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Additional EIPC Study Analysis: Interim Report on High Priority Topics

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Prepared by
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Additional EIPC Study Analysis: Interim Report on High Priority Topics

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November 2013

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ABBREVIATIONS

AEO	Annual Energy Outlook report by EIA
BAU	Business as Usual
CC	Combined Cycle
CO_2+	Scenario with CO_2 costs + aggressive EE/DR/DG + National RPS
CRA	Charles Rivers Associates
CT	Combustion Turbines
DG	Distributed Generation
DOE	Department of Energy
DR	Demand Response
EE	Energy Efficiency
EI	Eastern Interconnection
EIA	Energy Information Administration
EIPC	Eastern Interconnection Planning Collaborative
EISPC	Eastern Interconnection States Planning Council
ENT	Entergy (Entergy, central Missouri, east TX)
FRCC	Florida Reliability Coordinating Council - Florida minus panhandle
GW	GigaWatt =1,000 MegaWatts or 10^6 kiloWatts
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
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 MT, ND, SD, MN, IA)
MAPS	Multi-Area Production Simulation software from General Electric
MISO_IN	Mid-continent Independent System Operator - Indiana
MISO_MI	Mid-continent Independent System Operator - Michigan
MISO_MO-IL	Mid-continent Independent System Operator - Missouri-Illinois (eastern MO, much of IL)
MISO_W	Mid-continent Independent System Operator - West (parts of MT, ND, SD, MN, IA, MN, WI)
MISO_WUMS	Mid-continent Independent System Operator -Wisconsin-Upper Michigan
MRN-NEEM	Multi-Region National-North American Electricity and Environment Model
NE	Nebraska
NEEM	North American Electricity and Environment Model

NEISO	New England Independent System Operator
Non-RTO_Midwest	Non-Regional Transmission Operator Midwest (most KY, some OH 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
O&M	Operations and Maintenance
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 (NJ, DE, east MD)
PJM_ROM	PJM Rest of Mid-Atlantic Area Council (east PA, DC, east MD)
PJM_ROR	PJM Rest of Regional Transmission Operator (north IL, OH, west PA, west MD, WV, VA, east NC)
PS	Pumped Storage
PSS®E	Power System Simulator for Engineering from Siemens (formerly PSS/E)
RPS	Renewable Portfolio Standard
RPS/R	National Renewable Portfolio Standard/Implemented Regionally
RTO	Regional Transmission Operator
SOCO	Southern Company (GA, AL, east MS, west FL)
SPP_N	Southwest Power Pool - North (Kansas, western Missouri)
SPP_S	Southwest Power Pool South (Oklahoma, north TX, east NM, west AR, west LA)
SSC	Stakeholder Steering Commttee
TVA	Tennessee Valley Authority (TN, north MS, north AL, south KY)
TWh	TeraWatthour = 1,000 GigaWatthours = 10^6 MegaWatthours = 10^9 kiloWatthours
VACAR	Virginia-Carolina Sub-region - South Carolina, west 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. Phase 1 involved a long-term capacity expansion analysis that involved creation of eight major futures plus 72 sensitivities. Three scenarios were selected for more extensive transmission-focused evaluation in Phase 2. Five power flow analyses, nine production cost model runs (including six sensitivities), and three capital cost estimations were developed during this second phase.

The results from Phase 1 and 2 provided a wealth of data that could be examined further to address energy-related questions. A list of 13 topics was developed for further analysis; this paper discusses the first five.

TOPIC 1: HOW DO PHASE 2 RESULTS COMPARE TO PHASE 1?

Since Phase 2 was a more detailed look at the EI, it captured more of the complexities that a real system faces and operated the system under a broader set of circumstances (variable generation and demands). As a consequence, it required additional capacity (for reliability) and costs were higher, especially in the CO_2+ Scenario in reaction to the curtailed or unavailable resources. This can serve as a warning to any modeling done: accuracy is limited by the model and data used.

Capacity amounts for the total EI differed between 4% and 6% between the two phases depending on the scenario, with only Entergy, MISO_W, NEISO, PJM_E and IESO showing Phase 2 increases greater than 10%, while MISO_WUMS had a large decrease in peaking capacity in the RPS/R Scenario. Since the Phase 2 capacities were input based on results from Phase 1 (plus possibly modifications for reliability purposes), there should not have been great differences. Some of the regional differences were due to manually improved placement of combustion turbines (CTs) across the territories during Phase 2.

Generation amounts differed only slightly for the EI as a whole. There was greater regional variation because of differences in transmission modeling, hourly supply and demand variations, and reliability constraints for reserves. Several of the regions in the western EI had much lower Phase 2 generation (MAPP_US, MISO_W, MISO_MO-IL, MISO_IN, NE, SPP_N) in the CO2+ Scenario. This was likely due to the excess wind that had to be curtailed in many hours in those regions.

Inter-regional transmission was quite different between some of the regions, especially in the CO2+ Scenario. The hourly modeling in Phase 2 (and the greater variation in wind generation) meant greater opportunities for transfers. In addition, there was a more explicit and accurate build-out and modeling of power flow in Phase 2 than Phase 1. Phase 1 power flows were based on a simpler "bubble and pipe" model rather than true transmission system modeling. The inter-regional maximum and average flows in Phase 2 were most different for the windy regions (MISO_W, NE, SPP_N, and SPP_S).

Total costs in Phase 2 for all of the EI were 16% higher than Phase 1 in the CO2+ Scenario but only 4% and 1% in the other two scenarios. Cost differences can arise from differences in generation. However, generation differences would largely only affect the variable costs. Levelized capital costs varied both by the amount of capacity added, the cost applied to capacity, and the levelizing process. Phase 2 had more precise (and generally higher) capital costs as the different EIPC members developed costs based on known projects; also, the phase had higher generating capacities. Generating plant capital costs heavily outweighed that of transmission. The difference in cost is most noticeable in the CO2+ Scenario in the high wind regions, MISO_W, SPP_N, and SPP_S where wind capacity was highest (Figure ES-1).

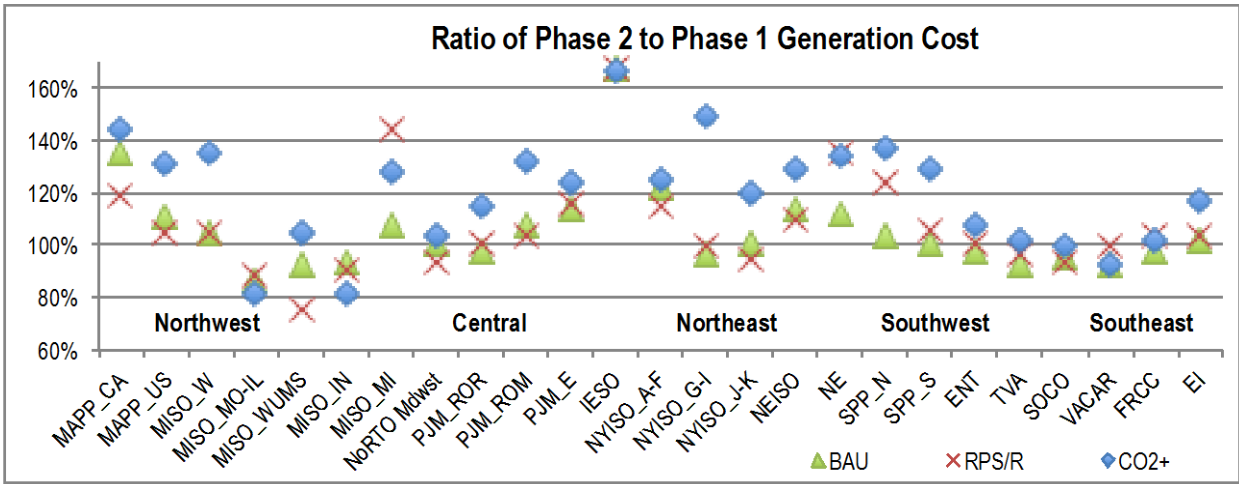
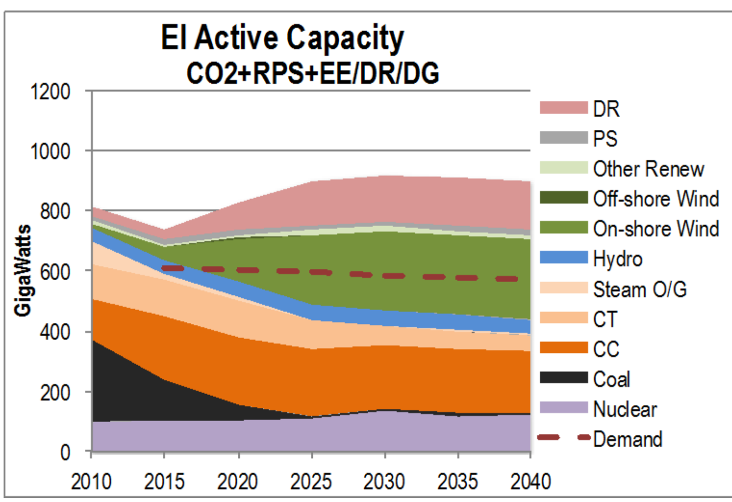


Figure ES- 1. Ratio of Phase 2 to Phase 1 costs in 2030 by region

TOPIC 2: WERE THERE SIGNIFICANT CHANGES IN EARLIER YEARS WITHIN VARIOUS REGIONS?

The most consistent change across the regions was the large increase in demand response expected by 2020 and 2025, especially in the CO2+ Scenario but also the other two scenarios. Most regions also had a large decrease in capacity between 2010 and 2015, most often that of fossil-fired steam plants.

The CO2+ Scenario had the largest change in all regions, as the carbon cost increased to high levels so carbon-based fuels declined (Figure ES-2). Coal generation was the first to decline, often replaced with combined cycle (CC) or wind initially. In the later years even CC plants decreased production in favor of nuclear or additional renewable generation. The western territories had a massive increase in wind capacity, with the Southwest having most growth by 2020 and the Northwest in 2025 and 2030. The Central territory largely increased their imports as internal coal capacity declined. Northeast demand declined over time so nuclear and imports made a larger share of supply. The Southeast relied more on combined cycle to supply production in the early years, with nuclear expanding to over 50% of demand in 2030.



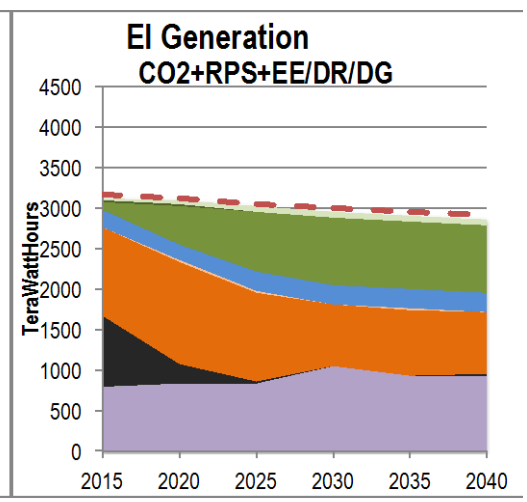


Figure ES- 2. CO2+ Scenario Phase 1 Capacity and Generation for the EI

In the RPS/R Scenario, most changes were more gradual. Wind and other renewables were added as the RPS requirement increased. As in the CO2+ Scenario, large wind increases occurred somewhat sooner in the Southwest than Northwest. Offshore wind and other renewables provided almost all new capacity in the Southeast. The BAU Scenario had very few large changes in capacity and generation over time in the various territories.

TOPIC 3: WHEN ALL COSTS ARE INTEGRATED, HOW DO RESULTS COMPARE BETWEEN SCENARIOS?

Cost evaluation included the annual fuel and operating costs, emissions costs, the levelized capital cost for generation and upgrades to transmission, and several other customer costs. The Phase 2 costs only evaluated 2030 rather than values over the full thirty-year period. Costs were highest for the EI in the CO2+ Scenario (Figure ES-3). Some of this higher cost represented CO_2 emissions costs that either are intangible costs (and so available for other purposes) or are costs that should be included in other scenarios for comparison. Regardless, costs were still high for the CO2+ Scenario and the RPS/R Scenario due to the large capital investment in new capacity. Fuel and other operating costs were much lower in the CO2+ Scenario though.

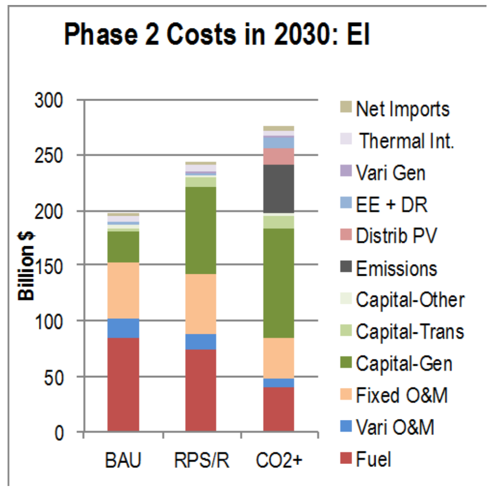


Figure ES- 3. Total Costs in 2030 for EI

The Northwest and Southwest territories had the highest relative capital cost in the CO2+ Scenario, but in the RPS/R Scenario new capacity shifted to the Central and Southeast territories so their highest costs were in the RPS/R Scenario.

On a cost per unit of demand basis, the Northwest and Southwest regions stand out as higher than the others in the CO2+ Scenario, even when adjusting to use the same demand levels in all scenarios. Reducing net costs to reflect the earnings by exporting power to other regions did not overcome the higher capital and operating costs due to new construction for these regions. The calculations assumed export sales at wholesale marginal costs; higher prices may be necessary to recover the capital investment.

Transmission cost represented only 10% of the overall capital cost, and less than 5% of total costs. It is likely that in those scenarios with high levels of curtailment and/or demand response, additional transmission capacity would provide opportunities for lower cost power to displace high cost power.

TOPIC 4: DO SOME REGIONS FACE OVER-RELIANCE ON CERTAIN FUELS OR TECHNOLOGIES?

Regions with a high reliance on a single fuel may be vulnerable to shortages. The CO2+ Scenario had the most regions with high levels of reliance on single technologies, with ten regions relying on a single source for over 2/3 of their generation. These regions were generally reliant on wind, hydro, or combined cycle, so may be vulnerable to intermittent shortages due to calm winds, long-term drought, low gas supply issues. Only six regions in the RPS/R and BAU Scenarios had high levels of reliance, with coal playing a role in most of them, which is less likely to be vulnerable to disruptions.

Figure ES-4 shows the shift in dominant sources for each region when going from the BAU to the RPS/R and CO_2+ scenarios. Note that coal dominance in BAU and RPS/R often switches to wind in the CO_2+ scenario. Nuclear is relatively dominant in a number of regions though rarely more than 50% of the total.

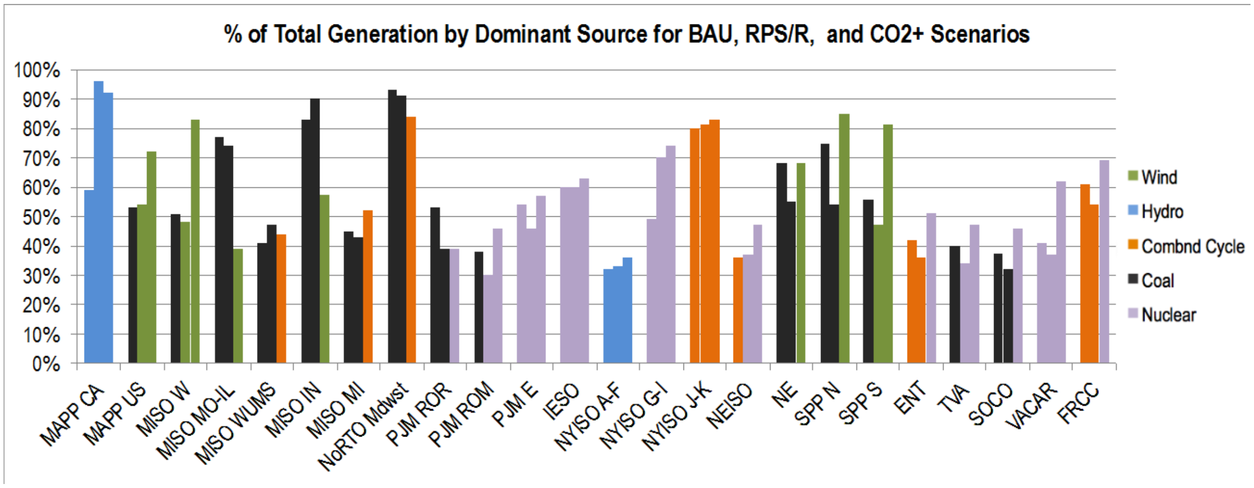


Figure ES- 4. Dominant Generation Source for each region and scenario

Using a different metric, we looked at the number of days one technology provided over 80% of generation for at least 20 of the 24 hours. In the CO2+ Scenario, six regions relied heavily on wind for multiple days (between 15 and 181 days), four relied on nuclear for between 4 and 47 days, two on combined cycle for 178 days (NYISO_J-K) and 243 days (Non-RTO Midwest), and MAPP_CA relied on hydro for 310 days. The RPS/R Scenario had coal dominate in four regions, most notably 339 days in MISO_IN and 360 days in Non-RTO Midwest. Nuclear, CC, hydro, and wind dominated some days in different regions. Coal increased in the number of regions and days in the BAU Scenario, with the most dominant being 360 days for Non-RTO Midwest. In all three scenarios, NYISO_J-K was dominated for internal generation by combined cycle, since this region has few other resources available.

TOPIC 5: ARE THERE SHORT-TERM OVER-RELIANCES ON NATURAL GAS USAGE IN SOME REGIONS?

The study used gas prices from DOE's Annual Energy Outlook (AEO) 2011 with a price of $6.58 by 2030. Since then, estimates of prices in 2030 have dropped 20% or more. A possible consequence is that the study did not capture the level of conversion to natural gas that is now expected by many in the industry. The exception might be that in the CO_2+ Scenario, even by 2015 total gas demand was 37% higher than in the BAU and RPS/R Scenarios, due to the relative cost impact of CO_2 emissions on coal versus gas generation.

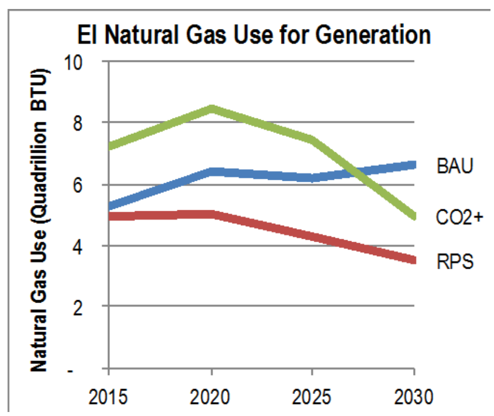


Figure ES- 5. Gas use for electricity

Some regions showed dominance by gas, most notably NYISO_J-K (and Non-RTO Midwest in the CO2+ Scenario). There did not appear to be a huge growth in gas demand between 2015 and 2030 for any region. Many regions saw declines between 2025 and 2030 in the CO2+ Scenario as CO_2 costs raised the cost of gas. When considering whether gas use in a region spiked during brief times, this appeared to hit the western regions most. This only occurred in Scenarios 2 and 3, and these regions were not heavy users of gas so it is unlikely they would face critical shortages.

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. At the same time, at the conclusion there were several questions or issues that were left unresolved. The Department of Energy sponsors asked Oak Ridge National Laboratory staffers 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 paper addresses the first set of topics identified, with later reports addressing the lower priority topics.

The Eastern Interconnection consists of most of the electricity grid east of the Rockies, as shown in Figure 1. The regions are interconnected by high voltage alternating current (HVAC) transmission lines so can transfer power readily between them. The differently colored regions within the EI represent organizations such as utilities, regional transmission operators, coordinating authorities, independent system operators, or other natural groupings based on the structure of the grid. In the EIPC study they are called NEEM regions based on the model used in Phase 1.

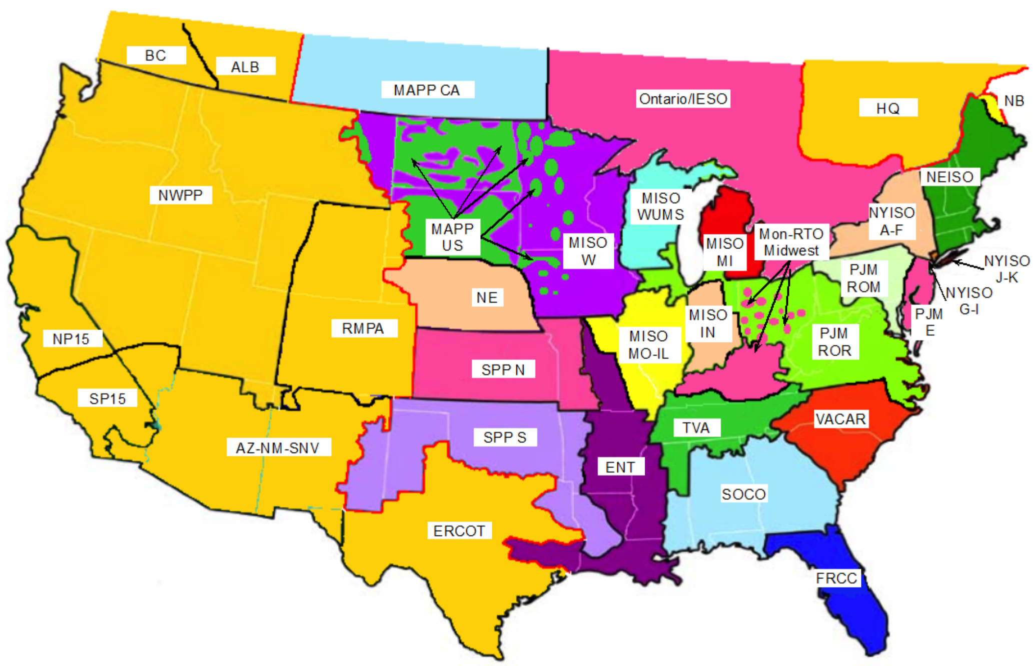


Figure 1. Map Of NEEM regions (EI includes all non-gold regions)

A more detailed description of each region in the EI is in Table 1. For this paper, we present the results at the level of the entire EI, the individual NEEM region, or as a collection of NEEM regions into a larger "territory". These territories collect the regions into five larger areas that have similar characteristics or transmission relationships.

Table 1. NEEM Regions and Territories in the EI

Region	Description	Territory
MAPP_CA	MAPP Canada (Manitoba-Saskatchewan)	Northwest
MAPP_US	MAPP US (non-MISO regions in MT, ND, SD, MN, IA)	Northwest
MISO_W	MISO West (parts of MT, ND, SD, MN, IA, MN, WI)	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 Michigan	Northwest
NonRTO_Midwest	Non-RTO Midwest (most KY, some OH public utilities)	Central
PJM_ROR	PJM Rest of RTO (north IL, OH, west PA, west MD, WV, VA, east NC)	Central
PJM_ROM	PJM Rest of MAAC (east PA, DC, east MD)	Central
PJM_E	PJM Eastern MAAC (NJ, DE, east MD)	Central
IESO	Ontario	Northeast
NYISO_A-F	New York Upstate	Northeast
NYISO_G-I	New York lower Hudson Valley	Northeast
NYISO_J-K	New York City-Long Island	Northeast
NEISO	New England ISO	Northeast
NE	Nebraska	Southwest
SPP_N	SPP North (Kansas, western Missouri)	Southwest
SPP_S	SPP South (Oklahoma, north TX, east NM, west AR, west LA)	Southwest
ENT	Entergy (Entergy, central Missouri, east TX)	Southwest
TVA	Tennessee Valley Authority (TN, north MS, north AL, south KY)	Southeast
SOCO	Southern Company (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). A few of the key characteristics of the Phase 1 modeling were:

- 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. 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 capacity generation capacity needed for each five-year point between 2010 and 2050, with only 2015-2040 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 Stakeholder Steering Committee. 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. 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. 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 below summarizes the different futures and sensitivities analyzed.

Table 2. Futures and main sensitivities studied in Phase 1

Sensitivities	Future 1: BAU	Future 2: CO2 Cost /National Implement	Future 3: CO2 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: CO2 + 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, explore effects of gas prices renewable costs, delayed environmental polices, among others. 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 in order to lower the level of CO_2 emissions to 20% of 2005 levels by 2050. The distinction between them was the amount of inter-regional 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). Since 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 ten sensitivities in this future and the final one, F6S10, was used for Phase 2. 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 the reader may see reference to the scenario F8S7.

Three scenarios were selected for more extensive transmission-focused evaluation in Phase 2. These three scenarios represent "bookends" of alternative futures in order to capture transmission needs under a broad array of hypothetical futures. The EI was modeled at a very detailed level (70,000 buses, 9,900 generators) in the 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 meeting reliability criteria in those hours. The resulting build outs of the transmission system in these scenarios were then used to model the EI in the GE MAPS model run by CRA. GE MAPS is a detailed economic dispatch and production cost model that simulates the operation for the electric power system, taking into account transmission topology. The GE MAPS model forecasted 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 as well as other costs not calculated in MAPS. Some of the key characteristics of the Phase 2 modeling phase were:

- The transmission build-out with PSS®E used an hour from Block 1 (peak summer) and Block 13 (mid-shoulder) hour, 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 8760 hours of 2030, incorporating CRA estimates of wind patterns for the different regions.
- Technologies to meet reserve requirements were more restrictive than in Phase 1, limiting it to coal, combined cycle, 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: higher gas prices, and higher demands.

The mixture of Futures, Sensitivities, and Scenarios with different nomenclature has caused some confusion during the process. While there were many cases and scenarios analyzed, the final results from the project discussed in this paper were focused on three main scenarios. Below is a list of the three with the names of the cases from the two different phases, the label used in this paper, and a brief description of the scenario.

- **Business As Usual**
  - Labeled **BAU**
  - Future 1 Sensitivity 17 (F1S17) in Phase 1
  - Scenario 3 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 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 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/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 to ask about possible additional analysis and what topics would be of most interest. A list of 13 possible study topics was developed and the group discussed the relative priority of the topics (Table 3). The order is arranged such that the earlier items contribute to the later items within the same priority.

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 Inter-relationships in the different regions?
	Medium Priority Topics
6	Regional operating and planning reserves
7	Wind Curtailment details
8	Demand Response analysis
9	"No Regrets" lines
	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

This interim report addresses on the high priority topics from the list. It begins with a section on the key insights derived from the analysis of the five high priority items. It then goes into more detail on each of the five in turn, with discussions of each region, territory, or phase as appropriate. Lastly, a set of graphs showing the capacity, generation, and cost results for the EI and each of the regions modeled is in Appendix A.

2. PHASE 1 VS PHASE 2 COMPARISON

The Phase 1 and Phase 2 analysis processes were described in the section above. The first question arose following the study whether the results from the two phases were so different to cause people to question the results. Was data between the two faithfully transferred? Are the differences in results explainable? How did differences in geography, time, and electrical system modeling influence the results? The sub-sections below compare the results between Phase 1 and Phase 2 for the power plant capacity, generation, inter-regional transmission, and costs.

2.1 CAPACITY

Figure 2 shows the total capacity in 2030 from Phase 2. The RPS/R Scenario has the largest overall capacity, largely because wind technologies were only credited at a fraction of their full capacity for purposes of determining reserve margins so more was needed to meet the minimum. While the CO2+ Scenario has more wind than the RPS/R Scenario, its overall demands were less so the total required was lower. In the CO2+ Scenario, demand response and wind are more significant fractions of capacity while peaking plants are reduced and coal is practically eliminated. The corresponding graphs for each region are included in Appendix A.

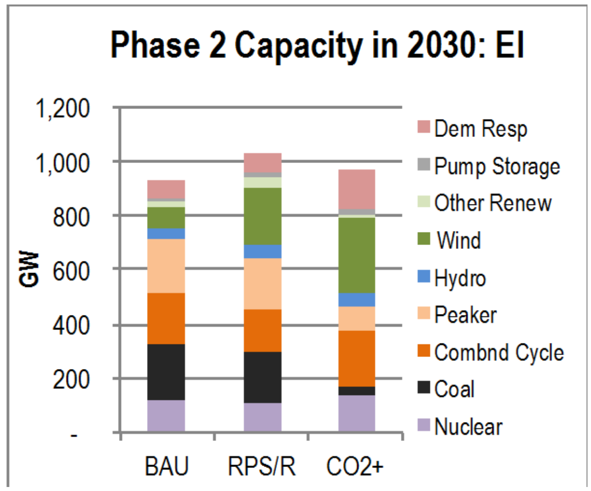


Figure 2. EI Capacity from Phase 2

While the total amount of generating capacity in most regions in Phase 1 and Phase 2 are close, more often the amounts are somewhat higher in Phase 2 than Phase 1. This is possibly due to a combination of higher capacities needed to meet ancillary services (reserves) requirements and incomplete deactivation of existing plants when transferring data from Phase 1 to Phase 2. Figure 3 shows the ratio of total capacity between the two phases. The ratio is greater than 100% for many regions, most notably for Entergy, MISO_W, PJM_E, and IESO. On the other hand, MISO_WUMS has ratio of only 62%, but just in the RPS/R Scenario. This occurs because in Phase 1, a large amount of CTs were added for MISO as a whole, but all were added in MISO_WUMS by NEEMS because capital costs were slightly lower there. The NEEM model did not use them for production so there was no impact on generation-related costs. In the final steps of Phase 1, these CTs were scattered across the territory more realistically in the CO_2+ and BAU scenarios, but not RPS/R (because a final sensitivity run was not needed for that case.) So a large share of the MISO variations in RPS/R is simply the movement of CTs from MISO_WUMS to the rest of MISO in Phase 2.

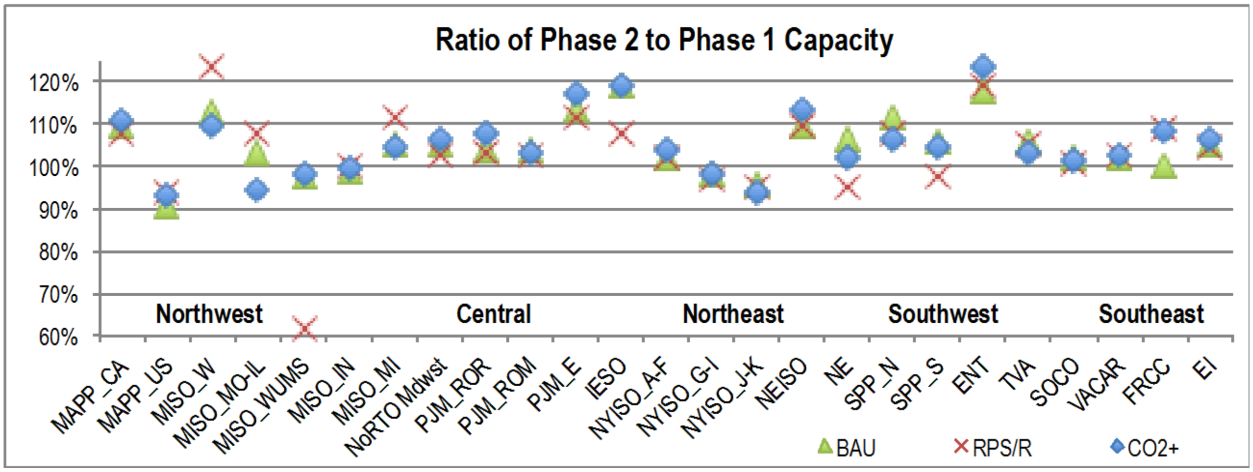


Figure 3. Ratio of Phase 2 to Phase 1 Capacity

The next set of graphs show the actual amounts of capacity in 2030 for each region by technology (Figure 4, Figure 5, and Figure 6). Some regions show slight differences in capacity between the two phases, mainly in coal, wind, and peaking plant technologies. Also on each column is a mark showing the level of peak demand for the region in 2030. Regions generally should have sufficient capacity to cover their peak demand plus a planning reserve of ~15%. Those with high wind capacity show a much larger capacity than demand, but this is because wind (and solar) contributions to reserves were only credited at 12% to 30% of their capacity. All regions have sufficient capacity to cover their demands except the downstate New York regions since they rely on firm imports for a portion of the capacity.

