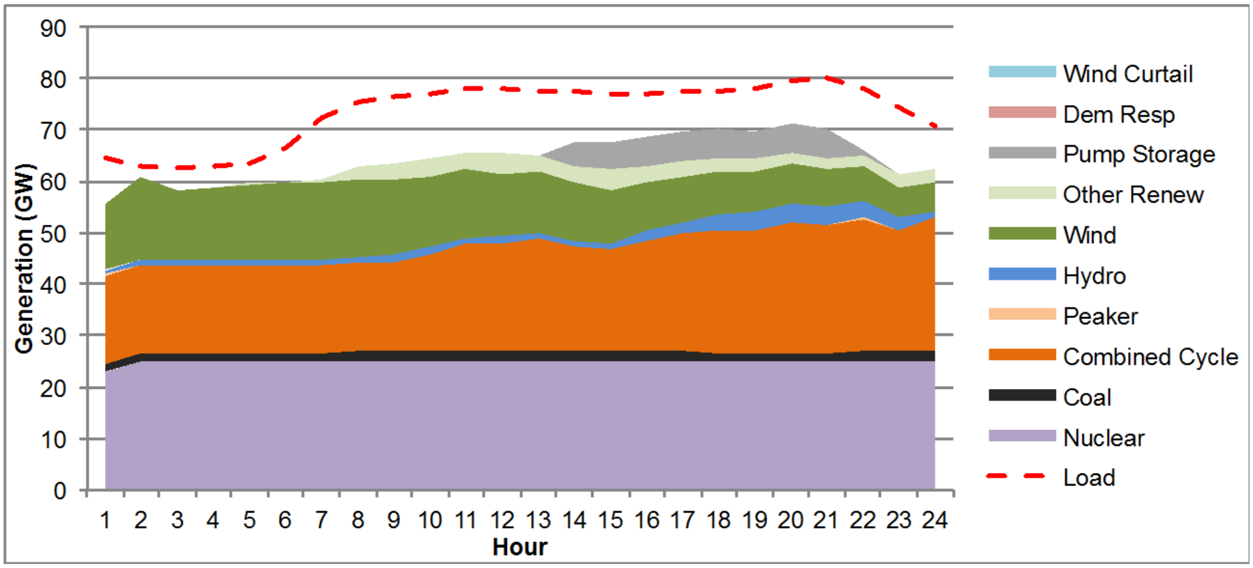

Fig. 8. Generation and loads for PJM regions on April 1 in the CO_2+ scenario.

A further bit of information about the state of the grid at any point in time is the locational marginal prices for the different balancing areas (BAs). CRA reports the hourly prices for 154 different BAs across the EI. These have been mapped to the general location of the areas, although some BAs cover overlapping regions and have their headquarters near each other. Plotting the points and color-coding based on the price shows the span of prices across the EI for the April 1 case (Fig. 9). Most areas have prices at or below \$10/MWh, with some areas even below zero. As all coal and CC plants have variable costs higher than this price, they must be operating at a loss on energy sales and operating because either they are needed for operating reserves or because they will be needed later in the day. (The location in North Dakota with a high spot price appears to be the result of a localized transmission issue resulting in a load pocket.) Sure enough, by 10 a.m. prices have risen across most of the EI to around \$60/MWh.

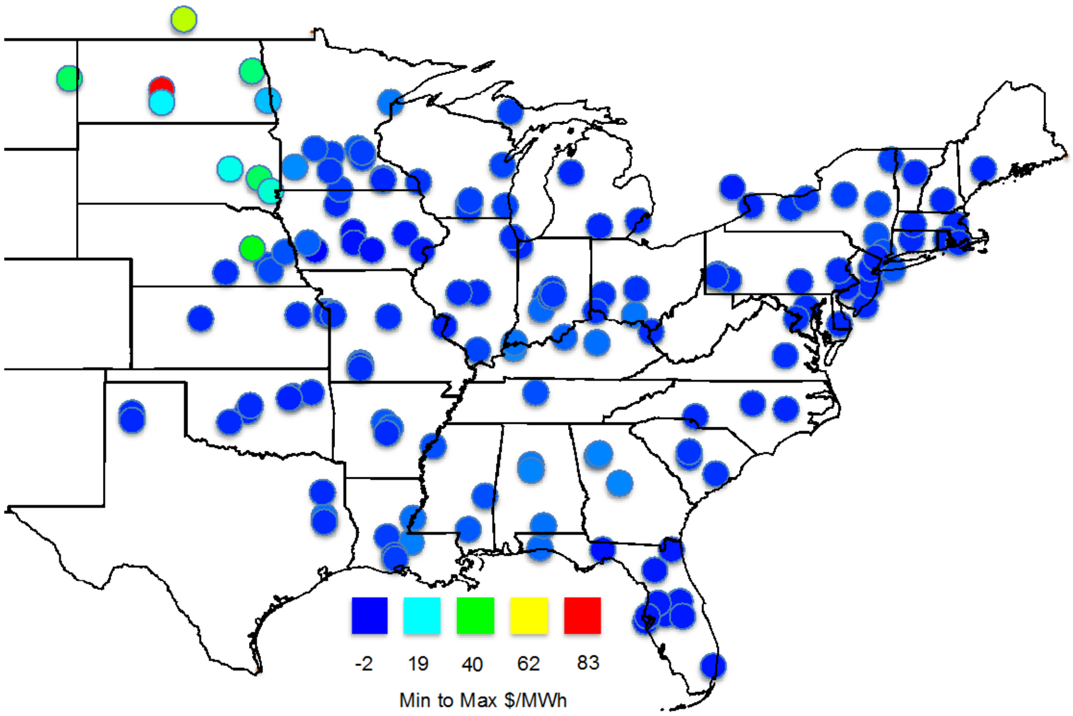

Fig. 9. Locational marginal prices for balancing areas across the EI on April 1 at 4:00 a.m. for the CO_2+ scenario.

3.5 EFFECT OF REDUCED SPIN REQUIREMENTS AND FLEXIBLE COMBINED CYCLE

Another means to examine the question is to evaluate the results from the Hi Spin sensitivity. As mentioned previously, spin requirements were lowered for several regions, while ramp rates (and consequent reserves supply) were increased for several technologies, and the minimum up and down times for these technologies were also reduced. These changes all combined to significantly reduce the curtailments in many of the hours of study. Production levels on April 1 are significantly different for both the curtailed regions and PJM, as shown in Fig. 10 and Fig. 11. Comparing these to Fig. 6 and Fig. 8 reveals a much lower level of curtailment in the curtailed regions and a greatly reduced level of CC production in PJM in the early hours of the day. Clearly the spin requirements and/or minimum up/down times in the base case played a role in the level of curtailments. This is further revealed in the tie line flows for 4 a.m. across the EI (Fig. 12). The HVDC lines become almost fully loaded and large amounts of power are transferred from MISO W, NE, and SPP N through SPP S to ENT, TVA, and SOCO (as compared to the CO_2+ case in Fig. 7.)

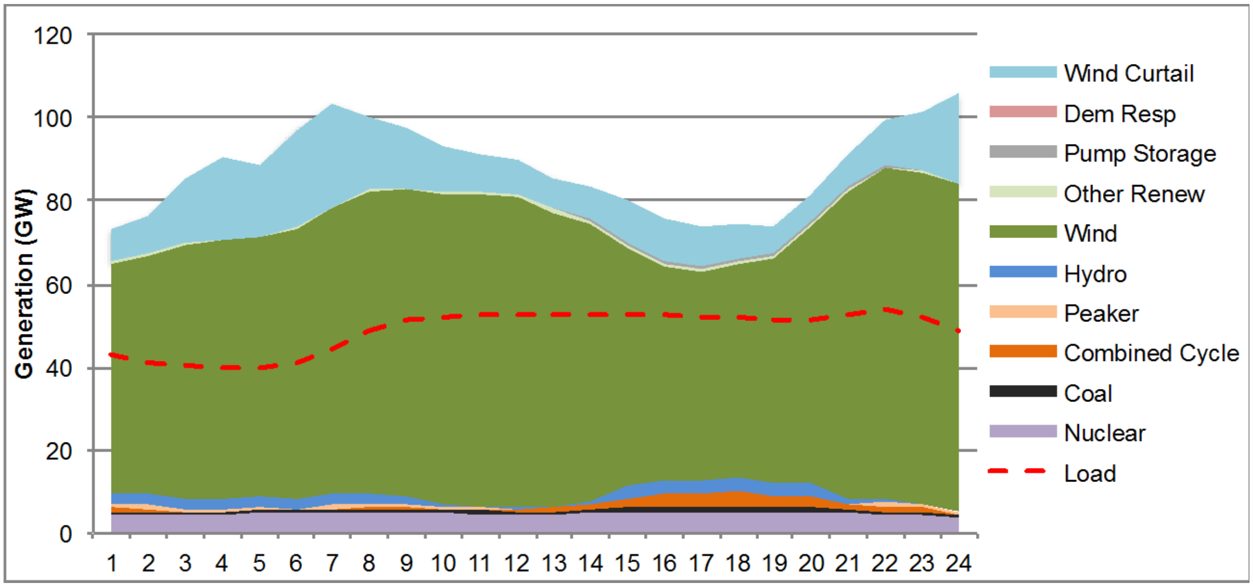

Fig. 10. Generation on April 1 in the curtailed regions in the Hi Spin sensitivity.

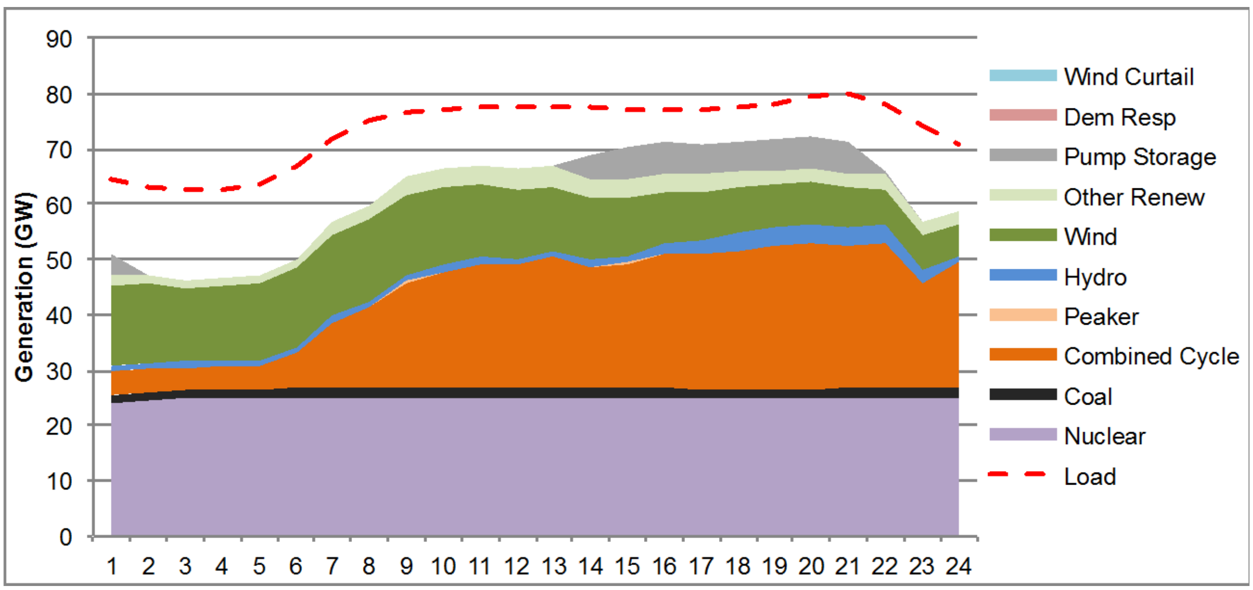

Fig. 11. Generation on April 1 in PJM in the Hi Spin sensitivity.

