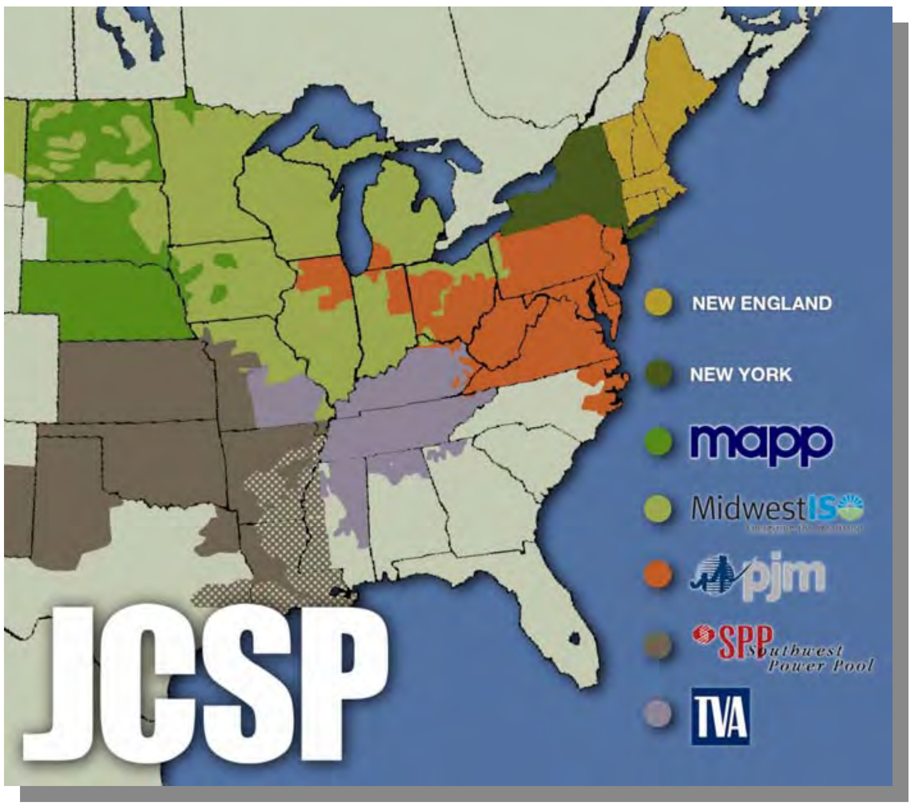

Joint Coordinated System Plan '08

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Section 1: Executive Summary

1.1 Joint Coordinated System Plan 2008 Overview

The Joint Coordinated System Plan 2008 (JCSP'08) analysis offers a conceptual regional transmission and generation system plan for a large portion of the Eastern Interconnection in the United States, developed with the participation of most of the major transmission operators in the Eastern Interconnection. This initial effort looks at two scenarios that expand transmission and generation opportunities between 2008 and 2024 – a Reference Scenario and a 20% Wind Energy Scenario in support of the U.S. Department of Energy's Eastern Wind Integration and Transmission Study. Future JCSP analyses will examine additional scenarios.

Several features distinguish the JCSP'08 study from prior transmission expansion studies:

- The JCSP'08 is the first inter-regional planning effort to involve most of the major transmission operators in the Eastern Interconnection. The study represents the collaborative efforts of Midwest ISO, SPP, PJM, TVA, MAPP and several key members of SERC. The New England and New York areas are also included in the study analysis. Most other transmission studies address smaller regional footprints.
- The JCSP'08 used a collaborative, transparent, stakeholder process to develop and screen key analytical assumptions and design the transmission expansion options for the two scenarios studied; many other transmission studies have less direct stakeholder involvement.
- The JCSP'08 uses common economic and system condition assumptions to characterize most of the Eastern Interconnection in a single multi-regional analysis, rather than through parallel, region-specific analyses.

This JCSP'08 study is valuable as a demonstration of the value of an inter-regional planning process, as well as for its analytical planning results. From the process standpoint, the JCSP'08 put together a wide-reaching stakeholder involvement process over a near-Interconnection-wide area; this will enhance the Eastern Interconnection's ability to conduct future planning activities pursuant to FERC Order 890. The JCSP'08 also developed a process to identify, evaluate and screen alternative high-voltage transmission overlays, which has rarely been done in planning to serve smaller regions. From an analytical standpoint, the JCSP'08 establishes that transmission overlays may provide significant economic value by reducing grid congestion and facilitating new renewable resource development (within the context of the scenarios evaluated).

The JCSP'08 offers a valuable foundation for future planning work within the Eastern Interconnection. Future interconnection-wide planning analyses should test additional scenarios to examine the reliability and economic impacts of alternative combinations of supply-and-demand-side resource technologies, densities and locations and transmission infrastructure options, and also conduct sensitivity analysis to determine the implications of varying assumptions such as fuel and technology costs, load projections, plant retirements, and carbon regulation options and costs.

Section 2 of this study describes the process of developing the JCSP'08.

1.2 JCSP'08 Scenario and Transmission Overlay Development

The traditional approach to transmission planning is to evaluate targeted transmission additions to meet specific reliability or economic needs, building individual high voltage transmission lines (mostly 345 kV and below) and adding substation and voltage management equipment to meet identified system needs such as load growth or new generation interconnection. These targeted additions are evaluated using both reliability and economic modeling, often under alternative scenarios stretching out to a specified future horizon year. An alternative to this approach entails using production cost simulation information to identify a portfolio of transmission system expansion options involving multiple, major, simultaneous high voltage additions (that can include HVDC as well as 765kV, 500kV and 345 kV technologies) that together serve and link entire regions and markets across an entire interconnection. Such a transmission expansion is called a "transmission overlay." The targeted method has been the dominant means of transmission expansion in the Eastern Interconnection. But with the possibility of national Renewable Portfolio Standards and the development of large amounts of new generation resources in certain regions of the nation to meet such standards, this JCSP'08 analysis was designed to look at the costs and benefits of transmission overlays that can serve a range of policy goals. As with any transmission expansion plan, evaluation of an overlay requires considering a broad range of reliability, economic, and environmental drivers.

The JCSP'08 Study developed and analyzed the costs and benefits of conceptual transmission overlays for two scenarios. The Reference Scenario assumes that the existing laws and policies governing generation resource choices remain in place and was premised on the assumption that incremental wind development would address existing RPS requirements, which translates to an average 5% wind energy development across the U.S. portion of the Eastern Interconnection. The scenario assumes each state will build as much new on-shore wind generation as its total RPS requires, and on-shore wind generation will be built as closely as possible to the regional load. For example, the JCSP'08 reference scenario assumes that wind needs within New England are met with on-shore wind projects within New England,[1] as opposed to wind imports from the Midwest or Canada. Under the Reference Scenario there will be about 60,000 MW of new wind developed by 2024, along with 75,600 MW of additional base load steam generation. Many possible transmission overlays were developed and one was selected to represent the Reference Scenario.

The second scenario, the 20% Wind Energy Scenario, assumes that the entire Eastern Interconnection will meet 20% of its energy needs using wind generation by 2024. In this scenario, the bulk of the wind production capacity is assumed to be located in those areas with the highest quality (best capacity factor) on-shore wind resources, which are located in the western part of the Eastern Interconnection.[2] The 20% Wind Energy Scenario assumes that 229,000 MW of new wind capacity will be built by the year 2024, with 36,000 MW of new base load steam generation. Here too, a number of possible transmission overlays were examined and one was selected because it provided the best optimal performance based on the assumptions in the study.

[1] It was beyond the scope of this study to examine and model the potential for off-shore wind development along the East Coast due to lack of data availability, but those options should be examined in future transmission development scenarios.

[2] The study authors recognize that beyond the specific 20% Wind Energy Scenario outlined here, there are other options for meeting a 20% wind energy target, as well as more broadly formulated targets for renewable energy, that would involve different renewable resource development patterns and different transmission overlay patterns. This study makes no judgment on the superiority or desirability of this scenario relative to others, which could and should be developed in future analyses of the Eastern Interconnection.

The JCSP'08 used an iterative process to assure that each conceptual overlay delivers economic value as well as system reliability. The planning process starts by performing a capacity expansion analysis for each of the regions under study. These capacity expansion assumptions are then incorporated into transmission and production cost models. These models then allow for the development of conceptual transmission overlays to economically deliver energy to the Eastern Interconnection. Established transmission planning processes evaluate the reliability requirements (under NERC standards) and economic benefits of the expansion options for the planning period; the JCSP'08 did so as well, although the JCSP'08 conducted the production cost analysis for 2024 before conducting the reliability analyses. As the production cost models perform security constrained economic dispatch of the entire Eastern Interconnection for each hour of the year being analyzed (here 2024), the conceptual transmission overlays that result from this process consider reliability only to the extent that they ensure that pre-overlay security constraints are enforced; however, a production cost-based analysis does not contain the level of detail required to satisfy all reliability analysis requirements.[3] More detailed reliability analysis of the conceptual transmission overlays must be conducted for each of the overlays, to make the final conceptual overly both economic and reliable.

The two scenarios are described in detail in Section 3. The Reference and 20% Wind Energy Scenarios share common load growth and economic assumptions; they differ in terms of how much wind is developed and how the wind penetration levels affect the need for transmission and other types of generation. Although the modeling results indicate that the bulk of new fossil generation under these scenarios could be coal-fired, that result appears to be an artifact of the modeling assumptions and process rather than a prediction regarding the implications of transmission overlay development. Future analyses that incorporate more detail on technology and fuel costs (e.g., carbon sequestration), carbon regulation options, and operational needs relating to intermittency (as it relates to assuring reliable grid operations with high levels of wind resources) will lead to more firmly grounded conclusions regarding future generation technology mixes.

Both transmission overlays incorporate specific transmission projects that will contribute to the system's reliability needs for the ten-year period through the year 2018, and provide economic benefits in the 2024 time frame. The conceptual overlays were developed consistent with assumptions about fuel costs, load levels and resource expansion through 2024 for most of the Eastern Interconnection, with the important assumption that the Eastern Interconnection would be operated as a fully coordinated market. The process of creating the overlay options entailed extensive discussions in workshops with Eastern Interconnection stakeholders. The overlay options were systematically refined, adding and dropping various combinations of transmission facilities to develop the final sets of options that are economic within the context of the study's assumptions.[4] The final overlays for these scenarios have been reviewed using basic reliability screens, but have not been subjected to detailed design and reliability analyses; these transmission overlays should be viewed as conceptual rather than project-specific.

[3] Additional reliability analyses needed include stability analysis, voltage and reactive power requirements, and analysis of the lower voltage systems that are necessary to successfully integrate the EHV transmission overlay's elements. Such analyses could be included in future transmission overlay analyses.

[4] Electric system cost-effectiveness analysis requires comparison of a project's economic savings relative to new generation and transmission capital and energy production costs. The JCSP study could not conduct rigorous cost-effectiveness analysis because it examined energy production costs and savings only for the years 2018 and 2024, and assumed that new transmission and generation investment occurred instantly (overnight) at the start of each horizon year. A more thorough cost-effectiveness analysis would incorporate the full stream of costs and benefits (i.e., energy and environmental savings) in every year of the forecast period; such a task was beyond the scope of this initial JCSP study.

The process of locating new generation and developing and refining the transmission overlays is described in Sections 4 and 5.

To determine the net costs and impacts of each scenario, the JCSP'08 compared each scenario to a common base case, which contains the transmission constraints inherent in the existing system. Each scenario is evaluated by comparing the costs and benefits (production cost savings) of the base or constrained case to those of the scenario to determine the net impact of the transmission and generation assumed in each scenario; however, due to time constraints, the economic impacts have been calculated as point estimates for the year 2024 alone, rather than as a full year-after-year stream of benefits and costs. Although these estimates are offered in future value terms (2024 $), the reader should not assume that the costs and benefits represent cumulative benefits over a number of years; estimated capital costs are represented as if all of the new wind and fossil generation and transmission were built overnight at the start of the examined year. For that reason, this study does not attempt to estimate cost-effectiveness results for the two scenarios studied. Future studies should put more effort into refining the cost and economic assumptions and developing more rigorous cost and benefits calculations that span the full analysis period

1.3 Study Results

The JCSP'08 study examined two different resource and transmission paths to serve a total of 745,000 MW of coincident peak load in the Eastern Interconnection, except Florida in 2024. The Reference Scenario, which assumes that present RPS requirements are met with local on-shore wind resources, would add 10,000 miles of new extra high voltage transmission at an assumed cost of approximately $50 billion. With 5% of the Interconnection's energy coming from wind and 54% from base load steam generation, total energy production costs in 2024 would equal $104 billion and total generation capital costs would equal $674 billion. In contrast, the 20% Wind Energy Scenario, which assumes a 20% national RPS requirement met by U.S. on-shore wind development, would add 15,000 miles of new EHV transmission at an assumed cost of approximately $80 billion. Under this scenario, energy production costs in 2024 would equal $85 billion and the capital cost of new generation would equal $1,050 billion. These results should be viewed as illustrative or "ballpark" costs rather than definitive findings about the costs of new transmission and generation related to either the status quo expansion path or a high-renewables scenario. Even with that caveat, however, the findings suggest that transmission overlays should be strongly considered as a way to improve the future reliability and economics of the nation's bulk power electric system under either policy path.

The transmission and generation additions assumed under each scenario are summarized below and discussed in detail in Section 5.

1.4 Incremental Capacity Needs By 2024

To maintain electric reliability in 2024, new resources must be added to keep up with assumed future increases in demand. A new resource can be generation and transmission, or demand-side measures such as efficiency and demand response. In this study, a capacity expansion path was developed for each of the nine areas in the study to maintain an approximate 15% reserve margin across the Eastern Interconnection.

The JCSP'08 process handled resource additions for wind, demand response, and remaining supply-side resources as follows. The amount of new wind resource is based on the requirements of meeting either the Reference (5% wind) or 20% Wind Energy Scenario needs. The amount of demand response for this study is assumed to maintain the same percentage level of demand response as exists in 2008 (e.g., if a region had DR serving approximately 2.5% of peak demand in 2008, then new demand response additions were added out through 2024 to maintain that 2.5% share); energy efficiency was assumed to be embedded within the demand forecast. The type and timing of all of the other new supply-side resource additions is based on the relative life cycle costs of those resources, given stakeholder-accepted forecast assumptions for different technologies' capital costs, fuel and production costs, and environmental costs.

Figure 1-1 shows the capacity additions projected for the Reference and 20% Wind Energy Scenarios. Because the wind capacity figures are essentially fixed in each scenario, the remaining resources were selected by a least cost regional resource forecast model to fill in around the wind capacity. Future analyses should look further at alternative scenarios that rely more heavily on energy efficiency and demand response as resources that modify both supply and demand patterns and capabilities, as well as at alternate supply-side resource fuel and technology mixes.

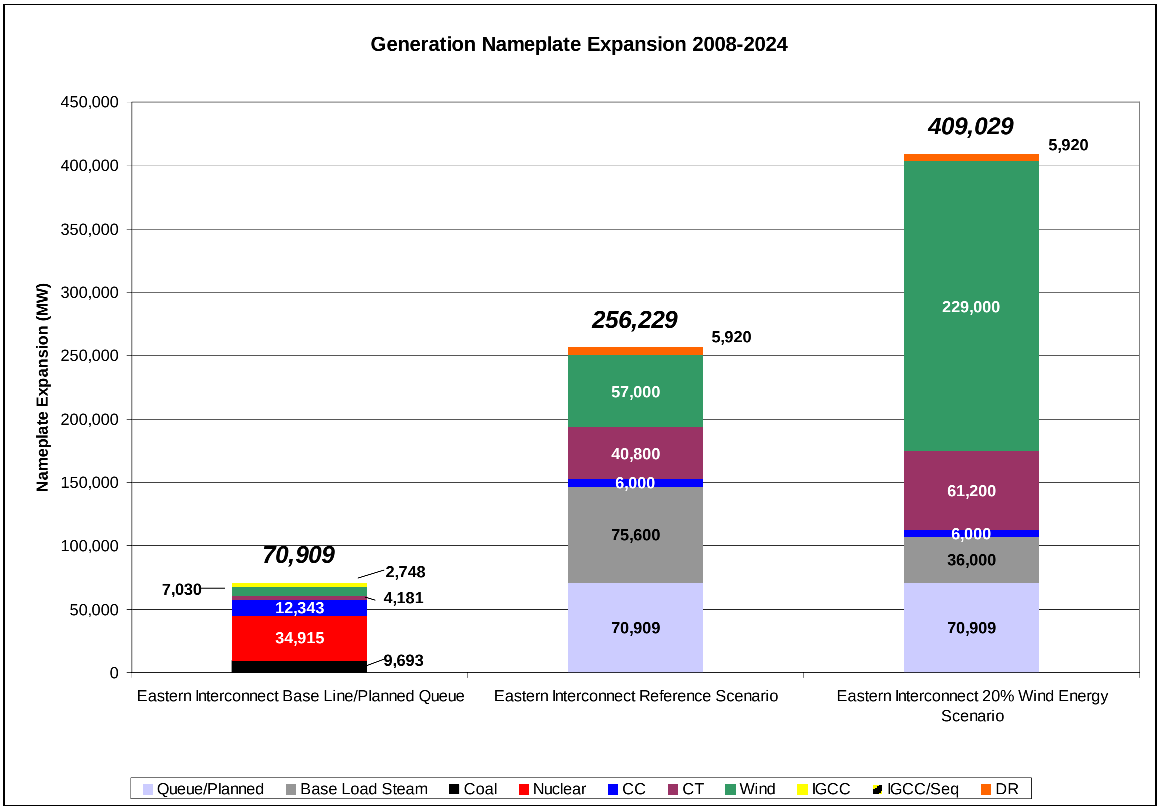


Figure 1-1: Capacity Additions by Resource Type

Table 1-1 provides more details on the transmission and generation investments made under the Reference and 20% Wind Energy Scenarios. While Figure 1-1 highlights the differences in generation types projected for each scenario, Table 1-1 shows that the Wind Scenario assumes significantly more high voltage direct current transmission construction (at a notably higher cost), reflecting the long distances over which wind energy is assumed to be shipped from the western Midwest to the northeast and southeast. There are high levels of base load steam generation assumed in both scenarios (54% under the Reference Scenario and 42% in the Wind Scenario), with the increased wind generation offsetting primarily base load steam production while requiring more production from fast-response, gas-fired combustion turbines. As might be expected, generation investment costs would be significantly higher under the 20% Wind Energy Scenario than under the Reference Scenario, but energy production costs would be lower with greater wind-power use, and those savings would increase over time.

		Reference Scenario		Wind Scenario	
			Percentage		Percentage
Transmission Overlay (Miles)	EHV AC (>=345kV)	7,109	71%	6,898	48%
	HV AC (<345kV)				
	HV DC	2,870	29%	7,582	52%
	Total	9,979	100%	14,480	100%
New Generation Expansion Capacity (MW)	Wind	58,000	31%	229,000	67%
	Base Load Steam	76,800	40%	37,200	11%
	Gas CT	49,200	26%	69,600	20%
	Gas CC	4,800	3%	4,800	1%
	Other Fossil	1,200	1%	1,200	0%
	Total	190,000	100%	341,800	100%
Energy Production (TWH)	Wind	242	6%	764	18%
	Base Load Steam	2,160	54%	1,741	42%
	Gas	210	5%	301	7%
	Other	1,356	34%	1,371	33%
	Total	3,968	100%	4,177	100%
Transmission Capital Cost (2024 million $)	Transmission - overlay	42,159		72,825	
	Transmission – substations	6,401		7,074	
Overnight Construction Costs for Capacity Added through 2024 (2024 million $)	Generation – Wind	176,009	26%	648,813	62%
	Generation – Base Load Steam	250,882	37%	134,401	13%
	Generation – Gas	68,317	10%	87,861	8%
	Generation – Other	179,138	27%	179,138	17%
	Total	674,346	100%	1,050,213	100%
2024 Production Cost and Savings (2024 million $)	Total Energy Production Cost	104,294		85,167	
	Total Production Cost Savings from Constrained Case	10,624		20,362	

Table 1-1: Summary Statistics for the Two Scenarios

Capacity expansion in these scenarios is driven by the underlying need to maintain appropriate reserve margins within each region and across the Eastern Interconnection as a whole. In these scenarios, only 15% of the wind generation is counted as a capacity resource for reserve calculation purposes. This is because wind generation is only available when the wind blows, and is not available and dispatchable by system operators during all time periods. Since system operators can only count on fully dispatchable and predictable resources (such as fossil and nuclear resources and hydro storage units) for reliability purposes, less of the wind resource can be counted toward regional and Interconnection-wide reserve margins. Changes in loads, technologies and costs (including environmental or carbon costs and the capability of dynamic response and smart grid technologies to firm intermittent wind generation) could significantly change the pattern of generation capacity expansion and should be studied through further scenario and sensitivity analyses.

1.5 Carbon Emissions

The capacity expansion analysis allows the calculation of the amount of carbon and other emissions produced under each scenario studied. The JCSP'08 analysis found that under the Reference Scenario, the generation mix in the Eastern Interconnection produced a total of 35 billion tons of carbon between 2008 and 2024, with 5% wind energy; under the 20% Wind Energy Scenario, comparable carbon emissions reached 32.1 billion tons, an 8% reduction.

These carbon output findings are highly dependent upon the generation mix developed under each scenario. Any combination of changes to the scenarios and their underlying assumptions could materially change the carbon emissions results, including assumptions about more energy efficiency, more renewable energy generated in Canada and East Coast off-shore wind, a carbon tax or tight carbon emissions regulation, the relative economics between base load steam and gas generation, or transmission capital costs and congestion as they affect the ability to move renewable or base load steam power across the Interconnection.

1.6 The Reference Scenario - New Transmission Projects Totaling $50 Billion of Investment

The Reference Scenario assumes that wind generation from relatively local, on-shore sources produces 5% of the U.S. Eastern Interconnection's energy use. These assumptions and the resulting generation and transmission needs drive design of a transmission overlay and underlying expansion that includes 10,000 miles of new extra high voltage (EHV) transmission at an estimated cost of $50 billion. The new transmission is comprised of a mix of transmission line sizes ranging from 345 kV to 765 kV for AC lines and up to 800 kV for DC lines. The transmission required under this scenario enables renewable and base load steam energy generated in the western side of the Eastern Interconnection to reach a wider area, and has the potential to reduce energy costs to eastern consumers. For these assumptions, work performed to date indicates the transmission overlay for the Reference Scenario, with 5% wind energy, may have benefits that exceed costs on an aggregate interregional basis.

The types and approximate locations for the new transmission are shown in Figure 1-2.

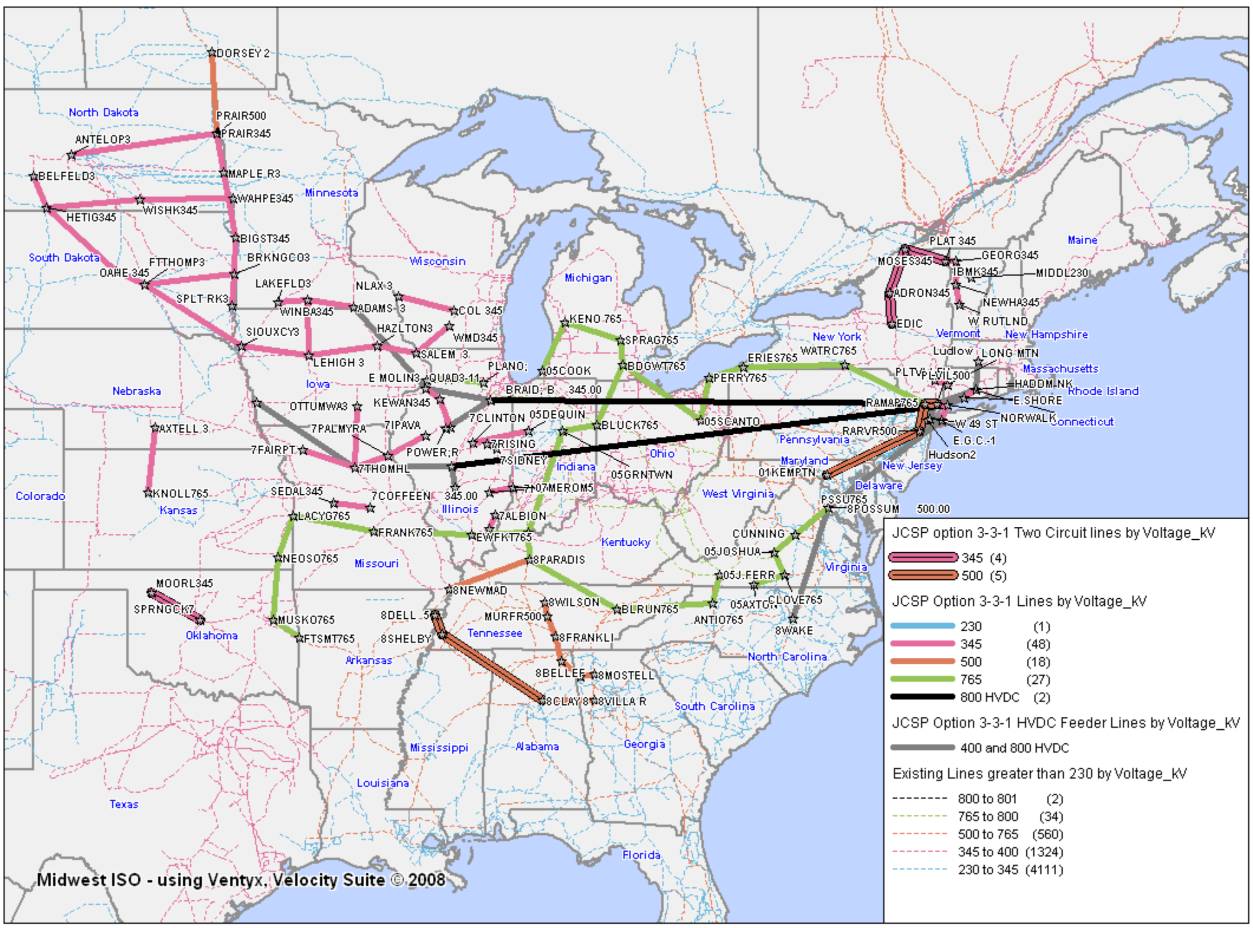


Figure 1-2: Reference Scenario Conceptual Transmission Overlay

1.7 The 20% Wind Energy Scenario – New Transmission Projects Totaling $80 Billion of Investment by 2024

The 20% Wind Energy Scenario presumes construction of a transmission overlay with 15,000 miles of new EHV transmission at an estimated cost of $80 billion. The new transmission would be a mix of transmission line sizes ranging from 345 kV to 765 kV for AC lines and up to 800 kV for DC lines. The majority of the conceptual overlay (approximately 75%) would be 765kV AC or 800kV DC. As in the Reference Scenario, the transmission overlay enables renewable and base load steam energy from the Midwest to reach a wider area and also has the potential to reduce energy costs to consumers along the Eastern Seaboard. Again, under the assumptions made in the JCSP'08, preliminary analysis indicates that this illustrative transmission overlay's benefits may exceed its costs.

The types and approximate locations for the new transmission are shown in Figure 1-3.

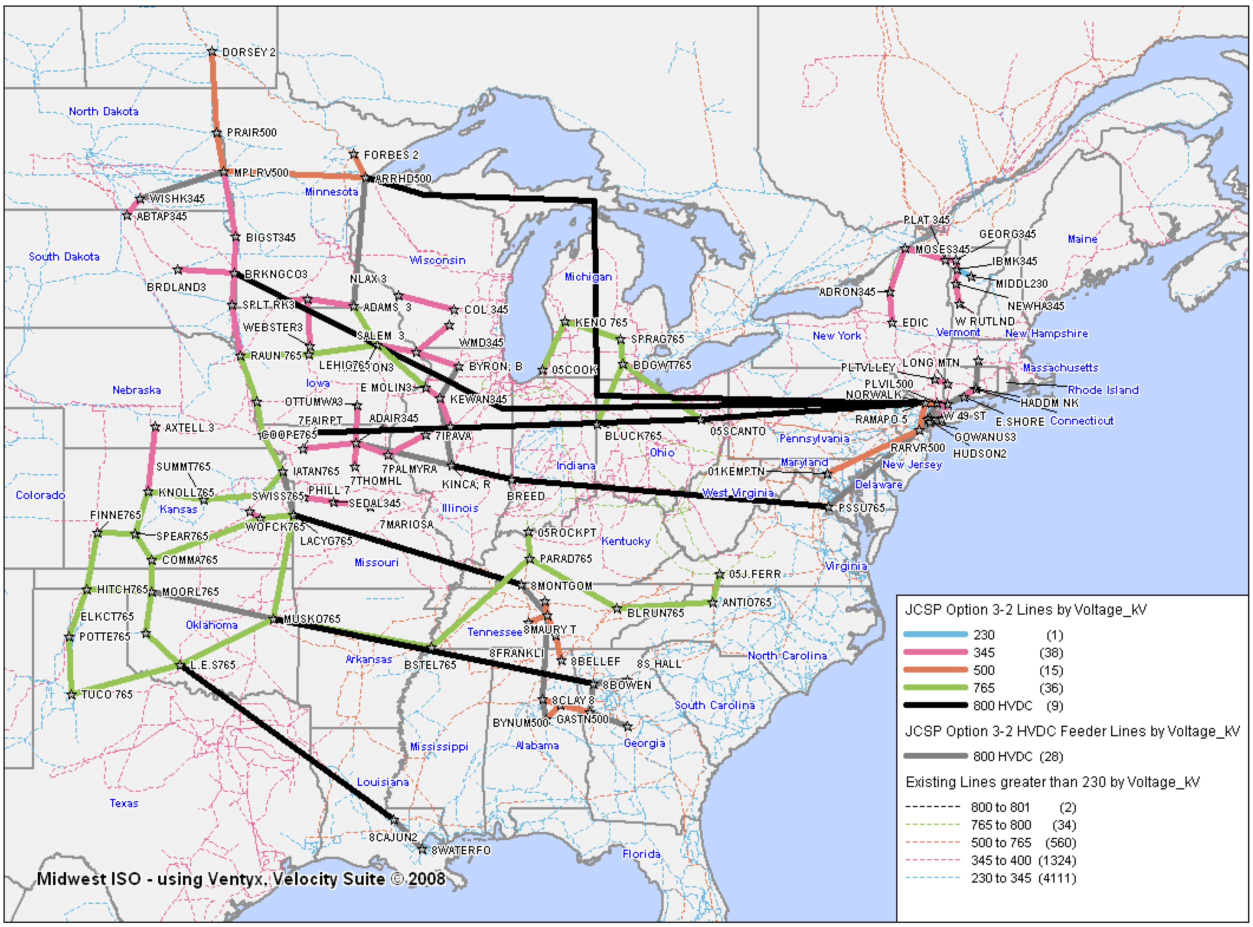


Figure 1-3: 20% Wind Energy Scenario Conceptual Transmission Overlay

Future analyses of high renewable generation scenarios should examine alternate assumptions about the location and density of future renewables development, with more attention to renewable resource development sited off-shore and in Canada and more local rather than long-distance production and transmission. Each of these resource options would affect the type, location and cost of new transmission infrastructure needed.

1.8 Looking Forward: JCSP'09 and Beyond

The JCSP'08 process offers an integrated approach to planning transmission and resource expansion for a very large area, considering both economic value and reliability needs. This approach has particular relevance if the nation is considering policies that would develop large amounts of remotely-located renewable and other generation distant from load centers. Although further analysis of reliability requirements is needed, the JCSP'08 study offers planners and policy-makers valuable insights for long-term transmission development.

Building upon the relationships and insights gained from this initial JCSP'08 effort, the stakeholders are looking forward. Possible changes include developing a new name -- the Eastern Interconnection Transmission Assessment Group (EITAG) -- to reflect the broader concept of the organization, and adoption of a formal charter. The EITAG will follow up on the JCSP'08 work and develop new scenarios to address analysis gaps. One question the EITAG can address is whether EHV transmission overlays offer superior reliability and economic results to incremental transmission development under alternative policy - and cost-driven scenarios. After examining a wide range of future generation, load and policy scenarios, planners should be able to identify the common transmission elements and principles that surface in all of these scenarios, and use those common elements as the foundation for a robust final transmission plan that serves the Eastern Interconnection economically and reliably as electricity policies and economics evolve. Insights developed by the EITAG can inform a broad spectrum of groups including policy makers, transmission owners and developers, generation owners and developers and regulators, and help to improve the nation's transmission over the long term.

Although the JCSP'08 and successor efforts can help improve bulk power system planning in the Eastern Interconnection, parallel efforts will be needed to turn those plans into realities. Although many new generation and transmission investments are moving forward, continuing uncertainties about the nation's policies with respect to carbon regulation, renewable development policies, and super-regional cost and benefit allocation for projects that span multiple regions constrain other investments. More clarity about these policy issues will facilitate new bulk power system investments needed to turn infrastructure plans into reality and make inter-regional and interconnection-wide transmission expansion planning effective.

Section 2: Description of JCSP'08

2.1 Study Participants

The Midwest ISO has Joint Operating Agreements (JOA) with Pennsylvania-New Jersey-Maryland Interconnection (PJM), Southwest Power Pool (SPP) and the Tennessee Valley Authority (TVA); the JOA's call for studies to be performed periodically. The Midwest ISO and PJM performed a Coordinated System Plan in 2006 but no such studies involving SPP or TVA had been undertaken. Instead of performing three separate studies with isolated value the participants decided to perform a single Joint Coordinated System Planning (JCSP'08) study that covered a significant portion of the Eastern Interconnect. During the same time frame that discussions on the JCSP'08 study scope were being developed, the Department of Energy (DOE) was implementing its Eastern Wind Integration Transmission Study (EWITS). The premise for EWITS was what transmission would be required to implement both a 20% and 30% Wind Energy Mandate within the Eastern Interconnect.

Given that both the JCSP'08 and EWITS studies were starting at the same time, with similar schedules and objectives, the JCSP'08 adopted the DOE's study scope in order to tie these two major studies together. While the Midwest ISO, PJM, SPP and TVA comprise a significant component of the Eastern Interconnect there was still a large portion of the Eastern Interconnection that was not represented. Expanding the study to include as much of the Eastern Interconnect as possible was pursued. The Mid-Continent Area Power Pool (MAPP) formally joined in the study. Many other areas participated in the study through TVA and SPP study links.

On an informal basis, the Southeast Inter Regional group has been formed within the South-Eastern Reliability Corp. (SERC) – both TVA and Entergy are part of this group. Entergy is participating in the JCSP'08 primarily through SPP. Therefore, TVA and SPP can act as a liaison between the JCSP'08 and this group.

2.2 Resource Forecasts and Siting

The initial kick-off meeting was held November 1, 2007 in Pittsburgh, PA, and represented the first of three stakeholder-wide meetings that covered the breadth of the study process. At this meeting the initial study scope was discussed for both the reliability and economic studies. The reliability study will be performed for the year 2018 while the economic study will be performed for 2024. The economic study scope involves collaboration with the DOE on their Eastern Wind Integration Transmission Study, associated with the transmission required to enable both a 20% and 30% Wind Energy Mandate for the majority of the Eastern Interconnection.

Over the ensuing eleven month period, nine regional stakeholder workshops were held to take input on assumptions and process. The first workshop was held December 11-12 in Nashville to outline the requirements for the regional resource planning model and discuss how those results are used in the model development process and study process. Future generation must be incorporated into the out years in both the power flow and economic assessment models. This workshop outlined the process and provided initial results for discussion and analysis.

The second stakeholder workshop was held in New Orleans on January 9-10 to provide additional regional coverage to the Nashville stakeholder workshop. This workshop covered the same material and was held specifically to enable greater stakeholder participation.

St. Paul served as the location for the third stakeholder workshop, held on February 5, 2008, to discuss the siting of the generation developed from the Nashville and New Orleans stakeholder workshop process. Midwest ISO staff worked closely with the staff from the DOE's National Renewable Energy Laboratory (NREL) in the siting of the wind facilities. Based on the siting work performed by DOE and Midwest ISO study staff, leading up to this workshop, it became apparent that siting wind resources for the 30% Wind Energy Mandate case would not be feasible until additional data became available. The needed data was not expected to be completed until the July timeframe as part of the EWITS. One of the three major components of the EWITS was the development of ten minute time synchronized wind mesoscale data for 2004 – 2006 for the study region represented in the JCSP'08 footprint. The wind data was to be provided in two km by two km grids for 80 meter hub heights. Without the mesoscale data, the siting of the 30% wind requirement just was not feasible and the 30% Wind Energy Case was put on hold.

2.3 Model Development

With the completion of the siting of all of the wind resources, in addition to all of the resources defined through the resource forecast, this information was incorporated at the bus level into the power flow and economic assessment models. SPP staff led the development effort for the power flow models while Midwest ISO staff developed the economic assessment models. The power flow models are built in Siemens PSS/E version 30.3. The 2007 Multi-area Modeling Working Group (MMWG) 2018 summer peak case served as the starting point for the JCSP'08 power flow model development. Each of the regions updated the initial power flow to provide the latest topology, ratings and interchange values. The development of the power flow and economic assessment models were completed in early April and have the following characteristics:

- Over 57,000 buses
- Nearly 7,900 generators
- 884,000 MW of total generation
- 788,000 MW of generation on-line
- 766,000 MW of load
- 22,000 MW losses

Two years of economic assessment models, 2018 and 2024, were completed shortly after the 2018 power flow model. While the primary study year for the economic study is 2024, a 2018 model is also developed to tie back to the reliability study and provide for robustness testing. With the power flow and economic assessment models complete, the next step in the process is the actual transmission design for the high voltage overlays in addition to the parallel reliability study.

PJM staff is leading the reliability study with support from all formal participants. The reliability study is discussed in detail in Volume II of this report.

Midwest ISO staff is leading the economic study with support from all formal participants. The JCSP'08 economic study will require a six month intensive effort and there will be upcoming workshops on the basic fundamentals of transmission design in addition to four workshops designed to produce the development of the high voltage overlay requirements associated with meeting the Reference Case and the DOE's 20% Wind Energy Case. These workshops will be held at various regional locations to obtain input from a broad cross section of participants.

A Transmission Fundamentals Workshop was held in Charleston, South Carolina and represented the fourth stakeholder workshop. This workshop provides essential background information required for the development of the high voltage transmission.

2.4 Conceptual Transmission Design

Four regional workshops during the month of June provided the stakeholder input to develop the conceptual transmission overlays. Development workshops were held to develop the transmission overlays for the Reference and the 20% Wind Energy Cases. The workshops were held in the following locations:

- Hartford, CT
- Wilmington, DE
- St. Louis, MO
- Knoxville, TN

Each regional workshop covered the same information, the multiple workshops were held to provide opportunity for participation by the broadest group of stakeholders. The results from the four workshops were combined into two overlays, one for the Reference Case and one for the 20% Wind Energy Case. The resulting overlays and interim results were presented at the interim all stakeholders meeting in Cincinnati, Ohio in mid August. Initial reliability results were also discussed at the Cincinnati meeting. Based upon comments and feedback, additional analyses were performed during the next six weeks to further refine the results for both the economic and reliability studies.

The last of the workshops, the ninth, was held in Carmel, Indiana in early October. Comments and input for additional refinement of the study results were received and incorporated into the final results contained in this report.

The JCSP'08 meetings held were:

Stakeholder Meeting	Pittsburgh, PA	Nov. 2007

The first of three stakeholder-wide meetings that covered the breadth of the study process. At this meeting the initial study scope was discussed for both the reliability and economic studies.

Workshop	Nashville, TN	Dec. 2007

The first workshop outlined the requirements for the regional resource planning model and discussed how those results are used in the model development process and study process.

Workshop	New Orleans, LA	Jan. 2008

The second workshop provided additional regional coverage to the Nashville stakeholder workshop. This workshop covered the same material and was held specifically to enable greater stakeholder participation.

Workshop	St. Paul, MN	Feb. 2008

The third workshop discussed the siting of the generation developed from the Nashville and New Orleans stakeholder workshop process.

Workshop	Charleston, SC	Apr. 2008

The fourth workshop featured a Transmission Fundamentals which provided essential background information required for the development of the high voltage transmission.

Workshop	Hartford, CT	Jun. 2008
Workshop	Wilmington, DE	Jun. 2008
Workshop	St. Louis, MO	Jun. 2008
Workshop	Knoxville, TN	Jun. 2008

Each regional workshop covered the same information, providing opportunity for participation by the broadest group of stakeholders. The results from the four workshops were combined into two overlays, one for the Reference Case and one for the 20% Wind Energy Case.

Stakeholder Meeting	Cincinnati, OH	Aug. 2008

The resulting overlays and interim results were presented. Initial reliability results were also discussed. Based upon comments and feedback, additional analyses were performed during the next six weeks to further refine the results for both the economic and reliability studies.

Workshop	Carmel, IN	Oct. 2008

Comments and input for additional refinement of the study results were received and incorporated into the final results contained in this report.

Stakeholder Meeting	Dallas, TX	Dec. 2008

Section 3: Scenario Planning

Approaching long-term transmission development using production cost models depends on an extensive set of assumptions which include economic conditions, regulatory concerns, and existing and planned infrastructure. The further the model year gets from current day conditions, the more uncertain and less accurate the assumptions become. Because of this, it is important to note that the planning of an electrical system, both generation and transmission, must not only satisfy the requirements of the specific study, but must also demonstrate robustness over conditions that may vary that specific study. The ultimate objective of scenario planning is to produce an integrated system that offers a wide range of flexibility to the operation of the electric system as well as attempt to minimize the cost to consumers.

There is plenty of uncertainty for the future in the power delivery industry. In the Eastern Interconnection the wide-scale impacts of Regional Transmission Organizations (RTO) are being felt in that broader outlet for low priced energy is available and flowing on the transmission system. Energy is flowing from and to areas that were not contemplated when the system was designed and built; and, new wind generation is being built in remote and widely dispersed areas. The system of yesterday is being stressed and used in ways that its design did not contemplate and it is still performing adequately; however, the one-off Band-Aid type fixes currently being employed are not coordinated and do not produce the greatest economic benefit. The JCSP'08 is the first study group to address bulk power transmission expansion issues and opportunities across the entire Eastern Interconnection using the breadth and scale of the existing RTO's and large non-RTO organizations. Not only does the effort serve to meet the goals of FERC Order 890, it also allows for improved evaluation of the cost and policy impacts of addressing issues of a national interest such as the impact of a 20% National Wind Energy Strategy.

Currently, there are discussions on the implementation of a Federal Renewable Portfolio Standard (RPS) that could lead to a greater penetration of renewable resources such as wind. Also under consideration are federal regulations to reduce greenhouse gasses; which could cause a substantial shift from base load steam and gas to a much larger reliance on wind and nuclear capacity. There are uncertainties associated with the cost of fuel; a decrease in the cost of natural gas may result in generation being sourced by combustion turbines and combined cycle units where a status quo economic assumption would continue to show base load steam powered capacity to be the preferred generation source. The focus of this study is to look at long-term transmission development that would prove robust over a number of potential scenarios that would result in a significant difference in the generation fleet.

Because possible future new coal generation may be subject to substantial environmental and economic drivers, this report generally uses the term "base load steam" generation rather than "coal" generation. This enables us to use existing modeling tools while recognizing that alternative types of generation may displace some of the technologies used in the past.

Tables 3-1 and 3-2 illustrate how the definition of a scenario guides the assumptions and values of certain variables. A scenario matrix table provides a visual representation of the scenarios and the different values that the variables within them can have. The table identifies each scenario in the leftmost column and lists each scenario variable across the top. A one letter representation of each variable's value for each scenario is shown in the body of the matrix. The uncertainty definition table and the scenario matrix table, together, represent the correlation of the scenario definitions and uncertainty variables.

Variables which can change, dependent on a scenario definition, are called uncertainty variables. The value of an uncertainty variable is defined in the uncertainty definition table and can be linked to the scenario matrix table by a one letter definition. The uncertainty definition table is a visual representation of each variable which can take on different values in different scenarios and the range of potential values for that variable. Only variables which can change values are listed in the table. Variables which remain static or unchanged in all scenarios are not represented here and are defined separately.

The ranges of the uncertainty variables are identified across the top of the table as a low, mid-low, reference, mid-high and high value (L, ML, R, MH or H), which correspond to the one letter correlations in the scenario matrix table. For example, the reference value (R) is used in the Reference Scenario for all uncertainty variables as seen in the scenario matrix table. The actual value the (R) represents for each variable is cross referenced in the uncertainty table. The actual values assigned to the uncertainty variables will later be discussed in full in Section 5.1.2.3. The table is for a convenient visual representation only.

As can be seen within the tables, it is determined that the scenarios defined for the JCSP'08 work should vary only in the penetration level of wind energy. Therefore, the scenario matrix table shown will have no variation in assumptions except for the penetration of wind energy.

	Uncertainties																						
	Capital Costs									Demand and Energy		Fuel				Emissions				Economic			Wind
SCENARIO	CC	CT	Base Load Steam	IGCC	Wind	Nuclear	CC w/Sequestration	IGCC w/sequestration	Demand Response	Demand growth Rate	Energy Growth Rate	Gas	Base Load Steam	Oil	Uranium	SO_2	NO_x	CO_2	Hg	Inflation	Discount Rate	Base Load Steam Uneconomic	Wind Penetration
Reference	R	R	R	R	R	R	R	R	R	R	R	R	R	R	R	R	R	R	R	R	R	R	R
DOE 20% Wind Mandate	R	R	R	R	R	R	R	R	R	R	R	R	R	R	R	R	R	R	R	R	R	R	MH
DOE 30% Wind Mandate	R	R	R	R	R	R	R	R	R	R	R	R	R	R	R	R	R	R	R	R	R	R	H

Table 3-1: Scenario Matrix Table

As additional scenarios are developed beyond the JCSP'08, a wider usage of the value range is expected.

Uncertainty	Unit	Low	Mid/Low	Reference	Mid/High	High
Capital Costs						
Base Load Steam	($/KW)	Reference -10%		1,833		Reference + 10%
CC	($/KW)	Reference -10%		857		Reference + 10%
CT	($/KW)	Reference -10%		597		Reference + 10%
Nuclear	($/KW)	Reference -10%		2,928		Reference + 10%
Wind	($/KW)	Reference -10%		1,713		Reference + 10%
IGCC	($/KW)	Reference -10%		2,118		Reference + 10%
IGCC w/Sequestration	($/KW)	Reference -10%		3,031		Reference + 10%
CC w/Sequestration	($/KW)	Reference -10%		1,683		Reference + 10%
Demand Response	($/KW)			Existing		
Demand and Energy						
Demand Growth Rate	%	PowerBase -25%		PowerBase		PowerBase +25%
Energy Growth Rate	%	PowerBase -25%		PowerBase		PowerBase +25%
Fuel Prices						
Gas	($/MBtu)	Reference -20%		2007 w/4% Growth	Ref + 20%	Reference + 50%
Oil	($/MBtu)	Reference -10%		2007 w/4% Growth	Ref + 20%	Reference + 50%
Base Load Steam	($/MBtu)	Reference -10%		2007 w/2% Growth		Reference + 10%
Uranium	($/MBtu)	Reference -10%		2007 w/2% Growth		Reference + 10%
Emissions						
SO_2	($/ton)	Reference -25%		PowerBase		Reference +25%
NOx	($/ton)	Reference -25%		PowerBase		Reference +25%
CO_2	($/ton)	0		0	7	25
Hg	($/ton)	Reference -25%		PowerBase		Reference +25%
Economic Variables						
Discount Rate	%	5		8		10
Inflation Rate	%	2		3		4.5
Wind						
Wind Penetration		RPS met with Wind		RPS met with Wind	20% Wind Energy	30% Wind Energy

Table 3-2: Uncertainty Definition Table

Section 4: Process Overview

To be fully capable of meeting the FERC Order 890 requirements for evaluating economic projects and integrating this evaluation process into the combined reliability and economic multi-region planning process, multiple, non-trivial requirements and processes must be developed. In order to perform a credible economic assessment, a period of analysis of at least 15 years is required. The following broad steps outline the requirements necessary for the JCSP'08 to perform the economic assessment and develop high voltage overlays to meet the requirements for each of the Scenarios evaluated.

- Step 1: Create a regional generation resource forecast
- Step 2: Site the new generation resources into both the power flow and economic models for each Scenario
- Step 3: Design preliminary transmission plans for each Scenario
- Step 4: Test for robustness
- Step 5: Perform reliability assessment and integration
- Step 6: Final design of integrated plans
- Step 7: Cost allocation

The flow of the process is outlined in Figure 4-1 and subsequently described in greater detail:

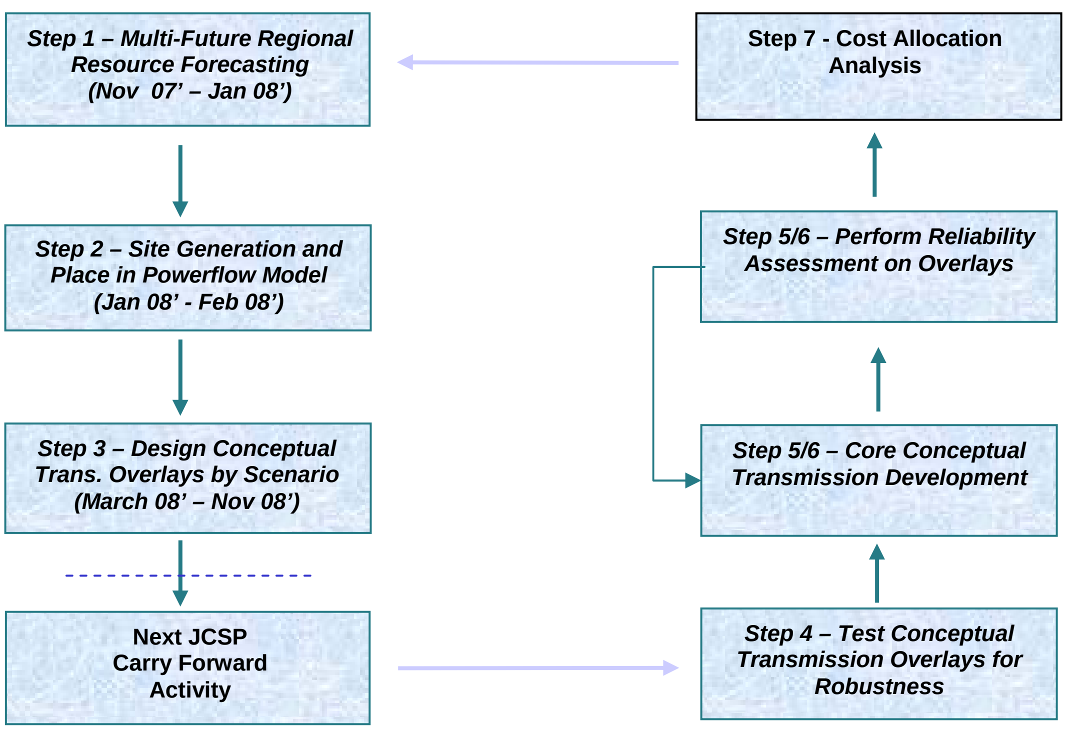


Figure 4-1: JCSP'08 Process – Economic Transmission Planning

For the JCSP'08 only Steps 1-3 are performed due to time limitations; however, all seven steps of the entire process are described on the following pages.

4.1 Step 1: Create a generation portfolio forecast and assessment process

To effectively design and evaluate the impact of new transmission within the JCSP'08 regions, a multi-dimensional analysis of future generation implications is necessary. The existing Generation Interconnection Queues provide initial insight into the new generation being proposed within the footprint, but do not provide the extended time horizon required. As the emphasis of the JCSP'08 study is wind energy requirements, in the form of Renewable Portfolio Standards (RPS) provisions, the wind capacity equivalent to the energy requirement has to be developed on a site specific basis. The amount of capacity is determined as follows:

Wind Capacity = MWh/(CF * 8760)

(Where CF represents the locational wind quality)

Since wind is an interruptible resource, and is not dispatchable, it does not qualify for the same level of capacity credit when measuring its value for resource adequacy purposes. For the JCSP'08 study, wind resources receive a 15% reserve margin credit. This effectively means that seven MW of wind resources are needed for every one MW of a dispatchable resource, such as coal-fired or gas-fired capacity. This is an important assumption since it determines the amount of additional resource capacity that needs to be added to each region's forecast resource mix through 2024.

A resource forecasting model is required to develop the total amount of resources needed to supplement the Generation Interconnection Queue capacity and defined wind capacity. The regional resource forecast model determines, on a consistent least-cost basis, the type and timing of new generation and energy efficiency resources that need to be incorporated into the planning models in order to maintain adequate reserves. For this purpose the Electric Generation Expansion Analysis System (EGEAS) model from the Electric Power Research Institute is used for the twelve regions in the Eastern Interconnection. Regional resource forecasts are developed for each of the three planning areas within Midwest ISO, MAPP, SPP, TVA, PJM, SERC, New York, New England and the IESO in Canada. Resource expansions are needed for all of these areas so as not to produce generation biases from one region to another which would in turn skew transmission flows. A target reserve margin of 15% was used for all areas, with the exception of PJM where 15.5% was used. Therefore, a minimum reserve margin of at least 15% was developed throughout the Eastern Interconnection using common assumptions.

Each area is generation sufficient.

4.2 Step 2: Incorporate Generation from Scenarios into Models

Once the future generation from the regional resource forecast process is developed it must be sited. The generation type and timing required to meet future load growth requirements must be sited within all the planning models to provide an initial reference condition. The questions at the heart of the matter are "do you first site transmission and then build generation, or, site likely generation and then build the transmission system to support the generation assumptions?" The indicative siting of generation is likely to be controversial; however, the tariff driven queuing system hasn't provided the time horizons required and, absent the generation assumption, transmission line benefits analysis have no economic under-pinning. Using the fixed in place generation as a starting point, the development of the transmission plan around this fixed generation can proceed to provide integrated reliability and economic enhancements. The future generation is needed for the development of the long-term transmission models and this process must be developed and completed as an input into those models.

Development of 16-year out JCSP'08 transmission models requires that adjustments to the model building process be undertaken. The ten year out North American Electrical Reliability Corp. (NERC) planning model developed by the Multi-area Modeling Working Group (MMWG) serves as the starting point. Transmission Owners supply known system upgrades, along with load growth forecasts, while the generation additions are incorporated from the Generation Interconnection Queue, wind siting, and the regional resource forecasting process.

With the development of the long-term power flow models the corresponding PROMOD security constrained economic dispatch models can then be developed. PROMOD requires an underlying power flow model for each year that is being studied. The economic evaluation process is structured to analyze future impacts and incorporate sensitivity and risk assessment in the process. A detailed risk evaluation analysis has not been performed in the JCSP'08 process due to time restrictions. Such evaluations will need to be part of the JCSP '09 objectives.

4.3 Step 3: Design Preliminary Transmission Plans for Each Scenario

The following methodology is applied to both the Reference and 20% Wind Energy Scenarios:

First, we use the power flow and PROMOD models developed in Step 2 and run PROMOD using the same assumptions used in the development of the regional resource forecasts. Since we have two Scenarios we develop two corresponding PROMOD models, one for the Reference Case, and one for the 20% Wind Energy Case with all of the uncertainty variables (e.g. emissions levels and rates, fuel prices and limitation, resource retirements, etc.) for that particular Scenario being incorporated. Transmission expansion concepts for the year 2024 were developed for each Scenario:

- Hourly economic simulations were run to determine the properties of the "Constrained" base system.
- Hourly economic simulations were run to determine the properties of an unconstrained base system or "Copper Sheet".
- "Constrained" system and the "Copper Sheet" differences provides:
  - The total benefit by geographic area that potentially could be "captured" by a conceptual transmission expansion.
  - The areas of economic sources and sinks as shown graphically in Figure 4-2. Interface Area boundary identification for monitoring is indicated by the color changes in Figure 4-2.
  - A "Monitored" case, based on the unconstrained case, provides the hourly flow information into each Interface Area and the benefit of the change of flow from the "Constrained" case. The benefit provides a rough budget estimate for transmission construction. The flows can be used to estimate the voltage and type of construction of the lines and transformers to transfer energy from the sources to the sinks.
  - Transmission concepts are formed and tested by economic simulation to determine the benefit capture percentage by area, individual hourly line and transformer hourly flow, the Interface flows, and flow not achieved in the "Monitored" case. Transmission constraints that are sorted by the summation of the hourly shadow prices for a year are also produced. Maps of the generation are used to locate transmission through areas requiring future interconnections. The transmission configurations are modified using the information provided. This process is repeated until there are few issues to resolve. Four steps are required to converge on an adequate solution.
  - Line ratings are then placed on the conceptual lines using a rating system as a multiple of the Surge Impedance Loading based on the line length for AC lines. High Voltage Direct Current (HVDC) lines are rated by the HVDC terminal capacity which usually matches the line power transfer capability. HVDC ratings do not change with distance with the exception of provision for losses.

Information on the mitigation of carbon dioxide, and other pollutants, are available from the computer simulations, as are the affects on capacity factors and fuel usage by other generation. These processes are all collaboratively performed with stakeholders in an open planning process.

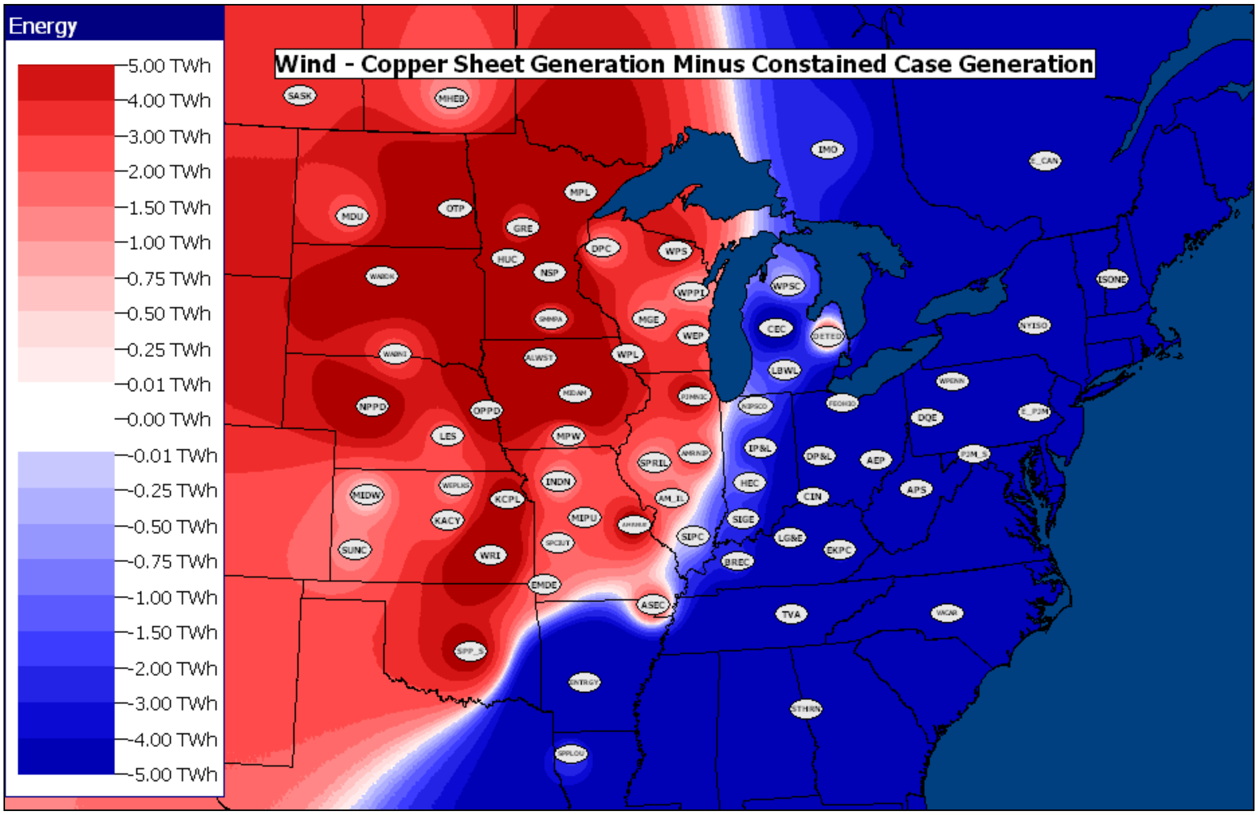


Figure 4-2: Location of Economic Sources and Sinks

4.4 Step 4: Test Transmission Plans for Robustness

The outcome of the process in Step 3 is the development of transmission plans for each Scenario being studied. Up to this point the preliminary plans are developed in isolation of each of the other Scenarios. Our ultimate goal is to develop one transmission plan that performs the best under all Scenarios. The planning process is fraught with uncertainty; our objective is to manage the uncertainty as best we can, therefore, each preliminary transmission plan must be analyzed under the uncertainty conditions associated with the development of each of the other plans. For the JCSP'08 we only have the two Scenarios and the primary difference is the amount of wind capacity and wind energy between the two. As more Scenarios are added and evaluated, a more complex analysis is required to test for robustness between all of the Scenarios. For example, if a transmission plan developed under a high Environmental Scenario performs well under a high Fuel Scenario and Renewable Energy Scenario it is considered to be robust; however if the plan developed under one set of Scenario conditions does not perform well under Other Scenario then potential adjustments to the transmission plan will need to be evaluated.

To perform the robustness tests, each preliminary plan is tested under the uncertainties used to develop each of the Other Scenarios and their associated transmission plans. A set of output attributes for making the value comparisons are used for the comparison process. Such output attributes could consist of the following:

- LOLE/Reserve margin effects
- Short and long-term cost metrics
- Investor impacts
- Economic development impacts
- Degree of difficulty in implementing
- Environmental
- National security implications

For each preliminary transmission plan PROMOD is run and output metrics/attributes are produced. The objective is to compare the output metrics/attributes of a transmission plan specifically created to be optimal in one Scenario over the range of all Scenarios. Therefore, the transmission plan developed to specifically best meet the objectives of the Reference Scenario is evaluated in PROMOD using the input uncertainties for the 20% Wind Energy Scenario and additional Scenarios to be added as they become available.

4.5 Step 5: Consolidate Overlays

Each conceptual transmission overlay is comprised of multiple lines and line segments. It is not feasible to test all combinations of line segments and lines, as performed in a dynamic program such as EGEAS, for capacity expansion. Instead, the value of each line segment, in combination with all other segments, is best obtained from a PROMOD analysis; however, the PROMOD model for the Eastern Interconnection contains extensive data and is an hourly chronological model that requires 3-5 days, on average, to complete a single year 2024 simulation. Clearly, the brute force option to run all combinations of line segments in the development of portfolios is not feasible. Alternate approaches are required. The use of a screening level model to test line segments for a subset of the 8,760 hours per year, 100-200 hours, is under evaluation for use beyond JCSP'08. This tool is currently being benchmarked to PROMOD results.

One advantage of evaluating multiple scenarios is to gain insight into what configurations produce value. If the same line appears in multiple scenarios, that is a good indicator that it is robust. Using engineering judgment in combination with screening tools allows for the development of meaningful portfolios of projects which can then be tested in detail in PROMOD. Once a set of portfolios are developed, based on the conceptual overlays, detailed power flow studies are needed to identify reliability issues and modify the portfolios as needed.

Portfolios identify discreet sets of lines that can be pursued for development if all of the conditions are met. In order to build the enabling transmission to support future generation growth and new energy policy, a number of conditions must first be met.

- **A robust business case for the plan –** First and foremost, it must be demonstrated that the hypothesized benefits of any plan, including a fully developed transmission overlay, exist. This includes a thorough understanding of value drivers, underlying assumptions and a complete evaluation of alternatives including an alternative in which significant transmission infrastructure build-out is not able to occur.
- **Increased consensus around regional energy policies** – Different states have different views about which benefits may have the highest importance. Differences in regional policies, such as inconsistent adoption of Renewable Portfolio Standards, exacerbate this divide, which can be a barrier to the development of large scale transmission projects which provide benefits of various types to users across multiple states or other entities.
- **A regional tariff that matches who benefits with who pays over time –** Over time, those paying for the increased transmission must derive and recognize proportional benefits to feel satisfied with the investment. This is particularly true in a Regional Transmission Organization (RTO), where participation is voluntary. The question of determining beneficiaries is complex and needs to incorporate a more complete set of value drivers, such as reflecting public policy drivers, into the transmission assessment process.
- **Cost recovery mechanisms that reduce financial risk –** Ultimately the investors in the transmission projects must be assured of appropriate returns, commensurate with the risks faced, and in the case of regulated utilities, that the shareholders will not subsidize the rate payers.

It may be possible to proceed with some level of increased transmission build-out after meeting a subset of these conditions; however, construction of an overlay system equivalent to the current interstate highway system will require all conditions to be met across the Eastern Interconnection.

4.6 Step 6: Evaluation of Conceptual Transmission for Reliability

The reliability of the JCSP'08 region is tested for 2018 in the parallel reliability study that is discussed in Volume II of the report. The 2018 reliability assessment is a stand alone study and is only indirectly tied to the economic assessment and development of conceptual overlay through the common power flow model. The conceptual overlays developed through the economic assessment portion of the JCSP'08, which is the subject of this volume of the report, need to be tested for their reliability benefits and identify short comings that can be addressed.

TVA has taken on the task of developing the updated 2018 reliability model with the economic overlay components for both the Reference and 20% wind energy overlays. The objective is to determine the reliability based value the overlays can contribute. As value driven regional expansions are justified, traditionally developed peak-hour based reliability plans will be affected and the combined impact has to be understood to produce a lower cost system. The economic overlays have reliability value and this task is to determine the extent of that value. This evaluation is currently on-going and adjustments to the conceptual overlays will be required based upon the reliability assessment.

4.7 Step 7: Cost Allocation

Cost allocation is not addressed in the JCSP'08. Cost allocation is mentioned in this report solely to recognize that it is the single most important issue impacting the development of regional and multi-regional high voltage transmission.

Cost allocation mechanisms vary across the Eastern Interconnection. There is not a single concept for addressing beneficiaries of projects with who pays for the projects. The whole concept of who benefits, and by how much, is a self defeating argument that leads to constant dissent. Any one project will have more or less value to one area relative to another. The value of the projects rests in what output attributes are considered in the determination of value. Minimization of existing costs may be attractive to one area while the minimization of long-term cost is to another. Access to renewable resources may be the primary driver for one constituency while local jobs may have more traction in another. Appendix 1 describes the Cost Allocation Philosophies and Practices that are existing and proposed for RTO's.

Section 5: Detailed Process Discussion

5.1 Introduction

The determination of wind resource capability and initial siting of the wind resources was performed by the Midwest ISO staff in conjunction with those of the Dept. of Energy (DOE) staff from the National Renewable Energy Lab (NREL) participating in the study. Final wind siting was determined by the input received from stakeholder workshops and the feedback received.

Once the siting process is completed, the powerflow and economic assessment models can be populated with all generation assigned to a specific bus. This completes Steps 1 and 2 of the study process and allows for the long-term transmission development phase of the study to proceed.

5.1.1 Scenario Definitions

A scenario is a prediction of what "could be" which guides the assumptions made about the variables within a model. An uncertainty is a variable which can change from scenario to scenario based on the assumptions made about it in the scenario definition. The outcome of each scenario modeled is a generation expansion plan, referred to as a portfolio. It identifies the optimal "least-cost" generation required to meet reliability criteria based on the assumptions for each scenario. Scenario based analysis provides the opportunity to develop plans for different Scenarios yielding different "best plans."

JCSP'08 started with three scenarios: Reference, 20% Wind Energy Mandate, and 30% Wind Energy Mandate. During the process, it was recognized that current knowledge of wind capability would not support the continuation of a 30% Wind Energy Mandate. Therefore, after the capacity expansion phase of the study process, the 30% Scenario was removed from the JCSP'08 study, but it is included in the Eastern Wind Integration Transmission Study (EWITS) that is scheduled for completion in 2009.

The Reference Scenario is considered the status quo Scenario. This Scenario models the power system as it exists today with reference values and trends based on recent historical data and assumes that existing standards for resource adequacy, renewable mandates, and environmental legislation will remain unchanged. Although Renewable Portfolio Standard (RPS) requirements vary by state, and have many potential resources that can apply, it is assumed that all incremental needs to meet RPS requirements will come from wind resources.

The 20% Wind Energy Scenario requires that 20% of the energy consumption in the Eastern Interconnect come from wind by 2024. Wind Generation will begin to be forced in the models starting in 2010, accounting for the two year lead time assumed with the generator assumptions. A 33% capacity factor, for existing wind generators, and a regional capacity factor, ranging from 35%-45%, is applied toward future wind units. Wind requirements from the Reference Scenario are included in this scenario, without changes on size and location of units.

5.1.2 Primary Assumption Discussion

5.1.2.1 Scenario Matrix Table and Uncertainty Definition Table

Tables 5-1 and 5-2 illustrate how the definition of a scenario guides the assumptions and values of certain variables. A Scenario Matrix Table provides a visual representation of the scenarios and the different values that the variables within them can have. The table identifies each scenario in the leftmost column and lists each scenario variable across the top. A one letter representation of each variable's value for each scenario is shown in the body of the matrix. The Uncertainty Definition Table and the Scenario Matrix Table, together, represent the correlation of the scenario definitions and uncertainty variables.

Variables which can change dependent on a scenario definition are called uncertainty variables. The value of an uncertainty variable is defined in the Uncertainty Definition Table and can be linked to the scenario matrix table by a one letter definition. The Uncertainty Definition Table is a visual representation of each variable which can take on different values in different scenarios and the range of potential values for that variable. Only variables which can change values are listed in the table. Variables which remain static or unchanged in all Scenarios are not represented here and are defined separately.

The ranges of the uncertainty variables are identified across the top of the table as a low, mid-low, reference, mid-high and high value (L, ML, R, MH or H), which correspond to the one letter correlations in the Scenario Matrix Table. For example, the reference value (R) is used in the Reference Scenario for all uncertainty variables as seen in the Scenario Matrix Table. The actual value the (R) represents for each variable is cross referenced in the Uncertainty Definition Table. The actual values assigned to the uncertainty variables will later be discussed in full. The table is for a convenient visual representation only.

As can be seen within the tables, it was determined that the scenarios defined for the JCSP'08 work should vary only in penetration level of capacity. Therefore, the Scenario Matrix Table shown will have no variation in assumptions except for the penetration of wind energy.