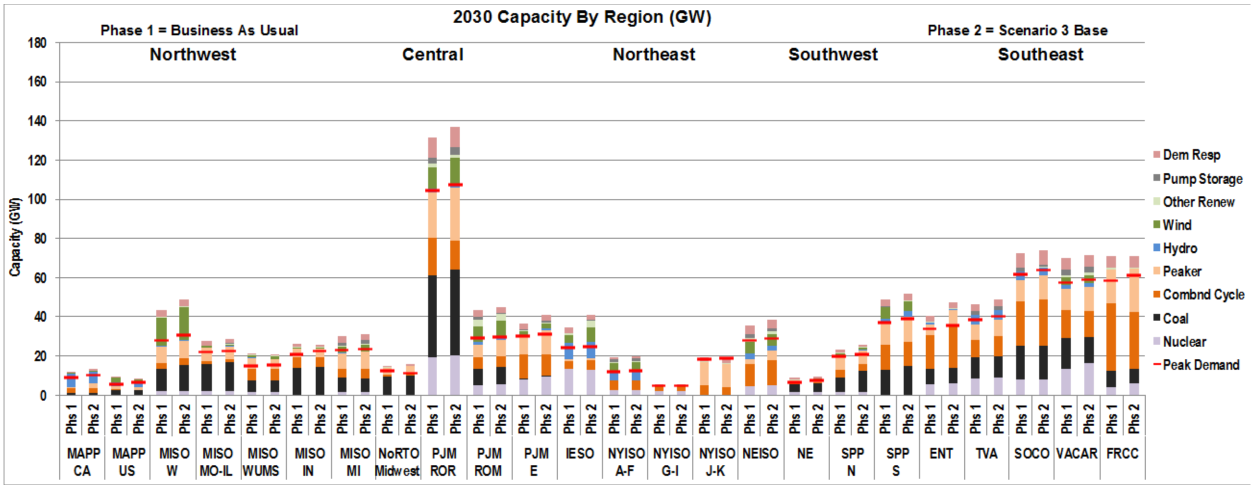


Figure 4. Capacity amounts by region in the BAU Scenario

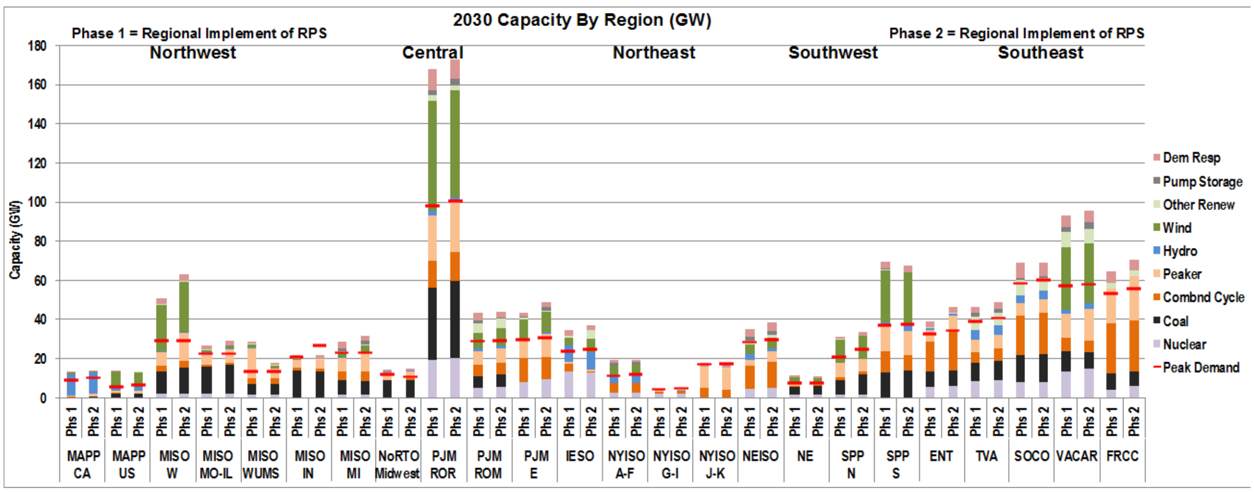


Figure 5. Capacity amounts by region in the RPS/R Scenario

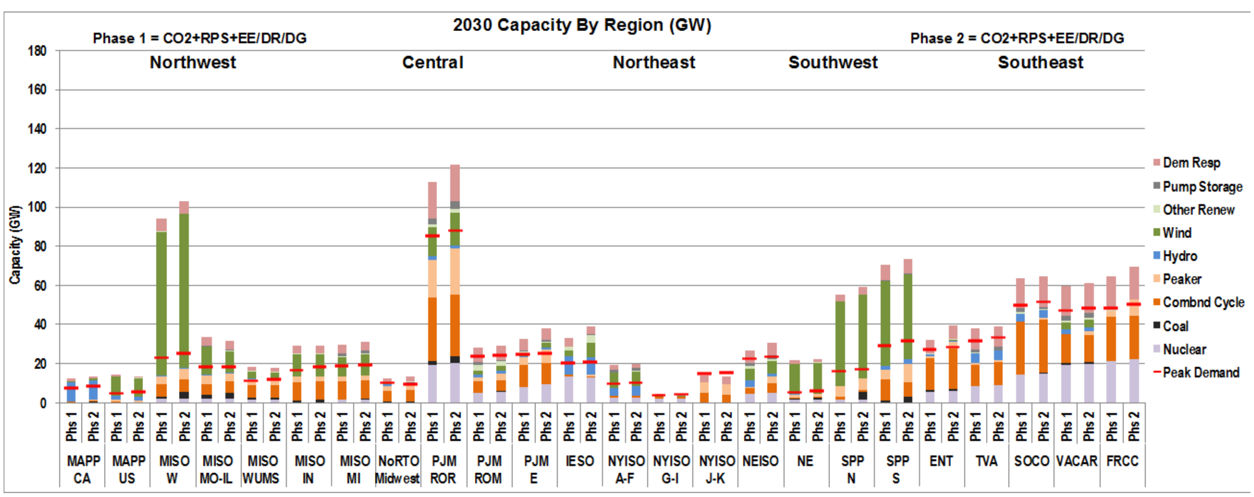


Figure 6. Capacity amounts by region in the CO2+ Scenario

2.2 GENERATION

Figure 7 to the right shows the total generation in 2030 from Phase 2. As expected, the BAU Scenario has the highest generation. The RPS/R Scenario did not explicitly have lower load growth, but had lower demand due to higher electricity prices in the MRN-NEEM model. In the CO2+ Scenario, demand was explicitly reduced to represent energy efficiency and distributed generation effects. Wind generation was highest in the CO2+ Scenario, while coal generation was almost eliminated. Combined cycle was used to provide flexible generation and reserves, while nuclear grew, largely in Florida. The corresponding graphs for each region and territory are included in Appendix A.

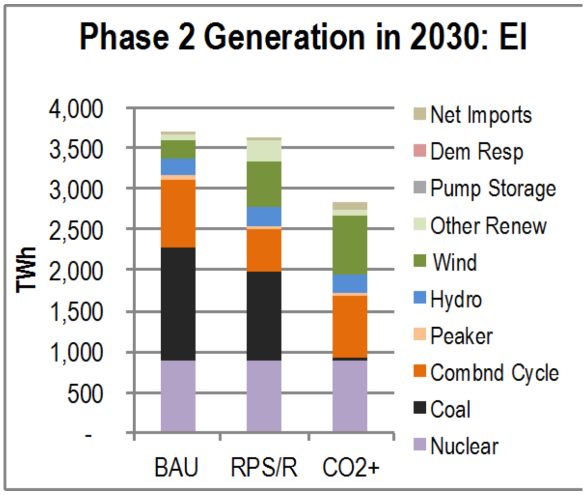


Figure 7. EI Generation from Phase 2

As with capacity, the generation amounts in Phase 1 and Phase 2 for most regions are very similar. This is shown in the graph below (Figure 8) as the ratio of generation in Phase 2 to Phase 1 for each region where 100% means they match exactly. If the values are similar this indicates that the models in the two phases dispatched the generation similarly and so the modeling in the two phases and the transfer of results between phases was generally accurate.

A number of regions (MAPP_US, MISO_MO-IL, MISO_IN, PJM_ROR) show lower generation in Phase 2, indicated by ratios below 100%, with countervailing increases in other regions (PJM_E, NYISO_J-K, NEISO). This is likely due to the improved modeling of the grid in Phase 2 with more detailed representation of flow and hourly variation versus the 20 power blocks used in Phase 1. With a more detailed representation, the physical limitations of electrical transmission (with flow following the path of least resistance so line flows are less controllable), greater fluctuations on wind generation, and local reserve requirements limited to specific technologies generally means less total transmission across regions. Note that the ratios are highest or lowest in the CO2+ Scenario, which involved the most inter-regional transmission.

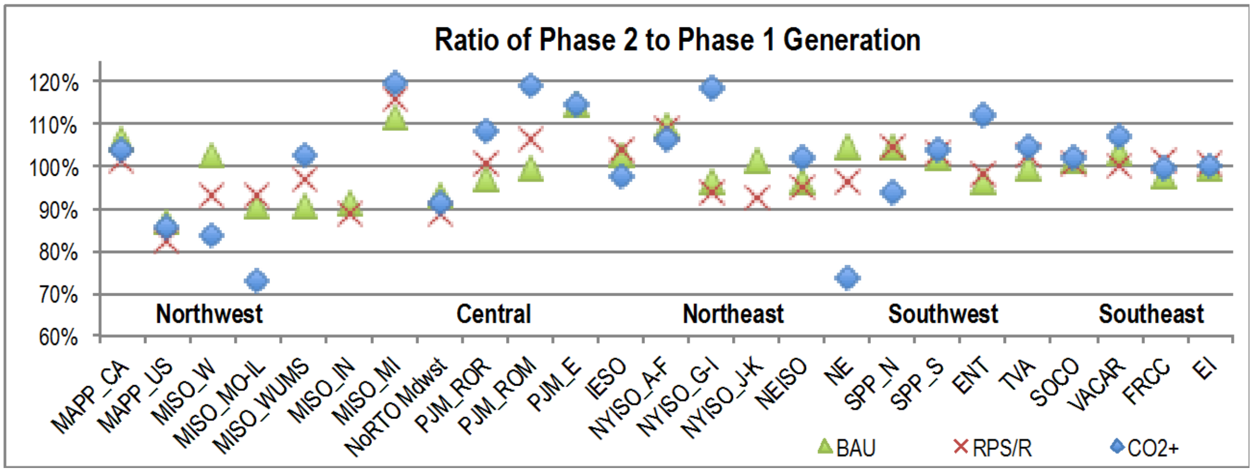


Figure 8. Ratio of Phase 2 to Phase 1 Regional Generation Amounts

Below are graphs showing the levels of generation for each region by technology in TWh (Figure 9, Figure 10, Figure 11). Also on each column is a mark showing the level of total demand for the region in

2030, including energy used for pumped storage. A few regions show some differences in generation between the two phases, most notably in coal, wind, and CC technologies.

In the CO2+ Scenario, a few regions are large exporters of electricity (notably MISO_W, Nebraska, SPP_N, SPP_S, and the Canadian regions) while most others import at least some of their energy needs. Several rely extensively on imports, such as Entergy, PJM, New York, and New England. (Imports from non-EI Canadian provinces are shown as a separate item in the columns.) Scenarios 2 and 3 have most of the regions relatively self-sufficient in power.

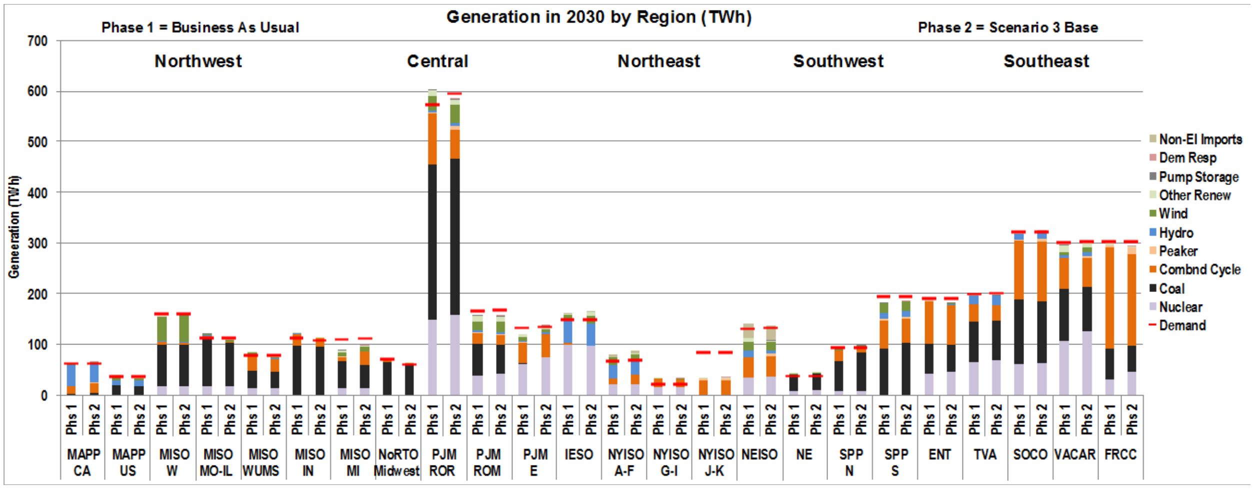


Figure 9. Generation amounts by region in the BAU Scenario

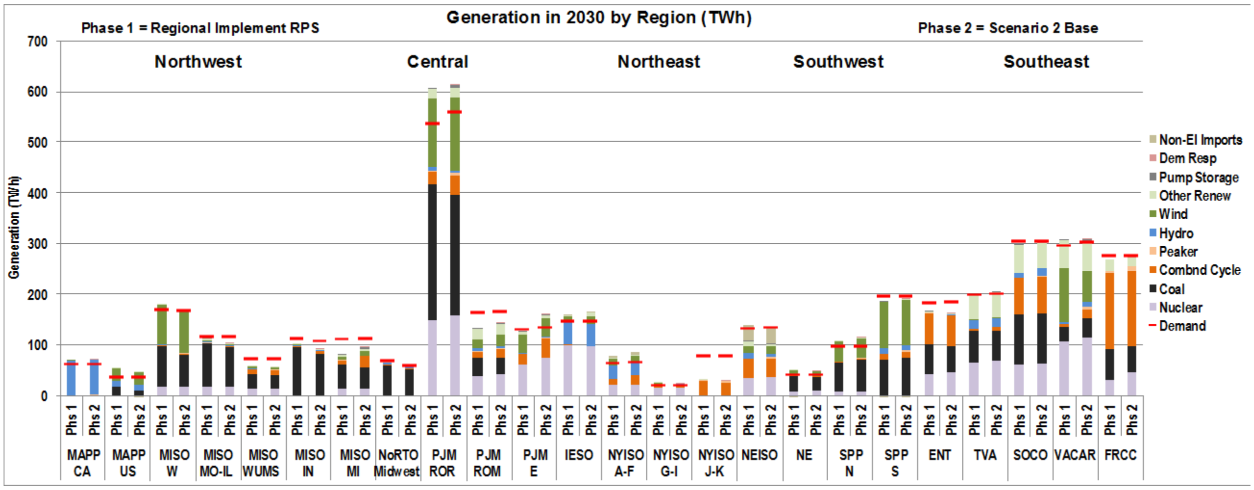


Figure 10. Generation amounts by region in the RPS/R Scenario

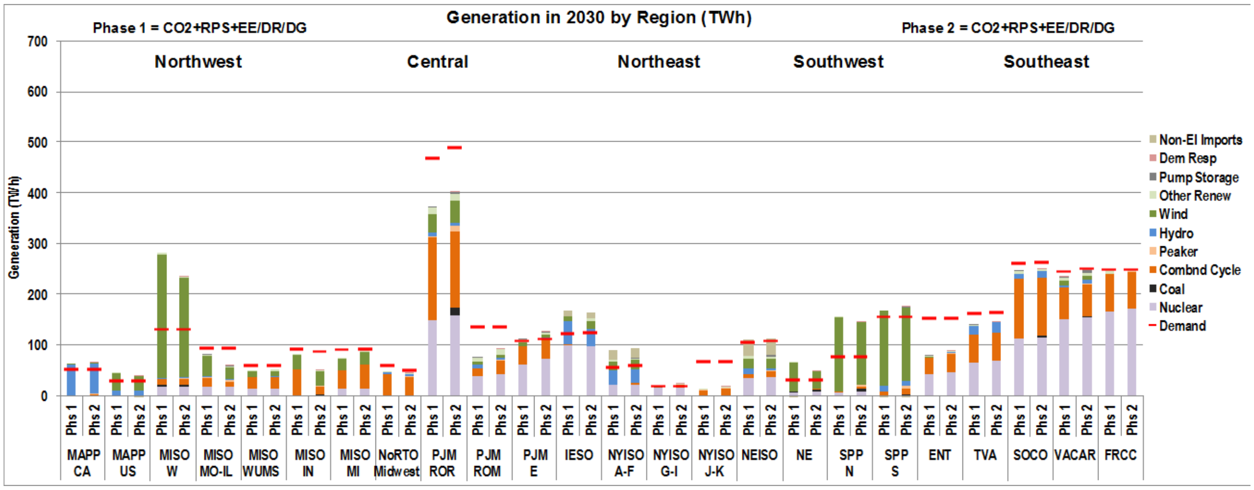


Figure 11. Generation amounts by region in the CO2+ Scenario

2.3 TRANSMISSION

Phase 1 and Phase 2 show significant differences in transmission between some of the key regions, largely because of refinements in the transmission system design in Phase 2. In Phase 1, transmission (or rather "transfer capacity") was modeled in a complicated process in order to let the NEEM model expand the capacity in connection with the relative cost difference between regions. First, the reference case was run with no expansion of transmission. Next, a "soft" future was run where the capacity was allowed to fluctuate based on the relative marginal generating costs between regions determined in the reference case. Lastly, the SSC examined the results over the 2025-2040 period and created a set of algorithms that "hardened" that capacity into available transfer capacity that applied in all years. In Phase 2, the EIPC began with the hardened transfer capacity calculated in Phase 1 as a target and set the generation and demand for each region based on the NEEM results from two points during 2030. They then added transmission lines in the PSS®E build-outs so that generation would supply the demand along with meeting key NERC reliability requirements.

Below are stylized maps of the NEEM regions and the peak amount of transmission between each region in Phase 1 and Phase 2. The peak amount is shown because tieline capacity (which is part of what transmission planning attempts to assess) is more directly related to the peak amount of transfer rather than the average amount. Usage of a transmission line will vary from hour to hour (or second to second in reality). Power transfer can reverse direction depending on the relative supply and demand for power in the different regions. Furthermore, the tielines shown here are rough approximations of actual transmission line flows. Electricity actually follows the "path of least resistance" and transfers between regions will travel over a number of lines and through multiple neighboring regions. Voltage levels, substation design, and other factors greatly complicate actual electricity flows over the wires.

The BAU Scenario had the least level of transfer (Figure 12 and Figure 13), since without an RPS or CO_2 cost, most regions used more of their internally generated fossil fuel power. There were no HVDC lines added in either Phase for this scenario. There was still some transfer due to variations in generation and cost between regions that facilitated exchange. Phase 2 showed relatively the same amounts of transfer as Phase 1; some regions had higher levels while others lower.

The RPS/R Scenario had increased peak amounts of transfer, and the peaks are higher for Phase 2 than for Phase 1 (Figure 14 and Figure 15). In this scenario, much of the transfer was from PJM_ROR to surrounding regions, rather than into the region as in the CO2+ Scenario. There were no HVDC lines added for this scenario. This is due to the regional implementation of RPS (resulting in little transmission to other regions) plus the lack of a CO_2 cost so that much of the coal capacity in the region remained active. The Phase 2 results have higher transfers because the hourly modeling with variations in wind and other generation gives opportunities for transfers that the Phase 1 NEEM model does not see.

For the CO2+ Scenario (Figure 16 and Figure 17), in Phase 1 the largest transfer is 19.8 GW from MISO_W to PJM_ ROR over the HVAC lines (blue), since there were no HVDC lines (red) included in the model. In Phase 2, PJM_ROR also received significant power from the two SPP regions (over HVDC lines) as well as from MISO_WUMS and MISO_MI. Significant flows go out from PJM_ROR in both phases, but in Phase 2 the flow returns back into MISO_IN instead of just to the east and south.

More detailed information on transmission amounts on each of the inter-regional tie-lines, including both peak and average flow amounts in the two phases for different scenarios, is available in Section 4.2.5 of the EIPC Phase 2 Report, Part 2 (EIPC 2012). The key result from that analysis was that in the CO2+ Scenario there was a total of 223 GW in peak power transfer in Phase 2 while the Phase 1 case only had 137 GW. The PSS®E analysis performed in Phase 2 increased the requirement for transmission capacity in the CO2+ Scenario beyond what Phase 1 specified in order to meet reliability constraints, and the MAPS model took advantage of the added capacity to the maximum extent possible.

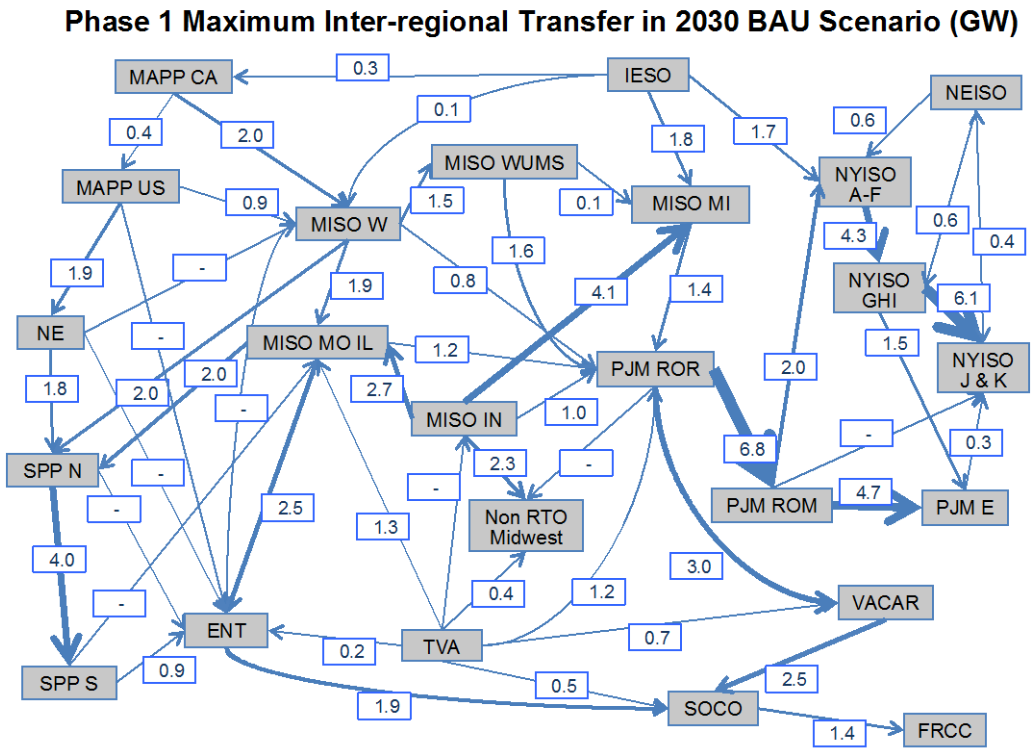


Figure 12. Phase 1 Peak Inter-regional Transfers in 2030 the BAU Scenario

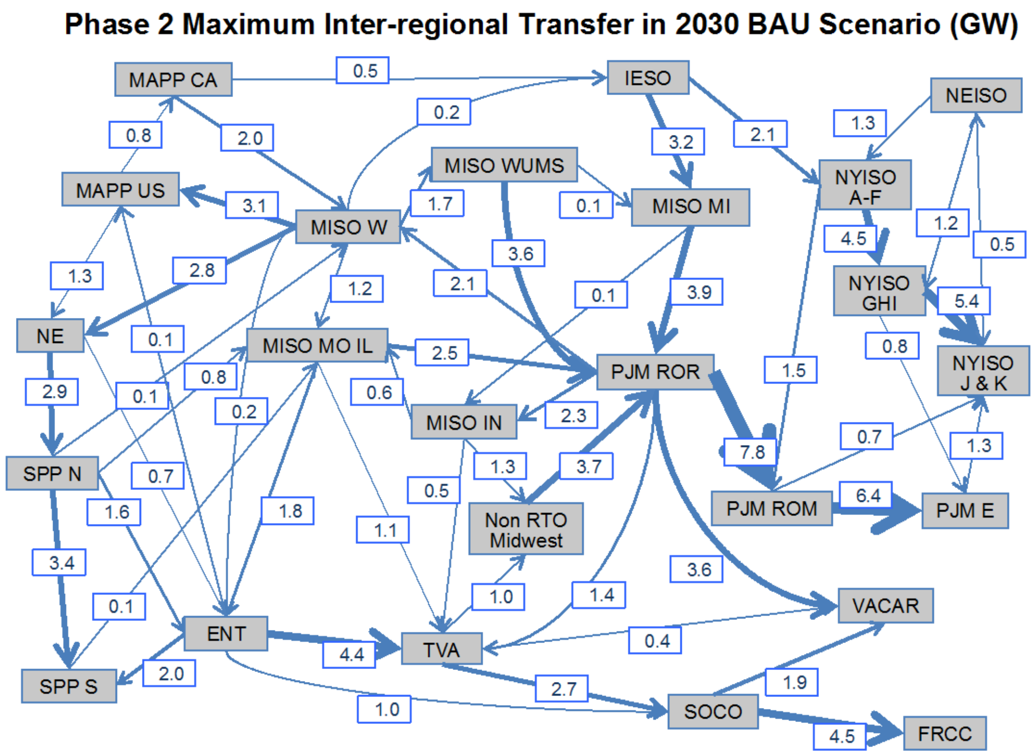


Figure 13. Phase 2 Peak Inter-regional Transfers in 2030 the BAU Scenario

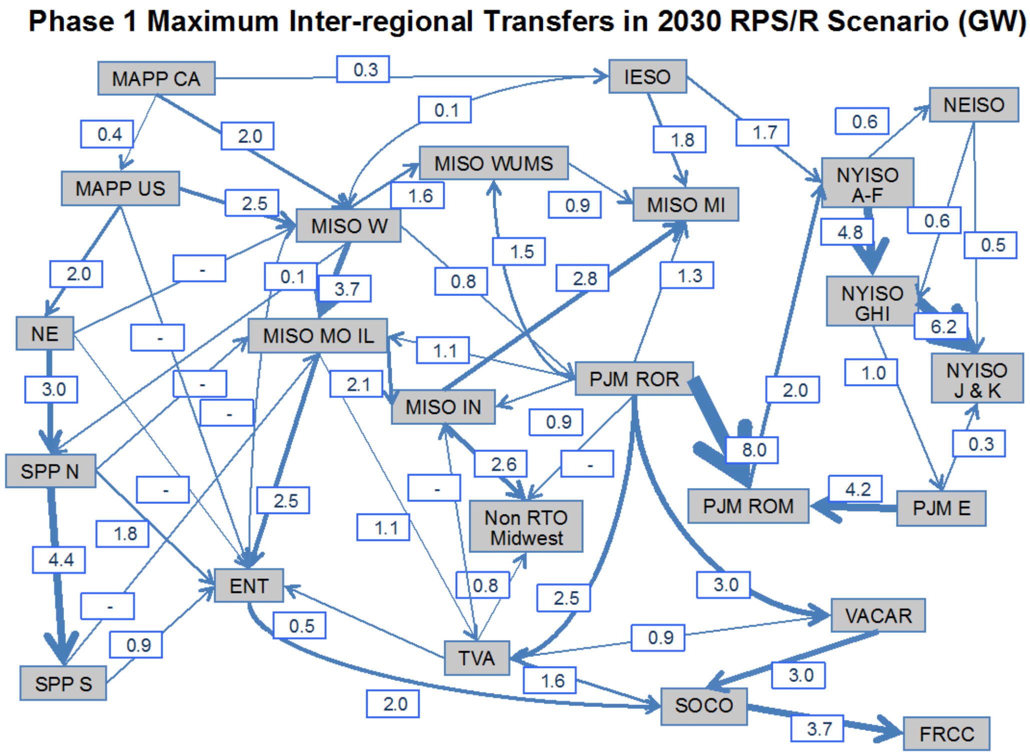


Figure 14. Phase 1 Peak Inter-regional Transfers in 2030 the RPS/R Scenario

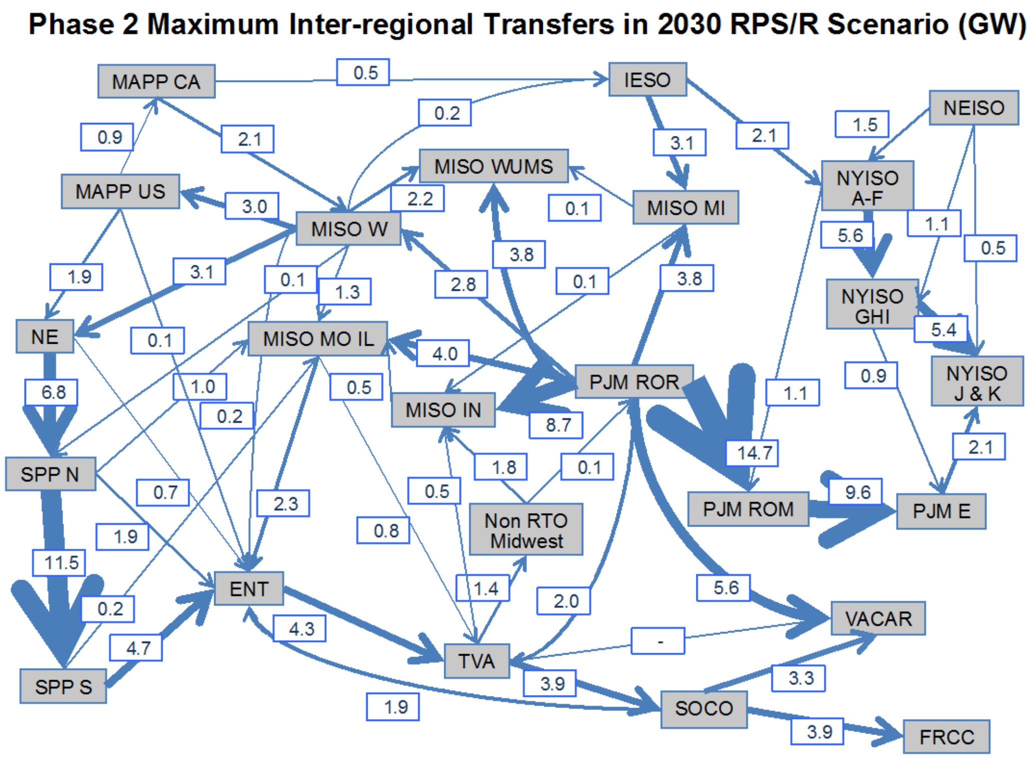


Figure 15. Phase 2 Peak Inter-regional Transfers in 2030 the RPS/R Scenario

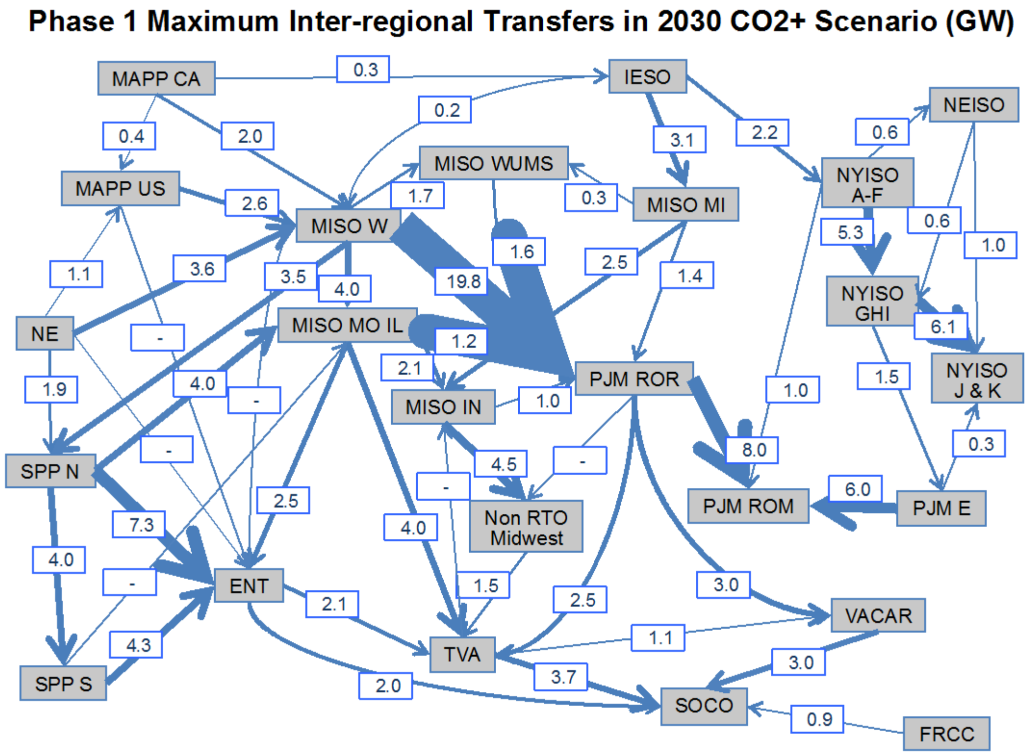


Figure 16. Phase 1 Peak Inter-regional Transfers in 2030 in the CO2+ Scenario

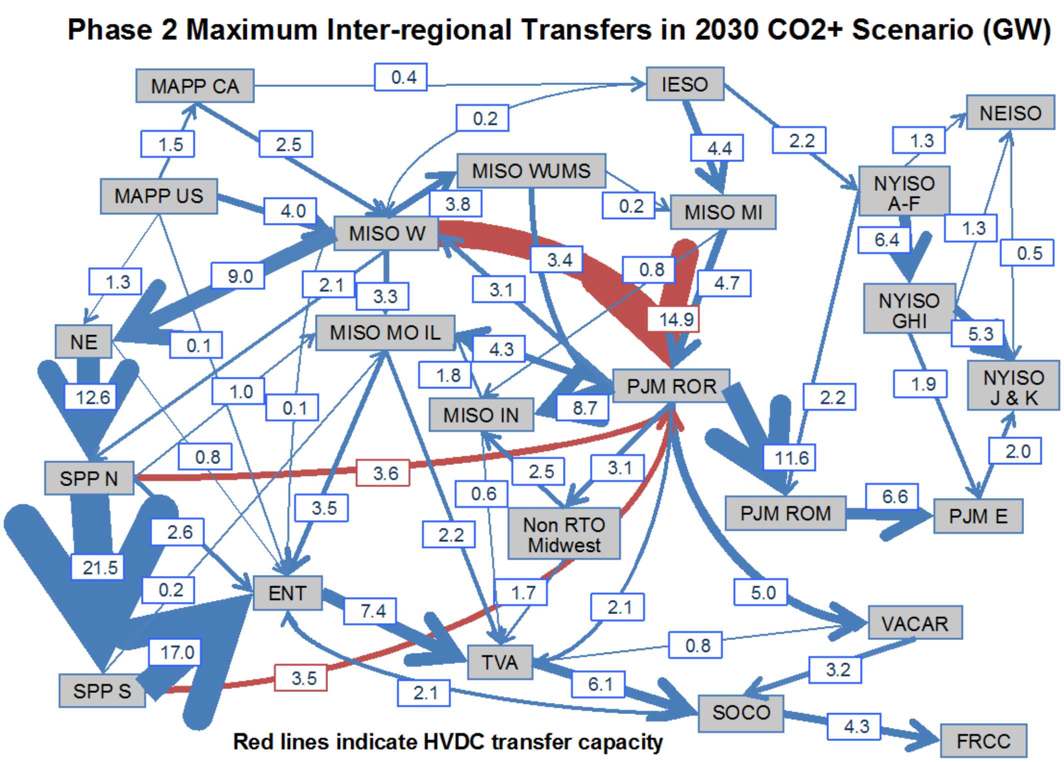


Figure 17. Phase 2 Peak Inter-regional Transfers in 2030 in the CO2+ Scenario

While the figures above focus on the peak amount of transfer between regions, another important factor is the total amount transferred over a year. The figures below show the average amount, or more precisely, the total amount in GWyears (= 8760 GWh). Besides the amount transferred, the regions are colored based on the net amount of generation either imported in (red) or exported out (blue) of the region. The scale for the colors varies depending on the highest exports and imports.