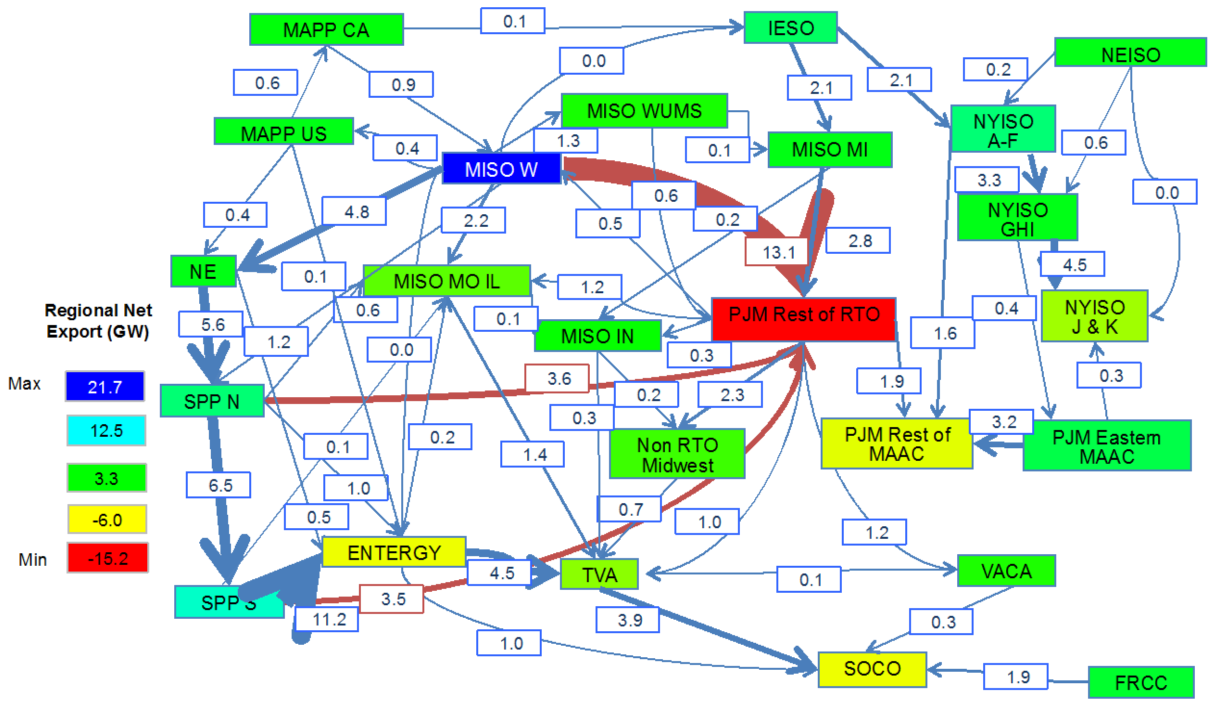

Fig. 12. Tie line flows on April 1 at 4:00 a.m. in the Hi Spin sensitivity.

While spinning reserve requirements and generating plant parameters had some effect on the amount of curtailment, relaxing those requirements still left most of the curtailments. The total curtailments dropped just 9% from 131 TWh in CO_2+ to 120 TWh in the Hi Spin sensitivity. MISO W curtailments for the whole year dropped just 5%, from 65 TWh to 62 TWh. Spinning reserve requirements do not seem to account for all wind curtailments. We next examined tie line loading to determine whether those constraints may have resulted in additional curtailment.

3.6 CURTAILMENTS VERSUS TIE LINE CAPACITY

It is possible that wind is curtailed because there is not enough transmission capacity to transport it to where it is needed. If the curtailments occurred due to tie lines being fully loaded, then most curtailment should occur during high tie line activity. We summed the hourly net tie line flows out of the five curtailed regions for which we calculated the curtailments by hour. We then compared that to the amount of curtailment in these five regions combined. In the CO_2+ scenario there is a general peak tie line flow out of the curtailed regions of around 40 GW (Fig. 13). The highest curtailments typically occurred when the tie lines were at this power level, which indicates that curtailments could probably have been reduced with increasing tie line capacity.

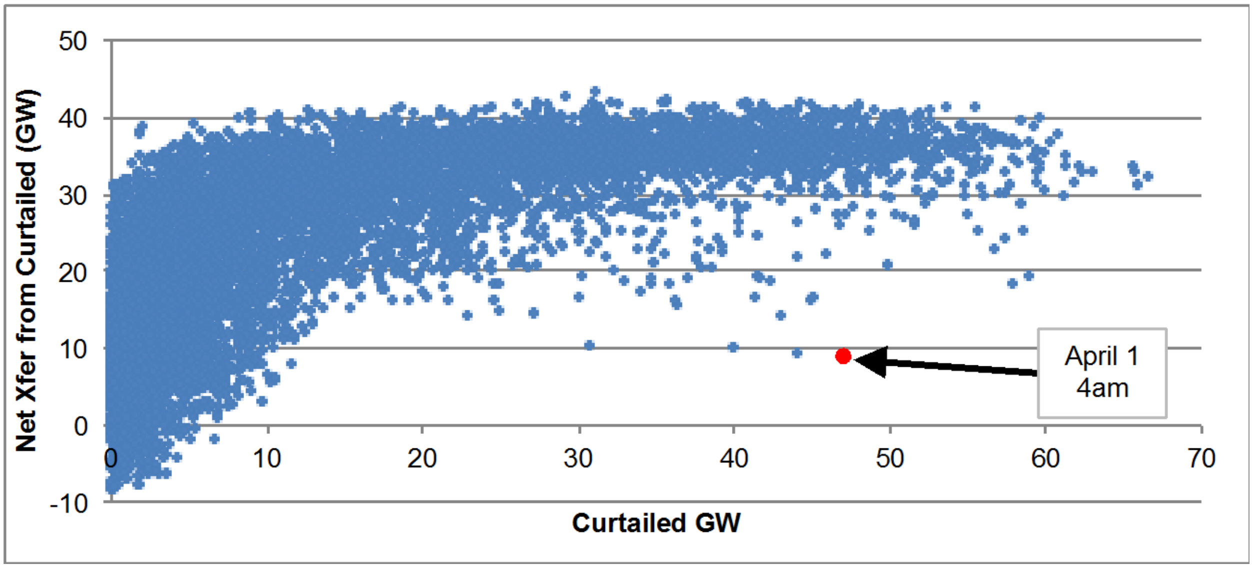

Fig. 13. Net transfer vs. curtailment in the curtailed regions for the CO_2+ scenario.

This is even more apparent when comparing the Hi-Spin sensitivity (Fig. 14). Many of the points with high curtailments but low tie line flows either increase their flow, reduce their curtailment, or both. Examples include the April 1 4:00 a.m. example, with curtailments and transfers for the two cases shown in Table 11. In those hours affected by the changes in reserve requirements and plant capabilities, the tie lines were more heavily used and the curtailment amounts went down because the power was used in the other regions.

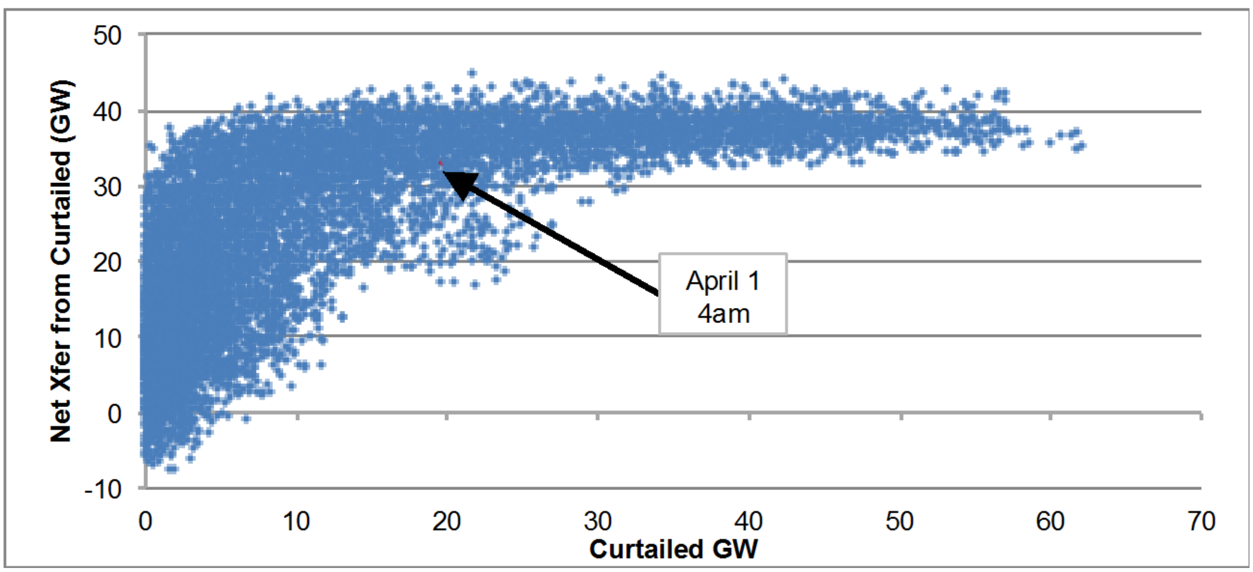

Fig. 14. Net transfer vs. curtailment in the curtailed regions for the Hi Spin sensitivity.

Table 11. Curtailments and Net Transfers
April 1 at 4:00 a.m. for curtailed regions

	Curtailments	Transfers
CO_2+ Scenario	47.0 GW	8.9 GW
Hi Spin Scenario	19.7 GW	33.2 GW

More than half the hours have curtailments below 10 GW in the five regions studied and over 70% of the time curtailments are below 20 GW. Fig. 15 is a histogram showing the fraction of the year for different ranges of curtailment levels. There is a slight difference between the CO_2+ scenario and the HI Spin sensitivity, reflecting the shift to lower curtailment amounts with the Hi Spin changes in reserves requirements and plant capabilities.

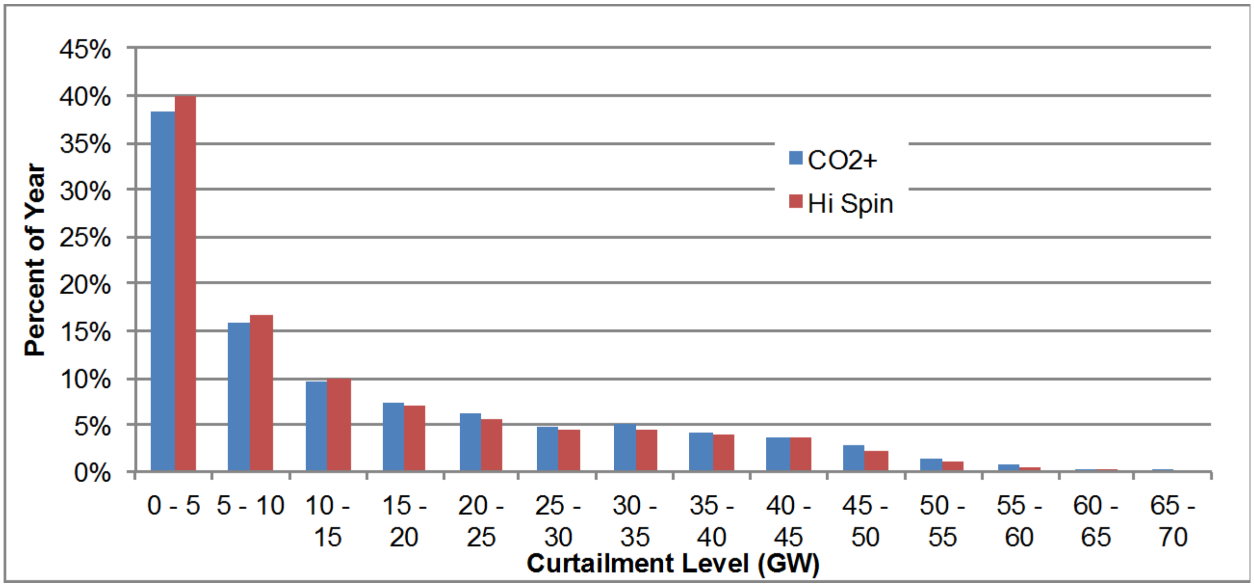

Fig. 15. Percent of year that curtailments in curtailed regions were at different levels.