	Uncertainties																						
	Capital Costs									Demand and Energy		Fuel				Emissions				Economic			Wind
SCENARIO	CC	CT	Base Load Steam	IGCC	Wind	Nuclear	CC w/Sequestration	IGCC w/sequestration	Demand Response	Demand growth Rate	Energy Growth Rate	Gas	Base Load Steam	Oil	Uranium	SO_2	NO_x	CO_2	Hg	Inflation	Discount Rate	Base Load Steam Uneconomic	Wind Penetration
Reference	R	R	R	R	R	R	R	R	R	R	R	R	R	R	R	R	R	R	R	R	R	R	R
DOE 20% Wind Mandate	R	R	R	R	R	R	R	R	R	R	R	R	R	R	R	R	R	R	R	R	R	R	MH
DOE 30% Wind Mandate	R	R	R	R	R	R	R	R	R	R	R	R	R	R	R	R	R	R	R	R	R	R	H

Table 5-1: Scenario Matrix Table

Uncertainty	Unit	Low	Mid/Low	Reference	Mid/High	High
Capital Costs						
Base Load Steam	($/KW)	Reference -10%		1,833		Reference + 10%
CC	($/KW)	Reference -10%		857		Reference + 10%
CT	($/KW)	Reference -10%		597		Reference + 10%
Nuclear	($/KW)	Reference -10%		2,928		Reference + 10%
Wind	($/KW)	Reference -10%		1,713		Reference + 10%
IGCC	($/KW)	Reference -10%		2,118		Reference + 10%
IGCC w/Sequestration	($/KW)	Reference -10%		3,031		Reference + 10%
CC w/Sequestration	($/KW)	Reference -10%		1,683		Reference + 10%
Demand Response	($/KW)			Existing		
Demand and Energy						
Demand Growth Rate	%	PowerBase -25%		PowerBase		PowerBase +25%
Energy Growth Rate	%	PowerBase -25%		PowerBase		PowerBase +25%
Fuel Prices						
Gas	($/MBtu)	Reference -20%		2007 w/4% Growth	Ref + 20%	Reference + 50%
Oil	($/MBtu)	Reference -10%		2007 w/4% Growth	Ref + 20%	Reference + 50%
Base Load Steam	($/MBtu)	Reference -10%		2007 w/2% Growth		Reference + 10%
Uranium	($/MBtu)	Reference -10%		2007 w/2% Growth		Reference + 10%
Emissions						
SO_2	($/ton)	Reference -25%		PowerBase		Reference +25%
NOx	($/ton)	Reference -25%		PowerBase		Reference +25%
CO_2	($/ton)	0		0	7	25
Hg	($/ton)	Reference -25%		PowerBase		Reference +25%
Economic Variables						
Discount Rate	%	5		8		10
Inflation Rate	%	2		3		4.5
Wind						
Wind Penetration		RPS met with Wind		RPS met with Wind	20% Wind Energy	30% Wind Energy

Table 5-2: Uncertainty Definition Table

5.1.2.2 Software

The following section describes the software used in the capacity expansion portion of the JCSP'08 study.

Powerbase is a separately licensed data management system from Ventyx. The program contains detailed market data for the United States and Canada and is the underlying source of data in the capacity expansion and production cost modeling software. The data in Powerbase can be replaced in whole, or in part, with newer or more appropriate data as desired.

Electric Generation Expansion Analysis System (EGEAS) from the Electric Power Research Institute (EPRI) is software used for long term regional resource forecasting. EGEAS performs capacity expansions based on long-term, least-cost optimizations with multiple input variables and alternatives. Optimizations can be performed on a variety of constraints such as reliability (loss-of-load hours), reserve margins, or emissions constraints. The JCSP'08 study optimization is based on minimizing the 20 year capital and production costs, with a reserve margin requirement indicating when new capacity is required.

Energy Map is mapping software from Ventyx. Energy Map is a mapping system which contains geographic and statistical data for the North American Energy system arranged in layers. This multivariate arrangement allows for spatial analysis to be performed in the siting of the generation portfolios and the representation of the final results.

5.1.2.3 Assumed Variables

The following sections describe variables which are applied consistently through all modeled scenarios without changes made to the values. Following the assumed - or "static" - variables is a discussion on the uncertainty variables, or the variables which can change values depending on the scenario being modeled.

Study Period

The regional resource forecasting model has a 20 year study period running from January 2008 to December 2027. All values presented in this report are assumed to be in 2008 dollars unless otherwise noted. All outputs from the regional resource forecasting model are through the year 2024 only; this is to avoid confusion between what the model expands for the entire study period and what is actually used to populate the security constrained dispatch models.

Area Definitions

The study analyzes ten designated regions within the Eastern Interconnect, shown in Figure 5-1. All regions were studied as a whole with the exception of the Midwest ISO, which was broken into three study regions based on the fact that the EGEAS software has a limitation of 1,000 thermal generating units allowed, and the Midwest ISO footprint exceeds this limitation. The JCSP'08 study adhered to the three planning regions corresponding to the existing Midwest ISO transmission expansion planning regions defined as the Central, East and West regions.

Each area is planned to have sufficient generation with the exception of specified interchange schedules and wind interchanges. From a capacity reliability viewpoint, each area can supply its needs.

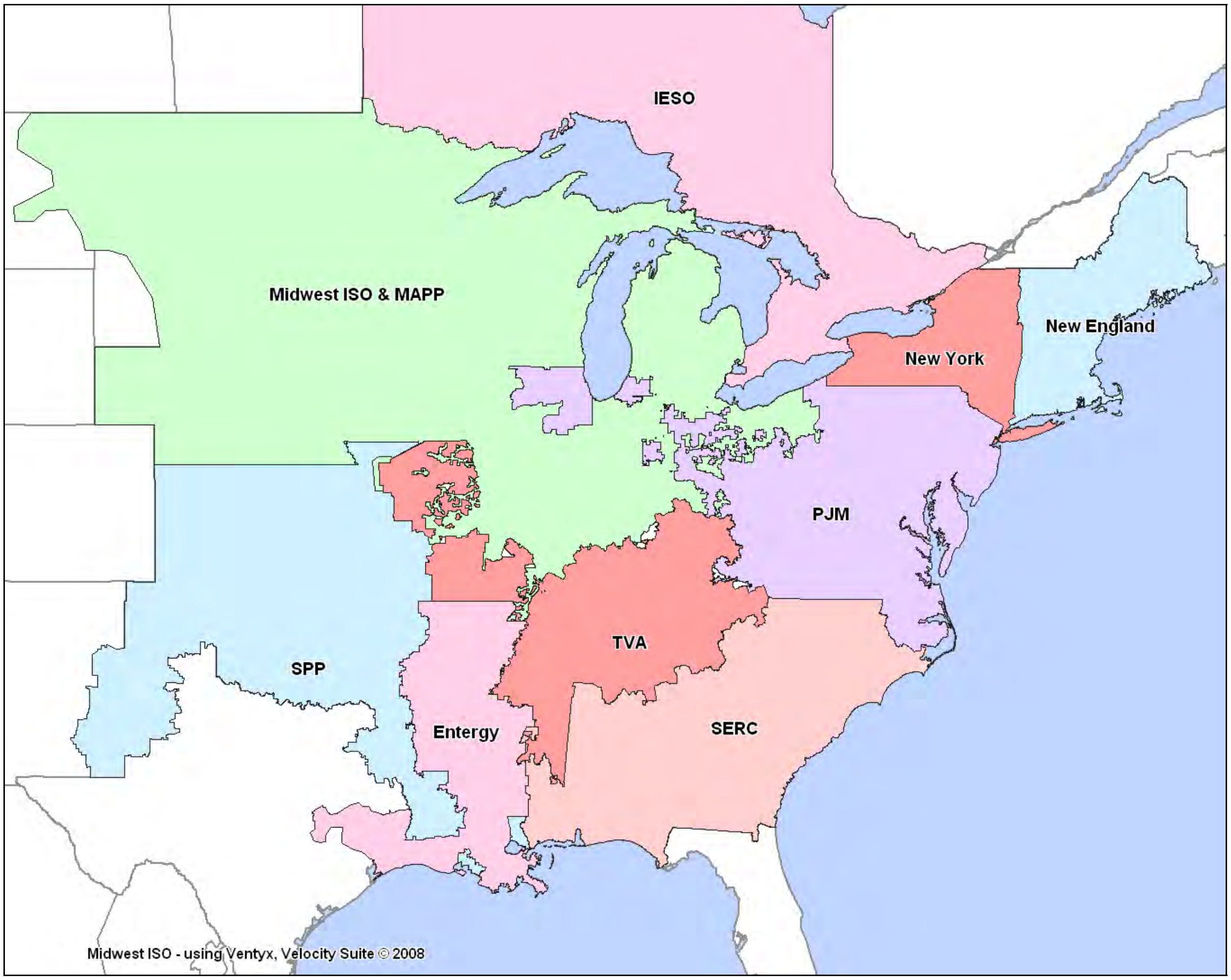


Figure 5-1: JCSP'08Capacity Expansion Planning Regions.

Demand and Energy

Demand growth and reserve margin requirements are the driving factors in the amount of new generation needed in each portfolio. The other uncertainty variables identified are the driving factors for type and timing of the optimal generation to be built in each Scenario based on production and capital costs. Because of the direct impact demand has on the amount of new generation required, three levels of demand escalation have been identified - low, reference and high.

Demand for all study regions is originally based on the information provided within the PowerBase Database, which is based on the 2006 FERC Form 714, 2006 NERC ES&D[1], and 2006 Powerflow data. The load data for all regions has been benchmarked against various reporting entities within each region and was also provided for review by all stakeholders during the study process. Through this process the Midwest ISO specifically adjusted demand and energy projections to coincide with its Module E filing. Other area comments on demand and energy resulted in non-coincident data benchmarking and found that the PowerBase provided data was suitable for the study.

Within the PowerBase, the annual peak demand for each company is provided. This demand value is applied to an hourly load profile for each company, provided by Ventyx, based on calendar year 2002. In the PowerBase Database, each company has its own unique hourly profile, with each company experiencing its peak demand at different times of the year. Because the expansions are performed on a regional basis, this requires aggregating each individual company's peak demand and determining a peak coincident factor for each study region. This is accomplished by summing the individual hourly peaks for each company for all 8,760 hours in the year. The maximum sum of the individual hourly peaks is the coincident peak for the year. Dividing the coincident peak by the sum of the individual company peaks provides a regional coincident factor. The coincident peak demand of each region is used in reserve margin calculations. A summary of the calculations is provided in Table 5-3. The annual coincident peak demand is the same in each scenario.

Just like the demand assumptions used in the study, annual energy values are also provided through the PowerBase database. The information values were provided to workshop participants for update or verification. The Midwest ISO made appropriate adjustments to its energy projections that coincided with the adjustments made to the demand values through the Midwest ISO Module E process.

Study Region	Study Region Coincidence Factor	2008 Non-Coincident Peak Demand (MW)	2008 Coincident Peak Demand (MW)	2008 Annual Energy (GWh)	Reference Annual Demand Esc (%)	Reference Annual Energy Esc (%)
Entergy	0.9968	27,712	27,622	142,362	1.80%	1.66%
IESO	1.0000	25,024	25,024	161,009	0.57%	0.92%
New England	0.9970	28,227	28,141	135,776	2.27%	1.69%
Midwest ISO Central	0.9963	39,569	39,421	207,471	1.26%	1.29%
Midwest ISO East	0.9875	40,624	40,116	202,398	0.82%	1.57%
Midwest ISO West	0.9740	35,669	34,741	180,793	1.79%	1.66%
MAPP	0.9585	16,106	15,437	78,425	1.21%	1.67%
New York	0.9789	35,064	34,323	171,054	0.92%	0.77%
PJM	0.9324	142,826	133,169	717,468	1.90%	1.65%
SERC	0.9740	96,071	93,577	472,752	2.37%	2.04%
SPP	0.9894	41,287	40,848	192,059	1.35%	1.85%
TVA	0.9956	47,633	47,421	257,337	2.27%	0.89%

Table 5-3: Demand and Energy Assumptions Used Within the JCSP'08 Scenario Definitions.

[1] North American Electrical Reliability Corp. (NERC) Electricity Supply & Demand (ES&D)

Generation Resources

The Midwest ISO uses the PowerBase software as its platform for existing unit generator information. Although Ventyx does benchmarking of its generator data, asset owners have more detailed information for units such as: generators participating in the markets and behind the meter generators, Scenario generators (Queue Generators), reported capacities, ownership, etc. Building upon the generators in the default PowerBase database, change cases are created to reflect the existing and future generation fleet. PowerBase generation was provided to stakeholders for comments in four regional forums and on the Midwest ISO website. Each generator in the database or in a queue was assigned a status of active, planned, future, or canceled as described in the Table 5-4.

Status	Generator Status Descriptions
Active	Existing online Generation including committed and uncommitted units. Does not include generation which has been mothballed or decommissioned.
Planned	A generator which is not online, has a future in-service date, is not suspended or postponed and has proceeded to a point where construction is almost certain. Examples would include generators which have a signed Interconnection Agreement, all permits have been approved, all study work has been completed, state or administrative law judge has approved, etc. One exception to this rule is the inclusion of recently proposed nuclear expansions throughout the Eastern Interconnect. Although the units do not qualify as “planned” units, stakeholders insisted that the units be considered as part of the planned generation fleet. These units are used in the model to meet future demand requirements prior to the economic expansions. All units coming online between August of 2007 and July of 2008 will show up as newly installed in 2008.
Scenario	Generators with a future online date that do not meet the criteria of the “planned” status. Generators with a future status are typically under one of the following categories: proposed, feasibility studies, permits applied, etc. These generators are not used in the models but are considered in the siting of future generation.
Canceled	Generators which have been suspended, canceled, retired or mothballed.

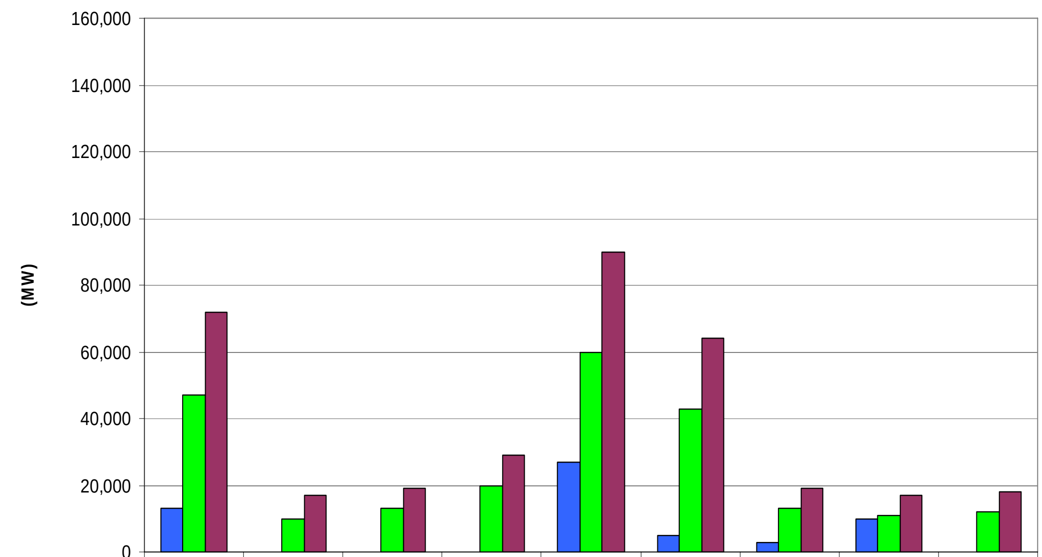
Table 5-4: Status Categories Applied To All Units Within the Database.

Synchronizing the PowerBase data with the various other sources of data requires a linkage between the datasets, a process known as mapping. Mapping of the PowerBase to the Midwest ISO Queue, PJM Queue, SPP Queue, New York Queue and New England Queue, and to the Global Energy Database was performed. Global Energy, Inc. is a company which provides electrical system information on power plants, transmission lines, substations, etc., for the United States and is now part of Ventyx. Additional stakeholder comments and changes were applied to the database prior to model population. Stakeholders provided comments that adjusted capacities, ownership, in-service dates, and operational status of units.

PowerBase has several types of generator categories which do not have a fuel assigned to them and are modeled as transactions in EGEAS. The categories include Industrial Load, Biomass, and Wind. Industrial load is represented as a firm sale and is unaffected by future growth and load duration curves. This transaction reduces the available capacity to serve the rest of the demand in the area. Biomass generation is modeled as a purchase into a region and 100% of its maximum capacity counts towards reserve margin calculations. Wind is considered a purchase into a region with 15% of its maximum capacity counting towards reserve margin calculations. A 33% capacity factor for existing wind generators and a regional capacity factor for new wind generators were applied toward energy contributions including the requirements for the renewable energy mandate.

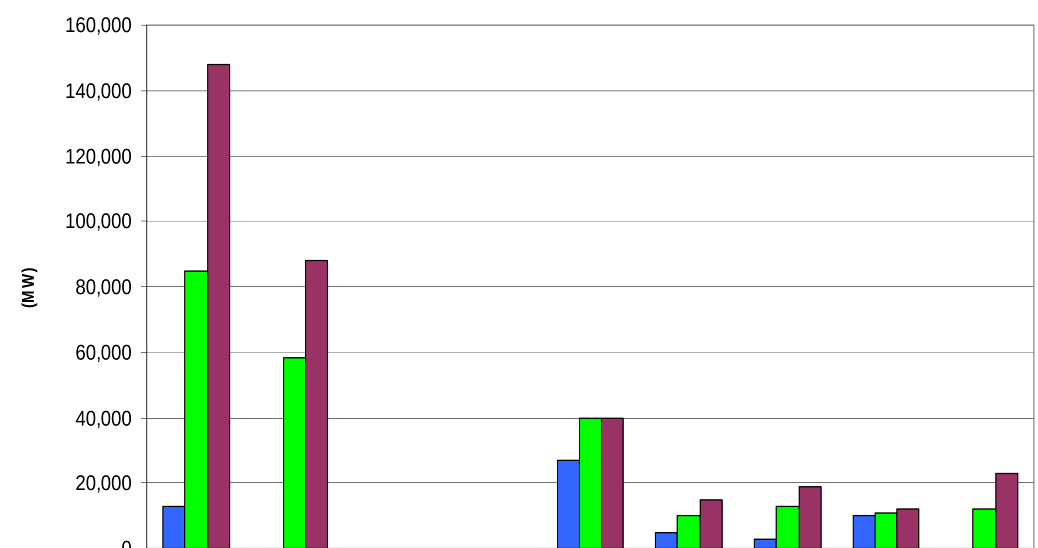
Interruptible loads are modeled as a capacity resource within the models. They are not counted as a reduction in load, but an increase in available capacity. The interruptible loads are modeled as thermal units with higher costs, which will allow them to be dispatched only when it is absolutely necessary to do so. Their capacity counts 100% towards reserve margin calculations.

Tables 5-5 through 5-9 provide a summary of the generation used in the study.



	MISO & MAPP	SPP	ENTERGY	TVA	PJM	SERC	New York	New England	IESO
Reference	13,000	0	0	0	27,000	5,000	3,000	10,000	0
20%	47,000	10,000	13,000	20,000	60,000	43,000	13,000	11,000	12,000
30%	72,000	17,000	19,000	29,000	90,000	64,000	19,000	17,000	18,000

Table 5-5: Estimated Wind Capacity Need by Region Used Within the JCSP'08 Expansions.



	MISO & MAPP	SPP	ENTERGY	TVA	PJM	SERC	New York	New England	IESO
Reference	13,000	0	0	0	27,000	5,000	3,000	10,000	0
20%	84,667	58,333	0	0	40,000	10,000	13,000	11,000	12,000
30%	148,000	88,000	0	0	40,000	15,000	19,000	12,000	23,000

Table 5-6: Estimated Wind Location by Region Used Within the JCSP'08 Study Process.

Fuel Type	Combined Cycle	Base Load Steam Turbine	Combustion Turbine	Hydro	IGCC	Nuclear	Biomass	Steam Turbine (Gas)	Storage	Wind	Total
Entergy	13,987	6,804	3,446	691		5,182	95	15,760	28		45,993
IESO	2,541	6,432	683	7,681		12,852	85	2,200	174	182	32,828
New England	12,610	3,195	2,569	1,734		4,389	935	6,932	1,675	70	34,109
Midwest ISO Central	1,523	29,712	11,032	476	282	2,324		755		15	46,118
Midwest ISO East	5,794	22,340	6,979	164		4,092	154	2,702	2,475	113	44,812
Midwest ISO West	5,396	18,746	9,690	768		3,866	132	461		2,735	41,793
MAPP	1,453	11,402	3,758	2,605		1,782		276		557	21,834
New York	8,699	3,092	5,994	4,356		5,069	286	11,898	1,280	42	40,716
PJM	24,491	70,656	30,944	2,647		30,769	669	9,253	3,625	514	173,567
SERC	18,271	45,448	23,638	6,261		17,151	147	1,169	3,844		115,929
SPP	11,685	22,301	8,439	2,414		1,165	56	12,691	296	1,991	61,038
TVA	6,159	24,830	10,605	5,074		7,117			1,712	29	55,526
TOTAL	112,608	264,959	117,776	34,872	282	95,758	2,557	64,096	15,109	6,246	714,263

Table 5-7: Active Generation Capacity by Region (without de-rates)

Fuel Type	Combined Cycle	Base Load Steam Turbine	Combustion Turbine	Hydro	IGCC	Nuclear	Biomass	Steam Turbine (Gas)	Storage	Wind	Total
Entergy	1,800	1,585				3,000					6,385
IESO	3,619		610	20		9,138				867	14,254
New England	110		70				50			607	837
Midwest ISO Central	420	1,792				2,600					4,812
Midwest ISO East						1,563				183	1,746
Midwest ISO West	1,815	2,180	374							1,122	5,491
MAPP		600								90	690
New York	640		1,100			1,600				331	3,671
PJM	1,127	92			2,071	4,706				902	8,898
SERC	1,652	500	280			8,848					11,280
SPP	500	2,395	1,407							2,808	7,110
TVA	660	549	340		677	3,460				50	5,736
TOTAL	12,343	9,693	4,181	20	2,748	34,915	50	0	0	6,960	70,910

Table 5-8: Planned Generation Capacity by Region without De-rates (2008-2024)

Fuel Type	Combined Cycle	Base Load Steam Turbine	Combustion Turbine	Hydro	IGCC	Nuclear	Biomass	Steam Turbine (Gas)	Storage	Wind	Total
Entergy											0
IESO		6,432									6,432
New England											0
Midwest ISO Central		76									76
Midwest ISO East											0
Midwest ISO West		582									582
MAPP											0
New York		177	825								1,002
PJM		1,695	868								2,563
SERC			62								62
SPP											0
TVA											0
TOTAL	0	8,962	1,755	0	0	0	0	0	0	0	10,717

Table 5-9: Generator Retirement Capacity by Region without De-rates (2008-2024)

Generation from Wind

From a capacity standpoint, wind is treated as an intermittent resource and receives a 15% capacity credit; whereas a dispatchable resource would receive a 100% capacity credit for resource adequacy purposes. For example, a 100 MW wind farm would have 15 MW of capacity applied to meeting the reserve margin requirement.

The Reference Scenario calculates the amount and sites wind based on meeting existing RPS incremental requirements with wind as of January 1, 2008. As stated before, there is a plethora of alternatives that satisfy RPS standards throughout the states; however, this study assumes that incremental mandate needs will be met with wind resources. States with goals, or proposed targets, are not included in this wind assignment. The 20% Wind Energy Scenario assumes that a federal 20% wind-only energy mandate is to be reached by 2024. All wind located in the Reference Scenario is carried forward to the 20% Wind Energy Scenario; so states which have a more aggressive mandate than 20% will use the wind energy in the Reference Scenario to supplement the wind requirements in other states.

All states with RPS provisions which require a phasing in of RPS designated capacity, with specific milestone requirements, are included in the wind calculations. Because wind generation has a two year construction lead time within the model, 2010 is the first year wind units are placed into service. Wind in the database with "planned" status is counted toward mandates, and any shortfalls prior to 2010 are made up for in that year. Figure 5-2 shows states with RPS provisions.

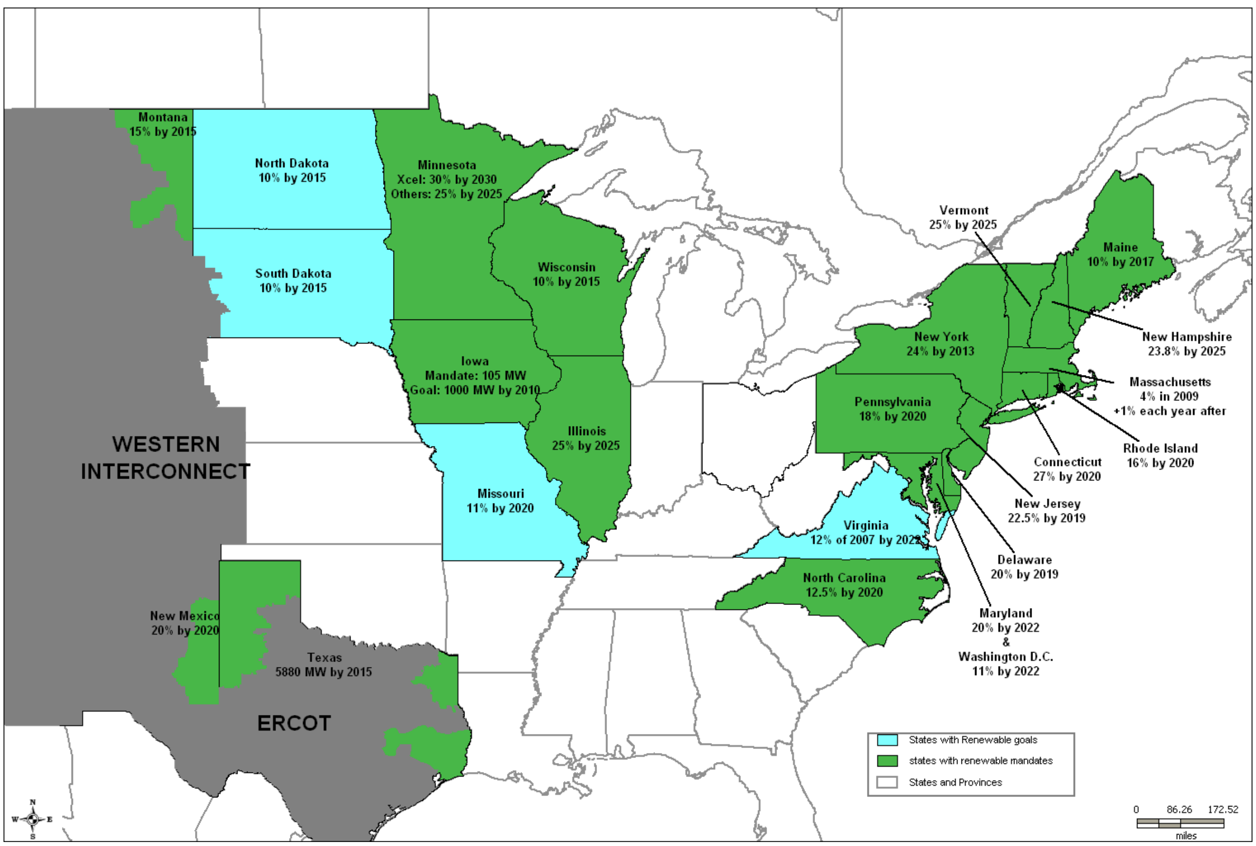


Figure 5-2: State RPS Mandates and Goals as of January 1, 2008

A process is required to calculate the amount and timing of wind that will be required to meet the Reference and 20% Wind Energy Scenarios prior to EGEAS model use. Although wind can be placed into the model to be selected on an economic basis, it has been found that the wind will not be selected at the levels to meet the requirement assumptions. Because of this, the wind nameplate MW to be installed are calculated and then forced into the capacity expansion model. The following steps walk through the process for determining the wind installation needs.

- **Reference Scenario wind need calculation.**
  - Identify state RPS provisions (most are energy based, but some do have nameplate requirements and both are handled accordingly).
  - Match database companies to RPS provisions.
  - Determine energy projections that apply to the RPS provisions.
  - Identify RPS requirement for the 20 year capacity expansion model planning period.
  - Identify existing and planned qualifying capacity contributions. These resources often include existing wind, biomass, solar, and hydro facilities; however, although hydro is a renewable resource, some RPS requirements do place size restrictions on qualifying hydro facilities.
  - Add wind generators in 1,000 MW increments until all yearly requirements are met. 1,000 MW units are large increments and not exact at all times; however, model limitations push to the larger sizes and the aggregation of multiple companies within a state help lessen the impact of the larger increments.
  - The generators are timed to meet staged requirements as well as back loaded to an extent that the model is moderating the annual in-service timing of the resources (spreading the capacity over multiple years).
- **20% Wind Energy Scenario.**
  - Start with assumptions and results of the Reference Scenario.
  - Remove non-wind resources as contributions to RPS provisions.
  - Repeat previous steps to meet incremental needs for the scenario.

Region	Wind CF Applied (%)	Mandate Required (%)	2024 Estimated Energy Need for Wind Mandate (GWh)	Existing or Planned Wind Energy by 2024 Applied (GWh)	Incremental Mandated Installed Nameplate (MW)
Midwest ISO Central*	40%	20%	50,939	43	15,000
Midwest ISO East*	35%	20%	51,938	1,065	17,000
Midwest ISO West*	45%	20%	47,610	9,040	10,000
MAPP*	45%	20%	20,460	1,869	5,000
Midwest ISO & MAPP		20%	170,947	12,016	47,000
IESO	35%	20%	37,254	3,230	12,000
New York	35%	20%	38,658	1,449	13,000
PJM	35%	20%	186,456	3,890	60,000
TVA	35%	20%	59,266	667	20,000
SERC	35%	20%	130,564	0	43,000
Entergy	35%	20%	37,061	0	13,000
New England	35%	20%	35,518	1,953	11,000
SPP	45%	20%	51,465	12,773	10,000
TOTAL			747,189	35,977	229,000

Table 5-10: 20% Wind RPS Calculation for Study Years for Siting 2008-2024
(* The Midwest ISO & MAPP values are calculated at sub-regional levels and aggregated for data reporting purposes)

There are essentially three ways to model wind resources within the EGEAS model:

1. The first method is to provide the wind resource monthly and annual energy limitations. Although this method would allow the proper amount of expected energy to be available during a time frame, the model would dispatch the energy at times when it is most economical to do so, during peak hours. This is not a proper application of the wind resource since most of its energy production is during off-peak hours.
2. The second methodology is to give the wind alternatives a specific profile that shows the variation by hour for an entire year. There will be times when the wind is running at the nameplate capacity of the unit as well as times when it is not operating at all. This would be the preferred methodology if not for limitations on wind profiles allowed within the EGEAS model. The EGEAS model allows for only nine profiles to be added. This study looks at adding hundreds of wind sites throughout the Eastern Interconnect. If this methodology was to be used, then all the sites populated would point to only nine difference profiles and would cause problems in the energy calculations within the model.
3. The third, and preferred, methodology for modeling wind within this study is the application of a synthetic wind profile that covers the 8,760 hours represented for each year within the model. This modeling technique took known profiles and created on-peak and off-peak averages for each month of the year. Because of this modeling, the wind contribution to the model will never be completely offline and will also never be online at 100% of nameplate capacity.

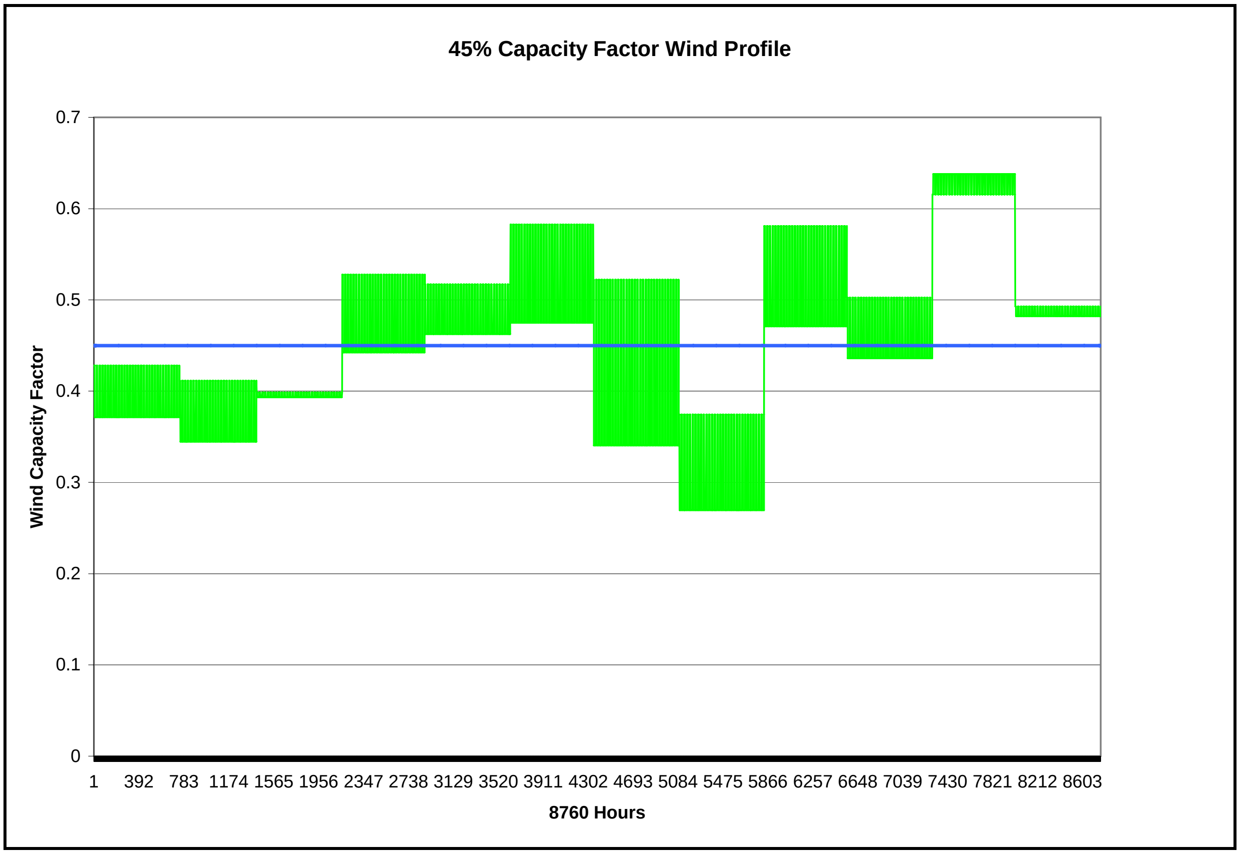


Figure 5-3: Example of Wind Profile Modeled Within EGEAS

Spinning Reserve

In addition to demand, an additional factor in calculating generator dispatch is spinning reserve requirements. Spinning reserve is the additional generation required to be online and available beyond what is needed to serve load. Spinning reserve does not affect reserve margin calculations but has an impact on generation dispatch and therefore production costs. Each region was modeled with a 1.125% spinning reserve requirement.

Generation Retirements

The study assumes the default PowerBase information and stakeholder feedback for the retirement of all units except nuclear. It is assumed all existing nuclear plants will renew any license requirements and will remain in operation throughout the 20 year study period.

Generation Variable Costs

No changes are made to the generation variable costs in the default database. These values maintain the escalation of 3.0 percent per year.

Generation Fixed Costs

No changes are made to the existing values in the default database. These values maintain the escalation of 3.0 percent per year.

Generation Unit Maintenance

No changes are made to the existing values in the default database. Maintenance is automatically scheduled for all existing units except for nuclear units. EGEAS schedules maintenance according to the overall system reliability as a target. Existing Nuclear unit maintenance is known from the Nuclear Regulatory Commission (NRC) web site and is part of the Powerbase database from Ventyx.

Generation Forced Outage Rate

No changes are made to the existing values in the default database. The forced outage rate information is based on data from the NERC Generator Availability Data System (GADS). The values are based on historical five-year average values by class type of generators.

Generation Must Run Status

All Base Load Steam and Nuclear units are set to Must Run units and all other units are not Must Run. If a generator is designated in the database as a Must Run unit, the minimum segment of the generator will be dispatched at all times regardless of its placement in the energy bid order. Only the minimum segment of the generator will be dispatched at all times. The upper segment will still be dispatched according to its bid cost. Changing the status of a generator to a Must Run does not affect the generation expansion analysis, but can affect the production costs. All units use the minimum capacity values as indicated in the Table 5-11 when dispatched.

Base Load Steam	25 %
Supercritical Base Load Steam	40 %
Nuclear	100 %
CT	50 %
CC	40 %
IGCC	40 %

Table 5-11: Modeled Generator Minimum Capacity

Because of operating limitations, supercritical base load steam units have a higher minimum capacity than other base load steam technology units and their minimum run capacity is set at 40%. The Global Energy Inc. Database was used to identify base load steam units which are supercritical.

Tie Limits

The capacity expansion is done by region without modeling transmission links to other areas; therefore tie limits are not modeled.

Firm Interchange

Scheduled interchange affects reliability calculations and is modeled as an adjustment to total capacity available in a region, thus affecting reserve margin calculations. It is assumed that all regions will build generation to meet their reserve margins. All regions were given the opportunity to include firm imports or exports as contributions to the reserve margin calculation. The larger regions being studied absorbed most of the firm interchanges occurring; however, New England had firm transactions from its Canadian neighbors that were modeled to a total of 5,500 MW of capacity coming from Quebec and the Maritime areas that count towards the reserve margin calculation. The Midwest ISO West Region also contains firm transactions over the study period from Manitoba that totals 3,000 MW by the end of the study period. Also included within the model are short-term firm transactions, within the Midwest ISO East and West regions, that represent much of the Midwest ISO internal transactions that show up because of the disaggregation of the footprint due to model limitations. These transactions are modeled to reduce, over time, to adhere to a particular region building to support its own reliability needs.

Losses

Losses are included in the database demand data.

Hurdle Rates

Hurdle rates influence the capability of a region to obtain support or sell energy to other regions. If two regions want to exchange energy, the difference of dispatch costs (Running Rates) between the buying region and selling region should be greater than the hurdle rate between them. Hurdle rates are not included within the EGEAS model because regions are modeled separately. However, the rates do apply within the PROMOD model.

Financial Variables

The variables in the Tables 5-12 and 5-13 are applied to the Base Overnight Construction Costs of each generator alternative to calculate the annual and total costs output from the EGEAS model.

	Rate (%)
Composite Tax Rate	39.00
Insurance Rate	0.50
Property Tax Rate	1.00
Discount Rate	8.00
AFUDC Rate	9.00

Table 5-12: Universal Assumptions Used in Financial Calculations Within the EGEAS Model.

Cost of Capital	Ratio (%)	Rate (%)	Before Tax Weighted Cost (%)
Debt	55	9.00	4.95
Preferred Stock	0	0	0
Common Stock	45	12.00	5.4
Before Tax Weighted Cost of Capital		10.35	

Table 5-13: Assumed Debt To Equity Split Used for Cost of Capital.

Reliability Criteria

Capacity additions in the model are based on reserve margin requirements. Reserve margin is calculated by the difference in available capacity and peak coincident demand divided by the peak coincident demand.

$$\text{Reserve Margin} = \frac{\text{Available Capacity - Peak Coincident Demand}}{\text{Peak Coincident Demand}}$$

Peak demand is determined using the non-coincident annual peaks applied to hourly load profile curves. The coincident peak occurs at the time the hourly load demand reaches its peak for the system. The available capacity is the maximum capacity available during the peak coincident demand from the following sources: net transactions, interruptible load and firm generation. Firm generation is the percent of a generator's maximum capacity that is counted toward calculation of the reserve margin. For example, wind units contribute 15% of their maximum capacity toward reserve margin calculations. Table 5-14 shows the current targets.

Region	Reserve Target
Entergy	15%
IESO	15%
New England	15%
MAPP	15%
Midwest ISO Central	15%
Midwest ISO East	15%
Midwest ISO West	15%
New York	15%
PJM	15.5%
SERC	15%
SPP	15%
TVA	15%

Table 5-14: Target Reserve Margins By Region.

Demand Response

Demand response represents changes in electricity use designed to be short-term in nature, centered on critical hours during a day or year when demand is high or when reserve margins are low. In the study demand response is modeled as interruptible load and direct load control. Demand response data was collected through the PowerBase database as well as reporting performed by New England and the Midwest ISO. The portion of demand response to total non-coincident peak demand for an area is calculated and that ratio is maintained for each company for the 20 year study period. Therefore, areas which currently have demand response are assumed to continue to maintain demand response programs in proportion to their total demand.

Assumed Annual Demand Response Incremental Additions (MW)	
PJM	73.2
New England	70.0
TVA	64.7
Midwest ISO West	58.3
SERC	51.5
New York	20.0
SPP	10.5
Midwest ISO Central	8.2
Midwest ISO East	7.9
IESO	1.8
MAPP	1.6
ENTERGY	1.1

Table 5-15: Modeled Annual Incremental Increases In Demand Response By Region.

(These additions maintain a percentage penetration for all years of the study.)

Interruptible demand and direct load control are modeled as a capacity resource in EGEAS just like a generator. The default data is used for the population of values from PowerBase to EGEAS. There are no fixed or variable costs associated with the capacity, a heat rate of 10 MBTU/MWh and a 2008 fuel price of $50.92 with a 3% annual escalation are givens. This allows for demand response to be dispatched only when needed, as its fuel price places it toward the last in the order to be dispatched.

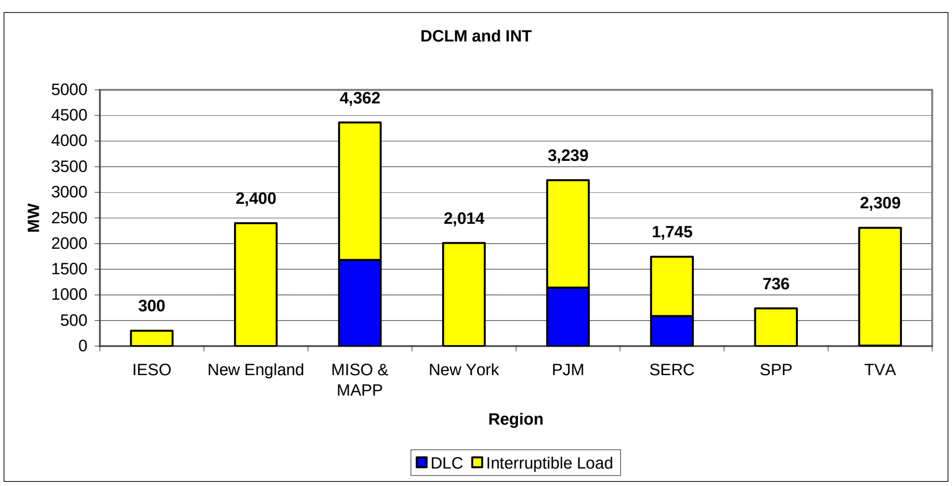


Figure 5-4: Modeled Existing Demand Response Values

Generation Prototype Information

Generation prototype information includes all information used to describe the generation available as a future capacity resource in the model including type, size, cost, construction time, maintenance, heat rates, etc. Data comes from a variety of sources including the Energy Information Administration (EIA) publication *Assumptions to the Annual Energy Outlook 2007*, the Michigan Capacity Needs Forum and stakeholder input. Unless otherwise specified, the assumption information came from the EIA. Some generation prototype information can vary depending on the Scenario being modeled and some information remains consistent in each scenario.

Many types of generators could be used as a capacity resource in the study. For example, the EIA data contains information for 19 alternatives. However, due to software limitations and the regional nature of our study in general, only eight alternatives are used including:

- Wind
- CC (Combined Cycle)
- CC with sequestration
- IGCC (Integrated Coal Gasification Combined Cycle)
- IGCC with sequestration
- Nuclear
- CT (Combustion Turbine)
- Base Load Steam

The overnight construction costs are derived by escalating the EIA 2007 EIA assumptions by 30% then adjusting them to 2008 dollars.

Fixed Operation and Maintenance (O&M) used the EIA data converted to 2008 dollars. Adjustments were made to CC and CT units to reflect costs associated with pipeline reservation for gas units. The adjustments made follow the same assumptions made in the Michigan Electric Capacity Need Forum (CNF) study. Added costs are $20/kW for CCs and $5/kW for CTs. Transmission system interconnection was not included in the study.

Variable O&M and heat rate data is based on the EIA data without changes other than adjusting to 2008 dollars.

Forced outage rate and maintenance hour values are from the Michigan Capacity Needs Forum. Table 5-16 summarizes the details for each alternative available for expansion within the study.

Type	Size	Overnight Const. Cost	Fixed O&M	Variable O&M	Heat Rate	Lead Time	Maint	FOR
	MW	$/kW	$/kW-Yr	$/MWh	Btu/kWh	Years	Hours	%
Base Load Steam	1200	1833	28.22	4.70	8,844	6	500	5.92
CC	1200	857	34.01	2.11	7,196	3	467	3.25
CT	1200	597	17.72	3.66	10,842	2	401	5.34
Nuclear	1200	2,928	69.57	0.51	10,400	11	710	2.00
Wind	1000	1,713	15.91	5.00		2		
IGCC	1100	2118	39.62	2.98	8,309	6	500	5.92
IGCC/Seq	760	3,031	46.64	4.55	9,713	6	500	5.92
CC/Seq	800	1,683	41.61	3.01	8,613	3	467	3.25

De-Commissioning Costs not modeled
Fixed O&M has fuel reservation capacity charge for:
CC $20/kW
CT $5/kW
No transmission connection charges included

Table 5-16: Modeled Generator Prototype Data Reference Values In 2008 Dollars

The generator prototype book and operating life are used to calculate the financial implications of each alternative and are provided in Table 5-17.

Generator Type	Operating Life (Years)	Book Life (Years)	Tax Life (Years)
Base Load Steam	60	40	20
CC	30	30	15
CT	30	30	15
Wind	25	25	15
Nuclear	60	40	20
IGCC	30	30	20
IGCC w/Seq	30	30	15
CC w/Seq	30	30	15

Table 5-17: Modeled Generator Prototype Book, Operating, and Tax Life

Construction lead times were changed from the EIA data reflecting stakeholder input to account for permitting and construction time. The time it takes to complete a generation construction project is outlined in Table 5-18. This expenditure schedule indicates the percentage of total construction dollars spent on the generation each year. This is used in the calculation of the capital expenditure profile of a generation alternative in EGEAS.

Year	Base Load Steam	CC	Nuclear	CT	IGCC	CC/Seq	IGCC/Seq
1	0.02	0.25	0.01	0.50	0.02	0.25	0.02
2	0.03	0.50	0.01	0.50	0.03	0.50	0.03
3	0.25	0.25	0.01		0.25	0.25	0.25
4	0.30		0.01		0.30		0.30
5	0.30		0.01		0.30		0.30
6	0.10		0.02		0.10		0.10
7			0.03				
8			0.20				
9			0.30				
10			0.30				
11			0.10				

Table 5-18: Modeled Expenditure Schedule for Alternatives

Generation prototypes emission rates are shown in Table 5-19. The values are taken from the Michigan Capacity Needs Forum. The two sequestered alternatives represent an 85% reduction in CO_2 production due to the capture and sequestration technologies being applied.

	SO_2	NO_X	Hg	CO_2
	lbs./MBTU	lbs/MBTU	lbs./MBTU	lbs./MBTU
Base Load Steam	0.05	0.08	1.22×10^{-6}	201
IGCC	0.03	0.06	8.05×10^{-7}	195
Nuclear	0	0	0	0
CC	0	0.03	0	120
CT	0	0.03	0	120
Wind	0	0	0	0
CC Sequestered	0	0	0	18
IGCC Sequestered	0.03	0.06	0	30

Table 5-19: Emission Outputs for Generation Prototypes

The generator prototypes were assigned an existing fuel source representative of the average fuel price in the region. Once assigned, the prototype fuel value is escalated at the same rate as existing units in the study. The 2008 dollar fuel prices for the alternatives are identified in the Table 5-20.

Region	Base Load Steam	Gas	Uranium	Oil
Entergy	1.34	8.19	0.55	18.33
IESO	1.88	8.37	0.53	18.33
New England	2.60	11.89	0.60	18.33
Midwest ISO Central	1.64	8.16	0.66	18.33
Midwest ISO East	1.87	8.59	0.66	18.33
Midwest ISO West	1.37	8.16	0.66	18.33
MAPP	1.37	7.83	0.66	18.33
New York	2.24	8.92	0.52	18.33
PJM	2.23	8.59	0.54	18.33
SERC	2.16	9.54	0.46	18.33
SPP	1.33	7.69	0.49	18.33
TVA	1.94	8.59	0.53	18.33

Table 5-20: Modeled Generator Prototype Fuel Prices In 2008$. (All prices represent the January seasonal values. Each cost has a seasonal profile applied for yearly variations.)

Fuel Prices

For existing online generation, the study used the November 2007 data update for PowerBase for initial coal, gas, uranium and oil prices. All fuel prices used the 2007 price as the current price, and then an assumption on the annual escalation was applied. Gas and oil use a 4% annual escalation. Coal and Uranium use the 2007 price for each unit and apply a 2% annual escalation. The PowerBase monthly price profile is maintained for each fuel source.

Environmental Allowance Costs

Each Generator in the PowerBase database has the type and rate of emission each unit will produce. There are also projections for emission costs in the default data. No changes are made to the default database regarding emissions.

Emission	Units	Allowance Cost	Annual Cost Escalation
CAIR Annual NOx	$/ton	1491	1.83%
CAIR SO_2	$/ton	330	1.83%
Clean Air Act SO_2	$/ton	330	1.83%
CO_2	$/ton	0	0%
Mercury	$/lbs.	36,041	1.83%

Table 5-21: Emission Allowance Costs and Escalations.

5.1.3 Capacity Expansion Results

As discussed, the EGEAS model was run for each of the defined regions within the JCSP'08. Individual area results can be found in Appendix 3. The capacity expansion needs are intended to represent approximations of the potential capacity needed for resource reliability on a long-term basis.

The capacity expansion model looks at production and capital costs in finding the least-cost plan within the constraints provided within the model. The primary constraint within the model is the reserve margin minimum requirement. The model uses dynamic programming to assess all possible combinations that satisfy the constraints placed on the analysis and results in a plan that minimizes total system costs over the expansion period plus an extension period. Because of this, the model will favor resources that provide high capacity credit towards the reserve margin requirement. It will also take into account that although some capacity, such as base load steam units, may be more expensive in capital investment cost, it will have a benefit in reduced production costs if there is a need for high capacity factor run times.

By inspecting the screening curve in Figure 5-5, it can be seen that under the assumption set discussed, base load steam capacity would be the preferred choice of the model when it is looking for both reliability and production cost benefits at higher capacity factors. Gas fired generation is the choice for low capacity factors. If the model determines that there is an economic need for cheaper install capacity, with the similar benefit to reliability contributions and only minimum run time, gas fired capacity would be the more economic choice. Throughout the entire study period, the model will develop a balance of needs incorporating base load, peaking, and some intermediate capacity.

Areas that do not have base load steam as an option would use the appropriate set of curves for the options available in that area.

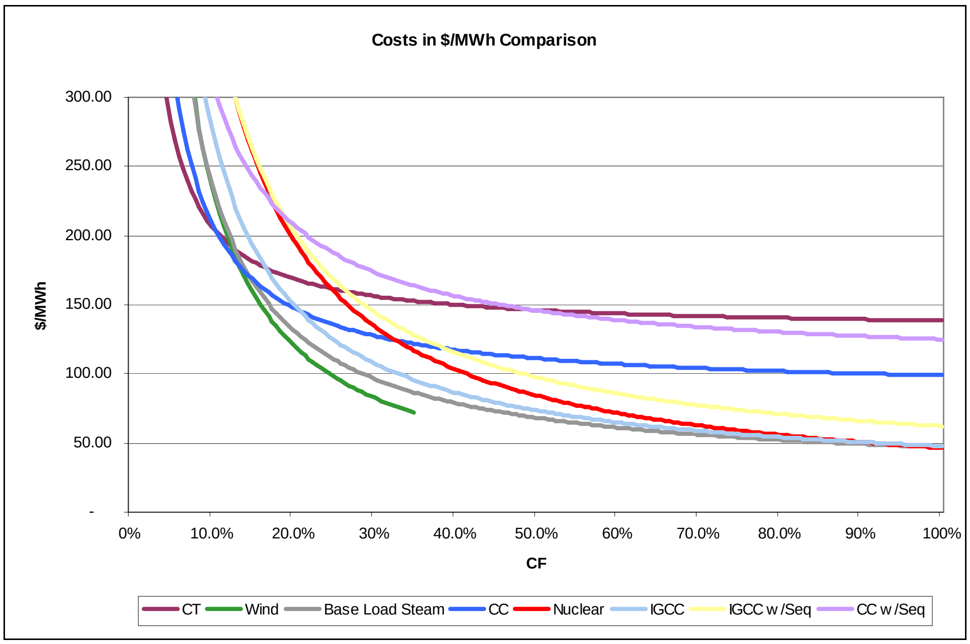


Figure 5-5: Screening Curve of Alternatives Used Within the Study

As can be seen in Figure 5-6, a significant amount of capacity must be added to the models to maintain the stated reliability targets for each region. The Reference Scenario represents a heavy base load steam capacity build-out. This is highly dependent on the definition of the scenario that the economic and political conditions of the future will look much like the recent past. Adding a cost to carbon or increasing the fuel cost of coal would potentially shift base load expansion from coal to nuclear. Also, note that a significant reduction in the modeled natural gas fuel cost would potentially remove base load capacity and replace it with intermediate capacity.

As wind capacity requirements increase, it can be noticed that base load capacity decreases while the capacity contributions from wind and gas fired capacity increase. The model recognizes the off-peak energy contribution associated with wind and selects gas capacity more abundantly for resource adequacy needs due to its smaller capital investment and less need for off-peak production.

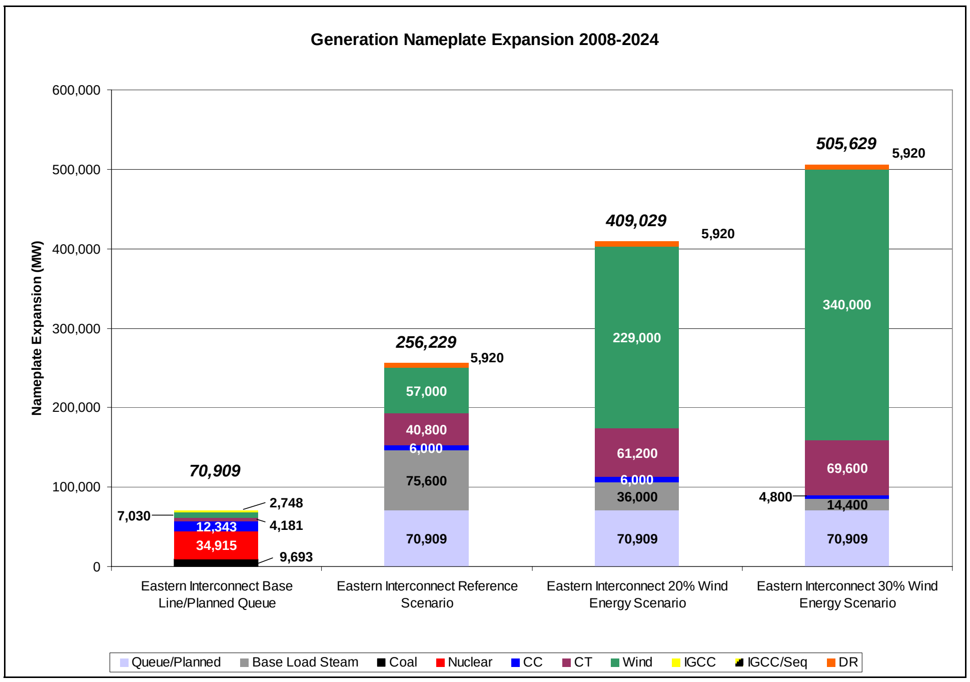


Figure 5-6: Modeled Systems Aggregate Nameplate Installed MW for PROMOD Study Year 2024

The model provides the capacity expansions in a type and timing format. Figures 5-7 through 5-9 show each of the scenarios by year of capacity need. Although the PROMOD model will look at the year 2024, it is important to recognize the need for capacity does not appear in one year. The model will project capacity expansion needs when required paralleling demand growth throughout the time period.

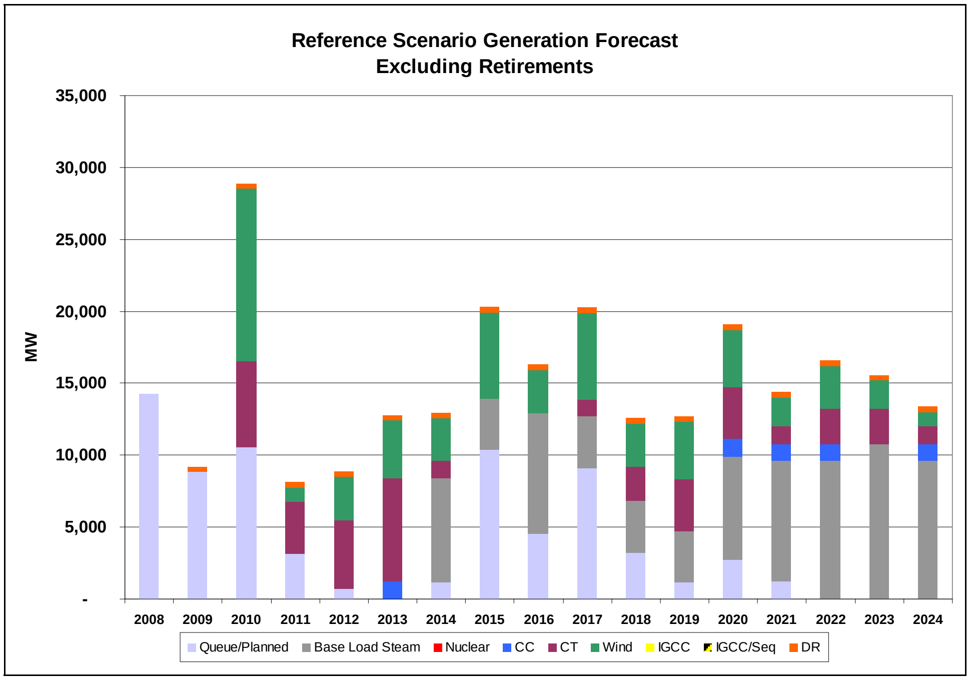


Figure 5-7: Reference Scenario Capacity Expansion Needs by Year to Meet Annual Reserve Margin Requirements

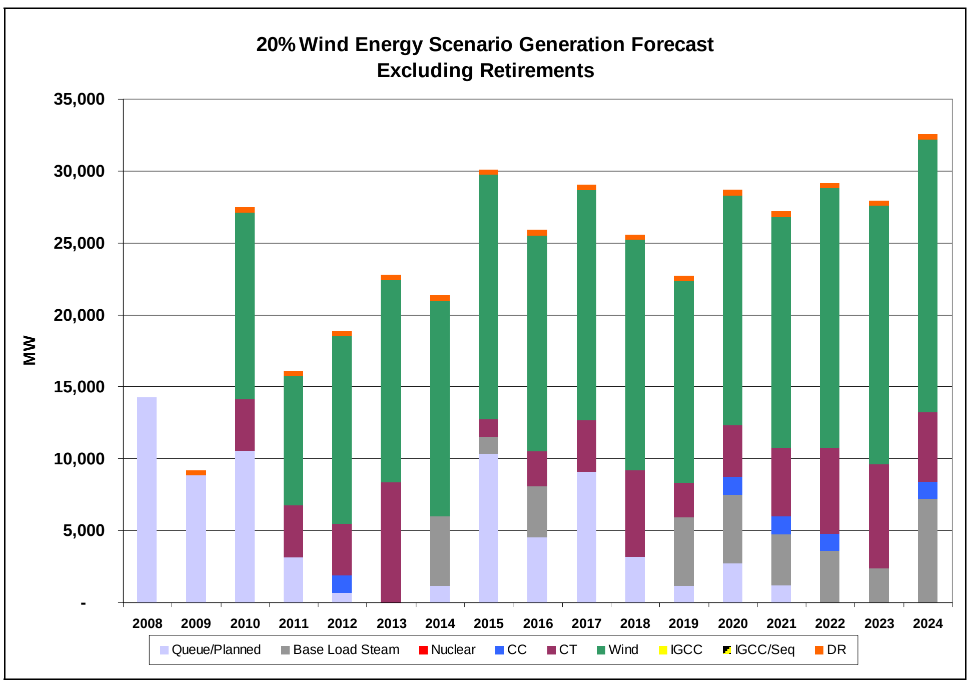


Figure 5-8: 20% Wind Energy Scenario Capacity Expansion Needs by Year to Meet Annual Reserve Margin Requirements

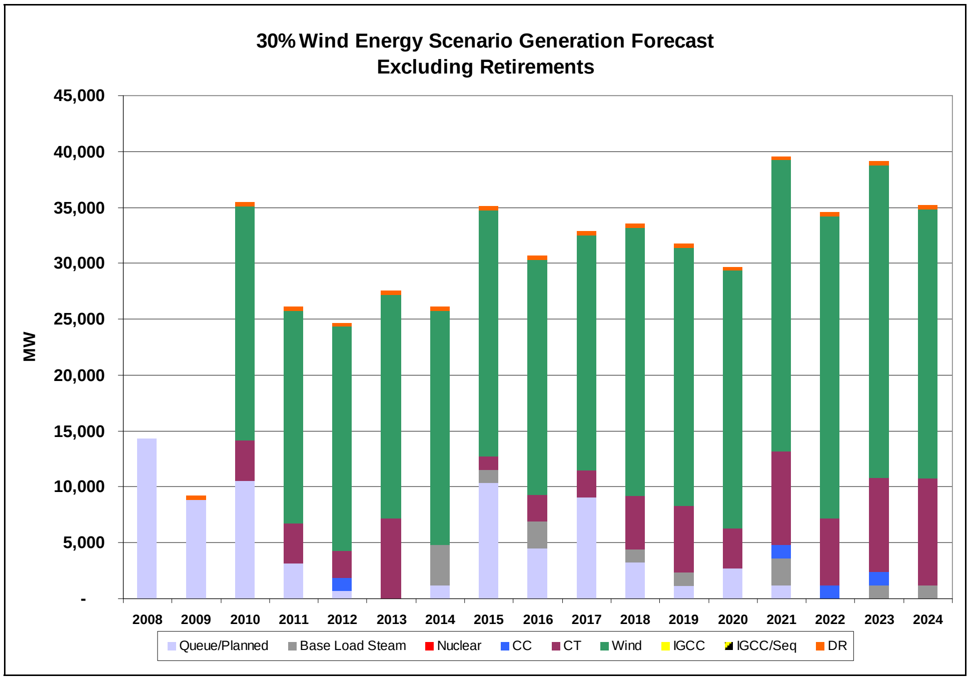


Figure 5-9: 30% Wind Energy Scenario Capacity Expansion Needs by Year to Meet Annual Reserve Margin Requirements

Figure 5-10 demonstrates the accumulative present value of costs for the study period through 2024. It should be noticed that total costs increase because of the capacity costs associated with the wind installation; however, the model does show reduction to production costs with the addition of the wind energy.

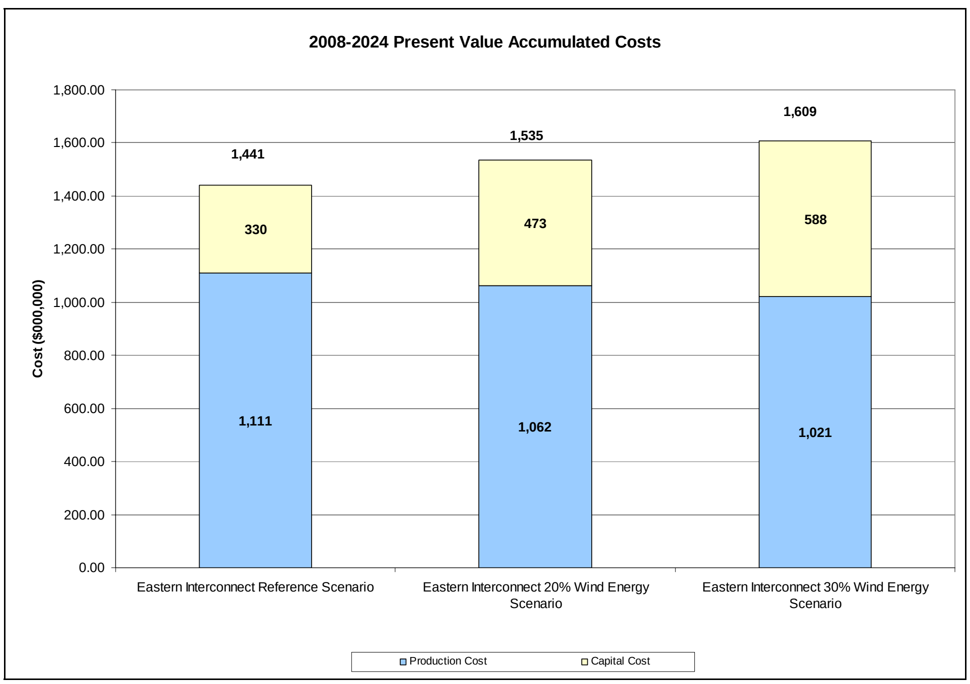


Figure 5-10: Costs of Aggregated System Accumulated Costs in 2008$

5.2 Siting Proxy Generation

The resources that are forecast from the expansion model, for each of the scenarios, are specified by fuel type and timing; but, these resources are not site specific at this point. A siting methodology to tie each resource to a specific bus in the PROMOD models is required to complete the process. A philosophy and rule based methodology, in conjunction with industry expertise, was used to site the forecast generation.

A generation siting process was created to site the proxy generation portfolios of each scenario. The siting involves a spatial analysis of geographic features based on the characteristics of each type of generator modeled. Once sited geographically, the generator is then placed in the PROMOD model for economic transmission analysis.

There are three components to the siting process:

- a general siting philosophy
- scenario specific siting philosophy, and
- a priority based siting order.

5.2.1 General Siting Philosophy

It is important to have an overriding set of conditions that would be similar for all scenario siting needs. The general siting philosophy is guided by the following principles and is applied to each scenario:

- **Do not use transmission as an initial siting factor**. In general, it is important to allow geographical and infrastructure limitations to guide the placement of proxy capacity. Focusing on the existing transmission system as an initial factor will potentially place capacity to locations that would minimize transmission impact rather than finding locations that could feasibly support the new capacity by having access to fuel sources, transportation needs, and potential water needs. Although transmission would not be an initial driving factor, it would be used as a weighting factor to pick one acceptable site over another.
- **Site proxy generation by region.** Placing region proxy capacity in the modeled expansion regions will avoid predetermined energy flow bias. For example, if all projected base load steam capacity was unrealistically placed within the western portion of the Eastern Interconnect, energy flow would be biased from west to east thus showing benefit in large transmission build-out. The purpose of the analysis is to produce, although not exact in the prediction of type and timing of capacity that will be built in the future, a reasonable representation of capacity expansion for a reasonable scenario analysis. The one exception to this rule will be the siting of wind. Through guidance from industry experts, wind will be sited locally to meet existing mandates with wind capacity; however, in a high Wind Energy Scenario, some capacity may be shifted to external regions that are more likely to support the higher penetrations of wind.

  In any particular region, it is unreasonable to locate all capacity in one state or intentionally avoid a state. Most states would have some expectation to site capacity as close to demand as possible.
- **Attempt to avoid Greenfield siting for natural gas fired capacity.** As will be seen later, natural gas fired capacity is very flexible in location. Because gas capacity can be located closer to urban centers, placing capacity at existing locations will reduce impact on the transmission system as well as decrease the amount of energy flow resulting from the generally peaking capacity.
- **Limit locations to 2,400 MW maximum capacity**. This limitation minimizes the impact of contingencies being able to remove excessive amounts of capacity from the system.
- **Site base load steam capacity in 600 MW increments and nuclear capacity in 1200 MW increments.** Specifying minimum capacity requirements will more realistically apply economies of scale associated with the assumptions of the two thermal units.

5.2.2 Scenario Specific Siting Philosophy

Reference Scenario

The siting requirement for this scenario focuses on exhausting identified queue generation that did not qualify as "planned" capacity within the assumptions for the model. The value in using proposed locations within the queues is the leveraging of work already performed to determine that the sites show promise in siting new capacity. Once the queue locations are exhausted, brownfield sites would be utilized to site the remaining capacity. Additional location needs will follow priority siting criteria described later. It is important to note that capacity will be appropriately matched - proxy base load steam to queue and brownfield base load steam - proxy combined cycle to queue and brownfield combined cycle - etc.

20% Wind Energy Scenario

The higher penetration of wind within the model results in a much larger need for proxy wind placement; conversely, the need for thermal capacity diminishes. Since the desire in the scenario analysis is to be able to compare and contrast based on the wind penetration, the siting for thermal capacity is dependent to a subset of sites identified in the Reference Scenario. The proxy wind capacity located within the Reference Scenario will carry over into the 20% Wind Energy Scenario. Additional wind site locations were dependent on feedback from stakeholders, preferring that wind be sited locally as much as possible, but understanding that there will be some requirements to site wind capacity remotely in higher capacity factor regions.

30% Wind Energy Scenario

At this point in the study, the knowledge set was not available for a reasonable siting of 30% wind energy penetration. The expectation is that this scenario will depend on offshore Atlantic wind capability and that reasonable data used to support decisions would not be available until after the study was completed. Therefore, this scenario within the JCSP analysis was terminated, but the transmission overlay for the30% Wind Energy Scenario is being developed in the EWITS which is scheduled for completion in 2009.

5.2.3 Siting Priority

In an attempt to standardize the application of locating generation in a logical and as-needed order, a list of priorities was established for actual siting of the capacity.

Priority 1: Generators With a "Scenario" Status

Potential sites under this priority are gathered from uncommitted locations within generation interconnection queues and Ventyx's "New Entrants" generators.