The BAU Scenario shows relatively little transfer over the full year in the two phases (Figure 18 and Figure 19). The major transfers are from upstate New York down to NYIS) J-K and from PJM_ROR to PJM_ROM and further east. There is little difference between the two phases.

The RPS/R Scenario has similar levels of annual flow as the BAU, although transfers are up slightly (Figure 20 and Figure 21). This is likely due to the increased renewable production in certain regions and transfers needed to move that to other regions. In this scenario, sharing of renewable resources occurred within territories for purposes of meeting the RPS.

For the CO_2+ Scenario, in Phase 1 there was a consistent high amount of transfer from MISO_W to PJM_ROR (Figure 22). This was a major driving force for adding four HVDC lines between the regions during the transmission build-out in Phase 2 (Figure 23). In addition, it worked well to have some of the exports from the Southwest go directly to PJM_ROR over two HVDC lines rather than transfer through MISO_W. An interesting side impact of the HVDC lines in Phase 2 was that a significant amount of power flowed back in to MISO_IN from PJM_ROR. This may be due to placement of several of the HVDC termini on PJM lines that are within Indiana.

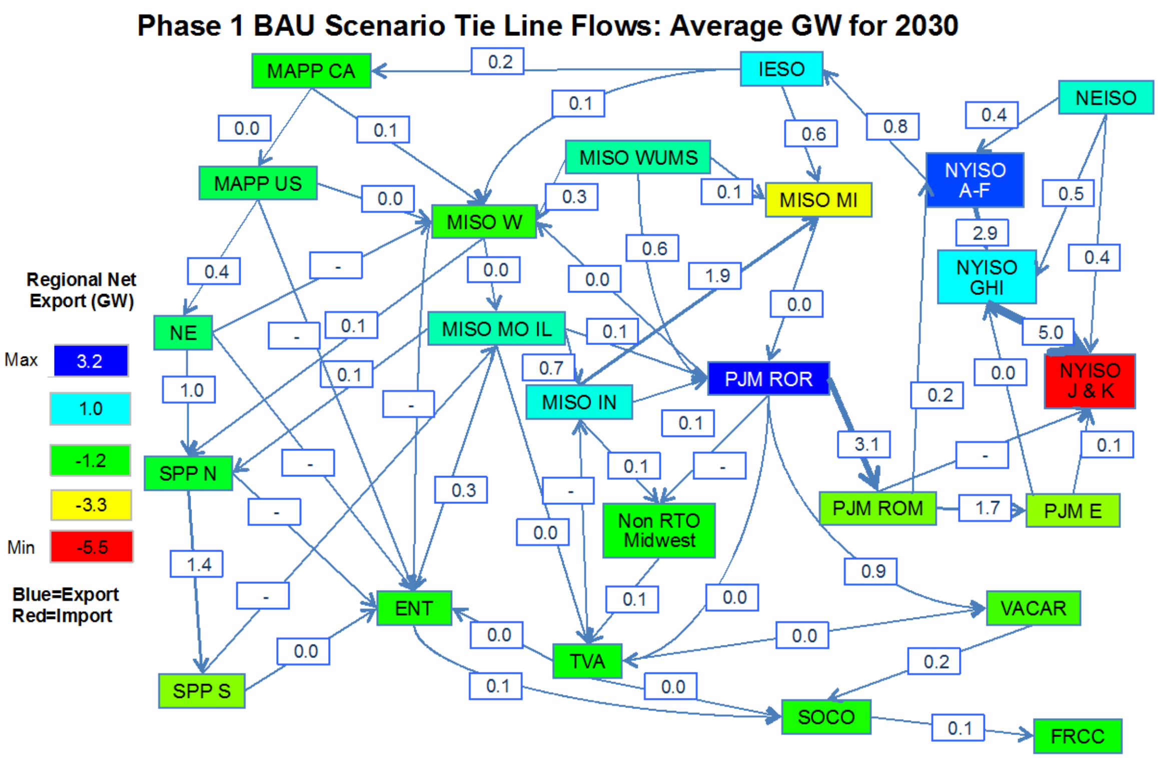


Figure 18. Phase 1 Average Inter-regional Transfers in 2030 the BAU Scenario

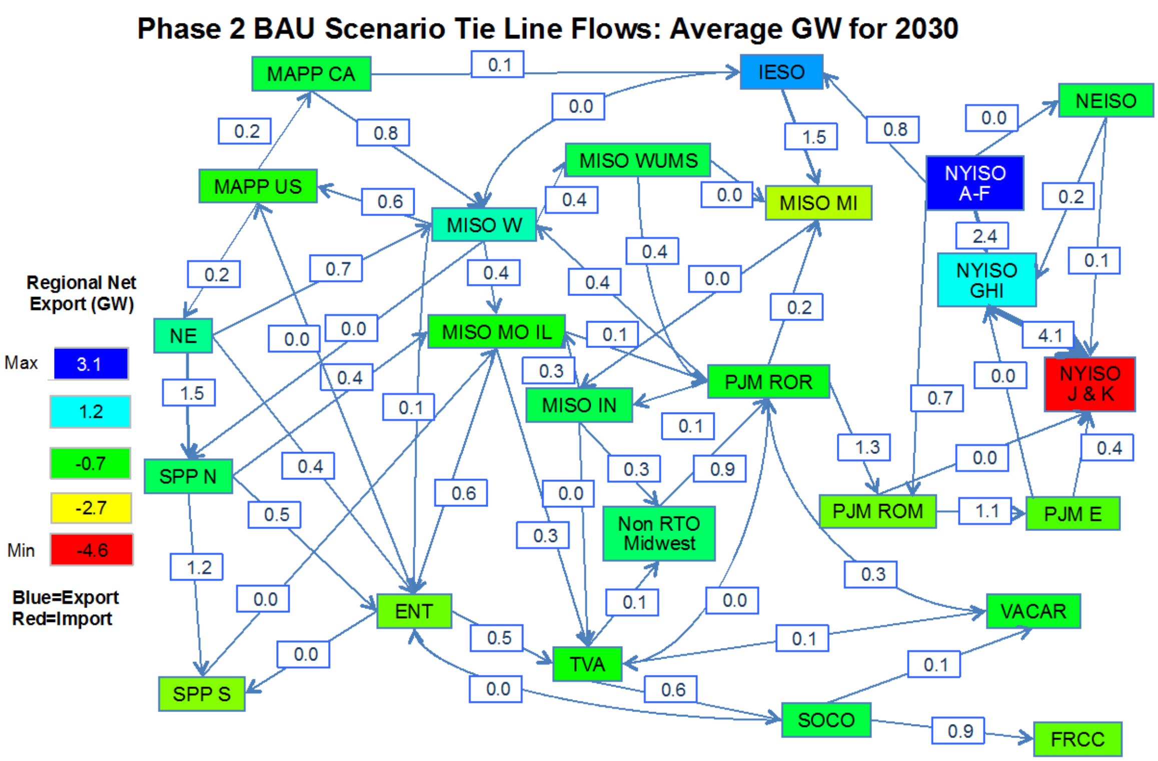


Figure 19. Phase 2 Average Inter-regional Transfers in 2030 the BAU Scenario

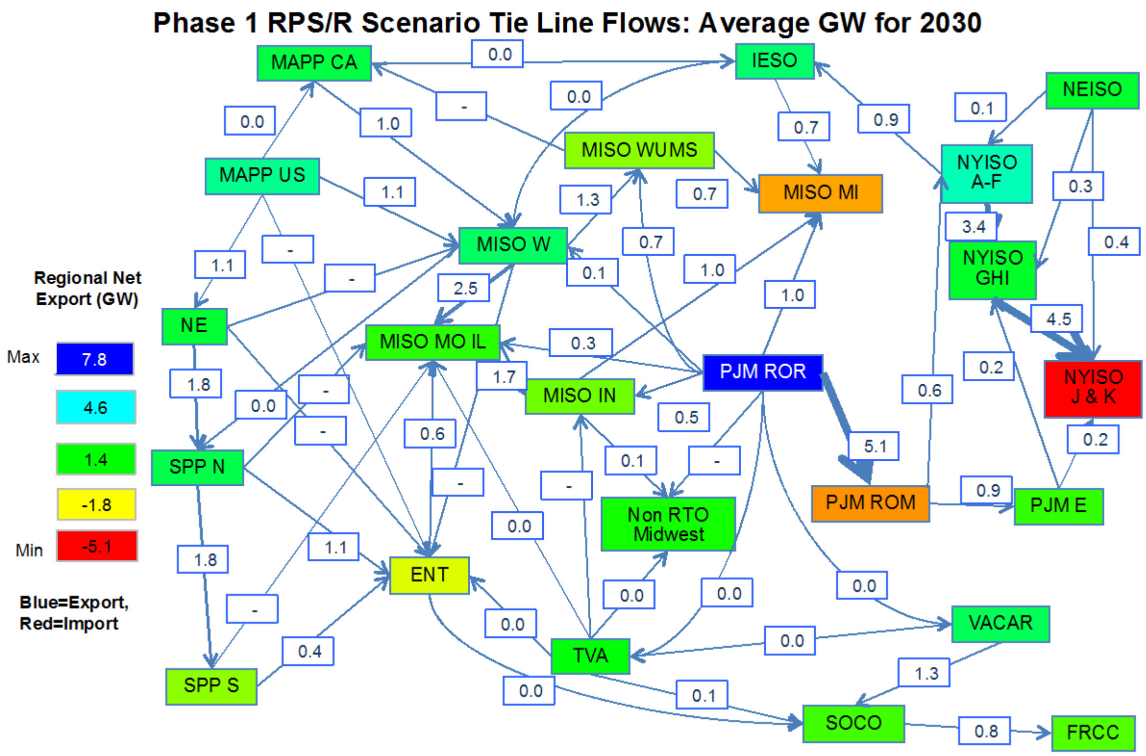


Figure 20. Phase 1 Average Inter-regional Transfers in 2030 the RPS/R Scenario

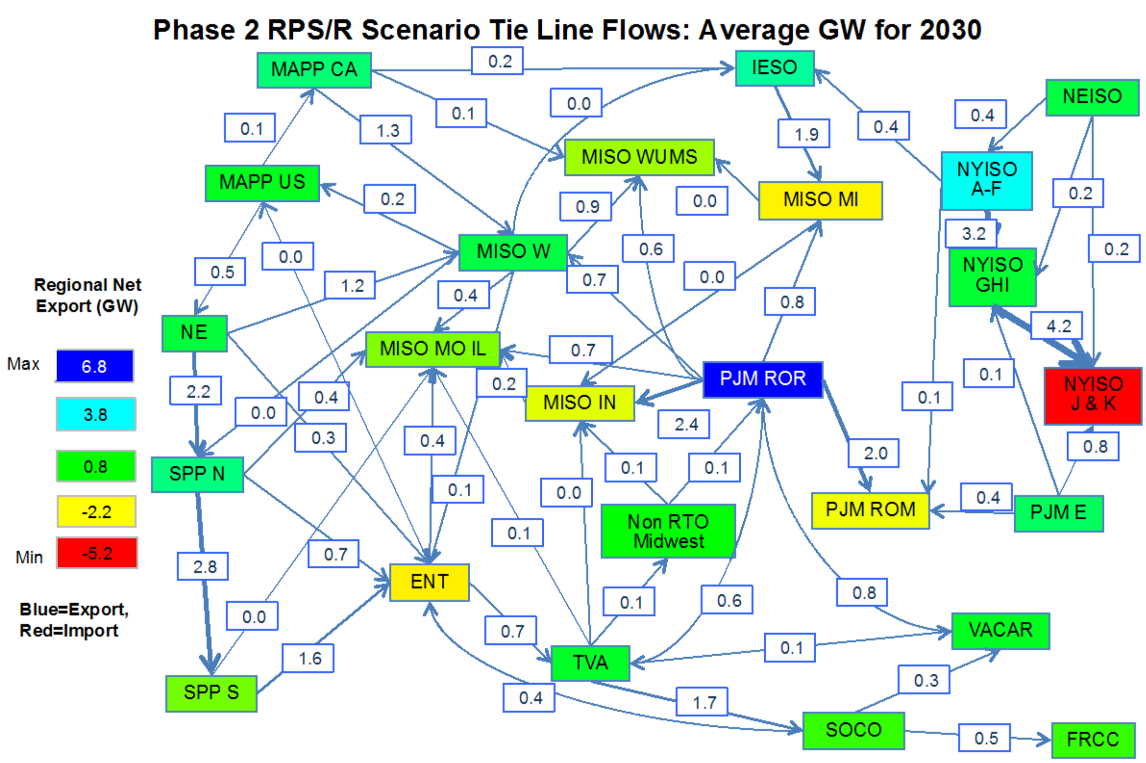


Figure 21. Phase 2 Average Inter-regional Transfers in 2030 the RPS/R Scenario

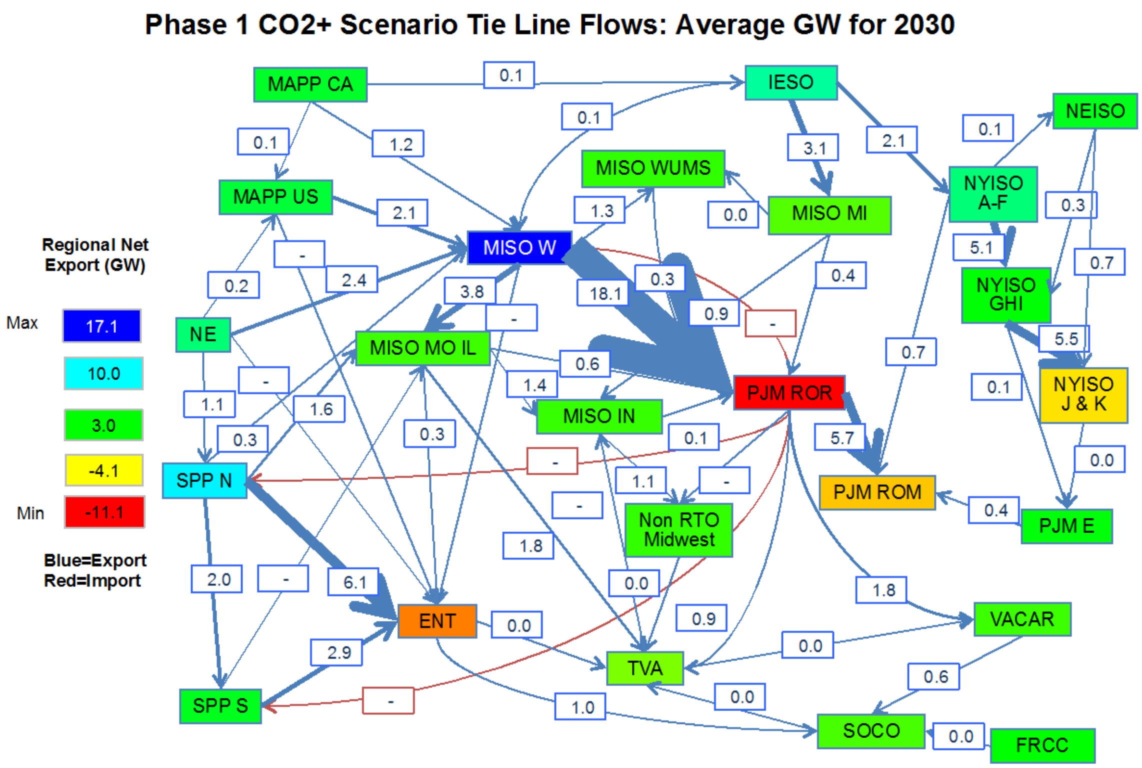


Figure 22. Phase 1 Average Inter-regional Transfers in 2030 in the CO2+ Scenario

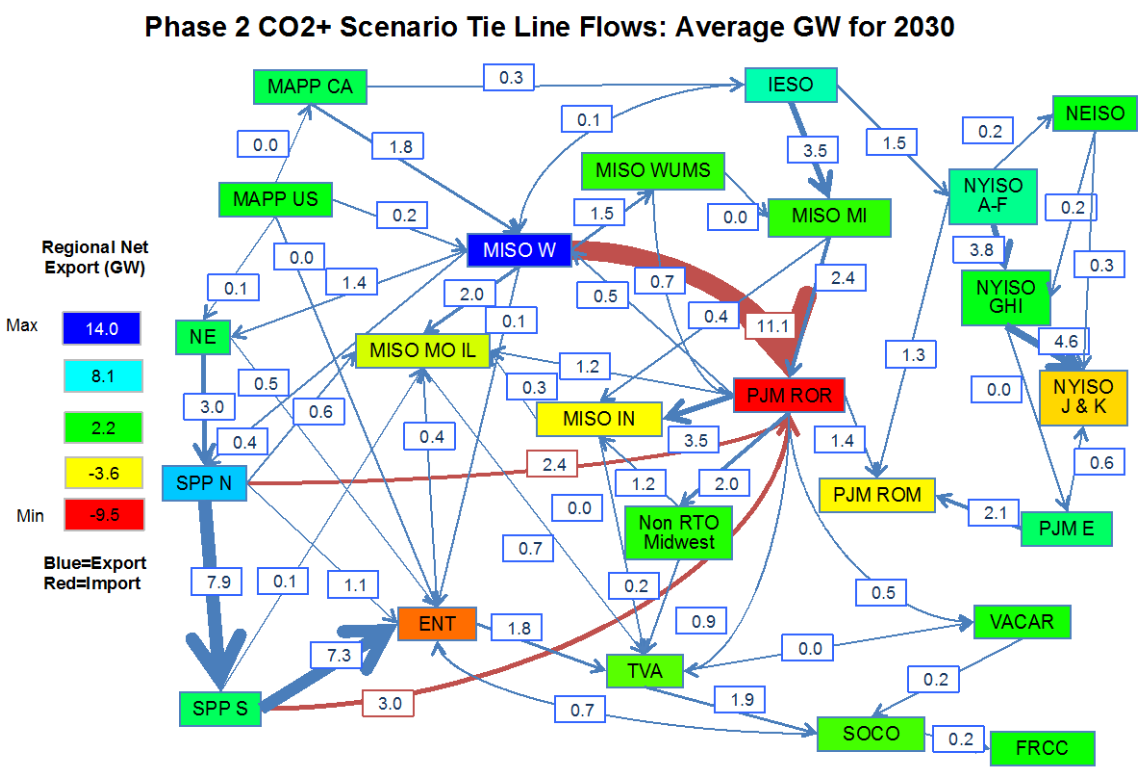


Figure 23. Phase 2 Average Inter-regional Transfers in 2030 in the CO2+ Scenario

A key difference between Phase 1 and Phase 2 was the number of periods analyzed over the course of a year, twenty blocks in Phase 1 versus 8760 hours in Phase 2. Table 4 shows the number of hours used in each block in Phase 1.

Table 4. Duration blocks used for each year modeled in NEEM.

	Summer										Shoulder					Winter				
Block	B1	B2	B3	B4	B5	B6	B7	B8	B9	B10	B11	B12	B13	B14	B15	B16	B17	B18	B19	B20
Hours	10	25	75	100	200	300	400	500	800	1262	25	200	600	900	1203	25	100	400	700	935

Modeling each hour separately in Phase 2 provided much more opportunity for transmission to increase, decrease, or even change direction depending on the generation and demands in different regions. We can aggregate the hourly results from Phase 2 into the corresponding blocks from Phase 1 to see how the transmission varied over the year. There are 56 tielines between the regions. To pick one as an example, Figure 24 below shows the power transferred between SPP_N and SPP_S during the CO2+ Scenario. This line saw much heavier use in Phase 2 than Phase 1. In Phase 1, each block could have a different transfer amount, so there were a maximum of 20 different transfer amounts over the course of a year in NEEM. These blocks contain between 10 and 1262 hours and total to the 8760 hours of the year. We aggregated the corresponding hours from the MAPS results and derived the average, maximum, and minimum for each block. The last set of points in the figure show the annual aggregated values.

In Block 1, the ten summer peak hours, Phase 1 results had 640 MW of power transferring from SPP_S to SPP_N; Phase 2 results had between 5 and 14 GW transferred from SPP_N to SPP_S, with an average of 10 GW. Recall that Phase 2 included the SPP high voltage overlay that provided extensive transfer capacity between the two regions. Other blocks showed even broader diversity in the amount transferred between the regions. (Blocks 11 and 16 are the peak hours for the other seasons so have less diversity.) During Block 18 (400 hours in the winter), in Phase 2 the transfers ranged from 3 GW traveling south to north to 21 GW traveling north to south. This variation could be due to wind pattern differences, plant outages, different internal or export demands, or the modeling of minor cost differences during times of surplus generation. This will be explored in more detail in the next set of topics.

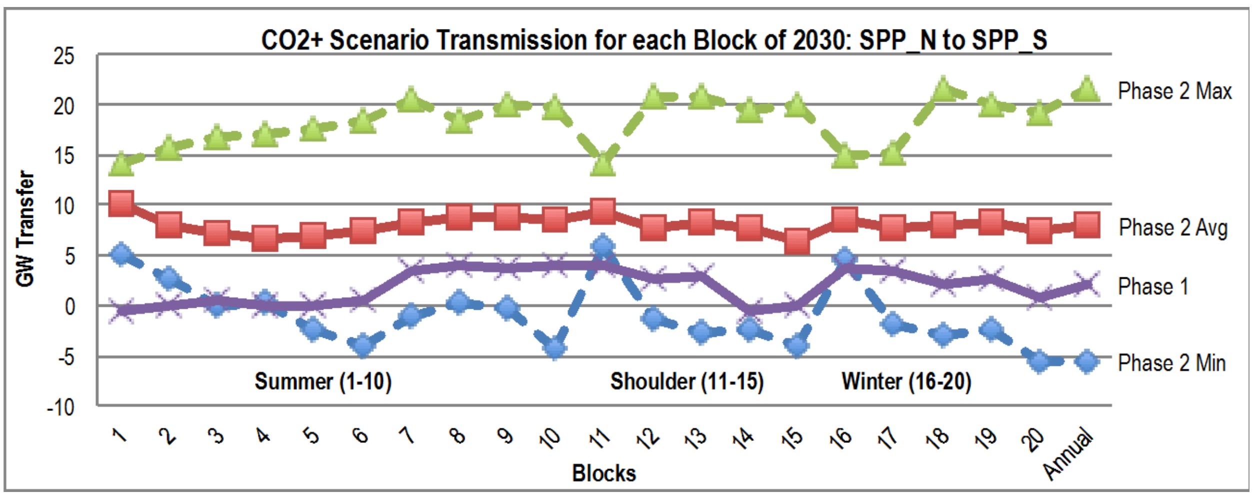


Figure 24. Inter-region transmission in the CO2+ Scenario aggregated to NEEM load blocks

2.4 COST COMPARISON

Total costs include generation costs as calculated within the models plus other costs calculated separately. These costs include the transmission capital costs, nuclear uprates, demand response, energy efficiency, distributed generation, and others. These are discussed in more detail in section 5 of this report. Some cost categories were calculated differently in Phase 1 than in Phase 2. For example, in Phase 1 the capital costs for generation were levelized into costs applied each year, using capital recovery factors between 11% and 12% depending on the technology. Transmission capital costs were only calculated as a single total construction cost for the whole period and only applied to transmission over and above the Stakeholder Selected Infrastructure (SSI). In Phase 2, both generation and transmission capital costs were calculated as the total period's construction cost. To levelize the generation and transmission construction costs, we applied an average capital recovery factor of 11.5% to all capital.

2.4.1 Ratio of Total Cost in 2030 between scenarios

Since the topic at hand in this section is how did Phase 2 results compare to Phase 1 results, the ratio of total 2030 cost indicates how they compared (Figure 25). Costs for most of the regions were higher in Phase 2 (ratio >100%), especially in the CO_2+ scenario with total costs 16% higher. Capital costs appear to be a main driver in this; Phase 2 capital costs were 24% higher for the entire EI. Only five regions had capital costs lower in Phase 2 than Phase 1.

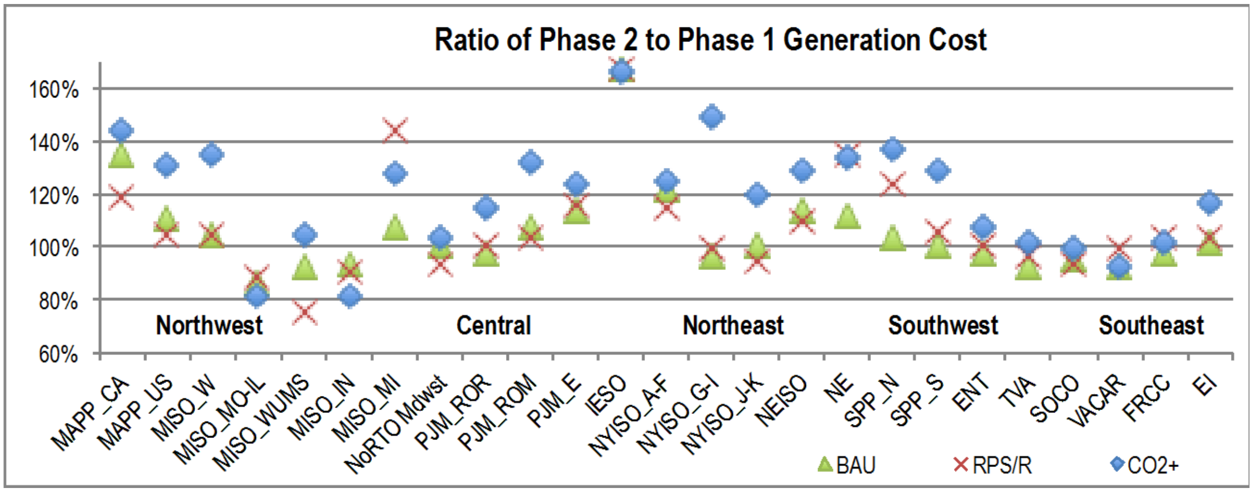


Figure 25. Ratio of Phase 2 to Phase 1 costs in 2030 by region

2.4.2 Total by Type and Region

Total costs for most regions are relatively similar between Phase 1 and 2 (Figure 26, Figure 27, and Figure 28). The largest differences are in those regions that have high wind generation (MISO_W, SPP_N, SPP_S) in the CO2+ Scenario. Capital costs make up the biggest difference in MISO_W, but in SPP the cost difference also includes more fuel and emissions cost due to the added coal, CC and CT generation during wind shortfalls or for reserves. Scenarios 2 and 3 do not have as large a difference between phases.

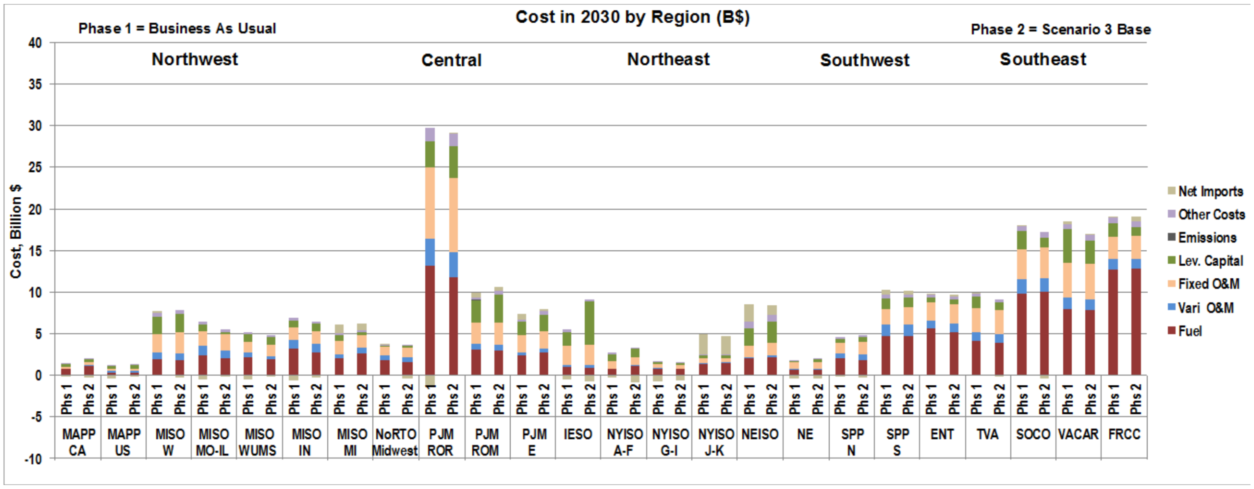


Figure 26. Phase 1 and Phase 2 Regional Total Costs in 2030 in the BAU Scenario

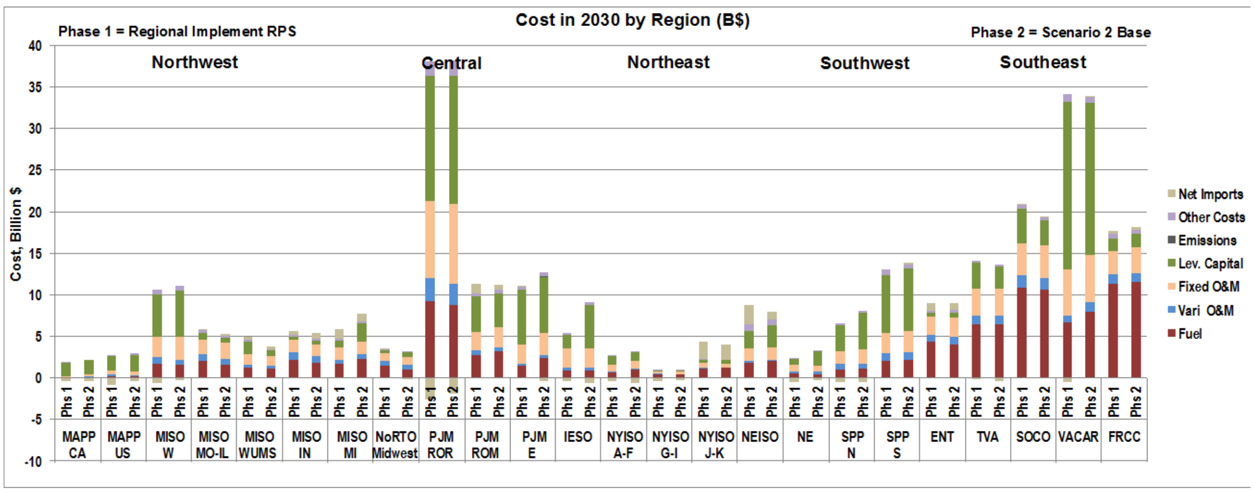


Figure 27. Phase 1 and Phase 2 Regional Total Costs in 2030 in the RPS/R Scenario

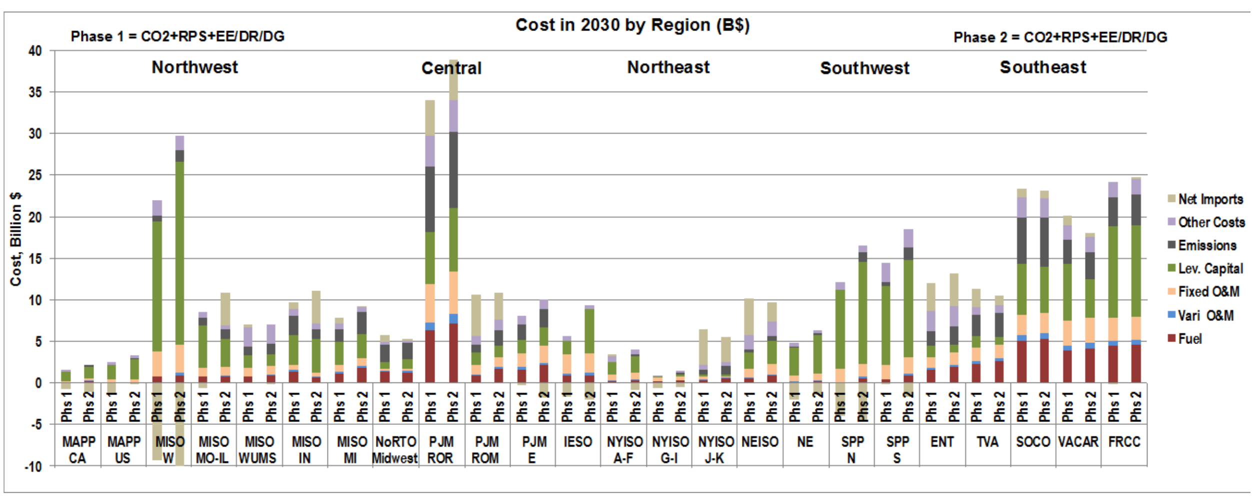


Figure 28. Phase 1 and Phase 2 Regional Total Costs in 2030 in the CO2+ Scenario

2.4.3 Cost per Unit of Generation

Cost per unit of generation puts cost aon a more comparable basis between regions (Figure 29, Figure 30, and Figure 31). Cost per unit of generation results amplify the differences in the CO2+ Scenario for those regions with high wind production. MAPP_US, MISO_W, NE, SPP_N, and SPP_S. These costs do not include the net import costs and the divisor does not include imports or exports, so this is a measure of the average cost per unit of generation, not cost per unit of demand in the region.