The amount of curtailments that could be resolved through tie line improvements is unknown. The CO_2+ scenario included 21 GW of additional HVDC lines (plus a large amount of conventional transmission). As there were still some hours with more than 60 GW of curtailment, adding 4 times as much HVDC capacity as in that scenario might eliminate most but still not all curtailments. Also, their construction would be quite difficult and placement would likely require significant upgrades in supporting infrastructure. The economic rationale for expansion of the grid, which must balance a large number of factors, is thus more complicated than just meeting reliability criteria during peak times (the method used in the EIPC study) or eliminating all wind curtailments.

An examination of the hourly curtailments in the Hi Spin sensitivity reveals that the periods with high levels of curtailments also have high levels of tie line transfers out of the curtailed regions. Fig. 16 shows the curtailments in the curtailed region (MISO W, MISO MO-IL, SPP N, SPP S, and NE) and the net transfer from the curtailed regions to other areas for each hour, the same as Fig. 14. The vertical red line represents the median hourly wind curtailment (7,712 MW). Thus, half of the hourly curtailments lie to the left of the line (lower than the median) and the other half lie to the right of the line (greater than the median). The horizontal red line represents the median hourly net transfer (27,174 MW) from the curtailed region. These lines divide the graph into four quadrants, described in Table 12.

If the two sets of data are independent, roughly the same number of points will lie in each quadrant. If quadrants I and III are overrepresented, the sets of data tend to be correlated. In this case, there are 3,690 h in each of quadrants I and III and 690 h in each of II and IV. This means that 42% of the time both transfers and curtailments are higher than the median, 42% of the time they are both lower than the median, and 8% for each of the other two possibilities. In general, this indicates that high levels of wind curtailments occur when net transfers are high and low levels of curtailments happen when net transfers are low.

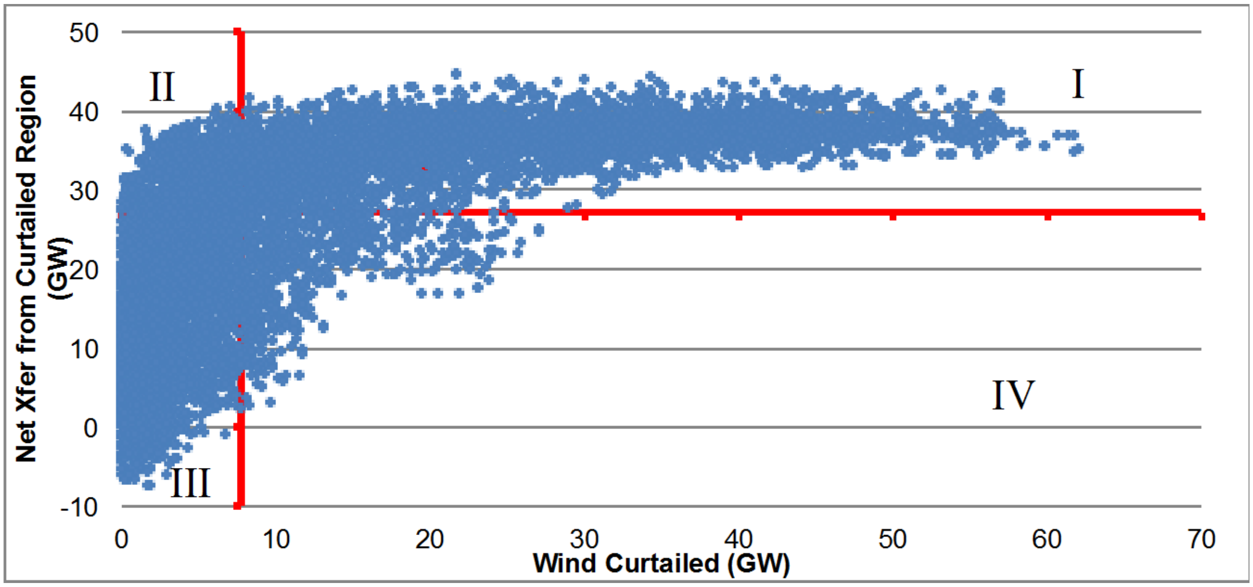

Fig. 16. Net transfer vs. wind curtailment in the curtailed regions in the Hi Spin sensitivity.

Table 12. Curtailment and Transfer Quadrants for the Hi Spin Sensitivity

Region	Transfers	Curtailments	Hours	Curtail TWh
I	> Median	> Median	3,690	96.5
II	> Median	< Median	690	3.1
III	< Median	< Median	3,690	9.4
IV	< Median	> Median	690	8.5

Looking further out toward the extremes, there are 1,390 hours where curtailments exceed 30 GW. Of those, only two occur in hours with less than 30 GW of transfers, and neither of those occurs when transfers are lower than the median. Thus, once we account for the hours where large amounts of curtailments result from spinning reserve requirements by adjusting the spinning reserve requirements and generator characteristics in the Hi Spin sensitivity, the high curtailments occur during hours with high transfers. This indicates that transfer limitations are a major factor.

A final point is that the vast majority of curtailed energy occurs in Quadrant I (last column in Table 12), when both curtailments and transfers are above the median. More than 96 TWh of curtailment from these five regions occurred in Quadrant I in the Hi Spin sensitivity. In the CO_2+ scenario, Quadrant I contained more than 101 TWh. The Hi Spin sensitivity only reduced curtailment by 9 TWh overall, so compared to spinning reserve requirements, the dominant reason for the curtailments was the transfer limitations.

3.7 MISO MO-IL SUPPLY POCKET

There still remain a number of hours in the Hi Spin sensitivity when net transfers are well below the peak amount but curtailments arise. These can occur when there are local pockets of congestion within a region. Wind power is available but blocked behind a bus with inadequate capacity, even though there is capacity available on one of the outbound tie lines. This occurred in the MISO MO-IL region (as well as the VACAR and MAPP US regions) a significant percent of the time.

Fig. 17 is a map of the locational marginal prices at the different BAs on April 1 at 10:00 a.m. in the CO_2+ scenario. The price in the Ameren Corporation control area, located in southwestern Illinois, is

$125/MWh (the highest in the EI), while in the neighboring Columbia Water and Light area (Columbia, Missouri), the price is only $1/MWh (the lowest in the EI) in that hour.

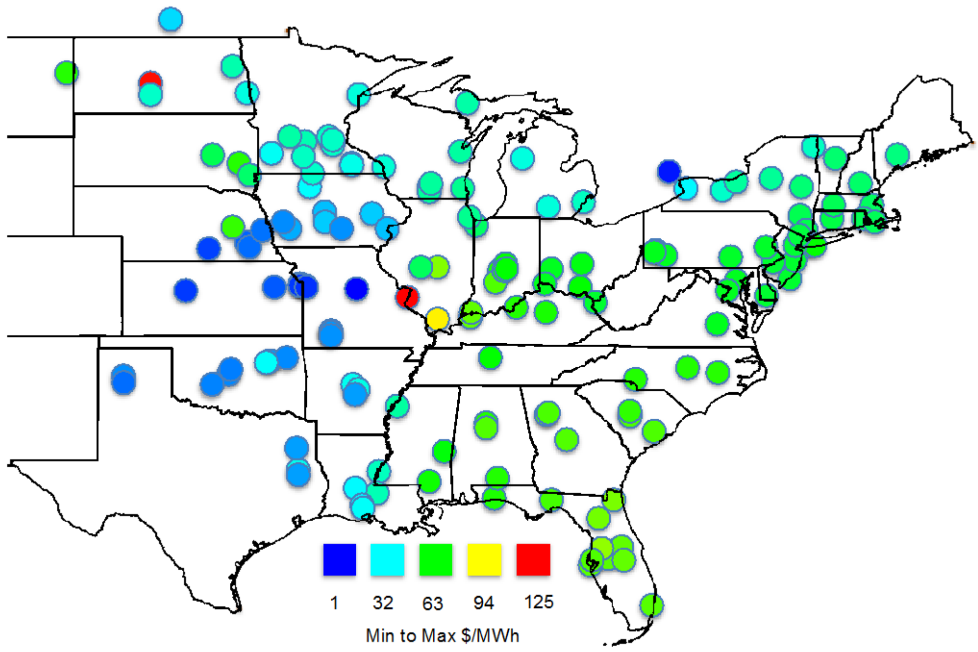

Fig. 17. Locational marginal prices on April 1 at 10:00 a.m. in the CO_2+ scenario.

Wind was curtailed in MISO MO-IL throughout the morning in this scenario, even though MISO MO-IL had to import significant amounts of power after 7:00 a.m. (Fig. 18). Meanwhile, some "peaker" capacity had to be run, especially in the late evening. This indicates that some regions within MISO MO-IL could not access the available power in other parts of the region.

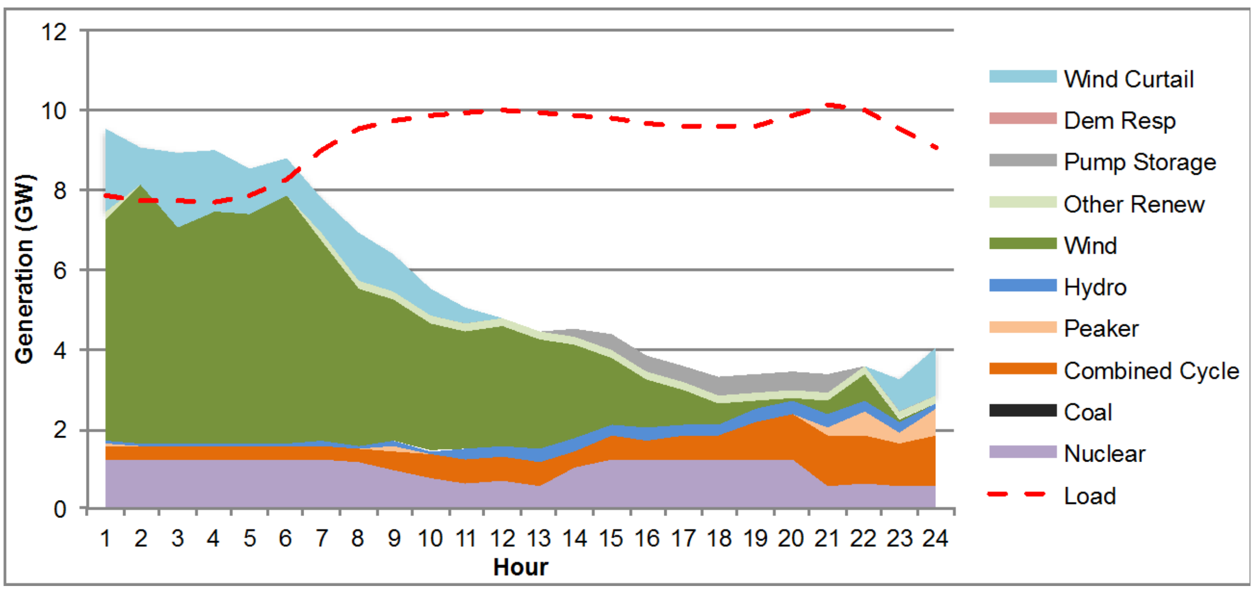

Fig. 18. MISO MO-IL generation and load on April 1 in the CO_2+ scenario.

Discussions with EIPC and examination of the transmission build-out revealed that a significant wind farm (4,000 MW) had been added to the grid in northeast Missouri. Shadow prices between flowgates from GE MAPS show a frequent difference in price between certain buses west of St. Louis. Likely, this bus or tie line should have been upgraded to open up the curtailed wind to the Ameren control area but was not caught during the first part of Phase 2. It would require further analysis in the PSS/E model to determine appropriate changes and possible consequent changes to other infrastructure.