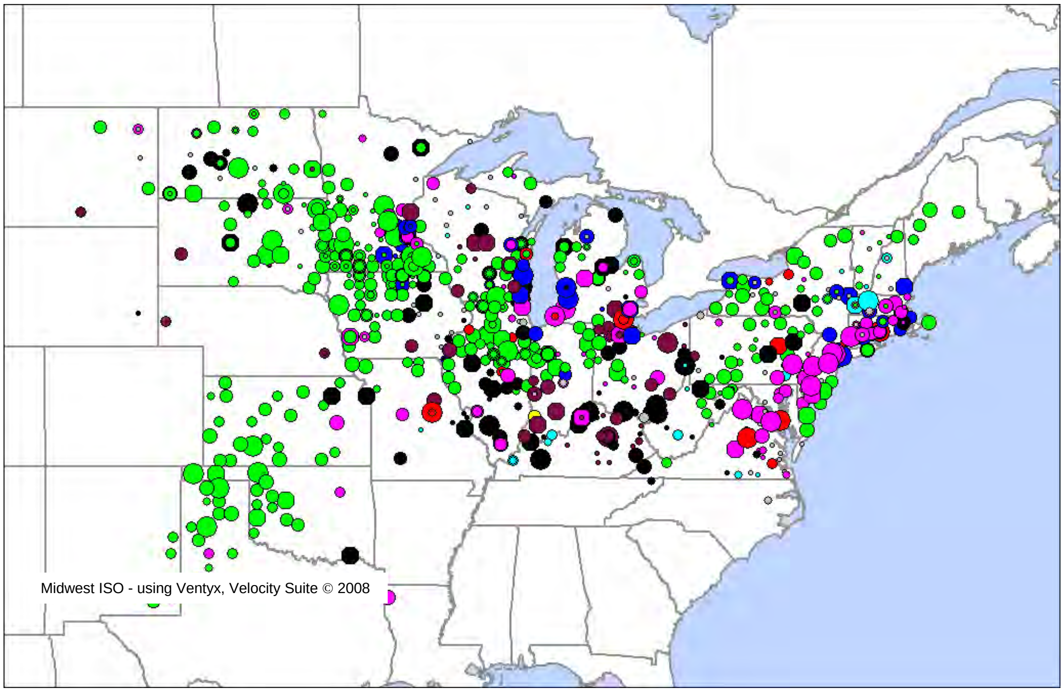


Figure 5-11: Generation Interconnection Queue Locations without Signed Interconnection Agreements

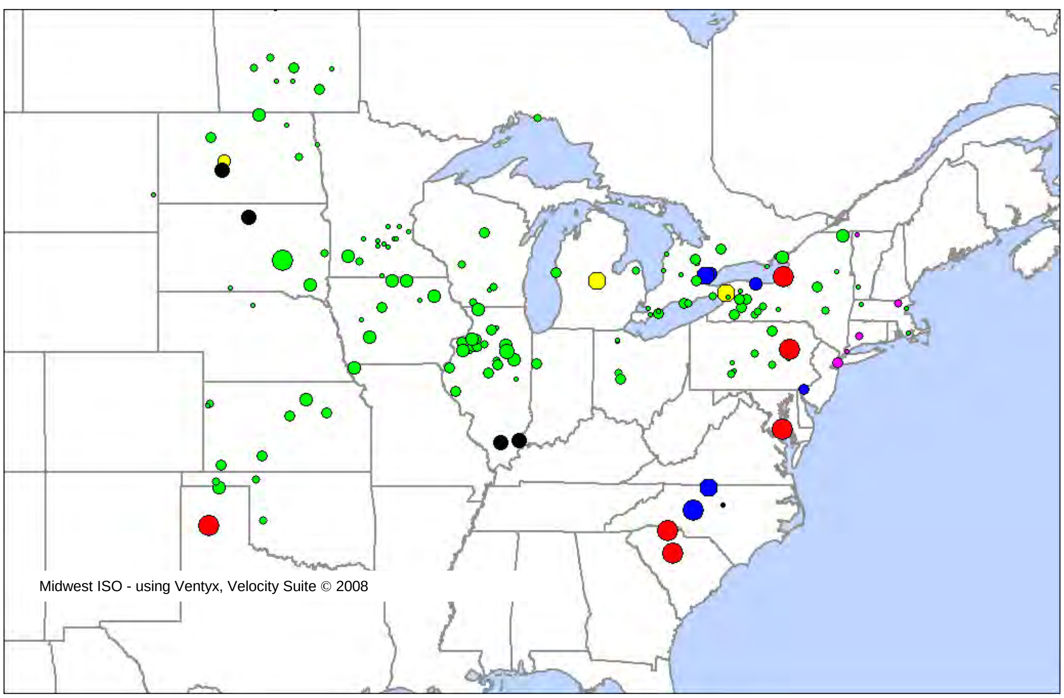


Figure 5-12: Ventyx's "New Entrants" Generators.

Priority 2: Brownfield Sites

The second priority focuses on utilizing existing capacity locations for expansion. Although not all the sites are ideal for expansion, participants in the process were requested to look at the sites identified and filter out the good candidates. Each fuel type has a set of requirements that further reduce the possible locations.

Existing coal capacity is considered to be a viable location if the existing capacity is greater than 200 MW. The assumption being that larger sites tend to be more adaptable for expansion. Coal plants located within a 25 mile buffer of major urban areas are excluded from the potential list due to potential emissions limitations. Finally, the Ventyx Energy Database can be used to help identify plants that were originally designed for additional capacity to be located.

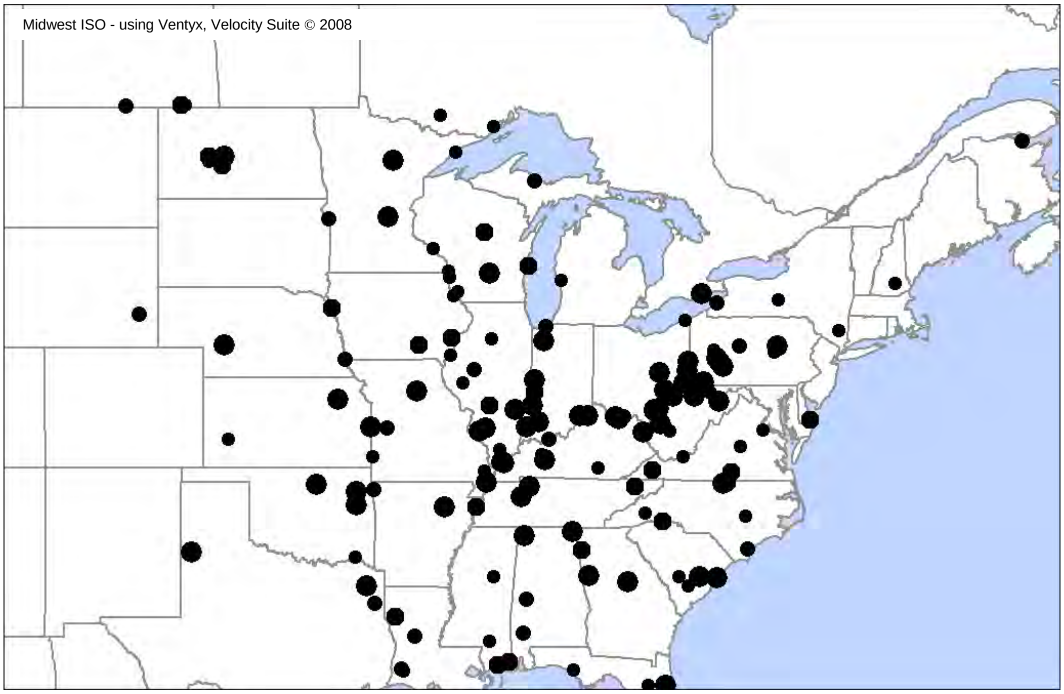


Figure 5-13: Candidate Brownfield Coal Locations

Like coal, combined cycle plants that are greater than 200 MW in existing size will be considered for possible expansion. However, an additional condition of an in-service date of 2000 or later will further limit the brownfield potential. Finally, a combined cycle site would be limited to 800 MW in total capacity and the proxy additions can be added in 300 MW increments.

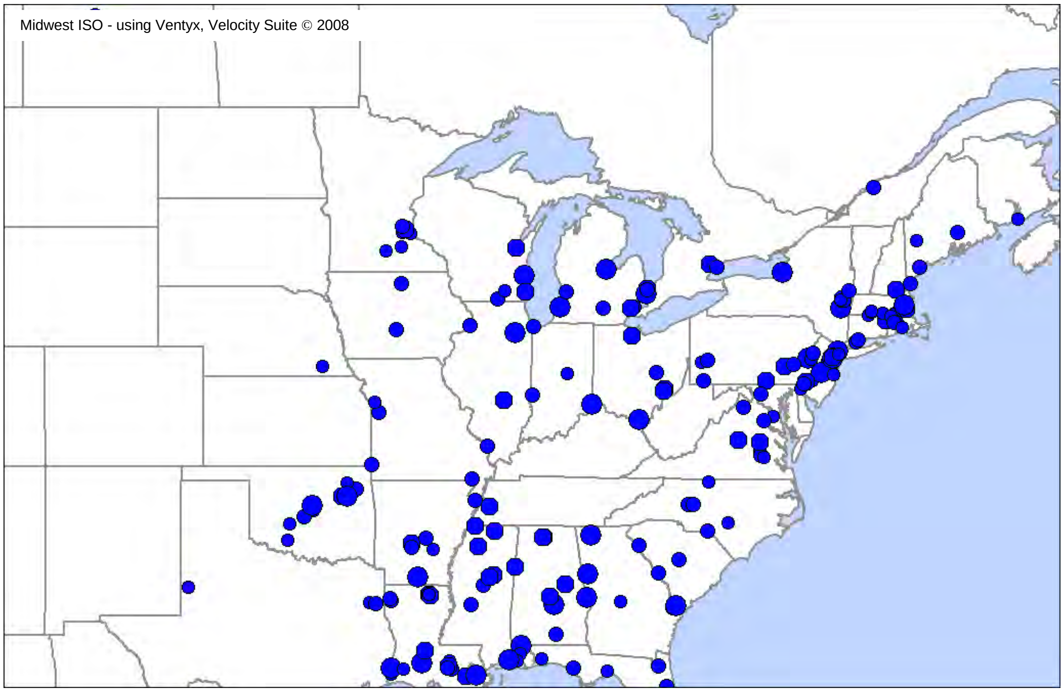


Figure 5-14: Candidate Brownfield Combined Cycle Locations

Existing combustion turbine sites will be limited to current units built since 1990 with a capacity greater than or equal 100 MW.

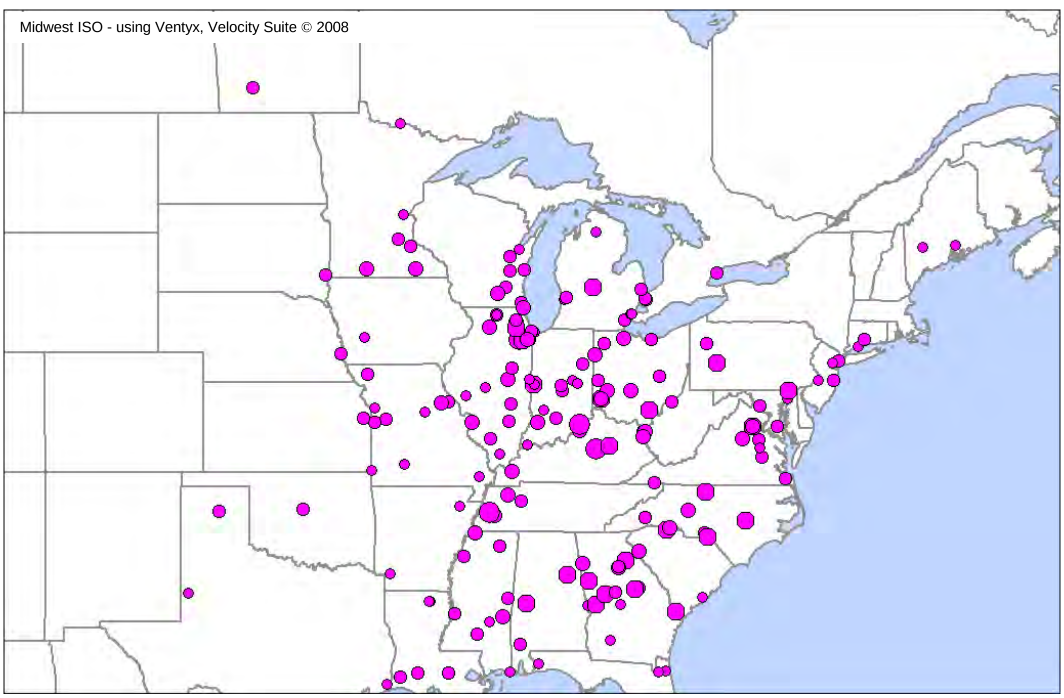


Figure 5-15: Candidate Brownfield Combustion Turbine Locations

Proxy nuclear unit siting should focus on sites that have been identified as potential expansions first. Once those sites are exhausted, all existing nuclear plants are considered potential sites for expansion.

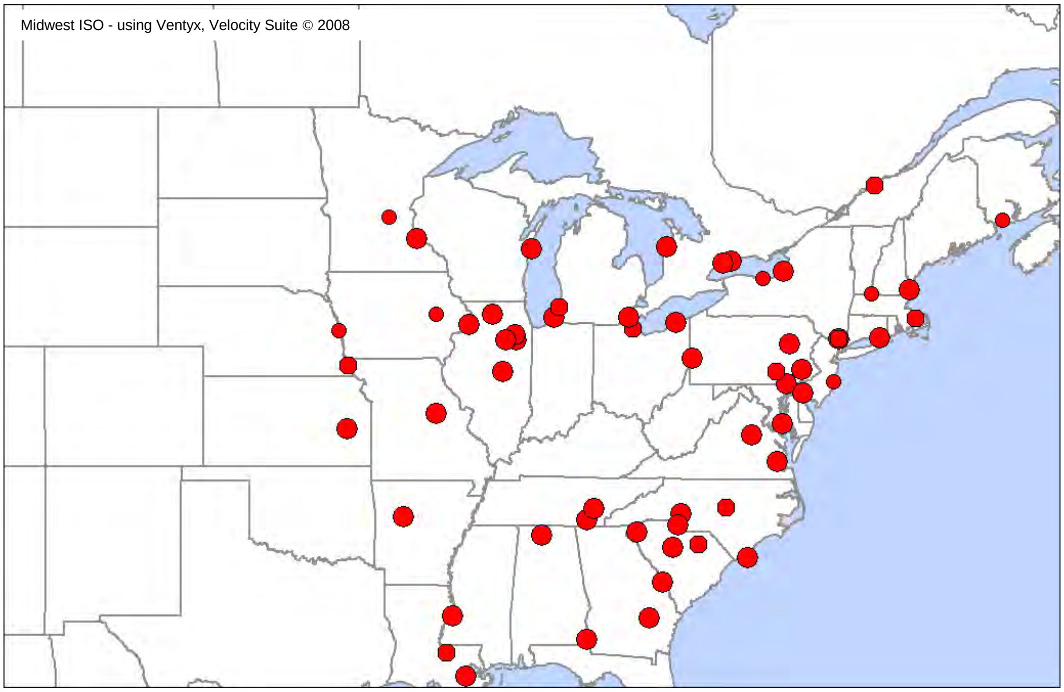


Figure 5-16: Candidate Brownfield Nuclear Locations

Priority 3: Retired/Mothballed Sites Which Have Not Been Re-used

Retired and mothballed sites are the next priority. It is assumed that although capacity may no longer operate at these locations, transmission capability, as well as infrastructure still existing, could be utilized in re-commissioning these sites with new capacity.

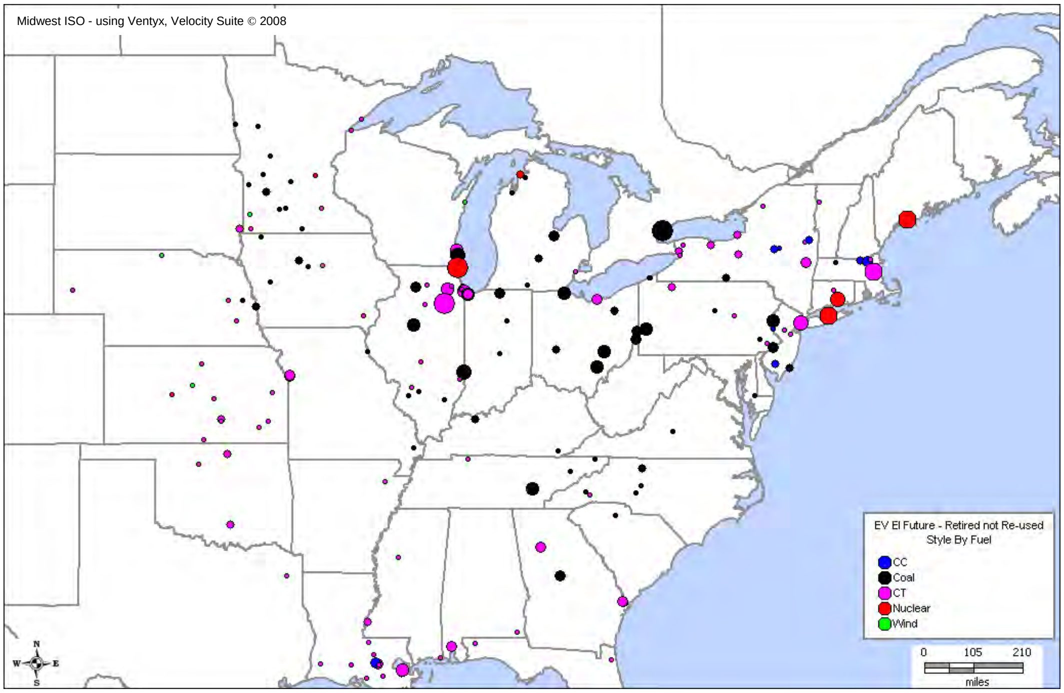


Figure 5-17: Retired and Mothballed Candidates for Proxy Capacity Expansion

Priority 4: Greenfield Sites – Cancelled or Postponed Projects

Priority 4 looks at units that have, at one time, been proposed through an interconnection queue process and for one reason or another have been cancelled. This list of units works as a good reference for initial Greenfield siting criteria; however, there are reasons why capacity additions have been cancelled and participant feedback is necessary for providing a strong list of candidate locations.

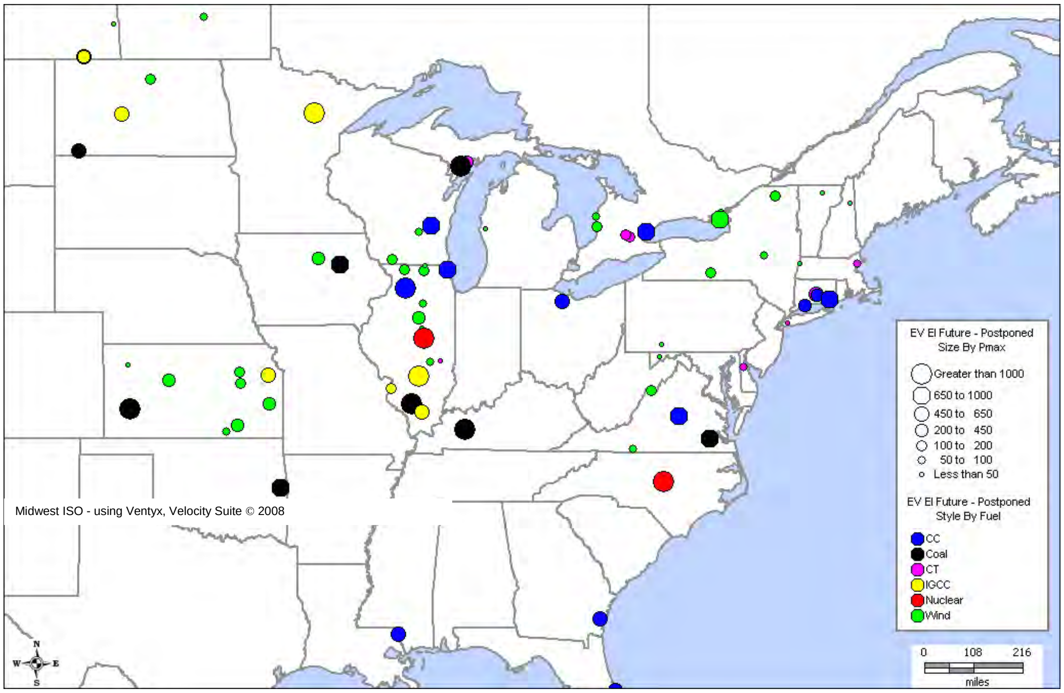


Figure 5-18: Cancelled and Postponed Units Identified In Ventyx's New Entrants Database

Priority 5: Greenfield Sites

The final priority focuses on pure Greenfield siting. In order to produce legitimate potential locations for new generation sites, a rule set is required. These rule sets are created within GIS software and potential sites are produced only when all requirements are satisfied.

Base Load Steam and IGCC capacity must have the following requirements:

- Within one mile of a railroad or a navigable waterway
- Within one half mile of a major river or lake
- Outside a 20 mile buffer of Class I lands
- Outside of an air quality non attainment region
- Outside a 25 mile buffer surrounding any major urban area (a population greater than 50,000 and an area larger than 25 mi^2)

In order to place priority among the potential proxy locations, a second set of criteria are applied to produce a stronger list of candidates:

- Within 20 miles of a coal mine or a dock capable of producing more than two million tons per year.
- Access to a gas pipeline
- Multiple railroad lines

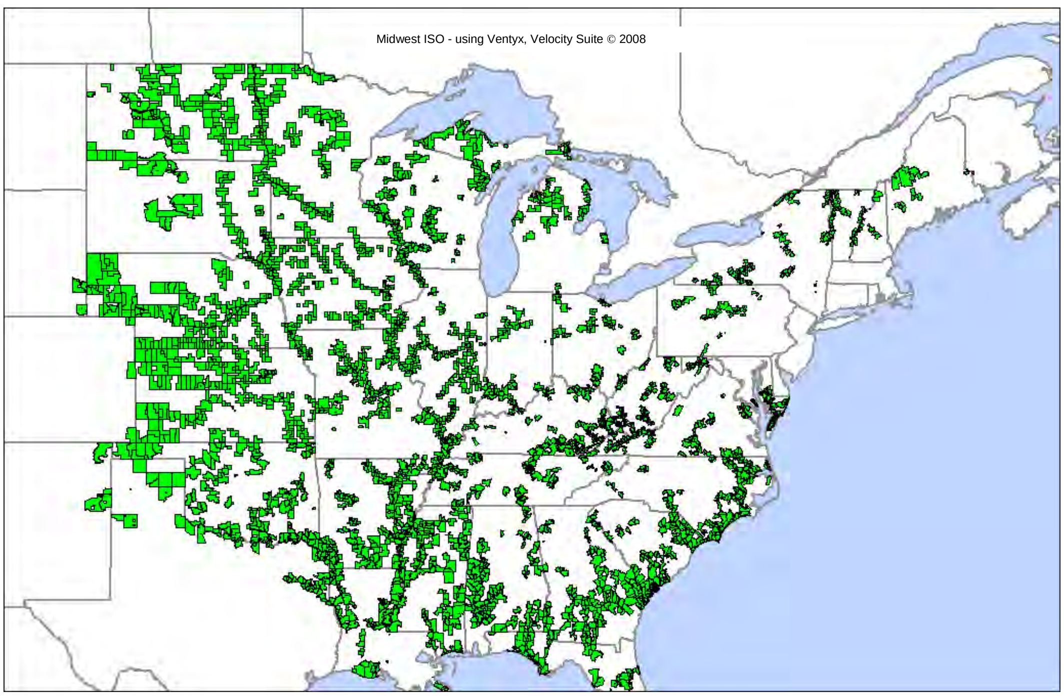


Figure 5-19: Potential Greenfield Candidates for Proxy Base Load Steam and IGCC Expansions

Combined Cycle capacity must have the following requirements:

- Within one mile of a railroad or a navigable waterway
- Within two miles of a major river or a lake
- Within 10 miles of a gas pipeline
- Outside a 20 mile buffer of Class I lands

In order to place priority among the potential proxy locations, a second set of criteria is applied to produce a stronger list of candidates:

- Close to an urban area (within a 25 mile buffer)

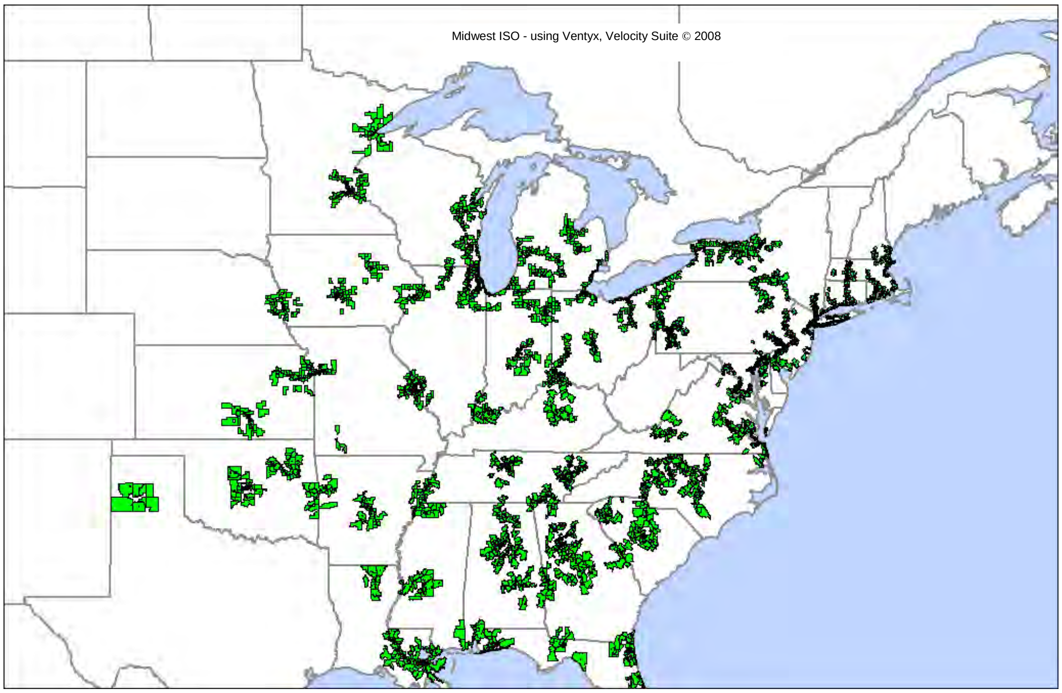


Figure 5-20: Potential Greenfield Candidates for Proxy Combined Cycle Expansions

Combustion Turbine capacity must have the following requirements:

- Within 20 miles of a railroad or navigable waterway
- Within five miles of a gas pipeline
- Outside the 20 mile buffer of Class I lands

In order to place priority among the potential proxy locations, a second set of criteria are applied to produce a stronger list of candidates:

- Within one mile of a river or a navigable waterway
- Within two miles of a major river or a lake

Potential Greenfield wind capacity locations were determined using industry expertise from NREL and consultants. The objective of the siting was to establish a reasonable distribution of wind throughout the Eastern Interconnect with the knowledge that high capacity factor wind areas may see more capacity sited than other areas.

No nuclear Greenfield sites are considered in the capacity expansion analysis. The determination through stakeholder feedback is to site proxy nuclear capacity at Brownfield locations only.

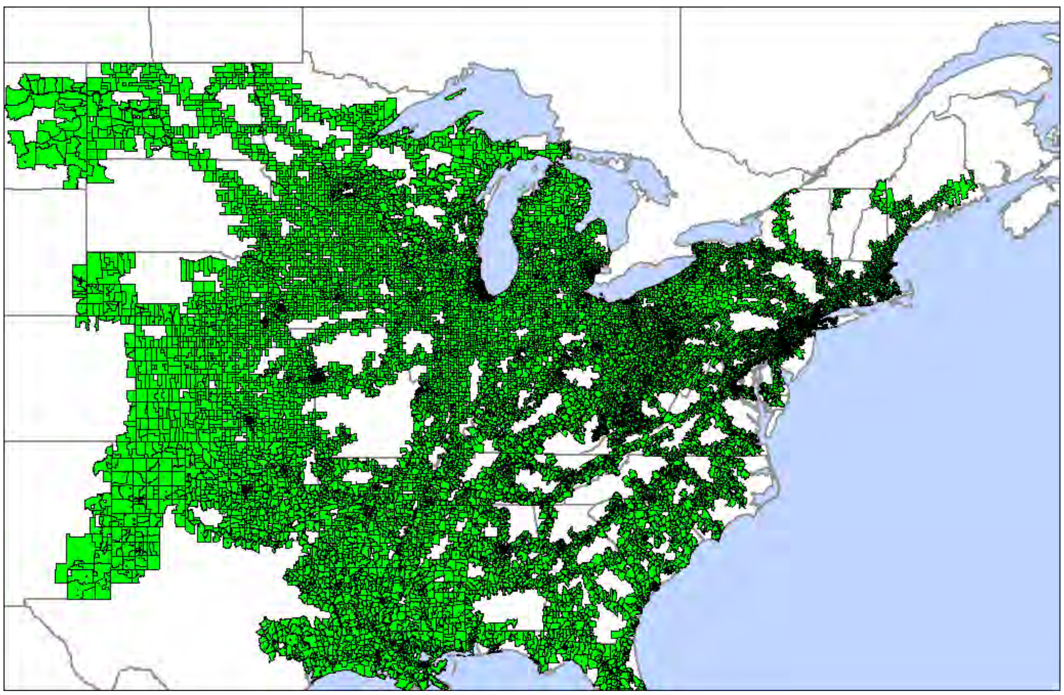


Figure 5-21: Potential Greenfield Candidates for Proxy Combustion Turbine Expansions

5.2.4 Reference Scenario Capacity Expansion Siting

Figure 5-22 represents the final siting locations used within the PROMOD model for the Reference Scenario. Detailed maps by region can be seen in Appendix 4. Note that within the criteria priority list, only the queue and brownfield priorities (1 and 2) were used for the thermal locations. The wind locations are all sited locally to meet the assumption that existing RPS requirements are to be met with local wind resources.

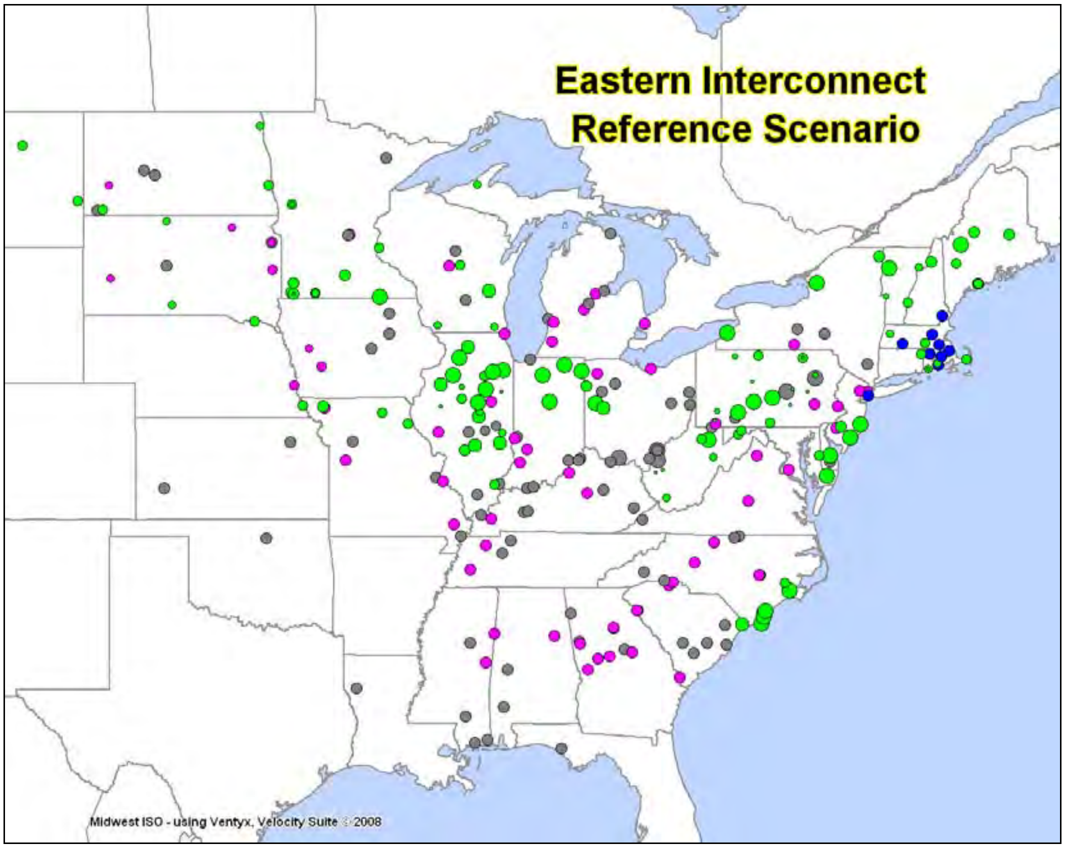


Figure 5-22: Reference Scenario Capacity Sites

Figure 5-23 represents the final siting used in the PROMOD model for the 20% Wind Energy Scenario. Detailed maps by region for this scenario can also be found in Appendix 4. Note the increase in wind capacity throughout the Eastern Interconnect, and that the combustion turbine capacity increases while the base load steam capacity decreases.

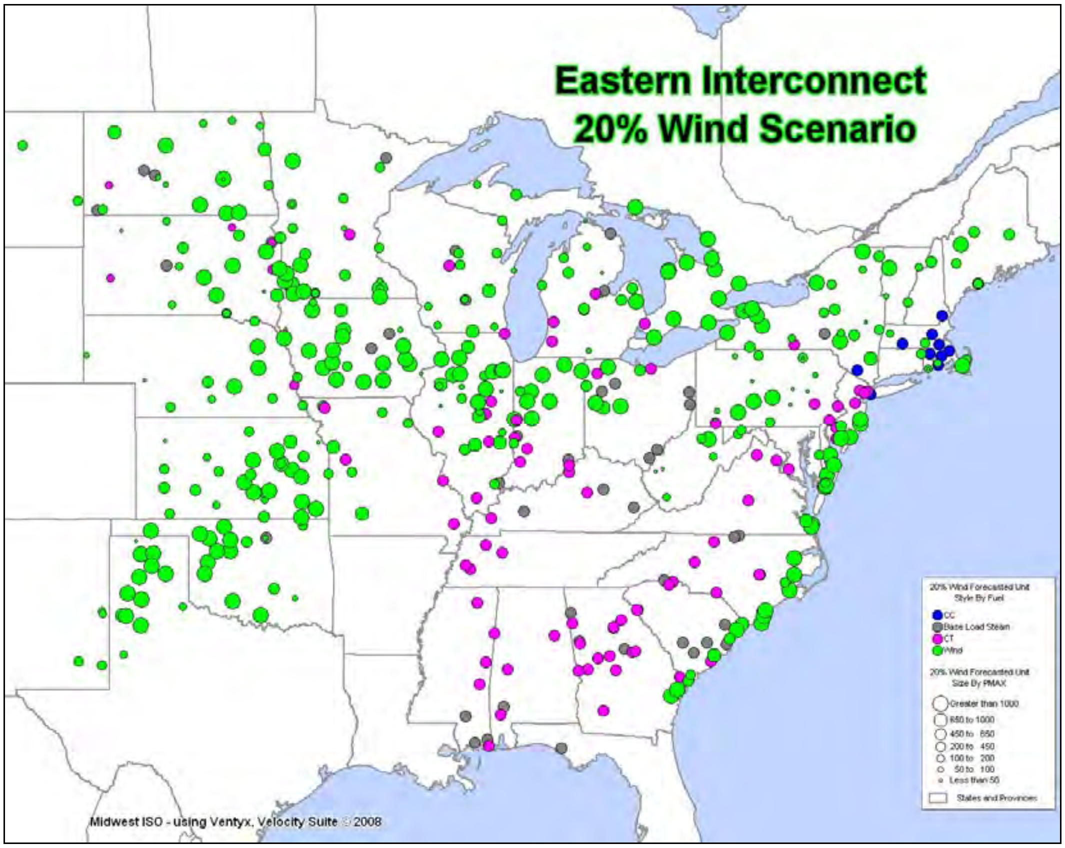


Figure 5-23: 20% Wind Energy Scenario

From these results, capacity is added to the PROMOD models for year 2024 economic analysis.

5.3 PROMOD Analysis

5.3.1 Reference Scenario

The focus of this section is to provide detailed information of the conceptual EHV transmission plan development for the reference generation scenario developed in Section 3. This section consists of four phases that describe the conceptual transmission plan development:

- Model discussion
- Pre-overlay economic analysis
- Transmission overlay development
- Post-overlay results

5.3.1.1 Model Discussion

This section describes the power flow model and PROMOD economic model development process and input assumptions.

Power Flow Model

The development of the 2018 reliability power flow model was led by the Southwest Power Pool. The ERAG MMWG[2] 2007 Series 2018 summer peak power flow model was used as the starting point for the reliability and economic transmission assessment study effort. In order to have a better representation of the latest and most accurate transmission system for this study, the power flow model was reviewed and updated by the JCSP'08 study participants to incorporate proper planned and/or proposed transmission projects. The same transmission network topology in the 2018 reliability power flow model was used in the 2024 economic assessment.

PROMOD Economic Model

PROMOD IV® is a commercial production cost model to perform hourly chronological security constrained unit commitment and economic dispatch recognizing both generation and transmission impacts. It can be used to evaluate the economic benefits of transmission expansion projects. The Midwest ISO used PROMOD IV® as the primary tool to evaluate the economic benefit of the conceptual EHV transmission overlay.

For the economic assessment in year 2024, the forecast loads and new generating capacity expansion through 2024 were developed for the majority of regions within the Eastern Interconnect footprint in parallel with the 2018 reliability power flow model development.

The study footprint includes the majority of the Eastern Interconnection excluding Florida. Eleven pools defined in the study footprint are:

● Midwest ISO	● PJM	● SPP	● MAPP	● SERCNI	● TVASUB
● MHEB	● JESO	● E_CAN	● New York	● New England	

A fixed transaction is modeled to represent the sales from SERC to Florida.

The latest Midwest ISO *Book of Flowgates* and NERC *Book of Flowgates* were used to create the event file consisting of the transmission constraints in the hourly, security constrained, unit commitment and economic dispatch model. The event file was sent out for JCSP'08 participants to review and was updated to reflect the identified changes or new additions.

[2] Eastern Interconnection Reliability Assessment Group (ERAG) Multi-area Modeling Working Group (MMWG)

Scenario Generation Portfolio

JCSP'08 Step 1 and Step 2 developed three different Scenario Generation Portfolios to represent each of the three Scenarios being studied, and each Scenario has different input assumptions and uncertainty variables. Please refer to Section 3, Scenario Planning, for more details on the Reference Scenario, 20% Wind Scenario and 30% Scenario.

The focus of this section is the Reference Scenario. The Reference Scenario is considered the status quo scenario as of January 1, 2008, which captures existing RPS requirements to be met with wind in the study footprint. This scenario creates an approximate 5% Eastern Interconnect wind energy model. All the wind units in the study footprint are modeled as load modifier transactions, with defined hourly wind profiles, to take into account the geographical diversity. The wind units are not dispatchable and are used to scale down the area loads prior to the economic dispatch process.

5.3.1.2 Pre-Overlay Economic Benefit Analysis

This section summarizes the pre-overlay economic analysis results required to provide necessary input information for the conceptual EHV transmission overlay development. The results were presented at the four regional transmission overlay development workshops described in Section 2.4 and the inputs from the broad cross section of stakeholders were combined to provide an initial conceptual overlay as the starting point for further in-depth analysis.

The initial study efforts considered two PROMOD economic simulations, the "constrained" base case and the "unconstrained" case assuming no transmission constraints. Examining the differences between the "constrained" case and the "unconstrained" case can provide the following information:

- The areas of economic energy sources and sinks;
- The interface flow changes to determine the incremental transfer capacity needs
- The total benefit savings to provide a rough estimate for the potential budget

Figure 5-24 shows the annual generation weighted Locational Marginal Pricing (LMP) contour map across the system for the constrained case in the Reference Scenario. Under economic market operation, energy tends to flow from low cost areas to high cost areas. The LMP contour map provides the direction where the energy would like to flow. To obtain the value from a transmission plan, the transmission must link the lower cost areas to the higher cost areas and relieve the transmission constraints. The more areas that are linked with the appropriately sized transmission, the greater the value.

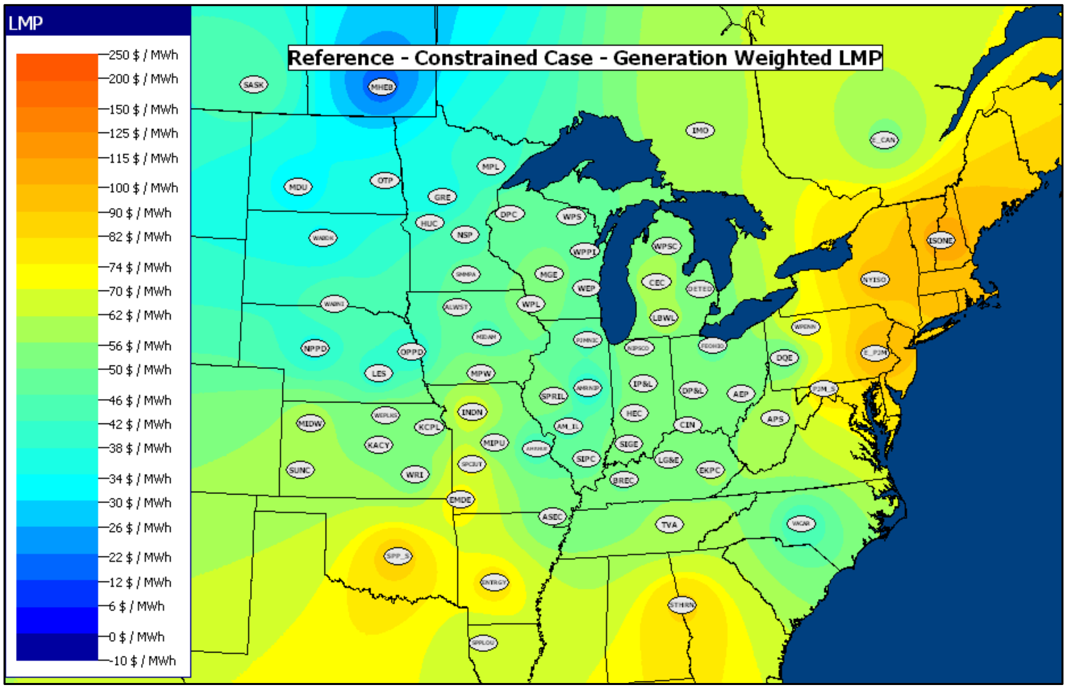


Figure 5-24: Reference Scenario Constrained Case Annual Generation Weighted LMP

Figure 5-25 shows the annual generation difference between the unconstrained and constrained cases for the Reference Scenario. This helps to define the energy source and sink areas and provide insight as to where the potential transmission lines and substations should be located. The red color represents the energy source areas while the blue color represents the energy sink areas.

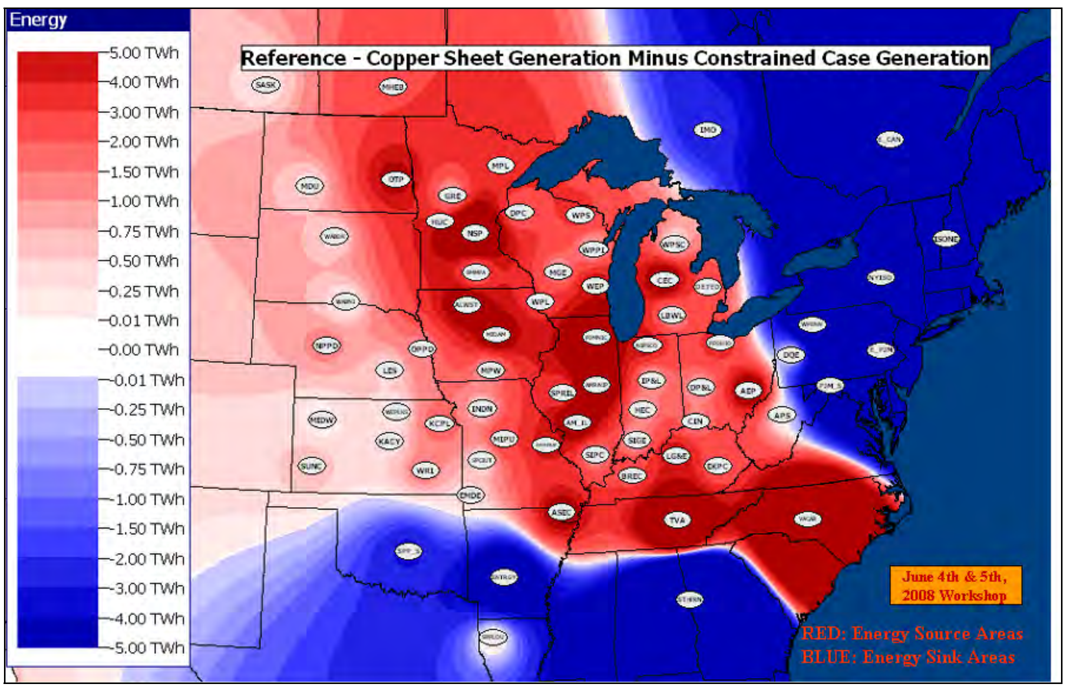


Figure 5-25: Reference Scenario Generation Difference between Unconstrained Case and Constrained Case

Figure 5-26 provides the annual energy differences between the unconstrained and constrained cases on each interface for Reference Scenario geographically; it shows the direction and magnitude of the interface flow changes. The red color indicates the largest and blue the smallest incremental flow change on the interface. The interface flows tending toward red indicate where energy would economically flow more if there were no constraints in the system and are the candidate locations for overlay lines to increase power transfer.

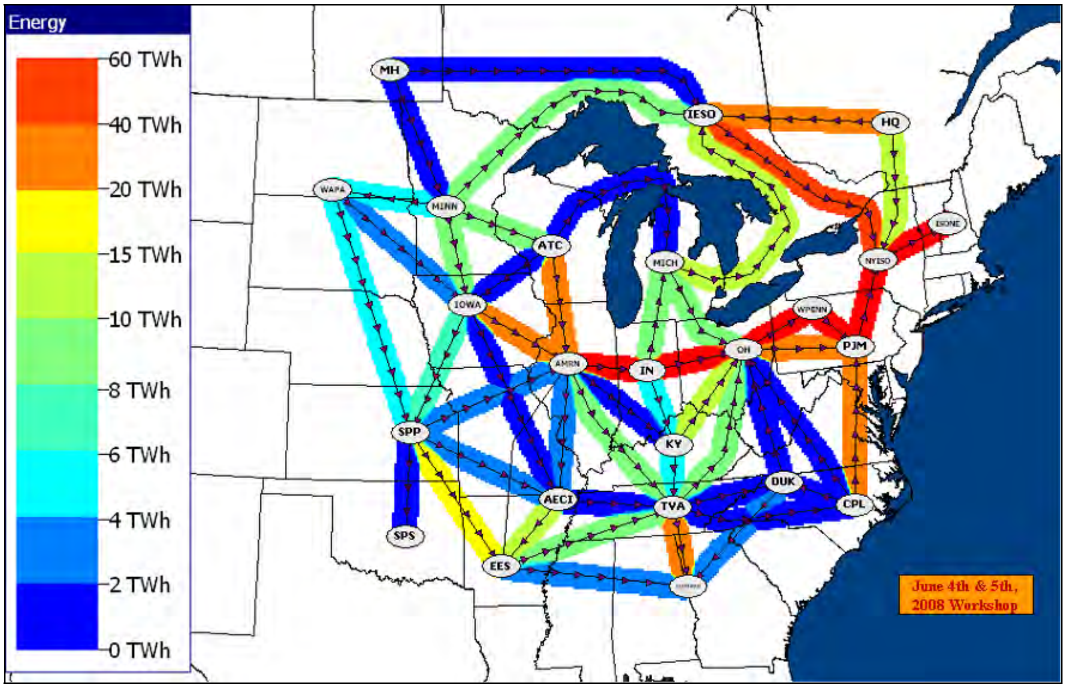


Figure 5-26: Reference Scenario Interface Annual Energy Difference: Unconstrained Case to Constrained Case

Table 5-22 lists the top 20 interfaces with the largest annual energy difference between the unconstrained and constrained cases and includes the same information as shown in figure 7-26. The additional transfer needs are calculated based on delivering 80% of the annual energy differences on each interface between the unconstrained and constrained cases. This information can be used to determine the type and size of the transmission lines and transformers.

INTERFACE	Coppersheet Minus Constrained		
	Total Positive Energy (GWh)	Total Negative Energy (GWh)	Additional Transfer Needed to Deliver 80% Energy (MW)
OH - EPJM	115,037	-153	12,031
AMRN - IN	75,285	-1,236	9,434
New Eng. - New York	160	-71,449	9,158
New York - PJM	1,740	-74,151	8,661
IN - OH	68,823	-339	8,143
IESO - New York	42,125	-1,301	6,027
IESO - HQ	7,724	-32,060	5,412
SOUTHERN - TVA	59	-29,702	4,501
MICH - IESO	18,584	-5,015	4,284
PJM - CPL	210	-26,613	3,754
AMRN - IOWA	345	-18,481	2,693
ATC - AMRN	17,546	-327	2,631
SPP - EES	17,485	-310	2,585
TVA - EES	2,355	-12,431	2,341
TVA - KY	2,893	-8,115	2,158
SOUTHERN - DUK	123	-6,128	2,054
MICH - IN	2,097	-12,041	2,032
New Eng. - HQ	1,310	-184	1,986
New York - HQ	10	-10,770	1,888
OH - KY	1,362	-11,119	1,805

Table 5-22: Reference Scenario:
Top 20 Interfaces with the Largest Annual Energy Difference

Net generation revenue, load cost savings, and adjusted production cost savings are calculated by taking the differences between the unconstrained and constrained cases for the Reference Scenario. Table 5-23 shows the detailed economic savings for each region plus the whole JCSP'08 study footprint. The adjusted production cost savings are used as the economic benefit value metrics for the transmission overlay and give the proxy estimate of potential budgets available for transmission development.

	Net Generation Revenue	Adj. Production	Load Cost
Pool	Increase (M$)	Cost Saving (M$)	Saving (M$)
PJM	-1,391	2,632	9,716
Midwest ISO	11,687	1,105	-10,293
TVASUB	3,616	1,003	-1,587
MAPP	2,652	207	-2,292
SPP	-530	1,193	2,926
SERCNI	2,148	3,842	7,227
E_CAN	3,572	4,404	1,727
IMO	446	570	418
New England	-2,342	2,835	6,369
MHEB	1,875	1,043	-1,049
New York	-1,677	3,682	8,074
Whole EI	20,056	22,516	21,235
JCSP'08	14,163	16,500	20,139

Table 5-23: Reference Scenario: Annual Economic Savings

5.3.1.3 Overlay Development

JCSP'08 Transmission Design Workshops

A series of workshops on the basic fundamentals of transmission design, in addition to regional design, were held from the end of April through June to facilitate the development of the high voltage overlay for both the Reference Scenario and the 20% Wind Energy Scenario. These workshops were held at various regional locations to obtain input from a broad cross section of participants as described in Section 2.4.

Four regional Transmission Overlay Development Workshops to develop the transmission overlays were held during June at Hartford, Wilmington, St. Louis and Knoxville respectively. Transmission inputs from each workshop were integrated into the initial conceptual overlay with some adjustments. Further post workshop refinements were made to improve benefits and reduce costs. As the result of the four design workshops, overlay plans from each workshop are shown in Figures 5-27 to 5-30.

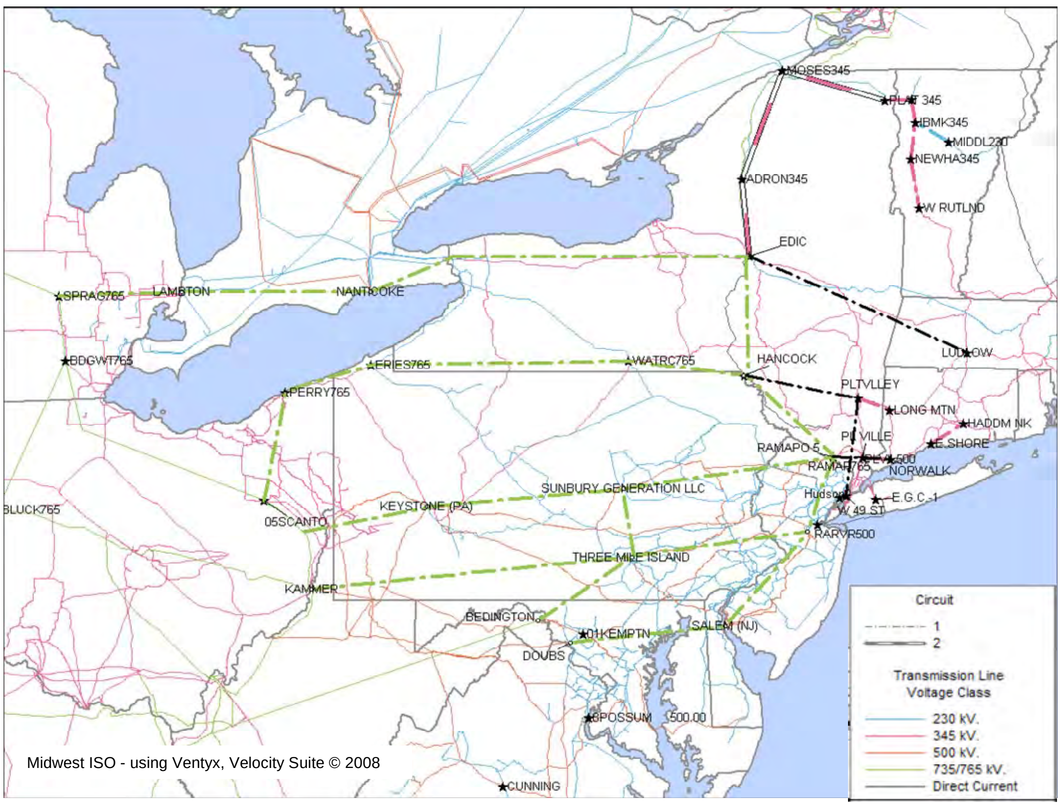


Figure 5-27: Hartford Workshop Input

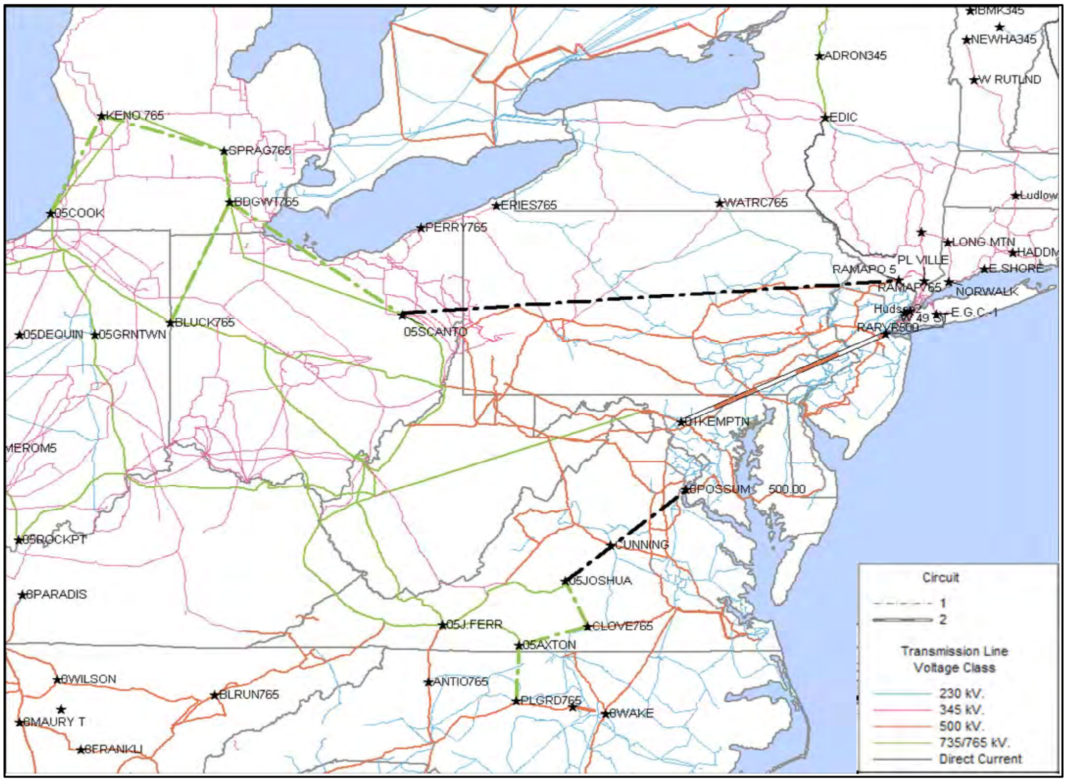


Figure 5-28: Wilmington Workshop Input

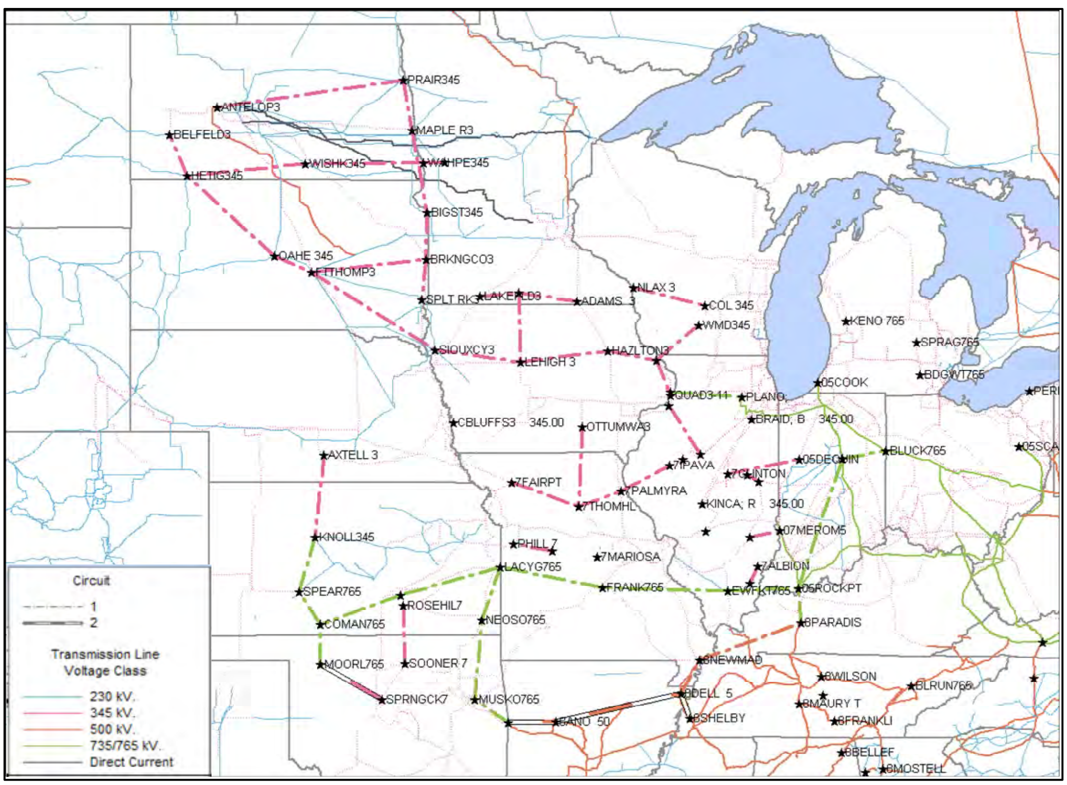


Figure 5-29: St. Louis Workshop Input

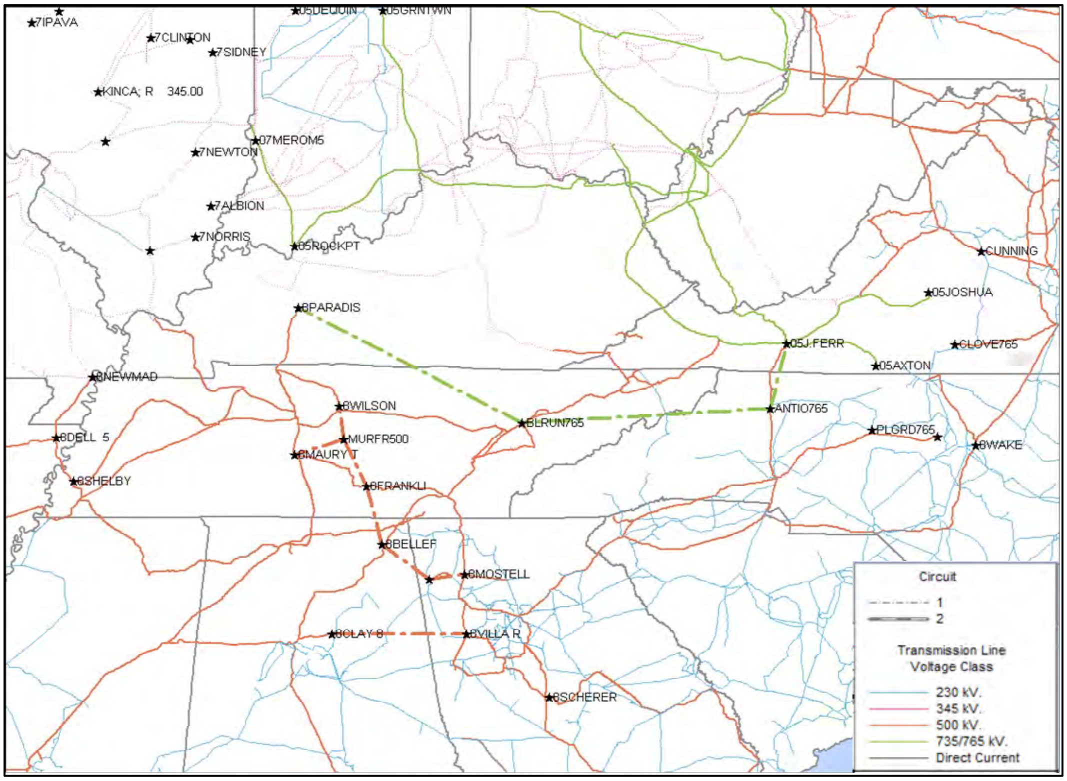


Figure 5-30: Knoxville Workshop Input

Figure 5-31 shows the adjustments made to the Reference Scenario overlay after the initial four transmission overlay design workshops. The adjustments are described as follows:

- Added two bipolar configuration 800 High Voltage Direct Current (HVDC) lines to increase economic transfer capability from Iowa/IL to NY/NE
- Added one 500 kV double circuit from TVA to Southern Company to provide additional delivery capability
- Replaced two DC lines in PJM by 765 kV AC lines and added one bipolar configuration 400 kV HVDC lines from PJM to NY
- Added 500 kV double circuits to loop from PJM to NY
- Updated details on DC terminals in NY/NE

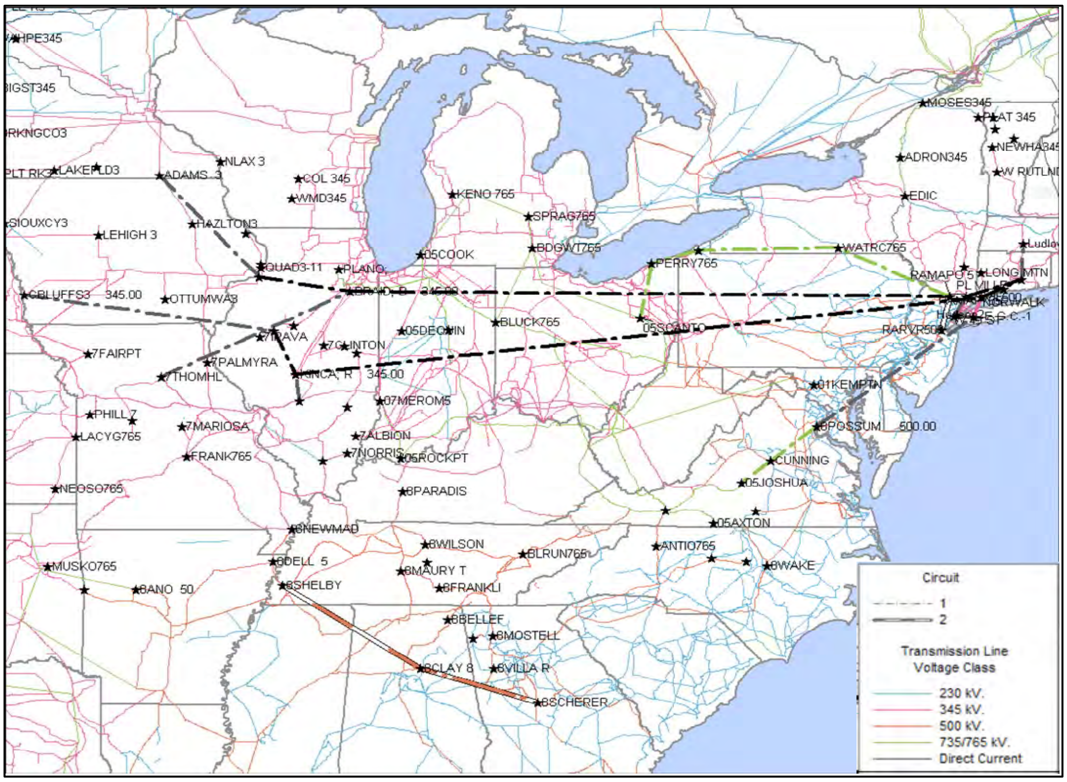


Figure 5-31: Overlay Adjustments Post Workshops

With the transmission workshop inputs and adjustments made above, the initial conceptual transmission overlay for the Reference Scenario is shown in Figure 5-32.

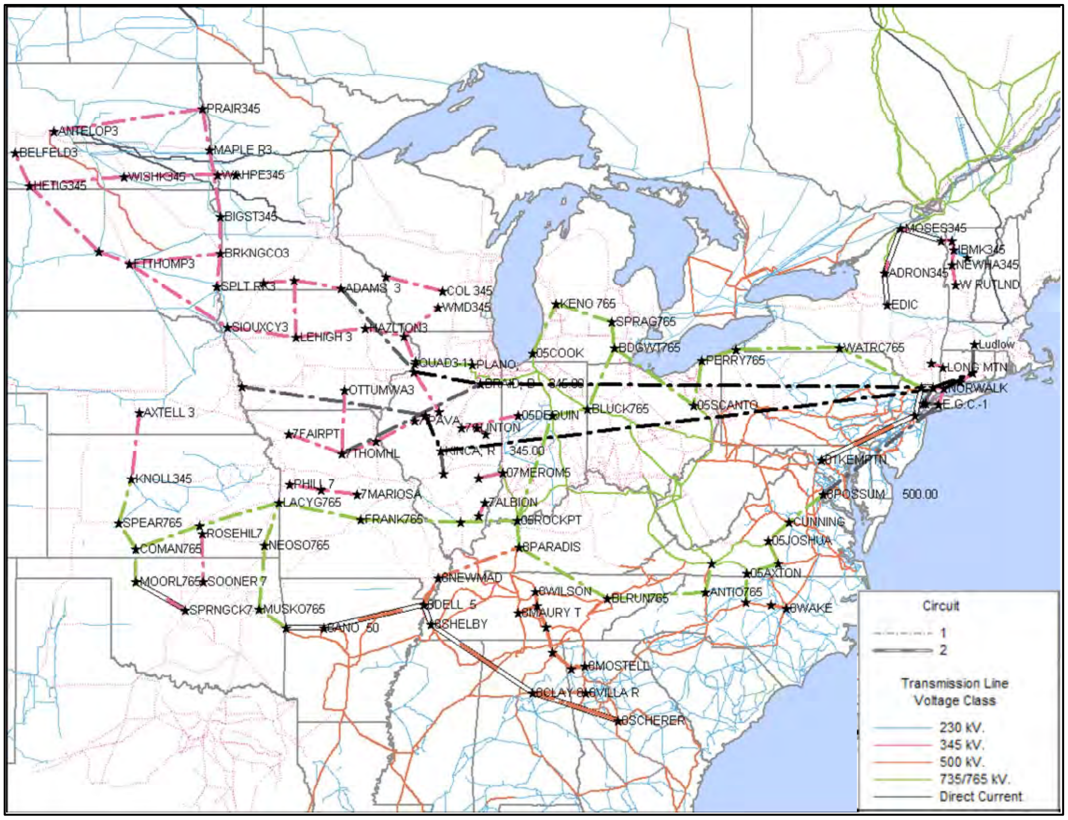


Figure 5-32: Initial Reference Scenario Combined Overlay

Transmission Overlay Refinement Post Interim Stakeholder Meeting

The results of the Reference Scenario initial conceptual EHV transmission overlay shown in Figure 5-32 were presented at the Interim Stakeholder Meeting held at Cincinnati, Ohio on August 14, 2008. Based on the comments and feedback, a total of eleven overlay options were evaluated after the interim meeting to continue the refinement of the overlay. An additional Transmission Refinement Workshop was held on October 2nd at Carmel, Indiana to review the results of the eleven options and further refine the overlay.

Figure 5-33 provides the flow chart for the eleven Reference Scenario transmission overlay options with associated Benefit/Cost ratios. Benefit/Cost ratios provide a relatively efficient way to evaluate the transmission overlay relative to each other. Adjusted production cost saving was used in calculation of the benefit/cost ratio and an annual revenue requirement of 15% of the total overlay cost was used to calculate the annual cost of the overlay. Section 5.3.5 provides more detailed information on B/C ratio calculation. The options highlighted in red indicate the path chosen for the refinement.