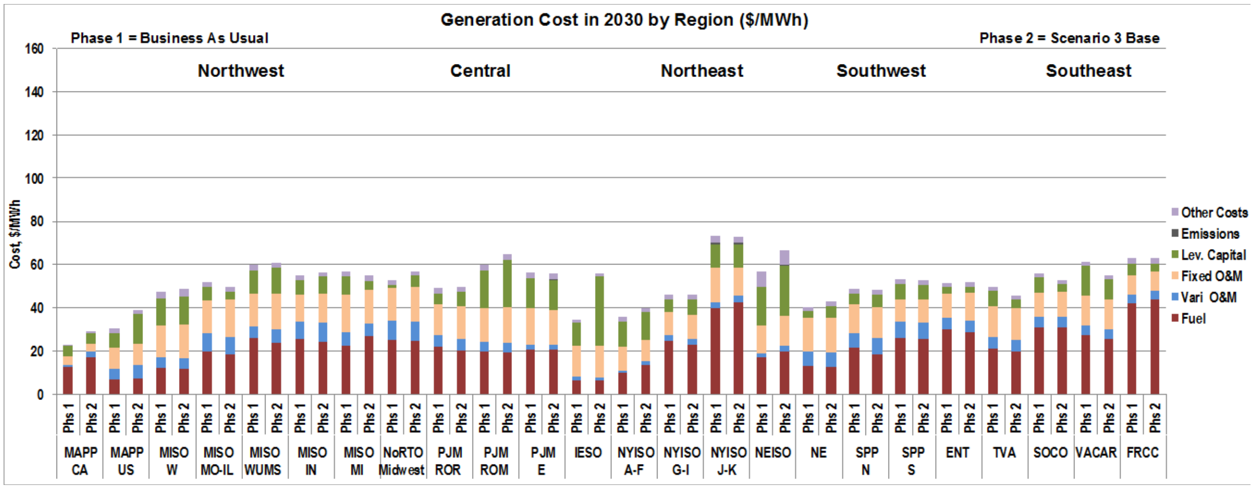


Figure 29. Phase 1 and Phase 2 Regional Total Cost per MWh Generated in the BAU Scenario

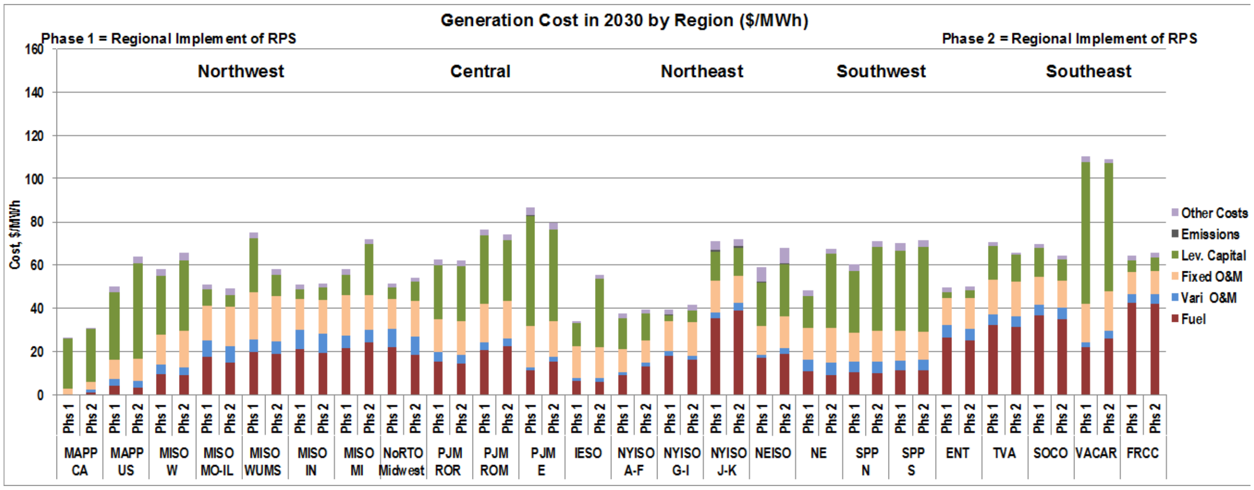


Figure 30. Phase 1 and Phase 2 Regional Total Cost per MWh Generated in the RPS/R Scenario

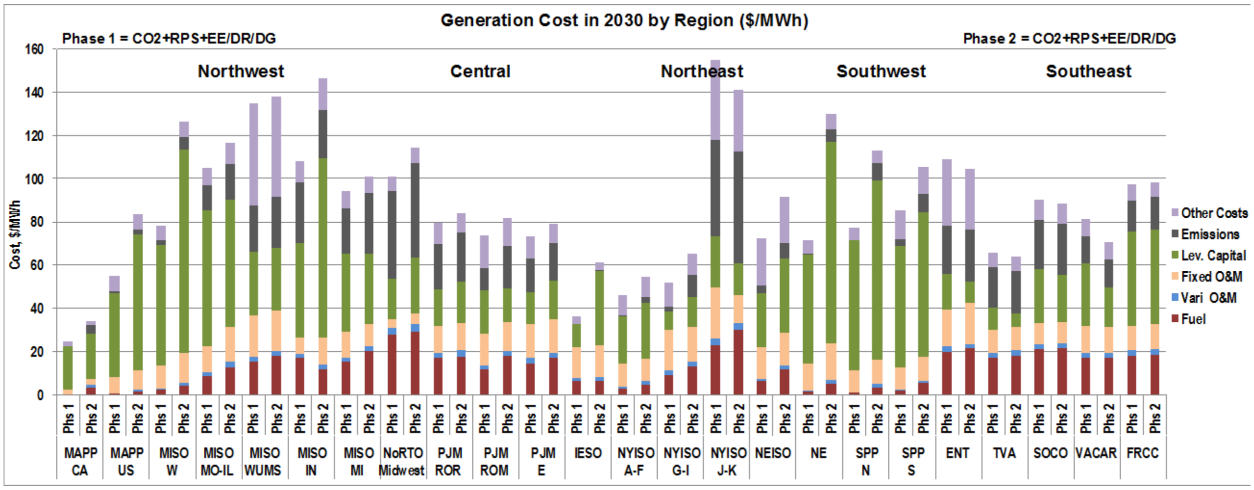


Figure 31. Phase 1 and Phase 2 Regional Total Cost per MWh Generated in the CO2+ Scenario

3. REGIONAL RESULTS OVER TIME

This section evaluates the change in capacity, generation, and inter-regional transfers over time. The reason for this topic is many regulators or other stakeholders were concerned that there might be issues that they may face in the nearer term than 2030. The most pressing issues might be changes in generation or transmission capacity, since these require the most upfront response.

Earlier years than 2030 were only analyzed in Phase 1 of the study. Most results were only reported in five-year increments beginning in 2015. The timing of transmission changes is difficult to evaluate because the amount of transfer capacity between regions was modeled as a constant over the full time period.

The figures below show the changes in capacity and generation over time, based on the Phase 1 results. Rather than show all 24 regions, the section below shows the changes for each of the major territories as defined in Table 1. In addition, tables showing the points of major change in capacity, generation, and net exports are highlighted. Only those technologies that have over 5% share of the generation and have a change greater than 25% are shown. Export changes greater than 10%+/- between years are highlighted. Changes past 2030 are not included in the tables since those years are more speculative and of less interest than results up to 2030.

In all regions and scenarios, excess generation is deactivated between 2010 and 2015 by MRN-NEEM. Most often this capacity is coal and steam oil/gas. Demand Response grows in capacity significantly through 2025.

The sections below show the graphs of capacity from 2010-2040 next to the graphs of generation from 2015-2040 for each scenario for a given territory (with that of the EI as a whole first.) Following them on the facing page are tables telling when significant changes occurred to capacity, generation, and net transfers for the territory occurred between 2010-2015 (capacity changes only), 2015-2020, 2030-2025, and 2005-2030. Following the tables is a brief description of key changes.

3.1 EASTERN INTERCONNECTION AS A WHOLE

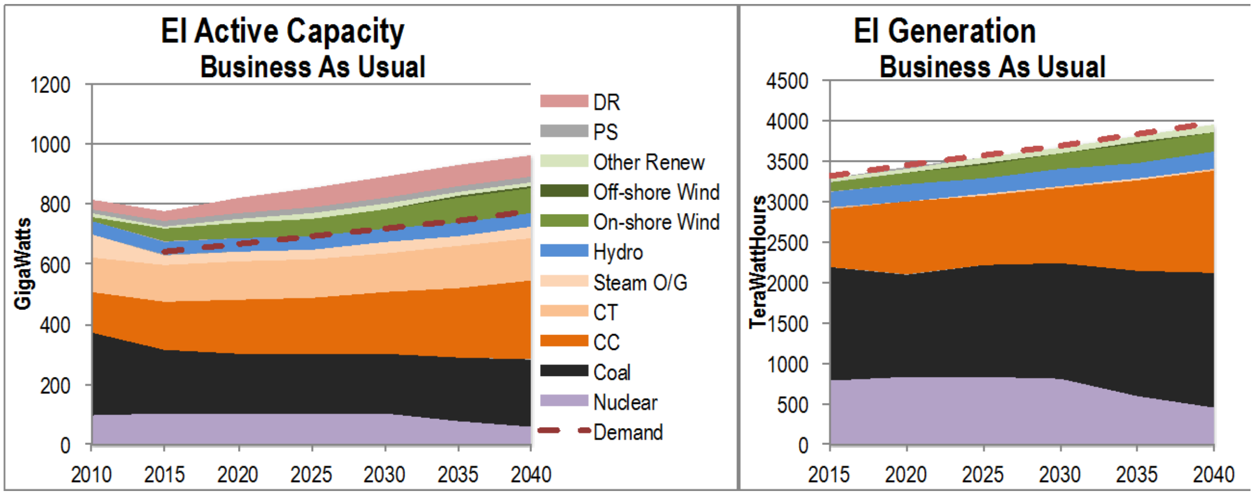


Figure 32. BAU Scenario Phase 1 Capacity and Generation for the Eastern Interconnection

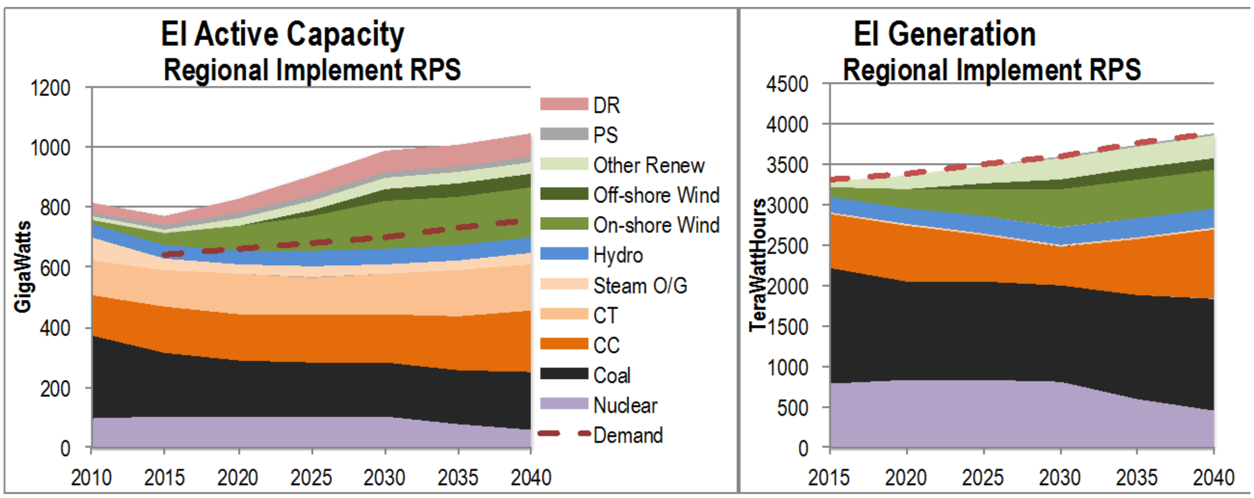


Figure 33. RPS/R Scenario Phase 1 Capacity and Generation for the EI

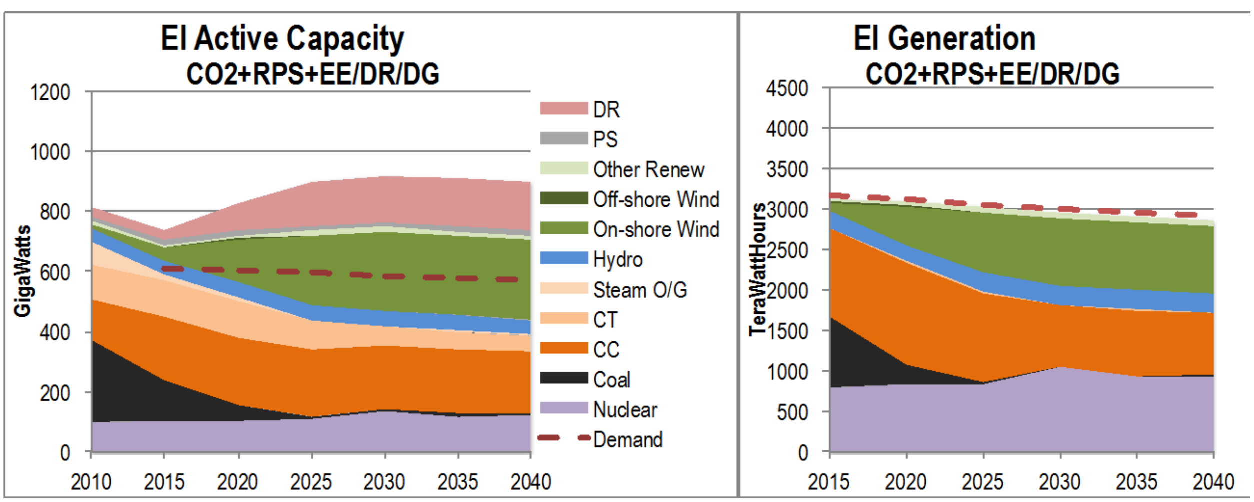


Figure 34. CO2+ Scenario Phase 1 Capacity and Generation for the EI

Table 5. BAU Scenario Significant Changes through 2030 in Eastern Interconnection

NEEM Region: EI 2015	2020	Scenario: F1S17 2025	2030
Significant Capacity Changes			
• Steam O/G down 52% to 34.6 GW • On-shore Wind up 119% to 40.9 GW	• On-shore Wind up 30% to 53.1 GW • DR up 53% to 48.6 GW	• DR up 40% to 68.2 GW	
Significant Generation Changes			
Significant Net Export Changes (negative = Imports)			

Table 6. RPS/R Scenario Significant Changes through 2030 in Eastern Interconnection

NEEM Region: EI 2015	2020	Scenario: F6S10 2025	2030
Significant Capacity Changes			
• Steam O/G down 50% to 35.9 GW • On-shore Wind up 119% to 40.9 GW	• On-shore Wind up 99% to 81.3 GW • DR up 53% to 48.6 GW	• On-shore Wind up 45% to 118.2 GW • DR up 40% to 68.2 GW	• On-shore Wind up 35% to 159.3 GW
Significant Generation Changes			
	• On-shore Wind up 95% to 227.5 TWh	• On-shore Wind up 46% to 332.6 TWh • Other Renew up 32% to 210.5 TWh	• On-shore Wind up 38% to 457.6 TWh
Significant Net Export Changes (negative = Imports)			

Table 7. CO2+ Scenario Significant Changes through 2030 in Eastern Interconnection

NEEM Region: EI 2015	2020	Scenario: F8S7 2025	2030
Significant Capacity Changes			
• Coal down 49% to 138.8 GW • CC up 56% to 207.2 GW • Steam O/G down 67% to 23.9 GW • On-shore Wind up 119% to 40.9 GW	• Coal down 66% to 47.2 GW • On-shore Wind up 259% to 146.7 GW • DR up 172% to 86.5 GW	• Coal down 78% to 10.2 GW • On-shore Wind up 58% to 231.5 GW • DR up 70% to 146.9 GW	• CT down 31% to 66.0 GW
Significant Generation Changes			
	• Coal down 72% to 250.6 TWh • On-shore Wind up 309% to 474.9 TWh	• Coal down 93% to 18.1 TWh • On-shore Wind up 57% to 746.6 TWh	• CC down 31% to 769.5 TWh
Significant Net Export Changes (negative = Imports)			

Changes to the EI as a whole have been described in the full EIPC report. The BAU Scenario has most growth occurring steadily, with coal and combined cycle the major contributors (Figure 32). In the RPS/R Scenario, on-shore wind grows more gradually over time; offshore wind and other renewables become more significant contributors in place of combined cycle (Figure 33). The CO2+ Scenario shows a rapid decline in coal capacity and generation, and a large increase in both wind and demand response capacity. Nuclear capacity grows somewhat and provides a growing fraction of generation (Figure 34).

3.2 NORTHWEST

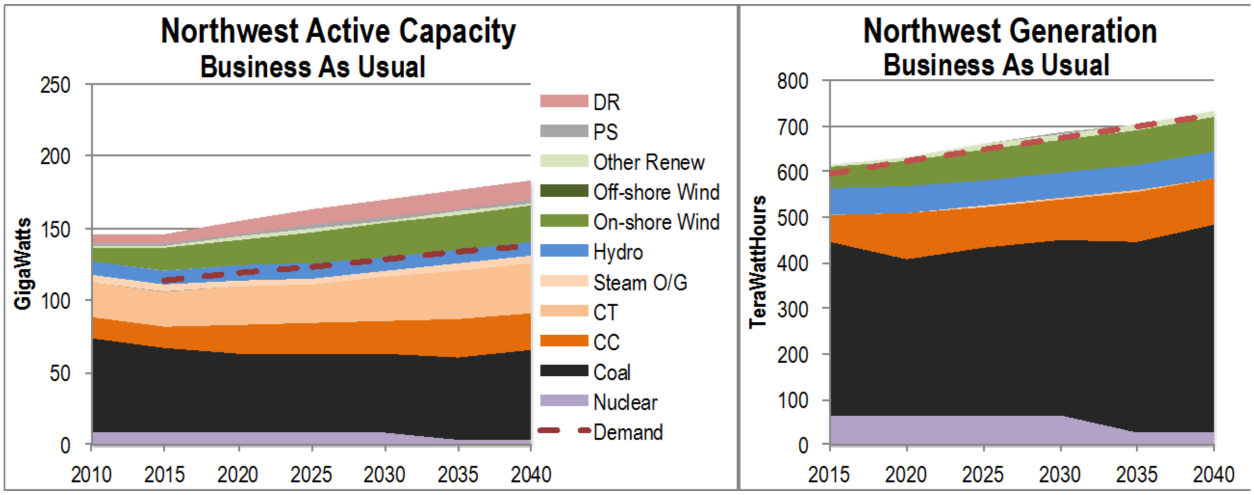


Figure 35. BAU Scenario Phase 1 Capacity and Generation for Northwest EI

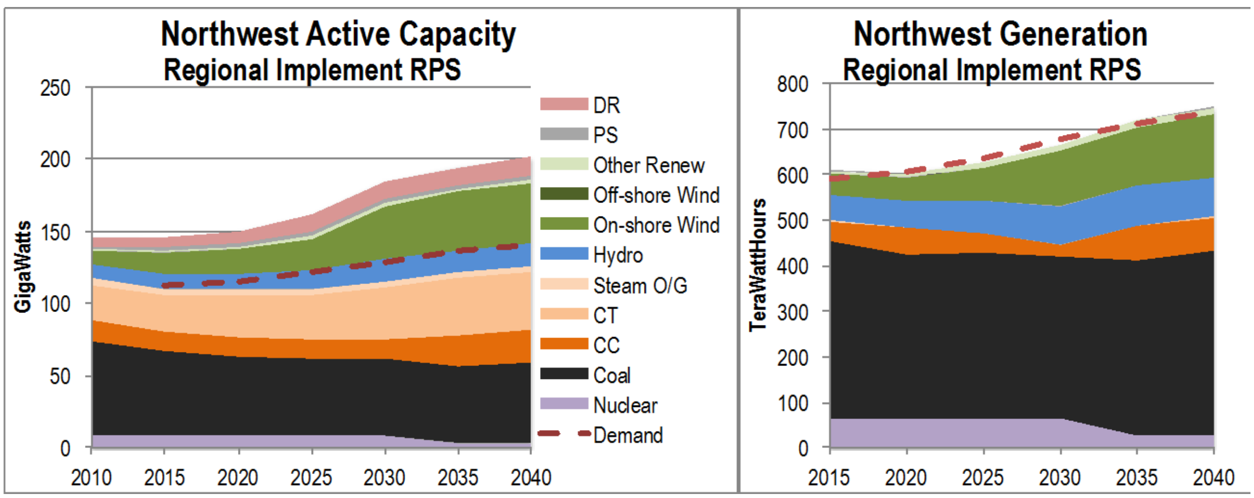


Figure 36. RPS/R Scenario Phase 1 Capacity and Generation for Northwest EI

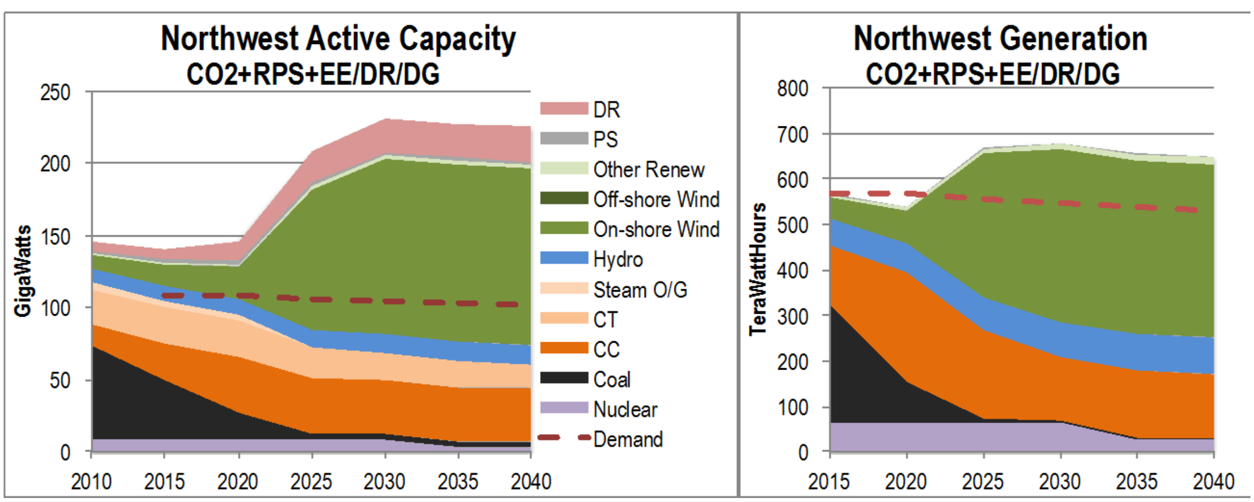


Figure 37. CO2+ Scenario Phase 1 Capacity and Generation for Northwest EI

Table 8. BAU Scenario Significant Changes through 2030 in Northwest EI

Territory: Northwest		Scenario: F1S17	
2015	**2020**	**2025**	**2030**
Significant Capacity Changes			
• On-shore Wind up 78% to 15.5 GW	• CC up 36% to 19.6 GW • DR up 40% to 8.6 GW	• DR up 34% to 11.6 GW	
Significant Generation Changes			
	• CC up 68% to 101.1 TWh		
Significant Net Export Changes (negative = Imports)			

Table 9. RPS/R Scenario Significant Changes through 2030 in Northwest EI

Territory: Northwest		Scenario: F6S10	
2015	**2020**	**2025**	**2030**
Significant Capacity Changes			
• On-shore Wind up 78% to 15.5 GW	• DR up 40% to 8.6 GW	• On-shore Wind up 30% to 22.2 GW • DR up 34% to 11.6 GW	• On-shore Wind up 67% to 36.9 GW
Significant Generation Changes			
	• CC up 34% to 58.7 TWh	• CC down 27% to 43.0 TWh • On-shore Wind up 32% to 69.8 TWh	• CC down 41% to 25.4 TWh • On-shore Wind up 71% to 119.4 TWh
Significant Net Export Changes (negative = Imports)			

Table 10. CO2+ Scenario Significant Changes through 2030 in Northwest EI

Territory: Northwest		Scenario: F8S7	
2015	**2020**	**2025**	**2030**
Significant Capacity Changes			
• Coal down 37% to 41.9 GW • CC up 84% to 25.0 GW • On-shore Wind up 78% to 15.5 GW	• Coal down 56% to 18.3 GW • CC up 56% to 39.0 GW • On-shore Wind up 50% to 23.4 GW • DR up 123% to 13.7 GW	• Coal down 79% to 3.8 GW • On-shore Wind up 319% to 97.8 GW • DR up 61% to 22.2 GW	
Significant Generation Changes			
	• Coal down 65% to 89.7 TWh • CC up 83% to 239.4 TWh • On-shore Wind up 56% to 74.9 TWh	• Coal down 93% to 6.4 TWh • On-shore Wind up 323% to 316.7 TWh	• CC down 29% to 139.8 TWh
Significant Net Export Changes (negative = Imports)			
		• Net Exports up 25% to 20% of demand	

The Northwest territory (MISO and MAPP) has a major expansion in wind capacity between 2020 and 2025 in the CO2+ Scenario (Figure 37), while the RPS/R Scenario's biggest increase is delayed to between 2025 and 2030 (Figure 36). Coal continues as the dominant resource in the BAU (Figure 35) and RPS/R scenarios, while wind dominates and CC generation expands in the CO2+ Scenario.

3.3 CENTRAL

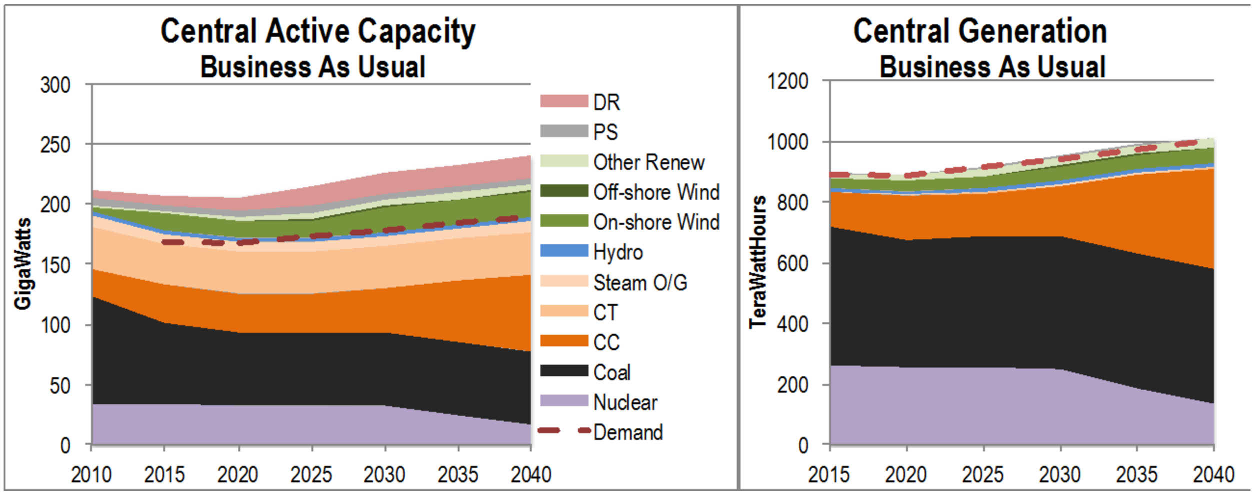


Figure 38. BAU Scenario Phase 1 Capacity and Generation for Central EI

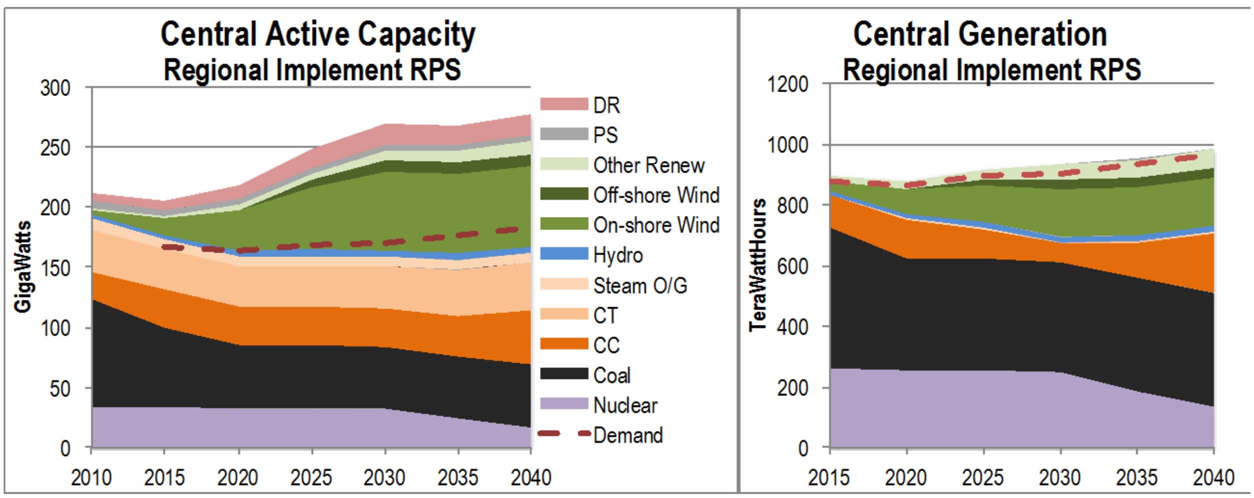


Figure 39. RPS/R Scenario Phase 1 Capacity and Generation for Central EI

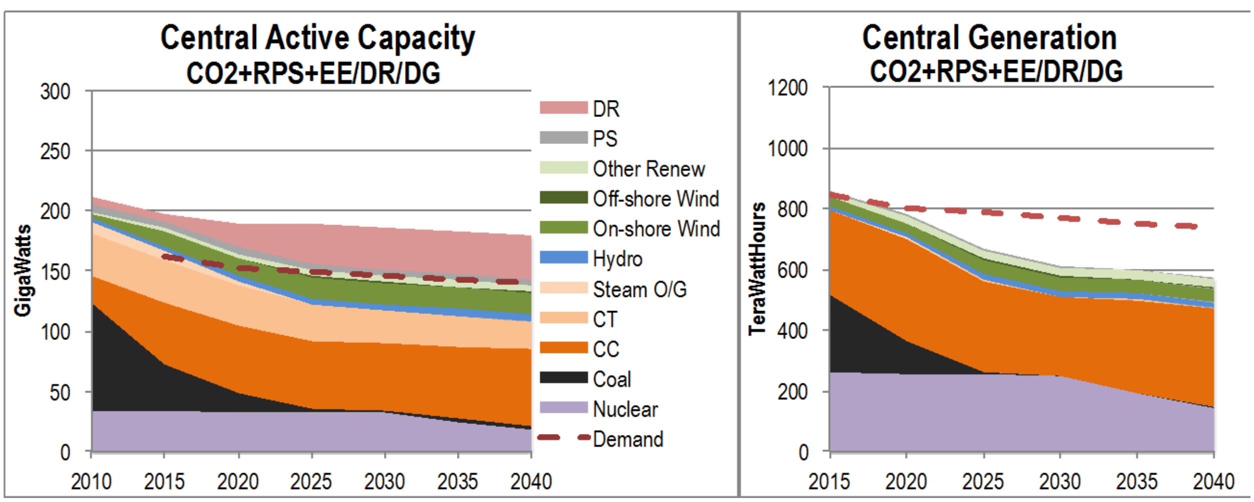


Figure 40. CO2+ Scenario Phase 1 Capacity and Generation for Central EI

Table 11. BAU Scenario Significant Changes through 2030 in Central EI

Territory: Central		Scenario: F1S17	
2015	**2020**	**2025**	**2030**
Significant Capacity Changes			
• Coal down 26% to 67.2 GW • CC up 42% to 31.6 GW • On-shore Wind up 292% to 13.4 GW	• DR up 59% to 11.2 GW	• DR up 45% to 16.3 GW	• On-shore Wind up 41% to 20.1 GW
Significant Generation Changes			
	• CC up 29% to 145.9 TWh		• On-shore Wind up 34% to 48.2 TWh
Significant Net Export Changes (negative = Imports)			

Table 12. RPS/R Scenario Significant Changes through 2030 in Central EI

Territory: Central		Scenario: F6S10	
2015	**2020**	**2025**	**2030**
Significant Capacity Changes			
• Coal down 28% to 65.6 GW • CC up 42% to 31.6 GW • On-shore Wind up 292% to 13.4 GW	• On-shore Wind up 149% to 33.2 GW • DR up 59% to 11.2 GW	• On-shore Wind up 55% to 51.4 GW • DR up 45% to 16.3 GW	• On-shore Wind up 27% to 65.2 GW
Significant Generation Changes			
	• On-shore Wind up 136% to 79.1 TWh	• CC down 26% to 92.9 TWh • On-shore Wind up 54% to 121.9 TWh	• CC down 32% to 62.9 TWh • On-shore Wind up 27% to 154.5 TWh • Other Renew up 63% to 47.0 TWh
Significant Net Export Changes (negative = Imports)			

Table 13. CO2+ Scenario Significant Changes through 2030 in Central EI

Territory: Central		Scenario: F8S7	
2015	**2020**	**2025**	**2030**
Significant Capacity Changes			
• Coal down 57% to 38.7 GW • CC up 132% to 51.5 GW • On-shore Wind up 292% to 13.4 GW	• Coal down 60% to 15.3 GW • DR up 174% to 19.4 GW	• Coal down 84% to 2.5 GW • DR up 71% to 33.2 GW	
Significant Generation Changes			
	• Coal down 58% to 106.6 TWh	• Coal down 94% to 6.2 TWh	
Significant Net Export Changes (negative = Imports)			
		• Net Exports down 13% to -15% of demand	

In the BAU Scenario, coal maintains its dominant market share of production (Figure 38). In the RPS/R Scenario, wind capacity including offshore wind is expanded, and other renewables are developed as well in order to meet the RPS requirements (Figure 39). Capacity declines in the CO2+ Scenario and the Central territory (PJM and Non-RTO Midwest) becomes a significant importer (Figure 40). Nuclear continues to play a significant role through 2030 and CC generation is expanded as coal is reduced.