3.8 CONCLUSIONS

The high levels of wind curtailments in Phase 2 occurred because the GE MAPS model was unable to use all of the available wind during a number of hours of the year. The factors driving this inability differed depending on the hour and region being examined. During certain hours, such as the morning of April 1, operating reserve requirements outside of the curtailed region limited the ability to export power even though tie line capacity was not being fully used. During other periods, tie line capacity was not sufficient to move the available power to other regions. Finally, local transmission congestion such as within the MISO MO-IL region created a generation pocket from which wind generation could not get out to the rest of the system.

4. TOPIC 8: DEMAND RESPONSE

4.1 DEMAND RESPONSE IN PHASE 1

DR is a complex collection of programs and technologies that let demand respond to supply, mainly through reduction of demand in the face of supply shortages. The Federal Energy Regulatory Commission (FERC) defines DR as "the changes in electric usage by demand-side resources from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized" (FERC 2009). Different DR programs can be automated or not, controlled by the utility or customer, involve direct price incentives or appeals, and apply to different demand sectors. Several studies on DR in the EI were commissioned during the EIPC process.[*] The following are two notable ones.

- Baek, Young Sun, et al. *Eastern Interconnection Demand Response Potential*. ORNL/TM-2012/303. Oak Ridge, TN: Oak Ridge National Laboratory, November 2012.

- Navigant, *Assessment of Demand-Side Resources within the Eastern Interconnection*, prepared for the Eastern Interconnection States' Planning Council, March 2013.

In June 2009, FERC released a study on DR, *A National Assessment of Demand Response Potential*, or NADR (FERC 2009). For the EIPC study, the amount of DR for each region was calculated using the state-by-state projections of DR from the FERC NADR model. The model projects both future DR and future peak demand through 2019 for four different scenarios: BAU, expanded BAU, achievable amounts, and full participation. The state-weighted average ratio of DR to peak demand was found for each NEEM region in the study.

For most of the futures in Phase 1, the SSC decided that the percentage of demand that DR could supply would transition from the percentages of demand in the FERC BAU scenario in 2015 to that of the FERC Expanded BAU by 2025 and then continue with those percentages to the end of the period. For the aggressive DR Future 4, the SSC transitioned from the BAU percentages in 2015 to the full participation

[*] A similar study (Satchwell et al., 2013) was conducted for the Western Interconnection.

percentages by 2025 and then continued those percentages to the end. Some utilities treat DR as an alternative supply (where 1 MW of DR equals 1 MW of supply) and some as a reduction in demand (where 1 MW of DR reduces demand by 1 MW, and so for calculation of the reserve requirement the DR is equal to its capacity times 1 plus the reserve margin). To approximate the variations between regions, the SSC multiplied the DR capacity by one plus half of the required reserve margin for each region.

The calculations fixed the amount of DR capacity that would be added within each region rather than allowing NEEM to select how much DR capacity to build. However, the model could choose to call upon, or dispatch, this power. Within NEEM, CRA modeled DR as a forced-in pseudo-generator with no fixed cost but a high energy cost (and consequent price for dispatch decisions) so that it would only be used when most or all other supplies were deployed. In Phase I of the modeling, the original amount of potential DR from NADR was calculated based on NADR's default ratio of critical peak price (CPP) to average price of 8. With the default ratio of CPP to average price and a rough estimate of average retail electricity price, the average price of dispatching DR was set at $750/MWh. This estimated DR price was applied to all DR supplies in the dispatch process of NEEM. However, in Phase 1 very little DR was dispatched, just 39 GWh in the VACAR and 24 GWh in the FRCC in the CO_2+ scenario and none in the other regions or scenarios. Even so, DR served to reduce the capacity requirements from other resources for all regions because it could be applied in the reserve margin calculations.

4.2 DEMAND RESPONSE SUPPLY CURVE FOR PHASE 2

The modeling in Phase 2 allowed a more detailed approach but still treated DR as pseudo-generators within each region. Instead of a single price, there could be up to six supply amounts, each at a different price point. Still, as with NEEM, the GE MAPS model did not limit DR to a maximum number of hours per year or total amount of generation over the year, so the modeling had to use price as a lever to get DR to be dispatched semi-realistically. A more realistic DR supply curve was needed than the single tier at $750/MWh. Therefore, a tiered pricing arrangement or supply curve for DR was calculated, with six different DR price tiers, but still with an average price for DR of $ 750/MWh to match the Phase 1 assumption.

ORNL researchers who conducted the DR study created a national stepwise DR supply curve for 2030 based on the ORNL version of the FERC NADR model (ORNL NADR). Under the full deployment scenario of the ORNL NADR, 30 different cases with a variation of CPP ranging from $50/MWh to $1,500/MWh were run to see how system peak load would respond to changes in CPP (Fig. 19).

Fig. 20 shows three supply curves for comparison: a supply curve for pricing-related full DR deployment, the five-tier step function of the same supply curve, and the supply curve used in NEEM for Phase 1. The NEEM curve from Phase 1 was driven based on the FERC 2009 NADR results and shows the maximum DR available in 2030 would be 209 GW.

Actual DR would have a mixture of programs that dispatchers could call upon. Some programs have no specific price but have time or frequency limits. Some allow customers to vary their response at different price points. In addition, the variation in CPP addresses only the impact from pricing programs (Fig. 19 and Fig. 20). To reflect such DR supply from nonpricing programs, ORNL researchers chose to allocate the nonpricing DR amount into each tier proportionally (Fig. 21). Seventy percent of the peak load reductions (PLR) that came from nonpricing DR was distributed into the first five price tiers, and the remaining 30% of PLR was allocated to a new sixth price tier. The price for this last tier was set so that the weighted average of DR price stayed at $750/MWh to maintain consistency with Phase 1.

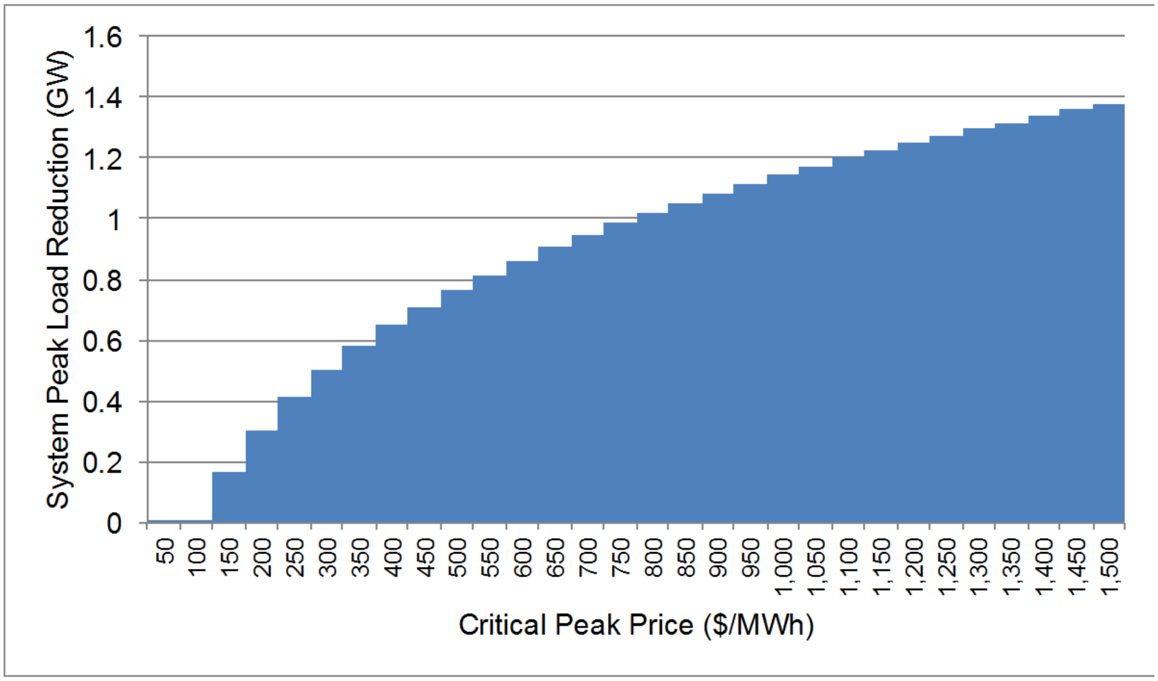

Fig. 19. ORNL NADR runs with variation in critical peak price.

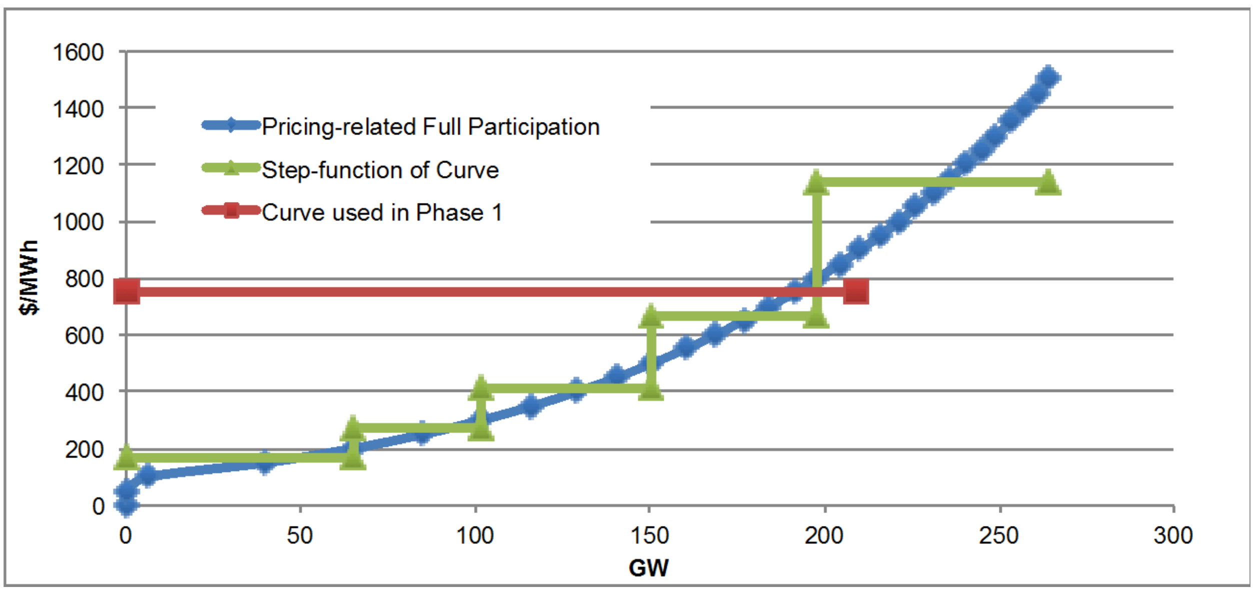

Fig. 20. Supply curve for pricing-related DR programs in 2030. Five-tier approximation and Phase 1 single tier curve also shown.

The lowest tier size was picked so that its average price would be in the neighborhood of the cost of a CT. The lowest cost tier of 22% of maximum DR available in any region could be supplied at the first price tier of $165/MWh, roughly between the efficient and inefficient CT costs, as shown in Fig. 21. This amount of DR could possibly replace CTs in the dispatch process. The last price tier represents exceptionally expensive DR options such as rotational blackouts that involve high societal costs but are not included in the typical DR program categories.