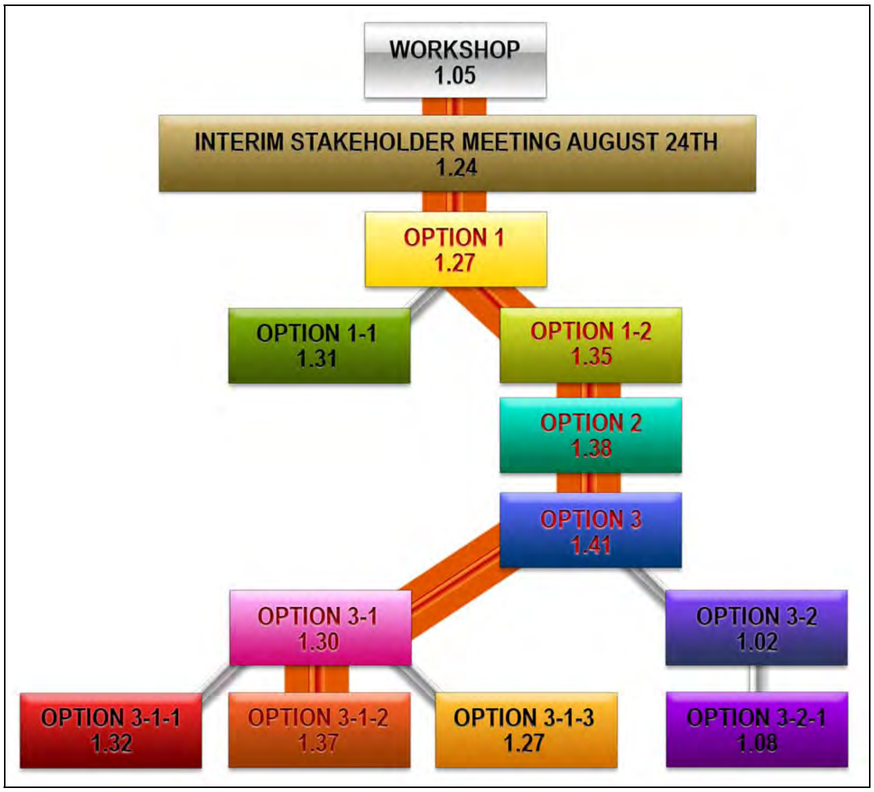


Figure 5-33: Reference Scenario Transmission Overlay Option Flow Chart

Table 5-24 shows, in detail, the eleven transmission overlay refinement options for the Reference Scenario using decision table based methodology. The starting point for the refinement investigation was the overlay presented at the August 14th Interim Stakeholder Meeting. The decision table makes it easy to observe and compare the actions taken for each of the overlay options.

Revisions Based on Interim Stakeholder Meeting August 14th Overlay	Opt. 1	Opt. 1-2	Opt. 1-1	Opt. 2	Opt. 3	Opt. 3-2	Opt. 3-2-1	Opt. 3-1	Opt. 3-1-1	Opt. 3-1-2	Opt. 3-1-3
Extend one 400 HVDC terminal to Wake 500kV station	■	■	■	■	■	■	■	■	■	■	■
Remove low loading overlay lines 500kv and below *		■	■	■	■	■	■	■	■	■	■
Add 765kV lines Adams - Salem - Quadcity - Emolin - Duckcreek - Dequine - Greentown; Add 76kV line Duckcreek - Kincaid			■								
Add 500kV line Dorsey - Prairie			■	■	■	■	■	■	■	■	■
Replace Duckcreek with Powertown station for 800HVDC line terminal				■	■	■	■	■	■	■	■
Drop down Quadcity - Piano 765 line at Nelson station					■	■	■	■	■	■	■
Replace three IL wind unit locations to resolve generation Interconnection Problem					■	■	■	■	■	■	■
Remove all three HVDC overlay lines; Two 800HVDC IL/IA/MN to NY/ISONE One 400HVDC SERC/PJM to NY						■	■				
Upgrade several 345kV overlay lines with 500kV and add additional 500kV lines and above to construct an AC overlay plan; Mapleriver - Bigstone - Brookingcounty - Splitrock - Adams 500kV; Prairie - Winger - Sherco - Chisago County - Hampton Corners - Adams 500kV; Adams - Hazilton - Quadcity - Emolin - Tazewell - Brokaw - Dequine - Greentown 765kV; Tazewill - Kincaid - Coffen - EW Frankfort 765kV; Kammer - Three Mile Island - Ramapo 765kV						■	■	■	■	■	■
Remove low loading 765kV overlay lines in SPP **											
Remove low loading 765kV AC overlay plan lines; Tazewell - Kincaid - Coffen - EW Frankfort							■			■	
Remove 400HVDC overlay line SERC/PJM to NY							■		■	■	■
2024 Benefit/Cost ratio											■
	1.27	1.35	1.31	1.38	1.41	1.02	1.08	1.30	1.32	1.37	1.27

Table 5-24: Transmission Overlay Refinement Option Decision Table

(* - see Table 5-25, ** - see Table 5-26)

Table 5-25 and Table 5-26 provide the detailed information of the removed low loading transmission overlay lines described in Table 5-24.

From Bus	Name	To Bus	Name	Voltage (kV)	Circuit ID	Length (Mile)	Rating (MW)
700103	FERGF345	700102	WAHPE345	345	1	26.4	1500
700037	SEDAL345	541200	PHILL 7	345	1	54	1500
532794	ROSEHIL7	514803	SOONER 7	345	2	78.7	1458
636600	E MOLIN3	349662	7TAZEWEL	345	1	61.1	1500
631140	SALEM 3	36384	QUAD3-11	345	2	53	1500
710010	MURFR500	360050	8MAURY T	500	1	26.5	3000
515305	FTSMITH8	337909	8ANO 50	500	2	70.4	2916
515305	FTSMITH8	337909	8ANO 50	500	3	70.4	2916
320255	8CLAY 8	317014	8SCHERER	500	1	164	1680
320255	8CLAY 8	317014	8SCHERER	500	2	164	1680
337909	8ANO 50	338187	8DELL 5	500	1	185	1596
337909	8ANO 50	338187	8DELL 5	500	2	185	1596

Table 5-25: Removed Low Loading Overlay Lines 500 kV and Below

From Bus	Name	To Bus	Name	Voltage (kV)	Circuit ID	Length (Mile)	Rating (MW)
700200	BENTN765	700021	COMAN765	765	1	119	4023
700012	LACYG765	700200	BENTN765	765	1	142	3591
700013	MOORL765	700021	COMMA765	765	1	54	6750
700021	COMMA765	700022	SPEAR765	765	1	51.2	6750
700022	SPEAR765	700039	KNOLL765	765	1	76	5373

Table 5-26: Removed Low Loading Overlay 765 kV Lines In SPP

One constructive comment from the August 14th Interim Stakeholder Meeting was on how to consolidate the two significantly different conceptual overlays from the Reference Scenario and the 20% Wind Scenario. The focus of the refinement from Option 3-1 to Option 3-2-1 is to form a core transmission overlay that can accommodate the various uncertainties and perform reasonably well under difference generation scenarios. Based on the core plan, potential adjustments and additions would have to be implemented for the 20% Wind Scenario to accommodate the increased wind mandate. As shown in Table 5-24, the major difference between Option 3-1-2 and Option 3 is the stronger AC 500 kV and above system upgrade in Option 3-1-2.

The conceptual transmission overlays for Option 3 and Option 3-1-2 are shown in Figure 5-34 and Figure 5-35 respectively. Compared to the initial overlay presented at the Interim Stakeholder Meeting shown in Figure 5-32, the new overlay lines added in Option 3-1-2 are provided in Figure 5-36 and the deleted floating overlay lines are given in Figure 5-37.

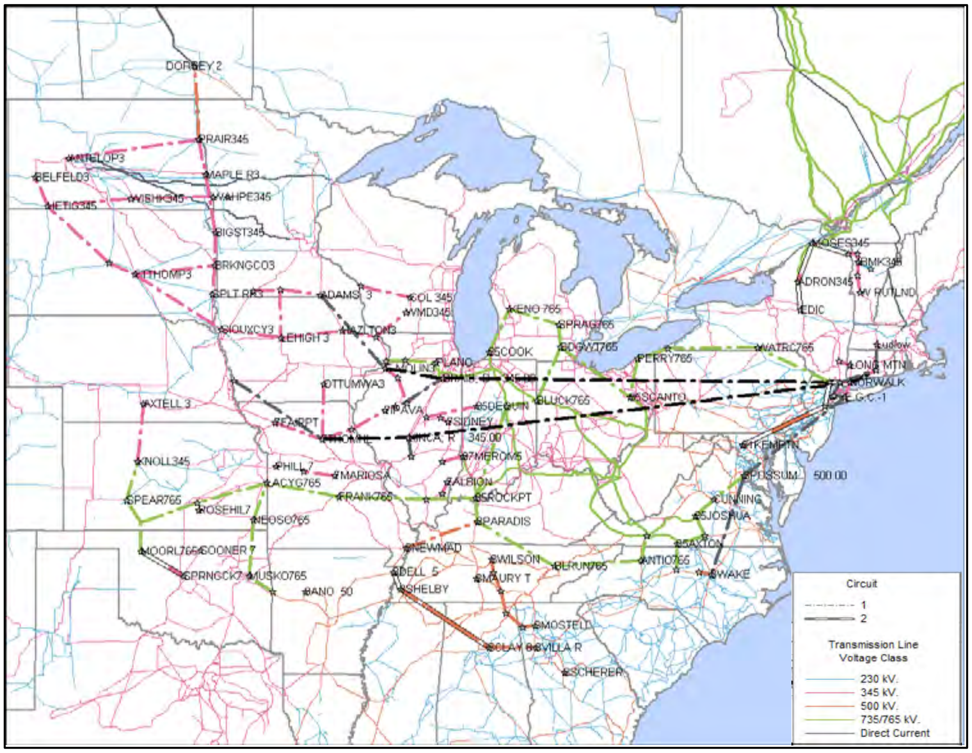


Figure 5-34: Reference Scenario Transmission Overlay Option 3

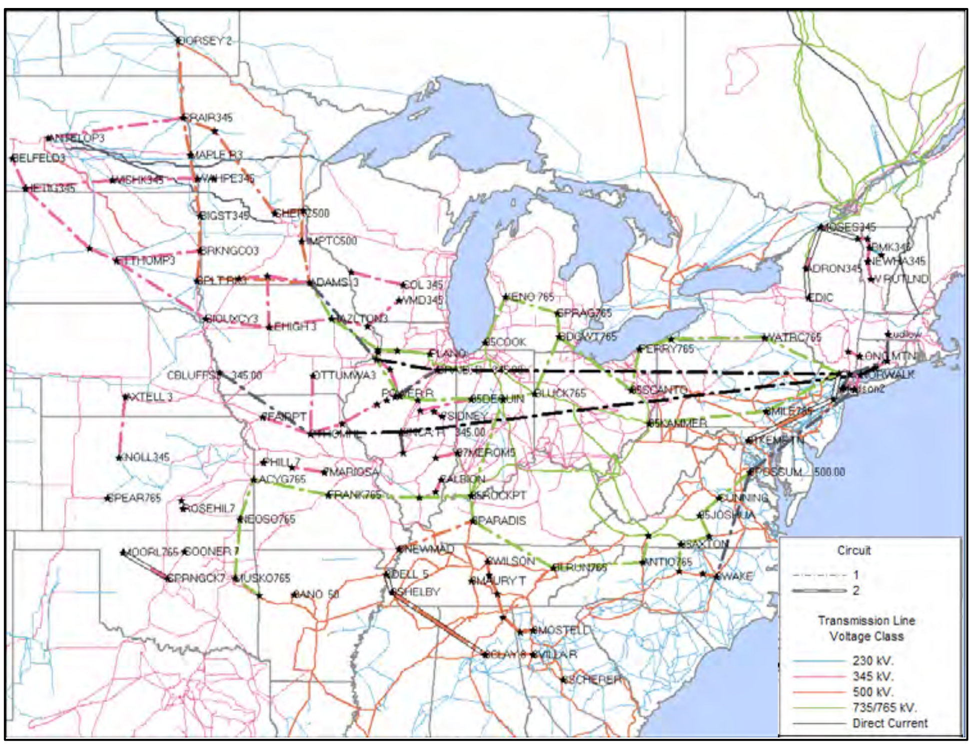


Figure 5-35: Reference Scenario Transmission Overlay Option 3-1-2

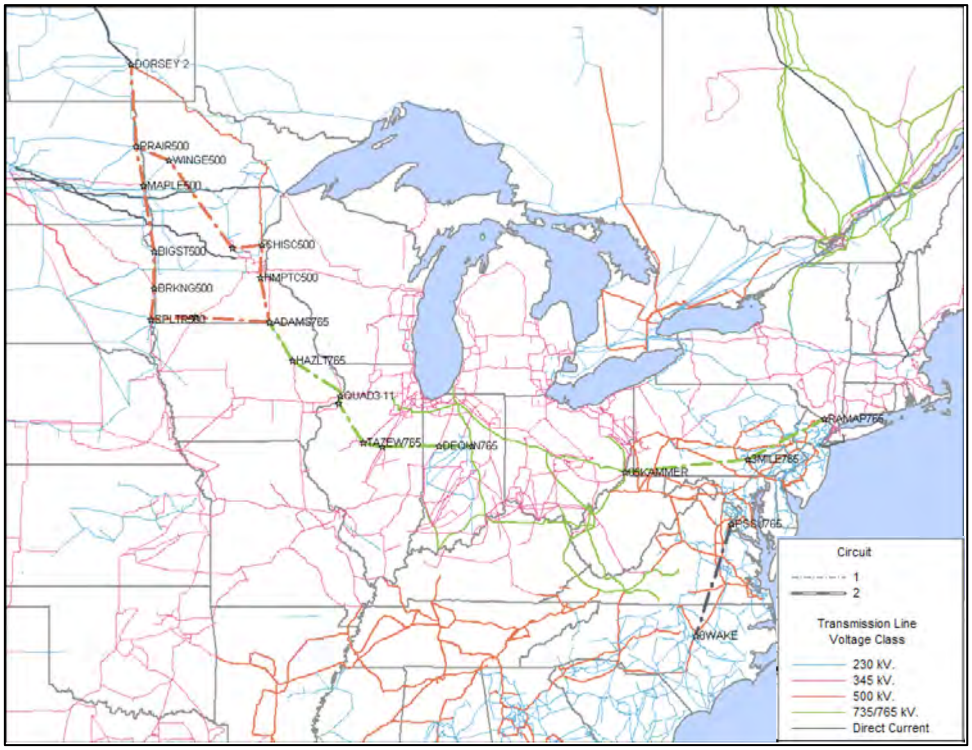


Figure 5-36: Reference Scenario Transmission Overlay Option 3-1-2 Added New Lines Post Interim Stakeholder Meeting

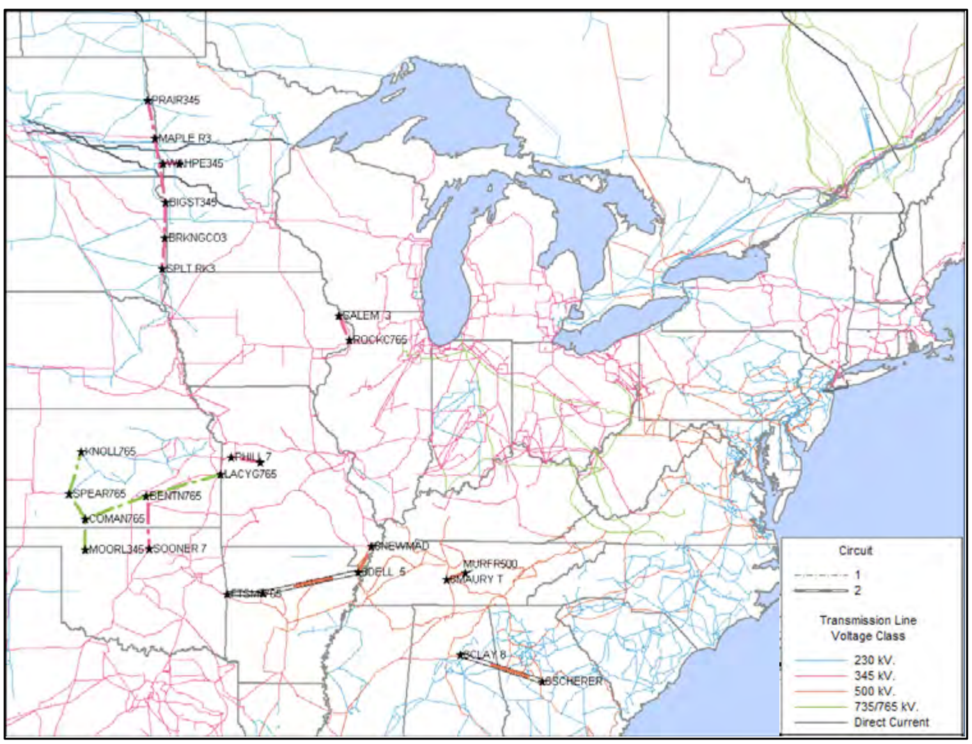


Figure 5-37: Reference Scenario Transmission Overlay Option 3-1-2 Removed Overlay Lines Post Interim Stakeholder Meeting

Transmission Overlay Refinement Post Carmel Oct. 2nd Workshop

The results of the eleven transmission overlay refinement options were presented at the October 2nd Transmission Refinement Workshop held at Carmel, Indiana. Further refinement work continued with stakeholder's input and feedback received from the workshop. Three additional options were performed after the October 2nd workshop.

Figure 5-38 provides the updated overlay refinement flow chart with the additional three options: Option 3-3-1, Option 3-1-2-1 and Option 3-1-2-2. The same B/C ratio calculation assumptions described in Section 5.3.4 carry though all the case studies.

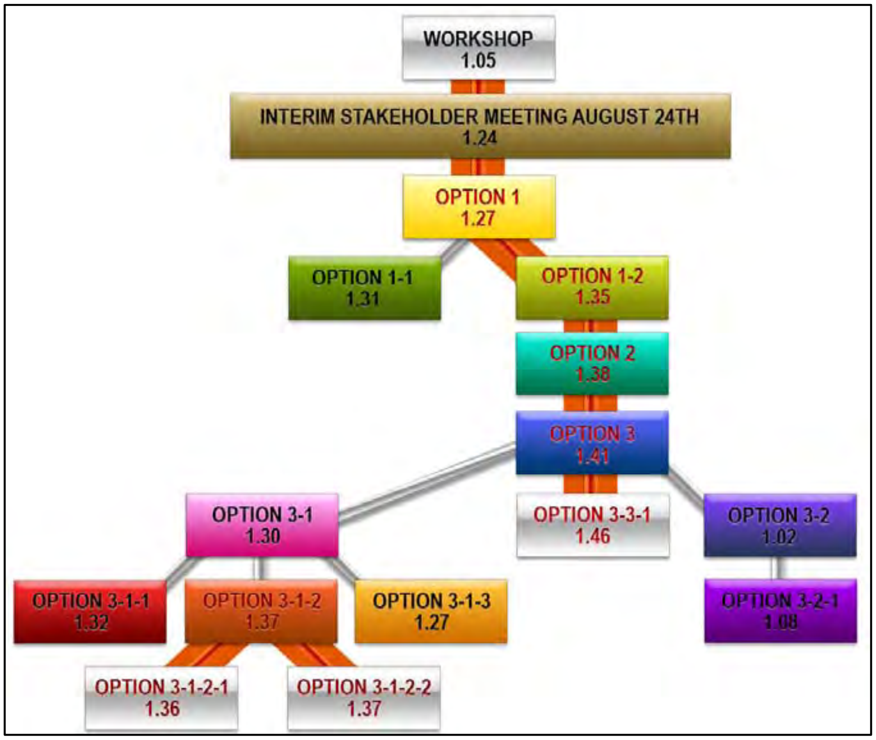


Figure 5-38: Reference Scenario Transmission Overlay Option Flow Chart

Table 5-27 lists the three additional refinement options in detail, which are highlighted in bold to provide easy comparison. Option 3 and Option 3-1-2 were served as the starting point for this refinement round.

Revisions Based on Interim Stakeholder Meeting August 14th Overlay	Opt. 3	Opt. 3-3-1	Opt. 3-1-2	Opt. 3-1-2-1	Opt. 3-1-2-2
Extend one 400 HVDC terminal to Wake 500kV station	✓	✓	✓	✓	✓
Remove low loading overlay lines 500kv and below *	✓	✓	✓	✓	✓
Add 765kV lines Adams - Salem - Quadcity - Emolin - Duckcreek - Dequine - Greentown; Add 76kV line Duckcreek - Kincaid					
Add 500kV line Dorsey - Prairie	✓	✓	✓	✓	✓
Replace Duckcreek with Powertown station for 800HVDC line terminal	✓	✓	✓	✓	✓
Drop down Quadcity - Piano 765 line at Nelson station	✓	✓	✓	✓	✓
Replace three IL wind unit locations to resolve generation Interconnection Problem	✓	✓	✓	✓	✓
Remove all three HVDC overlay lines; Two 800HVDC IL/IA/MN to NY/ISONE One 400HVDC SERC/PJM to NY					
Upgrade several 345kV overlay lines with 500kV and add additional 500kV lines and above to construct an AC overlay plan; Mapleriver - Bigstone - Brookingcounty - Splitrock - Adams 500kV; Prairie - Winger - Sherco - Chisago County - Hampton Corners - Adams 500kV; Adams - Hazilton - Quadcity - Emolin - Tazewell - Brokaw - Dequine - Greentown 765kV; Tazewill - Kincaid - Coffen - EW Frankfort 765kV; Kammer - Three Mile Island - Ramapo 765kV			✓	✓	✓
Remove low loading 765kV overlay lines in SPP **		✓	✓	✓	✓
Remove low loading 765kV AC overlay plan lines; Tazewell - Kincaid - Coffen - EW Frankfort			✓	✓	✓
Remove 400HVDC overlay line SERC/PJM to NY					
Add 765kV line LaCygne				✓	
Remove Pleasant Garden - Axton 765kV line and Wake - Parkwood 500kV line		✓			✓
2024 Benefit/Cost ratio	1.41	**1.46**	1.37	**1.36**	**1.37**

Table 5-27: Transmission Overlay Refinement Option Decision Table Oct 2nd

Although Option 3-3-1 has a better Benefit/Cost ratio, Option 3-1-2-2 could serve as the core plan for different generation scenarios to provide more energy transfer capability. The Step 4 process, described in Section 4 of the JCSP'08 economic transmission planning process, will perform a more comprehensive analysis to test for robustness.

As two bipolar 800 HVDC lines physically connect west to east, in addition to the primary transmission overlay development, two sensitivity cases were analyzed for Option 3-3-1 and Option 3-1-2-2 to model the energy exchange between Midwest ISO and New York/New England by adding the $3/MWH dispatch hurdle rates from Midwest ISO to New York and New England. With the hurdle rates modeled, the total adjusted production cost savings increased as shown in Table 5-28.

Sensitivity Case Benefit Comparison (2024 M$)		
Reference	2024 Adjusted Production Cost Savings	2024 B/C ratio
Option 3-1-2-2	11,525	1.37
Option 3-3-1	10,624	1.46
Sensitivity Option 3-1-2-2	11,868	1.41
Sensitivity Option 3-3-1	10,856	1.49

Table 5-28: Sensitivity Analysis Results

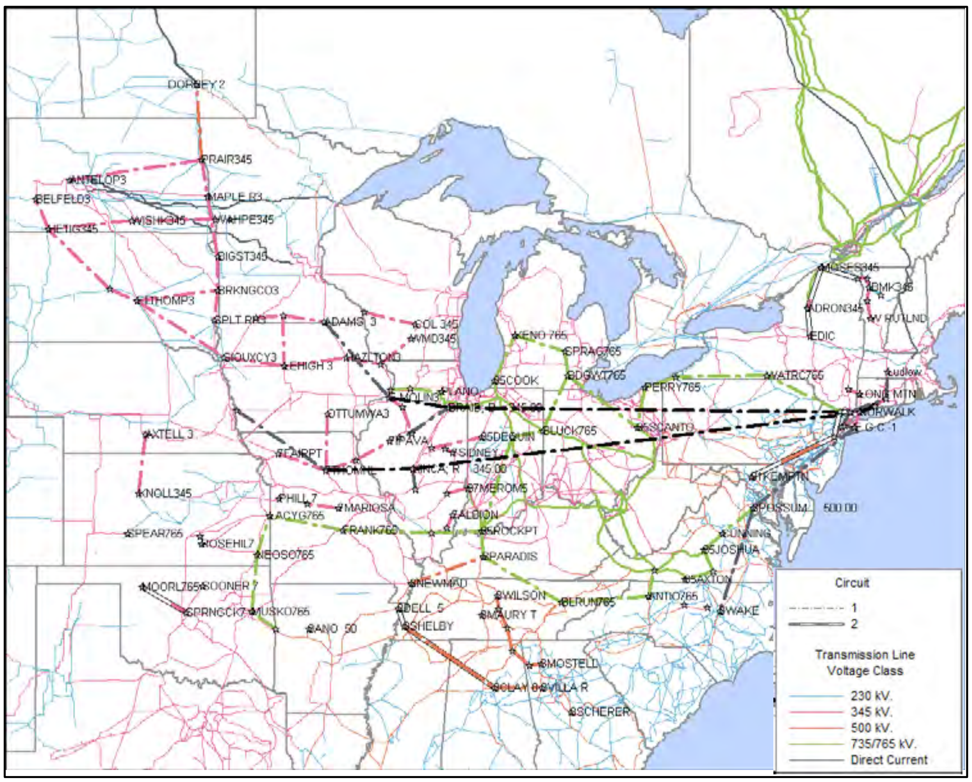


Figure 5-39: Transmission Overlay Option 3-3-1

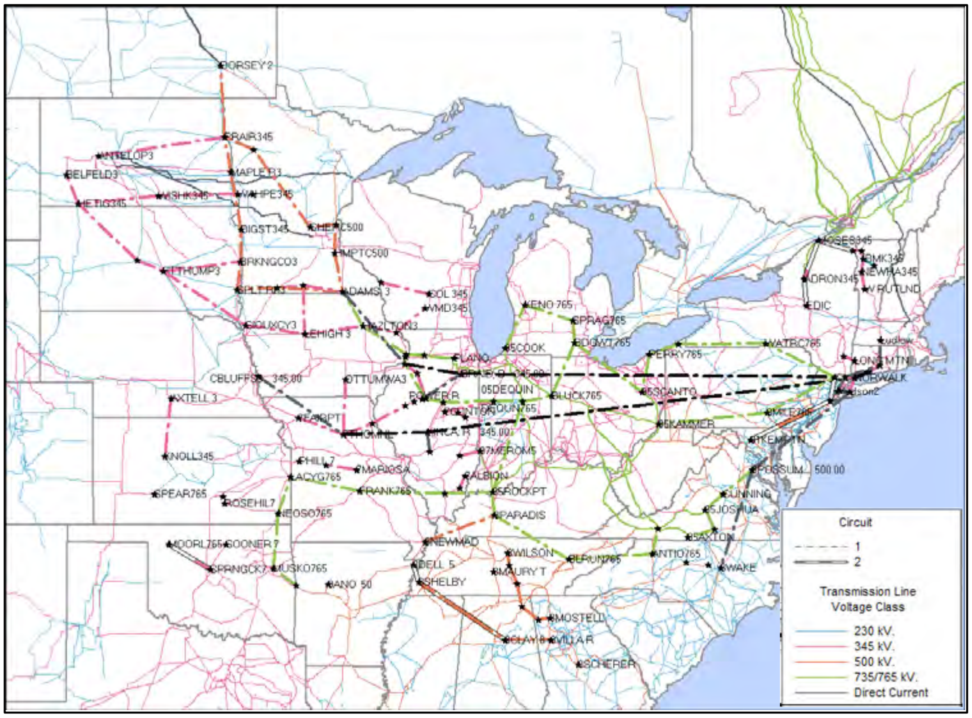


Figure 5-40: Transmission Overlay Option 3-1-2-2

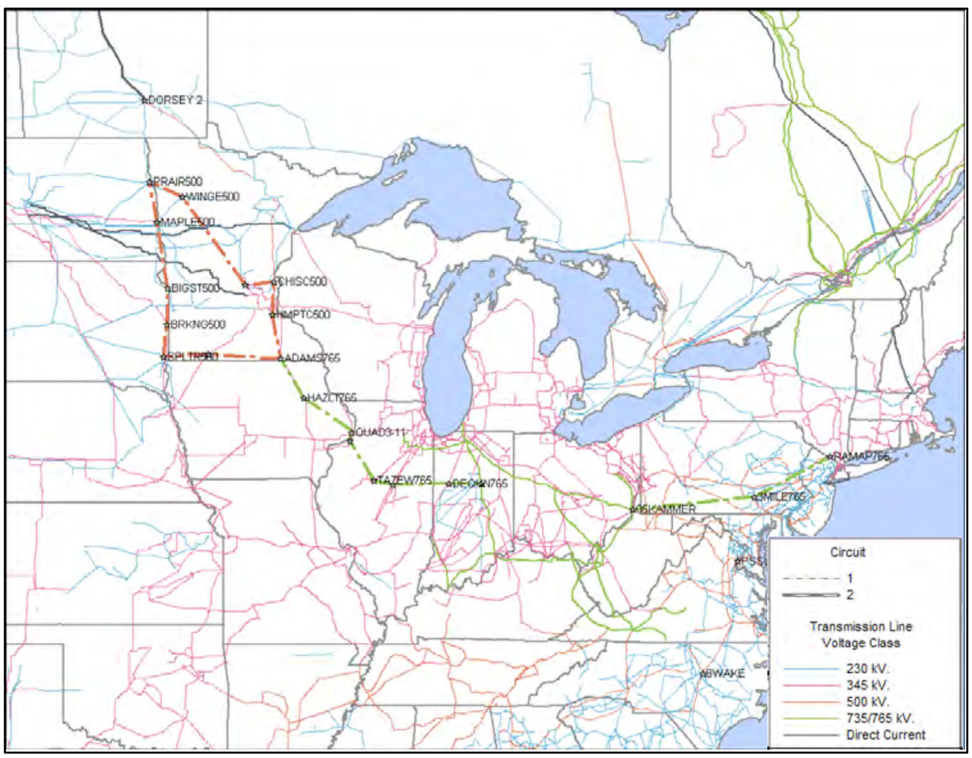


Figure 5-41: Difference between Overlay Option 3-1-2-2 and Option 3-3-1

5.3.1.4 Post Overlay Economic Assessment

Line Miles and Cost Information

Tables 5-29 through 5-31 summarize the cost-per-mile assumptions by voltage level, the estimated line miles by voltage level and the estimated cost in 2024 dollars for the Reference Scenario overlay options. In Table 5-33, the total AC line costs include a 25% adder to approximate the costs of substations and transformers, and the total HVDC line costs include terminals, communications and DC line costs.

For the Reference Scenario approximately 45% of the line miles are associated with 500 kV or lower voltages. To accommodate more wind mandate in the 20% Wind Scenario, more 765 kV and HVDC lines are required.

Cost-per-mile Assumption							
	345 kV	(2) - 345 kV	500 kV	(2) - 500 kV	765 kV	DC - 400 kV	DC - 800 kV
2024$	2,250,000	3,750,000	2,875,000	4,792,000	5,125,000	3,800,000	6,000,000

Table 5-29: Cost-per-mile

Estimated Line Mileage Summary (Miles)								
Reference	345 kV	345 kV (2)	500 kV	500 kV (2)	765 kV	DC-400 kV	DC-800 kV	Total
Workshop	3,254	292	508	468	2,544	0	1,810	8,877
Interim Stakeholder Meeting Aug 14th	3,254	292	508	914	3,118	282	2,400	10,768
Option 1	3,254	292	508	914	3,118	470	2400	10,956
Option 1-1	2,981	292	620	494	3,676	470	2400	10,934
Option 1-2	2,981	292	481	494	3,118	470	2400	10,237
Option 2	3,064	292	620	494	3,118	470	2400	10,459
Option 3	3,106	292	620	494	3,118	470	2400	10,501
Option 3-2	2,801	292	1,508	494	4,146	0	0	9,242
Option 3-1	2,801	292	1,508	494	4,146	470	2400	12,112
Option 3-2-1	2,801	292	1,508	494	3,508	0	0	8,604
Option 3-1-1	2,801	292	1,508	494	3,953	470	2400	11,919
Option 3-1-2	2,801	292	1,508	494	3,508	470	2400	11,474
Option 3-1-3	2,801	292	1,508	494	3,953	0	2400	11,449
Option 3-1-2-1	2,801	292	1,508	494	3,648	470	2400	11,614
Option 3-1-2-2	2,801	292	1,481	494	3,459	470	2400	11,398
Option 3-3-1	3,106	292	593	494	2,624	470	2400	9,980

Table 5-30: Estimated Line Mileage Summary for Refinement Options

Estimated Cost Summary Million (2024$)								
Reference	345 kV	345 kV (2)	500 kV	500 kV (2)	765 kV	DC-400 kV	DC-800 kV	Total
Workshop	9,152	1,371	1,825	2,806	16,299	0	13,903	45,355
Interim Stakeholder Meeting Aug 14th	9,152	1,371	1,825	5,472	19,975	1,698	14,400	53,892
Option 1	9,152	1,371	1,825	5,472	19,975	2,155	14,400	54,349
Option 1-1	8,383	1,371	2,229	2,960	23,549	2,155	14,400	55,048
Option 1-2	8,383	1,371	1,730	2,960	19,975	2,155	14,400	50,974
Option 2	8,617	1,371	2,229	2,960	19,975	2,155	14,400	51,707
Option 3	8,736	1,371	2,229	2,960	19,975	2,155	14,400	51,826
Option 3-2	7,879	1,371	5,419	2,960	26,558	0	0	44,187
Option 3-1	7,879	1,371	5,419	2,960	26,558	2,155	14,400	60,742
Option 3-2-1	7,879	1,371	5,419	2,960	22,476	0	0	40,105
Option 3-1-1	7,879	1,371	5,419	2,960	25,326	2,155	14,400	59,511
Option 3-1-2	7,879	1,371	5,419	2,960	22,476	2,155	14,400	56,660
Option 3-1-3	7,879	1,371	5,419	2,960	25,326	0	14,400	57,355
Option 3-1-2-1	7,879	1,371	5,419	2,960	23,373	2,155	14,400	57,557
Option 3-1-2-2	7,879	1,371	5,321	2,960	22,162	2,155	14,400	56,247
Option 3-3-1	8,736	1,371	2,130	2,960	16,810	2,155	14,400	48,562

Table 5-31: Estimated Cost Summary for Refinement Options

Benefit/Cost Ratio Calculation

The benefit value metrics considered in the JCSP'08 study is Adjusted Production Cost (APC) saving, which is calculated by taking the APC difference between the overlay case and the constrained case for the study footprint. For each case:

APC = Production Cost + Import * Load Weighted LMP (or) – Export * Generation Weighted LMP

An annual revenue requirement of 15% of the total overlay cost is used to calculate the annual cost of the overlay. All the dollar values represent the year 2024 only. The Annual Transmission Costs, Adjusted Production Cost savings and Benefit/Cost ratios for all transmission refinement options are included in Table 5-32. All the options have Benefit/Cost ratios greater than one and Option 3-3-1 has the highest Benefit/Cost ratio of 1.46. A further comprehensive cost benefit analysis of potential alternatives will be required before making any recommendations for need justification.

Cost and Benefit Comparison (2024 M$)			
Reference	2024 Annual Transmission Cost	2024 Adjusted Production Cost Savings	2024 B/C ratio
Workshop	6,803	7,138	1.05
Interim Stakeholder Meeting Aug 14th	8,084	10,029	1.24
Option 1	8,152	10,347	1.27
Option 1-1	8,257	10,778	1.31
Option 1-2	7,646	10,311	1.35
Option 2	7,756	10,736	1.38
Option 3	7,774	10,972	1.41
Option 3-2	6,628	6,752	1.02
Option 3-1	9,111	11,855	1.30
Option 3-2-1	6,016	6,515	1.08
Option 3-1-1	8,927	11,817	1.32
Option 3-1-2	8,499	11,651	1.37
Option 3-1-3	8,603	10,893	1.27
Option 3-1-2-1	8,633	11,716	1.36
Option 3-1-2-2	8,437	11,525	1.37
Option 3-3-1	7,284	10,624	1.46

Table 5-32: Cost and Benefit Comparison

While the screening of the results, and the determination of the cost component of the Benefit/Costs ratios, uses a 15% Levelized Fixed Charge Rate (LFCR), that rate is subject to fluctuation depending on the cost structure of the entity that builds the transmission. To account for the uncertainty surrounding the LFCR, and its impact on the cost component of transmission option 3-3-1, Figure 5-42 shows the resulting B/C ratio over a range of LFCRs from 15% to 25%.

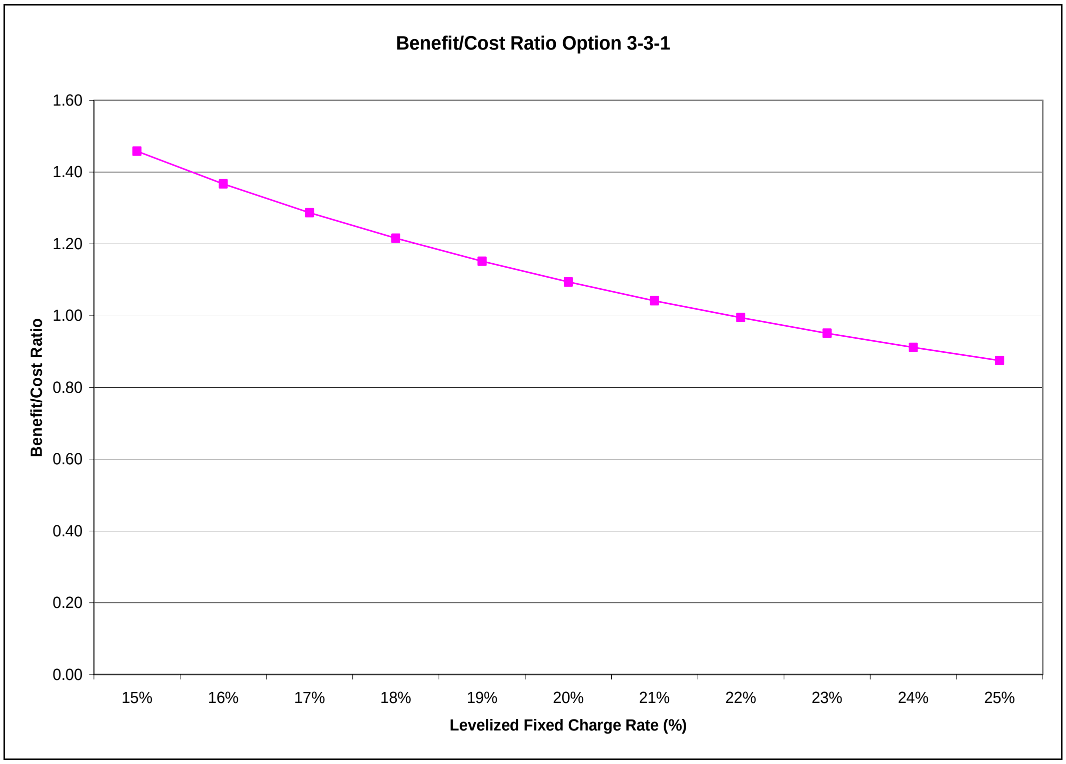


Figure 5-42: Benefit/Cost Ratio Change with LFCR

Economic Benefit Savings

Table 5-33 provides the total annual captured benefits by region and the total annual theoretical maximum benefits that can be achieved with no transmission constraints for Option 3-3-1. Assuming the efficiency is 0% if the captured benefits are negative, the efficiencies of Option 3-3-1 are included in the table as well. For adjusted production cost savings, the efficiencies for east regions including PJM, New York and New England are in the 70% range, while the efficiency for the Midwest ISO is 40%.

Option 3-3-1	Captured Benefits			Theoretical Benefits			Efficiency		
	Net Generation Revenue	Adj. Production	Load Cost	Net Generation Revenue	Adj. Production	Load Cost	Net Generation Revenue	Adj. Production	Load Cost
Pool	Increase (M$)	Cost Saving (M$)	Saving (M$)	Increase (M$)	Cost Saving (M$)	Saving (M$)	Increase (%)	Cost Saving (%)	Saving (%)
PJM	-1,905	1,817	6,587	-1,391	2,632	9,716	0%	69%	68%
Midwest ISO	5,438	446	-5,606	11,687	1,105	-10,293	47%	40%	0%
TVASUB	2,474	463	-1,853	3,616	1,003	-1,587	68%	46%	0%
MAPP	1,188	-6	-1,271	2,652	207	-2,292	45%	0%	0%
SPP	391	326	-26	-530	1,193	2,926	42%	27%	0%
SERCNI	-405	1,091	2,284	2,148	3,842	7,227	0%	28%	32%
E_CAN	-551	1,479	2,477	3,572	4,404	1,727	0%	34%	143%
IMO	-1,626	-63	1,558	446	570	418	0%	0%	372%
New Eng.	-2,396	1,886	4,858	-2,342	2,835	6,369	0%	67%	76%
MHEB	585	321	-379	1,875	1,043	-1,049	31%	31%	0%
New York	-2,261	2,865	6,857	-1,677	3,682	8,074	0%	78%	85%
Whole EI	933	10,624	15,484	20,056	22,516	21,235	5%	47%	73%
JCSP'08	2,524	8,887	11,829	14,163	16,500	20,139	18%	54%	59%

Table 5-33: Economic Benefit Savings for Option 3-3-1

Table 5-34 gives the same information for Option 3-1-2-2. With the stronger AC system in the west, the overlay efficiency for the Midwest ISO region increased by 11% and the total efficiency for the study footprint increased by 4%.

	Captured Benefits			Theoretical Benefits			Efficiency		
Option 3-1-2-2	Net Generation Revenue	Adj. Production	Load Cost	Net Generation Revenue	Adj. Production	Load Cost	Net Generation Revenue	Adj. Production	Load Cost
Pool	Increase (M$)	Cost Saving (M$)	Saving (M$)	Increase (M$)	Cost Saving (M$)	Saving (M$)	Increase (%)	Cost Saving (%)	Saving (%)
PJM	-2,666	1,917	7,876	-1,391	2,632	9,716	0%	73%	81%
Midwest ISO	6,127	559	-6,191	11,687	1,105	-10,293	52%	51%	0%
TVASUB	2,613	485	-1,997	3,616	1,003	-1,587	72%	48%	0%
MAPP	1,497	20	-1,550	2,652	207	-2,292	56%	10%	0%
SPP	495	314	-168	-530	1,193	2,926	48%	26%	0%
SERCNI	-359	1,098	2,259	2,148	3,842	7,227	0%	29%	31%
E_CAN	-541	1,545	2,547	3,572	4,404	1,727	0%	35%	147%
IMO	-1,652	-61	1,593	446	570	418	0%	0%	381%
New Eng.	-2,451	2,018	5,062	-2,342	2,835	6,369	0%	71%	79%
MHEB	1,035	571	-625	1,875	1,043	-1,049	55%	55%	0%
New York	-2,352	3,058	7,227	-1,677	3,682	8,074	0%	83%	90%
Whole EI	1,745	11,525	16,033	20,056	22,516	21,235	9%	51%	76%
JCSP'08	2,904	9,470	12,519	14,163	16,500	20,139	21%	57%	62%

Table 5-34: Economic Benefit Savings for Option 3-1-2-2

Regional Load Weighted LMP Changes

Table 5-35 provides the annual average load weighted LMP prices across the study footprint for the constrained case and the overlay cases for Option 3-3-1 and Option 3-1-2-2. Option 3-1-2-2 has a better percentage of LMP price reduction for east regions compared to Option 3-3-1.

	Constrained Case	Overlay Option 3-3-1		Overlay Option 3-1-2-2	
Region	Average Load Weighted LMP ($/MWH)	Average Load Weighted LMP ($/MWH)	Percentage of Reduction	Average Load Weighted LMP ($/MWH)	Percentage of Reduction
PJM	74.74	67.60	10%	66.21	11%
Midwest ISO	49.34	57.16	-16%	57.98	-18%
TVASUB	60.14	66.27	-10%	66.75	-11%
MAPP	43.82	54.70	-25%	57.09	-30%
SPP	76.99	77.10	0%	77.70	-1%
SERCNI	73.47	70.70	4%	70.73	4%
E_CAN	67.62	57.86	14%	57.58	15%
IMO	64.40	55.56	14%	55.36	14%
New England	100.40	73.03	27%	71.89	28%
MHEB	22.79	37.06	-63%	46.33	-103%
New York	105.72	70.88	33%	68.99	35%

Table 5-35: Regional Load Weighted LMP Changes

The LMP price change demonstrates the ability of the conceptual transmission overlay in providing a more competitive market within the Midwest ISO and the reduction in costs to the East Coast. With the conceptual transmission overlay, more low cost energy in the west regions is available to energy markets and is economically transferred to the high priced East Coast regions. As the result of the economic energy transfer, the west region LMP prices increase with the increased base load generation output, while the LMP prices decrease in the east regions because the output of the high priced generation are displaced by the imported low cost energy.

With the increased LMP prices in the west regions, significant amount of the generation revenue benefits are achieved and can potentially be reallocated back to the end use customers through the regulatory mechanism. Other mechanisms might have to be put in place to distribute the revenues back to load. Section 6 provides more information on cost allocation.

Table 5-36 provides the regional generation annual energy and capacity factor change between the unconstrained case and the overlay case by category for Option 3-1-2-2. The positive values represent the generation curtailment compared to the constrained case and the negative values represent the generation increase compared to the constrained case. With the transmission overlay Option 3-1-2-2, a total of 43 TWH increased annual energy output of the base load steam units in the Midwest ISO are transferred to the high cost east regions and the annual capacity factor increases by 6%, while the annual capacity factors of Combined Cycle and CT gas units in the East Coast decrease by 10% to 26%.

Annual Energy (GWH)						Option 3-1-2-2 Overlay Case Minus Constrained Case					
Category	E_CAN	IMO	New England	MAPP	MHEB	Midwest ISO	New York	PJM	SERCNI	SPP	TVASUB
Combined Cycle	-3,052	-3,432	-33,391	777	0	2,341	-24,070	-21,531	-4,080	-2,178	1,646
CT Gas	-19	14	-93	-52	2	-234	-4,330	-2,742	-3,973	28	66
CT Oil	8	1	0	0	0	22	-14	-50	-5	-3	-1
IGCC	0	0	0	0	0	-19	0	1,703	0	0	-1
Nuclear	0	0	0	0	0	0	0	0	0	0	0
ST Base Load Steam	-152	0	-412	6,964	428	43,718	-59	11,437	10,695	7,537	8,968
ST Gas	0	-46	-49	4	0	-9	-2,024	-160	234	12	0
ST Oil	1	0	-206	0	0	-7	-336	-500	-5	0	0
Annual Capacity Factor						Option 3-1-2-2 Overlay Case Minus Constrained Case					
Category	E_CAN	IMO	New England	MAPP COR	MHEB	Midwest ISO	New York	PJM	SERCNI	SPP	TVASUB
Combined Cycle	-25%	-6%	-22%	5%		2%	-26%	-10%	-1%	-3%	2%
CT Gas	-1%	0%	-1%	0%	0%	0%	-10%	-1%	-1%	0%	0%
CT Oil	0%	0%	0%	0%		0%	0%	0%	0%	0%	0%
IGCC						-1%		9%			0%
Nuclear	0%	0%	0%	0%		0%	0%	0%	0%	0%	0%
ST Base Load Steam	-1%	0%	-1%	6%	23%	6%	0%	1%	2%	3%	3%
ST Gas		0%	-1%	0%		0%	-4%	-1%	0%	0%	
ST Oil	0%		0%			0%	-1%	-1%	0%		

Table 5-36: Annual Energy and Capacity Factor Changes for Option 3-1-2-2

The same information for Option 3-3-1 is shown in Table 5-37. With less economic energy transfer capability in Option 3-3-1, the increased low cost base load steam unit annual output is lower compared to Option 3-1-2-2.

Annual Energy (GWH)	Option 3-3-1 Overlay Case Minus Constrained Case										
Category	E_CAN	IMO	New England	MAPP	MHEB	Midwest ISO	New York	PJM	SERCNI	SPP	TVASUB
Combined Cycle	-2,954	-3,286	-32,197	738	0	2,343	-22,856	-20,043	-4,133	-2,368	1,630
CT Gas	-19	12	-88	-55	1	-157	-4,181	-2,429	-3,916	11	28
CT Oil	8	1	0	-1	0	13	-14	-47	-5	-2	-1
IGCC	0	0	0	0	0	-19	0	1,687	0	0	-1
Nuclear	0	0	0	0	0	0	0	0	0	0	0
ST Base Load Steam	-173	0	-384	6,267	237	37,141	94	14,714	11,022	7,422	8,808
ST Gas	0	-53	-49	6	0	-8	-1,939	-145	220	-19	0
ST Oil	1	0	-200	0	0	-9	-326	-445	-5	0	0
Annual Capacity Factor	Option 3-3-1 Overlay Case Minus Constrained Case										
Category	E_CAN	IMO	New England	MAPP	MHEB	Midwest ISO	New York	PJM	SERCNI	SPP	TVASUB
Combined Cycle	-24%	-6%	-21%	4%		2%	-25%	-9%	-1%	-3%	2%
CT Gas	-1%	0%	-1%	0%	0%	0%	-9%	-1%	-1%	0%	0%
CT Oil	0%	0%	0%	0%		0%	0%	0%	0%	0%	0%
IGCC						-1%		9%			0%
Nuclear	0%	0%	0%	0%		0%	0%	0%	0%	0%	0%
ST Base Load Steam	-1%	0%	-1%	5%	13%	5%	0%	2%	2%	3%	3%
ST Gas		0%	-1%	0%		0%	-4%	-1%	0%	0%	

Table 5-37: Annual Energy and Capacity Factor Changes for Option 3-3-1

Interface Flow Improvement

Figure 5-43 shows the comparison of the interface annual energy difference changes without and with the transmission overlay. The left diagram represents the interface annual energy difference between the unconstrained and constrained cases, and the right diagram represents the interface annual energy difference between the unconstrained and overlay cases. The interface flows tending toward red indicate the requirement for more power transfer capacity, with the transmission overlay implemented the needs for additional transfer capacity is greatly reduced. The reduction of AC power flows to SERC is significant.

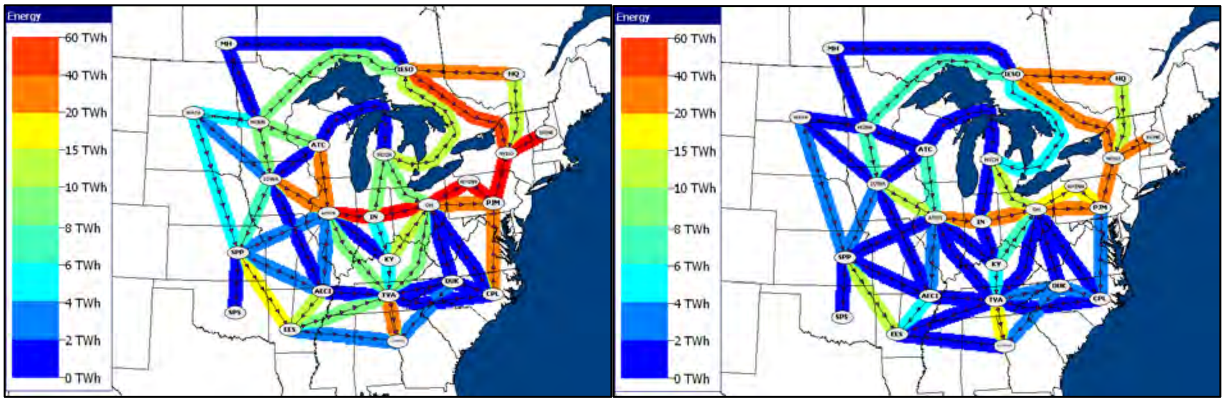


Figure 5-43: Interface Annual Energy Difference

5.3.2 20% Wind Energy Penetration Scenario

For both JCSP'08 Scenarios, the same power flow case was used to build the corresponding year's base case, i.e., all Scenarios have the same initial transmission system in that year. The 2018 power flow case was based on a 2018 Eastern Interconnection Reliability Assessment Group (ERAG) power flow model. The 2018 ERAG model was then reviewed and updated by all JCSP'08 parties including Midwest ISO, MAPP, SPP, PJM, TVA, New York and New England. The updated 2018 JCSP'08 power flow model was then used in both 2018 reliability and PROMOD study. The initial transmission system in 2018 and 2024 PROMOD models were the same. The generation and load in the 2018 PROMOD model were scaled up to match the 2024 values in the 2024 PROMOD model.

For the 20% Wind Scenario, a 20% Wind Energy Penetration Target is applied to all JCSP'08 regions. Several regions could not site all of the wind requirements within their regions, specifically TVA, Entergy and SERC; therefore, a redistribution of wind location by region was required. The Midwest ISO and SPP regions are most heavily impacted in that 92,000 MW of wind was shifted to these two regions. In PROMOD, these remote wind sites are modeled as wind generators sitting on Midwest ISO and SPP buses, but with the ownership of companies in other regions.

5.3.2.1 Pre-overlay PROMOD Run Results

An initial set of PROMOD cases were run with the 2024 Generation/Load defined in previous sections but no additional transmission. One case was run with the normal event file ("constrained case"); the other case was run with an empty event file ("coppersheet case"). The comparison between the two cases can provide useful information to help us design the transmission overlay for the future. The difference in the cases indicates where energy would flow if it could without constraint.

Figure 5-44 shows the company generation difference between constrained case and coppersheet case. This contour map can be seen as the energy source and sink definition. The areas with blue color are the potential energy source; those in red color are the potential energy sink. Since we sited most of our wind in western Midwest ISO, MAPP and SPP region, these regions show up as the potential energy source on the map. On the other side, from Michigan, Indiana, Kentucky, and Tennessee to the East Coast, these regions are the potential energy sink.

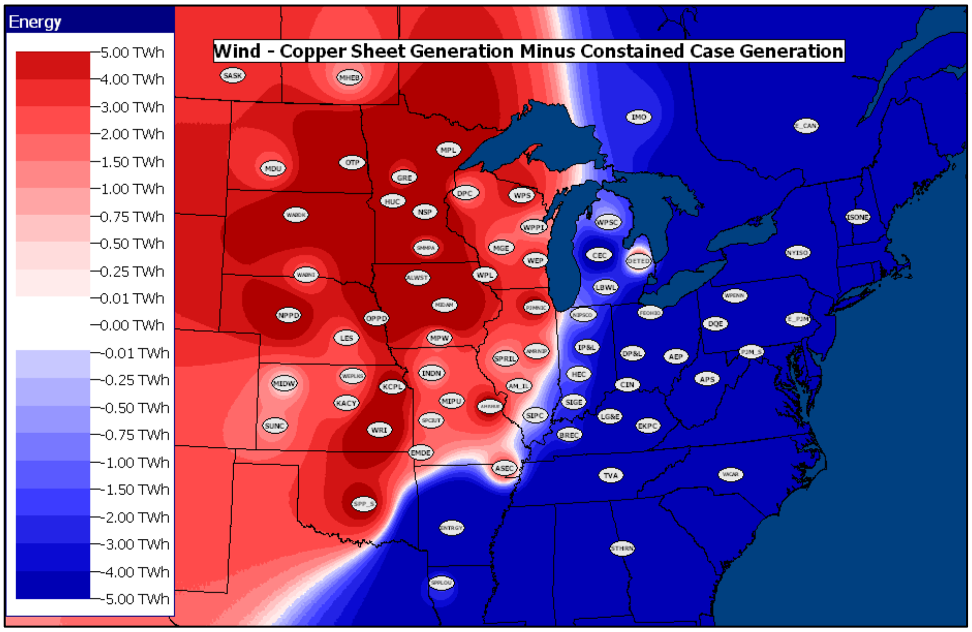


Figure 5-44: 20% Wind Generation Difference: Copper Sheet and Constrained Cases

Figure 5-45 and Figure 5-46 show the generation and load LMP contour map for the constrained case. Both contour maps provide similar information: LMP tends to increase from west to east. West Midwest ISO, MAPP and SPP region show very low or even negative load/generation LMP, while East Coast shows highest LMP price.

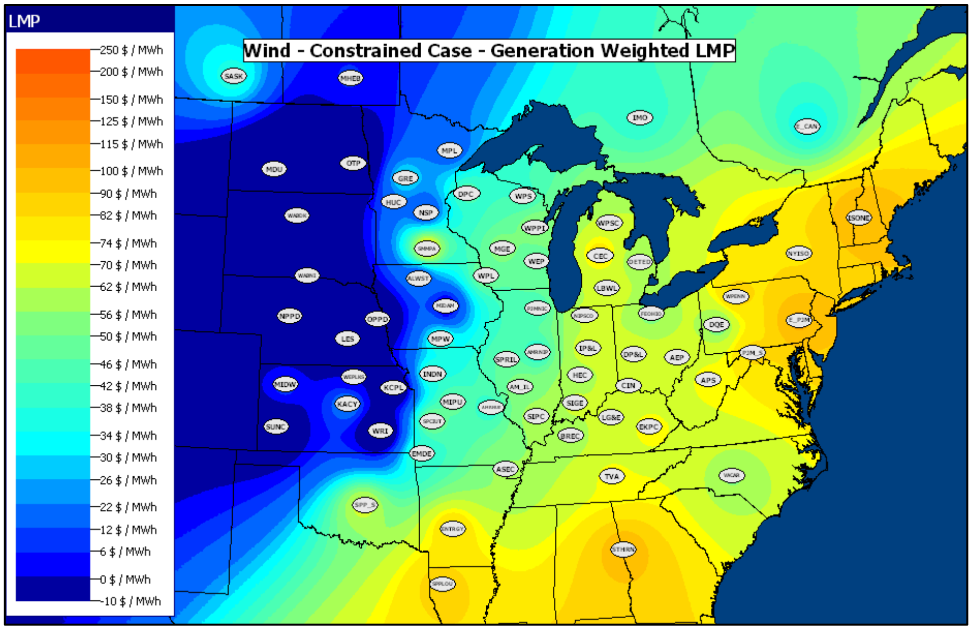


Figure 5-45: 20% Wind Full Constrained Case Annual Gen. Weighted LMP

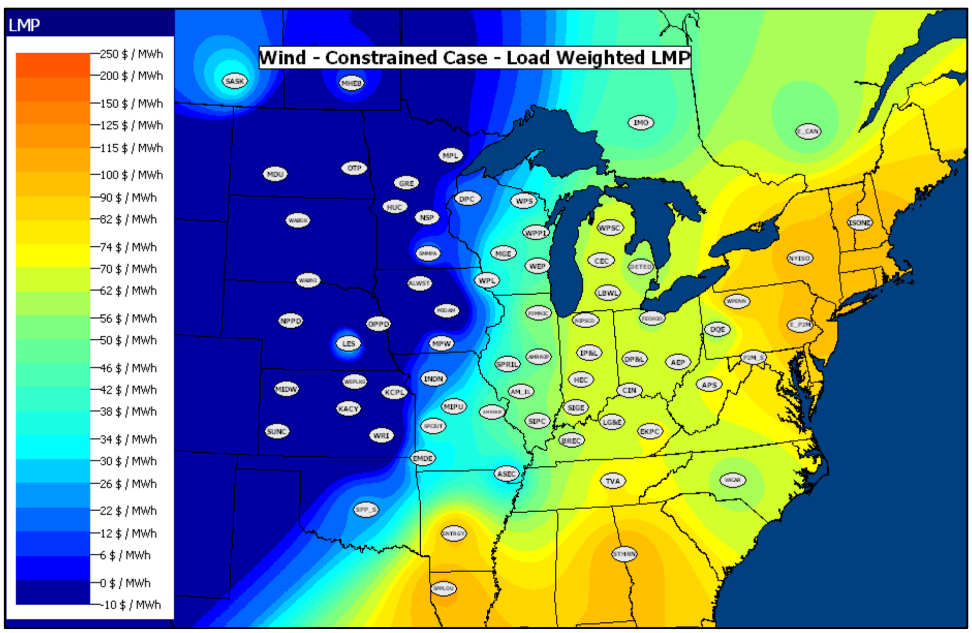


Figure 5-46: 20% Wind Full Constrained Case Annual Load Weighted LMP

Figure 5-47 is the interface contour diagram for the 20% Wind Scenario. Color shows the priority of the transfer needs on these interfaces. Red color indicates a more urgent need for additional transfer capability. From this diagram we can see two clear paths for energy transfer need:

- The first one starts from Minnesota, goes through Iowa/Wisconsin, Illinois, Indiana and Ohio, then sinks to PJM and New York, New England.
- The other path starts from SPP and SPP south, goes through Missouri, Oklahoma, Tennessee, then sinks to Southern Company.

This contour map serves as the basis for our economic transmission overlay design. Table 5-38 contains essentially the same information as shown in Figure 5-47, except only the top 25 constrained interfaces are shown with actual numbers.

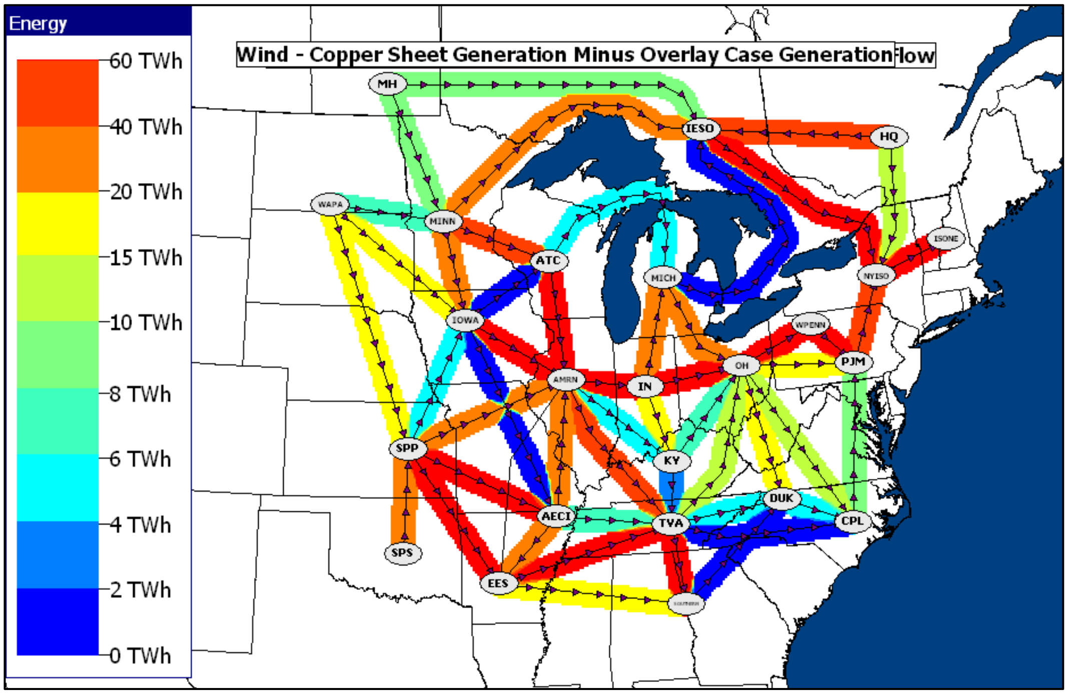


Figure 5-47: 20% Wind Interface Contour:
Annual Energy Difference Copper Sheet to Constrained Case

Top	INTERFACE	Total Positive Energy (TWh)	Total Negative Energy (TWh)	Average Energy (TWh)	80% CAP (MW)
1	AMRN - IN	235	0	27	26,878
2	IN - OH	177	0	20	19,334
3	OH-E_PJM	148	0	17	16,126
4	SPP - EES	107	0	12	12,567
5	AMRN - IOWA	0	-106	-12	12,204
6	New Eng. - New York	0	-88	-10	10,331
7	TVA - EES	0	-75	-9	9,472
8	SOUTHERN - TVA	0	-82	-9	8,860
9	IESO - New York	69	0	8	8,678
10	New York - PJM	5	-55	-6	8,430
11	ATC - AMRN	69	0	8	8,068
12	AECI - SPP	0	-61	-7	7,866
13	SPP - SPS	1	-37	-4	7,174
14	IESO - HQ	4	-41	-4	7,098
15	MINN - ATC	57	0	6	6,575
16	AMRN - TVA	42	0	5	4,691
17	AMRN - AECI	2	-22	-2	4,618
18	MICH - IN	2	-28	-3	4,568
19	MICH - IESO	13	-12	0	4,184
20	AECI - EES	37	0	4	3,976
21	SPP - AMRN	32	0	4	3,922
22	MINN - IOWA	22	0	2	3,424
23	MICH - OH	25	0	3	3,128
24	PJM - CPL	1	-14	-1	2,998
25	IOWA - SPP	6	-9	0	2,926

Table 5-38: 20% Wind Top 25 Interfaces With the Biggest Energy Difference

Columns three through five of Table 5-38 show the energy difference between the constrained case and the coppersheet case over a specific interface. Column 6 (80% Cap) provides the transfer capacity needed on the interface to deliver 80% of the energy difference shown in columns three through five. This number can then be used as the reference when we design the transmission overlay.

Table 5-39 shows the economic information derived from the constrained case and the coppersheet case. By removing all transmission constraints, as we did in the coppersheet case, the theoretical maximum savings that can be achieved are shown in three separate categories: net generation revenue, adjusted production cost, and load cost.

	Net Generation Revenue	Adjusted Production Cost	Load Cost
	Increase(M$)	Cost Saving (M$)	Saving (M$)
PJM	-14,601	4,034	27,632
Midwest ISO	3,889	5,309	-6,048
TVASUB	-3,179	1,445	5,397
MAPP	1,512	-4,761	-10,540
SPP	-85	-298	-9,686
SERCNI	-12,350	6,158	26,988
E_CAN	4,735	4,504	1,079
IMO	2,199	1,241	-953
New England	-2,405	3,524	7,949
MHEB	1,876	971	-1,033
New York	305	4,456	9,144
Whole EI	-18,107	26,583	49,930
JCSP'08	-26,916	19,868	50,837

Table 5-39: 20% Wind Annual Economical: Coppersheet Versus Constrained Case

In this section, the adjusted production cost saving is used as the measure for the economic benefit of the transmission overlay. From Table 5-39 we can see that a maximum of B$26.6 annual adjusted production cost saving can be achieved. This number will be used as the potential maximum budget for our transmission overlay design.

5.3.2.2 Overlay Development

Based on the initial information provided in Section 5.3.2.1, four JCSP'08 workshops were held to design the preliminary transmission overlay for Reference and 20% Wind Scenario. Four workshops were held in four different locations: Hartford, CT; Wilmington, DE; St. Louis, MO; and Knoxville, TN.

A large group of stakeholders attended these workshops and provided their inputs to the transmission overlay design. In addition to the discussion on the overall transmission overlay design, each workshop focused on their specific region to get the detailed transmission information. The Hartford Workshop focused on the New York and New England regions, the Wilmington Workshop focused on the PJM region, the St. Louis Workshop focused on the Midwest ISO and SPP regions, and the Knoxville Workshop focused on the TVA and SERC regions.

Regional transmission designs gathered from the workshops were then reviewed and put into the transmission overlay for the whole Eastern Interconnection. Figures 5-48 through 5-52 show the regional transmission design inputs from the four workshops.