3.4 NORTHEAST

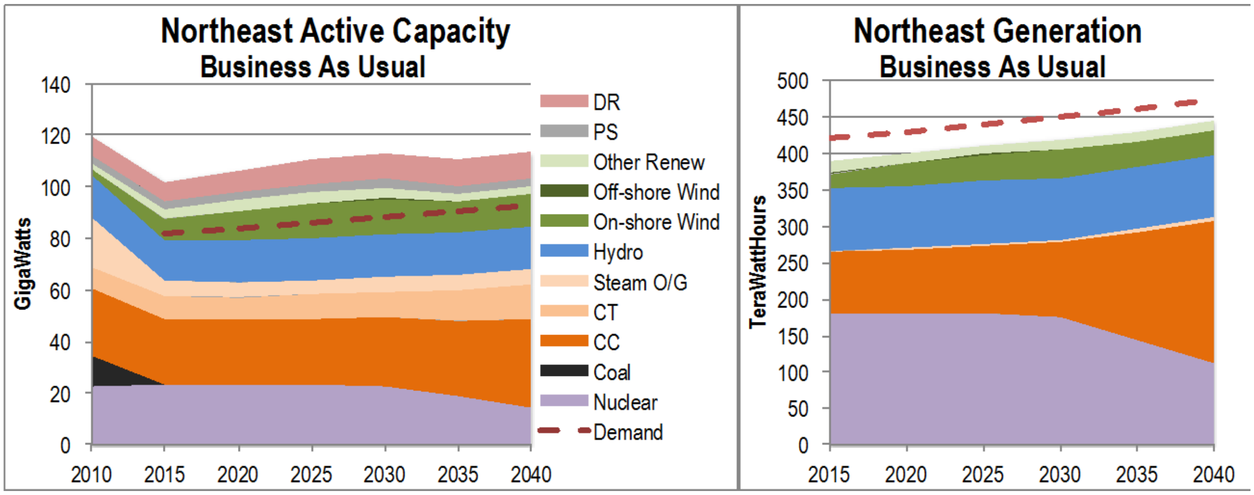


Figure 41. BAU Scenario Phase 1 Capacity and Generation for Northeast EI

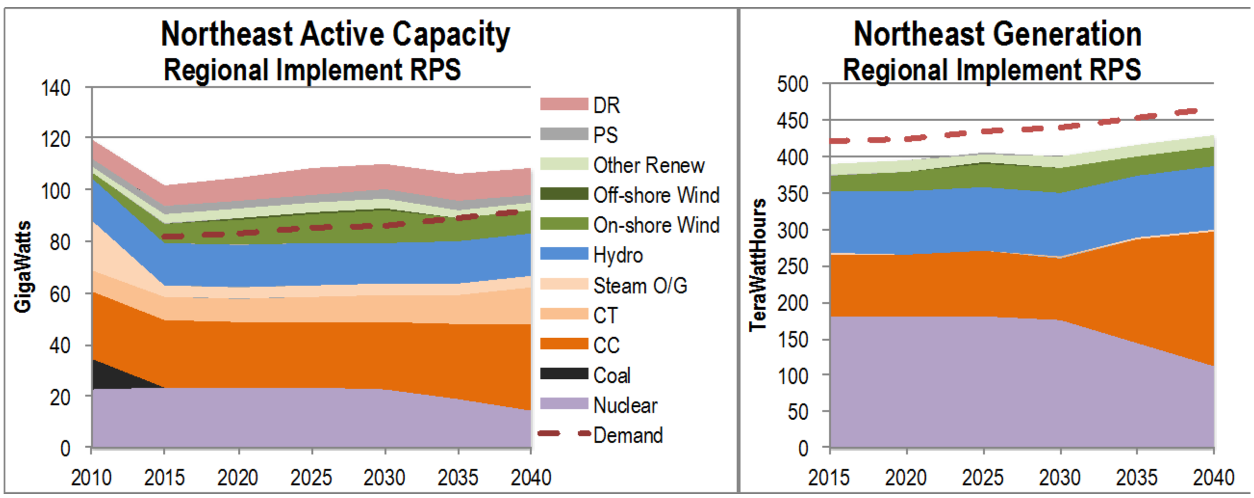


Figure 42. RPS/R Scenario Phase 1 Capacity and Generation for Northeast EI

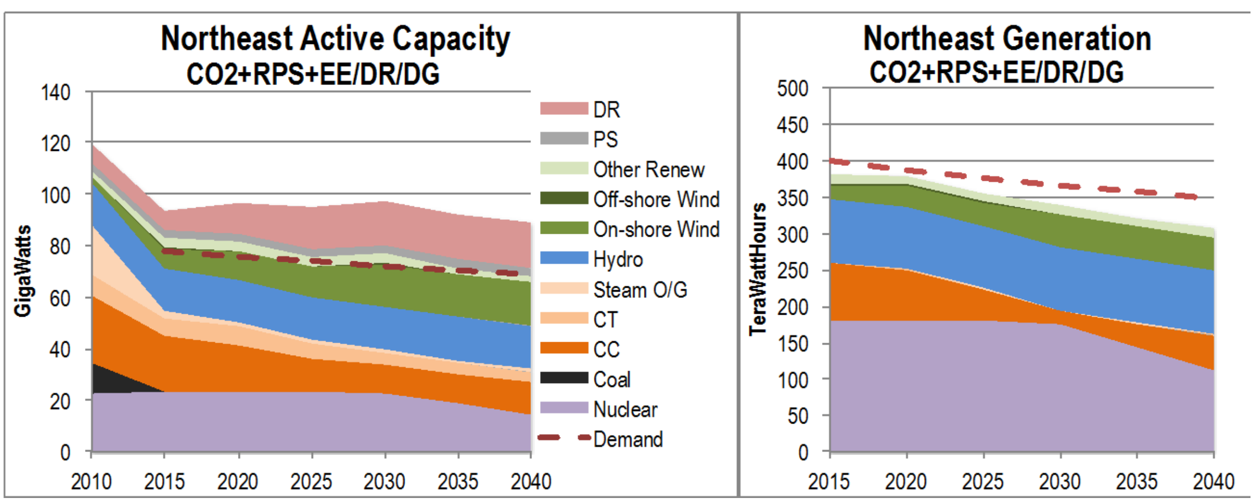


Figure 43. CO2+ Scenario Phase 1 Capacity and Generation for Northeast EI

Table 14. BAU Scenario Significant Changes through 2030 in Northeast EI

Territory: Northeast		Scenario: F1S17	
2015	2020	2025	2030
Significant Capacity Changes			
• Coal down 97% to 0.3 GW • Steam O/G down 71% to 5.7 GW • On-shore Wind up 174% to 7.6 GW	• On-shore Wind up 46% to 11.1 GW		
Significant Generation Changes			
	• On-shore Wind up 51% to 30.0 TWh		
Significant Net Export Changes (negative = Imports)			

Table 15. RPS/R Scenario Significant Changes through 2030 in Northeast EI

Territory: Northeast		Scenario: F6S10	
2015	2020	2025	2030
Significant Capacity Changes			
• Coal down 97% to 0.3 GW • Steam O/G down 77% to 4.4 GW • On-shore Wind up 174% to 7.6 GW	• On-shore Wind up 27% to 9.6 GW		
Significant Generation Changes			
	• On-shore Wind up 29% to 25.7 TWh		
Significant Net Export Changes (negative = Imports)			

Table 16. CO2+ Scenario Significant Changes through 2030 in Northeast EI

Territory: Northeast		Scenario: F8S7	
2015	2020	2025	2030
Significant Capacity Changes			
• Coal down 97% to 0.3 GW • Steam O/G down 85% to 2.9 GW • On-shore Wind up 174% to 7.6 GW	• On-shore Wind up 43% to 10.9 GW • DR up 55% to 11.8 GW	• CC down 31% to 12.6 GW • DR up 40% to 16.5 GW	• On-shore Wind up 40% to 16.6 GW
Significant Generation Changes			
	• On-shore Wind up 48% to 28.9 TWh	• CC down 38% to 43.8 TWh	• CC down 57% to 18.8 TWh • On-shore Wind up 40% to 44.6 TWh
Significant Net Export Changes (negative = Imports)			

The Northeast territory (New York, New England, and Ontario) imports power from Hydro Quebec and the Maritimes in all three scenarios, with the CO2+ Scenario having the highest imports (Figure 41, Figure 42, and Figure 43). There is a large proportion of power from nuclear and hydro, much from Ontario that supplies both internal demand and the other regions.

3.5 SOUTHWEST

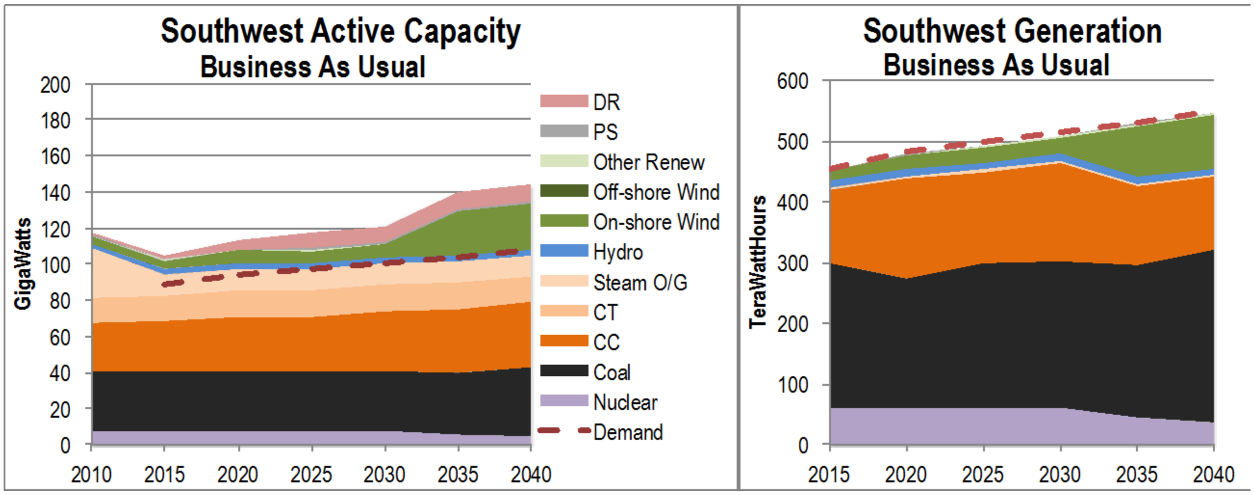


Figure 44. BAU Scenario Phase 1 Capacity and Generation for Southwest EI

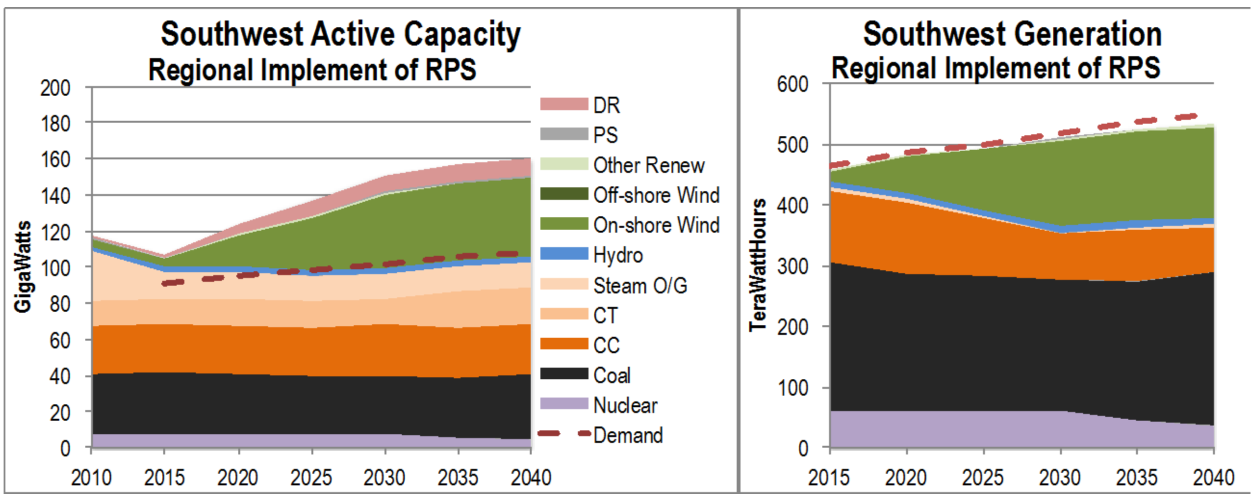


Figure 45. RPS/R Scenario Phase 1 Capacity and Generation for Southwest EI

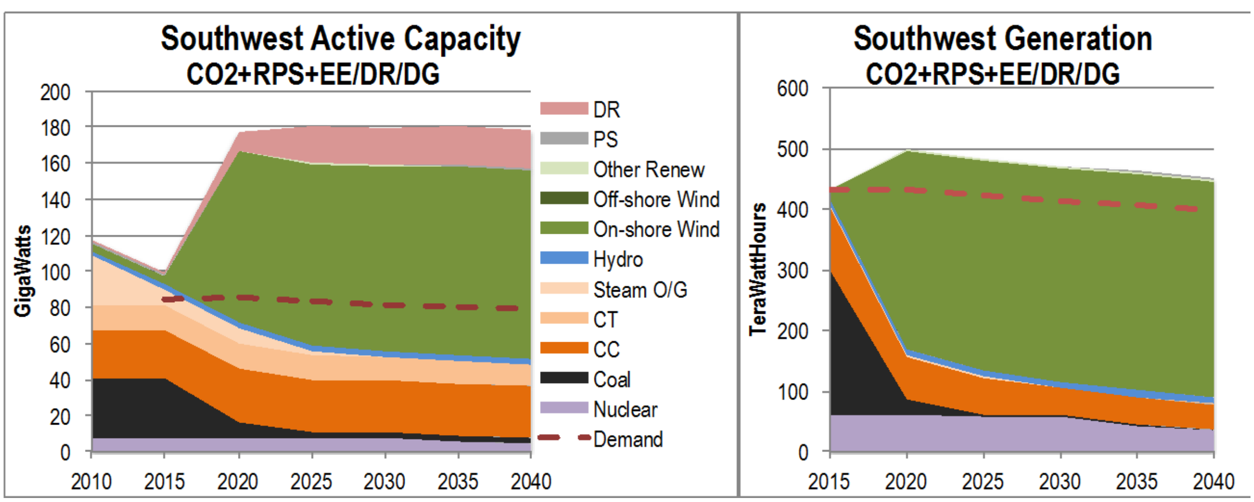


Figure 46. CO2+ Scenario Phase 1 Capacity and Generation for Southwest EI

Table 17. BAU Scenario Significant Changes through 2030 in Southwest EI

Territory: Southwest		Scenario: F1S17	
2015	**2020**	**2025**	**2030**
Significant Capacity Changes			
• Steam O/G down 57% to 11.9 GW	• On-shore Wind up 60% to 7.0 GW	• DR up 76% to 8.8 GW	
Significant Generation Changes			
	• CC up 37% to 164.2 TWh • On-shore Wind up 60% to 24.3 TWh		
Significant Net Export Changes (negative = Imports)			

Table 18. RPS/R Scenario Significant Changes through 2030 in Southwest EI

Territory: Southwest		Scenario: F6S10	
2015	**2020**	**2025**	**2030**
Significant Capacity Changes			
• Steam O/G down 46% to 14.8 GW	• On-shore Wind up 303% to 17.8 GW	• On-shore Wind up 65% to 29.3 GW • DR up 76% to 8.8 GW	• On-shore Wind up 40% to 40.9 GW
Significant Generation Changes			
	• On-shore Wind up 305% to 61.4 TWh	• On-shore Wind up 64% to 101.0 TWh	• On-shore Wind up 40% to 141.1 TWh
Significant Net Export Changes (negative = Imports)			

Table 19. CO2+ Scenario Significant Changes through 2030 in Southwest EI

Territory: Southwest		Scenario: F8S7	
2015	**2020**	**2025**	**2030**
Significant Capacity Changes			
• Steam O/G down 69% to 8.4 GW	• Coal down 74% to 8.6 GW • On-shore Wind up 2048% to 94.6 GW • DR up 615% to 10.2 GW	• DR up 92% to 19.7 GW	
Significant Generation Changes			
	• Coal down 89% to 26.7 TWh • CC down 33% to 68.9 TWh • On-shore Wind up 2060% to 327.3 TWh	• Coal down 88% to 3.3 TWh	
Significant Net Export Changes (negative = Imports)			
	• Net Exports up 15% to 15% of demand		

The Southwest territory (Nebraska, SPP and Entergy) has a large increase in wind capacity in the CO2+ Scenario in 2020, sooner than the Northwest territory, but with little further growth after that point (Figure 46). In the RPS/R Scenario the growth is more gradual over the study period (Figure 45) while in the BAU Scenario, wind capacity is relatively small until 2035 (Figure 44). Coal and CC provide the bulk of generation in the BAU and RPS/R scenarios.

3.6 SOUTHEAST

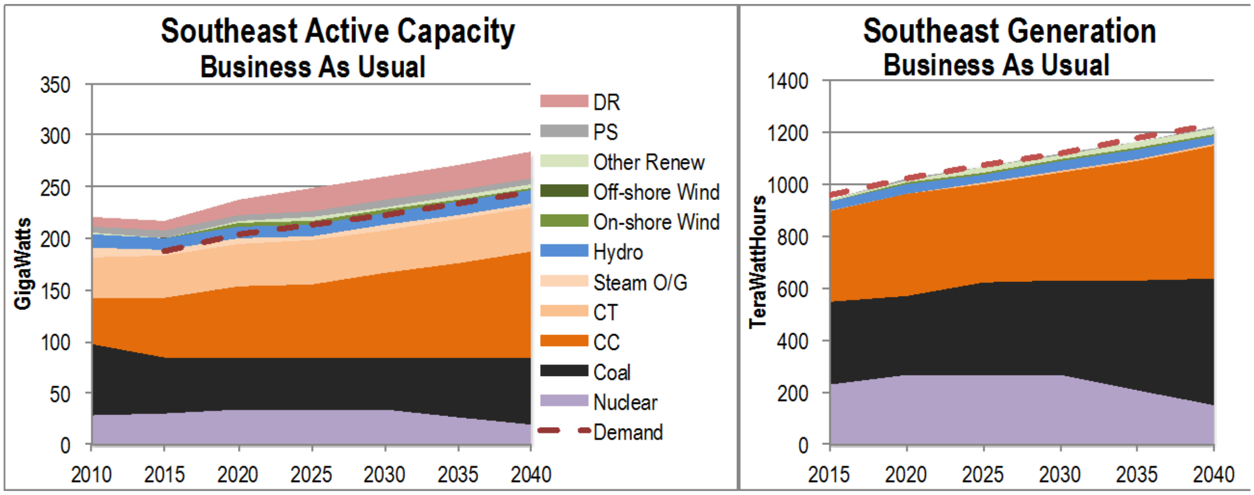


Figure 47. BAU Scenario Phase 1 Capacity and Generation for Southeast EI

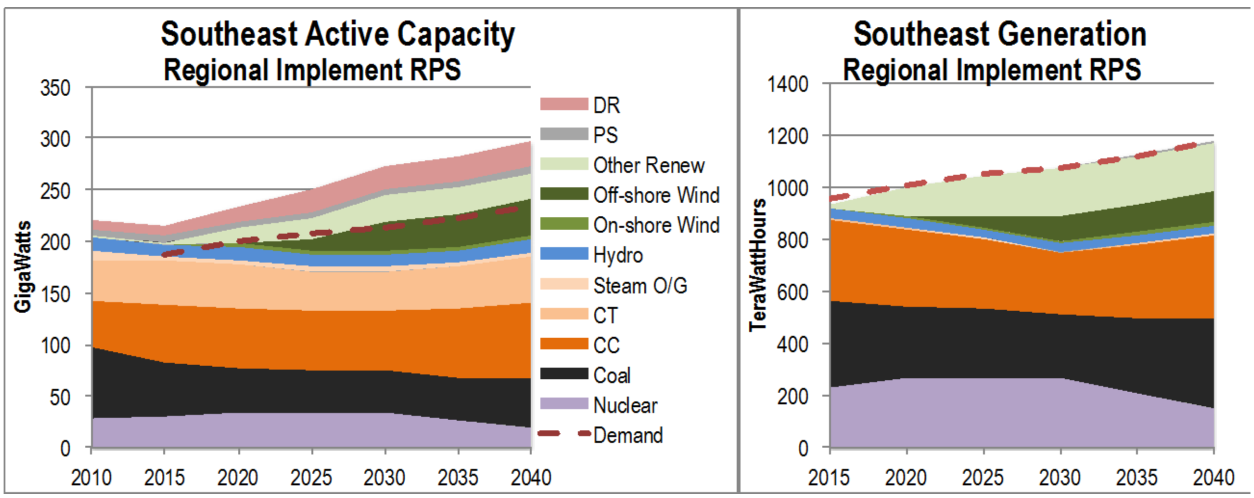


Figure 48. RPS/R Scenario Phase 1 Capacity and Generation for Southeast EI

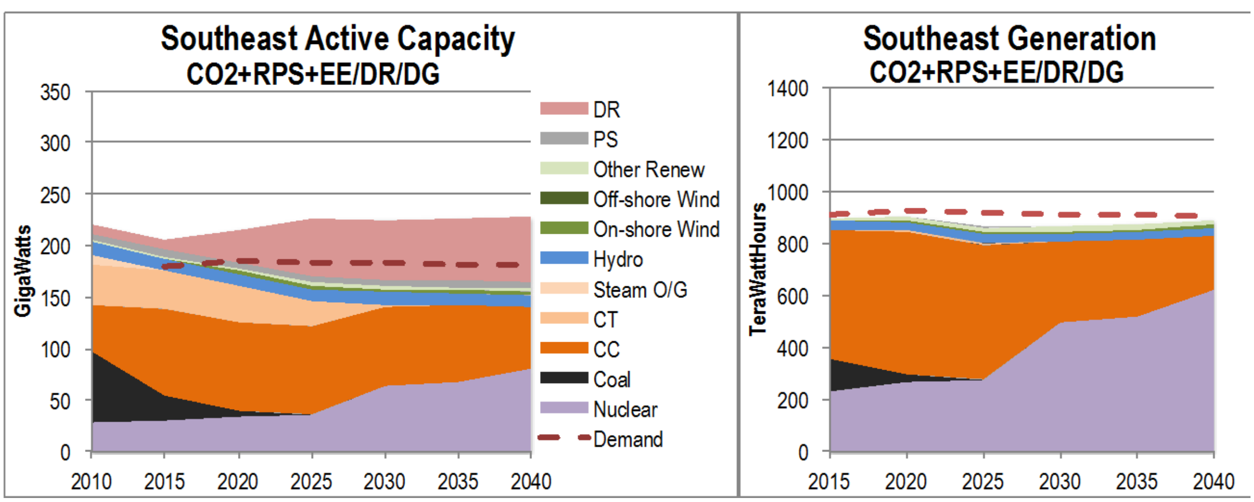


Figure 49. CO2+ Scenario Phase 1 Capacity and Generation for Southeast EI

Table 20. BAU Scenario Significant Changes through 2030 in Southeast EI

Territory: Southeast		Scenario: F1S17	
2015	2020	2025	2030
Significant Capacity Changes			
• CC up 32% to 59.0 GW	• DR up 60% to 15.2 GW	• DR up 43% to 21.8 GW	
Significant Generation Changes			
Significant Net Export Changes (negative = Imports)			

Table 21. RPS/R Scenario Significant Changes through 2030 in Southeast EI

Territory: Southeast		Scenario: F6S10	
2015	2020	2025	2030
Significant Capacity Changes			
	• Other Renew up 698% to 14.9 GW • DR up 60% to 15.2 GW	• Other Renew up 40% to 21.0 GW • DR up 43% to 21.8 GW	• Off-shore Wind up 150% to 28.5 GW
Significant Generation Changes			
	• Other Renew up 725% to 110.3 TWh	• Other Renew up 41% to 155.4 TWh	• Off-shore Wind up 150% to 98.7 TWh
Significant Net Export Changes (negative = Imports)			

Table 22. CO2+ Scenario Significant Changes through 2030 in Southeast EI

Territory: Southeast		Scenario: F8S7	
2015	2020	2025	2030
Significant Capacity Changes			
• Coal down 64% to 25.3 GW • CC up 85% to 82.6 GW	• Coal down 80% to 5.0 GW • DR up 230% to 31.2 GW	• CT down 32% to 24.5 GW • DR up 77% to 55.3 GW	• Nuclear up 79% to 63.6 GW • CT down 86% to 3.5 GW
Significant Generation Changes			
	• Coal down 78% to 27.6 TWh		• Nuclear up 79% to 495.1 TWh • CC down 40% to 311.6 TWh
Significant Net Export Changes (negative = Imports)			

In the CO2+ Scenario, the Southeast territory (TVA, SOCO, VACAR, and Florida) has few renewable resources but instead relies on nuclear and CC for the bulk of its capacity (Figure 49). Nuclear expands greatly between 2025 and 2030, most notably in Florida. An interesting note is that regional capacity is insufficient for the region except for significant employment of demand response. This gets reflected in the marginal prices during peak times in both Phase 1 and 2. Offshore wind and other renewables are aggressively developed in the RPS/R Scenario (Figure 48), while the BAU Scenario continues its reliance on nuclear, coal, and CC (Figure 47).

4. INTEGRATED COST COMPARISON BETWEEN SCENARIOS

Costs were determined in the study through a variety of means. In Phase 1, most of the major costs were calculated within the MRN-NEEM model. In addition, other costs were calculated by either the EIPC or by working groups of the SSC. In Phase 2, the MAPS model calculated fewer categories of costs. In some instances the missing values were recalculated based on Phase 2 analysis while in others, the Phase 1 results were simply transferred over.

Over the course of the study, costs were calculated in three formats: annual costs (either for every five years in Phase 1 or just 2030 in Phase 2), one-time costs over the course of the study period such as construction costs, or levelized capital costs that provided the annual cost to recover the construction cost plus interest and other associated costs. Besides these, sub-annual or hourly costs were calculated in some circumstances but these can be summed to annual costs. The list of costs, their sources, and formats are in Table 23.

Table 23. Types of cost outputs with source and format

Cost	Phase 1		Phase 2	
	Source	Format	Source	Format
Fuel	MRN-NEEM	Annual every 5 years	MAPS	2030 Cost
Variable Oper. & Maint.	MRN-NEEM	Annual every 5 years	MAPS	2030 Cost
Fixed Oper. & Maint.	MRN-NEEM	Annual every 5 years	Phase 1 adjusted	2030 Cost
Capital – Generating	MRN-NEEM	Levelized every 5 years	EIPC	One-time construction cost
Capital – Transmission	EIPC	One-time construction cost	EIPC	One-time construction cost
Capital – Nuclear Uprates	EIPC	One-time construction cost	EIPC	One-time construction cost
Capital –Pollution controls	MRN-NEEM	Levelized every 5 years	EIPC	One-time construction cost
Distributed PV	SSC	Annual and Levelized	Phase 1	2030 Cost
Energy Efficiency	SSC	Annual and Levelized	Phase 1	2030 Cost
Demand Response	SSC	Annual and Levelized	Phase 1	2030 Cost
Variable Generation Cost	SSC / MRN-NEEM	Annual and Levelized	SSC / MAPS	2030 Cost
Thermal Integration Cost	SSC / MRN-NEEM	Annual and Levelized	SSC / MAPS	2030 Cost
Net Imports	MRN-NEEM	Annual every 5 years	MAPS/Phase 1	2030 Cost

Phase 1 costs can be put on the same basis and summed by using the annual costs, treating the levelized costs as the cost to be paid each year, and levelizing the remaining construction costs to provide an annualized amount. Costs between the five-year increments can be interpolated as well in order to create an annual stream of costs. These were then discounted to created the net present value of the costs for each scenario. This methodology was used in reporting the Phase 1 results (EIPC 2011).

Phase 2 costs are largely either costs only for 2030 or the one-time construction cost without interest, otherwise known as overnight construction cost. It is possible to scale the annual costs in other years from Phase 1 based on the relationship between the 2030 costs from the two phases for each scenario. The study conducted by Synapse, Inc. (Fagan et al. 2013) utilizes this method to attempt to compare the relative costs of the three scenarios for the entire EI, taking into account that emissions costs assumptions and kWh output are different in each.

It would be difficult, however, to apply a consistent scaling method if looking at regional costs, since regional capacity, generation, technologies, and transfers were different between the two phases. For that reason, the analysis below focuses simply on integrating the costs in the year 2030 for each region using Phase 2 results. Comparisons to Phase 1 costs in 2030 are in Figure 26, Figure 27, and Figure 28 above.