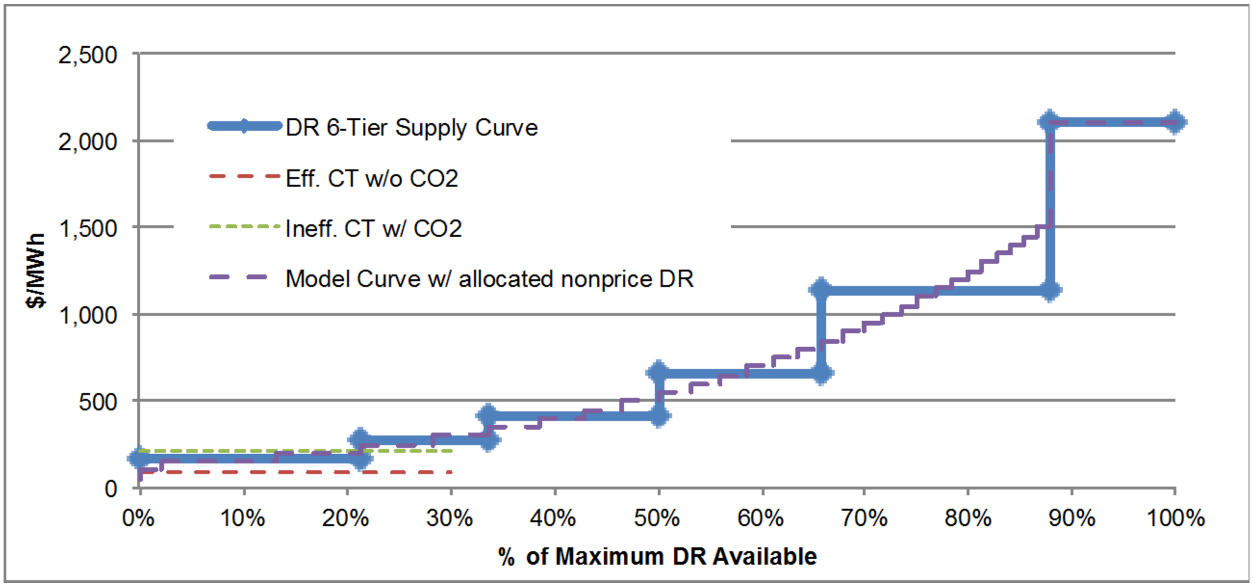

Fig. 21. Six-tier supply curve and model curve with allocated nonprice DR in 2030 for Phase 2.

The resulting six tiers with both their price and the fraction of total DR within each region, as used in the EIPC Phase 2 study, are shown in Table 13. Each region's total DR potential for the scenario in question was multiplied by the fractions from the table and priced at the amount shown. This simplified the supply curve for modeling each region's DR amounts for the purpose of the analysis.

Table 13. Demand Response Supply Curve as Proportion of Total DR Available in Regions for EIPC Study

Tier	Price $/MWh	Percent of Total Capacity	
		Incremental	**Cumulative**
1	165	22	22
2	273	12	34
3	418	16	50
4	665	16	66
5	1,142	22	88
6	2,100	12	100

4.3 DEMAND RESPONSE DISPATCHED IN PHASE 2

As shown in Fig. 2, many of the regions rely on DR to supply some amount of capacity to meet 100% of their peak demand. This is also shown for the CO_2+ scenario in Fig. 22 for all of the NEEM regions individually. The wind and solar capacities are split between the fraction that counts toward the reserve margin and the uncredited capacities that do not contribute to the reserve margin. The red lines show the peak demand for the year in specific regions for the CO_2+ scenario. DR equals a significant fraction of the supply as shown in Table 14 (between 20% and 30% in most regions).

In the BAU and RPS/R scenarios, DR generation is concentrated in the three most southeastern regions (Table 14). Overall DR capacity and generation was highest in the CO_2+ scenario. All regions had at least some small amount of DR use. The most significant use is in two regions with wind power (MISO MO-IL, and MAPP US) where, based on BA prices, there appeared to be some internal load pockets or generation constraints as described in the previous section. The other major area was the Southeast, with FRCC, SOCO, and especially VACAR showing high levels of DR use. These regions do not have easy access to significant amounts of wind power and so must rely on DR to provide power during peaking periods.

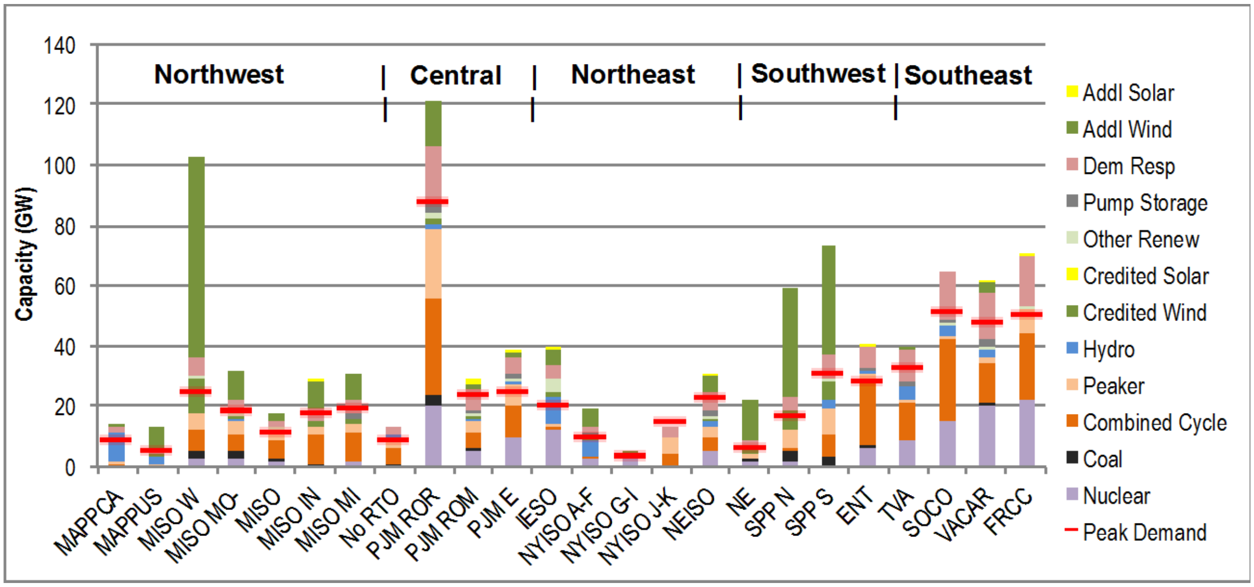

Fig. 22. Capacities and peak demand for each region for the CO_2+ scenario.

Table 14. Phase 2 Demand Response Capacity (in gigawatts and percent of demand) and Generation in NEEM Regions

Region	BAU Capac-ity (GW)	BAU Capac-ity (% Peak)	BAU Gener-ation (GWh)	RPS/R Capac-ity (GW)	RPS/R Capac-ity (% Peak)	RPS/R Gener-ation (GWh)	CO_2+ Capac-ity (GW)	CO_2+ Capac-ity (% Peak)	CO_2+ Gener-ation (GWh)
MAPP CA	0.6	6%	1	0.56	6%	0	1.49	18%	26
MAPP US	0.4	6%	-	0.39	6%	-	0.99	19%	119
MISO W	3.4	11%	-	3.26	11%	-	5.99	24%	3
MISO MO-IL	2.2	10%	-	2.17	10%	0	4.60	25%	139
MISO WUMS	0.8	5%	-	0.67	5%	-	1.80	16%	1
MISO IN	1.5	7%	0	1.83	7%	0	3.93	22%	14
MISO MI	3.1	13%	1	3.06	13%	0	4.04	21%	16
Non-RTO Midwest	0.7	7%	-	0.72	7%	-	2.46	27%	7
PJM ROR	10.2	9%	5	9.54	9%	7	18.79	21%	147
PJM ROM	3.5	12%	5	3.41	12%	4	7.32	30%	69
PJM E	2.5	8%	2	2.44	8%	3	5.85	23%	25
IESO	2.4	10%	-	2.39	10%	-	4.41	22%	0
NYISO A-F	1.2	10%	1	1.11	10%	1	2.14	22%	19
NYISO G-I	0.5	10%	1	0.42	10%	1	0.83	22%	6
NYISO J-K	1.8	10%	2	1.68	10%	2	3.27	22%	26
NEISO	4.3	15%	5	4.35	15%	4	6.28	27%	42
NE	1.0	14%	-	0.97	13%	1	1.75	30%	66
SPP N	1.5	7%	-	1.78	7%	2	3.81	23%	2
SPP S	3.7	10%	81	3.53	10%	5	7.68	25%	2
ENT	2.9	8%	0	2.83	8%	1	7.09	25%	5
TVA	3.4	9%	-	3.45	9%	-	10.49	32%	2
SOCO	7.5	12%	573	7.09	12%	135	15.60	30%	677
VACAR	5.9	10%	212	5.84	10%	64	15.12	32%	1,929
FRCC	5.9	10%	48	5.36	10%	24	16.72	33%	151

4.4 SOUTHEAST DEMAND RESPONSE USE AND PRICE IMPACTS

The lack of local surplus wind and solar in the Southeast is further compounded in that DR cannot be used as reserves, so the regions must run their CC plants at partial load to supply required operating reserves while using DR to supply energy. This is shown for the CO_2+ scenario in Fig. 23 and Fig. 24 for the VACAR and SOCO regions on August 1. Demands increase throughout the day, and various technologies are added (at increasing cost) to respond. However, as demand continues to rise, CC generation declines slightly to provide a compensating supply of reserves. "Peakers" are added and pumped storage is used, and DR is called upon for a number of hours over the day. The gap between generation and load is supplied by imports. If DR or peakers could be used for reserves, then additional CC capacity could be used for generation. The figures also include the locational marginal price for each region (a weighted average based on the prices and loads in the different BAs within the region.) The rise in prices as DR was called upon is readily apparent. If DR had been allowed to qualify for reserves, then less would have been dispatched and prices would have been lower.

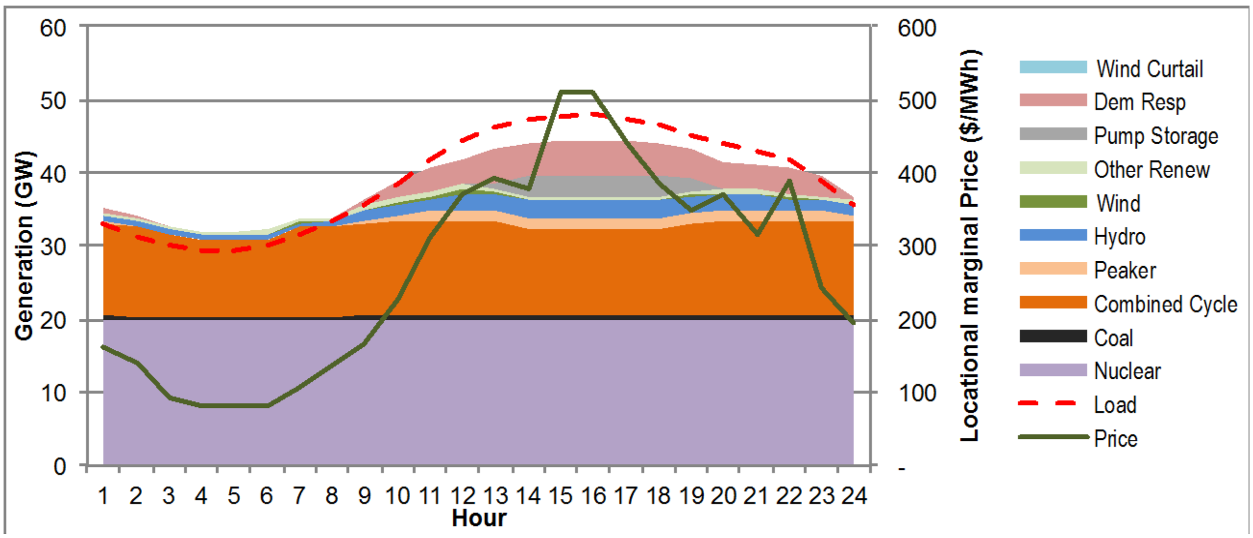

Fig. 23. VACAR generation, load and marginal prices on August 1 under the CO_2+ scenario.