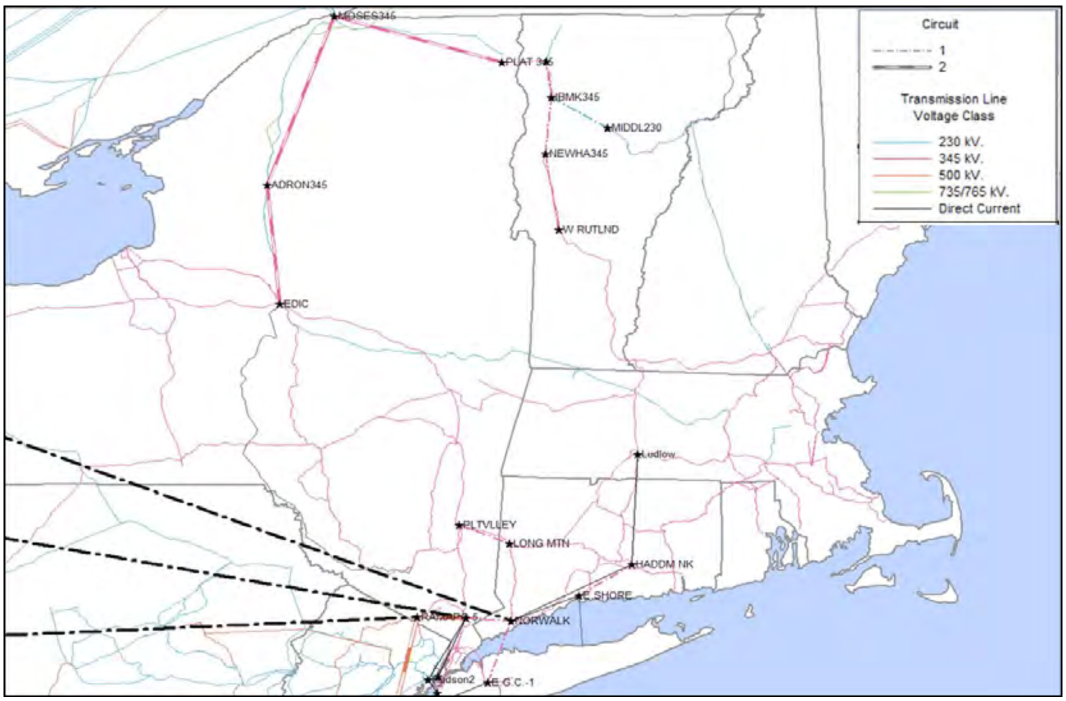


Figure 5-48: 20% Wind Future – Hartford Workshop Input

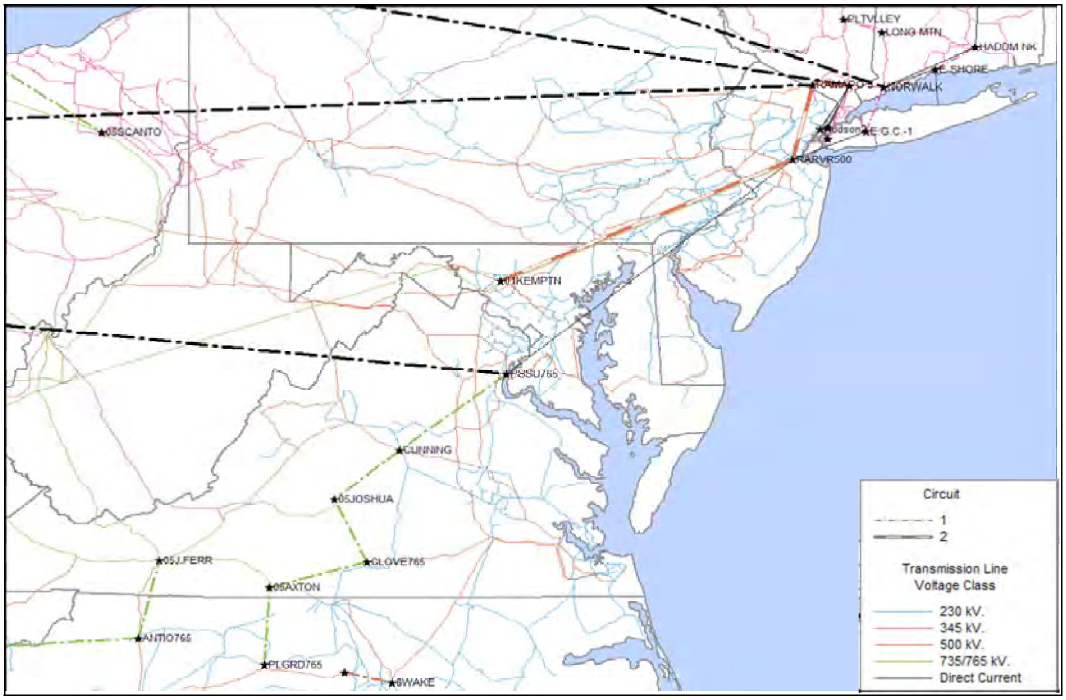


Figure 5-49: 20% Wind Scenario – Wilmington Workshop Input

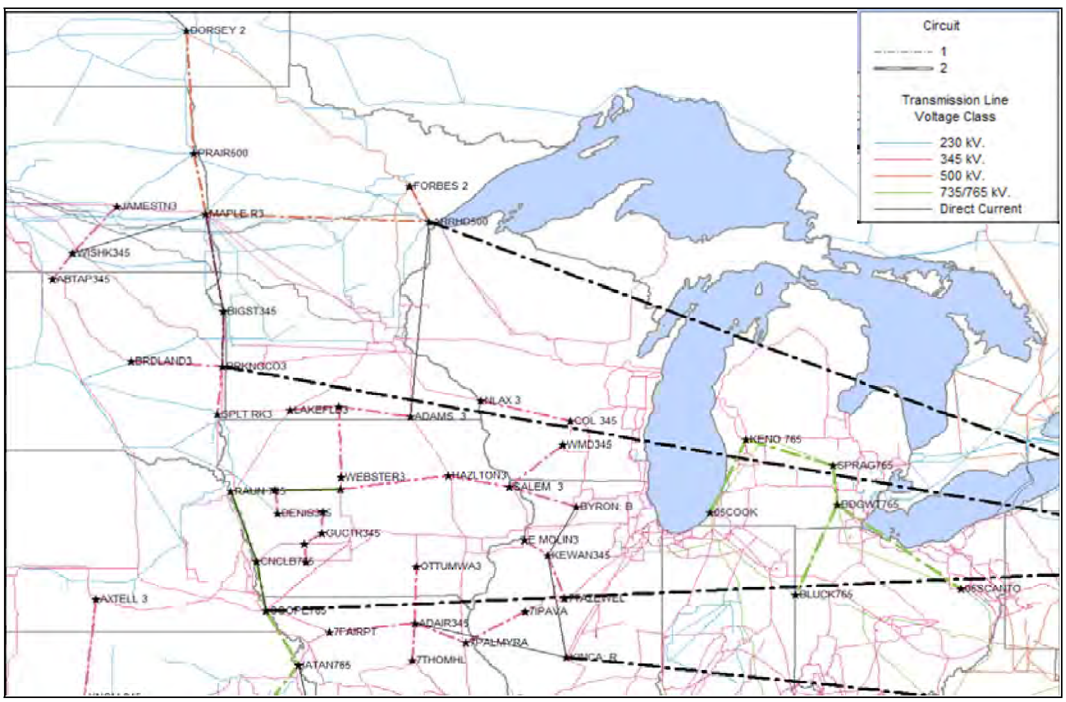


Figure 5-50: 20% Wind Scenario – St. Louis Workshop Input #1

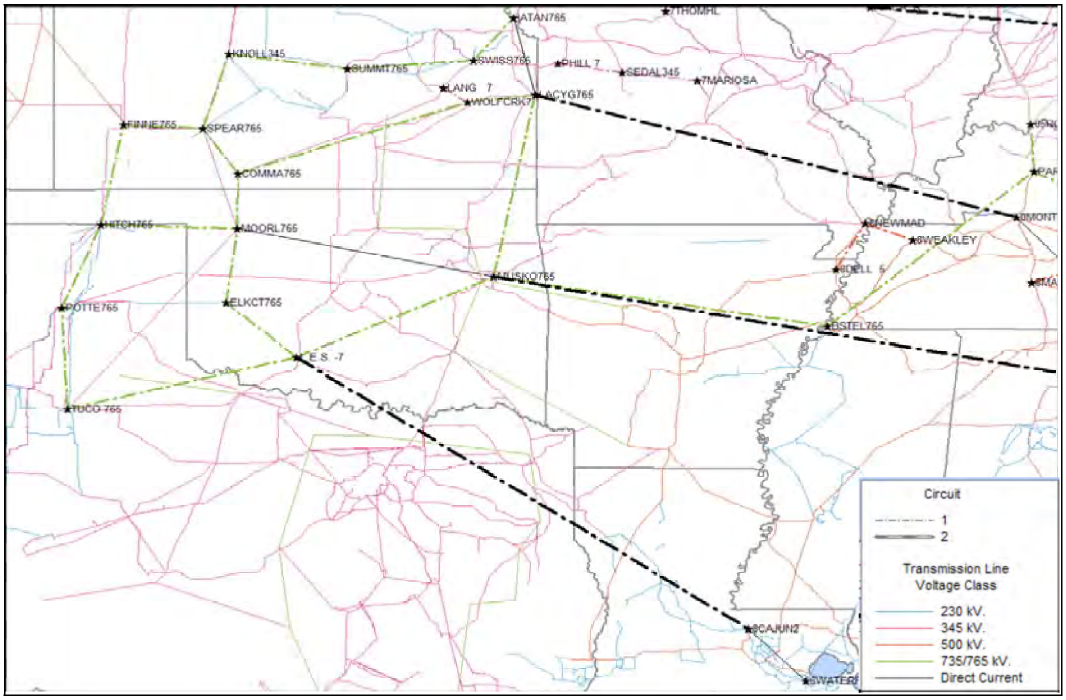


Figure 5-51: 20% Wind Scenario – St. Louis Workshop Input #2

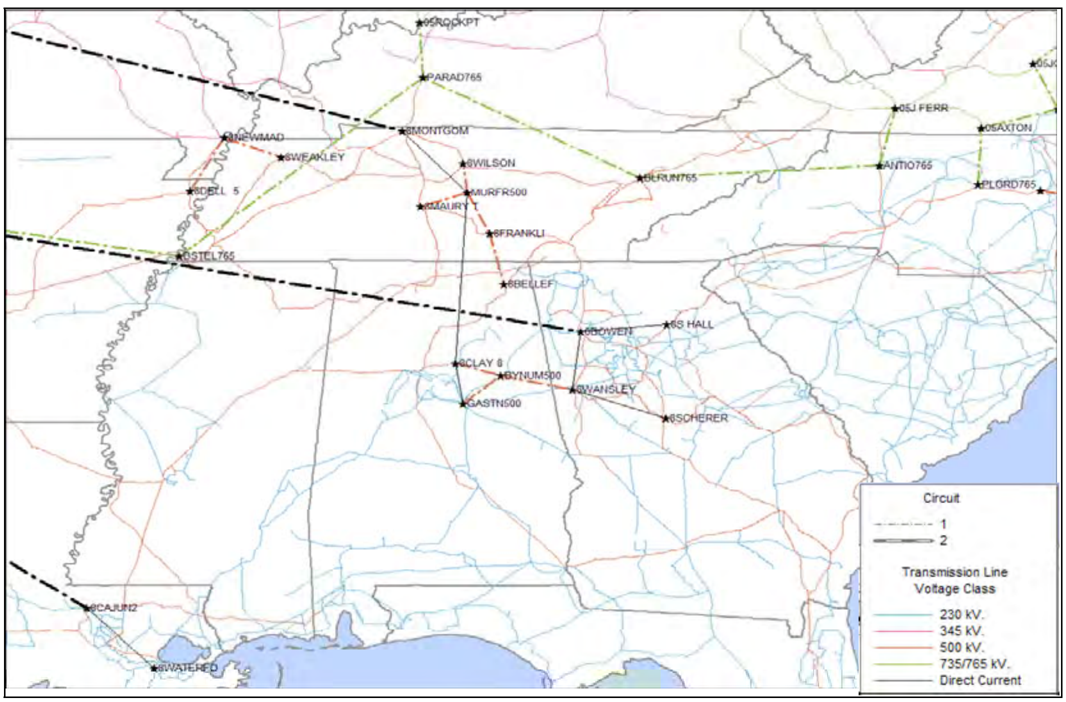


Figure 5-52: 20% Wind Scenario – Knoxville Workshop Input

Several transmission changes/updates were made before the full transmission overlay was assembled from the above workshop inputs:

- Updated details on multi-terminal DC lines: assigned collection points and drop points for each of the multi-terminal DC lines
- Added several backup AC lines (765 kV) to support the DC line contingency
- Added a 345 kV wind collection system in Iowa

Figure 5-53 shows the above updates on a transmission map.

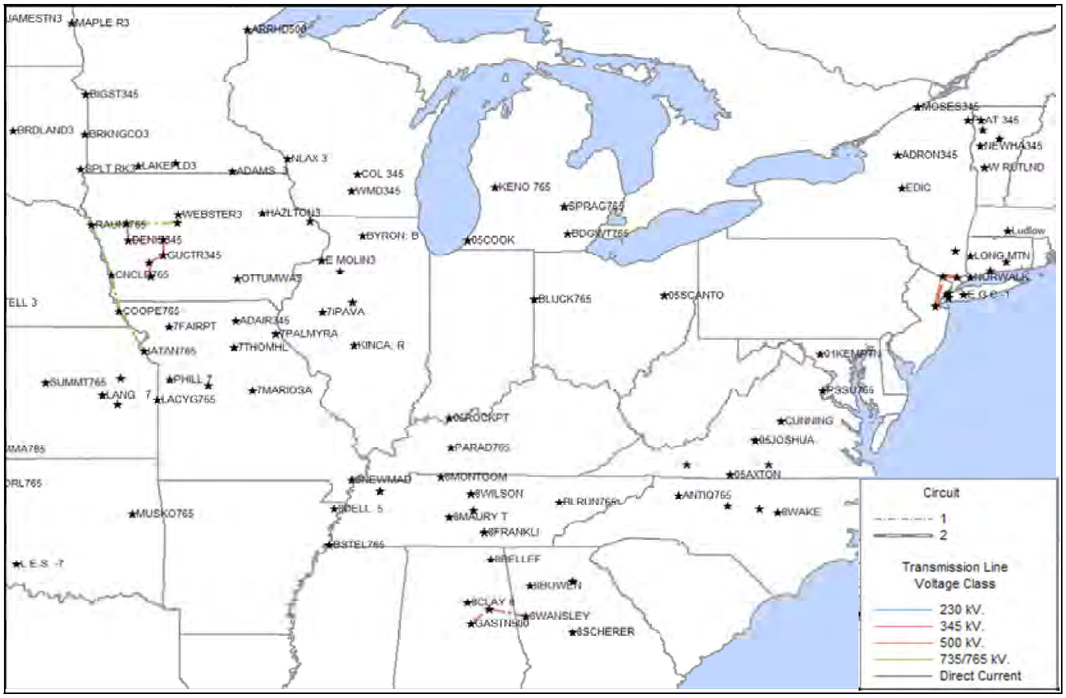


Figure 5-53: 20% Wind Scenario – Adjustments after Workshops

The preliminary transmission overlay design for the 20% Wind Scenario is shown in Figure 5-54. There are a total of seven multi-terminal DC lines connecting west to east and south: four to PJM, New York and New England regions and three to TVA, SERC and Entergy regions. Each DC line is rated as 6,400 MVA, with four terminals at both ends. The detailed transmission line information can be found in Appendix 6.

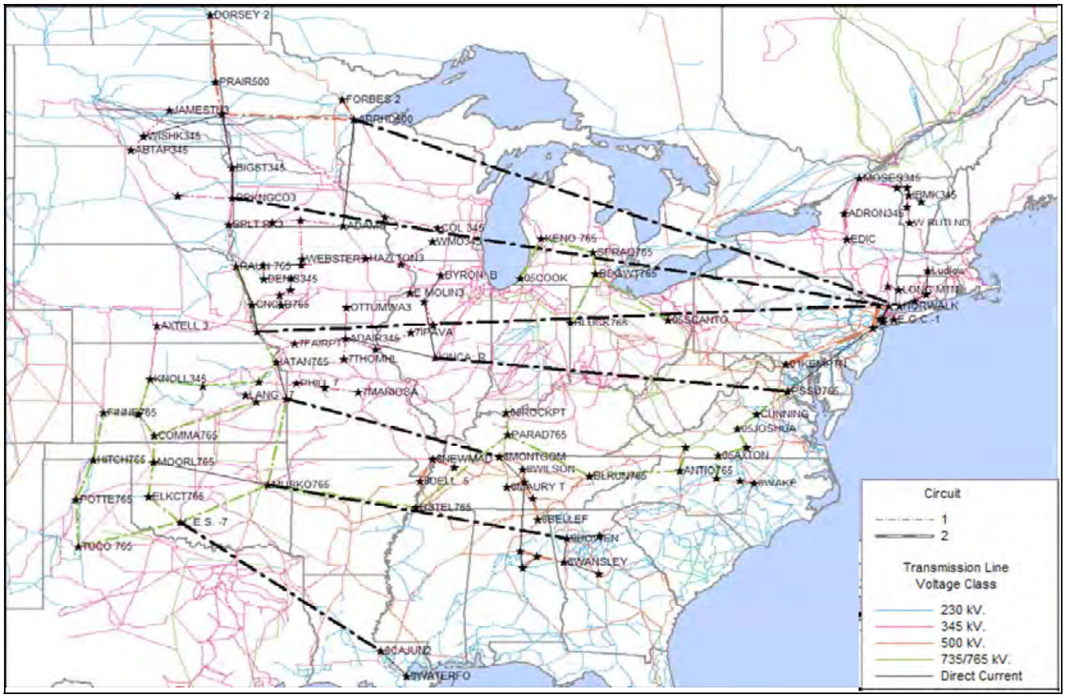


Figure 5-54: 20% Wind Scenario – Preliminary Transmission Overlay Design

Table 5-40 is a summary of the total line mileage and estimated cost for the 20% Wind Scenario preliminary transmission overlay. The cost for DC converters and a third terminal are included in the cost-per-mile assumption for DC lines directly. All other AC lines used a 25% cost adder to reflect the substation cost, right of way cost, etc.

2024	345 kV	(2) - 345 kV	500 kV	(2) - 500 kV	765 kV	DC - 400 kV	DC - 800 kV	Total
Cost-per-mile Assumption($)	2,250,000	3,750,000	2,875,000	4,792,000	5,125,000	3,800,000	6,000,000	
Mileage	2,042	193	864	279	3,977	0	7,582	14,937
Estimated Cost (M$)	5,742	905	3,106	1,671	25,478	0	45,492	82,394

Table 5-40: 20% Wind Scenario Preliminary Transmission Overlay Estimated Mileage and Cost

PROMOD runs were then performed on the preliminary transmission overlay. Table 5-41 shows the economic benefit of the transmission overlay compared to the constrained case without overlay. The achievable benefits represented the theoretical maximum benefit as shown in Table 5-39.

Using a 15% annual fixed charge rate, the annual cost for the preliminary transmission overlay is M$12,359, compared to the adjusted production cost savings of M$11,082, the B/C ratio for the preliminary transmission overlay is 0.9.

Pool	Achieved Benefits (overlay – constrained)			Achievable Benefits (coppersheet – constrained)			Efficiency		
	Net Gen. Rev. Inc. (M$)	Adj. Prod. Cost Saving (M$)	Load Cost Saving (M$)	Net Gen. Rev. Inc. (M$)	Adj. Prod. Cost Saving (M$)	Load Cost Saving (M$)	Net Gen. Rev. Inc. (%)	Adj. Prod. Cost Saving (%)	Load Cost Saving (%)
PJM	-11,692	2,451	16,398	-14,601	4,034	27,632	0%	61%	59%
Midwest ISO	1,052	2,382	-5,866	3,889	5,309	-6,048	27%	45%	0%
TVASUB	-3,230	1,101	3,998	-3,179	1,445	5,397	0%	76%	74%
MAPP	840	-4,380	-6,537	1,512	-4,761	-10,540	56%	0%	0%
SPP	-57	-827	-5,415	-85	-298	-9,686	0%	0%	0%
SERCNI	-11,147	2,912	14,481	-12,350	6,158	26,988	0%	47%	54%
E_CAN	-1,808	1,206	3,651	4,735	4,504	1,079	0%	27%	338%
IMO	-2,206	-185	2,029	2,199	1,241	-953	0%	0%	0%
New Eng.	-2,975	2,521	6,397	-2,405	3,524	7,949	0%	72%	80%
MHEB	826	392	-533	1,876	971	-1,033	44%	40%	0%
New York	-2,245	3,510	8,476	305	4,456	9,144	0%	79%	93%
Whole EI	-32,643	11,082	37,080	-18,107	26,583	49,930	0%	42%	74%
JCSP’08	-29,455	9,670	31,932	-26,916	19,868	50,837	0%	49%	63%

Table 5-41: 20% Wind Scenario Preliminary Transmission Overlay Economic Benefit Savings

Table 5-42 shows the top 25 interfaces with largest annual energy difference compared to the coppersheet case. With a preliminary transmission overlay, we can clearly see that the transfer capability needs on the AMRN-IN interface decreased from 27 GW to 15 GW. The average energy difference also decreased from 27 GW to 9 GW.

INTERFACE	Coppersheet Minus Pre-Overlay Constrained			Coppersheet Minus Overlay Constrained		
	Total Positive Energy (TWh)	Total Negative Energy (TWh)	Additional Transfer Needed to Deliver 80% Energy (MW)	Total Positive Energy (TWh)	Total Negative Energy (TWh)	Additional Transfer Needed to Deliver 80% Energy (MW)
AMRN - IN	235	0	26,878	90	-7	15,210
IN - OH	177	0	19,334	58	-3	9,211
OH-E_PJM	148	0	16,126	58	-5	9,998
SPP - EES	107	0	12,567	61	-5	10,743
AMRN - IOWA	0	-106	12,204	3	-36	6,087
New Eng. - New York	0	-88	10,331	1	-35	6,056
TVA - EES	0	-75	9,472	6	-40	7,661
SOUTHERN - TVA	0	-82	8,860	0	-38	5,715
IESO - New York	69	0	8,678	40	-2	6,551
New York - E_PJM	5	-55	8,430	19	-12	7,558
ATC - AMRN	69	0	8,068	29	-2	4,861
AECI - SPP	0	-61	7,866	2	-17	3,519
SPP - SPS	1	-37	7,174	0	-15	3,165
IESO - HQ	4	-41	7,098	6	-39	6,866
MINN - ATC	57	0	6,575	19	0	3,320
AMRN - TVA	42	0	4,691	14	-1	2,193
AMRN - AECI	2	-22	4,618	5	-5	1,884
MICH - IN	2	-28	4,568	11	-22	5,333
MICH - IESO	13	-12	4,184	5	-26	5,414
AECI - EES	37	0	3,976	6	0	916
SPP - AMRN	32	0	3,922	12	-2	2,218
MINN - IOWA	22	0	3,424	8	-3	2,724
MICH - OH	25	0	3,128	28	0	3,541
PJM - CPL	1	-14	2,998	1	-4	1,315
IOWA - SPP	6	-9	2,926	10	-2	2,692

Table 5-42: 20% Wind Scenario Preliminary Transmission Overlay Top 25 Interface Flow Change

Figure 5-55 is the interface contour map representing the annual energy difference between the coppersheet case and the overlay case. Compared to Figure 5-47, there are fewer red colored arrows, representing the decreased annual energy difference after the transmission overlay is applied.

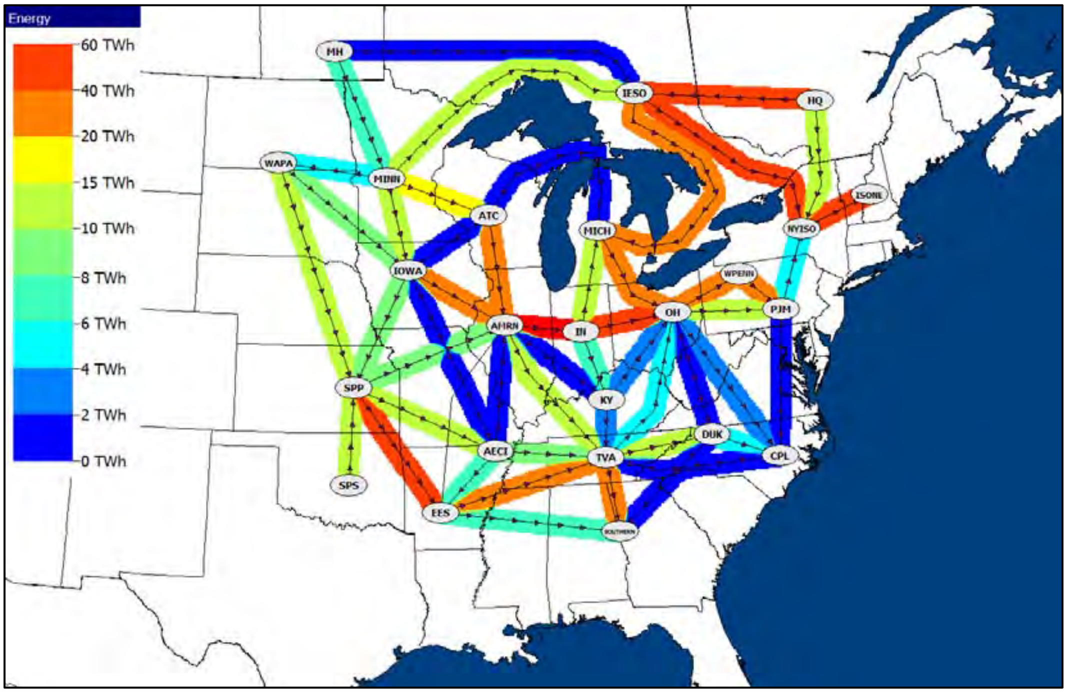


Figure 5-55: 20% Wind Interface Contour:
Annual Energy Difference Copper Sheet to Overlay Case

5.3.2.3 Overlay Iterations

Based on the preliminary transmission overlay results, another interim workshop was held in Cincinnati, OH. Comments and suggestions on further improvement of the transmission overlay were discussed in the workshop. After the workshop, several more iterations were performed trying to improve the B/C ratio of the transmission overlay.

Table 5-43 shows a flowchart of the iteration process.

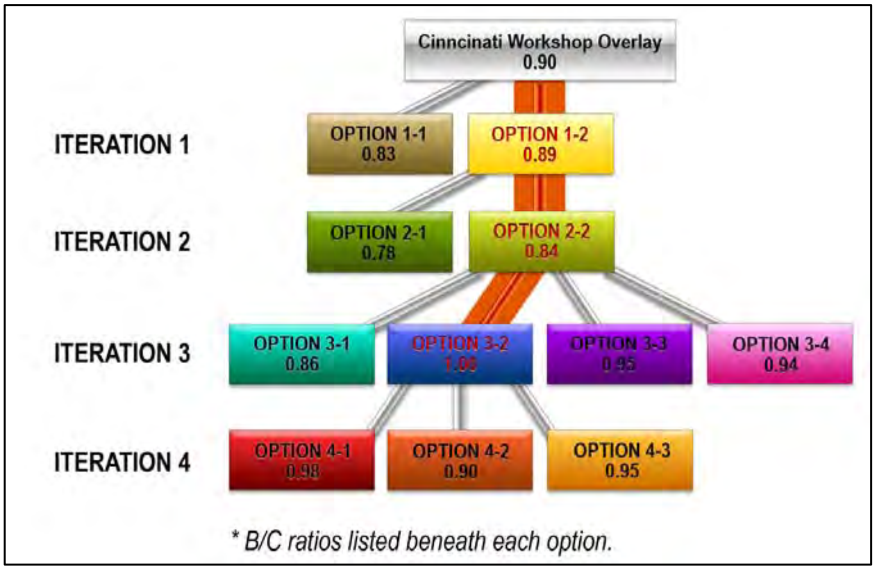


Table 5-43: 20% Wind Scenario Transmission Overlay Iteration Process

B/C ratios in Table 5-43 are calculated using the adjusted production cost saving numbers. Options highlighted in red represent the best B/C ratios for each iteration. A total of eleven PROMOD runs were performed for the iterations shown above. For the 20% Wind Scenario, each annual PROMOD run takes around 190 hours of run time and three hours of post-processing time.

Iteration 1

Iteration 1 is based on the preliminary transmission overlay presented in the Cincinnati Workshop:

- Option 1-1 (B/C ratio = 0.83)
  - All low voltage (below 220 kV) constraints were eliminated from the event file
  - Estimated cost to fix all low voltage constraints was assumed as 25% of the total overlay cost
- Option 1-2 (B/C ratio = 0.89)
  - Low voltage constraints were unchanged
  - A few light-loaded lines from the preliminary transmission overlay were removed
  - A third terminal, in Central and East Midwest ISO, was added for each of three DC lines to PJM, New York and New England

Iteration 2

Iteration 2 is based on option 1-2 modifications:

- Option 2-1 (B/C ratio = 0.78)
  - A 765 kV backup system was added in Iowa
  - DC line section from the Evans to Norwalk substation was removed
  - DC line section from the Lawton to Cajun substation was removed
  - A 765 kV AC line was added to replace the Lawton to Cajun DC line
- Option 2-2 (B/C ratio = 0.84)
  - A 765 kV backup system was added in Iowa
  - DC line section from the Evans to Norwalk substation was removed
  - The voltage class of the Lawton to Cajun DC line is lowered from 800 kV to 400 kV

Iteration 3

Iteration 3 is based on option 2-2 modifications:

- Option 3-1 (B/C ratio =0.86)
  - Another DC terminal at Tuco was added to the Lawton to Cajun 400 kV DC line
- Option 3-2 (B/C ratio = 1.0)
  - Another DC terminal at Tuco was added for the Lawton to Cajun 400 kV DC line
  - DC line section from the Evans to Norwalk substation was added back
- Option 3-3 (B/C ratio = 0.95)
  - Another DC terminal at Tuco was added for the Lawton to Cajun 400 kV DC line
  - DC line section from the Evans to Norwalk substation was added back
  - A 765 kV AC line from Barstow to Sullivan was added
- Option 3-4 (B/C ratio = 0.94)
  - Another DC terminal at Tuco was added for the Lawton to Cajun 400 kV DC line
  - DC line section from the Evans to Norwalk substation was added back, but the voltage class was lowered from 800 kV to 400 kV

Iteration 4

Iteration 4 is based on option 3-2 modifications:

- Option 4-1 (B/C ratio =0.98)
  - The voltage class of the DC line section from the Breed to Possum Point substation was lowered from 800 kV to 400 kV
  - The DC line middle terminal location was updated.
    (Breed to Sullivan, South Canton to Blue Creek)
- Option 4-2 (B/C ratio = 0.9)
  - The voltage class of the DC line section from the Breed to Possum Point substation was lowered from 800 kV to 400 kV
  - The DC line middle terminal location was updated.
    (Breed to Sullivan, South Canton to Blue Creek)
  - The voltage class of the Lawton to Cajun DC line was increased from 400 kV to 800 kV
- Option 4-3 (B/C ratio = 0.95)
  - The DC line middle terminal location was updated.
    (Breed to Sullivan, South Canton to Blue Creek)

Among all the options during the iteration process, option 3-2 provided the best B/C ratio as 1.0.

5.3.2.4 Overlay Iteration After the Carmel Workshop

The transmission overlay iteration processes were presented in an Oct. 2nd workshop in Carmel, Indiana. During the workshop, several more comments regarding the transmission overlay were received, including:

- Switching the DC terminal from the Byron to Collins Substation
- Switching the DC terminal from the Montgomery to Rockport substation
- Removing the upper part of the Michigan 765 kV loop: Cook to Keno and Keno to Sprague 765 kV line
- Adding a third terminal at Sprague for the Arrowhead to Norwalk DC line
- Replacing the La Cygne to Montgomery DC line with a La Cygne to Rockport 765 kV AC line

The above changes were then evaluated in another round of iteration under the different combinations listed below:

Iteration 5

Iteration 5 is based on option 3-2 modifications:

- Option 5-1 (B/C ratio =0.94)
  - A third terminal at the Sprague substation was added into the Arrowhead to Norwalk DC line
  - Two DC terminals switched location: Byron switched to Collins for the Kincaid to Possum Point DC line; Montgomery switched to Rockport for the La Cygne to Montgomery DC line
- Option 5-2 (B/C ratio = 0.97)
  - A third terminal at the Sprague substation was added into the Arrowhead to Norwalk DC line
  - Two DC terminals switched location: Byron switched to Collins for the Kincaid to Possum Point DC line; Montgomery switched to Rockport for the La Cygne to Montgomery DC line
  - The upper part of the Michigan 765 kV loop was removed: Cook to Keno 765 kV line and Keno to Sprague 765 kV line
- Option 5-3 (B/C ratio = 0.9)
  - The La Cygne to Montgomery DC line was removed
  - A 765 kV AC line from the La Cygne to Rockport substation was added to replace the La Cygne to Montgomery DC line
- Option 5-4 (B/C ratio = 0.94)
  - A third terminal at the Sprague substation was added into the Arrowhead to Norwalk DC line
  - Two DC terminals switched location: Byron switched to Collins for the Kincaid to Possum Point DC line; Montgomery switched to Rockport for the La Cygne to Montgomery DC line
  - The upper part of the Michigan 765 kV loop was removed: Cook to Keno 765 kV line and Keno to Sprague 765 kV line
  - Removed the middle terminal Breed from Kincaid to Possum Point DC line
- Option 5-5 (B/C ratio =0.94)
  - Two DC terminals switched location: Byron switched to Collins for the Kincaid to Possum Point DC line; Montgomery switched to Rockport for the La Cygne to Montgomery DC line

None of the five options in this iteration provides a higher B/C ratio than option 3-2.

5.3.2.5 Further discussion on wind delivery cost and curtailment threshold

As we mentioned at the beginning of Section 5.3.2.1, there are 92,000 MW of direct wind sales from SPP and Midwest ISO to SERC and PJM included in the 20% Wind Scenario. Appropriate transmission service would be necessary to deliver the direct wind sales. The overlay designed in the final option 3-2 served two purposes: direct wind sales and economic energy transfer. To capture the proper cost/benefit ratio of the transmission overlay, we need to subtract the cost of direct wind sales from the total transmission overlay cost. Since 92,000 MW of direct wind sales accounts for 38% of total wind (240,000 MW) sited in the 20% Wind Scenario, the cost for direct wind sales should range from 0% to 38% of the total transmission overlay cost. Considering the LFCR variation, we can calculate the B/C ratio for option 3-2 in Table 5-44:

	15% LFCR	25% LFCR
0% cost to direct wind sales	1	0.6
38% cost to direct wind sales	1.6	0.95

Table 5-44: Option 3-2 B/C Ratio Variation

The wind curtailment threshold in PROMOD can also impact our results. PROMOD models wind units as load modifier transactions with a sharply sloped "V" curve, which has a slope of about +/- $1,000/MW. The load modifier transactions will scale down the area loads and will not participate in the economic dispatch process. Only when the LMP prices go down to -$1,000/MW, the wind output at that location will be curtailed. Increasing the cut off price to $0/MW will increase the total wind curtailment as well as the system B/C ratio. We did the test on option 3-2 with both -$1000/MW and $0/MWH cut off price for wind generation. Table 5-45 shows the comparison of total wind curtailment:

20% Wind Total wind curtailment	at -$1000/MW	at $0/MW
Base case	16.93%	34.58%
Overlay case	2.10%	8.09%

Table 5-45: Option 3-2 Wind Curtailment Variation

With $0/MW curtailment price, we also recalculated the economic benefit and B/C ratio for option 3-2:

Pool	Achieved Benefits (overlay-constrained)			Achievable Benefits (coppersheet – constrained)			Efficiency		
	Net Gen. Rev. Inc. (M$)	Adj. Prod. Cost Saving (M$)	Load Cost Saving (M$)	Net Gen. Rev. Inc. (M$)	Adj. Prod. Cost Saving (M$)	Load Cost Saving (M$)	Net Gen. Rev. Inc. (%)	Adj. Prod. Cost Saving (%)	Load Cost Saving (%)
PJM	-6,666	3,464	17,251	-14,601	4,034	27,632	0%	86%	62%
Midwest ISO	3,634	2,136	-645	3,889	5,309	-6,048	93%	40%	0%
TVASUB	-1,687	1,744	4,488	-3,179	1,445	5,397	0%	121%	83%
MAPP	2,192	-214	-2,523	1,512	-4,761	-10,540	145%	0%	0%
SPP	1,852	789	-895	-85	-298	-9,686	0%	0%	0%
SERCNI	-6,508	5,385	15,250	-12,350	6,158	26,988	0%	87%	57%
E_CAN	-1,100	1,181	3,043	4,735	4,504	1,079	0%	26%	282%
IMO	-1,036	-154	1,714	2,199	1,241	-953	0%	0%	0%
New England	-1,633	2,247	5,548	-2,405	3,524	7,949	0%	64%	70%
MHEB	1,079	483	-612	1,876	971	-1,033	58%	50%	0%
New York	-645	3,300	7,764	305	4,456	9,144	0%	74%	85%
Whole EI	-10,518	20,362	50,383	-18,107	26,583	49,930	0%	77%	101%
JCSP'08	-9,462	18,852	46,238	-26,916	19,868	50,837	0%	95%	91%

Table 5-46 20% Wind Scenario final transmission overlay economic benefit savings ($0/MW wind curtailment)

From this table we see a dramatic increase of efficiency for the same transmission overlay design. The B/C ratio also increased from 1.00 to 1.70 without cost allocation and LFCR adjustment mentioned in table 7-44.

With transmission cost allocation and LFCR variation, the B/C ratio for $0/MW curtailment case is shown in Table 5-47:

	15% LFCR	25% LFCR
0% cost to direct wind sale	1.70	1.02
38% cost to direct wind sale	2.74	1.65

Table 5-47 Option 3-2 B/C ratio Variation with $0/MW wind curtailment

These results of the sensitivity can be used to determine what factors need to be refined to form a conclusion from the study. The cost of projects, the LFCR, the schedule of projects and the way wind generation is curtailed are key factors that need to be better defined.

Section 6: Issues of Importance

6.1 Carbon Implications

Scenario planning in the development of conceptual transmission can provide ancillary information associated with the scenarios studied. Of primary concern in today's power industry policy discussions is the reduction of green-house gasses, primarily carbon. A capacity expansion model, such as the Electrical Generation Expansion Analysis System (EGEAS), can demonstrate the impact of a chosen scenario on carbon production within the generation fleet over the study period.

The EGEAS model determines a capacity expansion in a defined system by selecting the least-cost optimal plan based on the assumptions and constraints entered into the model. Different economic and policy assumptions can result in significantly different capacity expansions. Those expansions will have an effect on total system costs as well as potential impacts on green-house gas production.

Through the JCSP'08, three scenarios were used in creating capacity expansions for the Eastern Interconnect: Reference, the 20% Wind Energy Mandate, and the 30% Wind Energy Mandate. For further information, Midwest ISO staff also provided an Environmental Scenario in which carbon production is taxed at $25/ton. As can be seen in Figure 6-1, the implementation of wind as a primary energy resource or the application of a cost for carbon will potentially reduce carbon output from the pooled generation fleets.

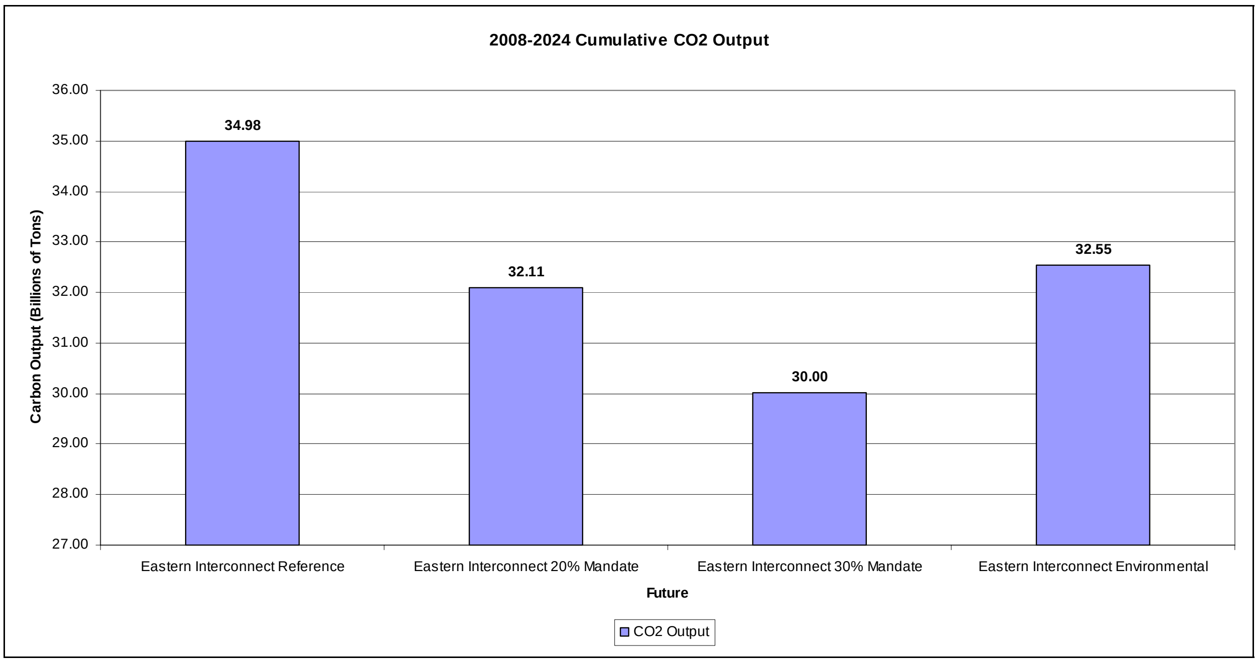


Figure 6-1: Accumulated Carbon output for defined scenarios.

Environmental Scenario performed by Midwest ISO staff and not a part of the JCSP'08 study)

Within the wind mandate scenarios modeled, wind energy and capacity replaces much of the base load steam expansion that can be seen in the Reference Scenario. By replacing this capacity as well as providing carbon neutral energy, a reduction of total carbon production is inherent. Within the Environmental Scenario modeled, the capacity expansion model replaces base load steam capacity with base-load, carbon-neutral nuclear capacity as the least-cost economic capacity expansions. This reduction of expanded base load steam units, along with the economic model dispatching less high carbon producing capacity because of the higher costs, results in the reduction of carbon production over the model study period versus what is produced in the Reference (status quo) case.

Carbon reduction is only part of the whole picture being analyzed within the JCSP’08 - it is an ancillary benefit of the primary objective. A carbon reduction scenario that focuses on a significant decrease in the production of greenhouse gasses over time will require further looks into a combination of solutions. Wind, potentially, is a partial answer and only gets the system so far. Including nuclear capacity, carbon sequestration technologies, and other methods to reduce carbon production while still maintaining a reliable, cost-effective system would need to be looked into in more detail.

Section 7: Appendices

Appendix 1: Cost Allocation Philosophies and Practices by Regional Transmission Organization (RTO)

	PJM -- Cost Allocation Philosophies and Practices	
	EXISTING	UNDER CONSIDERATION
PJM Reliability Upgrades	RTEP baseline facilities at or above 500 kV voltage level Also includes costs of those related facilities below 500 kV needed to support a 500 kV upgrade. Considered "Regional Facilities" by FERC – region-wide allocation. Load ratio share at the time of EACH ZONE's annual peak of previous year ending October 30. Merchant transmission is share based on firm transmission withdrawal rights, per respective Interconnection Service Agreements. Baseline BELOW 500 kV…allocation process pending before FERC with respect only to appropriate allocation to merchant transmission exports General If cost estimate < $5 million, costs allocated to zone where upgrade is required If cost estimate > = $5 million, costs allocated based on distribution factor (DFAX) analysis; DFAX percentages based on zonal load and merchant transmission firm withdrawal rights Lines, Transformers, etc. Allocate based on impact of each TO zone on the constrained facility, i.e. (change in power flow due to that TO zone)/total power shift on constrained facility) Circuit Breakers (CBs) If need associated with a planned transmission upgrade, allocate CB cost as part of that upgrade; If need is independent of any other planned transmission system upgrade, cost allocated to zone in which CB is located PJM/Midwest ISO Cross-border Transfer distribution factor (DFAX) analysis to calculate each RTO's flows affecting a constrained facility that a proposed cross-border facility is to relieve Total net flow of each RTO on a constrained facility, i.e. (all positive flow) less (all counterflow) After cross-border facility costs are allocated to each RTO, each RTO then allocates internally according to its own OATT.	Baseline BELOW 500 kV for cost assignment to merchant transmission Cost assignment for reliability upgrades awaiting FERC action in pending dockets. Merchant transmission developers believe that they should either have no cost allocation for future transmission system upgrades or that they should only have allocations for upgrades that are not related to load growth. Other parties believe that allocations to merchants should be based on firm withdrawal rights specified in ISAs.

PJM Economic Upgrades	PJM -- Cost Allocation Philosophies and Practices	
	EXISTING	UNDER CONSIDERATION
	AT OR ABOVE 500 kV Load ratio share at the time of EACH ZONE's annual peak of the previous year ending October 30. Merchant transmission share based on firm transmission withdrawal rights, per respective ISAs. BELOW 500 kV, modifications to reliability upgrades already in RTEP Cost allocation based on distribution factor methodology, as discussed above. BELOW 500 kV, accelerated reliability upgrades already in RTEP. Compare allocation factors based on: [1] DFAX; [2] LMP benefit over acceleration period based on load payments by LSEs; if differential >= 10%, use relative LMP benefit; otherwise, use DFAX methodology.	BELOW 500 kV, ECONOMIC ONLY. FERC, per a 7/29/08 order, required parties to file a methodology within one year. BELOW 500 kV for cost assignment to merchant transmission. Cost assignment for economic upgrades awaiting FERC action in pending dockets order.

	SPP -- Cost Allocation Philosophies and Practices	
	EXISTING	UNDER CONSIDERATION
SPP Reliability Upgrades	All voltage levels, upgrade cost > $100,000… 1/3 of revenue requirement for upgrade is allocated regionally via postage stamp rate. [per SPP OATT, Attachment J]. 2/3 allocated to zones based on each zone's share of incremental positive MW-mile benefits…yielding Base Plan Zonal Annual Transmission Revenue Requirement (BPZATRR), [per SPP OATT, Schedule 11] Each network load customer and TO charged (1/12) x (zonal load ratio share) x (BPZATRR).	
	SPP -- Cost Allocation Philosophies and Practices	
	EXISTING	UNDER CONSIDERATION
SPP Economic Upgrades	All voltage levels. Paid by the project sponsor. The sponsor is provided revenue credits for subsequent service SPP is able to sell because of the upgrades.	[Subject of pending August 15, 2008 SPP FERC filing.] 345 kV voltage level and above and certain lower voltage facilities under specific conditions. Region-wide cost allocation via postage stamp rate for economic upgrades if part of a balanced portfolio of economic upgrades (vs. project by project assessment of benefit). Balanced Portfolio of Economic Upgrades Balanced means a benefits/costs ratio >= 1.0, using adjusted production cost for determination of benefits. Adjusted Production Cost = Production Cost + Purchases - Sales Ten-year present value of zonal benefit should not be less than levelized revenue requirement via region-wide postage stamp rate. If a balanced portfolio of economic upgrades can not be found… Costs assigned to zones that are deficient in benefits are removed from the calculation of zonal rate and added to the region-wide postage stamp rate to balance costs and benefits. Helps to equalize economic capability across SPP footprint without charging more highly developed portions of the system with the cost of upgrades for less developed portions. More costs can be collected through a region-wide rate, less via zonal license plate rates. If all zones are currently at the same level of development, SPP is likely to develop a balanced portfolio based solely on transmission upgrades and, thus, transfers are not likely to be needed to provide balance. Production cost savings offset transmission rates paid by load. Profits that would otherwise be captured as a result of increased sales vis-à-vis increased transmission rates are refunded/credited back to load. No customers in SPP's footprint have retail choice at this date, or in the foreseeable future. The Balanced Portfolio allows each pricing zone and each state to claim a positive benefit, a significant political point. There is no requirement for a Balanced Portfolio each year. In a given year, should the cost become too great or not enough projects found then the year is simply skipped. The policy decision on the balanced portfolio was determined by SPP's Regional State Committee (RSC) through a stakeholder process

Midwest ISO Reliability Upgrades	Midwest ISO -- Cost Allocation Philosophies and Practices	
	EXISTING	UNDER CONSIDERATION
	Baseline Reliability Projects (BRPs) >= 345 kV: 20% per Postage Stamp based on load ratio shares; remaining 80% based on Line Outage Distribution Factor (LODF) calculation methodology used for sub-regional allocations. Baseline Reliability Projects of 100 kV to 344 kV: 100% of eligible cost is allocated to pricing zones based on LODF in terms of [LODF] x [Miles]. Sub-regional percentage share for a given pricing zone is calculated as the relative zonal share of the sum of absolute values. Generation Interconnection Project cost of network upgrades: 50% based on the same sub-regional and/or postage stamp allocation rules applicable for BRPs; remaining 50% assigned to the Interconnection Customer Interconnecting to American Transmission Company, International Transmission Company, Michigan Electric or ITC Midwest pricing zones: 50% to pricing zone; 50% to affected pricing zones based on sub-regional and/or postage-stamp allocation rules Transmission Delivery Service Projects: needed for new Point-To-Point Transmission Service, or new Network Resource designation…assigned to transmission customer until appropriate regulatory authority permits roll-in to existing transmission rates PJM/Midwest ISO Cross-border: transfer distribution factor (DFAX) analysis to calculate impact of each RTO's flows on constraint, based on Total Net Flow. Total Net Flow of each RTO on a constraint = (all positive flow) less (all counterflow) After allocation to each RTO, each RTO then allocates according to its own OATT.	[No modifications presently under consideration.]

<table>
<tr><td rowspan="3">Midwest ISO
Economic Upgrades</td><td colspan="2">Midwest ISO -- Cost Allocation Philosophies and Practices</td></tr>
<tr><td>EXISTING</td><td>UNDER CONSIDERATION</td></tr>
<tr><td>"<u>Regionally Beneficial Projects" (RBPs)</u>:
20% allocated on a system-wide rate to all transmission customers;
80% allocated to three defined sub-regions based on relative "weighted-gain-no-loss" value of positive present value of annual benefits…
70% weighted on adjusted production cost changes
30% on <u>Locational Marginal Price (LMP)</u> changes.
"Cost" eligibility: >= $5 million
"Voltage" threshold: >= 345 kV; and those under 345 kV needed to achieve benefit of associated upgrades over 345 kV
"Benefit" Eligibility for regional cost allocation:
(1) Present Value of annual benefits > 0;
(2) minimum specified benefit/cost ratio met based on in-service date…
Within 1 year… 1.2 : 1
Within 2 years… 1.4 : 1
Within 3 years… 1.6 :1
Within 4 years… 1.8 : 1
Within 5 years… 2.0 : 1
…increasing linearly up to 3.0 : 1 within 10 years</td><td>"…as experience with [RBPs] and additional value driver analytics mature, tariff filings to adjust or amplify the inclusion criteria and minimum benefits threshold are expected…additional value drivers might include generation reserve margin considerations, fuel diversity considerations, reliability considerations and national and state energy policy goals, and risks to implementation to name some that warrant consideration."</td></tr>
</table>

	NY -- Cost Allocation Philosophies and Practices	
	EXISTING	PENDING FERC APPROVAL
New York Reliability Upgrades	New York “all source” planning process. Reliability needs identified; solutions from marketplace solicited; transmission, generation and demand response on a level playing field. New York evaluates all proposed solutions against needs but does not pick any specific solution; explicit preference is given to market-based solutions. Regulated backstop solutions, provided by TOs, can be triggered if market-based solutions are not available. NYPSC reviews regulated backstops and alternative regulated proposals and determines which should go forward. Cost allocation philosophy…beneficiary pays.	[Subject of pending June 18, 2008 New York FERC Filing] Regulated Reliability Transmission Projects: Applicable to projects triggered prior to 1/1/2016, after which New York to propose continuation or another alternative approach. June 18, 2008 filing included 3-step approach based on scope of area that has requirement for installed capacity: (1) Locational Need; (2) Statewide need; (3) Bounded Region/Constrained Interface Need. Based on a 1-day-in-10-years loss-of-load-expectation standard and beneficiary pays principle; Locational Need: i.e., NYC and Long Island - 100% of costs allocated to LSEs in respective zone(s). Then, Step 2. Statewide Need: i.e., New York Control Area - reliability upgrades necessary to bring control area to 1-day-in-10 reliability, under UNCONSTRAINED system, i.e., all transmission constraints relaxed; allocation to all load zones in control area based on load ratio share of control area coincident peak; zonal credits for meeting locational capacity requirements where locational upgrade cost allocation offsets statewide reliability upgrade cost allocation. If Step 2 is invoked - i.e., upgrades triggered under this test – then methodology stops with this Step; otherwise move on to Step 3 Bounded Region/Constrained Interface Need: determine zones with binding interfaces, preventing sufficient capacity from being deliverable throughout the control area; “compensatory MW” added to bounded region based on greatest LOLE impact to reach 1-day-in-10 standard; successive iterations run until 1-day-in-10 is achieved across control area; compensatory MW are allocated to zones within a bounded region based on zonal contribution to control area coincident peak; “compensatory MW” are resources required to fulfill identified need and can be transmission, generation and/or demand response solutions. Regulated Reliability NON-TRANSMISSION Projects: “Costs…will be recovered by [Transmission Owners] and other developers in accordance with the provisions of …state law.” “Although the NY Public Service Commission has adopted a cost allocation mechanism that differs from the consensus methodology described [for TRANSMISSION, as above] it is the understanding of New York and NY TOs that the [commission staff] does not object to the consensus methodology for transmission projects….and that the staff will present that methodology to the NY PSC…for their consideration and adoption for NON-TRANSMISSION regulated reliability projects ”

	NY-ISO -- Cost Allocation Philosophies and Practices	
	EXISTING	PENDING FERC APPROVAL
New York Economic Upgrades	Current planning process includes a procedure for analysis and posting of historic congestion information to assist stakeholders in developing resource plans.	[Subject of pending December 7, 2007 New York FERC Order 890 compliance filing.] New York Congestion Assessment and Resource Integration Study ("CARIS"): New York analyzes potential solutions to congestion over a 10-year period based upon requests for studies prioritized by New York stakeholders. Will consider all resources as potential solutions. Threshold based upon statewide production cost savings compared to total estimated project revenue requirement over ten years. New York will also calculate zonal locational marginal cost based savings, losses, transmission congestion contracts and other metrics. Cost of regulated economic transmission projects allocated to load based on share of total savings. At least 80% of beneficiaries must vote in favor of the project in order to be eligible to receive regulated recovery under the New York tariff. Developer must file revenue requirements with FERC upon completion of project.

	New England -- Cost Allocation Philosophies and Practices	
	EXISTING […on or after January 1, 2004 per ISO-NE Open Access Transmission Tariff]	UNDER CONSIDERATION
New England Reliability Upgrades	Reliability Benefit Upgrades (RBU): 115 kV or above; Meet definition of Pool Transmission Facilities (PTF); And be included in Regional System Plan as either a Reliability Transmission Upgrade (RTU) or a Market Efficiency Transmission Upgrade (METU). RBUs are eligible for regional cost recovery as part of "Pool-Supported PTF costs". Must meet PTF definition based on ISO review of transmission plans submitted by market participants and TOs; ISO determines Localized Costs – "the costs of transmission upgrades that exceed reasonable requirements . . . shall be deemed Localized Costs." Localized Costs are not included in the Pool-Supported PTF costs. Determination based on ISO assessment of proposed engineering design and construction methods and practices, alternative upgrades, allowance for expansion and load growth, as well as relative costs, timing, implementation, efficiency and reliability of proposed upgrades. Pool-Supported PTF costs (i.e., those not localized) are allocated region-wide. RTUs: are those "…upgrades necessary to ensure the continued reliability of the New England Transmission System based on applicable reliability standards."	[No modifications presently under consideration.]

	ISO-NE -- Cost Allocation Philosophies and Practices	
	EXISTING […on or after January 1, 2004 per ISO-NE Open Access Transmission Tariff]	UNDER CONSIDERATION
New England Economic Upgrades	Market Efficiency Transmission Upgrade (METU) "upgrades designed primarily to provide a net reduction in total production cost to supply the system load." "[D]esigned to reduce bulk power system costs to load system-wide; …net present value of the reduction in bulk power system costs to load system-wide exceeds the net present value of the cost of the transmission addition or upgrade; …"bulk power system costs to load system-wide" includes, but is not limited to, the costs of energy, capacity, reserves, losses and impacts on bilateral prices for electricity." METU costs that meet RBU criteria are included in the Pool-Supported Costs. METUs that are not RBUSs are not included in the Pool-Supported PTF Costs. By definition, neither METUs or RBUs are "related to the interconnection of a generator," unless determined otherwise under Schedule 11.	[No modifications presently under consideration.]

ERCOT Reliability Upgrades	ERCOT -- Cost Allocation Philosophies and Practices	
	EXISTING	UNDER CONSIDERATION
	Costs allocated regionally to load and to power exports from ERCOT region, based on load-ratio share. Reliability upgrades include those to mitigate constraints both between and within established ERCOT sub-regions Specific transmission system improvements are evaluated for projected longer-term problems on the 345 kV network. Lines ordered as a result of the state's recently legislated Competitive Renewable Energy Zone (CREZ) process may supersede these projects.	[No modifications presently under consideration.]
ERCOT Economic Upgrades	**ERCOT -- Cost Allocation Philosophies and Practices**	
	EXISTING	UNDER CONSIDERATION
	In addition to identified reliability upgrades, significant uneconomic congestion would be experienced if these were the only improvements and upgrades implemented. ERCOT also identifies congested system elements and evaluate upgrades that would be economic in reducing the energy production cost for the system by relieving these congested elements. Costs for such upgrades are also allocated regionally to load and to power exports from ERCOT region based on load-ratio share. Lines ordered as a result of the state's recently legislated Competitive Renewable Energy Zone (CREZ) process may supersede these projects.	[No modifications presently under consideration.]

Cal-ISO Reliability Upgrades	Cal-ISO -- Cost Allocation Philosophies and Practices	
	EXISTING	UNDER CONSIDERATION
	For need as determined by the ISO for the following types of proposed transmission additions or upgrades, cost is borne by each Participating TO and reflected in its Transmission Revenue Requirement: Reliability driven projects Economically driven projects Long-term congestion revenue rights feasibility Costs recovered via Participating Transmission Owners (PTOs) revenue requirement through ISO administered charges; facilities at 200 kV and above: Transmission Access Charge (TAC) -- paid by Load Serving Entities based on pro-rata load share. Wheeling Access Charge (WAC) -- paid for transactions wheeled Out or Through ISO. Location Constrained Resource Interconnection Facility (LCRIF)… transmission projects to connect generators in designated transmission constrained areas; PTOs finance up-front costs; costs associated with the unsubscribed portion of the LCRIF will be included in TAC, until additional generators are interconnected, at which time costs will be assigned to such generators going forward on a pro-rata basis.	[No modifications presently under consideration.]

Cal-ISO Economic Upgrades	Cal-ISO -- Cost Allocation Philosophies and Practices	
	EXISTING	UNDER CONSIDERATION
	Economic Transmission Project proposals: include upgrades or additions proposed to reduce Local Capacity Area Resource requirements, reduce or eliminate Congestion, or Merchant Transmission Facilities to obtain Merchant Transmission Congestion Revenue Rights. Costs are recovered per the process described above for reliability upgrades. Merchant Transmission Facility: a transmission addition or upgrade whose costs are paid by a Project Sponsor that does not recover the cost of the transmission investment through the TAC or WAC or other regulatory cost recovery mechanism. Rather than obtain a recovery of costs through a regulated rate, the Project Sponsor of the Merchant Transmission Facility obtains Merchant Congestion Revenue Rights	[No modifications presently under consideration.]

Appendix 2: JCSP'08 PROMOD Cases and Assumptions

In JCSP'08, we developed PROMOD cases for each Scenario. The two Scenarios are Reference and 20% Wind Mandate. We used the same PowerBase database used in JCSP'08 process Step 1 and 2 as the basis for building the PROMOD cases. Therefore the following data used in PROMOD and Powerbase/EGEAS[1] are the same:

- Demand and Energy
- Generation Resources
- Generation Retirement
- Generation Variable Costs
- Generation Fixed Costs
- Generation Forced Outage Rate
- Generation Must Run Status
- Behind Meter Generation
- Split Units (Joint Own Units)
- Fuel Price
- Fuel Supply
- Environmental Allowance Costs
- Uneconomic Coal Retirement
- Uncertainty Variables definition for each Scenario

For detailed assumptions of these data, please refer to the assumption document of JCSP'08 Step 1 and Step 2. In this document, we focus on the assumptions specially used in PROMOD cases building.

New Generators Identified by EGEAS

In JCSP'08 Step 1 and Step 2, we did the resource forecasting for the whole Eastern Interconnection (except Florida) for the next 20 years (2008 to 2027). For each Scenario (Reference and 20% Wind Mandate), a set of new generators are identified. These units are sited based on the methodology developed by Midwest ISO together with our stakeholders. The resource forecasting is done region by region for the whole Eastern Interconnection. The list of the new generators for each region can be found in the appendices of the JCSP'08 Step 1 and Step 2 assumption document.

Power Flow Cases

For both Scenarios, the same power flow case was used to build the corresponding year's base case, i.e., both Scenarios have the same initial transmission system in that year. The 2018 power flow case was based on a 2018 Eastern Interconnection Reliability Assessment Group (ERAG) power flow model. The 2018 ERAG model was then reviewed and updated by all JCSP'08 parties including Midwest ISO, MAPP, SPP, PJM, TVA, New York and New England. The updated 2018 JCSP'08 power flow model was then used in both the 2018 Reliability and PROMOD studies. The initial transmission system in the 2018 and 2024 PROMOD models were the same. The generation and load in the 2018 PROMOD model were scaled up to match the 2024 values in the 2024 PROMOD model.

[1] Electrical Generation Expansion Analysis System (EGEAS)

PROMOD Study Footprint

The power flow cases used in PROMOD include the whole Eastern Interconnection. But, because of the limitations of PROMOD, we excluded Florida from the PROMOD study footprint. A fixed transaction, SETRANS sale to Florida, is modeled to capture the influence of Florida to the study footprint.

Because the Florida area is not in the study footprint, the hourly load will be kept the same for the study year. The generators in the Florida area will not be dispatched in the security constrained economic dispatch. In each hour, PROMOD simply scales the generations in Florida area up or down to match the load plus the fixed transactions values.

Pool Definition

A pool is an area in which all its generators are dispatched together to meet its loads. Hurdle rates are defined between pools to allow the energy exchange between pools.

A pool is formed by a set of companies. Normally, it represents an energy market, such as Midwest ISO or PJM. A study footprint will be broken into several pools based on the structure of the energy market. In JCSP'08 PROMOD case, eleven pools were defined in the study footprint: Midwest ISO, PJM, SPP, MAPP, SERCNI, TVASUB, MHEB, New York, New England, IESO and E_CAN.

Figure A2-1 shows all the companies modeled in the study footprint and which companies are included in each pool.

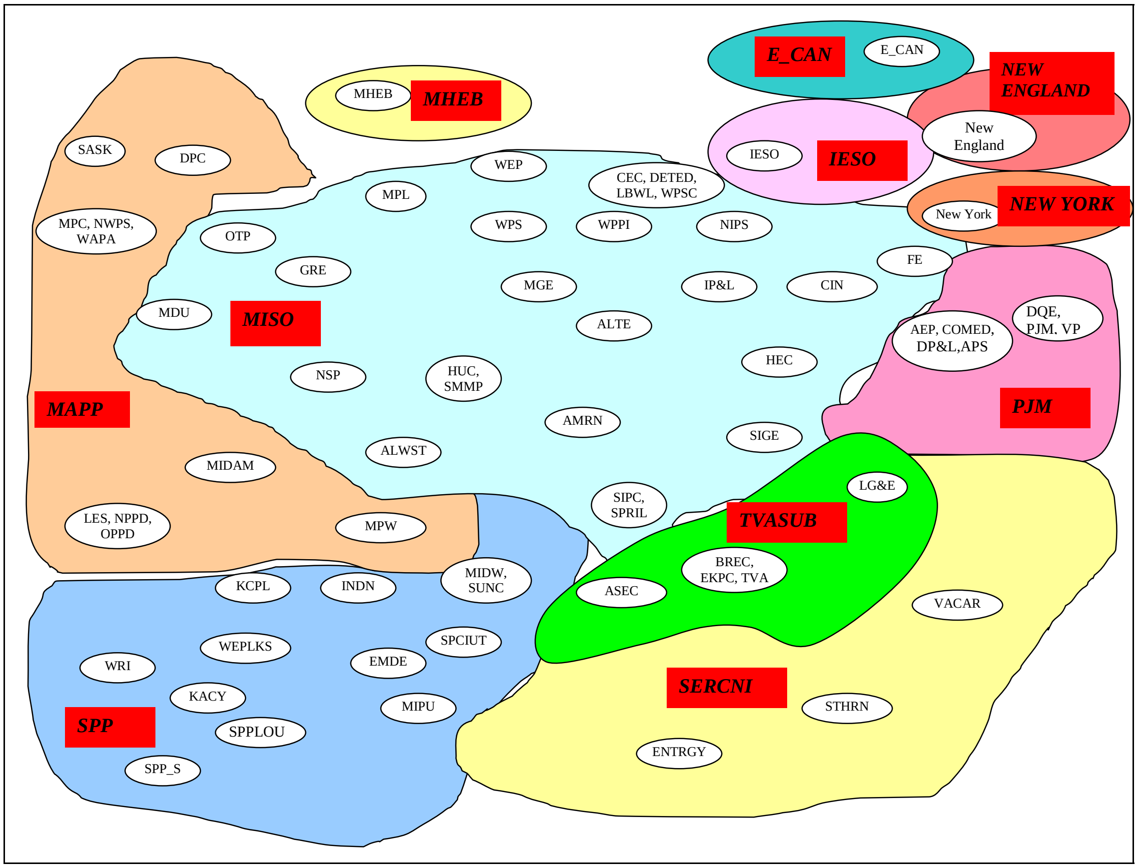


Figure A2-1: Companies and Pools in PROMOD Cases

Hurdle Rates

The hurdle rate will influence the capability of a pool to obtain support or sell energy to other pools. If two pools want to exchange energy, the difference of dispatch costs between the buying pool and the selling pool should be greater than the hurdle rate between them.

PROMOD performs the security constrained unit commitment and economic dispatch. So its solution includes two steps: the first step is unit commitment; the second one is economic dispatch. For each step, the user can define its own hurdle rate. The hurdle rate defined for the unit commitment step is called the commitment hurdle rate, and the hurdle rate defined for the economic dispatch step is called the dispatch hurdle rate.

Normally, users will set the commitment hurdle rate to be more expensive than the dispatch hurdle rate such that the pool units will be dispatched against its own pool load first in order to get the commitment order right and then allow pool interchange during the final dispatch via the dispatch hurdle rate.

There is no standard way to define the hurdle rates. Normally, hurdle rates are determined based on the filed transmission through-and-out rates, plus a market inefficiency adder.

In this study, the commitment hurdle rates are set as $10/MWH between all pools. Exception was Midwest ISO to MH, where we set the commitment hurdle rate as $0/MWH. The dispatch hurdle rates between pools are shown in Table A2-1.

	Dispatch Hurdle Rate ($/MWH) Peak/Off-Peak										
To->	PJM	Midwest ISO	TVASUB	MAPP	SPP	SERCNI	E_CAN	IMO	New Eng.	MHEB	New York
From											
PJM	*	2.5/2.5	4.8/4.8	4.8/4.8	N/A	4.8/4.8	N/A	N/A	N/A	N/A	7/7
Midwest ISO	2.5/2.5	*	7.6/5.4	7.6/5.4	7.6/5.4	7.6/5.4	N/A	7.6/5.4	N/A	0/0	N/A
TVASUB	6.5/4.5	8.3/8.3	*	N/A	8.3/8.3	8.4/5.7	N/A	N/A	N/A	N/A	N/A
MAPP	4.3/3.7	4.3/3.7	N/A	*	N/A	N/A	N/A	N/A	N/A	6.5/4.5	N/A
SPP	N/A	5.1/5.1	5.1/5.1	5.1/5.1	*	5.1/5.1	N/A	N/A	N/A	N/A	N/A
SERCNI	6.5/4.5	8.3/8.3	6.8/5.0	N/A	8.3/8.3	*	N/A	N/A	N/A	N/A	N/A
E_CAN	N/A	N/A	N/A	N/A	N/A	N/A	*	N/A	5/5	N/A	5/5
IMO	N/A	10.5/8.5	N/A	N/A	N/A	N/A	N/A	*	N/A	10.5/8.5	6.5/4.5
New England	N/A	N/A	N/A	N/A	N/A	N/A	5/5	N/A	*	N/A	5/5
MHEB	N/A	0/0	N/A	11.6/7.3	N/A	N/A	N/A	11.4/7.1	N/A	*	N/A
New York	5/5	N/A	N/A	N/A	N/A	N/A	5/5	7/5	5/5	N/A	*

Table A2-1: Hurdle Rate

Losses

There are three options to treat losses in PROMOD. They are:

- **Option 1:** Load in PROMOD equals actual load plus the loss. Losses and Locational Marginal Pricing (LMP) loss component are not calculated by PROMOD.
- **Option 2:** Load in PROMOD equals actual load plus the loss. Losses are not calculated by PROMOD. LMP loss component is calculated by PROMOD in an approximation method.
- **Option 3:** Load in PROMOD equals actual load. PROMOD calculates losses and the LMP loss component through dynamic iteration. This is sometimes called "marginal loss" calculation method. But this option will triple the run time and will only be used in some special studies in which you need to accurately calculate the loss.

We used Option 2 is this study.

Generation Outage and Maintenance

For a specified time interval, generally one year, PROMOD can generate an outage library for all units by using random number generators. There are actually two components to that construction. First, the random-number process determines whether or not a forced outage will occur, using a unit's mean-time-to-failure function. If so, a secondary process establishes the length of that outage, using the unit's mean-time-to-repair function.

PROMOD also can automatically schedule maintenance to conform to the maintenance cycle requirements of each unit. It will automatically schedule maintenance to provide for the best overall system reliability. The criteria for determining the best time is the minimization of risk in terms of loss-of-load for any given week.

The generation outage and maintenance have a big influence on the economic analysis. In our study, the main purpose is to analyze the economic benefit brought by the new transmission. We do not want to see any noise in the benefit value incurred by generation outage and maintenance. So for each Scenario's PROMOD case, we only generate the outage library and maintenance schedule one time. Then we will use the same generation outage library and maintenance schedule for later runs.

Transmission Outage

In the JCSP'08 PROMOD cases, we did not consider the transmission outage. The status of the transmission lines and transformers are the same as in the corresponding power flow case.

Operating Reserve Requirement

Operating reserve requirement can be divided into two parts: quick start and spinning reserve. Since the quick start reserve requirement can be easily met by installed combustion turbine generators, we only consider the spinning reserve requirement in our study.

For companies in the Midwest Contingency Reserve Sharing Group, we used its latest contingency reserve requirement (year 2008) as the contingency reserve requirement for Year 2013, 2018 and 2024. Forty percent of these contingency reserve requirements are spinning reserve requirements. For the regulatory reserve requirement, we assumed it is 1% of the load, and all are spinning reserve requirements. Table A2-2 shows the 2024 spinning reserve requirements for the Midwest Contingency Reserve Sharing Group companies. In the PROMOD case, we assume the Ancillary Service Market in Midwest ISO is up, so Midwest ISO serves as a single Balance Authority.

	2008 Contingency Reserve Requirement (MW)	2024 Spinning Reserve Requirement (MW)*
DPC	12	16.95
LES	10	15.2
MIDAM	65	88.28
MPW	2	2.92
NPPD	39	48.13
OPPD	33	44.65
WAPA	38	58.64
MHEB	55	87.57
BREC	21	18.09
EKPC	38	60.49
LG&E	95	134.41
Midwest ISO	1500	2,271.43 #
* Spinning Reserve = 40%* Contingency Reserve Requirement + 1% Load (Regulate Reserve Requirement) # Midwest ISO added 250 MW head room		

Table A2-2: Spinning Reserve Requirements for MCRSG Companies

For other regions, the reserve requirement data are either from original Ventyx PowerBase database, or from the Joint Coordinated System Planning (JCSP'08) group. Table A2-3 shows the reserve requirements of other regions and the source of the data. Each region is modeled as a Balance Authority in PROMOD case, i.e., the reserve requirement is met in region level, not the company level.

	Operational Reserve	Spinning Reserve	Source
	(Negative: MW, Positive: % of Load)		
ENTRGY	4.35	50	Ventyx PowerBase
HQ	-1,819.4	50	Ventyx PowerBase
IMO	-881	50	Ventyx PowerBase
New England	-1,158	50	JCSP'08 Group
New York	-1,200	50	Ventyx PowerBase
PJM	-3,350	100	JCSP'08 Group
SPP	-1,539	50	JCSP'08 Group
STHRN	4	50	JCSP'08 Group
TVASUB	-1,750	23	JCSP'08 Group
VACAR	-1,139.7	50	Ventyx PowerBase

Table A2-3: Reserve Requirements for Other Regions

Wind Modeling

In the JCSP'08 study, a lot of new wind generators were added in all four Scenarios. Variability and uncertainty are the two attributes of wind generation that cause most of the concerns related to power system operations and reliability. Wind energy output varies from seconds to hours, days and seasons. Because wind generation is driven by the same physical phenomena that control the weather, the uncertainty associated with the prediction of wind generation level at some future hour, maybe even the next hour, is significant.