Fixed O&M costs from Phase 1 were adjusted based on the capacity changes in Phase 2 for each technology. To convert the overnight construction costs to costs in 2030, we applied an average capital recovery factor (or fixed cost recovery factor) of 11.5% to the construction costs. Actual capital recovery factors as used in Phase 1 (Table 12 of the Input Assumptions (CRA 2010)), varied from 11.2% for nuclear, 11.3% for combined cycle, and 11.8% for most other technologies. (Coal was set at 10.5% but represents little or no portion of new construction.) Since total generating construction costs were not disaggregated by type and no factor was set for transmission costs, a single representative number seemed most fitting. This value may understate the capital cost for renewables while overstate that for traditional technologies and transmission.

Net import costs represent the cost of imports into a region minus the revenues from sales out of the region. The costs are based on the sales amount and marginal cost at the time of generation. (MRN-NEEM also applies transfer and wheeling charges in their Phase 1 calculations.) In Phase 2, the hourly locational marginal prices (LMPs) were reported for 154 balancing areas spread across the NEEM regions. These were averaged on a weighted basis across each NEEM region to determine regional marginal prices. Any transfers between regions were costed at the price in the importing region. For example, if region A during a specific hour had a marginal price of $50/MWh and the neighboring region B had a price of $60/MWh, the sales into region B would be priced at $60/MWh. This calculation is somewhat simplistic since it does not take into account bilateral trades that may be priced at a fixed cost, but rather treats all sales as a wholesale market activity.

For a given NEEM region that exports electricity, the cost of that export would be included in the fuel, variable O&M, etc. costs, but the revenue from those exports would offset those costs. Similarly, if a region imported power, it would be costed at its LMP. The final sum of costs including the net import cost will give a better representation of the total cost of power for that region.

Hydro Quebec power was modeled differently than other regions in Phase 1 and 2; in Phase 1, the import capability to different regions was modeled as pseudo-units. The resulting imports were priced based on LMPs. For Phase 2, the interchange flows were taken from Phase 1 and applied as generation sources in the various regions. To cost this power, we applied the average cost of the Hydro Quebec power from Phase 1 to the generation (which essentially matched Phase 1) so both phases had the same costs. Exports and imports to WECC and ERCOT were calculated within MRN-NEEM and MAPS. Unit costs associated with them were determined from NEEM results in Phase 1 and applied to Phase 2.

Table 24, Table 25, and Table 26 below show the costs for each major territory and category in the three scenarios. Note that these do not include major costs that are common to all cases, such as capital on existing assets and stakeholder selected infrastructure and base levels of distributed generation. Demand response and energy efficiency expenses are those specified for 2030 so do not include earlier years' values. Only the average value for categories that had high/low ranges are shown.

Table 24. Phase 2 Costs in 2030 for the BAU Scenario ($Billion)

	EI	Northwest	Central	Northeast	Southwest	Southeast
Fuel	85.1	12.6	19.1	6.5	12.3	34.5
Variable O&M	18.4	4.1	4.7	0.9	3.4	5.4
Fixed O&M	50.3	9.5	14.8	5.7	6.6	13.7
Lev. Capital-Gen.	27.9	4.5	8.0	8.8	1.7	4.9
Lev. Cap.-Trans	1.8	0.4	0.4	0.5	0.4	0.1
Lev. Cap.-Other	3.1	0.7	1.0	0.1	0.5	0.8
Emissions	0.2	-	0.1	0.1	-	-
Distributed PV	-	-	-	-	-	-
EE + DR	1.5	0.2	0.4	0.6	0.0	0.2
Vari Gen Penalty	1.1	0.4	0.3	0.2	0.1	0.0
Large Thermal	6.2	1.0	1.7	0.6	0.9	2.1
Net Imports	1.6	(0.2)	0.5	0.9	0.1	0.2
Total	196.9	33.1	51.0	24.9	26.1	61.9

Table 25. Phase 2 Costs in 2030 for the RPS/R Scenario ($Billion)

	EI	Northwest	Central	Northeast	Southwest	Southeast
Fuel	73.8	8.5	15.4	5.6	7.7	36.6
Variable O&M	15.5	3.4	3.9	0.8	2.7	4.7
Fixed O&M	54.0	9.6	15.7	5.5	7.3	15.9
Lev. Capital-Gen.	78.1	11.3	24.0	8.6	10.4	23.9
Lev. Cap.-Trans	7.8	1.2	1.9	0.5	3.3	0.8
Lev. Cap.-Other	2.9	0.7	0.8	0.1	0.5	0.7
Emissions	0.1	-	0.1	0.1	-	-
Distributed PV	-	-	-	-	-	-
EE + DR	1.5	0.2	0.4	0.6	0.0	0.2
Vari Gen Penalty	2.6	0.6	0.9	0.2	0.6	0.3
Large Thermal	5.0	0.8	1.4	0.5	0.7	1.6
Net Imports	1.4	1.3	(1.6)	1.3	0.3	0.1
Total	242.6	37.5	63.0	23.8	33.5	84.8

Table 26. Phase 2 Costs in 2030 for the CO2+ Scenario ($Billion)

	EI	Northwest	Central	Northeast	Southwest	Southeast
Fuel	40.8	5.2	12.2	3.0	3.5	16.8
Variable O&M	6.4	1.0	1.8	0.7	0.7	2.2
Fixed O&M	36.6	7.3	8.5	4.9	6.1	9.9
Lev. Capital-Gen	99.8	33.6	9.9	9.5	26.0	20.9
Lev. Capital-Trans	11.3	4.0	2.3	1.0	3.2	0.9
Lev. Capital-Other	1.3	0.3	0.4	0.1	0.2	0.2
Emissions	45.3	7.6	15.0	2.0	5.1	15.7
Distributed PV	13.9	3.2	2.9	1.8	3.2	2.8
EE + DR	8.9	1.7	2.3	1.3	1.1	2.5
Vari Gen Cost	2.9	1.2	0.2	0.2	1.2	0.0
Therm Integ Cost	3.8	0.4	1.1	0.4	0.3	1.6
Net Imports	3.8	(3.6)	6.8	1.8	(3.8)	2.6
Total	275.0	61.9	63.4	26.7	46.8	76.2

In all scenarios, transmission capital costs represent at most 10% of the overall capital cost, and less than 5% of total costs. It is likely that in those scenarios with high levels of curtailment and/or demand response, additional transmission capacity would provide opportunities for lower cost power to displace high cost power. This will be examined more thoroughly in the next set of topics.

Total cost may be a better comparison between scenarios than cost per kWh since demands and generation differ but the energy services are essentially same. Energy efficiency, distributed generation, price elasticity, etc. all influence the amount of energy generated, thereby influencing the denominator. On the other hand, cost/kWh with regional imports and exports accounted for may provide an additional perspective on the possible cost for electricity to consumers under the different scenarios. Generation cost/MWh are shown in Figure 29, Figure 30, and Figure 31 above for each region. Below are the graphs showing the components based on demand, first in billion dollars for each territory (using the data from Table 24, Table 25, and Table 26) and then final graphs showing the cost per unit of demand.

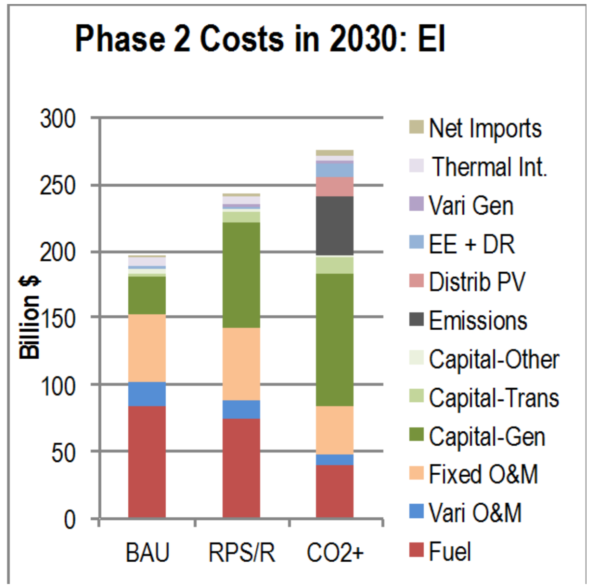


Figure 50. Total Costs in 2030 for EI

Figure 50 presents the cost summation for the entire EI. Fuel costs are highest in the BAU Scenario while levelized capital costs increase drastically in the other scenarios. Generator capital cost far outweighs the impact of transmission and other capital costs. On a straight comparison, the CO2+ Scenario has the highest cost. However, from a societal perspective, the picture is complex. Much of the top categories of costs are generally not born by the electricity sector, in that energy efficiency and distributed PV costs are largely borne by end-users. Large CO_2 emissions costs are only accounted for in the CO2+ Scenario and customers do not purchase a physical resource unique to this scenario, but rather the legal right to emit CO_2. Either the funds can be considered unencumbered and other societal costs (e.g. taxes) could be reduced, or they represent a damage cost that should be borne by CO_2 emissions in the other scenarios also but is not. Nevertheless, the various cost impacts do serve to raise the price of electricity in this scenario, thereby driving demand lower.

The following graphs present the cost information for each of the major territories of the EI as defined in Table 1. More detailed regional information is presented in Appendix A.

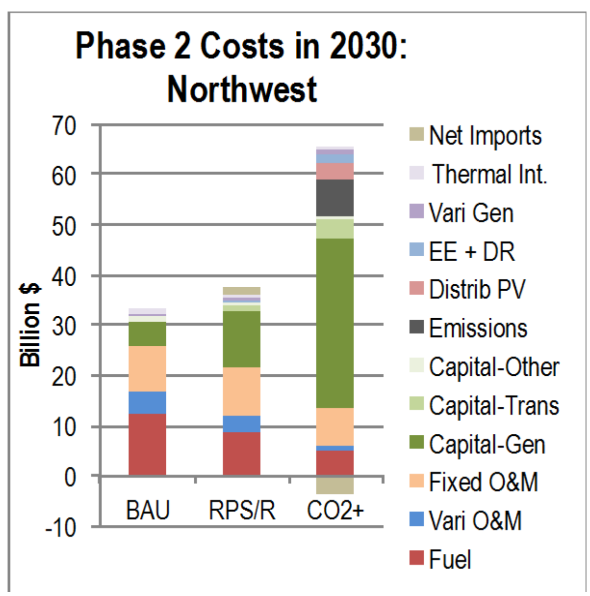


Figure 51. 2030 Costs for Northwest EI

The Northwest territory (MISO + MAPP) develops a large amount of wind capacity in the CO2+ Scenario, almost 100 GW more than in the BAU Scenario. They also build 15 GW more CC plants. Together, these lead to the large levelized capital cost for generating plants as shown in Figure 51. Some export revenue is returned to the region to offset some of the costs, but in Phase 2 (shown) more of the generation remained in the region than during Phase 1. Emissions costs are 11% of total costs in that scenario. The RPS/R Scenario has some increase in capital costs due to wind and CC build-out, but much less than the CO2+ Scenario. With the local preference for renewable resources and no CO_2 cost, new capacity is spread to other regions and 50 GW of coal capacity is left online. Rather than exports, the territory as a whole imports a small amount of power. The BAU Scenario has much lower capital costs, but the highest fuel cost. Coal and CC production is highest in this scenario. The corresponding graphs for each region and territory are included in Appendix A.

The Central territory (PJM and Non-RTO Midwest) has slightly lower costs in the CO2+ Scenario than the RPS/R Scenario. It imports power from several regions in the CO2+ Scenario, most notably the Northwest and Southwest through new HVDC lines. This territory's emissions costs are highest of all at 24% of total costs. With lower production (due to both lower demand and imports) operating and fuel costs are reduced. In the RPS/R Scenario capital costs are much higher as new renewable capacity is constructed within the region to achieve the renewable portfolio standard. A small amount of generation is exported. The BAU Scenario has the highest fuel and other operating costs but much lower capital costs and no CO_2 emissions cost.

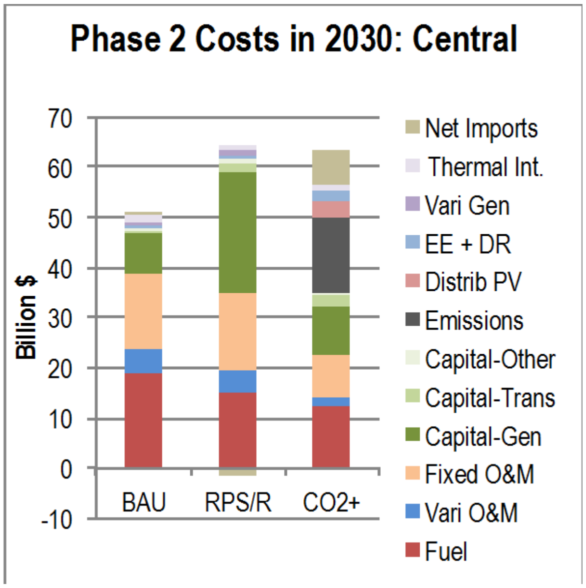


Figure 52. 2030 Costs for Central EI

The Northeast territory (New York, New England, and Ontario) has relatively similar costs in all three scenarios. The CO2+ Scenario has lower fuel costs but higher capital and emissions costs. The territory also imports more power from Hydro Quebec in the CO2+ Scenario. The RPS/R Scenario has the lowest overall cost with reductions in most categories. However, imports are 0.4 B$ higher. Within the territory, there is a great deal of difference in generation and cost between regions. NYISO_A-F, NYISO_G-I, and IESO are all net exporters, while NYISO_J-K and NEISO are net importers. Hydro Quebec power flows to IESO, NYISO_A-F, and NEISO, but much of it then passes on to the other two NYISO regions. NYISO_J-K gets 58% to 74% of their demand from imports, comprising 45% to 55% of their total cost. These results can be seen in Appendix A.

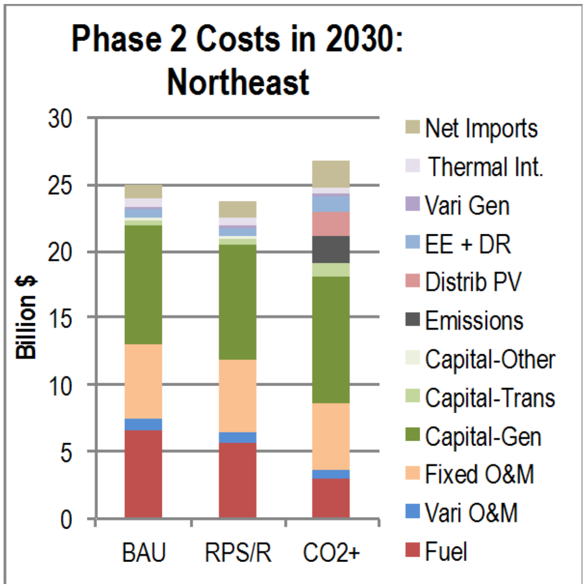


Figure 53. 2030 Costs for Northeast EI

As with the Northwest territory, the Southwest territory has a large build-out of wind (94 GW more than the BAU Scenario) to offset deactivations of coal, CC and less efficient peaking plants. Although the region does export a good share of its power, much of it is used internally since the Entergy region becomes a large importer. The territory is relatively self-sufficient in Scenarios 2 and 3. Wind capacity is 34 GW higher in the RPS/R Scenario than the BAU Scenario and capital costs are higher accordingly. Also, both the CO2+ Scenario and the RPS/R Scenario have an extensive build-out of transmission to collect the wind generation. The BAU Scenario has lowest cost, with little addition in capacity over and above the baseline for all three cases. Fuel costs are higher, since coal and gas are major sources.

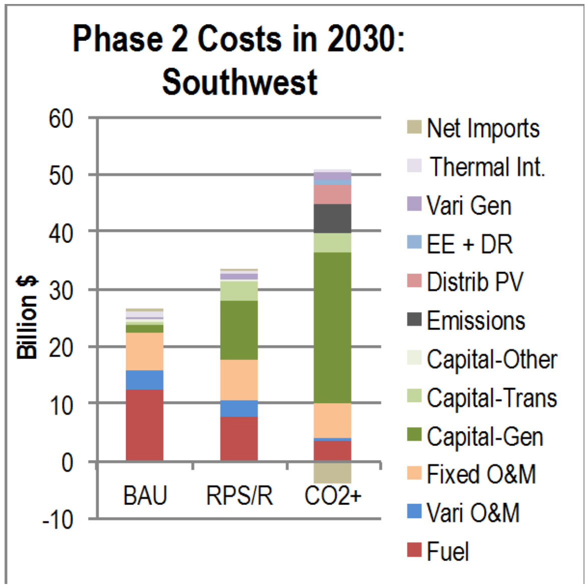


Figure 54. 2030 Costs for Southwest EI

The Southeast territory of the EI (TVA, Georgia, Alabama, Florida, and Carolinas) has high capital costs in the CO2+ Scenario, largely from a build-out of 26 GW of nuclear power, mainly in Florida. With fewer renewable resources available, the region uses nuclear power for a non-carbon resource. The region also relies more heavily on CC capacity (at 35% of total) than any other region. In the RPS/R Scenario, offshore wind is developed to provide local renewable resources, despite their relatively high cost. Fuel cost is higher both because of the need for local generation and increases in biomass and other renewables.

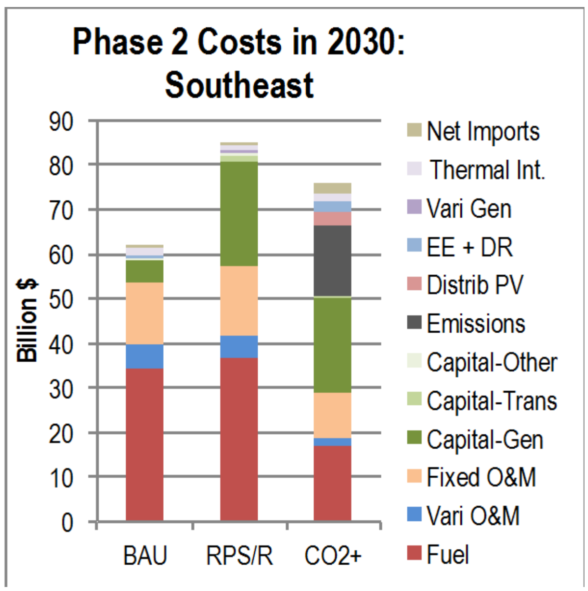


Figure 55. 2030 Costs for Southeast EI

Figure 56 below shows the relative cost per MWh for each territory, dividing the total cost (including net imports) by the demand in the region. As explained above, this is closer to a comparison of what each region would pay for electricity rather than the relative cost to provide the energy services. The next graph (Figure 57) uses the BAU Scenario demands for each territory to lessen that distortion. However, even with a constant denominator in all three scenarios, the CO2+ Scenario is still relatively expensive. Most interesting is the cost in the Southwest and Northwest territories. There is a high capital cost for new generation, but exports only recover a portion of that. Much of the new generation is used internally within the territory. For example, the Southwest includes the exporting regions of SPPN, SPP_S, and NE, while ENT is a major importer. Part of this higher cost per unit is due to the large amount of curtailed wind power in the CO2+ Scenario for these two regions.

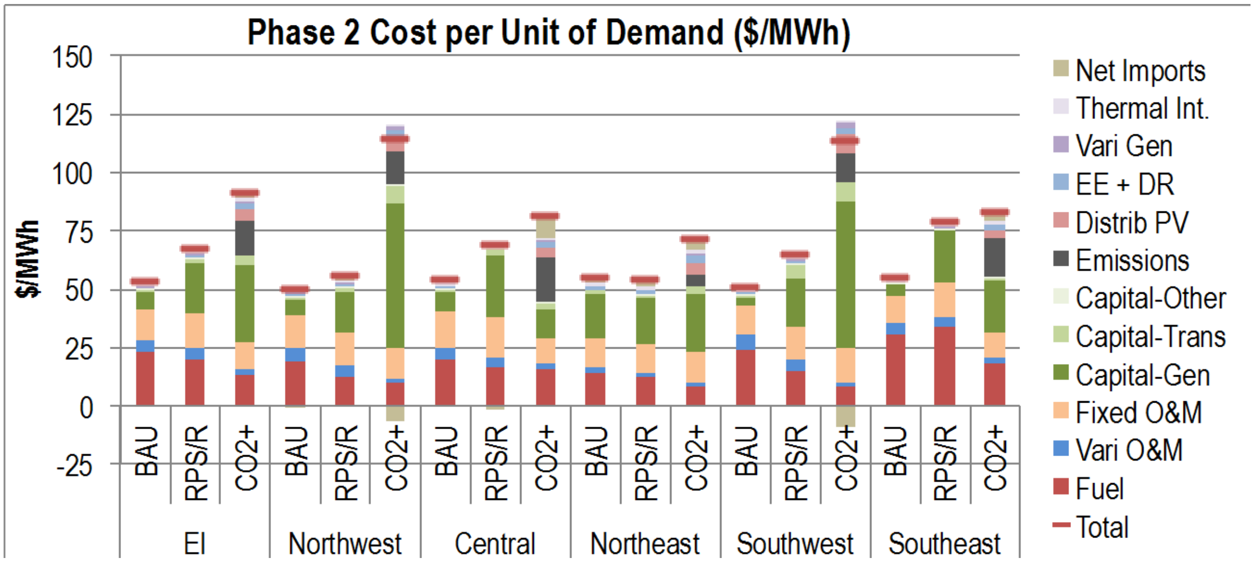


Figure 56. 2030 Cost per Unit Demand for EI and each Territory

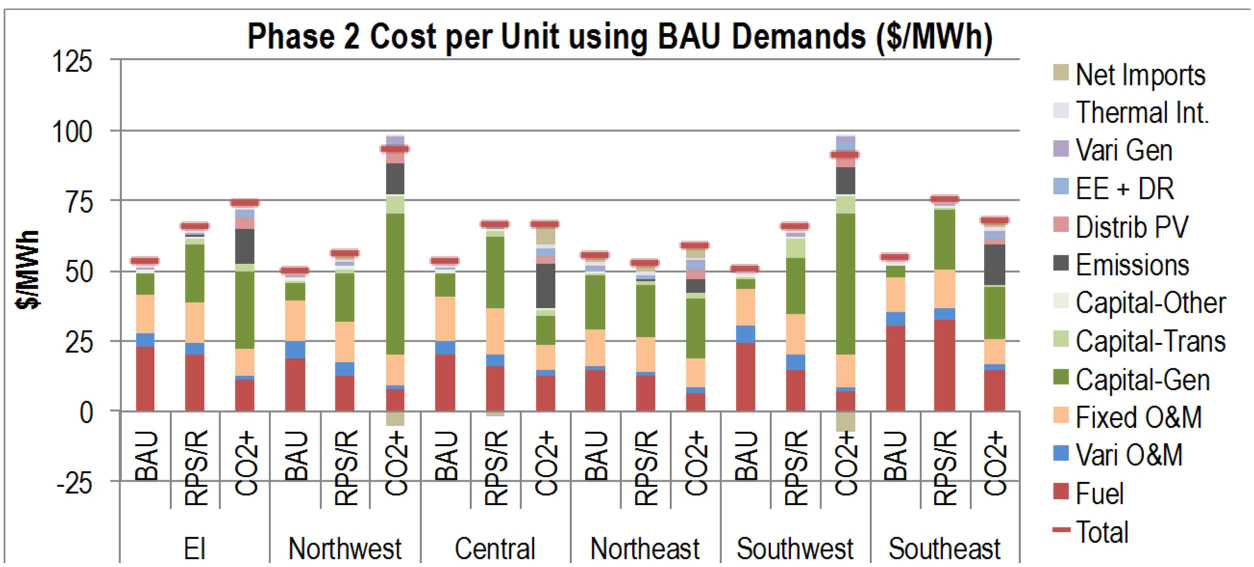


Figure 57. 2030 Cost per Unit using the BAU Scenario Demands for EI and each Territory

5. REGIONAL RELIANCES

According to the Phase 2 hourly generation reports, some regions can have one technology dominate their generation over extended periods such as a week or the course of the year. First, the table below (Table 27) shows the most dominant generating technologies over the full year of 2030 in Phase 2 for each of the regions and territories. In the CO2+ Scenario, ten regions have one technology provide more than two thirds of their generation from one technology (highlighted in red). In the RPS/R and BAU Scenarios only six do. Wind is often dominant in the CO2+ Scenario with some regions relying on nuclear or CC. The wind regions export a fair amount of that production, but still face some issues of wind curtailment and/or high demand response use. These will be examined more in the next report. Coal continues its dominance in the BAU but declines some in the RPS/R Scenario. The CO2+ Scenario clearly shows the shift to new technologies, where CO_2 producing technologies are heavily penalized and so production minimized.

Table 27. Most dominant technologies in each region or territory with percent of total generation

	BAU		RPS/R		CO2+	
Region or Territory	**Technology**	**% Gen in 2030**	**Technology**	**% Gen in 2030**	**Technology**	**% Gen in 2030**
MAPP_CA	Hydro	59%	Hydro	**96%**	Hydro	**92%**
MAPP_US	Coal	53%	Wind	54%	Wind	**72%**
MISO_W	Coal	51%	Wind	48%	Wind	**83%**
MISO_MO-IL	Coal	**77%**	Coal	**74%**	Wind	39%
MISO_WUMS	Coal	41%	Coal	47%	Comb Cycle	44%
MISO_IN	Coal	**83%**	Coal	**90%**	Wind	57%
MISO_MI	Coal	45%	Coal	43%	Comb Cycle	52%
NonRTO_Midwest	Coal	**93%**	Coal	**91%**	Comb Cycle	**84%**
PJM_ROR	Coal	53%	Coal	39%	Nuclear	39%
PJM_ROM	Coal	38%	Nuclear	30%	Nuclear	46%
PJM_E	Nuclear	54%	Nuclear	46%	Nuclear	57%
IESO	Nuclear	60%	Nuclear	60%	Nuclear	63%
NYISO_A-F	Hydro	32%	Hydro	33%	Hydro	36%
NYISO_G-I	Nuclear	49%	Nuclear	**70%**	Nuclear	**74%**
NYISO_J-K	Comb Cycle	**80%**	Comb Cycle	**81%**	Comb Cycle	**83%**
NEISO	Comb Cycle	36%	Nuclear	37%	Nuclear	47%
NE	Coal	**68%**	Coal	55%	Wind	**68%**
SPP_N	Coal	**75%**	Coal	54%	Wind	**85%**
SPP_S	Coal	56%	Wind	47%	Wind	**81%**
ENT	Comb Cycle	42%	Comb Cycle	36%	Nuclear	51%
TVA	Coal	40%	Nuclear	34%	Nuclear	47%
SOCO	Coal	37%	Coal	32%	Nuclear	46%
VACAR	Nuclear	41%	Nuclear	37%	Nuclear	62%
FRCC	Comb Cycle	61%	Comb Cycle	54%	Nuclear	**69%**
Northwest	Coal	55%	Coal	48%	Wind	53%
Central	Coal	46%	Coal	33%	Nuclear	41%
Northeast	Nuclear	41%	Nuclear	43%	Nuclear	50%
Southwest	Coal	52%	Coal	42%	Wind	**66%**
Southeast	Comb Cycle	34%	Nuclear	27%	Nuclear	57%
EI	Coal	38%	Coal	30%	Nuclear	37%

Figure 58 provides this data in a chart showing the dominant resource for each region for each of the scenarios. The first column in each grouping is the BAU, the second is the RPS/R, and the third is CO_2+. Note that coal dominance in BAU and RPS/R often switches to wind in the CO_2+ scenario. Nuclear is relatively dominant in a number of regions though rarely more than 50% of the total.

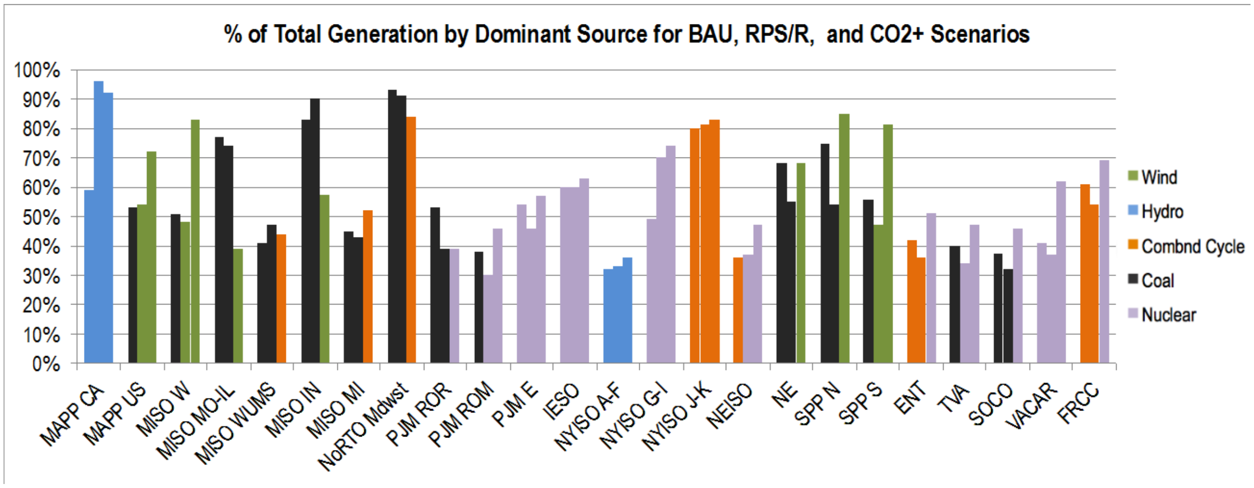


Figure 58. Dominant Generation Source for each region and scenario

Another indicator of domination by a single technology is how many days in a year do certain technologies provide the overwhelming share of generation. Even in regions that do not have a dominant technology over the entire year, there may be periods of time when the region is highly reliant on a single one. Below are tables showing the number of days in 2030 that one technology provides over 80% of the generation in at least 20 of the 24 hours of the day (Table 28, Table 29, and Table 30).

Table 28. Number of days that technology dominates region's generation in the BAU Scenario

	Coal	Combined Cycle
MISO_IN	162	-
MISO_MO-IL	45	-
NE	3	-
NonRTO_Midwest	360	-
NYISO_G-I	-	3
NYISO_J-K	-	269
SPP_N	27	-

Table 29. Number of days that technology dominates region's generation in the RPS/R Scenario

	Nuclear	Coal	Comb. Cycle	Hydro	Wind
MAPP_US	-	-	-	-	18
MISO_IN	-	339	-	-	-
MISO_MO-IL	-	24	-	-	-
MISO_W	-	-	-	-	3
NonRTO_Midwest	-	360	-	-	-
NYISO_G-I	15	-	-	-	-
NYISO_J-K	-	-	281	-	-
SPP_N	-	2	-	-	4
MAPP_CA	-	-	-	348	-

Table 30. Number of days that technology dominates region's generation in the CO2+ Scenario

	Nuclear	Comb. Cycle	Hydro	Wind
ENT	47	-	-	-
FRCC	13	-	-	-
MAPP_US	-	-	-	101
MISO_IN	-	-	-	40
MISO_W	-	-	-	181
NE	-	-	-	15
NonRTO_Midwest	-	243	-	-
NYISO_G-I	31	-	-	-
NYISO_J-K	-	178	-	-
SPP_N	-	-	-	157
SPP_S	-	-	-	111
VACAR	4	-	-	-
MAPP_CA	-	-	310	-

Note that in the CO2+ Scenario, wind is a dominant provider for more than 15 days in six different regions. All of the regions located along the western part of the EI have numerous days where wind is the main contributor. Nebraska (NE) is reduced because they have two nuclear plants that continue to provide baseload non-carbon electricity. Four regions have nuclear providing a dominant share on multiple days. These are regions that do not have significant renewable resources. Lastly, two smaller regions utilize CC plants for much of their generation. They either have converted their coal to gas production or have few other resources available.

In the RPS/R Scenario coal continues to be viable and dominates in several regions, especially two regions (MISO_IN and NonRTO_Midwest) in the Midwest that currently have high coal market share. Hydro is a major component of MAPP_Canada as they build additional capacity for the RPS market. In the BAU Scenario, coal dominates more regions since there is less renewable development, although current projected EPA regulations continued to be modeled in this scenario as in the others. Combined cycle generation dominates in NYISO_J-K (NYC and Long Island) in all three scenarios.

6. GAS USAGE

Many people expect that the amount of natural gas used for generation will increase significantly in the coming years. The rapid increase in availability of shale gas has lowered the prices for natural gas, making it a viable wide-scale source of baseload power. One topic of interest was how much growth was projected by the EIPC cases. Regionally, might the growth be significantly more than current amounts, such that current infrastructure may need rapid expansion to handle the growth.