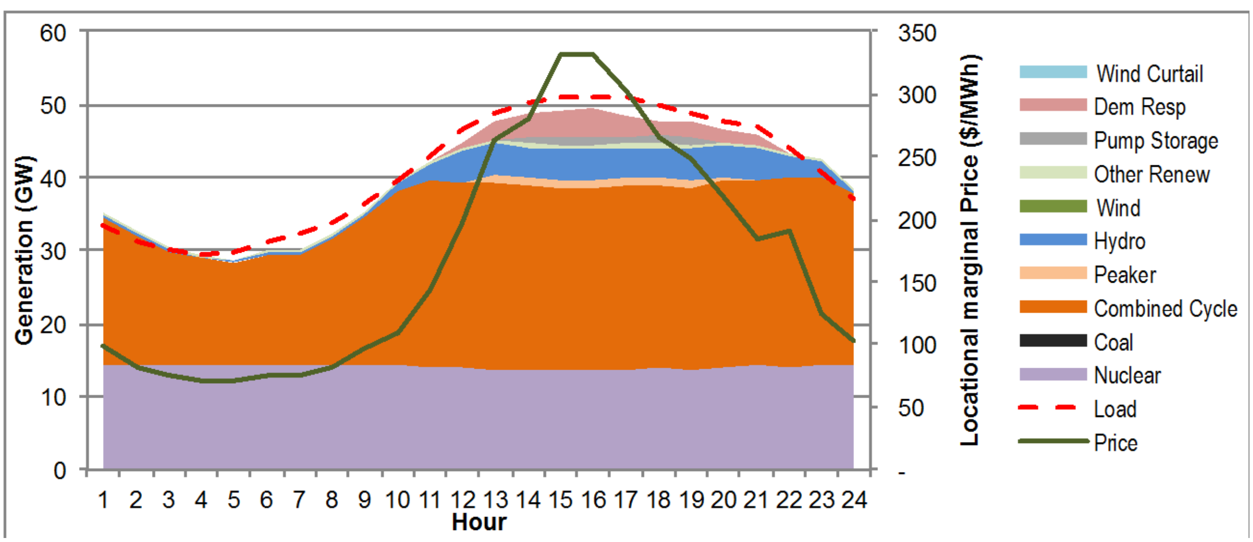

Fig. 24. SOCO generation, load, and marginal prices on August 1 under the CO_2+ scenario.

A key question that arose during the EIPC study was the lack of new lines in the Southeast despite high prices for the region, especially VACAR. The August 1 data are a case in point. VACAR can send and receive power from PJM ROR, SOCO, and TVA. In the scenario represented in Fig. 25, at 4:00 p.m. VACAR is receiving 4.5 GW of power from PJM ROR, which is near the maximum. It also receives a small amount from TVA and actually ships power to SOCO to supply its shortfall. SOCO is also using DR to meet demands while getting power from ENT, TVA, and VACAR and sending power to FRCC.

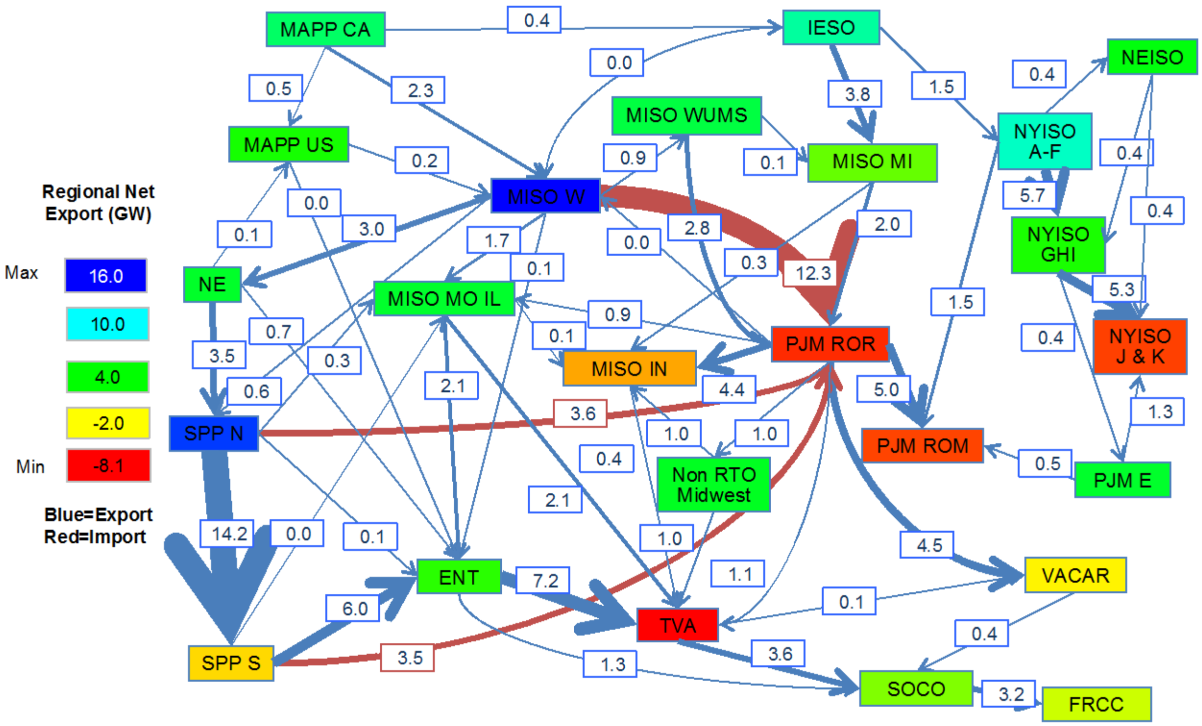

Fig. 25. Eastern Interconnection tie line loads on August 1 at 4:00 p.m. for the CO_2+ scenario.

An examination of the flows and shadow prices on the individual flowgates to, from, and within VACAR show where some of the congestion occurs. There are three main flowgates from PJM ROR to VACAR; in this hour much of the power is flowing from central Virginia down toward central South Carolina, with a shadow price of $100/MWh. This represents the cost difference for power at either end of the line and indicates a congested line. (Other flowgates from PJM ROR do not appear to have shadow prices and so are not immediate congestion points.) Larger congestion occurs on the lines between SOCO and VACAR. There are three main flowgates between the two. Around 2.7 GW is flowing from VACAR to SOCO on the western link, but power is flowing in the other direction on the eastern two. Shadow prices are high on the line from Plant Vogtle into South Carolina, reflecting this line being highly constrained. A review of the PSS/E results indicates that this line is heavily loaded. There are also a few lines within the state that are congested in this hour, as shown by flowgate shadow prices.

Similar analyses show a mixture of congested lines within SOCO. While there were no shadow prices between it and ENT, within SOCO there were several lines indicating congestion, with marginal prices between $100/MWh and $500/MWh. These would indicate load pockets within the state that caused the dispatch of DR shown in Fig. 24.

As shown in Fig. 21, the DR capacity has a rising price as more is required. The DR was modeled by CRA as being spread across a region in proportion to its peak load, so DR can be called upon in load pockets even if the region as a whole has lower cost capacity available. Because DR generation was only reported at the NEEM region level and marginal prices at the BA level, while potential load pockets were at the bus level, it is difficult to show the relationship between prices and supply. However, by plotting the marginal prices within VACAR vs. the DR amounts a distinct supply curve appears.

Fig. 26 plots the marginal prices for each of the six BAs in VACAR versus the total VACAR DR generation in the BAU scenario in the 412 hours where DR was dispatched. Three of the regions [Santee Cooper, Central Electric Power Cooperative, and South Carolina Electric and Gas (SCE&G)] have prices that stair step at DR levels of 300 MW, 600 MW, and 1,200 MW. The last one, SCE&G, is located in the southern part of the state next to Georgia, while the other two are cooperatives that purchase much of their power from the other utilities. As mentioned previously, there appears to be a transmission constraint between SOCO and VACAR, and so these areas are the first to reach constraints and need to dispatch DR.

The last three entries in the legend for Fig. 26 (Progress Energy, Duke, and Greenville Utilities) are located in North Carolina or the northern part of South Carolina. Their prices are lower and smoother than the first three utilities and are likely less constrained by having transmission access to PJM and TVA. The Progress and Greenville prices don't rise above $200/MWh until the total DR generation increases above 1,200 MW. DR for these two utilities starts being dispatched at this time, starting with the lowest cost supply for each. Duke prices are lowest, likely because it has the easiest access to the supplies of other regions. It likely does not start dispatching DR until the others have already begun using theirs. As DR continues to be dispatched, all utilities start to see increasing marginal prices, with some fluctuations at the highest levels where all utility prices become more highly correlated.

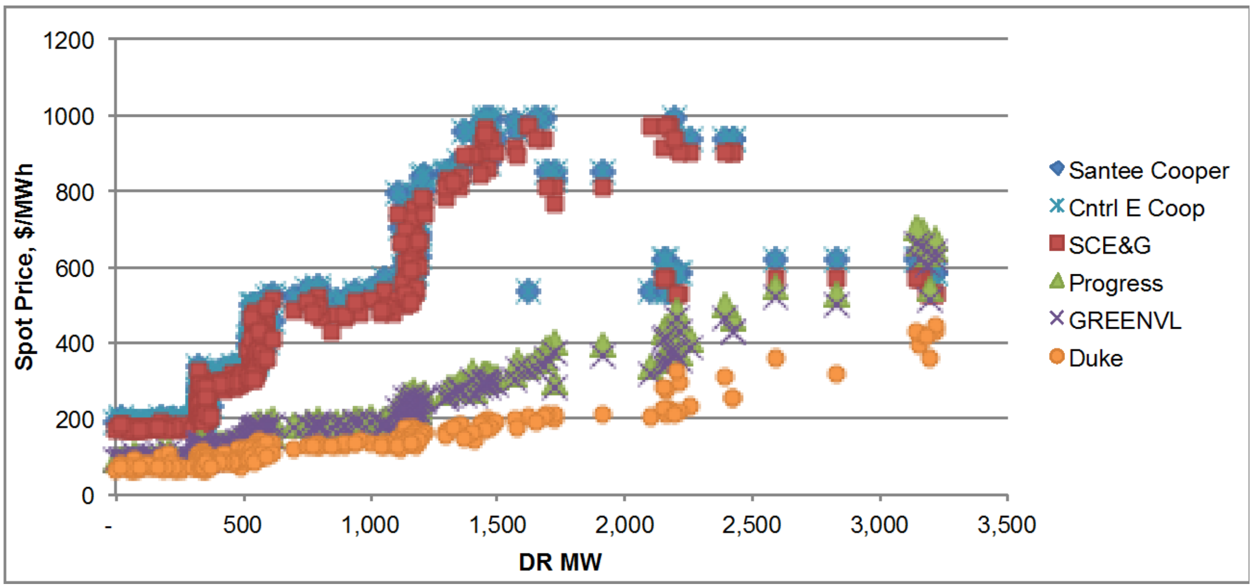

Fig. 26. Marginal prices at six balancing areas versus the corresponding DR demand for all of VACAR in the BAU scenario.

4.5 SOUTHEAST TRANSMISSION BUILD-OUTS

If DR was needed for a number of hours in these scenarios, why were lines not built during Phase 1? In Phase 1, the initial NEEM run for each future established the marginal prices between regions and the second run calculated "soft" lines between each region based on those prices and the relative power needs. NEEM added soft lines that varied in capacity for each block of each year studied. Because a "real" line had to be set at a constant size for all blocks and years, the SSC had to calculate a representative size to "harden" the lines between regions.