Wind is not a dispatchable resource in PROMOD. The default wind generation model in PowerBase is a constant power output at a certain capacity factor (15% summer/20% winter), and then translated into PROMOD as load modifier transactions. This method is inaccurate and cannot reflect the high variability and uncertainty of the wind generators.

The hourly wind profile is used to model wind generation in the study footprint. For every existing and planned wind generator in PowerBase, a specific hourly pattern is applied to it according to the location of the generator. These generators are then translated into PROMOD as load modifier transactions. In the second phase of the JCSP'08 study, the latest hourly wind profile data is collected by the National Renewable Energy Lab (NREL) for new wind power development in 2004-2006.

Event File

Monitored flowgates in PROMOD constitute an "event file". The source for this event file is the Midwest ISO *Book of Flowgates* and North American Electrical Reliability Corp. (NERC) *Book of Flowgates*. Certain flowgates may have operating guides associated with them in real time operations. Hence the "event file" is scrubbed to remove any flowgates that might have an operating guide associated with them.

Appendix 3: Regional Expansion Results

Entergy Region Expansion Results

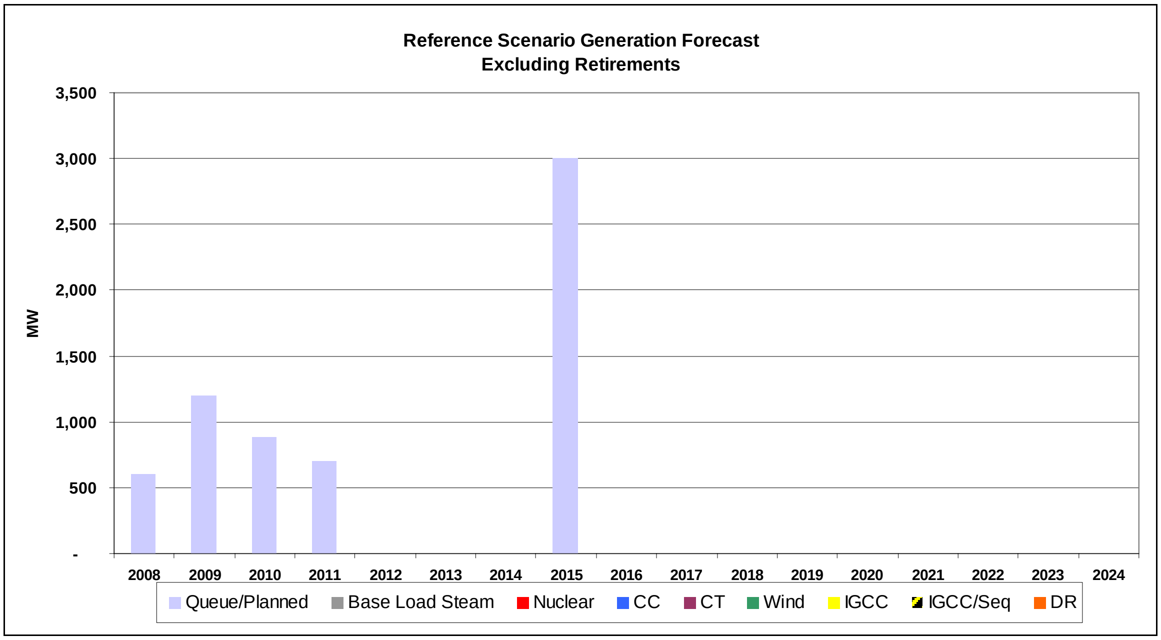


Figure A3-1: Annual Reference Scenario Forecasts Including Committed Capacity Not Yet In Service.

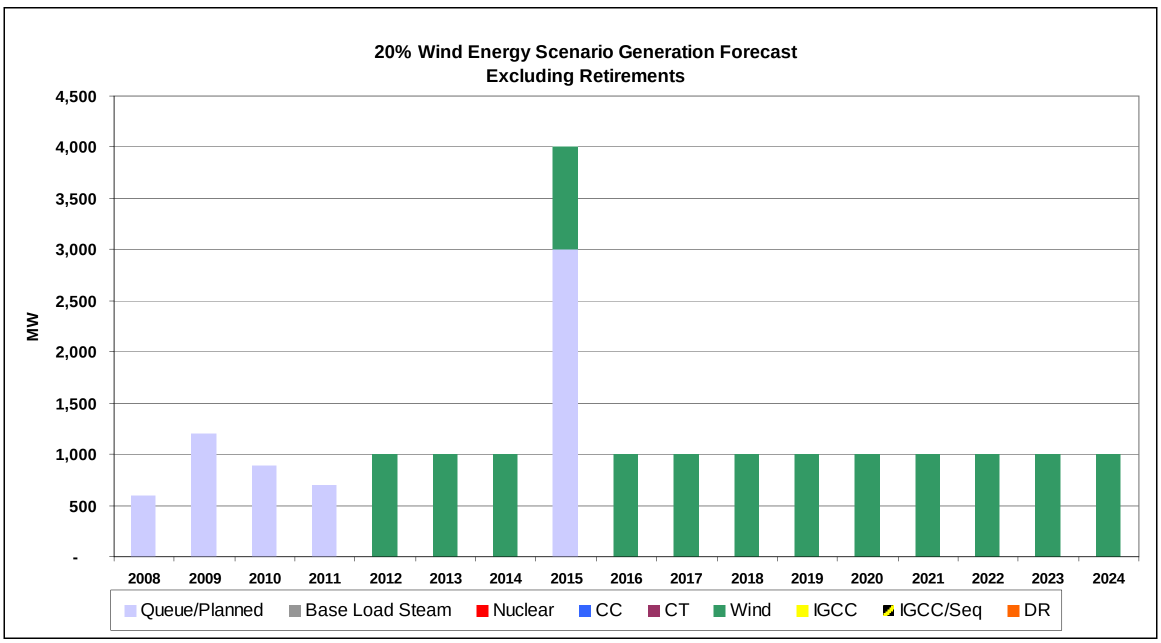


Figure A3-2: Annual 20% Wind Energy Scenario Forecasts Including Committed Capacity Not Yet In Service.

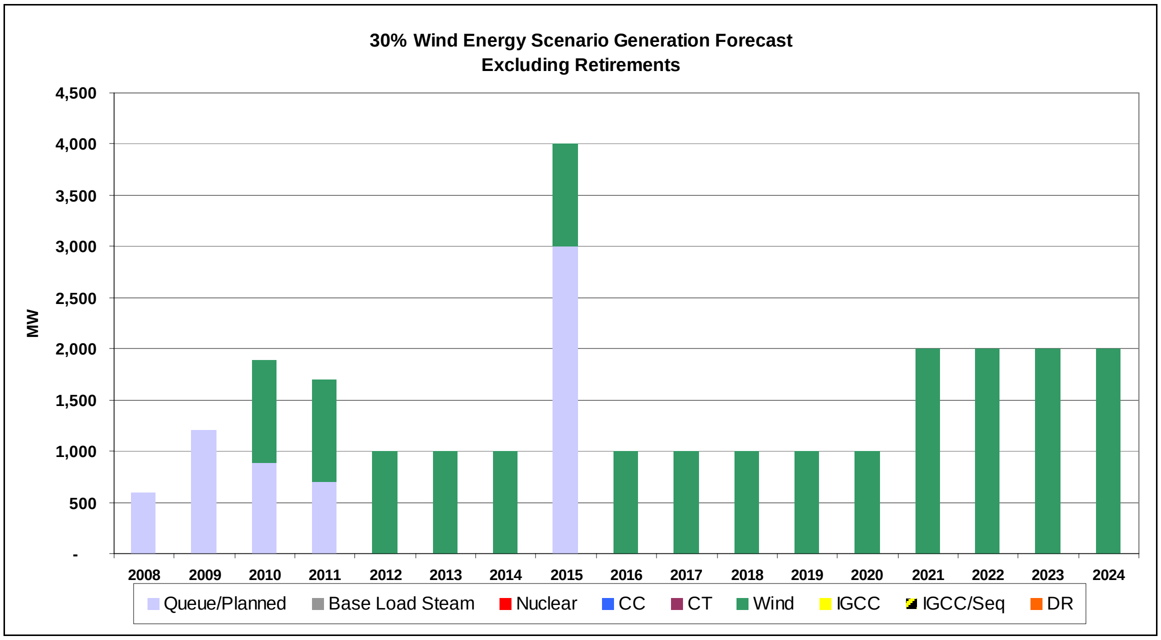


Figure A3-3: Annual 30% Wind Energy Scenario Forecasts Including Committed Capacity Not Yet In Service.

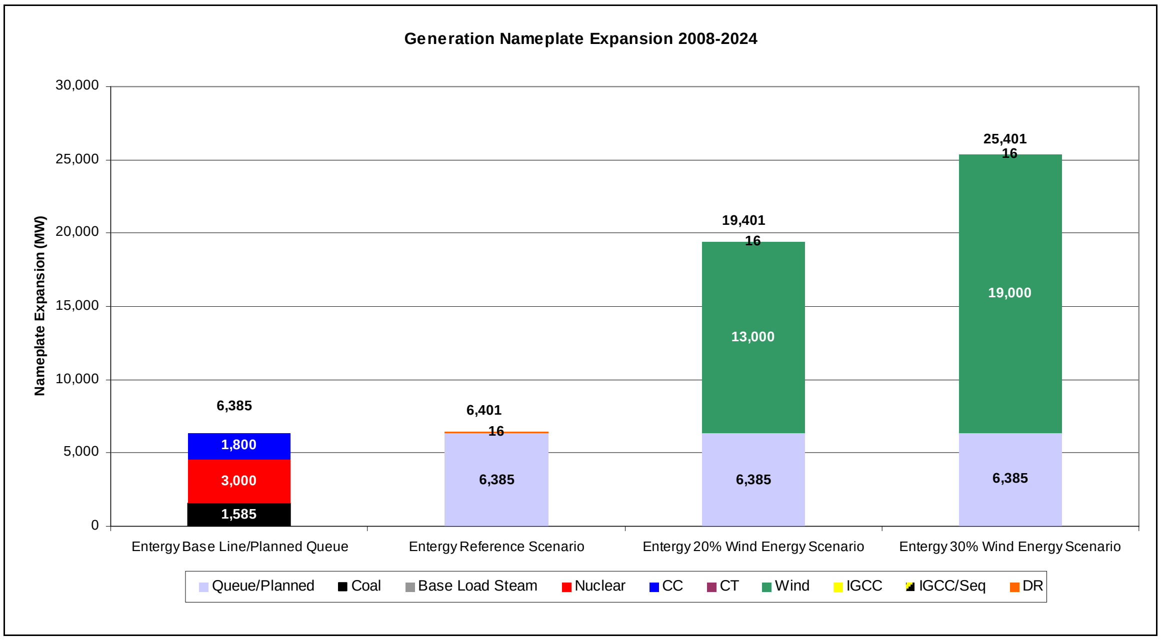


Figure A3-4: Total Nameplate Capacity Forecast with Queue Capacity Identified.

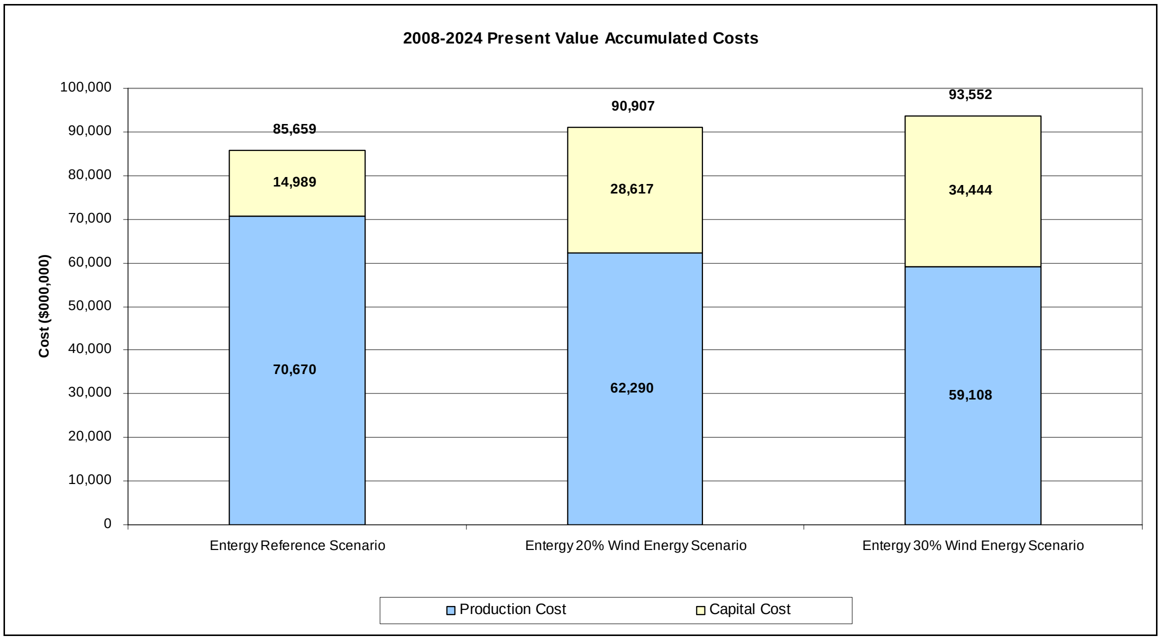


Figure A3-5: Region Accumulative Present Value Costs through 2024.

IESO Region Expansion Results

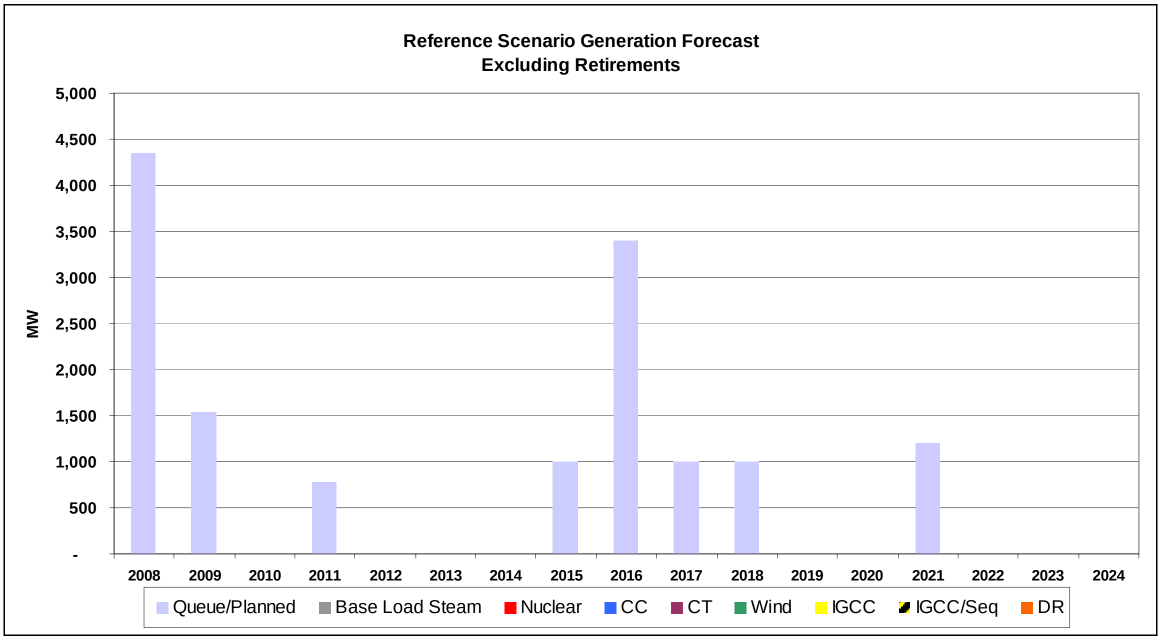


Figure A3-6: Annual Reference Scenario Forecasts Including Committed Capacity Not Yet In Service.

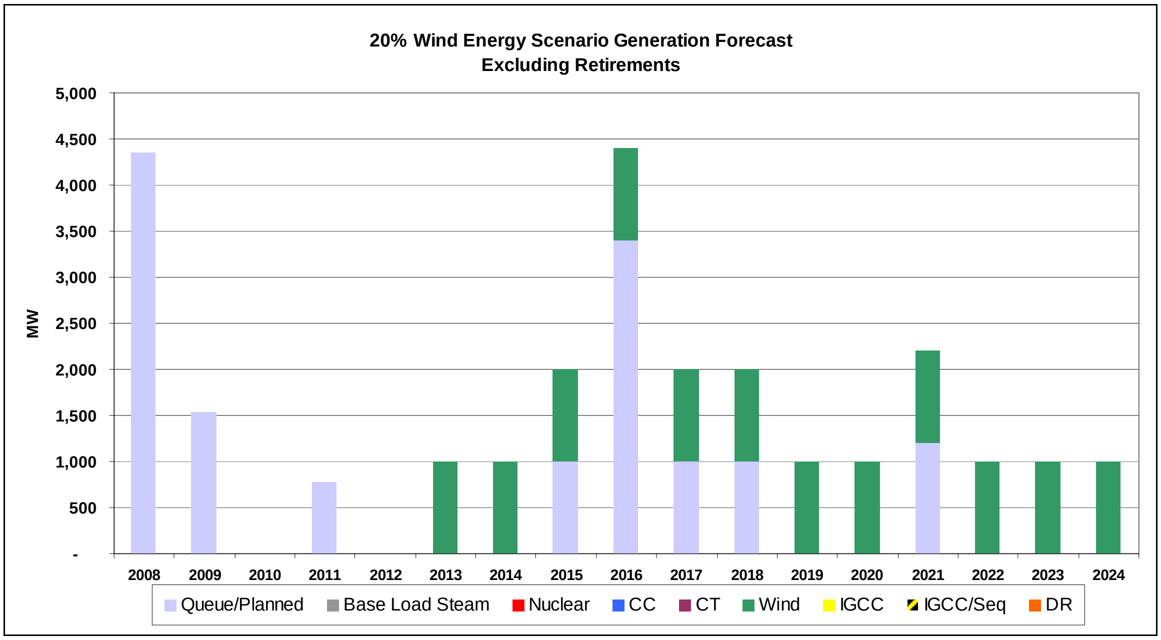


Figure A3-7: Annual 20% Wind Energy Scenario Forecasts Including Committed Capacity Not Yet In Service.

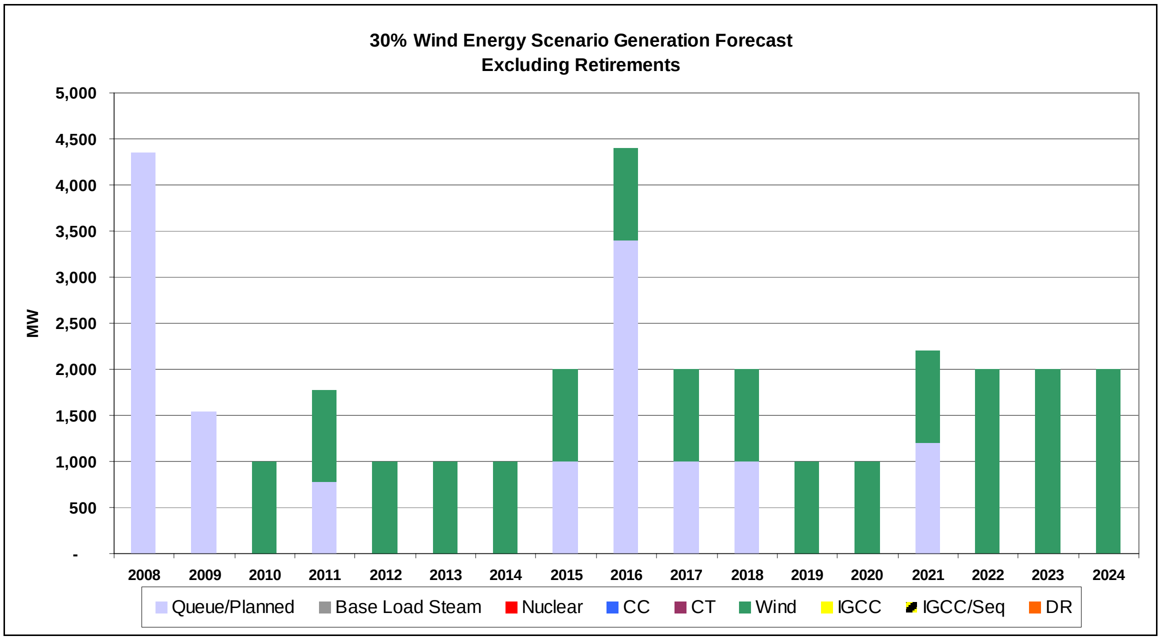


Figure A3-8: Annual 30% Wind Energy Scenario Forecasts Including Committed Capacity Not Yet In Service.

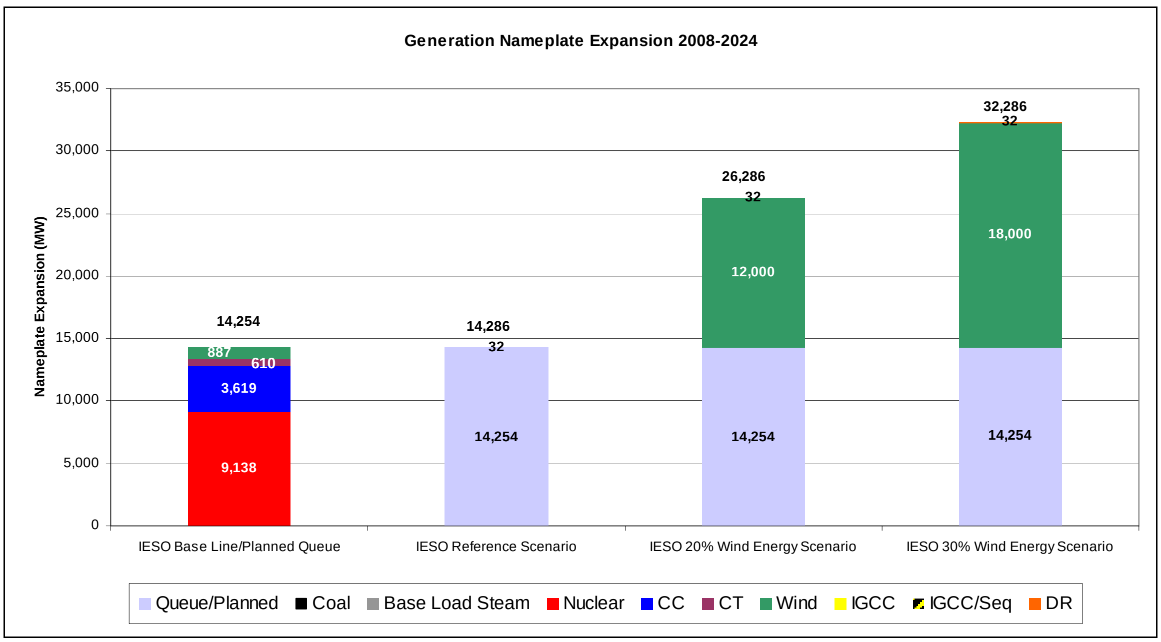


Figure A3-9: Total Nameplate Capacity Forecast with Queue Capacity Identified.

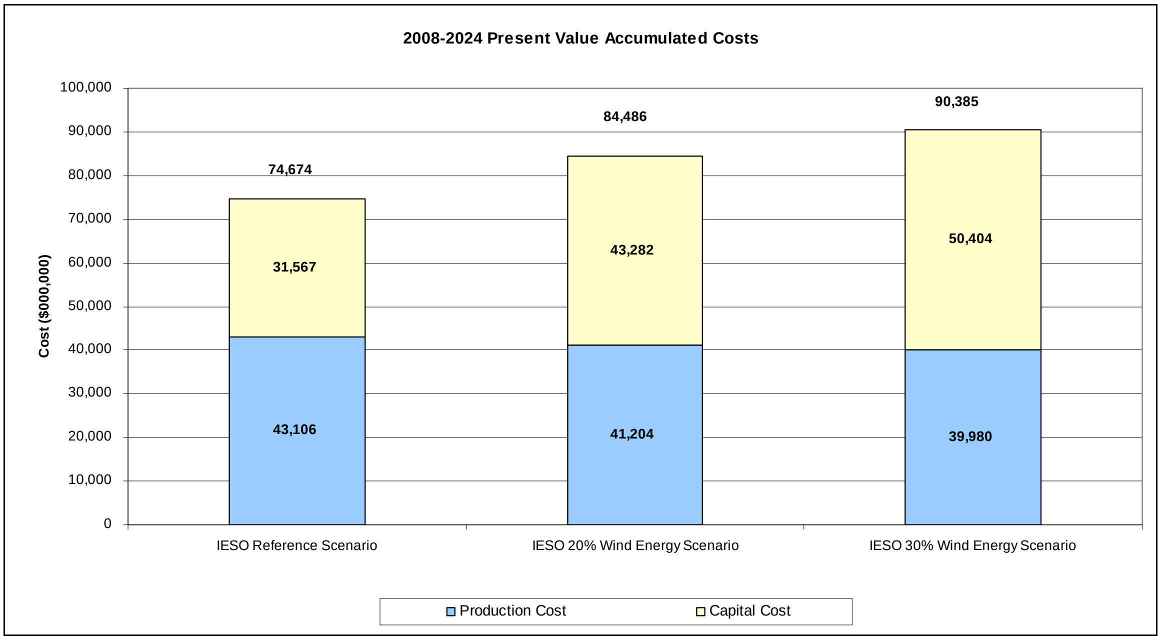


Figure A3-10: Region Accumulative Present Value Costs through 2024.

New England Region Expansion Results

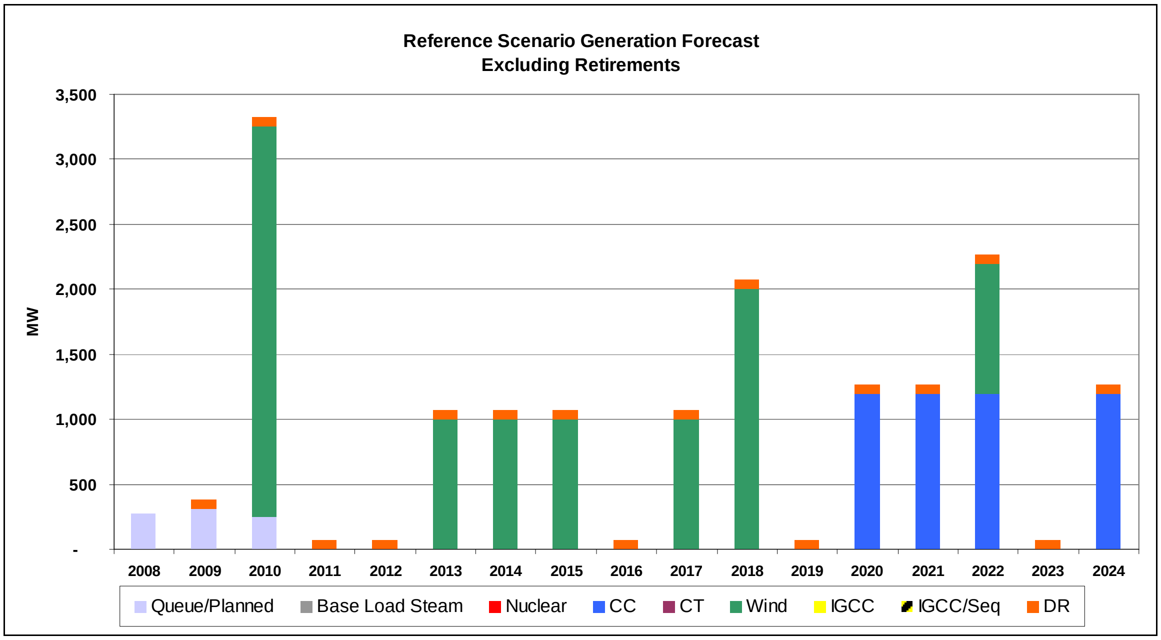


Figure A3-11: Annual Reference Scenario Forecasts Including Committed Capacity Not Yet In Service.

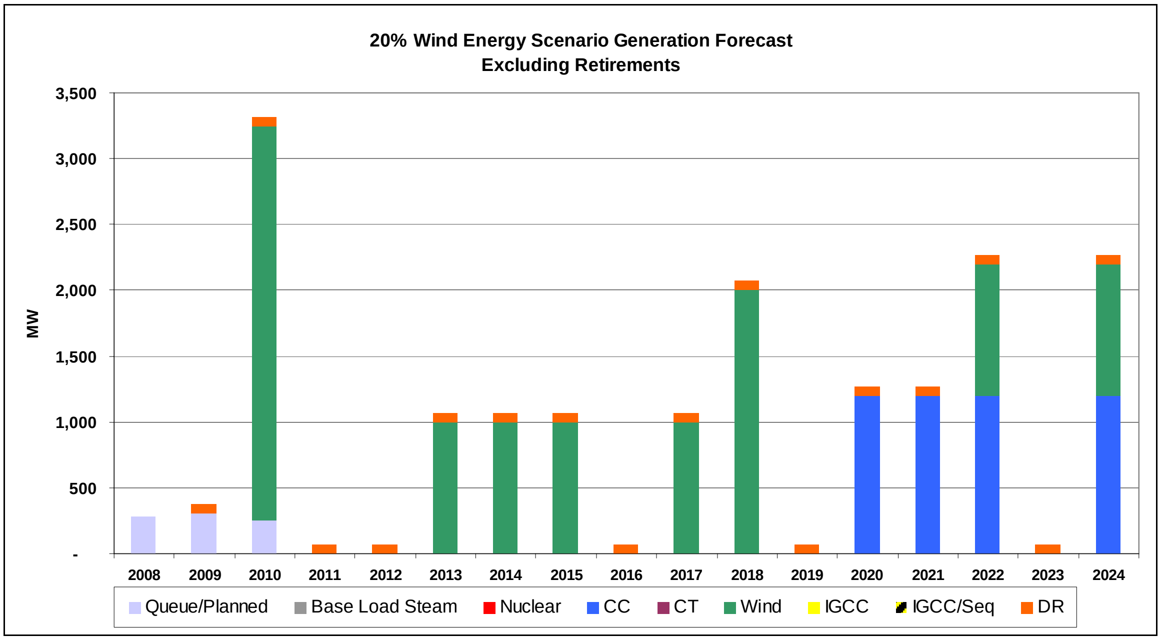


Figure A3-12: Annual 20% Wind Energy Scenario Forecasts Including Committed Capacity Not Yet In Service.

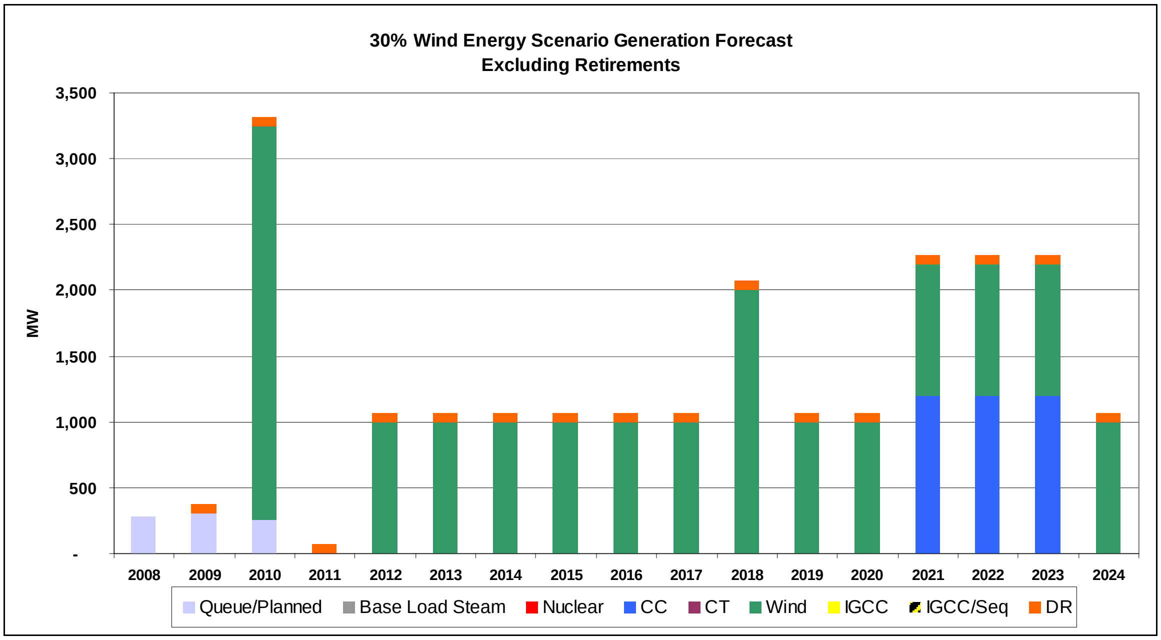


Figure A3-13: Annual 30% Wind Energy Scenario Forecasts Including Committed Capacity Not Yet In Service.

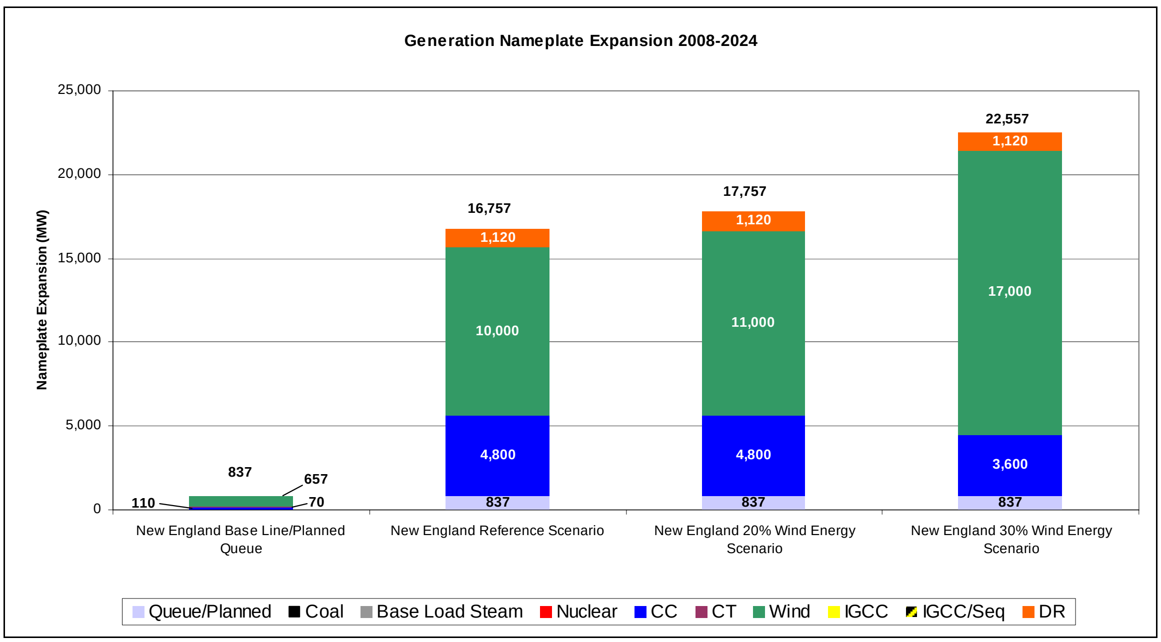


Figure A3-14: Total Nameplate Capacity Forecast with Queue Capacity Identified.

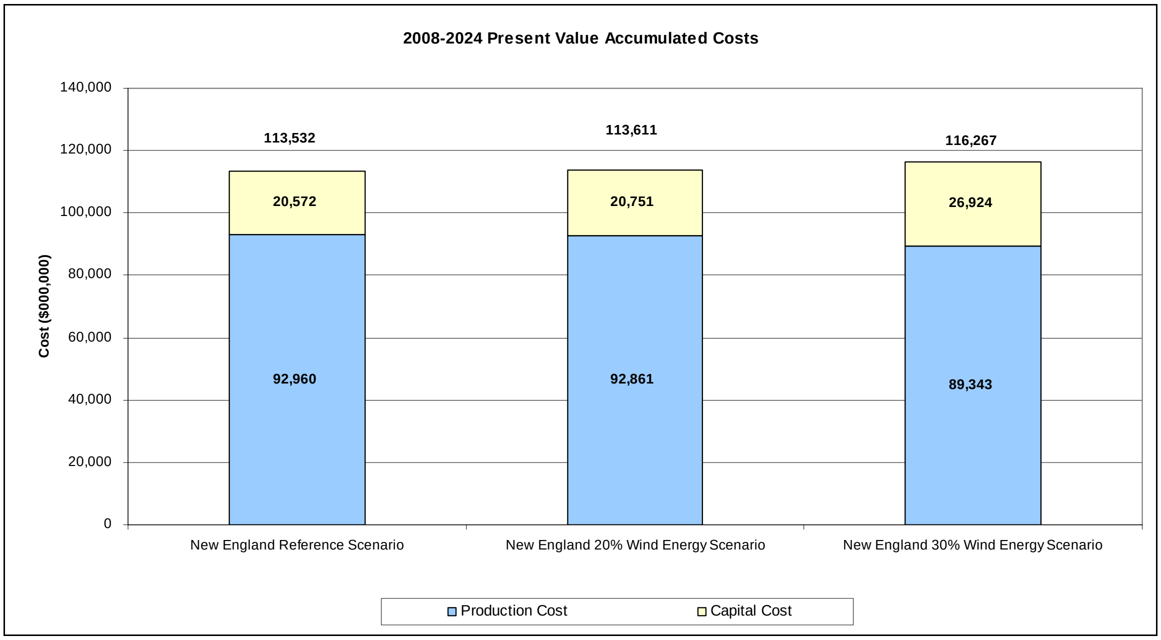


Figure A3-15: Region Accumulative Present Value Costs through 2024.

MAPP Region Expansion Results

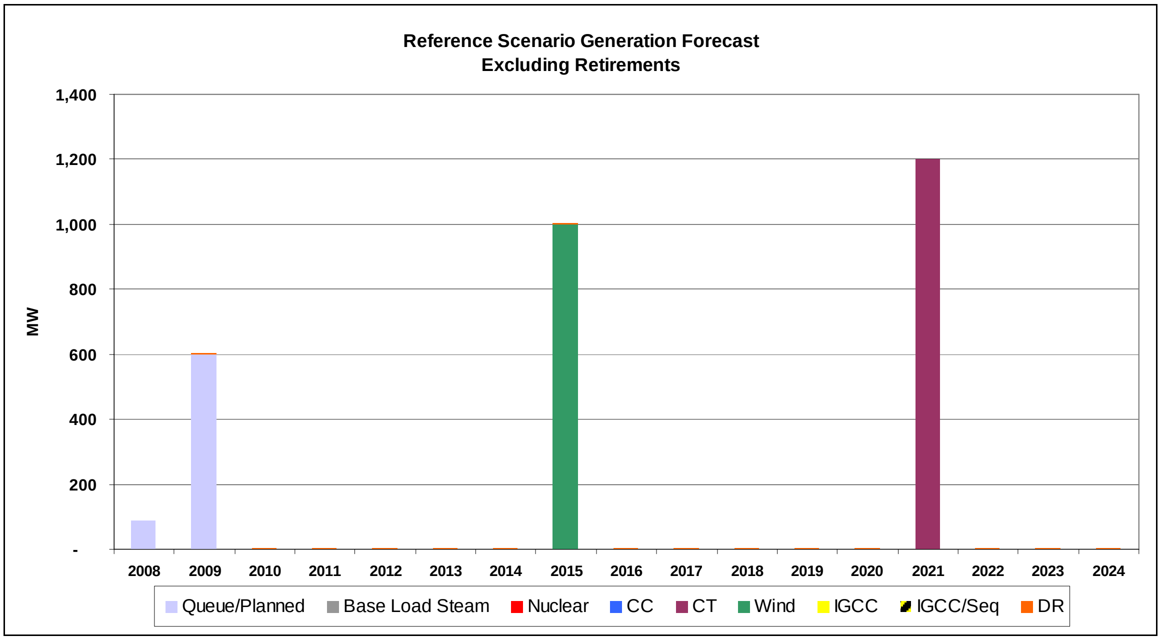


Figure A3-16: Annual Reference Scenario Forecasts Including Committed Capacity Not Yet In Service.

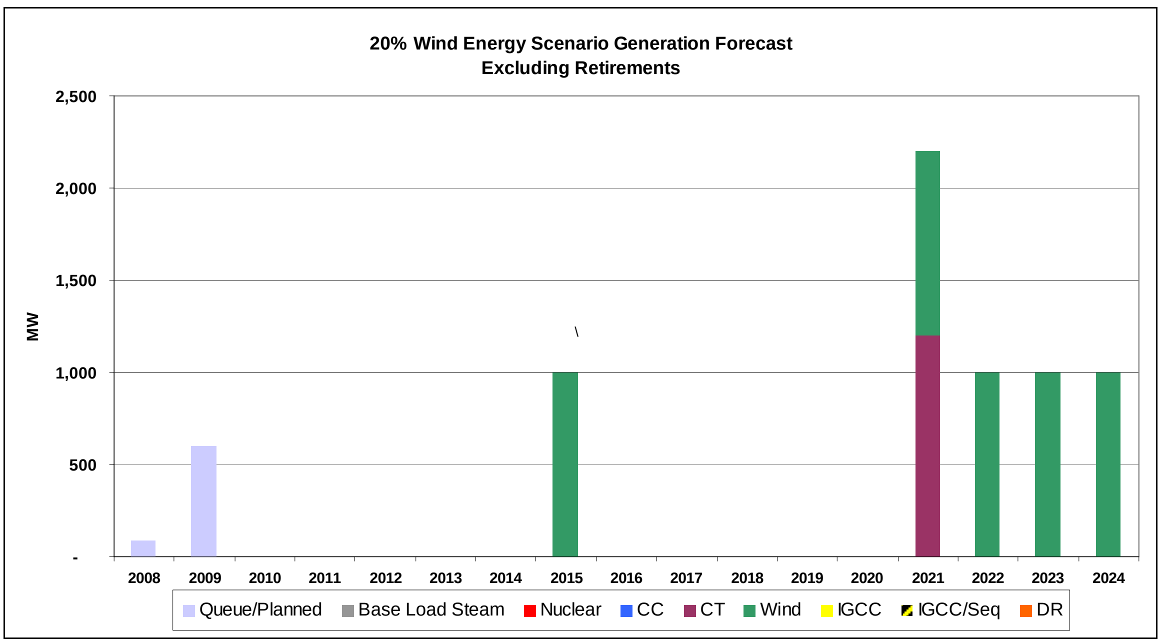


Figure A3-17: Annual 20% Wind Energy Scenario Forecasts Including Committed Capacity Not Yet In Service.

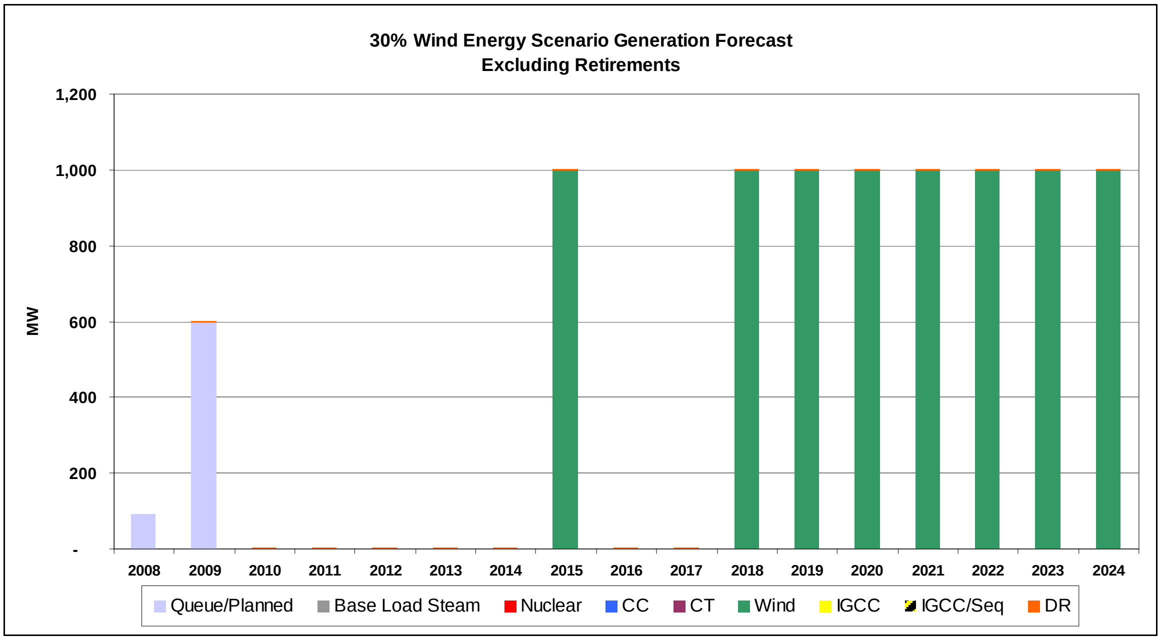


Figure A3-18: Annual 30% Wind Energy Scenario Forecasts Including Committed Capacity Not Yet In Service.

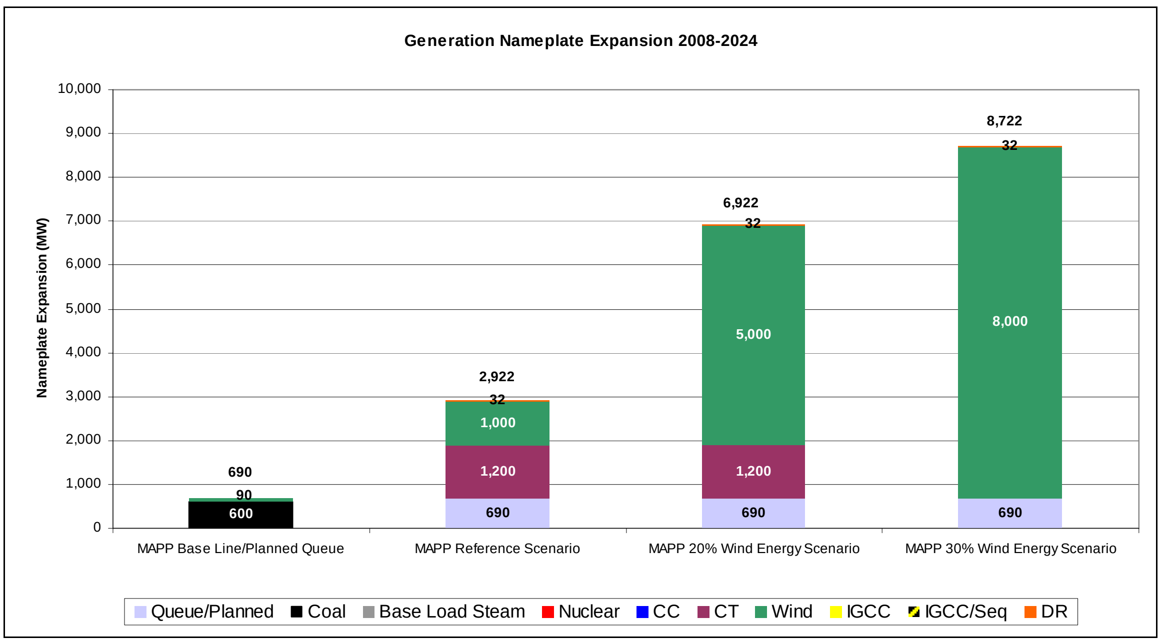


Figure A3-19: Total Nameplate Capacity Forecast with Queue Capacity Identified.

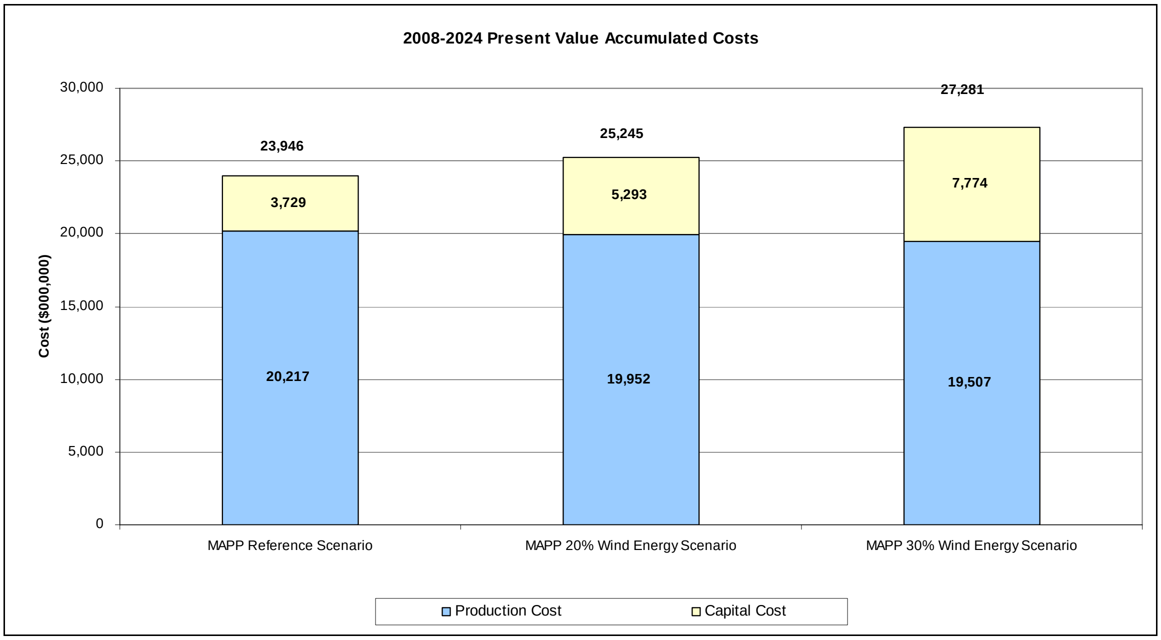


Figure A3-20: Region Accumulative Present Value Costs through 2024.

Midwest ISO Central Region Expansion Results

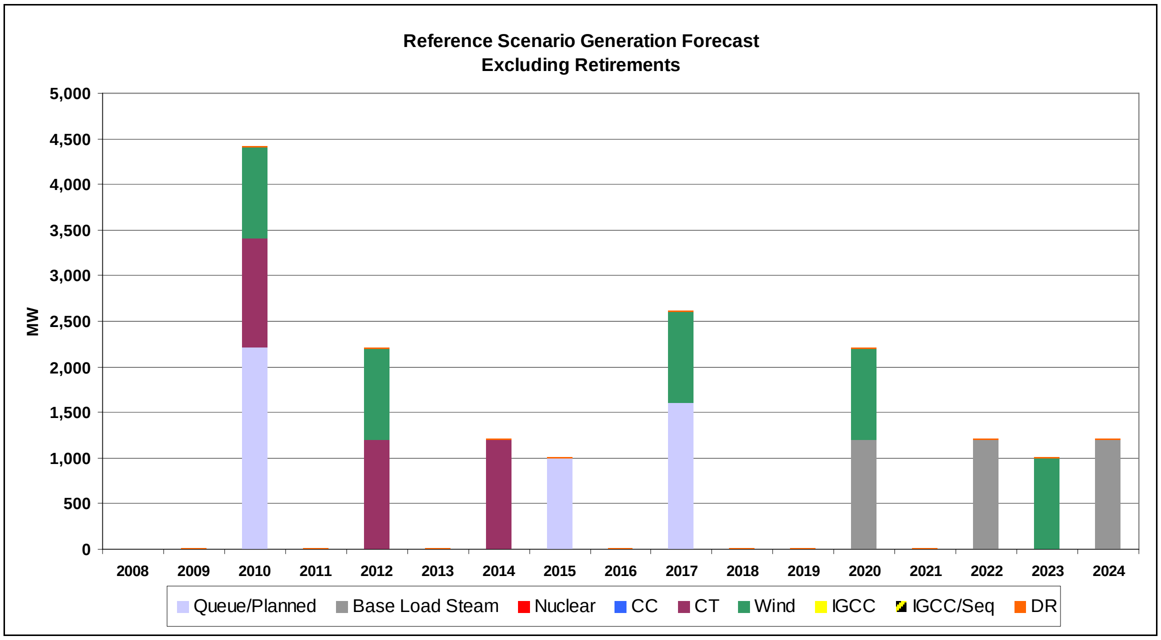


Figure A3-21: Annual Reference Scenario Forecasts Including Committed Capacity Not Yet In Service.

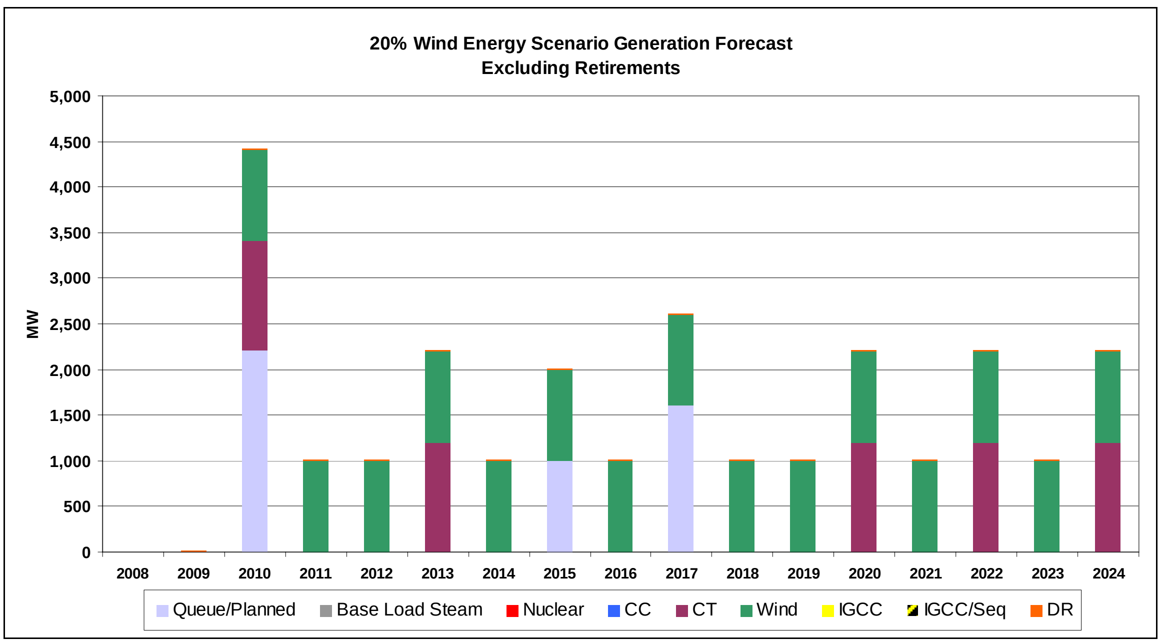


Figure A3-22: Annual 20% Wind Energy Scenario Forecasts Including Committed Capacity Not Yet In Service.

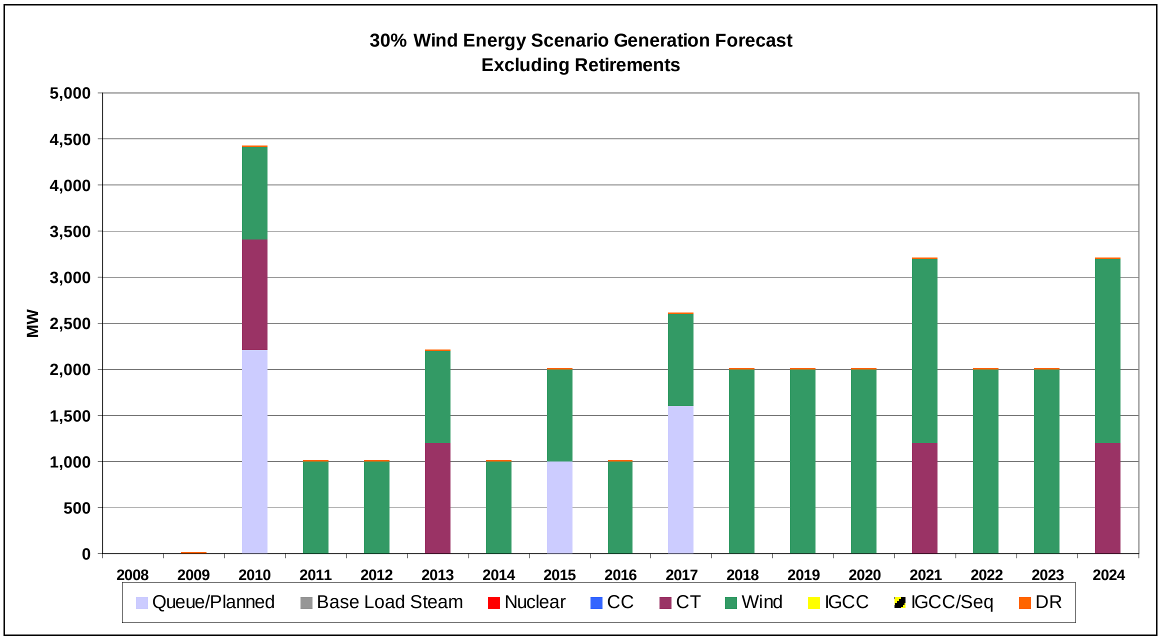


Figure A3-23: Annual 30% Wind Energy Scenario Forecasts Including Committed Capacity Not Yet In Service.

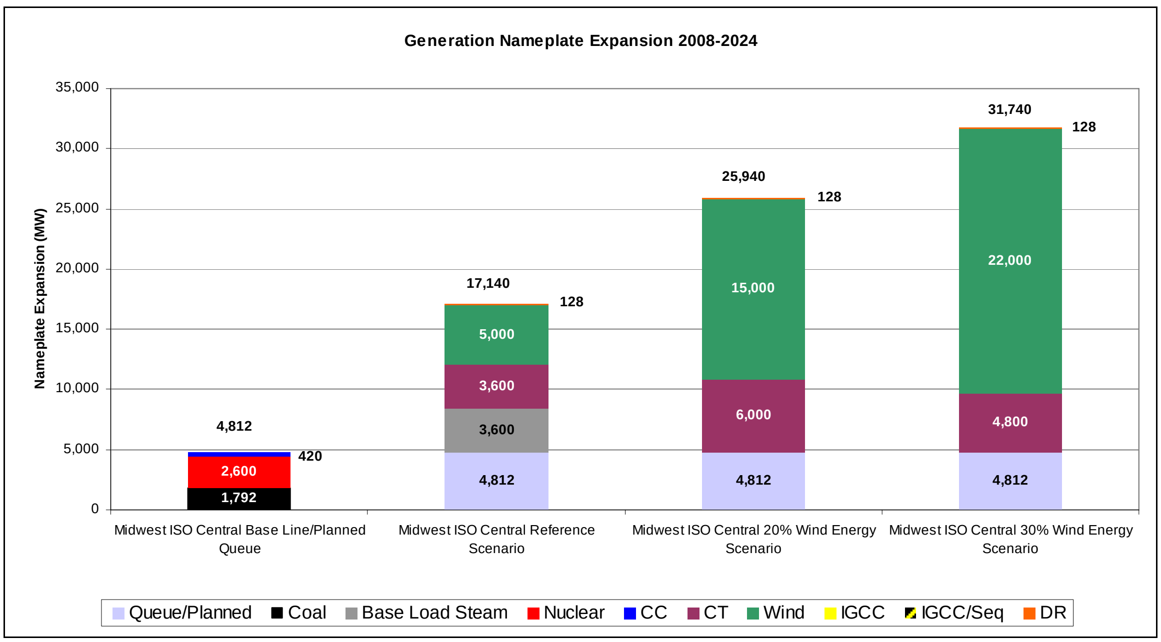


Figure A3-24: Total Nameplate Capacity Forecast with Queue Capacity Identified.

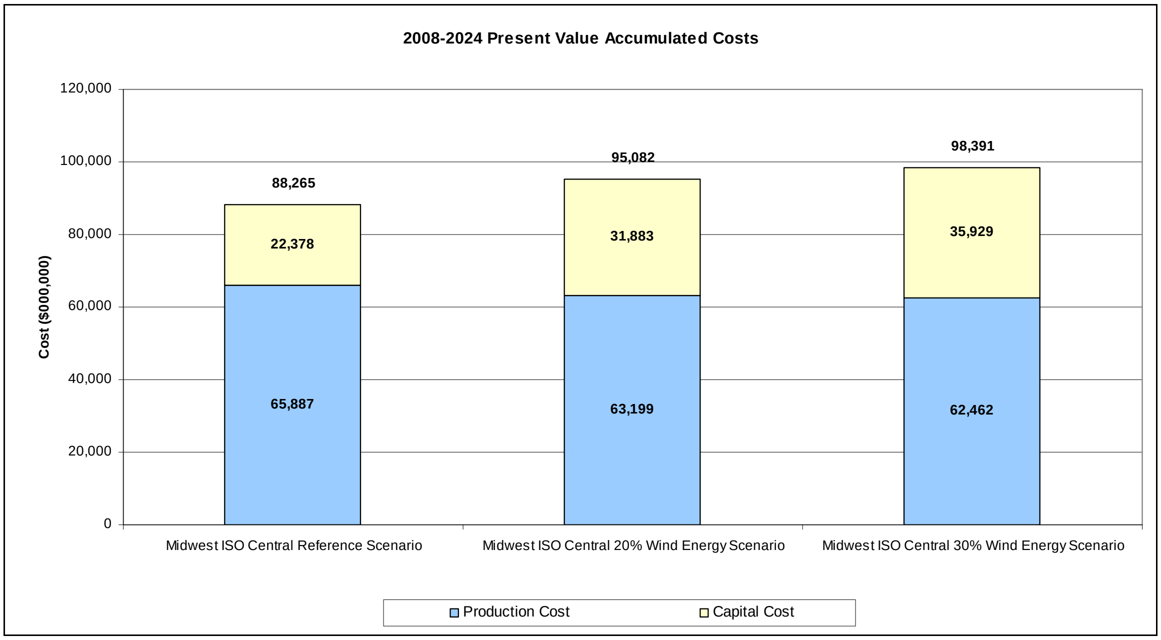


Figure A3-25: Region Accumulative Present Value Costs through 2024.

Midwest ISO East Region Expansion Results

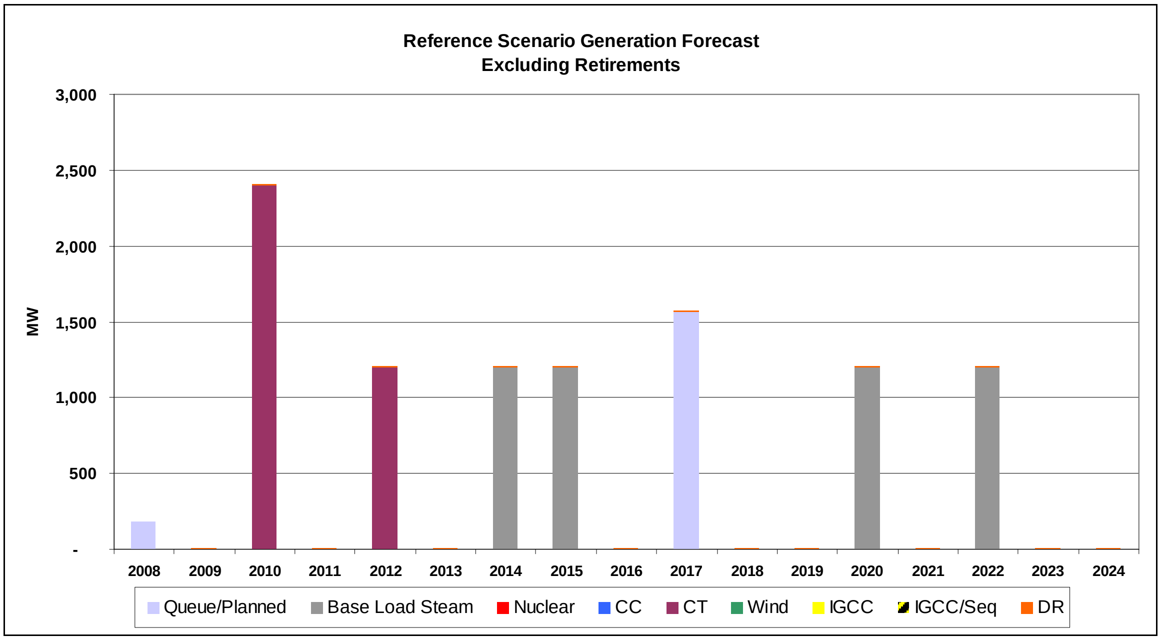


Figure A3-26: Annual Reference Scenario Forecasts Including Committed Capacity Not Yet In Service.

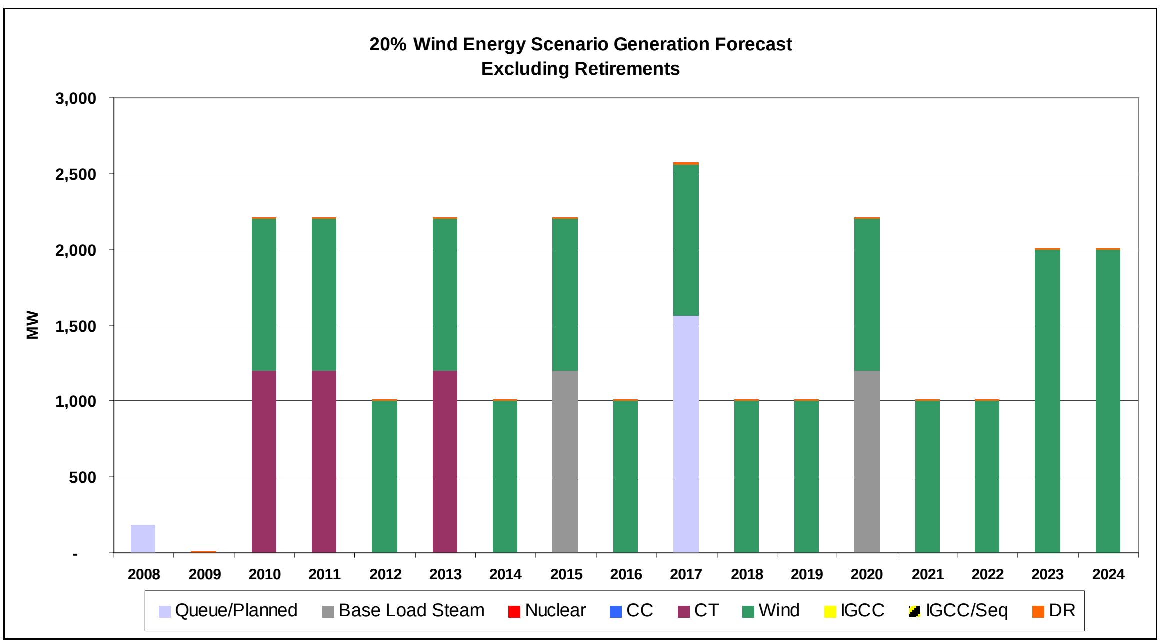


Figure A3-27: Annual 20% Wind Energy Scenario Forecasts Including Committed Capacity Not Yet In Service.

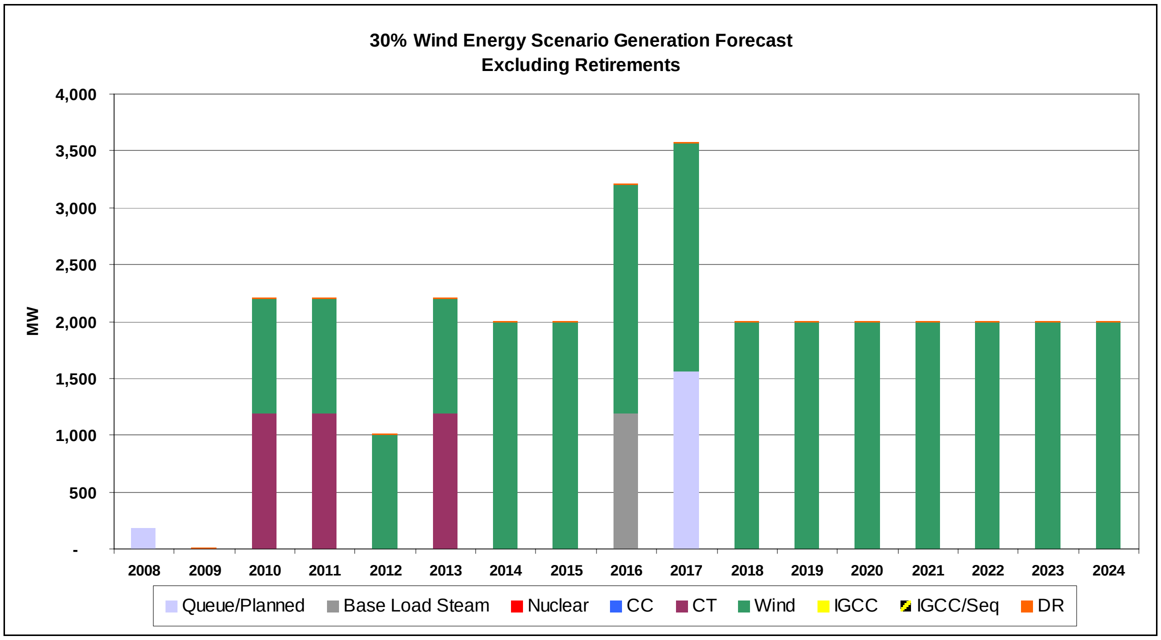


Figure A3-28: Annual 30% Wind Energy Scenario Forecasts Including Committed Capacity Not Yet In Service.