While natural gas prices in the EIPC cases were projected to moderate from previous years' estimates, they did not take fully into account the current drop in prices. Figure 59 is a graph of the prices as used in the cases, based on the Annual Energy Outlook 2011 Early Release reference case (AEO2011ER). Also on the graph are other years' projections from EIA, including the Annual Energy Outlooks from 2010, 2011, 2012, and 2013. Note how the most recent estimate has natural gas prices by 2030 roughly 20% ($1.27) lower than the price used for the EIPC study. The "low gas price" sensitivities in Phase 1 used a constant price of $4.50 for the entire period, while the "high gas price" sensitivities had a gradual shift from the AEO2011ER price to the AEO2010 price by 2025 and the AEO2010 price for all subsequent years. This equaled $8.20 in 2030. So the current expected gas prices were bounded by the high and low sensitivities in 2030, although the AEO2013 prices are below the low gas sensitivity through 2022.

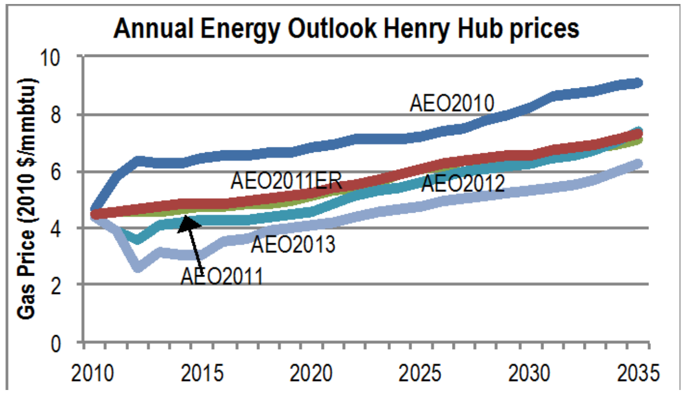


Figure 59. Gas prices from Annual Energy Outlooks

6.1 GAS TRENDS IN SCENARIOS

Natural gas use for electricity in the EI started at about the same level in the BAU and RPS/R scenarios, 5.3 quadrillion btus (quads) in the BAU Scenario and only 4.9 Quads in the RPS/R scenario. Demands were slightly lower in the latter, and less combined cycle generation was used. Gas use stayed flat and then further declined in the RPS/R scenario since coal generation remained economic while renewable generation increased its percentage, squeezing gas use. In the CO_2+ Scenario gas use in 2015 is 7.2 Quads, 38% more than in the BAU. Even at the beginning of the study period, CO_2 costs cause the conversion of coal to natural gas generation; and gas generation continues to grow to 8.4 Quads by 2020. However, by 2028 or so, the reduction in demand in the CO_2+ Scenario lowered gas usage to below that of the BAU Scenario.

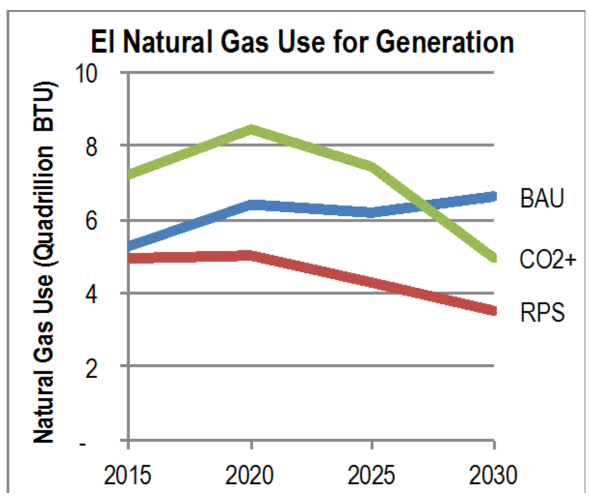


Figure 60. Gas use for electricity

6.2 REGIONAL GAS USE

As expected, natural gas use changes over time and is highly dependent on the scenario studied. Below are three figures showing the gas usage from Phase 1 for 2015-2030 for each scenario. In addition, they also show the approximate gas usage for 2030 from Phase 2 on the right side of the graphs. Some of the key region results are named in the graphs, with the rest of the regions shown as fainter lines.

In the BAU Scenario (Figure 61), most regions have a relatively flat amount of natural gas use over the period. FRCC had continued growth as CC plants were used to provide additional power. PJM_ROR had less CC generation in Phase 2 than Phase 1 (Figure 9), resulting in lower gas use.

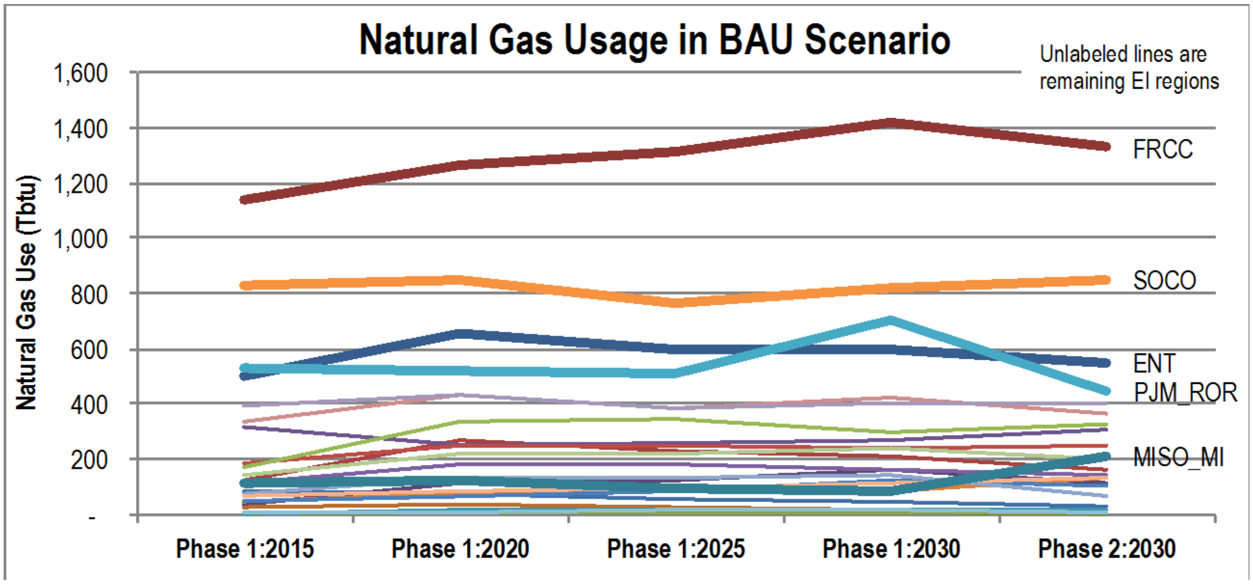


Figure 61. Natural Gas Use in the BAU Scenario

In the RPS/R Scenario (Figure 62), most regions had relatively flat or declining growth in gas use, as renewables gradually assumed a larger share of the market. Some regions, such as PJM_ROR and MISO_MI, had higher gas levels in Phase 2 than Phase 1. Their CC generation was higher in Phase 2, although a small portion of their overall generation (Figure 10.)

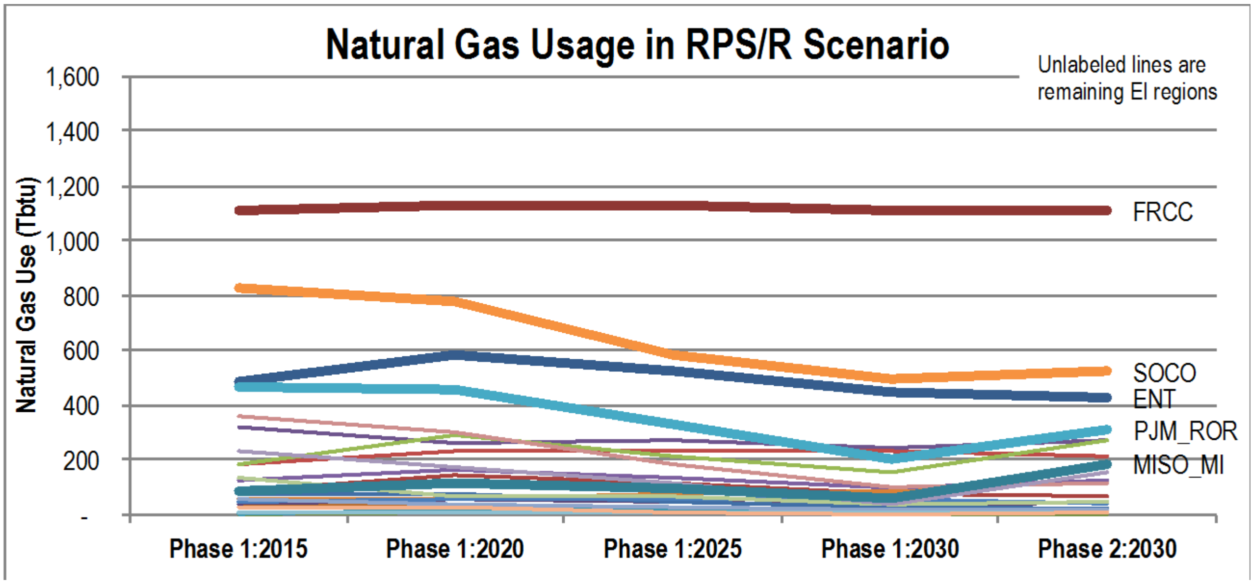


Figure 62. Natural Gas Use in the RPS/R Scenario

In the CO2+ Scenario (Figure 63), all of the regions showed declines in gas use between 2025 and 2030, as gas production decreased while other resources increased, due largely to the increase in CO_2 costs.

Most notable was the drop in FRCC; the region had a large increase in nuclear capacity between those years that supplanted much of the gas generation. PJM_ROR and SOCO were other large users in gas. While most regions saw roughly the same amount of gas use in 2030 from both Phase 1 and 2, a few saw significant changes. MISO_IN had the biggest difference, as can be seen by the slope of the line between the last two points. In Phase 2, that region received a good amount of its power from MISO_W through PJM_ROR from the HVDC lines, resulting in lower internal generation (Figure 11.)

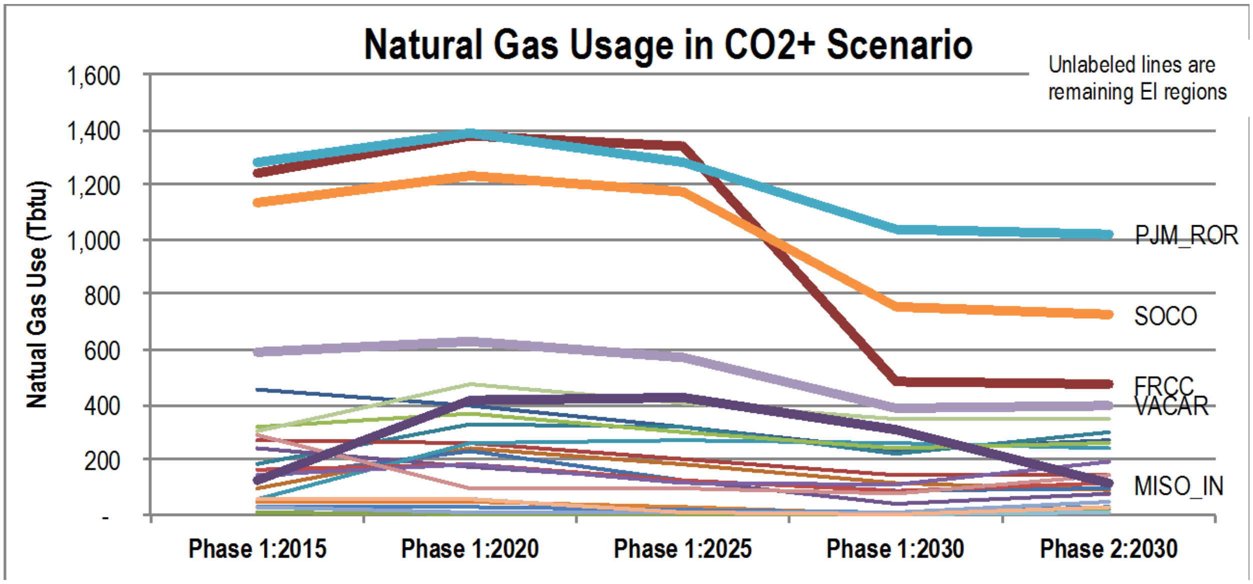


Figure 63. Natural Gas Use in the CO2+ Scenario

Many people may be surprised by the high amount of natural gas used in FRCC in the three scenarios. Combined cycle plants are the dominant supply for most years, except by 2030 in the CO2+ Scenario where nuclear became a major source. They have historically been a high gas user since they are relatively far from coal sources, while having more available access to natural gas from the Gulf.

6.3 KEY RELIANCES

While there does not appear to be a large growth in gas use between 2015 and 2030 (–32% in the CO2+ Scenario, –29% in the RPS/R Scenario, +26% in the BAU Scenario) the other question raised was whether there were key times in a year when natural gas was a critical source of power. Did natural gas use spike at certain times so that while the annual amount was low, the relative amount was high for certain days.

This is somewhat the converse of the topic in section 5. In that section, we showed that combined cycle technology dominated in only NYISO_J-K for all three scenarios. This region, New York City and Long Island, has limited other technologies available. The other major sources there are peaking plants and they are largely fueled by natural gas as well. Imports provided almost all of the rest of the power needed. In the CO2+ Scenario, CCs also provided a large portion of supply for Non-RTO Midwest, since their coal plants were largely converted to gas. In FRCC in the BAU Scenario, natural gas played an important role as the main source of new production. Nevertheless, in that scenario gas use only rose by 25% over a fifteen-year period.

Those regions that have low relative levels of natural gas use generally have their peak amount occur in the peak months of July and August. During this time CT and other peaking capacity is needed. In the CO2+ Scenario, no region required more than 10% of their total gas in a single week and no region used more than 21% of their annual demand in a three-week period. In the RPS/R Scenario, the western regions had the largest spike in the gas use, during mid-July. MAPP_US used 56% of their annual amount in the middle three weeks of July, with MISO_W and NE at 48% and SPP_N at 38%. The BAU Scenario had similar spikes in gas demand, with MAPP_US needing 54% of their annual gas, Nebraska at 45%, and both MISO_W and MISO_MO-IL at 39%. None of these regions were among the highest gas users, so it is unclear if they may feel some constraints during this time.

7. SUMMARY

Below is a summary of the main insights from the five topics studied.

7.1 TOPIC 1: HOW DO PHASE 2 RESULTS COMPARE TO PHASE 1?

Since Phase 2 was a more detailed look at the EI, it captured more of the complexities that a real system faces and operated the system under a broader set of circumstances (variable generation and demands). As a consequence, it required additional capacity (for reliability) and costs were higher, especially in the CO_2+ Scenario in reaction to the curtailed or unavailable resources. This can serve as a warning to any modeling done: accuracy is limited by the model and data used.

Capacity amounts for the total EI differed between 4% and 6% between the two phases depending on the scenario, with only Entergy, MISO_W, NEISO, PJM_E and IESO showing Phase 2 increases greater than 10%, while MISO_WUMS had a large decrease in peaking capacity in the RPS/R Scenario. Since the Phase 2 capacities were input based on results from Phase 1 (plus possibly modifications for reliability purposes), there should not have been great differences. Some of the regional differences were due to manually improved placement of combustion turbines (CTs) across the territories during Phase 2.

Generation amounts differed only slightly for the EI as a whole. There was greater regional variation because of differences in transmission modeling, hourly supply and demand variations, and reliability constraints for reserves. Several of the regions in the western EI had much lower Phase 2 generation (MAPP_US, MISO_W, MISO_MO-IL, MISO_IN, NE, SPP_N) in the CO2+ Scenario. This was likely due to the excess wind that had to be curtailed in many hours in those regions.

Inter-regional transmission was quite different between some of the regions, especially in the CO2+ Scenario. The hourly modeling in Phase 2 (and the greater variation in wind generation) meant greater opportunities for transfers. In addition, there was a more explicit and accurate build-out and modeling of power flow in Phase 2 than Phase 1. Phase 1 power flows were based on a simpler “bubble and pipe” model rather than true transmission system modeling. The inter-regional maximum and average flows in Phase 2 were most different for the windy regions (MISO_W, NE, SPP_N, and SPP_S).

Total costs in Phase 2 for all of the EI were 16% higher than Phase 1 in the CO2+ Scenario but only 4% and 1% in the other two scenarios. Cost differences can arise from differences in generation. However, generation differences would largely only affect the variable costs. Levelized capital costs varied both by the amount of capacity added, the cost applied to capacity, and the levelizing process. Phase 2 had more precise (and generally higher) capital costs as the different EIPC members developed costs based on known projects; also, the phase had higher generating capacities. Generating plant capital costs heavily outweighed that of transmission. The difference in cost is most noticeable in the CO2+ Scenario in the high wind regions, MISO_W, SPP_N, and SPP_S where wind capacity was highest.

7.2 TOPIC 2: WERE THERE SIGNIFICANT CHANGES IN EARLIER YEARS WITHIN VARIOUS REGIONS?

The most consistent change across the regions was the large increase in demand response expected by 2020 and 2025, especially in the CO2+ Scenario but also the other two scenarios. Most regions also had a large decrease in capacity between 2010 and 2015, most often that of coal-, oil- or gas-fired steam plants.

The CO2+ Scenario had the largest change in all regions, as the carbon cost increased to high levels so carbon-based fuels declined. Coal generation was the first to decline, often replaced with combined cycle (CC) or wind initially. In the later years even CC plants decreased production in favor of nuclear or additional renewable generation. The western territories had a massive increase in wind capacity, with the Southwest having most growth by 2020 and the Northwest in 2025 and 2030. The Central territory largely increased their imports as internal coal capacity declined. Northeast demand declined over time so nuclear and imports made a larger share of supply. The Southeast relied more on combined cycle to supply production in the early years, with nuclear expanding to over 50% of demand in 2030.

In the RPS/R Scenario, most changes were more gradual. Wind and other renewables were added as the RPS requirement increased. As in the CO2+ Scenario, large wind increases occurred somewhat sooner in the Southwest than Northwest. Offshore wind and other renewables provided almost all new capacity in the Southeast. The BAU Scenario had very few large changes in capacity and generation over time in the various territories.

7.3 TOPIC 3: WHEN ALL COSTS ARE INTEGRATED, HOW DO RESULTS COMPARE BETWEEN SCENARIOS?

Cost evaluation included the annual fuel and operating costs, emissions costs, the levelized capital cost for generation and upgrades to transmission, and several other customer costs. The Phase 2 costs only evaluated 2030 rather than values over the full thirty-year period. Costs were highest for the EI in the CO2+ Scenario. Some of this higher cost represented CO_2 emissions costs that either are intangible costs (and so available for other purposes) or are costs that should be included in other scenarios for comparison. Regardless, costs were still high for the CO2+ Scenario and the RPS/R Scenario due to the large capital investment in new capacity. Fuel and other operating costs were much lower in the CO2+ Scenario though.

The Northwest and Southwest territories had the highest relative capital cost in the CO2+ Scenario, but in the RPS/R Scenario new capacity shifted to the Central and Southeast territories so their highest costs were in the RPS/R Scenario.

On a cost per unit of demand basis, the Northwest and Southwest regions stood out as higher than the others in the CO2+ Scenario, even when adjusting to use the same demand levels in all scenarios. Reducing net costs to reflect the earnings by exporting power to other regions did not overcome the higher capital and operating costs due to new construction for these regions. The calculations assumed export sales at wholesale marginal costs; higher prices may be necessary to recover the capital investment.

Transmission capital cost represented only 10% of the overall capital cost, and less than 5% of total costs. It is likely that in those scenarios with high levels of curtailment and/or demand response, additional transmission capacity would provide opportunities for lower cost power to displace high cost power.

7.4 TOPIC 4: DO SOME REGIONS FACE OVER-RELIANCE ON CERTAIN FUELS OR TECHNOLOGIES?

Regions with a high reliance on a single fuel may be vulnerable to shortages. The CO2+ Scenario had the most regions with high levels of reliance on single technologies, with ten regions relying on a single source for over 2/3 of their generation. These regions were generally reliant on wind, hydro, or combined cycle, so may be vulnerable to intermittent shortages due to calm winds, long-term drought, low gas supply issues. Only six regions in the RPS/R and BAU Scenarios had high levels of reliance, with coal playing a role in most of them, which is less likely to be vulnerable to disruptions.

Using a different metric, we looked at the number of days one technology provides over 80% of generation for 20 of the 24 hours. In the CO2+ Scenario, six regions relied heavily on wind for multiple days (between 15 and 181 days), four relied on nuclear for between 4 and 47 days, two on combined cycle for 178 days (NYISO_J-K) and 243 days (Non-RTO Midwest), and MAPP_CA relied on hydro for 310 days. The RPS/R Scenario had coal dominate in four regions, most notably 339 days in MISO_IN and 360 days in Non-RTO Midwest. Nuclear, CC, hydro, and wind dominated some days in different regions. Coal increased in the number of regions and days in the BAU Scenario, with the most dominant being 360 days for Non-RTO Midwest. In all three scenarios, NYISO_J-K was dominated for internal generation by combined cycle, since this region has few other resources available.

7.5 TOPIC 5: ARE THERE SHORT-TERM OVER-RELIANCES ON NATURAL GAS USAGE IN SOME REGIONS?

The study used gas prices from DOE's Annual Energy Outlook (AEO) 2011 with a price of $6.58 by 2030. Since then, estimates of prices in 2030 have dropped 20% to $5.31 in the most recent AEO. A possible consequence is that the study did not capture the level of conversion to natural gas that is now expected by many in the industry. The exception might be that in the CO_2+ Scenario, even by 2015 total gas demand was 37% higher than in the BAU Scenario, due to the relative cost impact of CO_2 emissions on coal versus gas generation. The low gas price sensitivities used a price of $4.50 for all years so they may provide a view of the impact of current prices. These will be examined in the third stage of this study, the "low priority" questions.

As mentioned above, some regions showed dominance by gas, most notably NYISO_J-K (and Non-RTO Midwest in the CO2+ Scenario). There did not appear to be a huge growth in gas demand between 2015 and 2030 for any region. Many regions saw declines between 2025 and 2030 in the CO2+ Scenario as CO_2 costs raised the cost of gas. When considering whether gas use in a region spiked during brief times, this appeared to hit the western regions most. During three weeks in July, these regions could use over 40% of their annual gas requirements to provide peaking power. This only occurred in Scenarios 2 and 3, and these regions were not heavy users of gas so it is unlikely they would face critical shortages.

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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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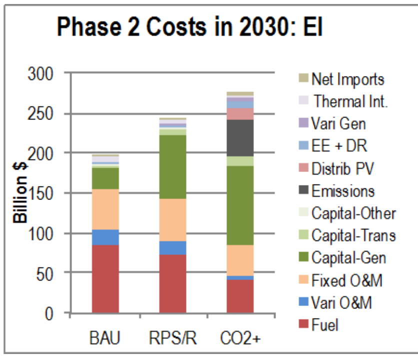
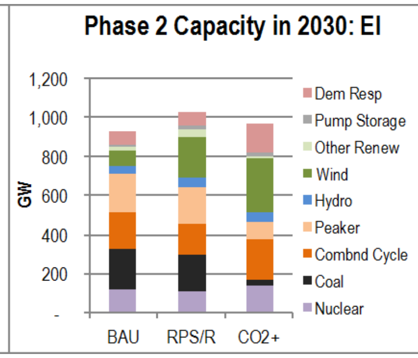
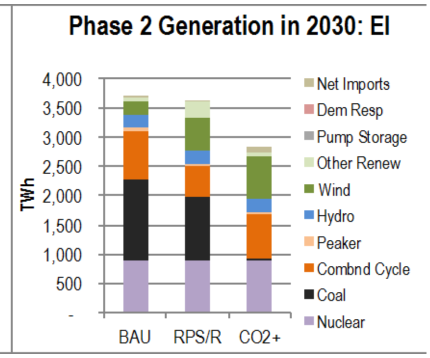
APPENDIX A: COST, CAPACITY, AND GENERATION BY REGION

EASTERN INTERCONNECTION







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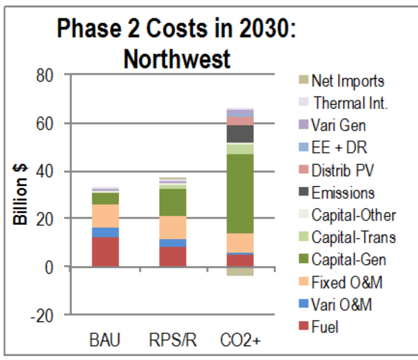
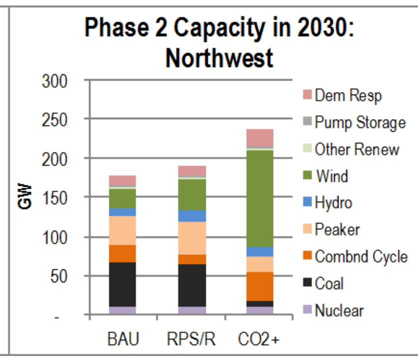
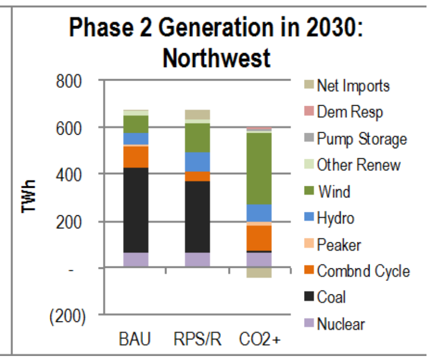
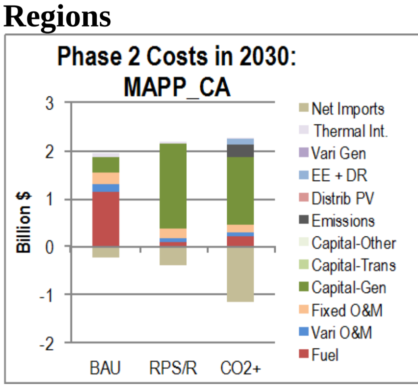
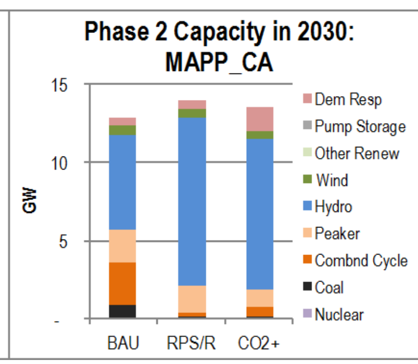


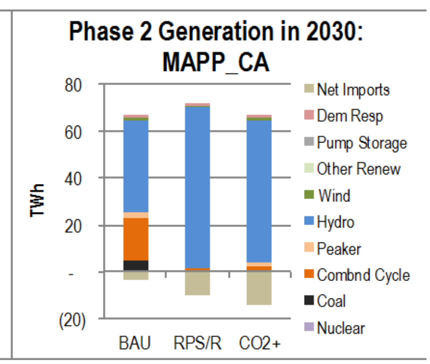


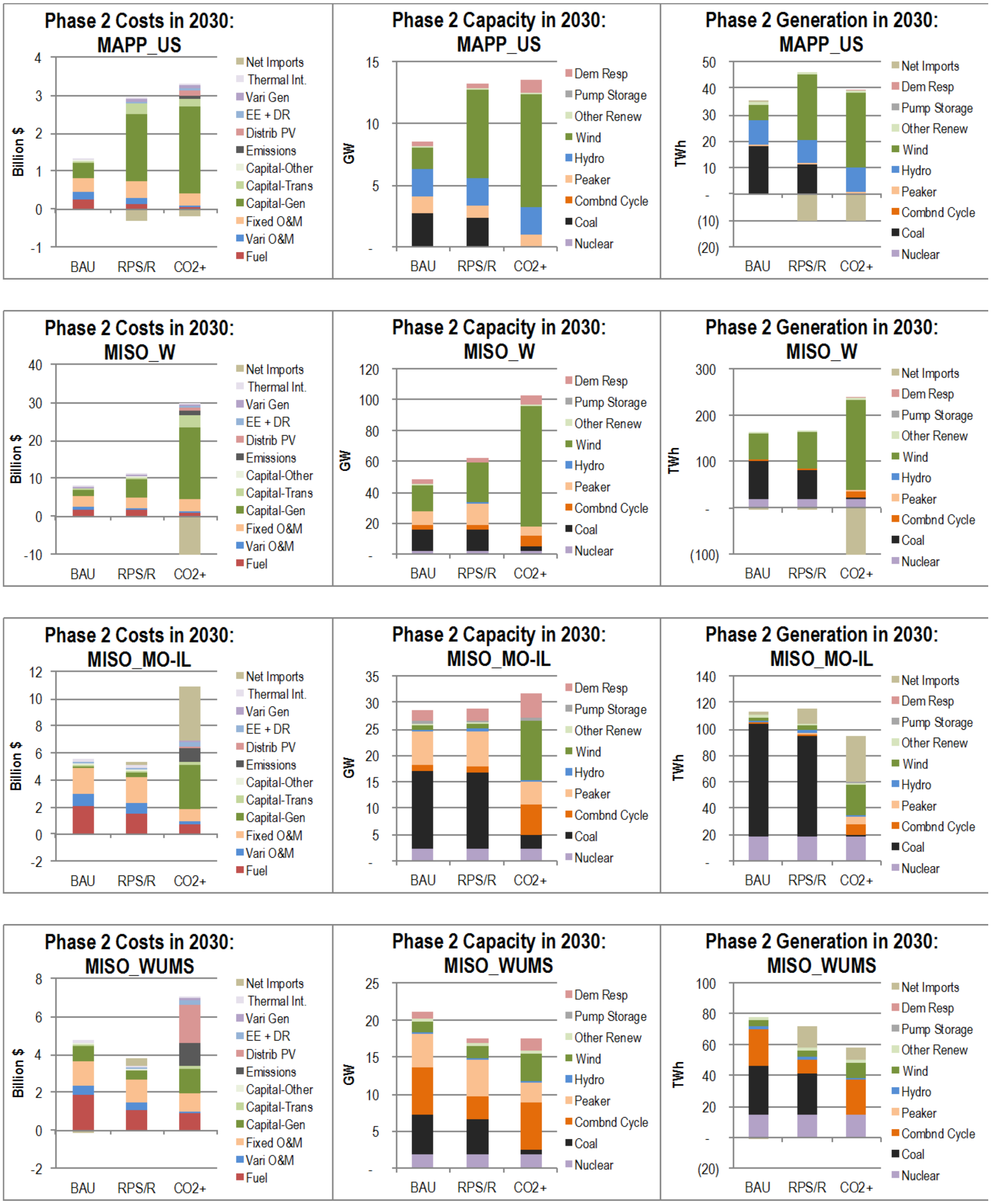


Regions









Phase 2 Costs in 2030: MAPP_US
Billion $
4
3
2
1
0
-1
BAU RPS/R CO2+
Net Imports
Thermal Int.
Vari Gen
EE + DR
Distrib PV
Emissions
Capital-Other
Capital-Trans
Capital-Gen
Fixed O&M
Vari O&M
Fuel
Phase 2 Capacity in 2030: MAPP_US
GW
15
10
5
-
BAU RPS/R CO2+
Dem Resp
Pump Storage
Other Renew
Wind
Hydro
Peaker
Combnd Cycle
Coal
Nuclear
Phase 2 Generation in 2030: MAPP_US
TWh
50
40
30
20
10
-
(10)
(20)
BAU RPS/R CO2+
Net Imports
Dem Resp
Pump Storage
Other Renew
Wind
Hydro
Peaker
Combnd Cycle
Coal
Nuclear
Phase 2 Costs in 2030: MISO_W
Billion $
40
30
20
10
0
-10
BAU RPS/R CO2+
Net Imports
Thermal Int.
Vari Gen
EE + DR
Distrib PV
Emissions
Capital-Other
Capital-Trans
Capital-Gen
Fixed O&M
Vari O&M
Fuel
Phase 2 Capacity in 2030: MISO_W
GW
120
100
80
60
40
20
-
BAU RPS/R CO2+
Dem Resp
Pump Storage
Other Renew
Wind
Hydro
Peaker
Combnd Cycle
Coal
Nuclear
Phase 2 Generation in 2030: MISO_W
TWh
300
200
100
-
(100)
BAU RPS/R CO2+
Net Imports
Dem Resp
Pump Storage
Other Renew
Wind
Hydro
Peaker
Combnd Cycle
Coal
Nuclear
Phase 2 Costs in 2030: MISO_MO-IL
Billion $
12
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BAU RPS/R CO2+
Net Imports
Thermal Int.
Vari Gen
EE + DR
Distrib PV
Emissions
Capital-Other
Capital-Trans
Capital-Gen
Fixed O&M
Vari O&M
Fuel
Phase 2 Capacity in 2030: MISO_MO-IL
GW
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BAU RPS/R CO2+
Dem Resp
Pump Storage
Other Renew
Wind
Hydro
Peaker
Combnd Cycle
Coal
Nuclear
Phase 2 Generation in 2030: MISO_MO-IL
TWh
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40
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BAU RPS/R CO2+
Net Imports
Dem Resp
Pump Storage
Other Renew
Wind
Hydro
Peaker
Combnd Cycle
Coal
Nuclear
Phase 2 Costs in 2030: MISO_WUMS
Billion $
8
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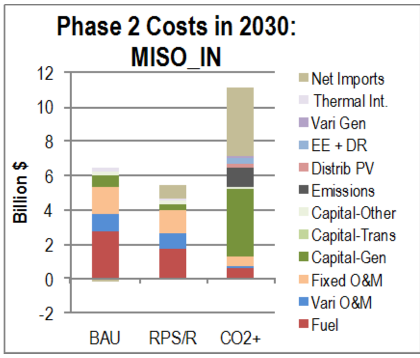
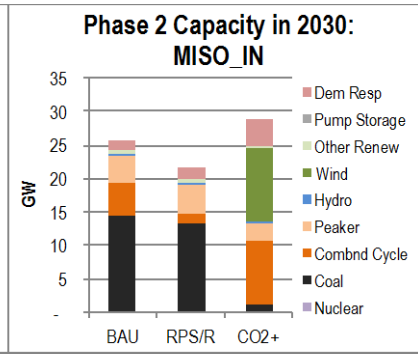
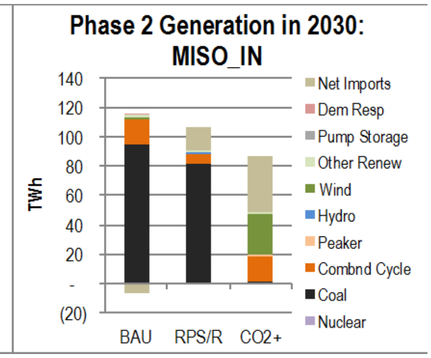
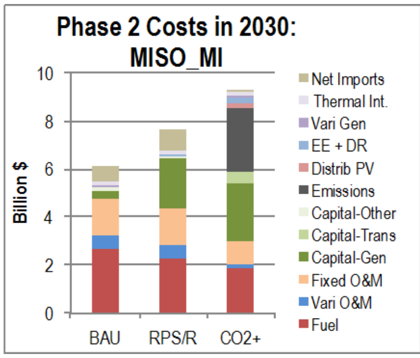
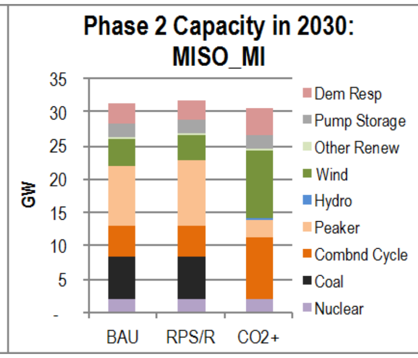
-2
BAU RPS/R CO2+
Net Imports
Thermal Int.
Vari Gen
EE + DR
Distrib PV
Emissions
Capital-Other
Capital-Trans
Capital-Gen
Fixed O&M
Vari O&M
Fuel
Phase 2 Capacity in 2030: MISO_WUMS
GW
25
20
15
10
5
-
BAU RPS/R CO2+
Dem Resp
Pump Storage
Other Renew
Wind
Hydro
Peaker
Combnd Cycle
Coal
Nuclear
Phase 2 Generation in 2030: MISO_WUMS
TWh
100
80
60
40
20
-
(20)
BAU RPS/R CO2+
Net Imports
Dem Resp
Pump Storage
Other Renew
Wind
Hydro
Peaker
Combnd Cycle
Coal
Nuclear