In the case of the southeastern regions, the soft lines added by NEEM were used for roughly 20% of the year, during the peak periods. As an example, Fig. 27 shows the flow duration curves for the PJM ROR to VACAR tie line in Phase 1 for several different study years. In Phase 1, members of the modeling working group of the SSC developed several complex methods that considered the capacity factors over multiple years to harden the lines. The results of the different methods are the data points on the baseline that represent existing capacity. The soft expansions in the Southeast were not used for a large enough fraction of the year to justify their construction as hardened lines in the Phase 1 modeling. Instead, it was more cost-effective to use DR or peaking plants for the time they would be needed. There could be additional factors such as hurdle rates between the regions or it could simply be due to the “peakiness” of loads in the south with higher summer demand.

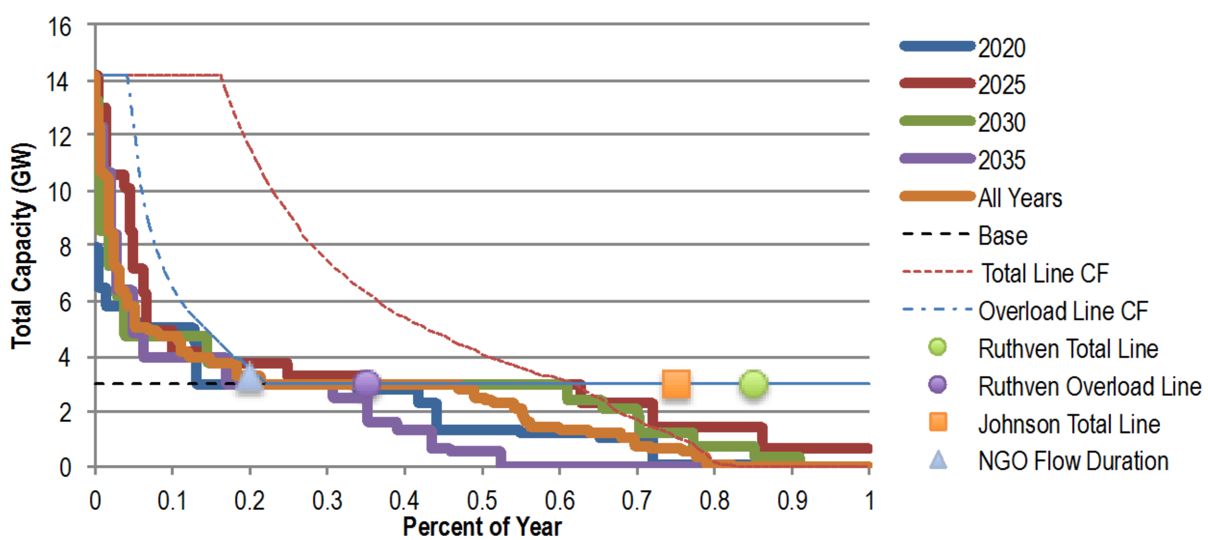

Fig. 27. Phase 1 CO_2+ flow duration curves for the “soft” tie line between PJM ROR and VACAR.

In Phase 2, the build-out of lines was based on the results from Phase 1 plus the addition of lines solely for reliability purposes during the hour studied. Also, in Phase 2 the interregional flows were based on actual transmission lines and flowgates, so tie line capacities could be different from Phase 1. Loop flows could also have limited the amount of net power transfer. As an example, Fig. 27 shows the Phase 1 flows with the existing capacity set at 3,000 MW, but in Phase 2 the maximum flow between PJM ROR and VACAR was 5,000 MW. Economics did not play a role in the build-out portion of the study. It was only in the last part when using GE MAPS that the full cost impact over the period was identified. In addition, there were one or two lines between SOCO and VACAR that should have been strengthened during the first part of Phase 2 but were missed by the planners.

4.6 CONCLUSIONS

The modeling efforts in this study provide only a rough approximation of the vital role DR can play in balancing supply and demand. The resource had to be modeled as a pseudo-generator with a price set high to model its limited availability. In Phase 1, because only a single price for all DR could be applied, it was set at roughly what the available models represented for the total potential supply. In Phase 2 a more complex supply curve with six price steps provided a more nuanced approach. Because DR was used in meeting the minimum planning reserve margin, some regions relied on it to meet their peak demand. In the CO_2+ scenario DR capacity was highest cost and those regions without access to surplus wind (most notably VACAR) used high levels of DR at consequent high prices. Some of this was due to the differences in the geographic, transmission, and time step detail in Phase 1 and Phase 2 modeling. At times, DR was called on because of transmission constraints that limited the ability to import power from other regions or elsewhere within a region.

5. TOPIC 9: "NO REGRETS" LINES

5.1 TRANSMISSION ELEMENTS COMMON TO MULTIPLE SCENARIOS

In Phase 2 a number of transmission components were included in the build-outs of each of the three scenarios to address reliability concerns. Because the scenarios capture significantly different outlooks for the future, there may be value in examining the components that show up in all three scenarios as they potentially represent elements that will be needed under a wide variety of future circumstances. If they were to be constructed, it would not be at the expense of other opportunities or more advantageous outcomes as it appears they will be needed regardless of what happens in the future.

An important consideration when examining the transmission elements that are common to all three scenarios is the development of the Stakeholder-Specified Infrastructure (SSI) in Phase 1. Before the MRN-NEEM runs, stakeholders identified new transmission and generation facilities that were to be included in the models. The SSI would eventually impact the transmission build-outs for all three scenarios as some of the elements common to all scenarios were added to fully integrate the SSI additions rather than strictly for reliability reasons.

Table 15 lists the number of transmission build-out elements that are common to all three scenarios by region and stated reason for inclusion. A large number of the NEISO elements resulted from the inclusion of a number of wind farms in the SSI. A number of lines and transformers were included to interconnect those facilities to the network.

Table 15. Elements in Common Across All Scenarios by Region

Region	Interconnect New Generation	Prevent Overloads	Prevent Low Voltage	Total
ENT		11		11
FRCC		3		3
MAPP CA		3		3
MISO IN		1		1
MISO MI		2		2
MISO W	1			1
MISO WUMS		1		1
NEISO	41	4	1	46
Non-RTO Midwest		1		1
NYISO		1		1
PJM ROM	2	2		4
PJM ROR		5		5
SOCO		3		3
VACAR	5	2		7
TOTAL	49	39	1	89

Of the 89 elements, 49 are new transmission lines, 14 are new transformers or autotransformers, 8 are new reactive support devices (reactors or static var controllers), and 18 are upgrades to existing facilities. A number of the new devices also require modifications to existing facilities (like adding bays to a substation), but they are classified as new here. In some instances, there were two separate circuits added between a pair of buses. Those are treated as separate lines for this purpose. (The appendix to this report is a list of the elements, including a description of the project and reason for its need.)

Most of the costs associated with the common elements are for connecting new generation, much of which is associated with the SSI. Table shows the midrange estimate of the overnight capital costs of the common elements by reason of inclusion and the total costs from the three scenarios [from Table ES-3 of the EIPC Phase 2 Report (EIPC 2012)].

Table 16. Overnight Capital Costs (billions of 2010 dollars)

Costs	Common	CO_2+	RPS/R	BAU
Interconnect New Generation	5.7	49.6	54.3	7.3
Prevent Overloads	2.8	48.4	13.0	7.9
Prevent Low Voltage	0.04	0.5	0.1	0.2

Fig. 28 shows the locations of buses where the common transmission lines have a termination point or where common transformers or reactive support devices are located.

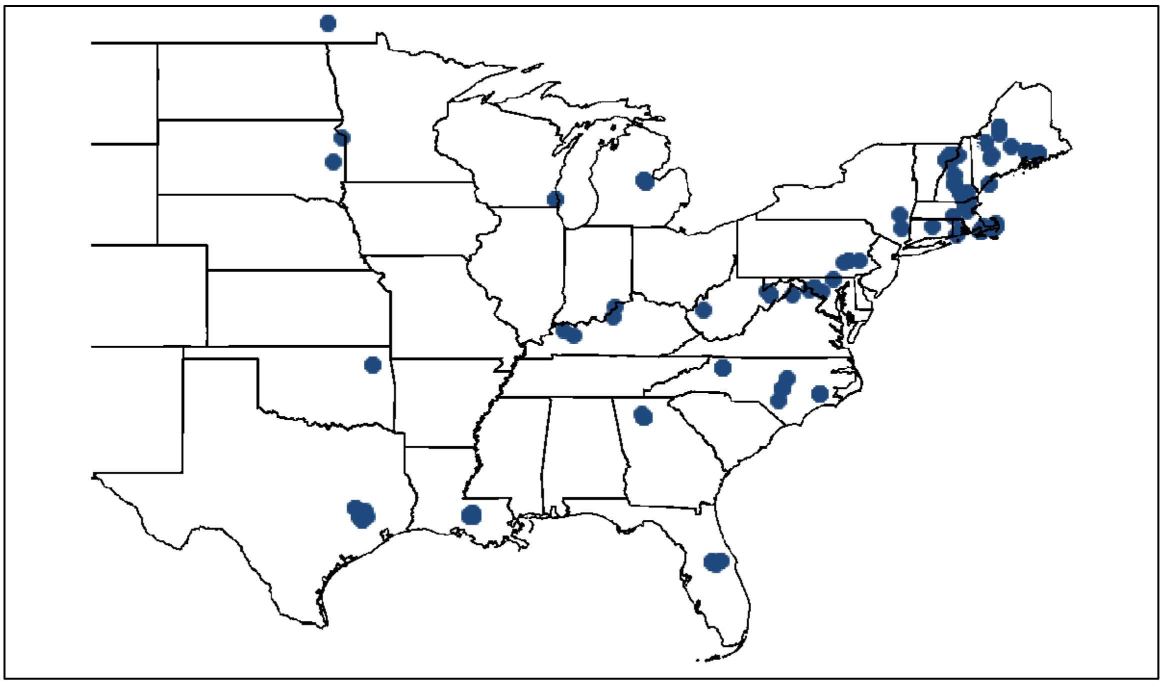

Fig. 28. Locations of buses with upgrades common to all three scenarios.

In some cases, elements were added or upgraded in each of the three scenarios, but the same thing is not done in each one. For instance, while one scenario may add an additional circuit to a transmission line, the others re-conductor the existing circuit. Alternatively, one scenario may include an element with a higher rating. While the stated reason is generally the same across all scenarios, this is not always the case. The scenario that used the least cost method is used for the reason in Table 17.

Table 17. Elements in Common with Different Methods by Region

Region	Interconnect New Generation	Prevent Overloads	Prevent Low Voltage	Total
ENT		1		1
FRCC		2		2
MAPP CA		5		5
MISO MI		2		2
MISO MO-IL			1	1
NEISO	1			1
PJM E	1			1
PJM ROM	3			3
PJM ROR	1			1
SPP S		7		7
VACAR	1	1		2
TOTAL	7	18	1	26

There are also a number of instances where an element shows up in two of the three scenarios. Of the total, 176 elements are common to the CO_2+ and RPS/R scenarios but not the BAU scenario. Many of these are in SPP and MISO as part of the wind collector systems. There are 50 pairs of buses that have entries in common with the CO_2+ and BAU scenarios but not the RPS/R scenario. There are 46 pairs of buses that have entries in common to RPS/R and BAU but not CO_2+.

5.2 CONCLUSIONS

There are 89 transmission elements that are common to all three scenarios. In another 26 instances something was done at a bus (or between a pair of buses) under each scenario, but the same thing was not done in all three. In many cases, the elements were included to support new generation that was included by the SSC in the early stages of the Phase 1 process. Those elements would only be "no regrets" if the associated new generation is actually constructed.