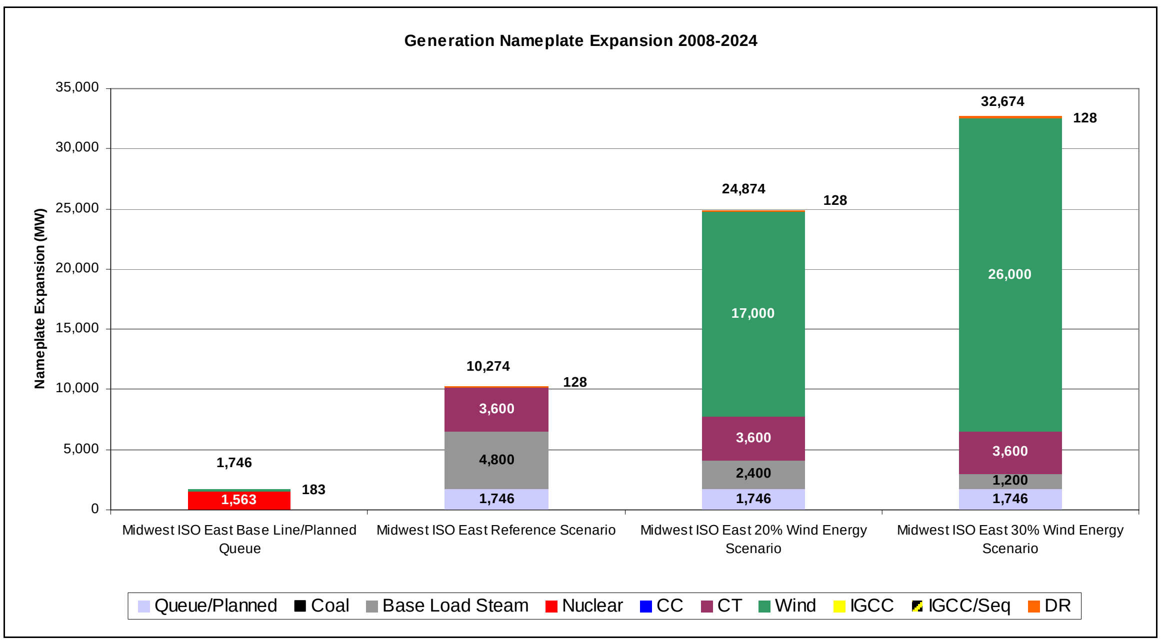


Figure A3-29: Total Nameplate Capacity Forecast with Queue Capacity Identified.

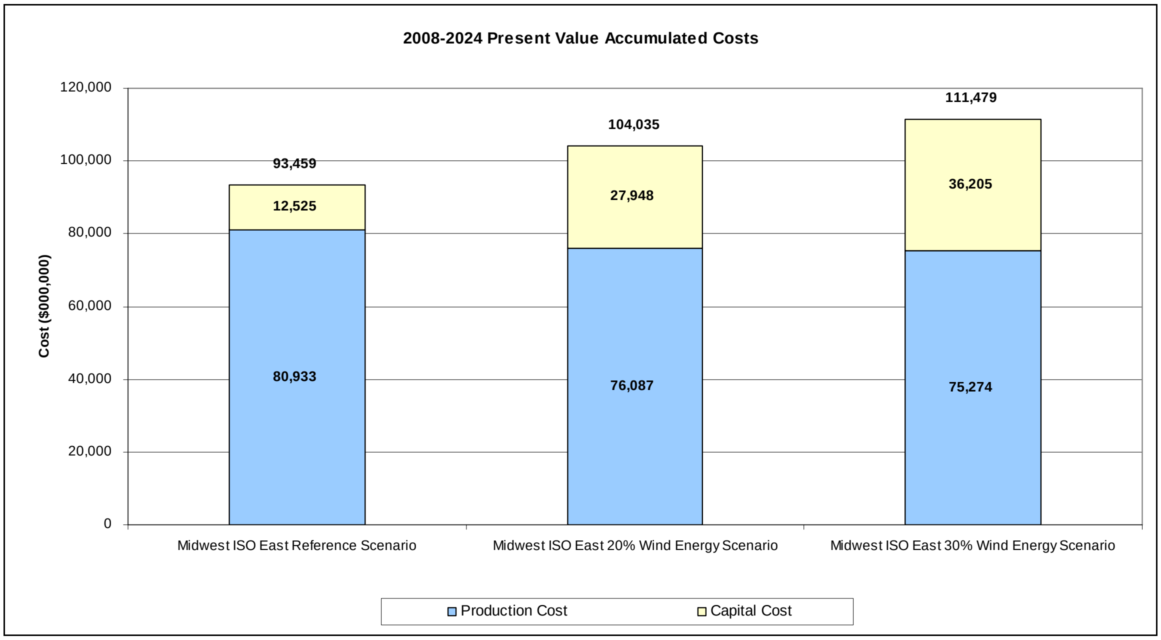


Figure A3-30: Region Accumulative Present Value Costs through 2024.

Midwest ISO West Region Expansion Results

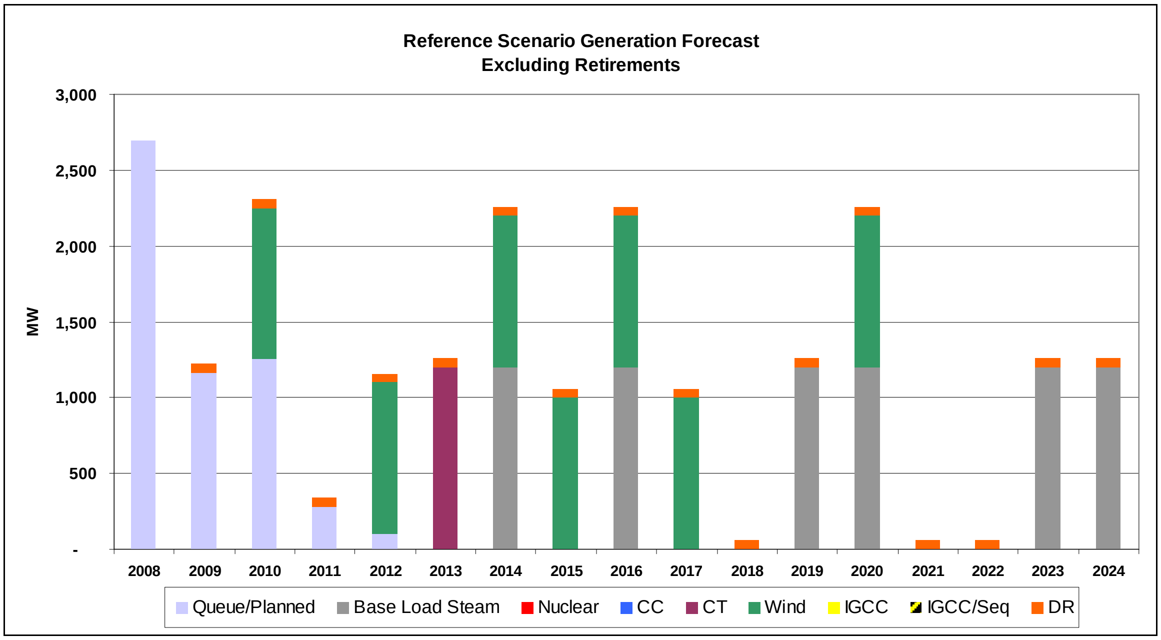


Figure A3-31: Annual Reference Scenario Forecasts Including Committed Capacity Not Yet In Service.

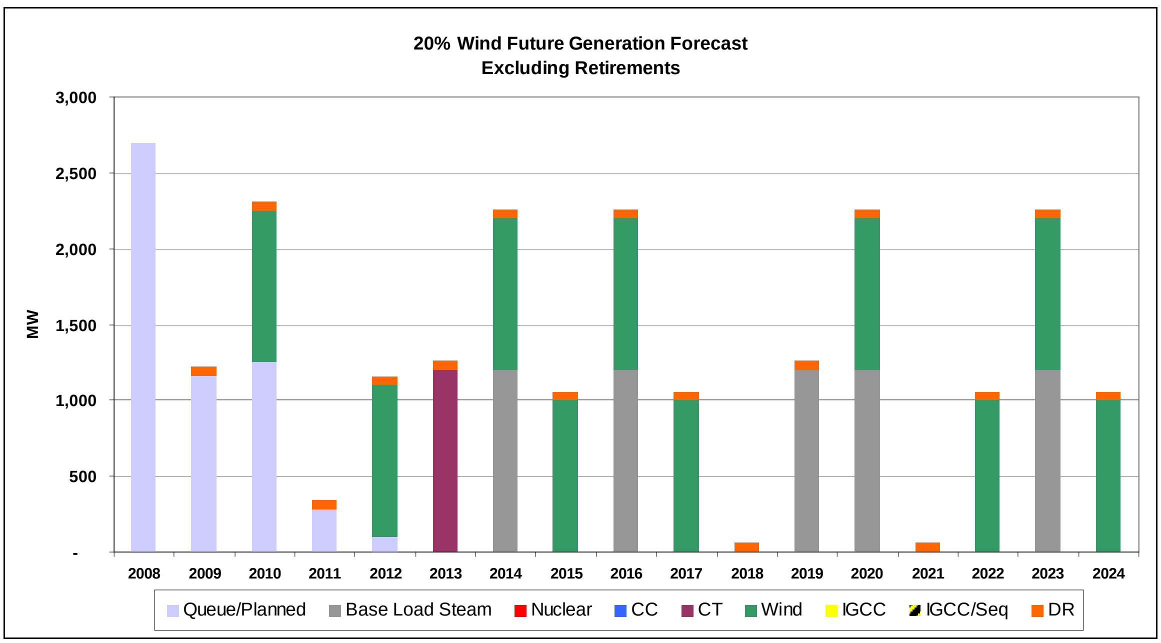


Figure A3-32: Annual 20% Wind Energy Scenario Forecasts Including Committed Capacity Not Yet In Service.

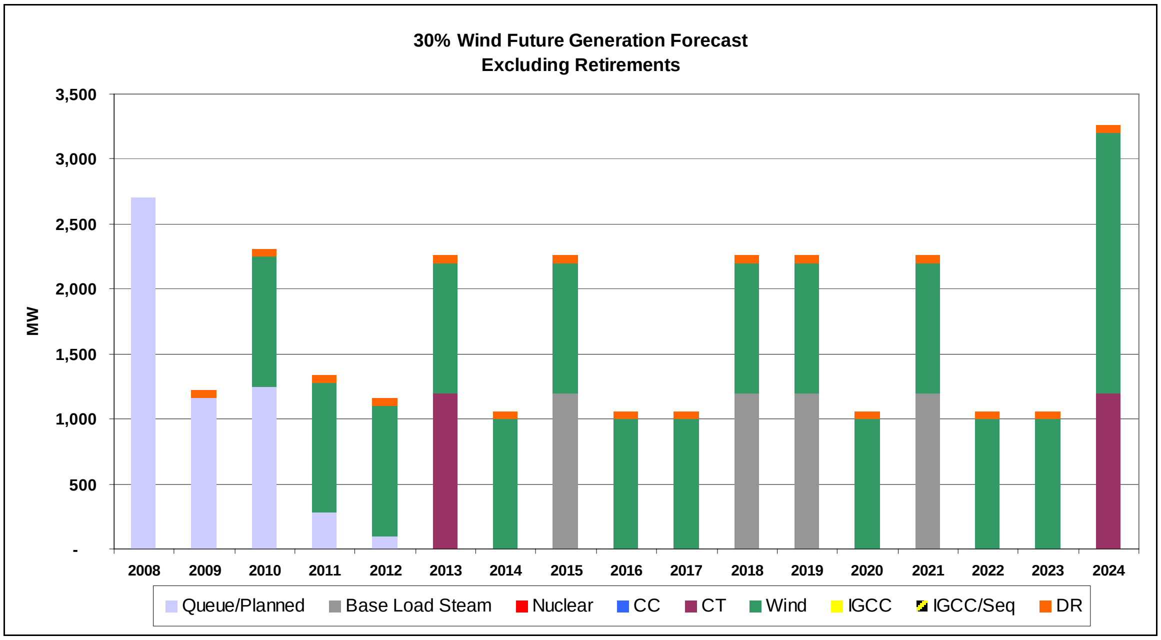


Figure A3-33: Annual 30% Wind Energy Scenario Forecasts Including Committed Capacity Not Yet In Service.

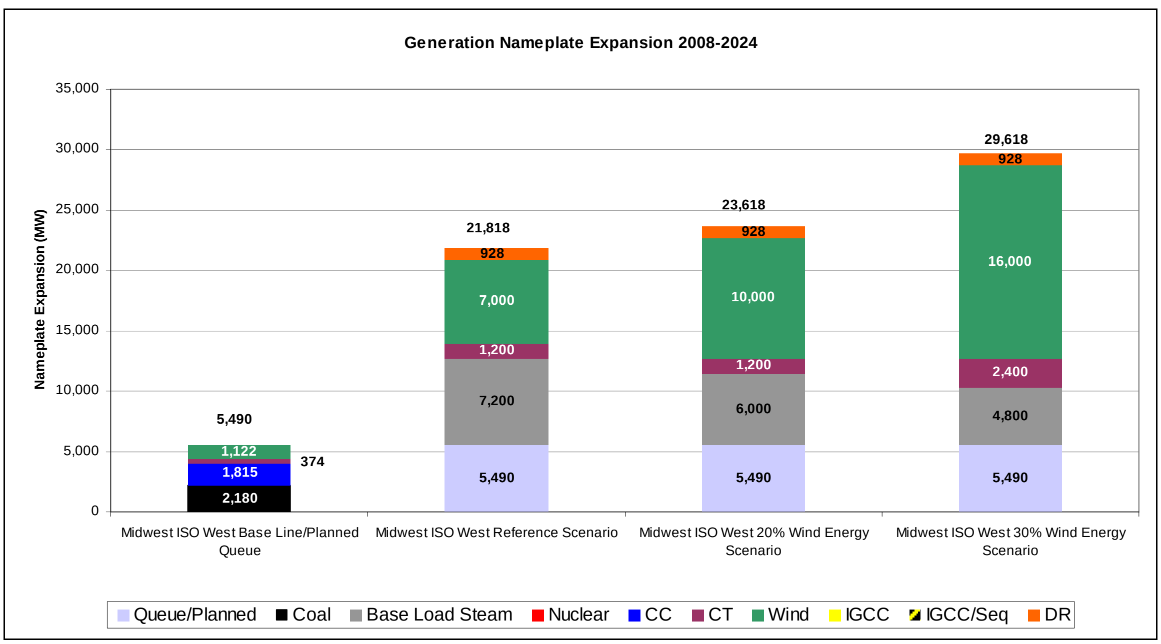


Figure A3-34: Total Nameplate Capacity Forecast with Queue Capacity Identified.

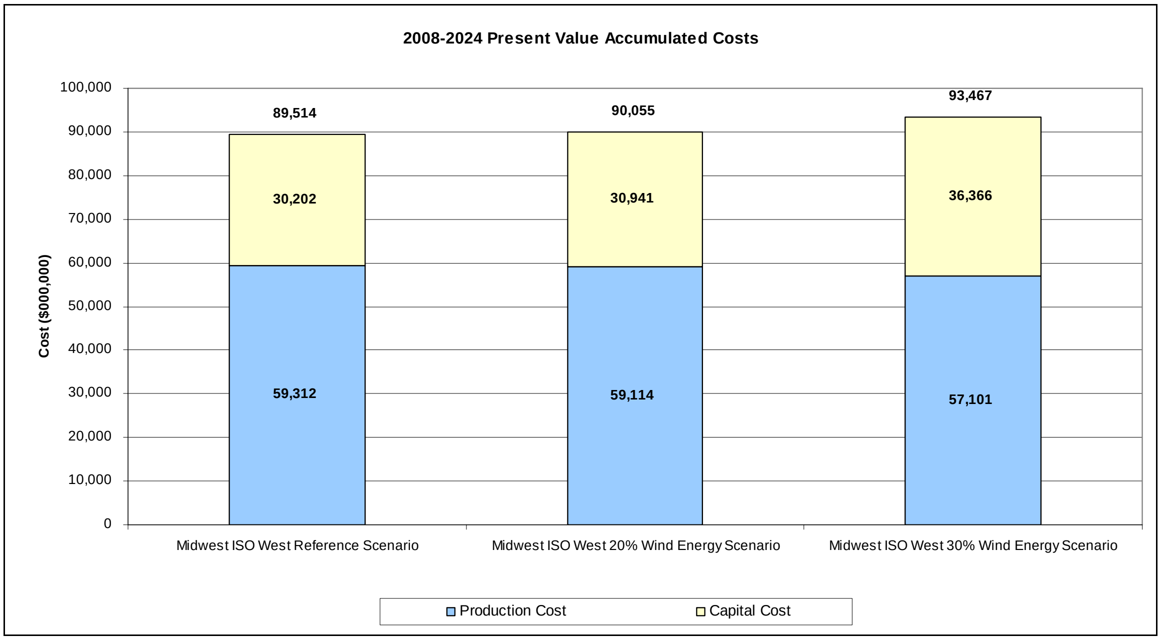


Figure A3-35: Region Accumulative Present Value Costs through 2024.

New York Region Expansion Results

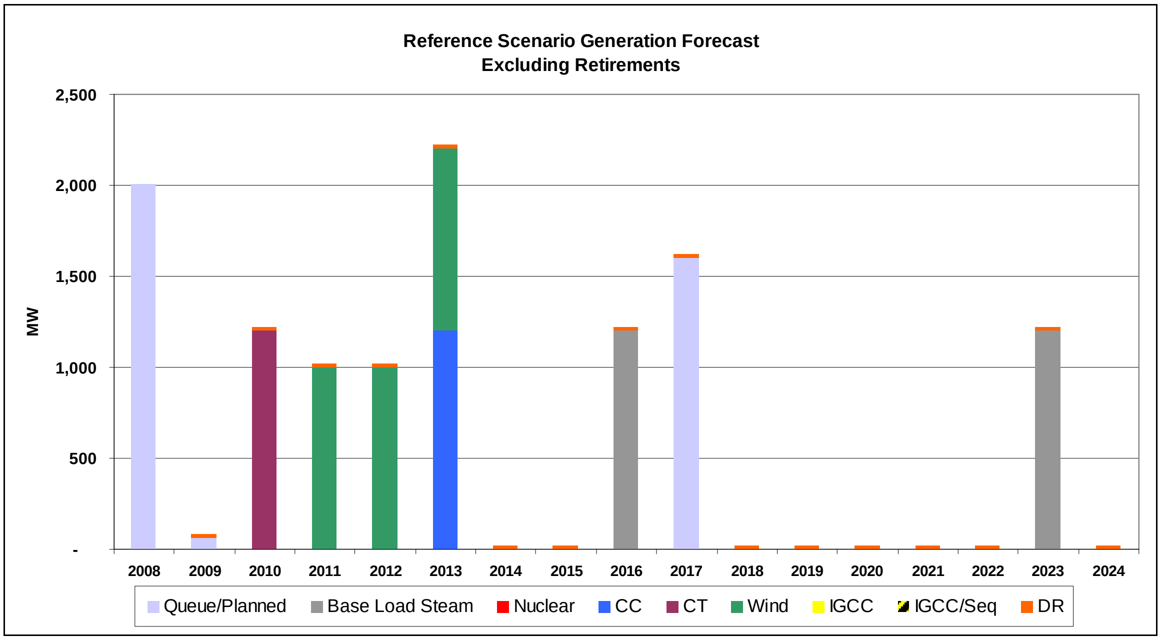


Figure A3-36: Annual Reference Scenario Forecasts Including Committed Capacity Not Yet In Service.

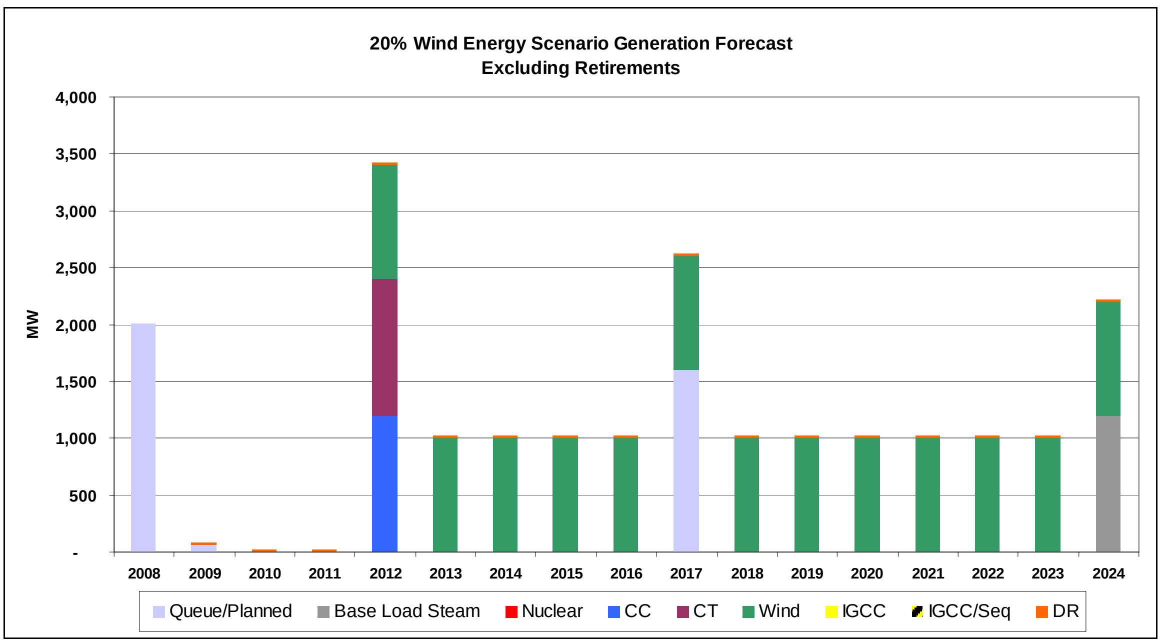


Figure A3-37: Annual 20% Wind Energy Scenario Forecasts Including Committed Capacity Not Yet In Service.

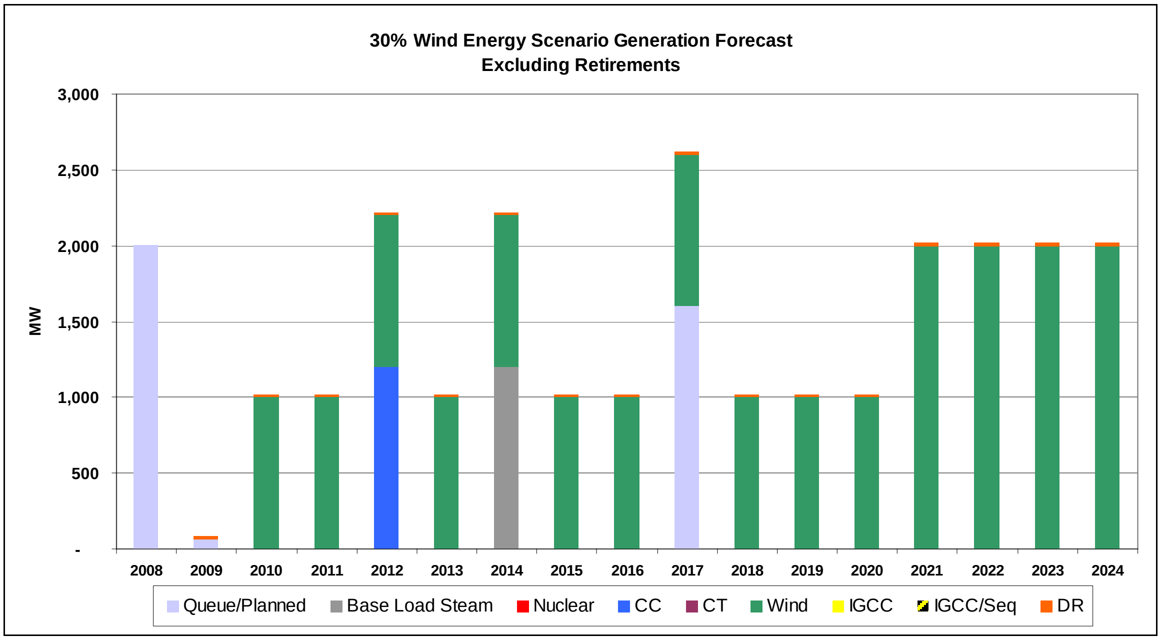


Figure A3-38: Annual 30% Wind Energy Scenario Forecasts Including Committed Capacity Not Yet In Service.

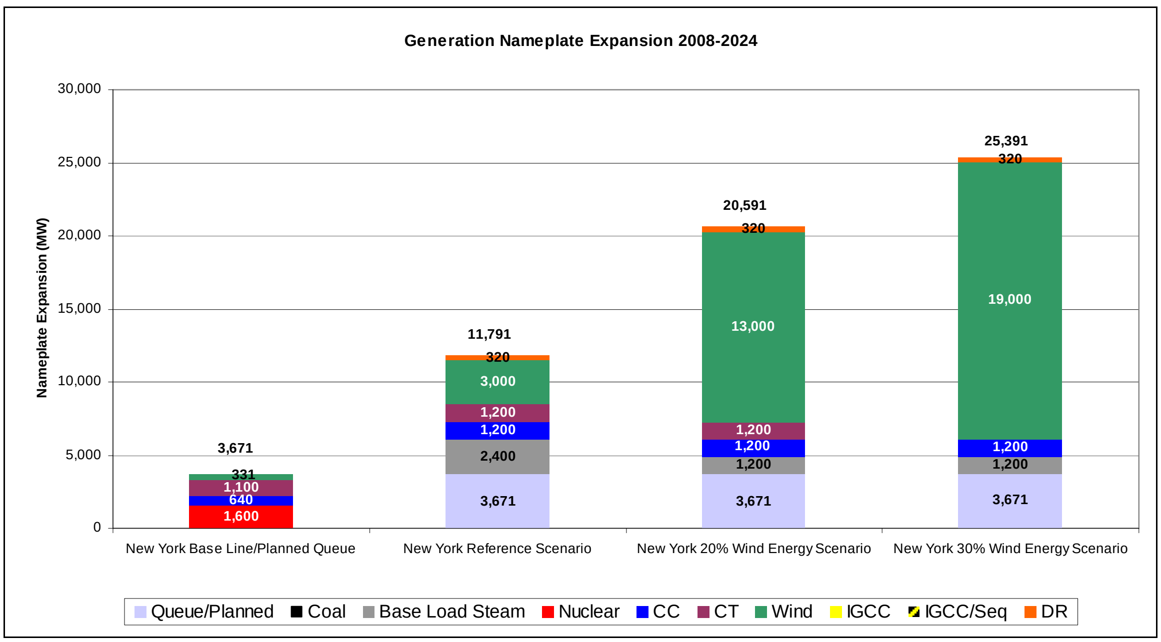


Figure A3-39: Total Nameplate Capacity Forecast with Queue Capacity Identified.

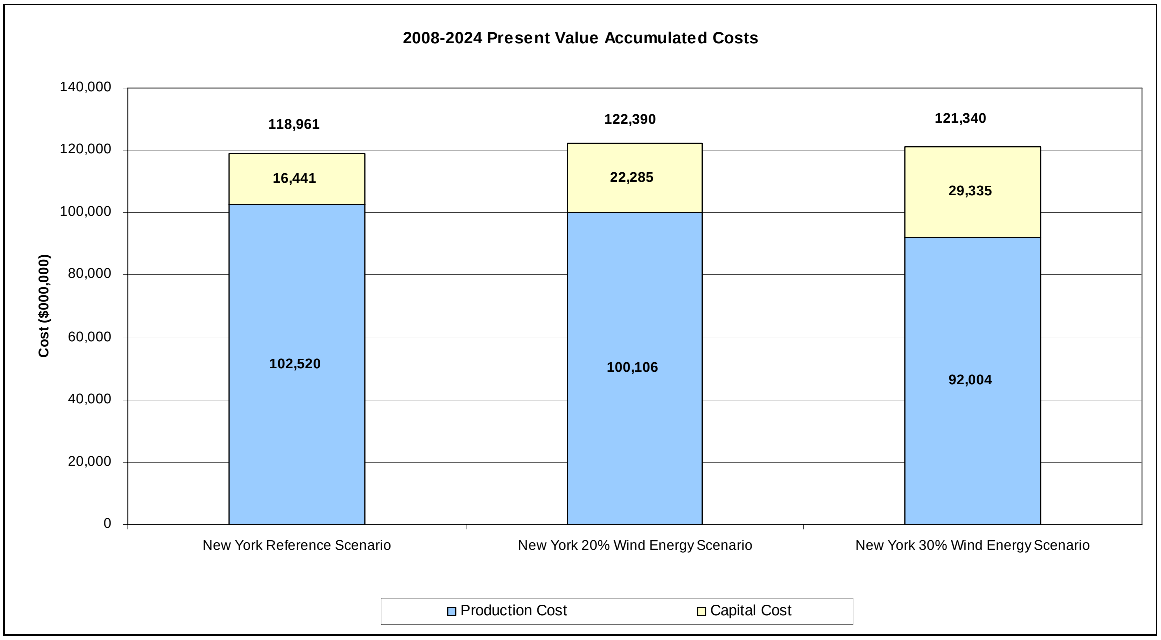


Figure A3-40: Region Accumulative Present Value Costs through 2024.

PJM Region Expansion Results

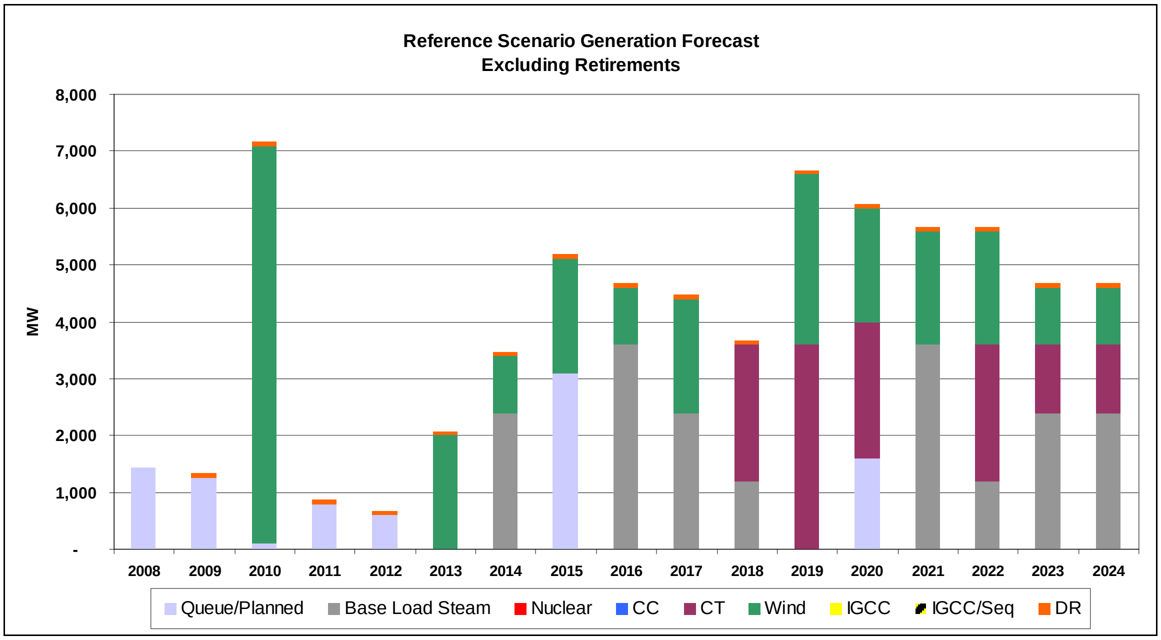


Figure A3-41: Annual Reference Scenario Forecasts Including Committed Capacity Not Yet In Service.

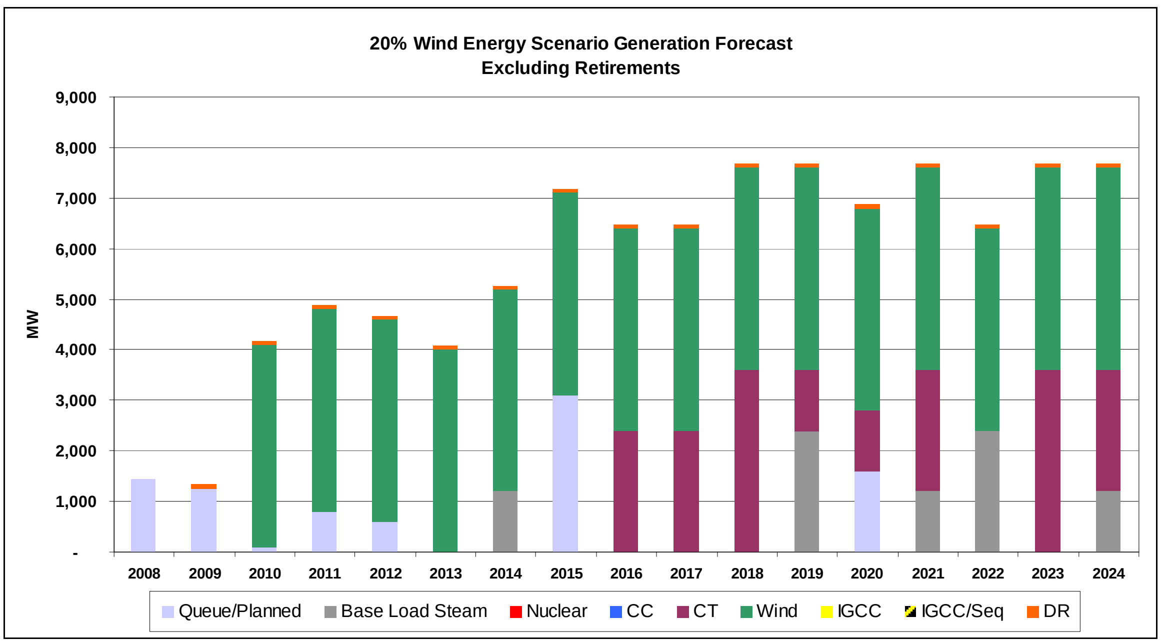


Figure A3-42: Annual 20% Wind Energy Scenario Forecasts Including Committed Capacity Not Yet In Service.

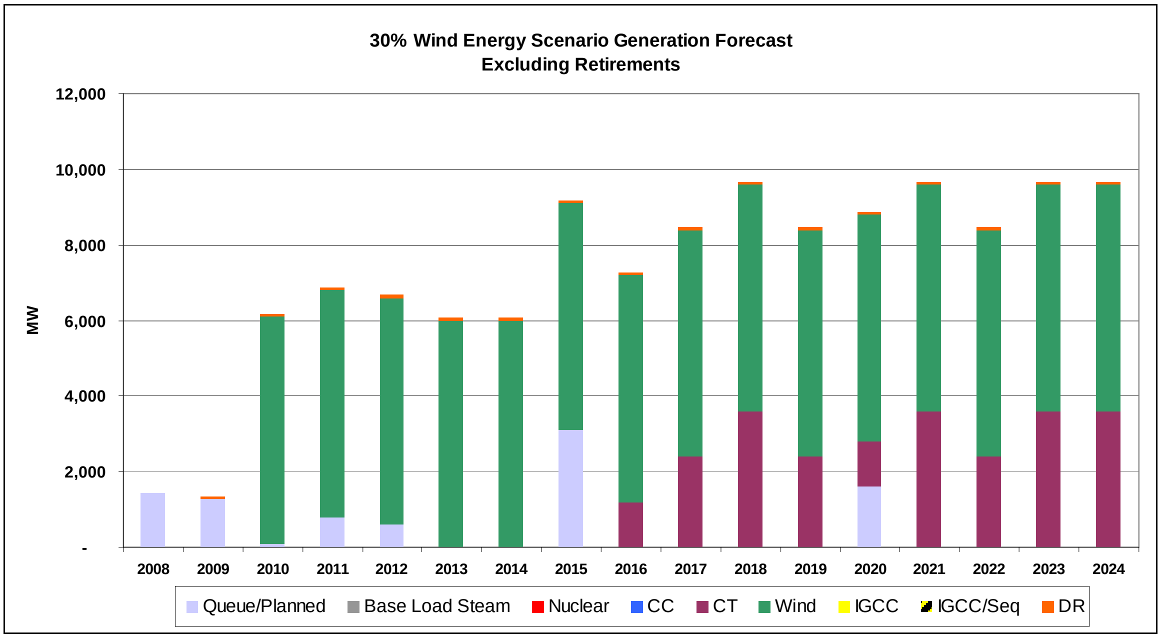


Figure A3-43: Annual 30% Wind Energy Scenario Forecasts Including Committed Capacity Not Yet In Service.

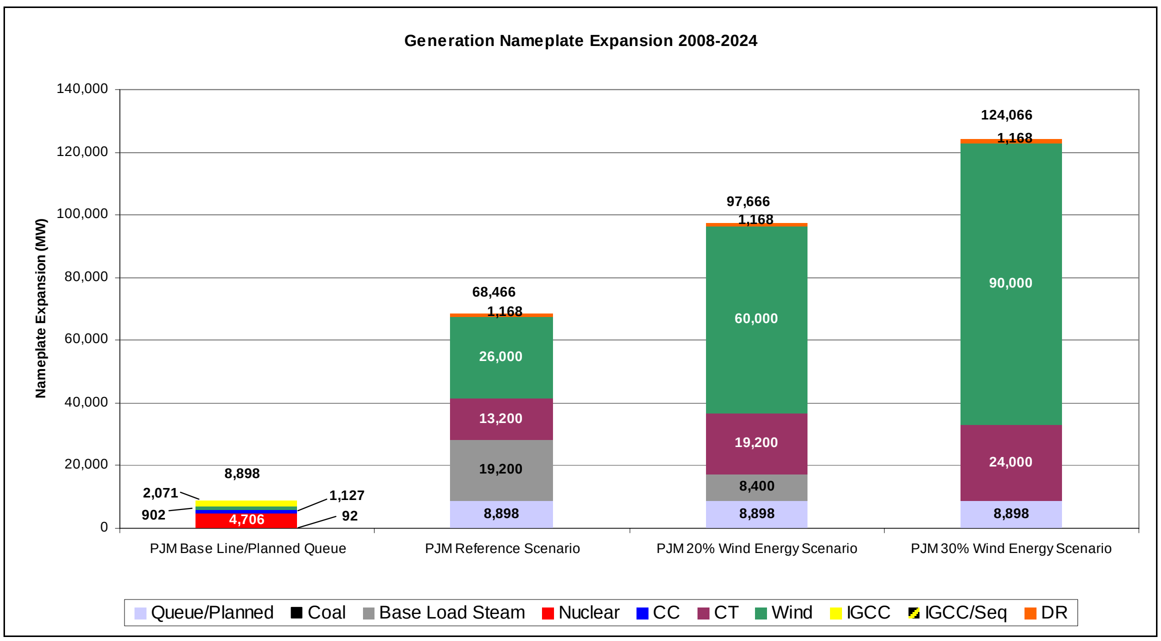


Figure A3-44: Total Nameplate Capacity Forecast with Queue Capacity Identified.

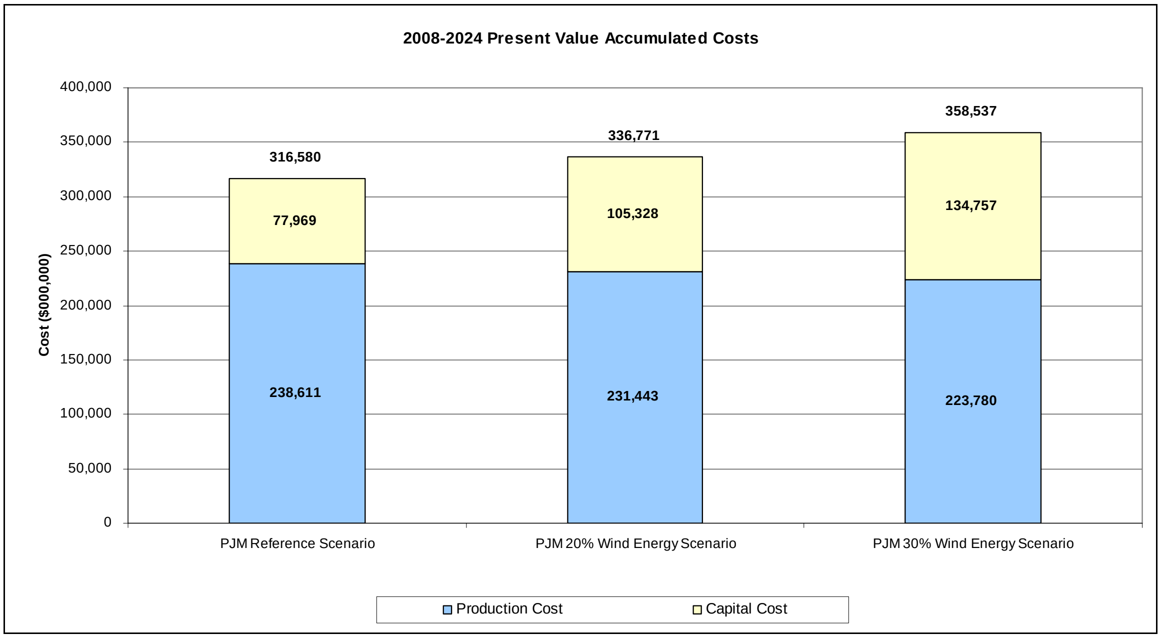


Figure A3-45: Region Accumulative Present Value Costs through 2024.

SERC Region Expansion Results

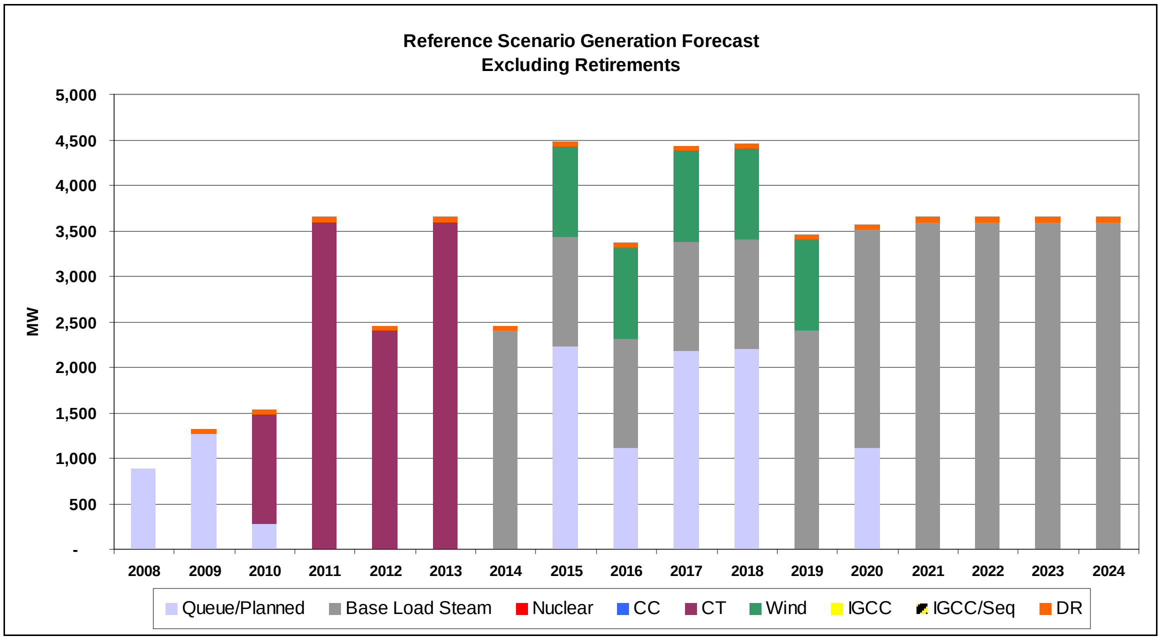


Figure A3-46: Annual Reference Scenario Forecasts Including Committed Capacity Not Yet In Service.

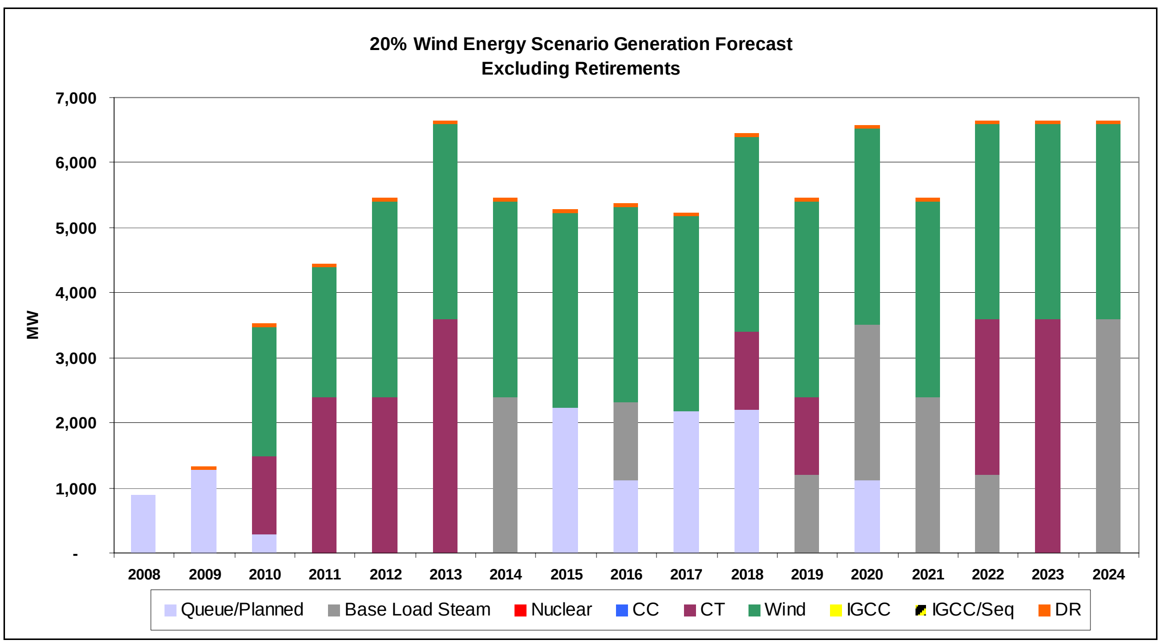


Figure A3-47: Annual 20% Wind Energy Scenario Forecasts Including Committed Capacity Not Yet In Service.

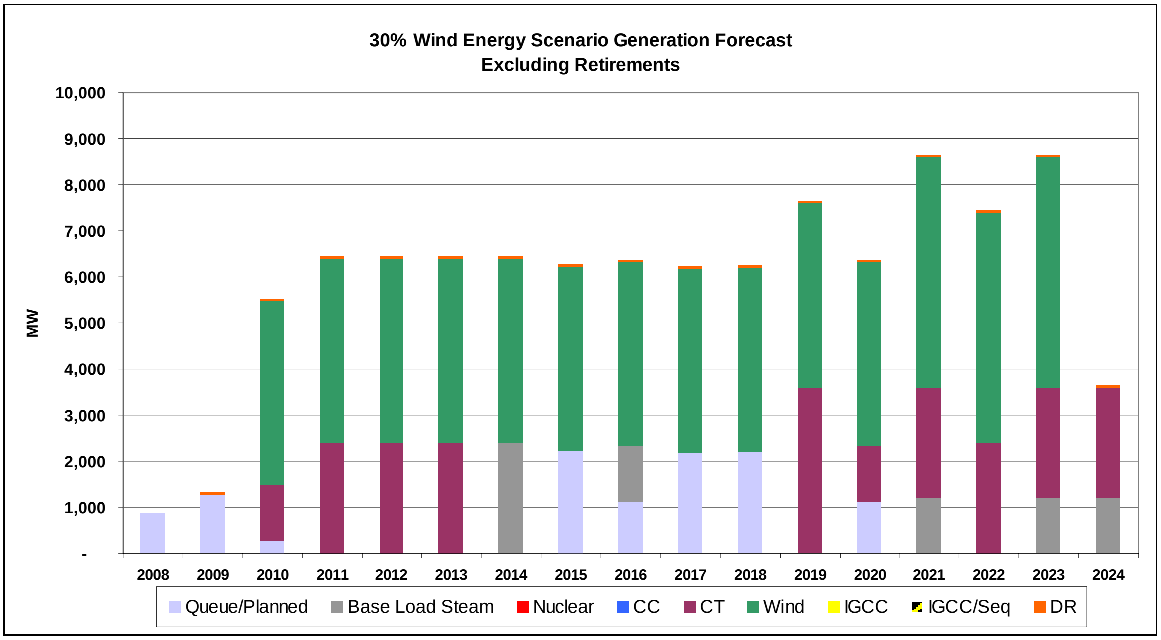


Figure A3-48: Annual 30% Wind Energy Scenario Forecasts Including Committed Capacity Not Yet In Service.

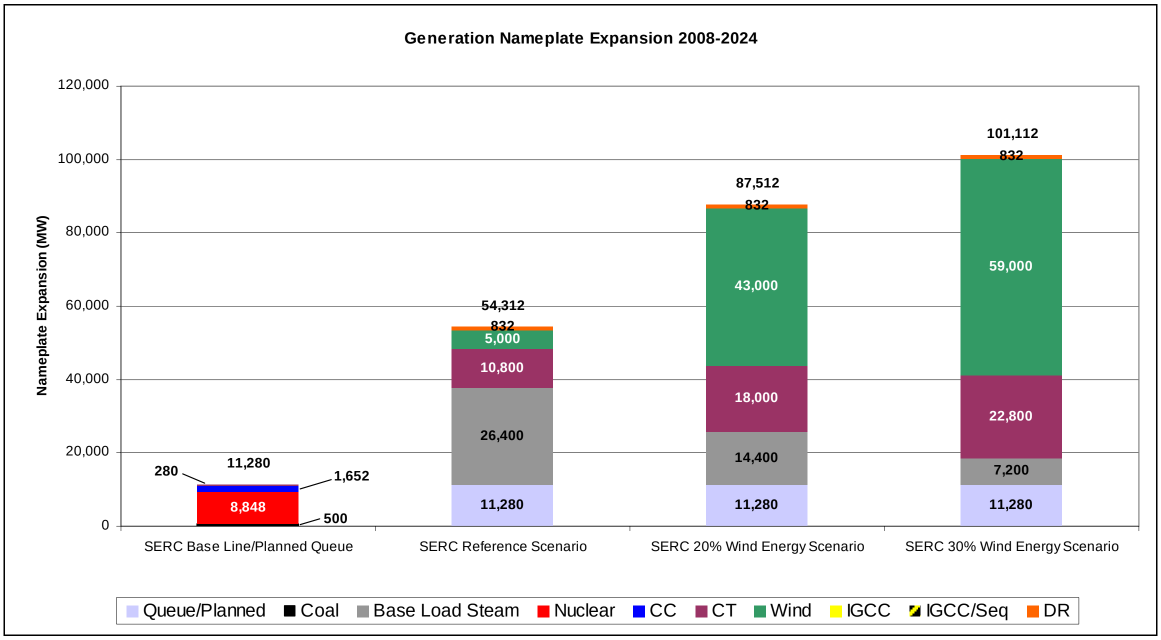


Figure A3-49: Total Nameplate Capacity Forecast with Queue Capacity Identified.

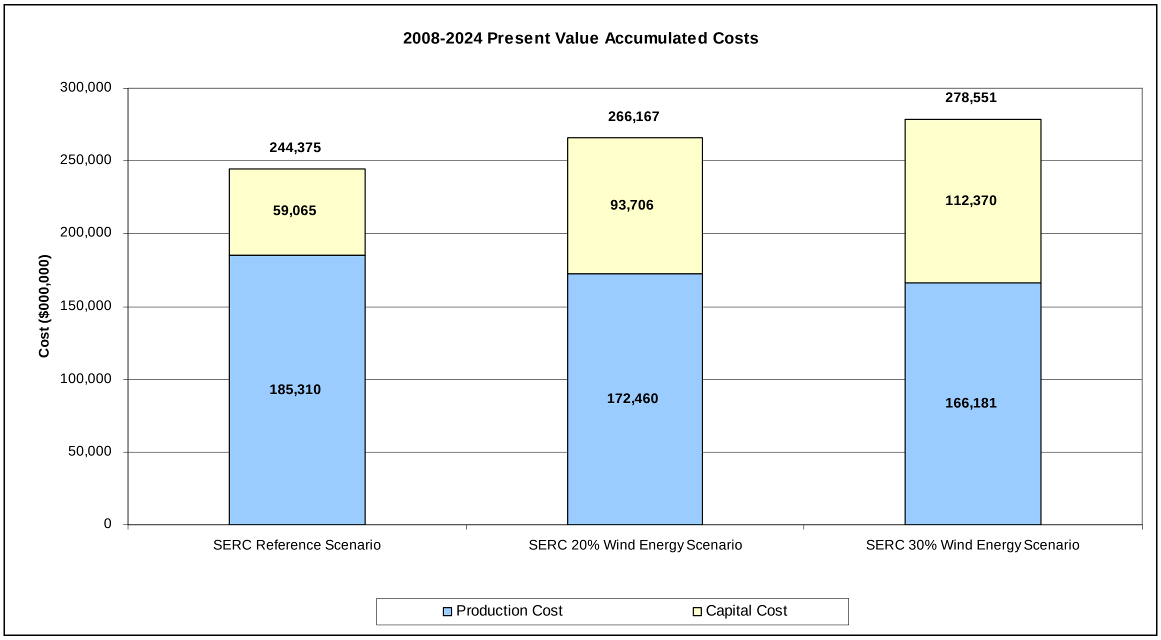


Figure A3-50: Region Accumulative Present Value Costs through 2024.

SPP Region Expansion Results

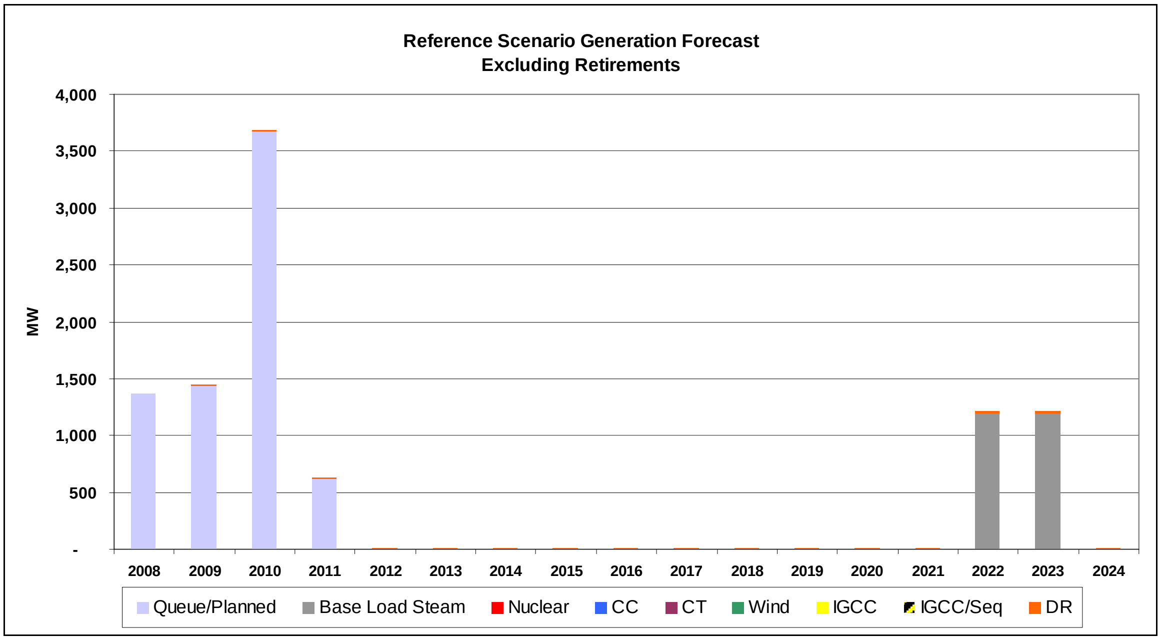


Figure A3-51: Annual Reference Scenario Forecasts Including Committed Capacity Not Yet In Service.

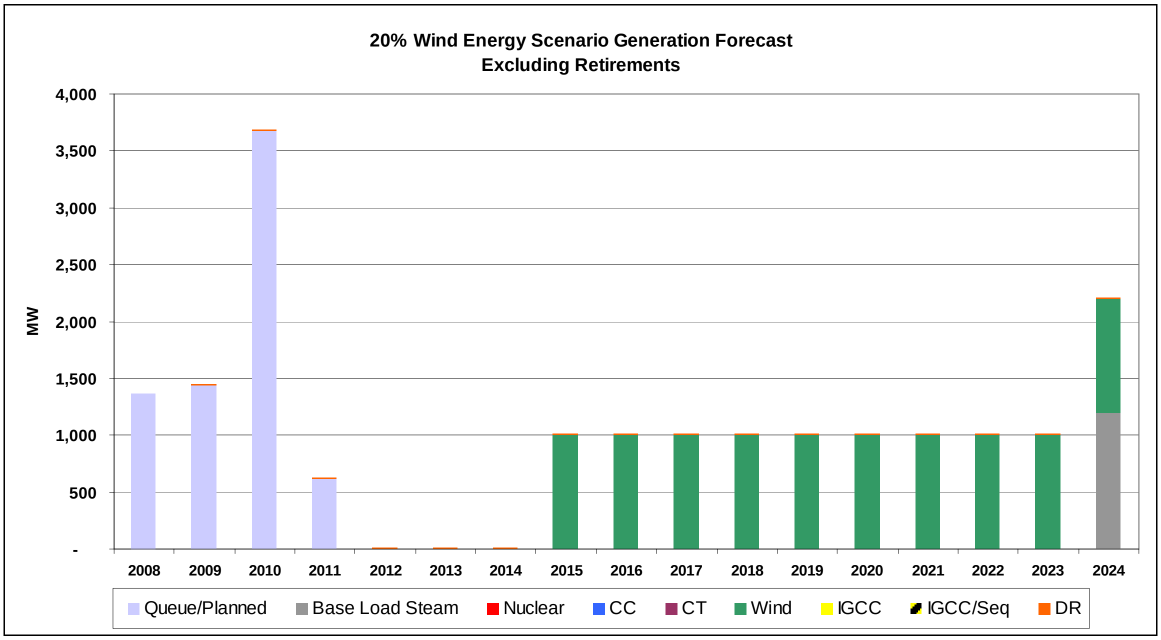


Figure A3-52: Annual 20% Wind Energy Scenario Forecasts Including Committed Capacity Not Yet In Service.

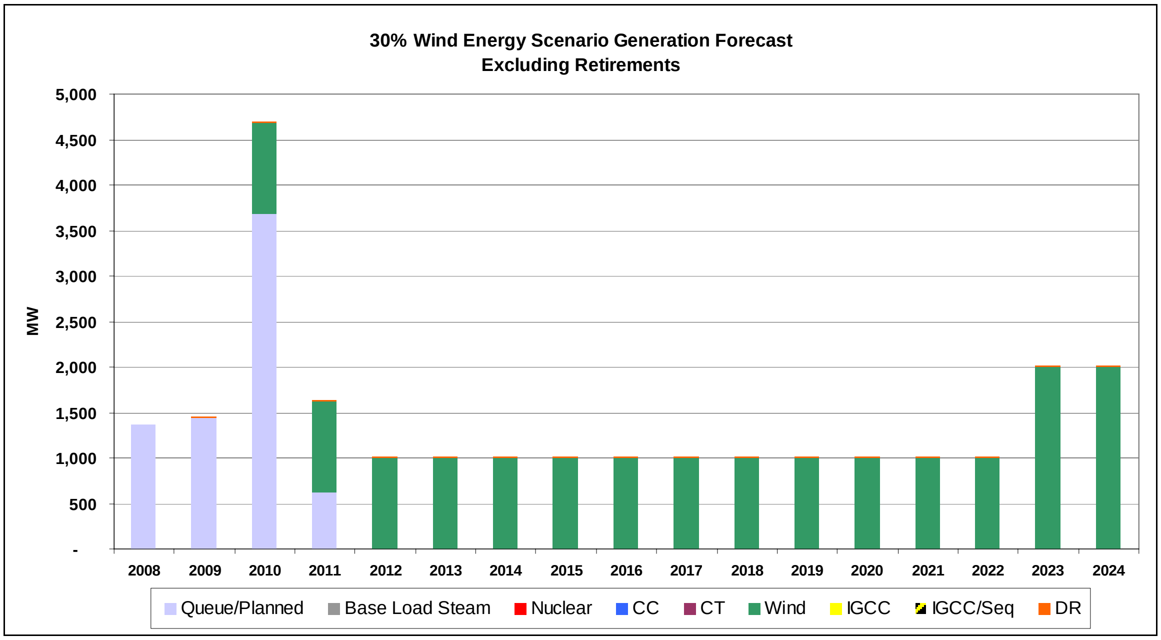


Figure A3-53: Annual 30% Wind Energy Scenario Forecasts Including Committed Capacity Not Yet In Service.

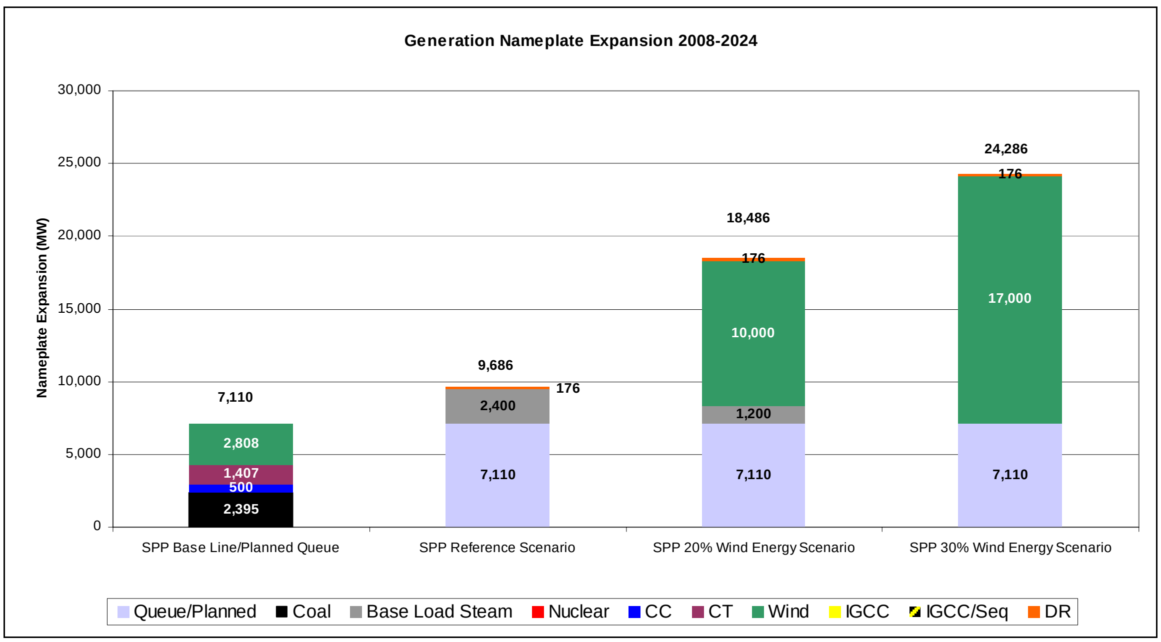


Figure A3-54: Total Nameplate Capacity Forecast with Queue Capacity Identified.

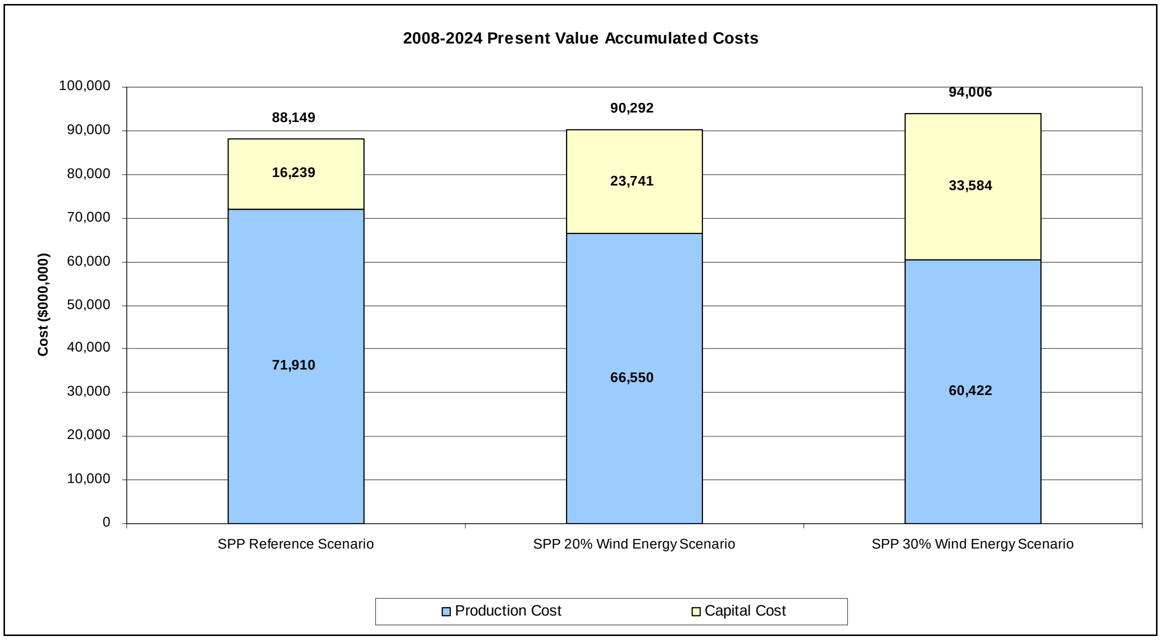


Figure A3-55: Region Accumulative Present Value Costs through 2024.

TVA Region Expansion Results

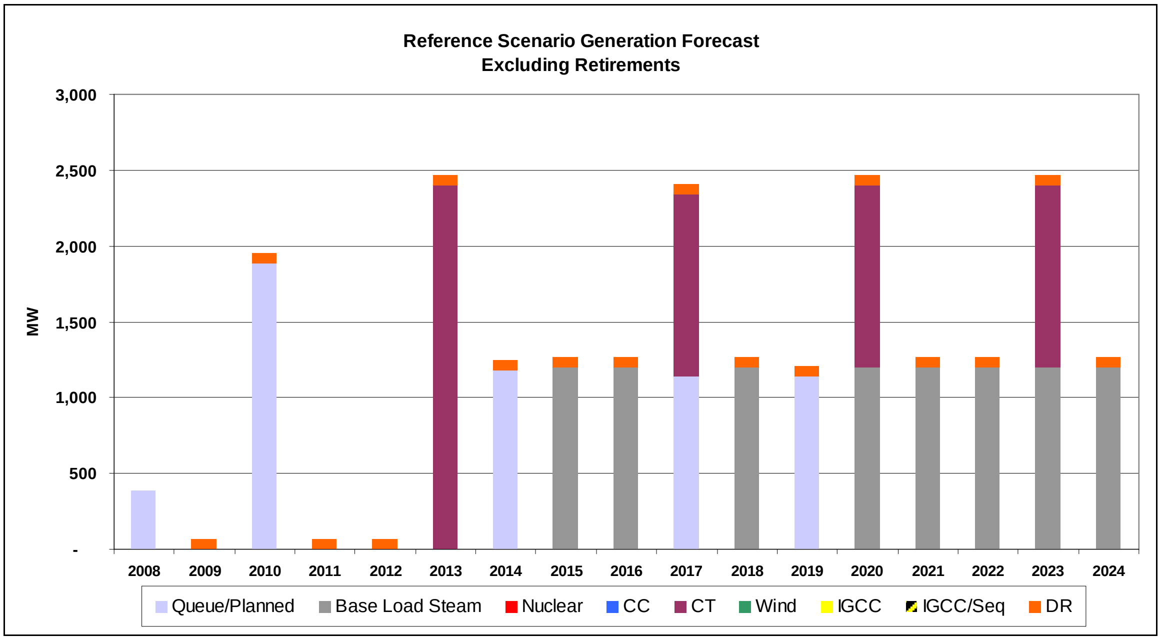


Figure A3-56: Annual Reference Scenario Forecasts Including Committed Capacity Not Yet In Service.

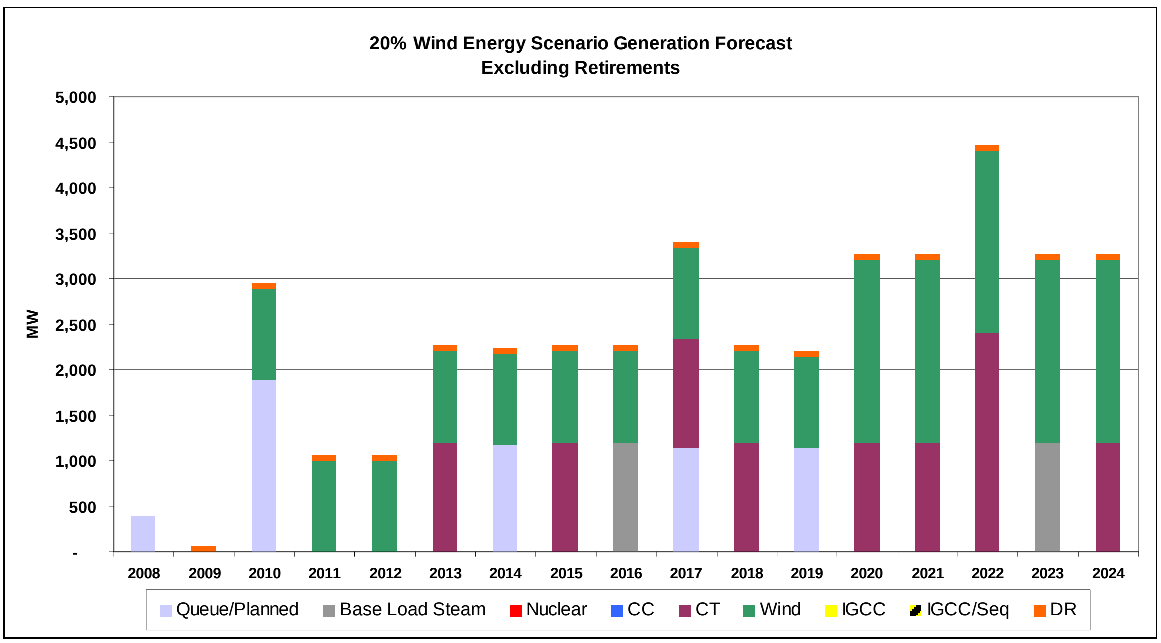


Figure A3-57: Annual 20% Wind Energy Scenario Forecasts Including Committed Capacity Not Yet In Service.