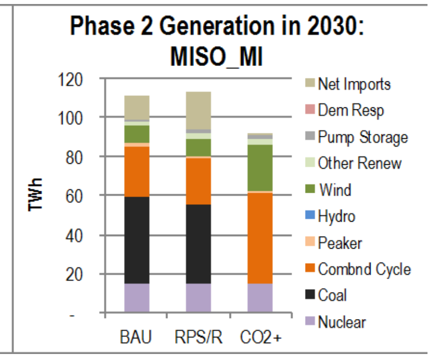




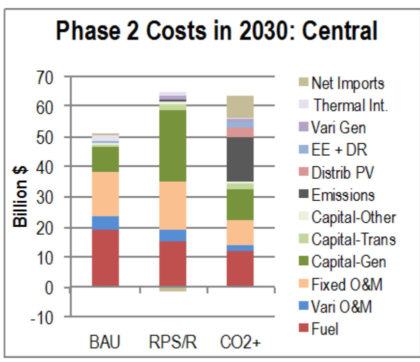


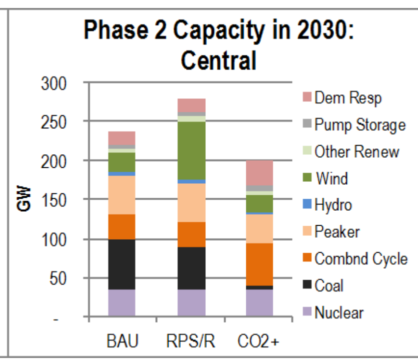


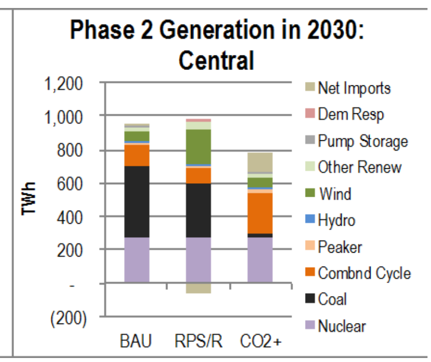




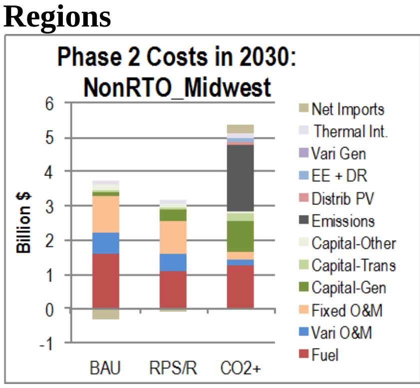
CENTRAL TERRITORY

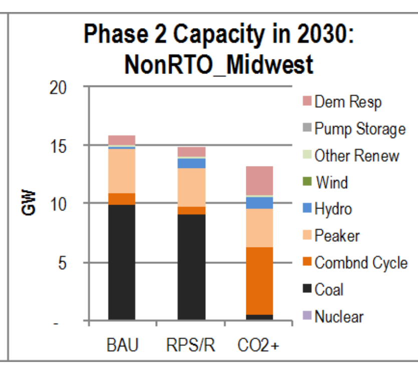


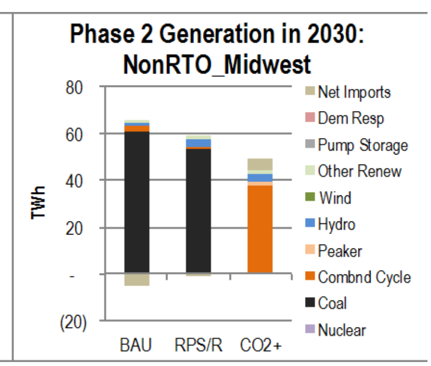


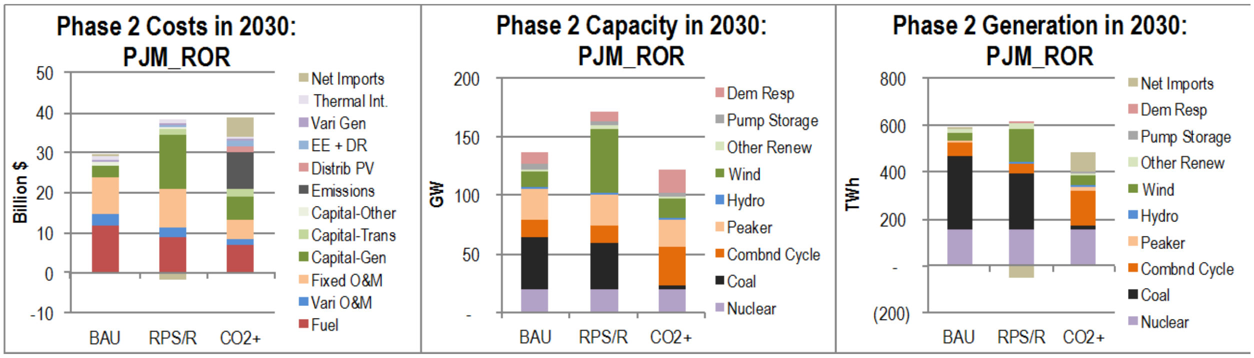


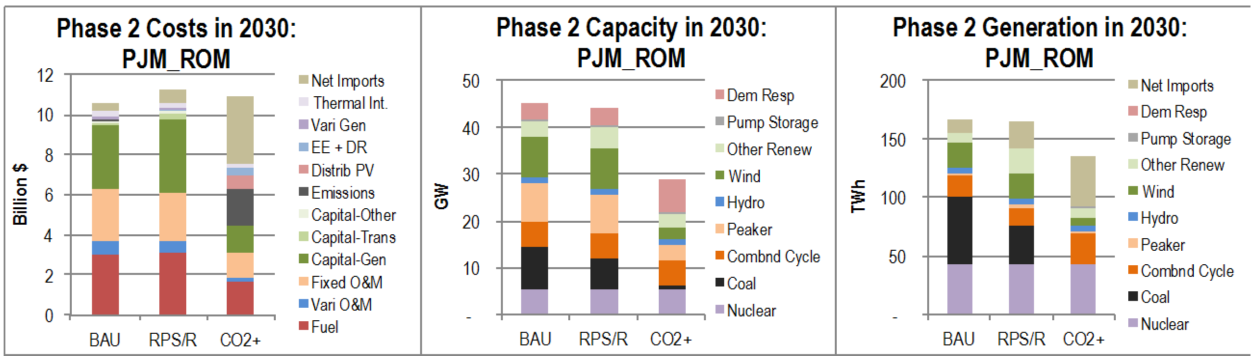
Regions

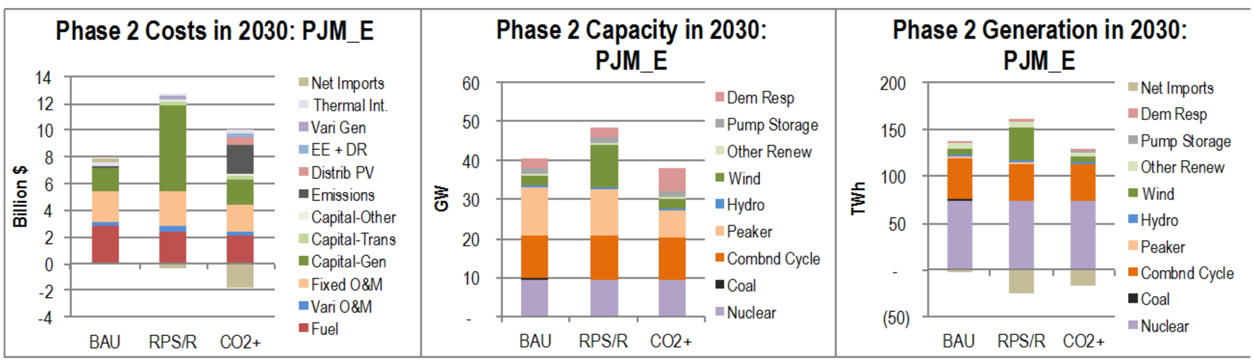




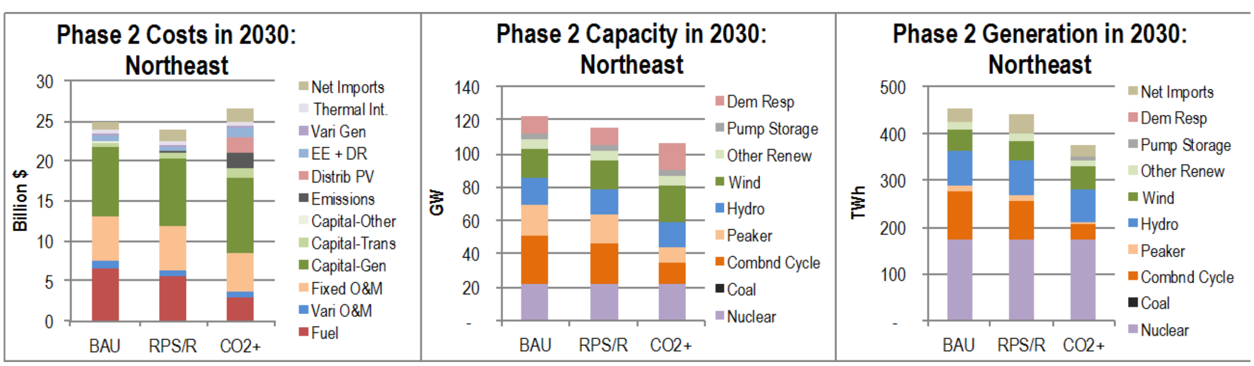




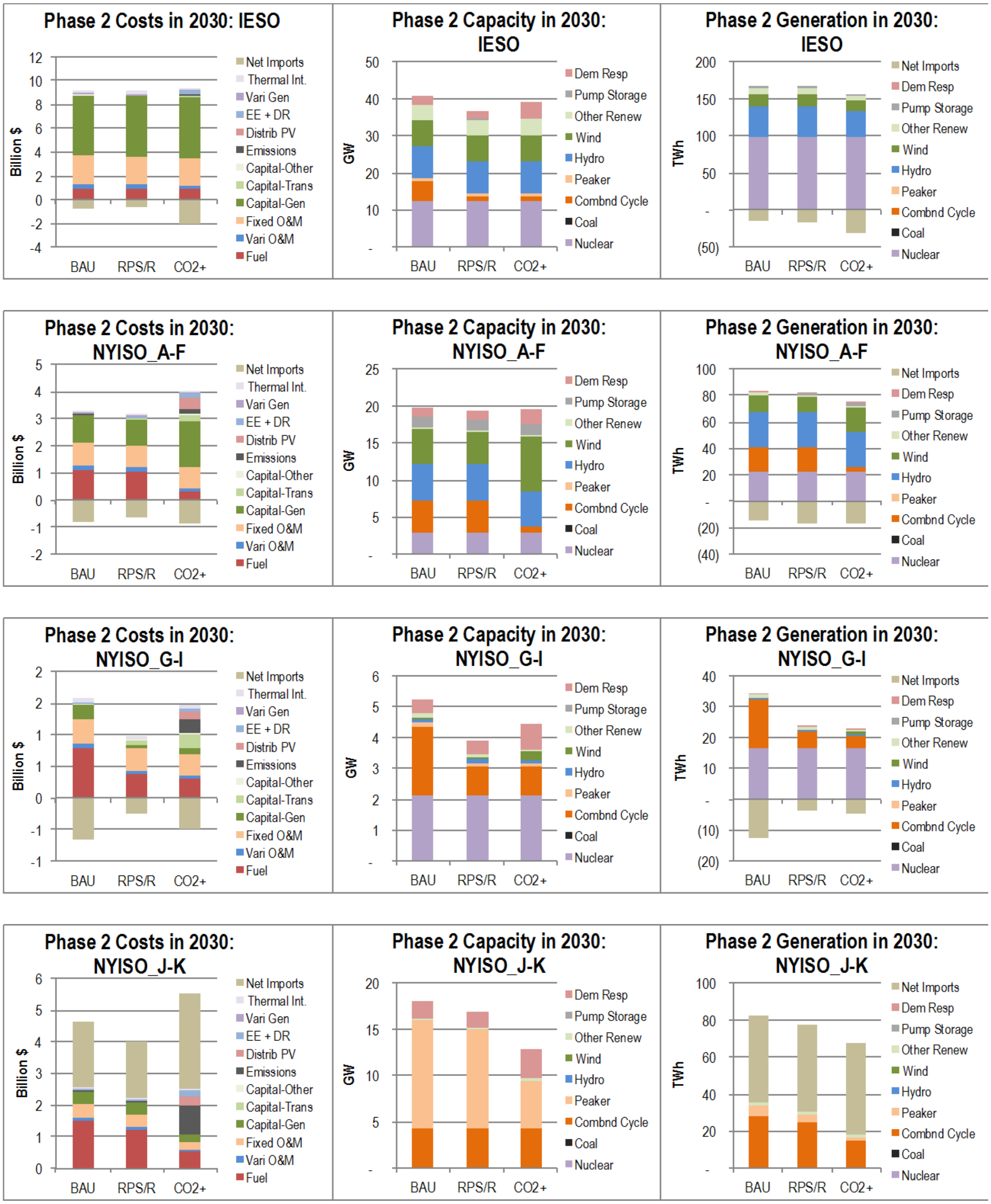


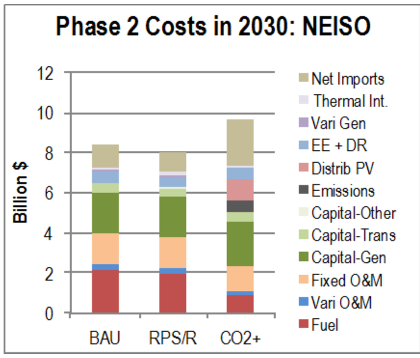


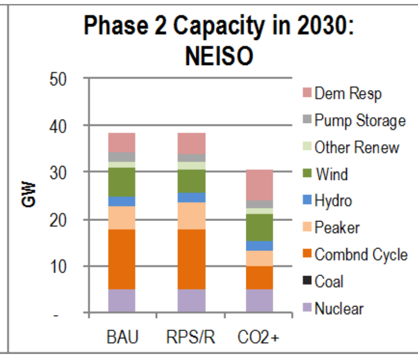
NORTHEAST TERRITORY

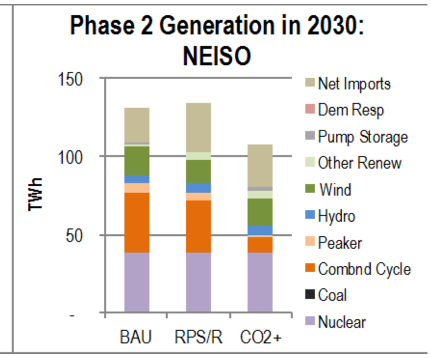


Regions

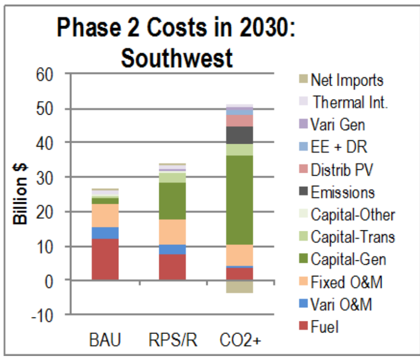

Phase 2 Costs in 2030: IESO
Billion $
12 10 8 6 4 2 0 -2 -4
BAU RPS/R CO2+
Net Imports
Thermal Int.
Vari Gen
EE + DR
Distrib PV
Emissions
Capital-Other
Capital-Trans
Capital-Gen
Fixed O&M
Vari O&M
Fuel
Phase 2 Capacity in 2030: IESO
GW
50 40 30 20 10 -
BAU RPS/R CO2+
Dem Resp
Pump Storage
Other Renew
Wind
Hydro
Peaker
Combnd Cycle
Coal
Nuclear
Phase 2 Generation in 2030: IESO
TWh
200 150 100 50 - (50)
BAU RPS/R CO2+
Net Imports
Dem Resp
Pump Storage
Other Renew
Wind
Hydro
Peaker
Combnd Cycle
Coal
Nuclear
Phase 2 Costs in 2030: NYISO_A-F
Billion $
5 4 3 2 1 0 -1 -2
BAU RPS/R CO2+
Net Imports
Thermal Int.
Vari Gen
EE + DR
Distrib PV
Emissions
Capital-Other
Capital-Trans
Capital-Gen
Fixed O&M
Vari O&M
Fuel
Phase 2 Capacity in 2030: NYISO_A-F
GW
25 20 15 10 5 -
BAU RPS/R CO2+
Dem Resp
Pump Storage
Other Renew
Wind
Hydro
Peaker
Combnd Cycle
Coal
Nuclear
Phase 2 Generation in 2030: NYISO_A-F
TWh
100 80 60 40 20 - (20) (40)
BAU RPS/R CO2+
Net Imports
Dem Resp
Pump Storage
Other Renew
Wind
Hydro
Peaker
Combnd Cycle
Coal
Nuclear
Phase 2 Costs in 2030: NYISO_G-I
Billion $
2 2 1 1 0 -1 -1
BAU RPS/R CO2+
Net Imports
Thermal Int.
Vari Gen
EE + DR
Distrib PV
Emissions
Capital-Other
Capital-Trans
Capital-Gen
Fixed O&M
Vari O&M
Fuel
Phase 2 Capacity in 2030: NYISO_G-I
GW
6 5 4 3 2 1 -
BAU RPS/R CO2+
Dem Resp
Pump Storage
Other Renew
Wind
Hydro
Peaker
Combnd Cycle
Coal
Nuclear
Phase 2 Generation in 2030: NYISO_G-I
TWh
40 30 20 10 - (10) (20)
BAU RPS/R CO2+
Net Imports
Dem Resp
Pump Storage
Other Renew
Wind
Hydro
Peaker
Combnd Cycle
Coal
Nuclear
Phase 2 Costs in 2030: NYISO_J-K
Billion $
6 5 4 3 2 1 0
BAU RPS/R CO2+
Net Imports
Thermal Int.
Vari Gen
EE + DR
Distrib PV
Emissions
Capital-Other
Capital-Trans
Capital-Gen
Fixed O&M
Vari O&M
Fuel
Phase 2 Capacity in 2030: NYISO_J-K
GW
20 15 10 5 -
BAU RPS/R CO2+
Dem Resp
Pump Storage
Other Renew
Wind
Hydro
Peaker
Combnd Cycle
Coal
Nuclear
Phase 2 Generation in 2030: NYISO_J-K
TWh
100 80 60 40 20 -
BAU RPS/R CO2+
Net Imports
Dem Resp
Pump Storage
Other Renew
Wind
Hydro
Peaker
Combnd Cycle
Coal
Nuclear

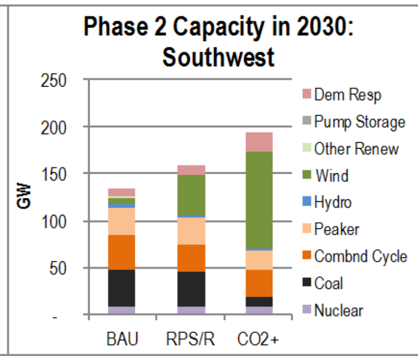


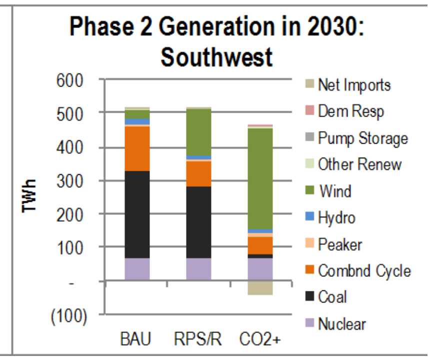




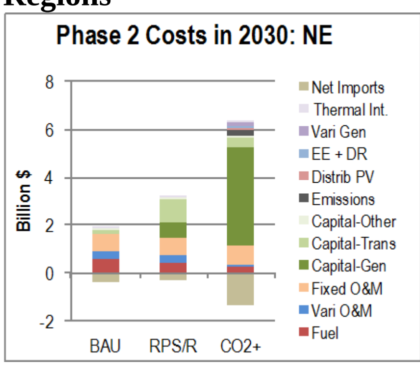
SOUTHWEST TERRITORY

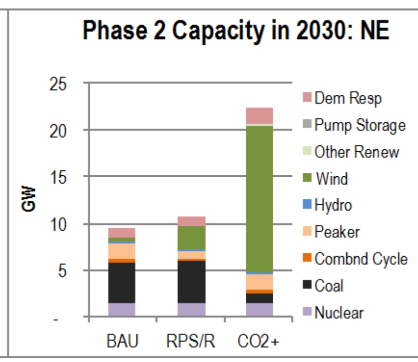


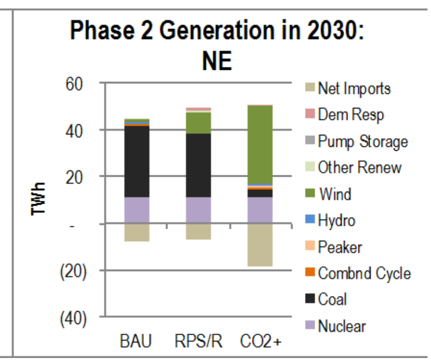


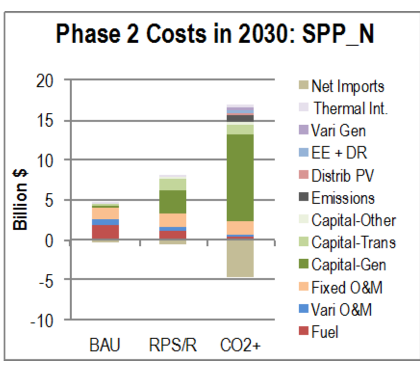


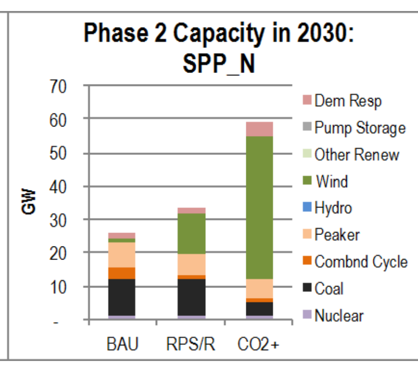
Regions

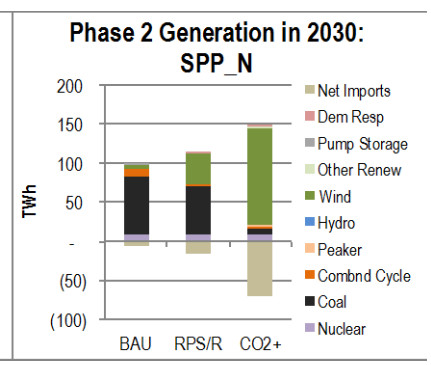


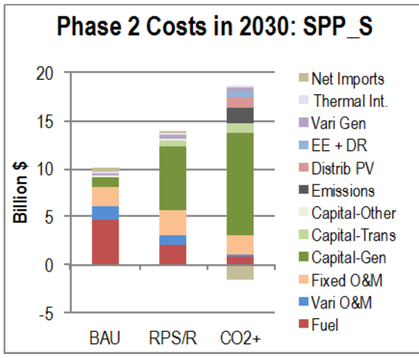


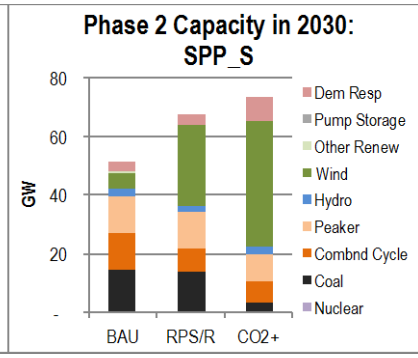


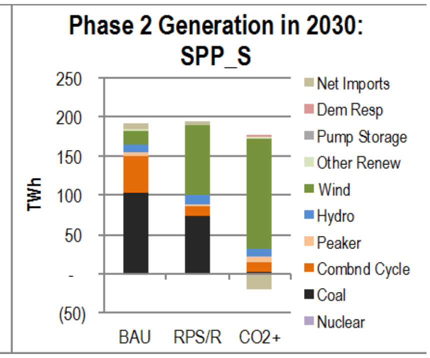


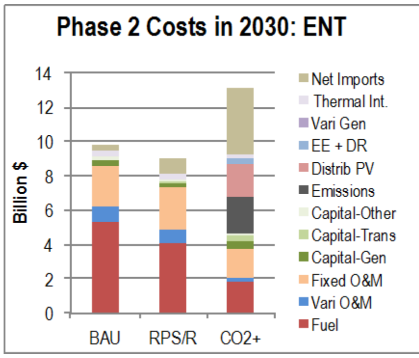


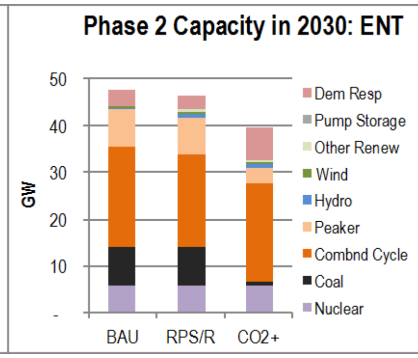


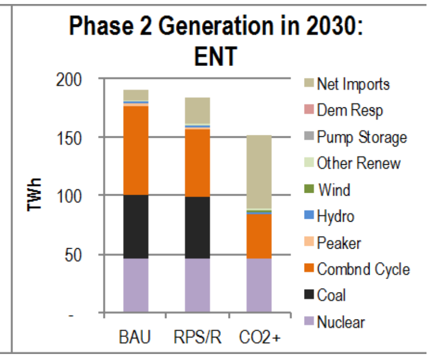




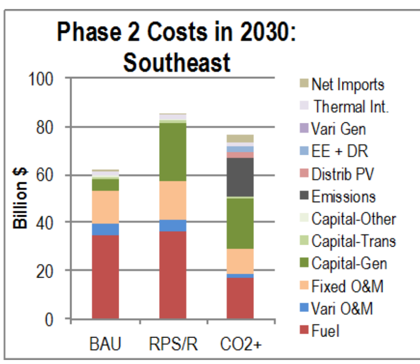


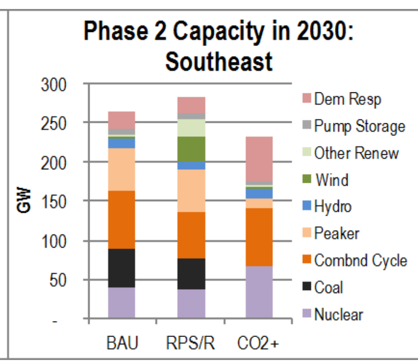


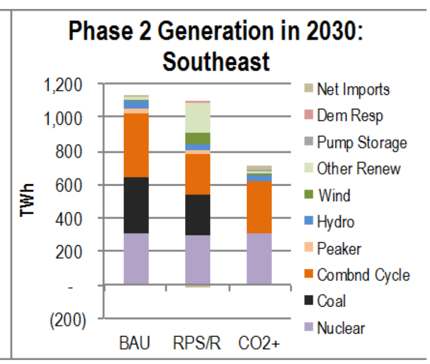




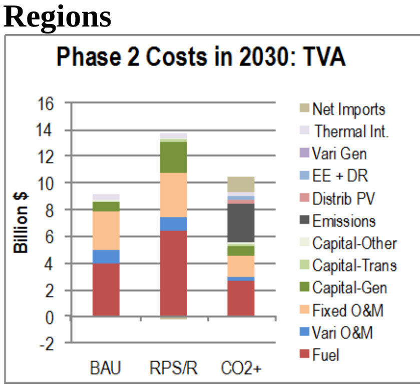
SOUTHEAST TERRITORY

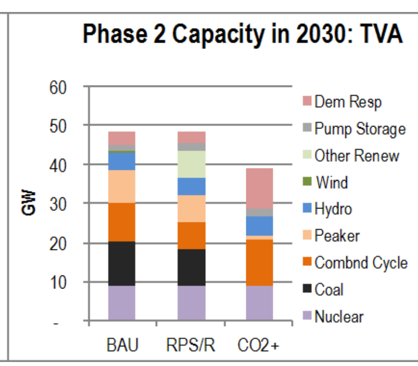


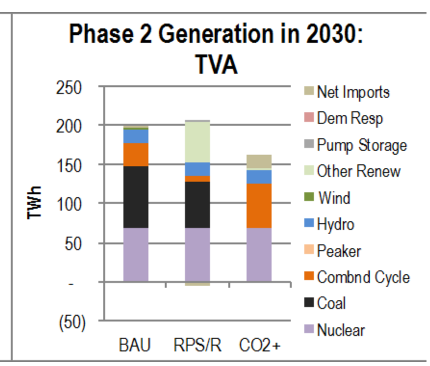




Regions








Phase 2 Costs in 2030: SOCO
Billion $
25
20
15
10
5
0
-5
BAU
RPS/R
CO2+
Net Imports
Thermal Int.
Vari Gen
EE + DR
Distrib PV
Emissions
Capital-Other
Capital-Trans
Capital-Gen
Fixed O&M
Vari O&M
Fuel
Phase 2 Capacity in 2030: SOCO
GW
80
60
40
20
-
Dem Resp
Pump Storage
Other Renew
Wind
Hydro
Peaker
Combnd Cycle
Coal
Nuclear
Phase 2 Generation in 2030: SOCO
TWh
400
300
200
100
-
(100)
Phase 2 Costs in 2030: VACAR
40
30
20
10
0
Phase 2 Capacity in 2030: VACAR
120
100
80
60
40
20
-
Phase 2 Generation in 2030: VACAR
350
300
250
200
150
100
50
-
(50)
Phase 2 Costs in 2030: FRCC
30
25
20
15
10
5
0
Phase 2 Capacity in 2030: FRCC
80
60
40
20
-
Phase 2 Generation in 2030: FRCC
350
300
250
200
150
100
50
-