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- Phase 1 Modeling Results
- http://www.eipconline.com/Modeling_Results.html

- Phase II Modeling Inputs
- http://www.eipconline.com/Modeling_Inputs.html

- Phase II Modeling Results
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APPENDIX: LINES AND TRANSFORMERS COMMON TO ALL SCENARIOS

Region	Name	Reason/Need	Description
NEISO	CT LAKES - SEA STRATTON115 kV TL	Interconnect New Generation	Include new transmission line and 1 new 115 kV susbstation
NEISO	PITTSTON ME - PITTSTN CLR1 115 kV TL	Interconnect New Generation	Include new transmission line and 2 new 115 kV susbstation
NEISO	Pittston ME 115/345 kV XFMR	Interconnect New Generation	1 new 345/115 kV XFMR
NEISO	PITTSTON ME - HARRIS HYDRO 115 kV TL	Interconnect New Generation	Include new transmission line
NEISO	MARTHAS VYND - FALMOUTH TAP 115 kV TL	Interconnect New Generation	Include new transmission line and 1 new 115 kV susbstation
NEISO	Ashland ME 115/345 kV XFMR	Interconnect New Generation	1 new 345/115 kV XFMR
NEISO	Canal 115/345 kV XFMR	Interconnect New Generation	1 new 345/115 kV XFMR
NEISO	CANAL - HATCHVILLE 115 kV TL	Interconnect New Generation	Include new transmission line and 1 new 115 kV susbstation
NEISO	SEA STRATTON - PITTSTON ME 345 kV TL	Interconnect New Generation	Includes new transmission line and 2 new 345 kV substations
NEISO	SEA STRATTON - ORRINGTON 345 kV TL	Interconnect New Generation	Includes new transmission line
NEISO	Sea Stratton 345/115 kV XFMR	Interconnect New Generation	1 new 345/115 kV XFMR
NEISO	Sea Stratton 345 kV - 50 Mvar Reactor	Interconnect New Generation	Includes new reactor
NEISO	DRACTU MA - ORRINGTON 345 kV TL	Interconnect New Generation	Includes new transmission line
NEISO	DRACTU MA - MILLBURY 345 kV TL	Interconnect New Generation	Includes new transmission line
NEISO	PITTSTON ME - ASHLAND ME 345 kV TL	Interconnect New Generation	Includes new transmission line and 1 new 345 kV substation
NEISO	Pittston ME 345 kV - 30 Mvar Reactor	Interconnect New Generation	Includes new reactor
NEISO	WHITTING ME - HARRINGTON 345 kV TL	Interconnect New Generation	Includes new transmission line, 1 new 345 kV substation and 1 new 345/115 kV XFMR
NEISO	WHITTING ME -ORRINGTON 345 kV TL	Interconnect New Generation	Includes new transmission line, 1 new 345 kV substation and 1 new 345/115 kV XFMR
NEISO	Whiting ME 345 kV - 60 Mvar Reactor	Interconnect New Generation	Includes new reactor
NEISO	HARRINGTON - TRENTON 345 kV TL	Interconnect New Generation	Includes new transmission line, 1 new 345 kV substation and 1 new 345/115 kV XFMR
NEISO	Harrington 345 kV - 40 Mvar Reactor	Interconnect New Generation	Includes new reactor
NEISO	TRENTON - ORRINGTON 345 kV TL	Interconnect New Generation	Includes new transmission line
NEISO	Trenton 345 kV - 40 Mvar Reactor	Interconnect New Generation	Includes new reactor
NEISO	BARNSTABLE - LONG TRM LSM 345 kV TL	Interconnect New Generation	Includes new transmission line, 1 new 345 kV substation and 1 new 345/115 kV XFMR
NEISO	Barnstable 345 kV - 150 Mvar SVC	Interconnect New Generation	Includes new static var controller (SVC)
NEISO	ASHLAND ME - ORRINGTON 345 kV TL	Interconnect New Generation	Includes new transmission line
NEISO	Ashland ME 345 kV - 20 Mvar Cap Bank	Interconnect New Generation	Includes new capacitor bank

Region	Name	Reason/Need	Description
NEISO	Whitefield - Littleton 230 kV TL	Interconnect New Generation	Includes new transmission line
NEISO	Lost Nation - Whitefield 230 kV TL	Interconnect New Generation	Includes new transmission line and 1 new 230 kV substations
NEISO	Paris - Lost Nation 230 kV TL	Interconnect New Generation	Includes new transmission line and 1 new 230 kV substations
NEISO	Pontook - Paris 230 kV TL	Interconnect New Generation	Includes new transmission line and 2 new 230 kV substations
NEISO	STURTEVANT - LIVERMORE FL 115 kV TL	Interconnect New Generation	Includes new transmission line
NEISO	Merrimack 230 kV - 150 Mvar SVC	Low Voltage	Includes new SVC
NEISO	Scobie - Tewksbury 345 kV TL	Loading >100% of System Emergency	Includes new transmission line
NEISO	BEEBE RIVER - WEBSTER 115 kV TL	Interconnect New Generation	Includes new transmission line
NEISO	WEBSTER - DEERFIELD 115 kV TL	Interconnect New Generation	Includes new transmission line
NEISO	Woburn - N. Cambridge 345 kV TL	Loading >100% of System Emergency	Includes new transmission line
NEISO	BARNSTABLE - HATCHVILLE 115 kV TL	Interconnect New Generation	Includes new transmission line
NEISO	BARNSTABLE - HARWICH MCGR 115 kV TL	Interconnect New Generation	Includes new transmission line
NEISO	FALMOUTH TAP - HATCHVILLE 115 kV TL	Interconnect New Generation	Includes new transmission line
NEISO	WELLFLEET - ORLEANS 115 kV TL	Interconnect New Generation	Includes new transmission line
NEISO	HARWICH MCGR - ORLEANS 115 Kv TL	Interconnect New Generation	Includes new transmission line
NEISO	MILLBURY - MANCHESTER 345 kV TL	Interconnect New Generation	Includes new transmission line
NEISO	Tewksbury - Woburn 345 kV TL	Loading >100% of System Emergency	Includes new transmission line
NEISO	Ward Hill - Wakefield JCT 345 kV TL	Loading >100% of System Emergency	Includes new transmission line
NEISO	KENYON - KENT COUNTY 115 kV TL	Interconnect New Generation	Includes new transmission line
NYISO__A-F	Leeds - Pleasant Valley 345 kV	Loading >100% of System Emergency	New 345 kV line
PJM_ROM	Brighton - Kemptown 500kV TL (PATH)	Loading >100% of System Emergency	Upgrade oper temp facil/reconductor 500 KV line
PJM_ROM	Conastone - Kemptown 500kV TL (PATH)	Loading >100% of System Emergency	Upgrade oper temp facil/reconductor 500 KV line
PJM_ROM	North Temple - North Kill 230kV TL (terminal equip. uprate)	Interconnect New Generation	Upgrade 230 KV sub/upgrade 230 KV sub
PJM_ROM	North Temple - Hosensack 230kV TL (terminal equip. uprate)	Interconnect New Generation	Upgrade 230 KV sub/upgrade 230 KV sub
PJM_ROR	Doubs - Kemptown 500kV TL (PATH)	Loading >100% of System Emergency	Upgrade oper temp facil/reconductor 500 KV line
PJM_ROR	Meadow Brook - Welton Springs 500kV TL (PATH)	Loading >100% of System Emergency	Upgrade oper temp facil/reconductor 500 KV line
PJM_ROR	Welton Springs - Kemptown 765kV TL (PATH)	Loading >100% of System Emergency	New 765 KV line/new 765 KV line
PJM_ROR	Welton Springs - John Amos 765kV TL (PATH)	Loading >100% of System Emergency	New 765 KV line/new 765 KV line

Region	Name	Reason/Need	Description
PJM_ROR	Welton Springs - Mt Storm 500kV TL (PATH)	Loading >100% of System Emergency	Upgrade oper temp facil/reconductor 500 KV line
MISO_MI	MCV - Tittabawasee 345 Ckt 1 Reconductor	Loading >100% of System Emergency	Reconductored Transmission Line + 2 Upgraded Bays
MISO_MI	MCV - Tittabawasee 345 Ckt 2 Reconductor	Loading >100% of System Emergency	Reconductored Transmission Line + 2 Upgraded Bays
ENT	New Sportman 345/161 kV third auto	Loading >100% of System Emergency	Add 345 kV Auto
VACAR	Wake-Wommack 500kV TL	Interconnect New Generation	Includes new transmission line, 1 new 500 kV substation
VACAR	Cumberland-Wommack 500kV TL	Interconnect New Generation	Includes new transmission line, 1 new 500 kV substation
VACAR	New Bern 500/230kV XFMR	Interconnect New Generation	New transformer
VACAR	New Bern 500/230kV XFMR	Interconnect New Generation	New transformer
VACAR	New Bern-Wommack 500kV TL	Interconnect New Generation	Includes New Transmission Line
VACAR	Antioch 500/230 kV XFMR	Loading >100% of System Emergency	New transformer
VACAR	Antioch 500/230 kV XFMR	Loading >100% of System Emergency	New transformer
NonRTO_Midwest	Upgrade Trimble Co to Middletown 345 kV	Loading >100% of System Emergency	Upgard Operating Temperature
ENT	New Lewis Creek to West Conroe SS 230 kV	Loading >100% of System Emergency	Construct new 230 kV Line and 230 kV substation at W. Conroe and terminal at Lewis Creek
ENT	New 230/138/13/8 kV three winding transformer at Conroe SS	Loading >100% of System Emergency	Add 230 kV Auto
ENT	New West Conroe SS to Grimes 230 kV	Loading >100% of System Emergency	Construct new 230 kV Line and 230 kV substation at Grimes
ENT	Upgrade West Conroe SS to Conroe 138 kV	Loading >100% of System Emergency	Upgrade 138 kV line
ENT	New 345/230 kV auto at Grimes	Loading >100% of System Emergency	Add 345 kV Auto
ENT	New Addis to Tiger 230 kV Ckt 2	Loading >100% of System Emergency	Construct new 230 kV line and add terminals at Addis and Tiger
ENT	Construct second Dowmeter to Air Liquide Tap 230 kV	Loading >100% of System Emergency	Construct new 230 kV line and add terminals at Dowmeter
ENT	Upgrade Air Liquide Tap to Chenango 230 kV	Loading >100% of System Emergency	Upgrade 230 kV line
ENT	Upgrade Chenango to Iberville 230 kV line	Loading >100% of System Emergency	Upgrade 230 kV line
ENT	Upgrade Iberville to Evergreen 230 kV line	Loading >100% of System Emergency	Upgrade 230 kV line
MISO_IN	7WILSON 345 - 7REID 345 Reconductor	Loading >100% of System Emergency	Reconductored Transmission Line + 2 Upgraded Bays
SOCO	McGrau Ford - Hopewell 230kV TL	Loading >100% of System Emergency	230kV Transmission Line, 230kV Bay @ McGrau Ford & Hopewell
SOCO	Hopewell 230kV/115kV TL	Loading >100% of System Emergency	230kV/115kV XFMR
SOCO	Hopewell - Milton 230kV TL	Loading >100% of System Emergency	230kV Transmission Line
FRCC	Re-conductor CURRY FD 230.00 to STANTONW 230.00	Loading >100% of System Normal	Replace conductors
FRCC	Re-conductor SO WOOD 230.00 to C CENTER 230.00	Loading >100% of System Normal	Replace conductors

Region	Name	Reason/Need	Description
FRCC	Re-conductor TAFT 230.00 to C CENTER 230.00	Loading >100% of System Normal	Replace conductors
MISO_W	Brookings County - Big Stone 345	Interconnect New Generation	New Transmission Line + 2 Bays
MAPP_CA	MYSLKRD-DUNLOP 230 kV TL	Loading >100% of System Emergency	Line, 2 230 kVbays,
MAPP_CA	DUNLOP-PONTON 230 kV TL	Loading >100% of System Emergency	Line, 2 230 kVbays,
MAPP_CA	RIEL 500/230 kV XFMR	Loading >100% of System Emergency	One 500kV transformer, one 500kV bay
MISO_WUMS	Oak Creek-Elm Rd 230-345kV T884 XFMR Replacement	Loading >100% of System Emergency	Includes 1 new 345kV/230kV XFMR