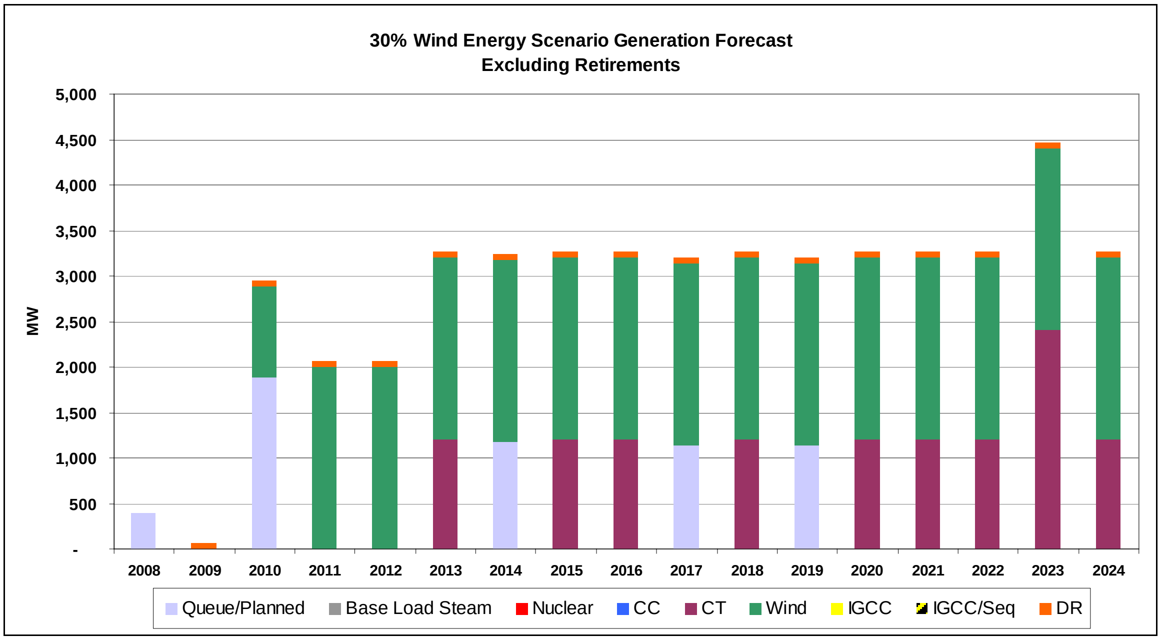


Figure A3-58: Annual 30% Wind Energy Scenario Forecasts Including Committed Capacity Not Yet In Service.

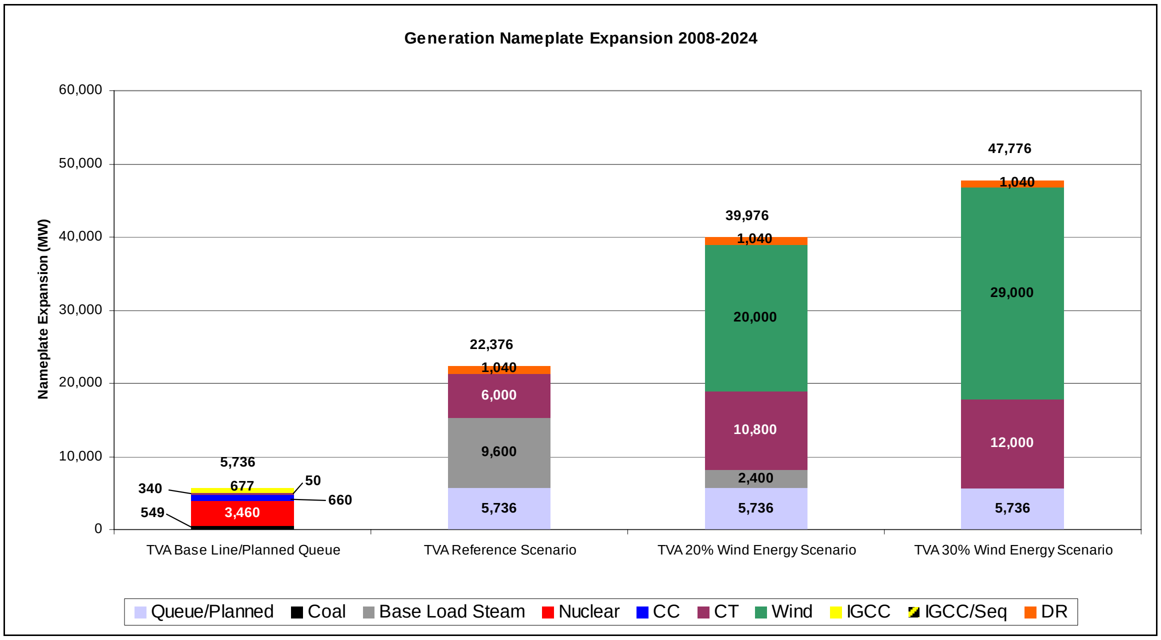


Figure A3-59: Total Nameplate Capacity Forecast with Queue Capacity Identified.

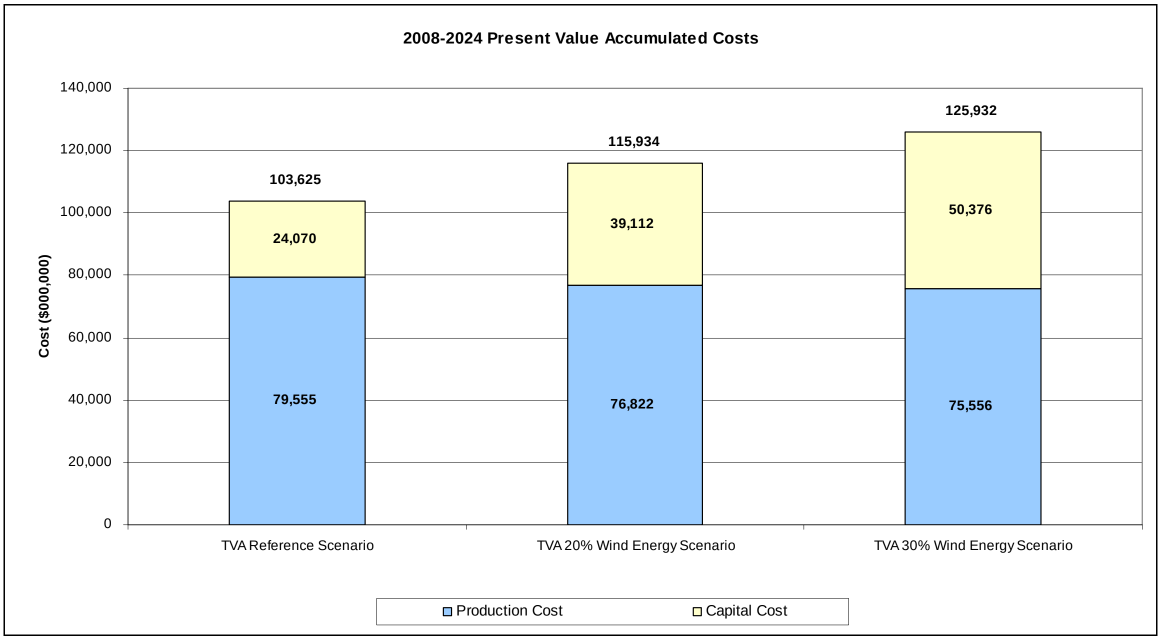


Figure A3-60: Region Accumulative Present Value Costs through 2024.

Appendix 4: Maps

Included in this appendix are the regional maps identifying the locations used for the regional resource forecasts. The maps also include a mapping of committed capacity within the models that is not online yet. Also included is a spreadsheet with more detail information regarding the units identified on the maps as well as the existing capacity present in the economic planning models.

Entergy Regional Resource Forecast Siting

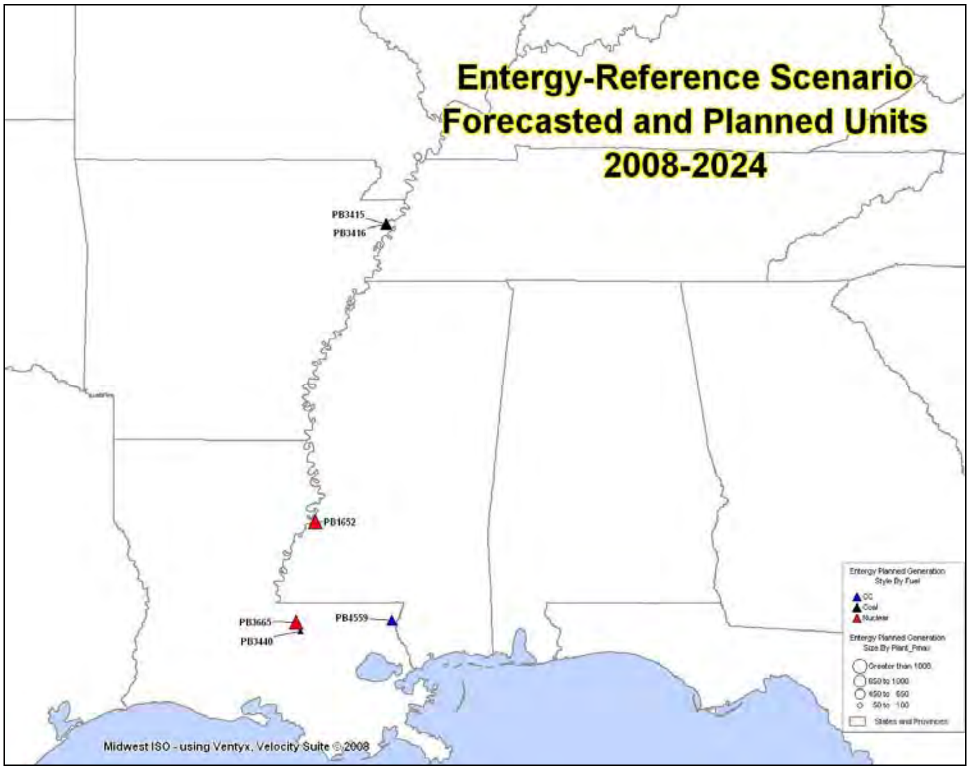


Figure A4-1: Reference Scenario Planned and Forecast Siting.

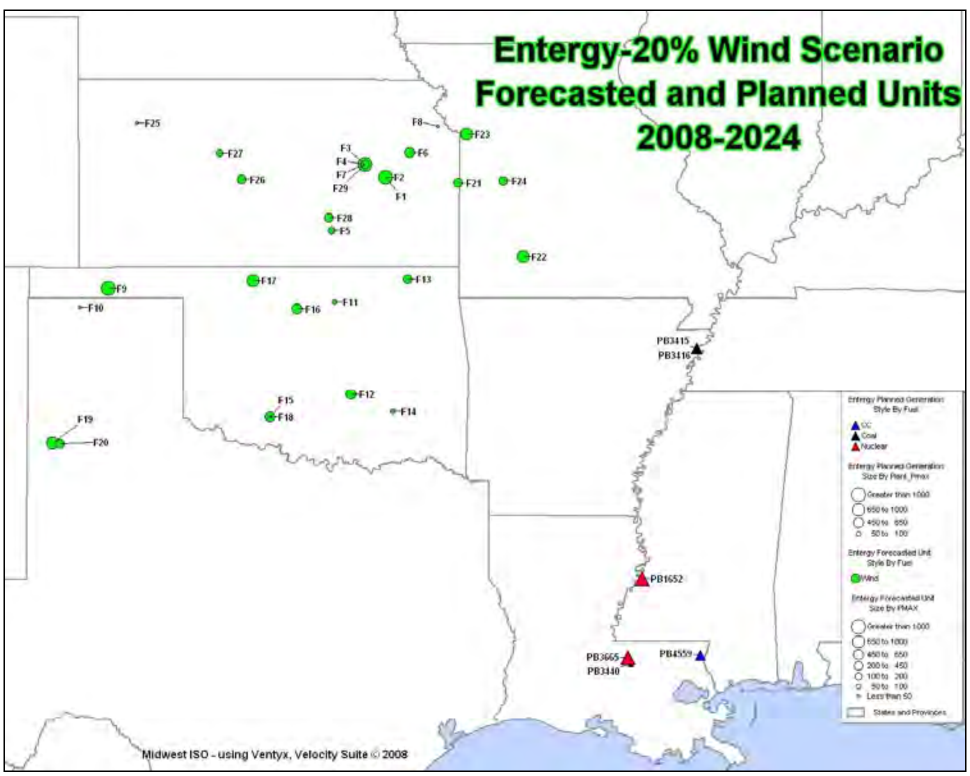


Figure A4-2: 20% Wind Energy Scenario Planned and Forecast Siting.

IESO Regional Resource Forecast Siting

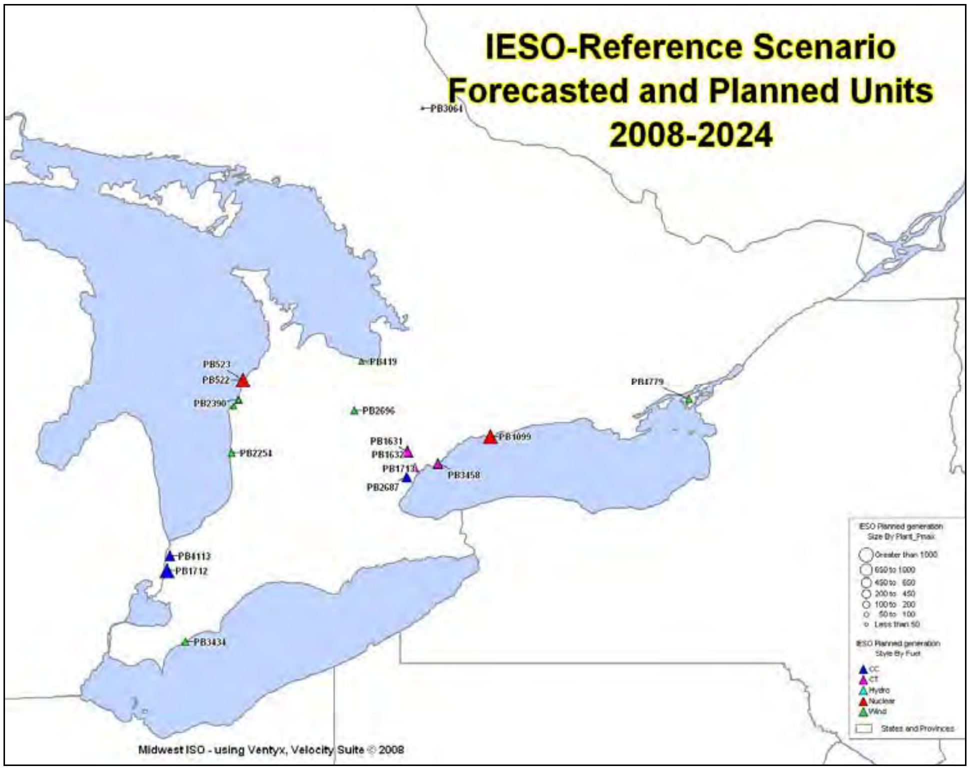


Figure A4-3: Reference Scenario Planned and Forecast Siting.

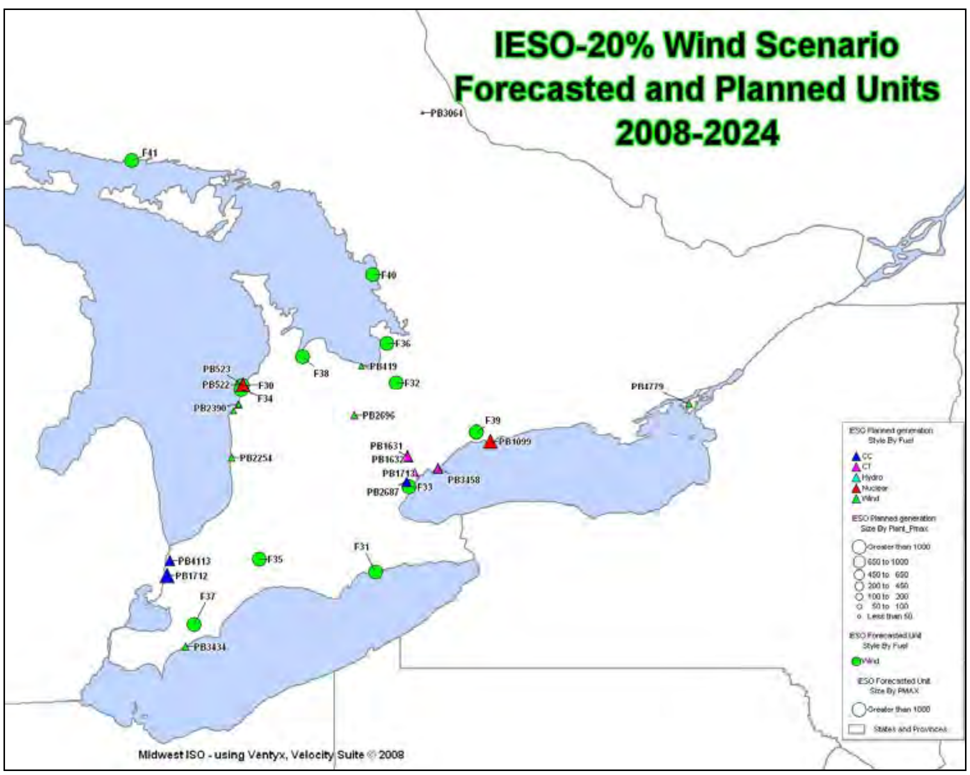


Figure A4-4: 20% Wind Energy Scenario Planned and Forecast Siting.

New England Regional Resource Forecast Siting

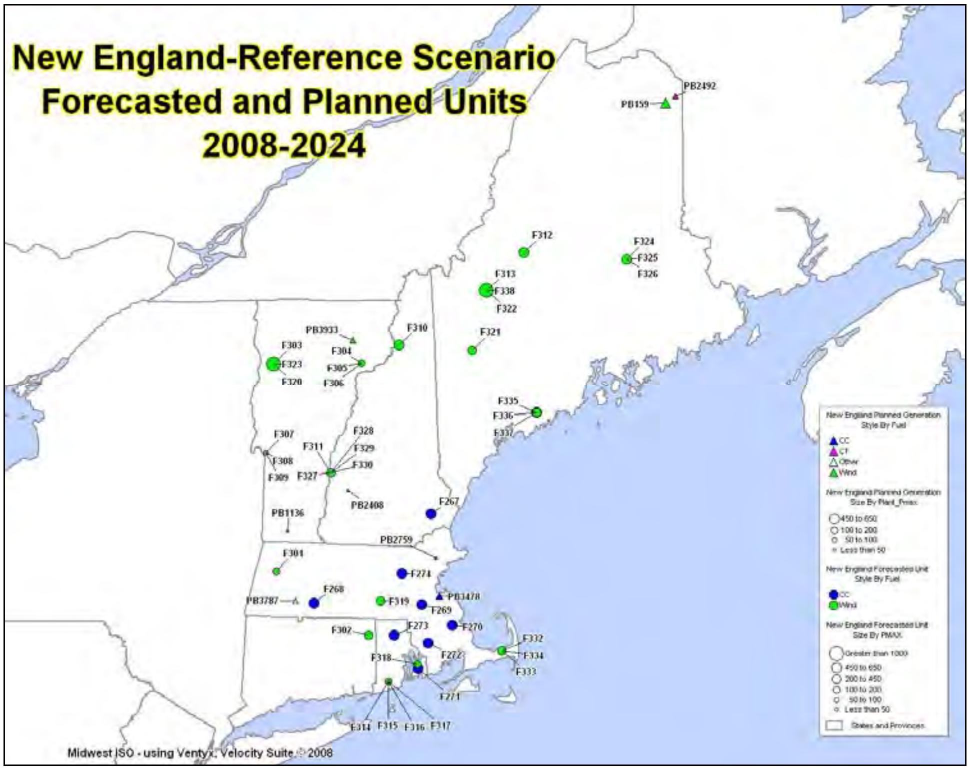


Figure A4-5: Reference Scenario Planned and Forecast Siting.

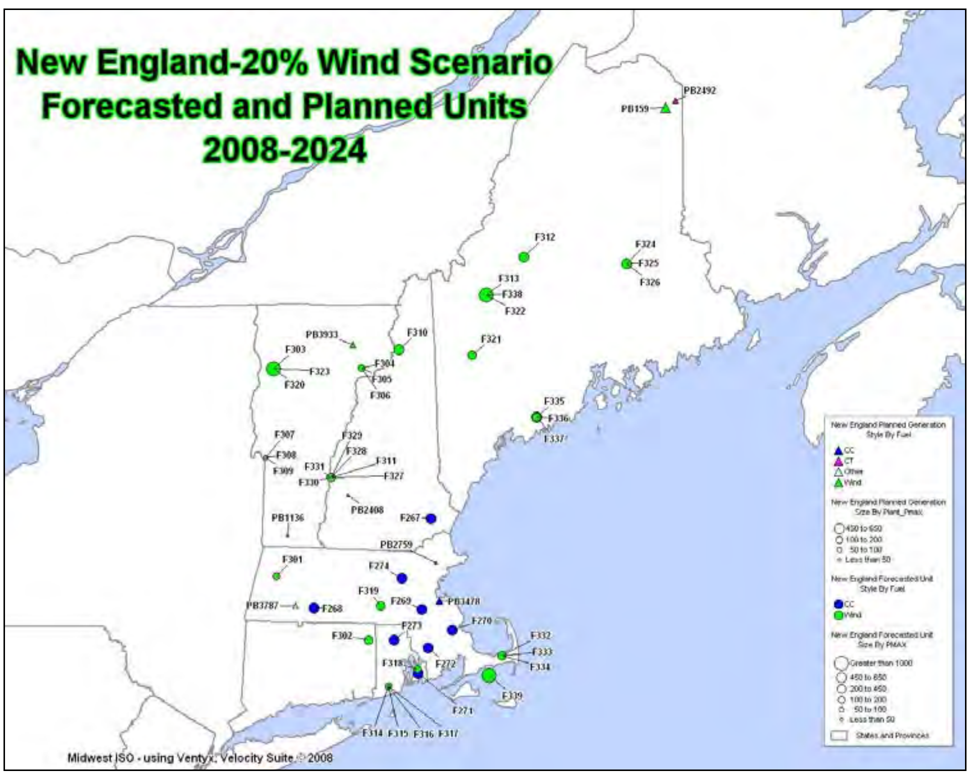


Figure A4-6: 20% Wind Energy Scenario Planned and Forecast Siting.

MAPP Regional Resource Forecast Siting

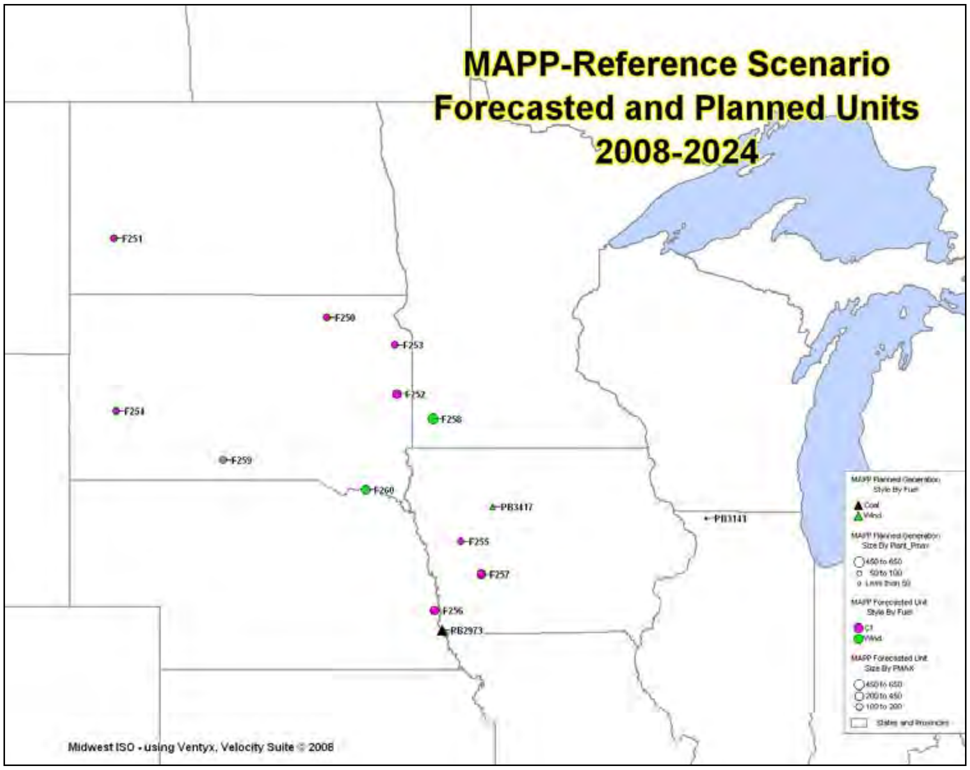


Figure A4-7: Reference Scenario Planned and Forecast Siting.

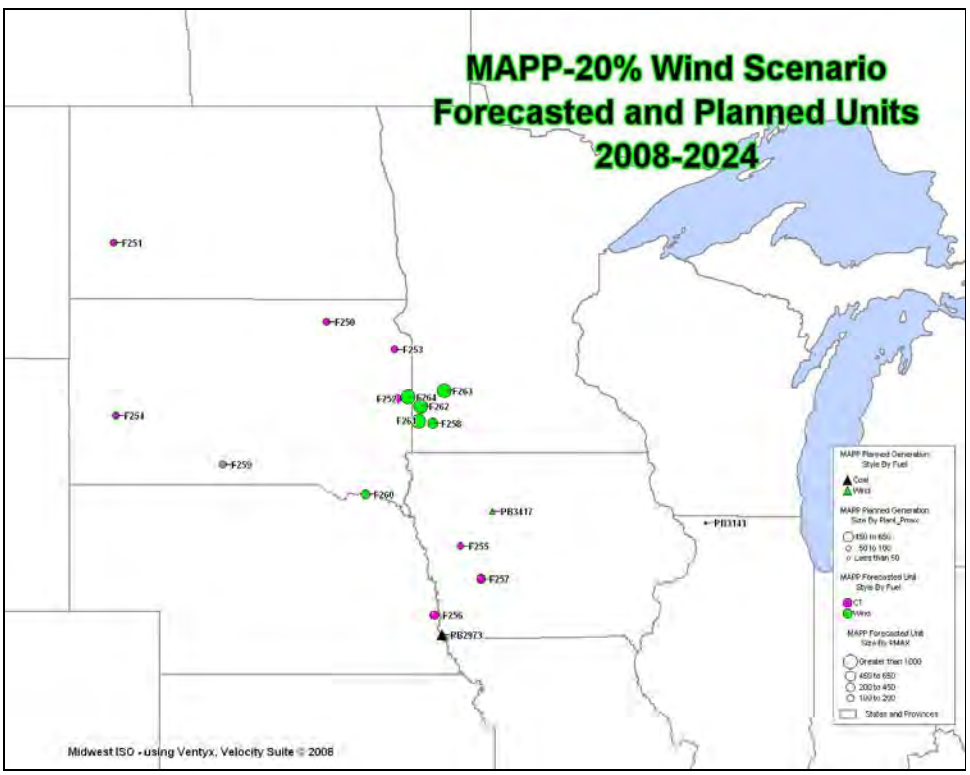


Figure A4-8: 20% Wind Energy Scenario Planned and Forecast Siting.

Midwest ISO Central Regional Resource Forecast Siting

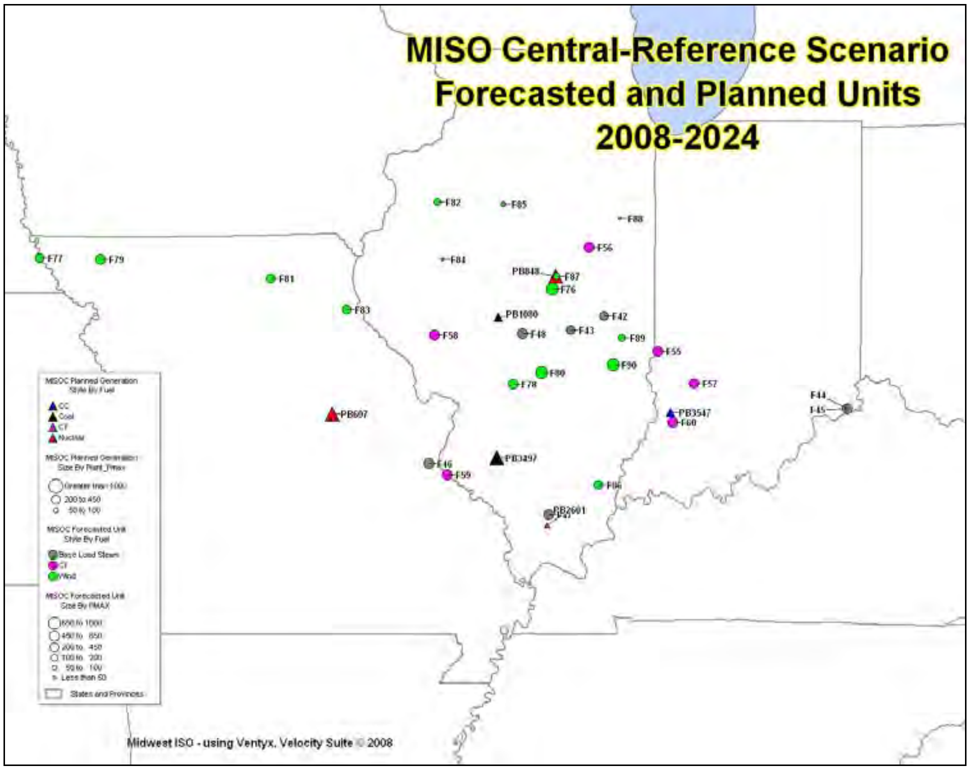


Figure A4-9: Reference Scenario Planned and Forecast Siting.

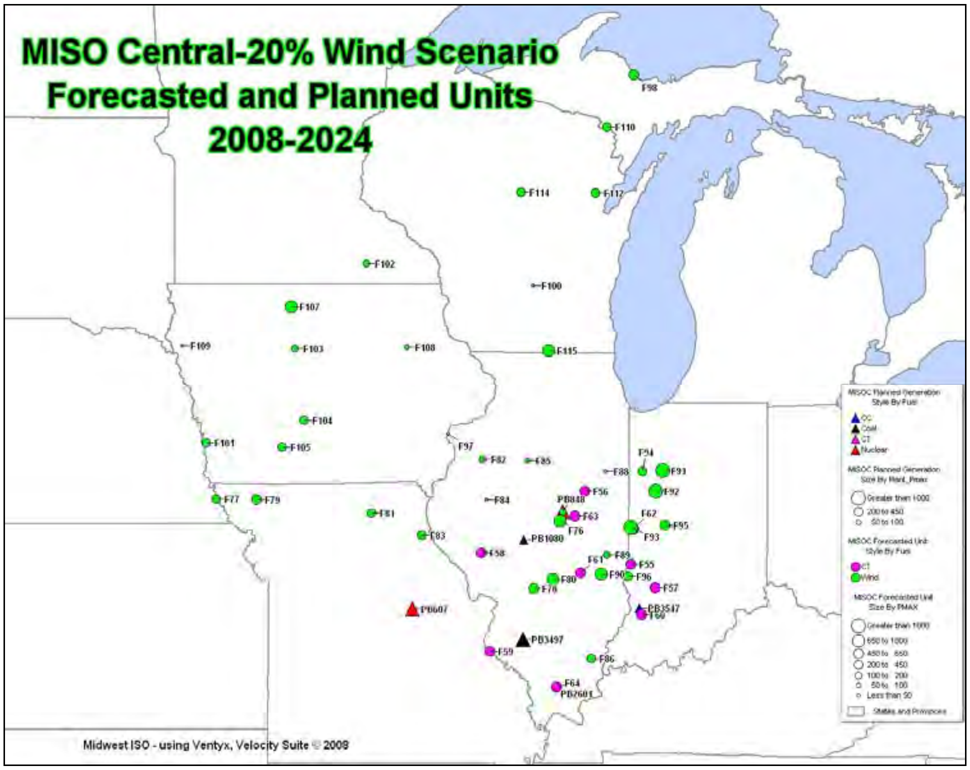


Figure A4-10: 20% Wind Energy Scenario Planned and Forecast Siting.

Midwest ISO East Regional Resource Forecast Siting

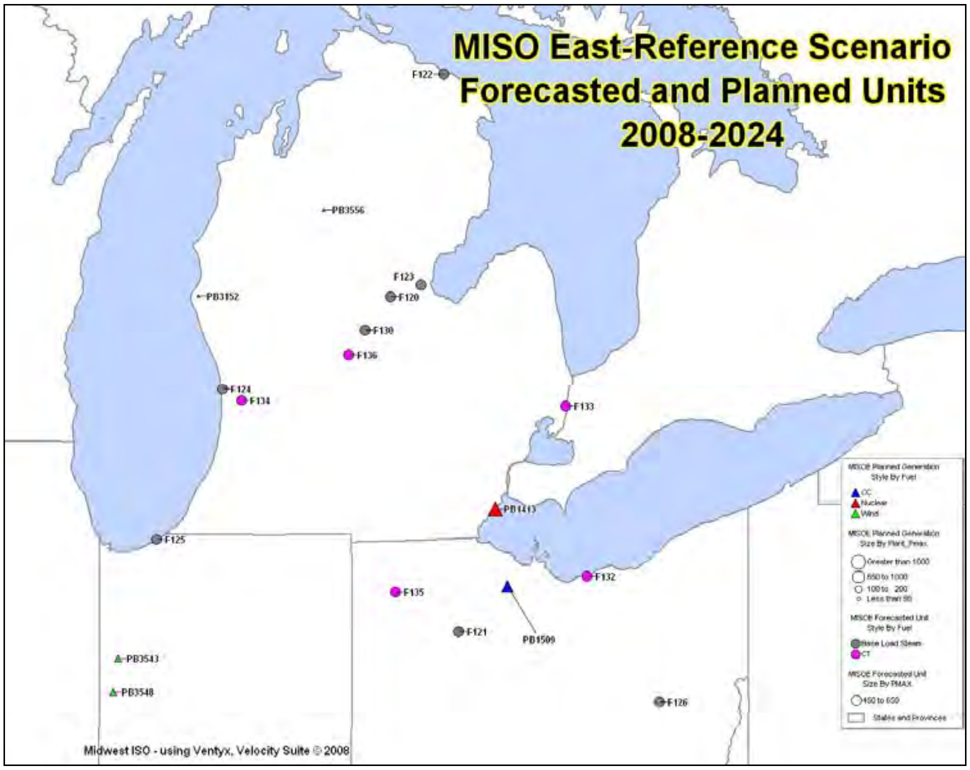


Figure A4-11: Reference Scenario Planned and Forecast Siting.

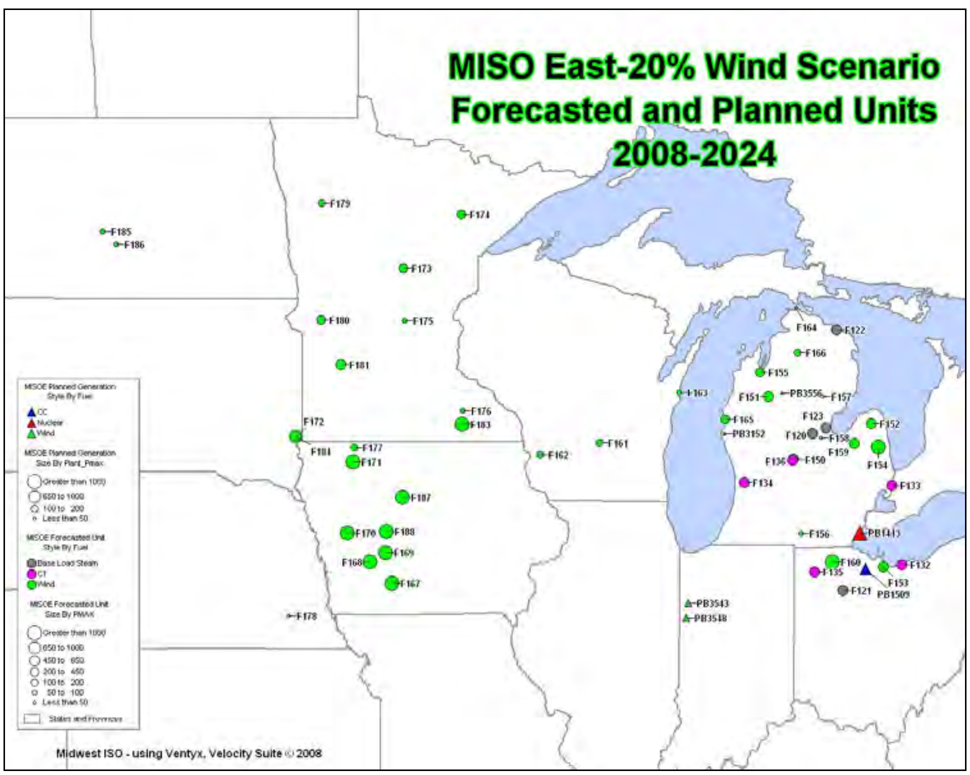


Figure A4-12: 20% Wind Energy Scenario Planned and Forecast Siting.

Midwest ISO West Regional Resource Forecast Siting

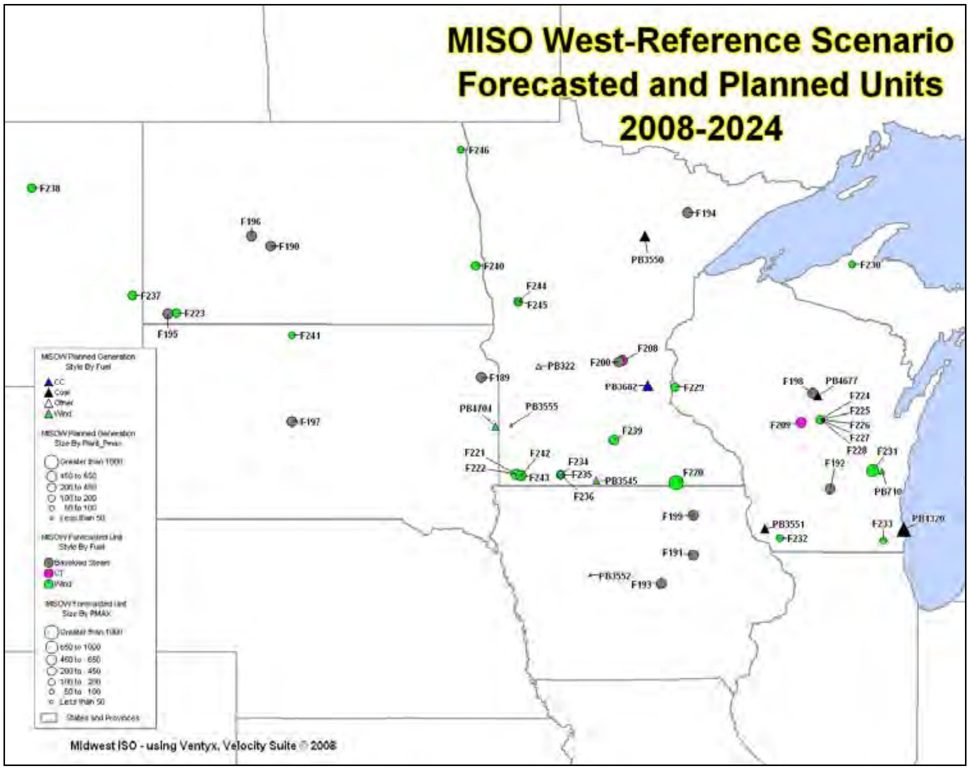


Figure A4-13: Reference Scenario Planned and Forecast Siting.

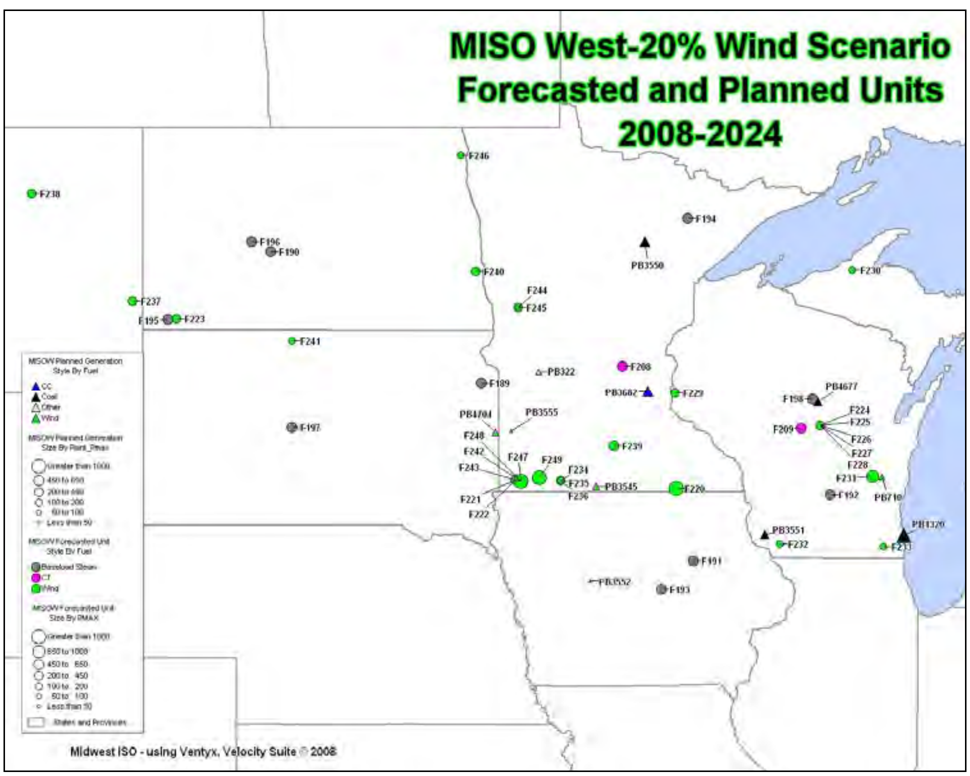


Figure A4-14: 20% Wind Energy Scenario Planned and Forecast Siting.

New York Regional Resource Forecast Siting

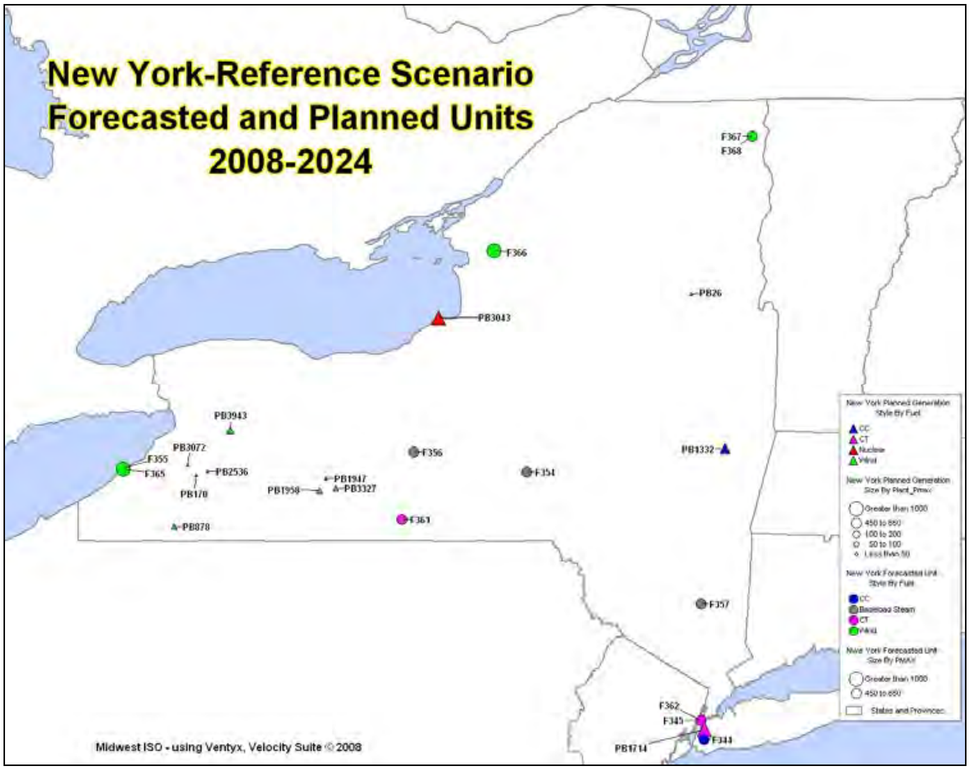


Figure A4-15: Reference Scenario Planned and Forecast Siting.

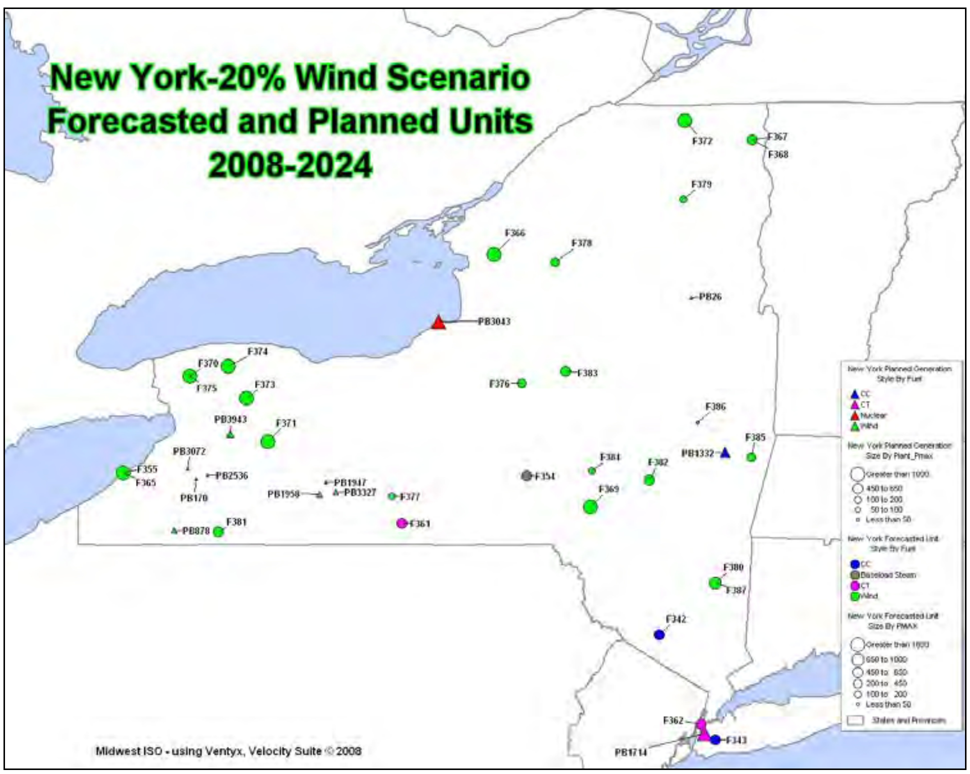


Figure A4-16: 20% Wind Energy Scenario Planned and Forecast Siting.

PJM Regional Resource Forecast Siting

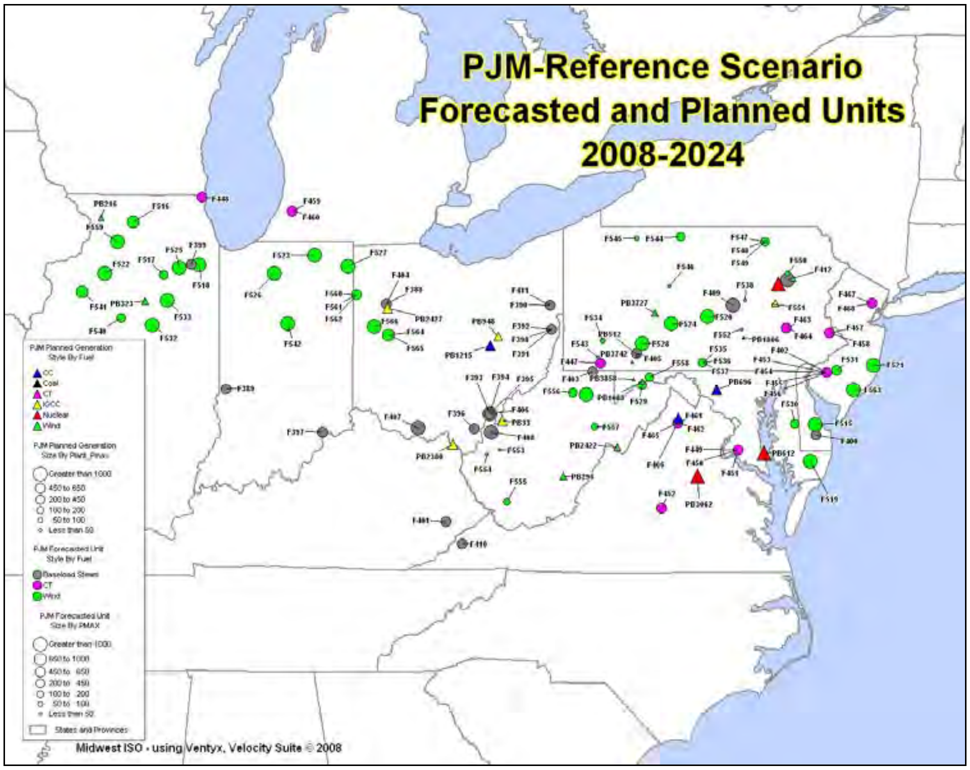


Figure A4-17: Reference Scenario Planned and Forecast Siting.

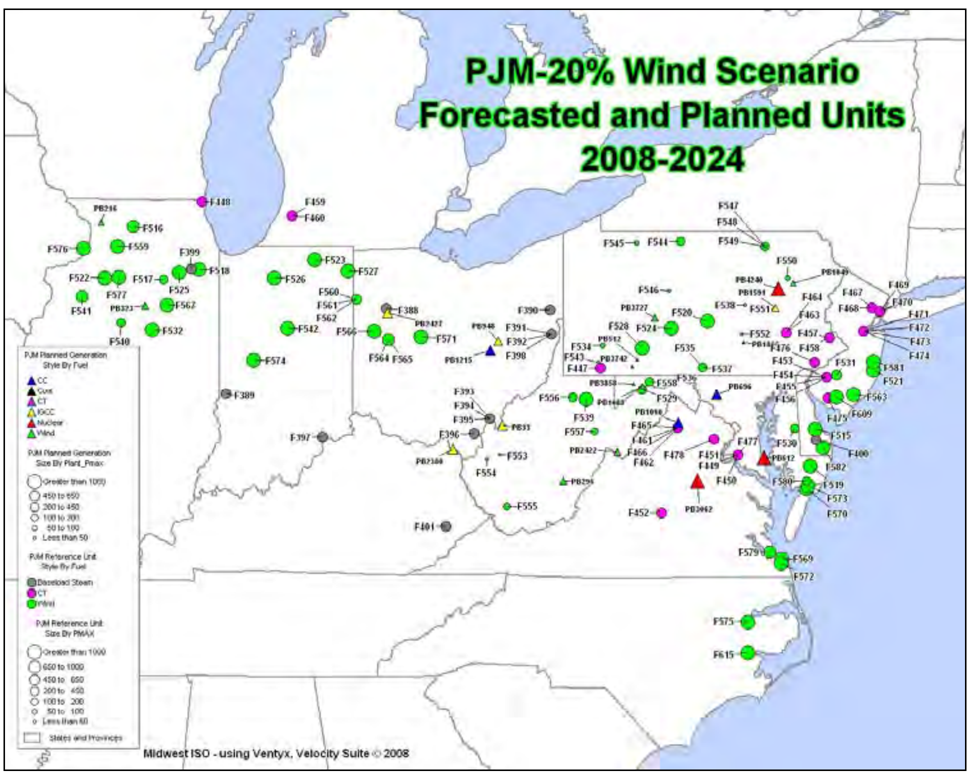


Figure A4-18a: 20% Wind Energy Scenario Planned and Forecast Siting.

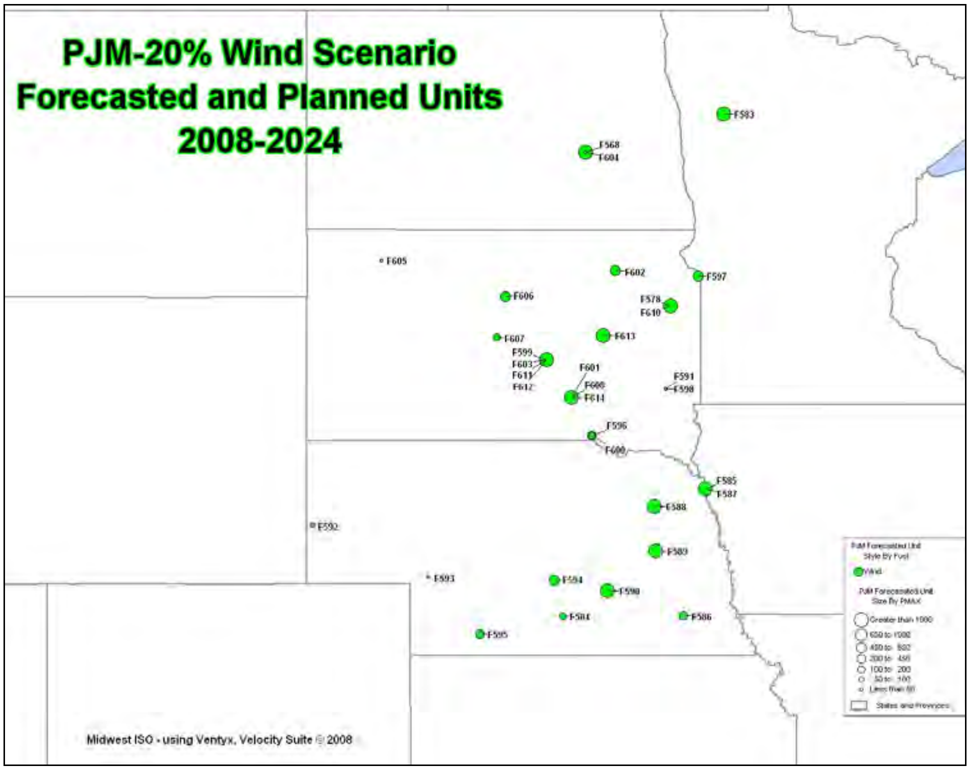


Figure A4-18b: 20% Wind Energy Scenario Planned and Forecast Siting.

SERC Regional Resource Forecast Siting

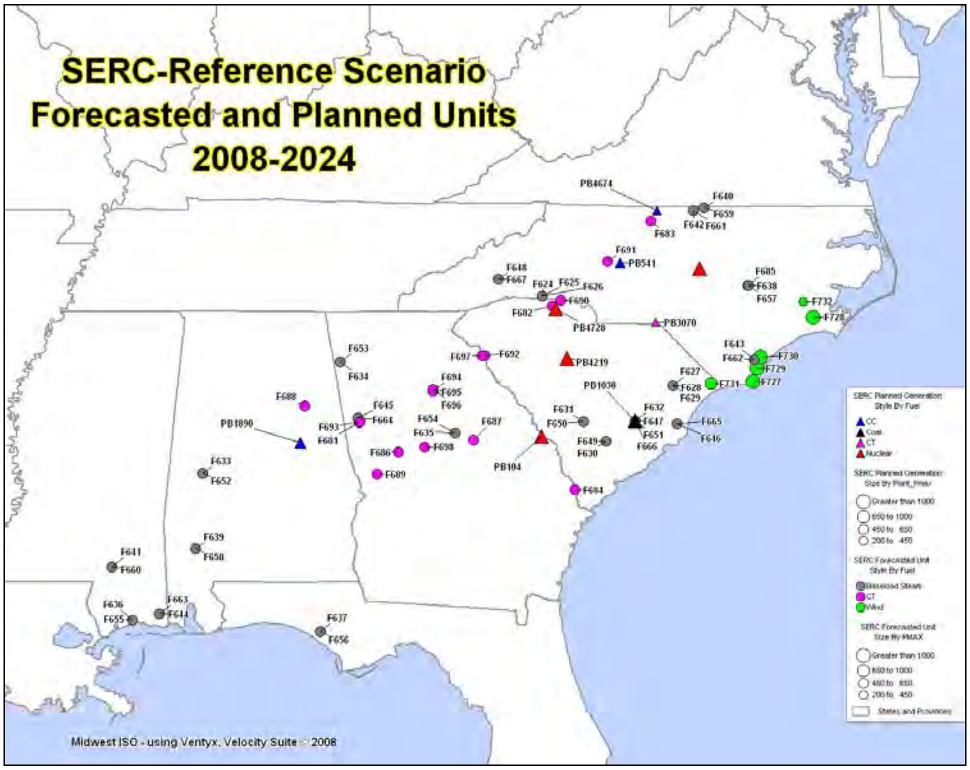


Figure A4-19: Reference Scenario Planned and Forecast Siting.

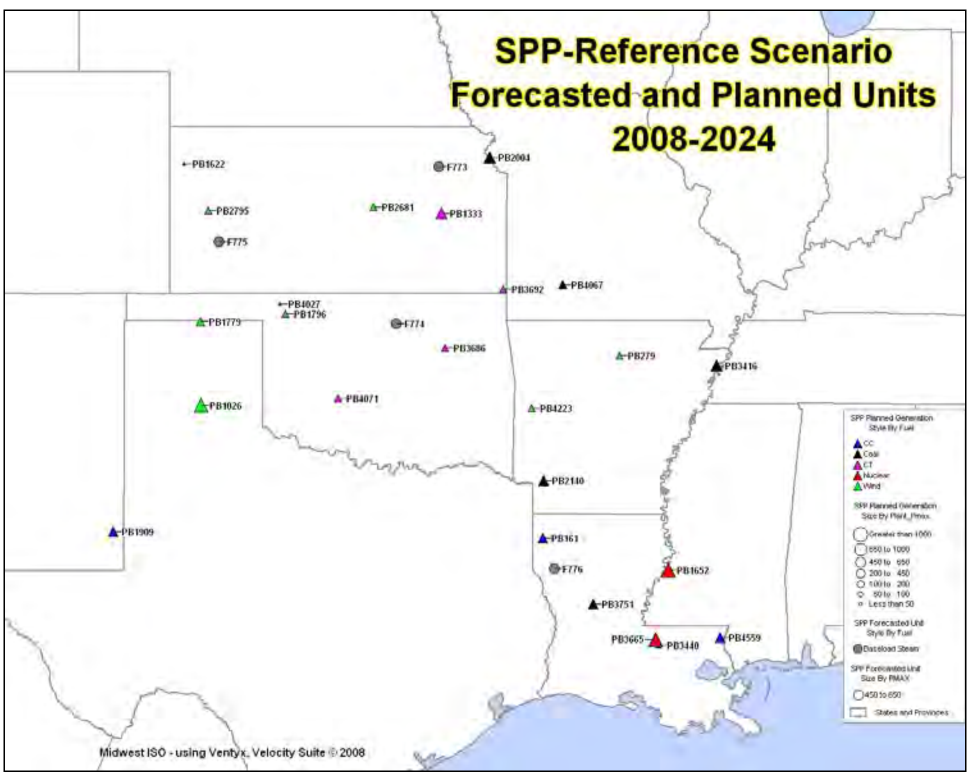


Figure A4-20: 20% Wind Energy Scenario Planned and Forecast Siting.

SPP Regional Resource Forecast Siting

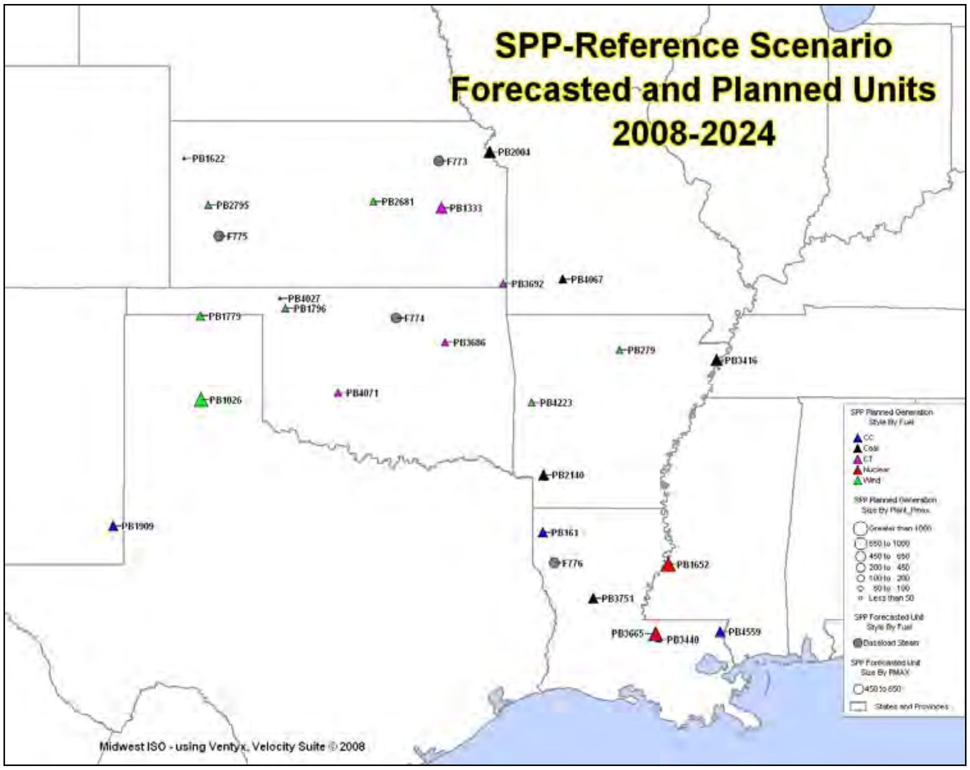


Figure A4-21: Reference Scenario Planned and Forecast Siting.

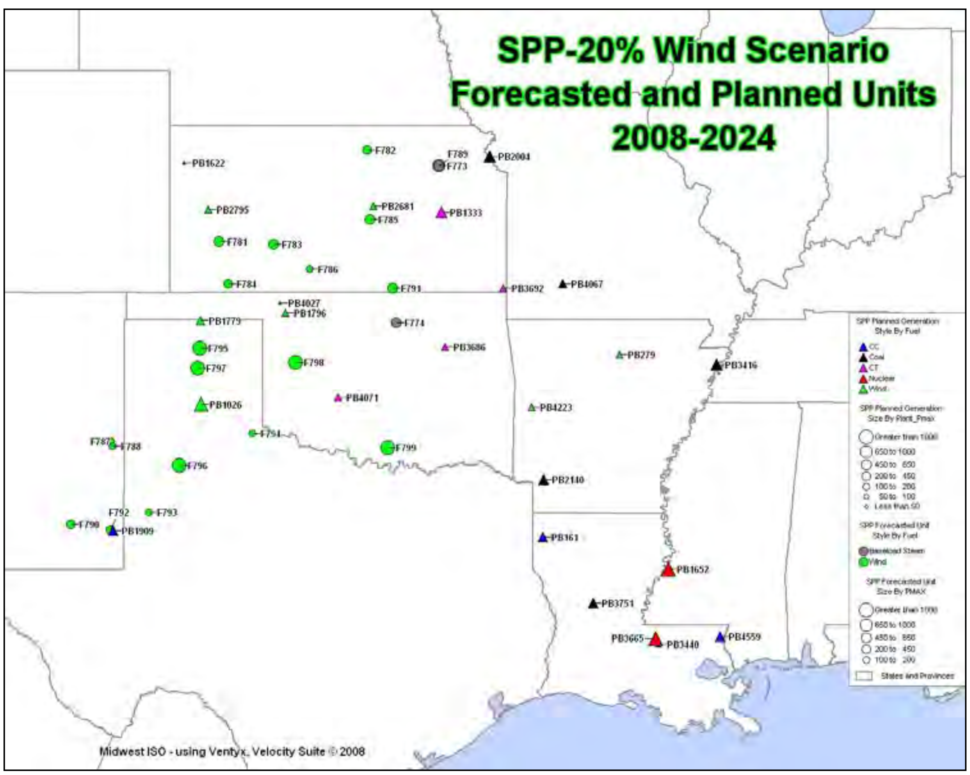


Figure A4-22: 20% Wind Energy Scenario Planned and Forecast Siting.

TVA Regional Resource Forecast Siting

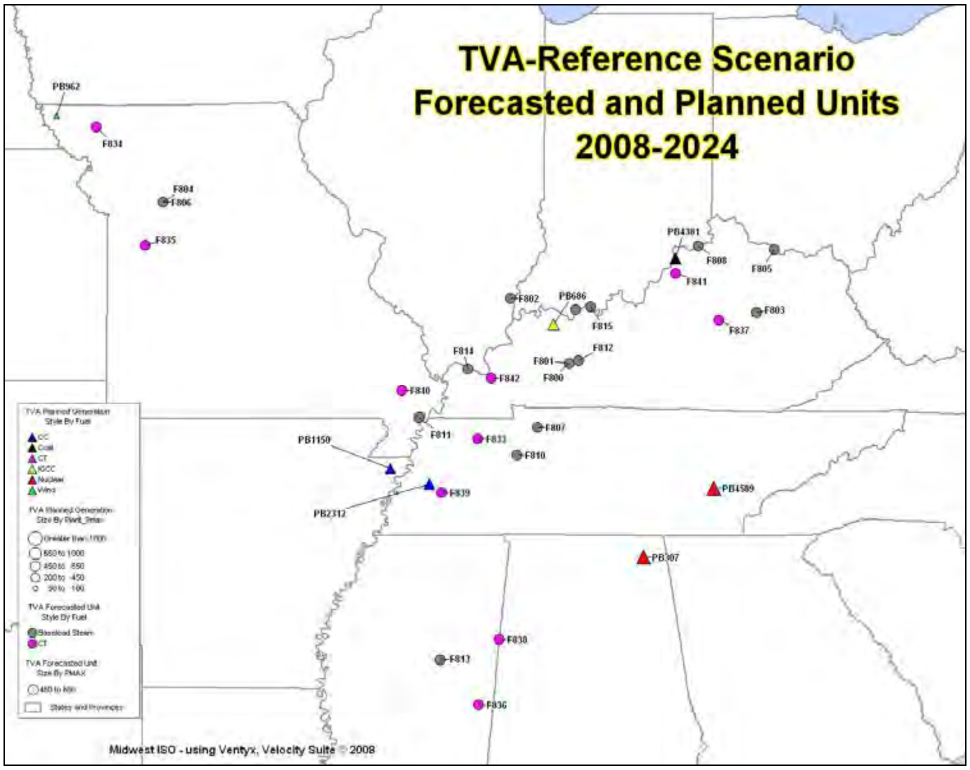


Figure A4-23: Reference Scenario Planned and Forecast Siting.

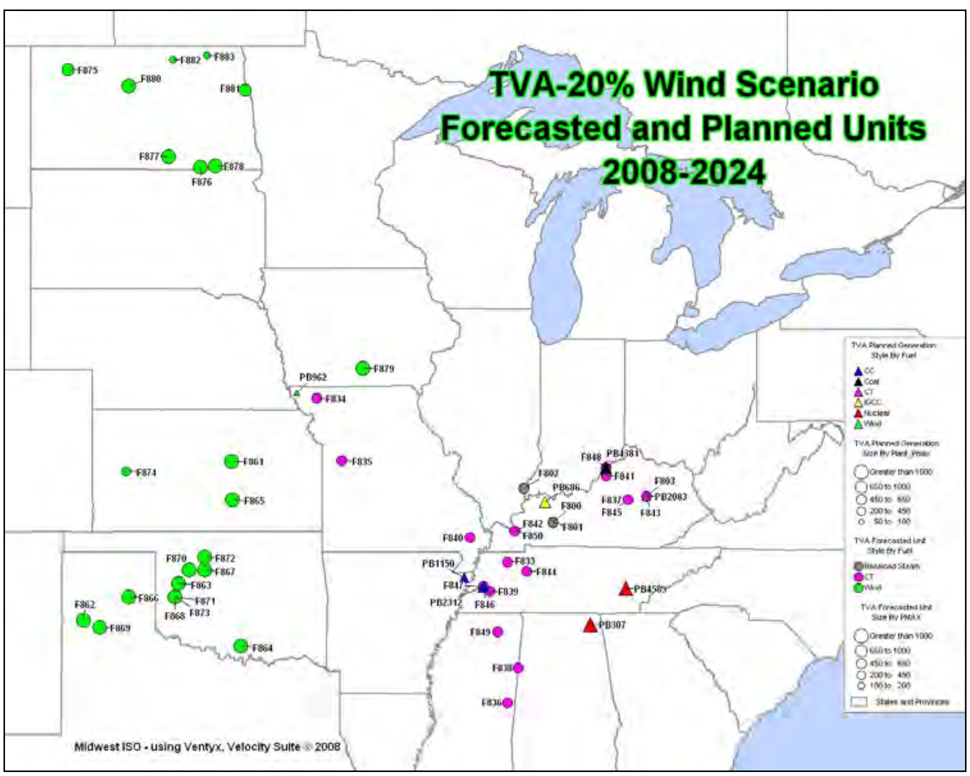


Figure A4-24: 20% Wind Energy Scenario Planned and Forecast Siting.

Appendix 5: HVDC and AC

The JCSP'08 overlays used both 800 kV High Voltage Direct Current (HVDC) and 765 kV AC transmission to form an overlay grid.

Many alternatives can be eliminated from the analysis process by using a few guidelines based on economic principles**. Large systems, such as the Eastern Interconnection, are very difficult to design economical transmission for large energy sources, such as wind generation, without tools that produce economic information. The JCSP'08 process was developed to allow a fast convergence on an economic transmission overlay.** Sensitivity studies using detailed system modeling can be run to verify the validity of the assumptions based on the guidelines.

Distance.

Four primary economic factors determined the choice of the HVDC transmission design elements for the conceptual JCSP'08 overlay transmission designs:

- Economics-minimum cost to deliver energy competitively
- Ability to schedule energy to market signals for HVDC
- Simple to understand how the conceptual JCSP'08 transmission overlays may work
- Financially separable and identifiable from the existing AC grid

1. Economic selections depend on the delivered cost, distances and the ability to load the transmission expansion economically.

Figure A5-1 is a simple comparison of the cost of construction of transmission of various types in \$/MW mile. The same costs in Figure A5-2 are used from Figures A5-1 and A5-3. Figure A5-1 determines **distance**; Figure A5-2 determines **voltage level** and rough power flow requirements. Figure A5-3 is more detailed and determines the number of transmission lines of a voltage to reach the break over power transfer levels for a single loss of a line of that voltage. Distance and losses are not a factor for Figure A5-3. Much more detailed and involved studies are used for actual transmission expansion designs, but these figures demonstrate simple decisions that enable the selection of the transmission lines and some guidance on how to incorporate the lines into the conceptual JCSP'08 transmission expansion overlay design.

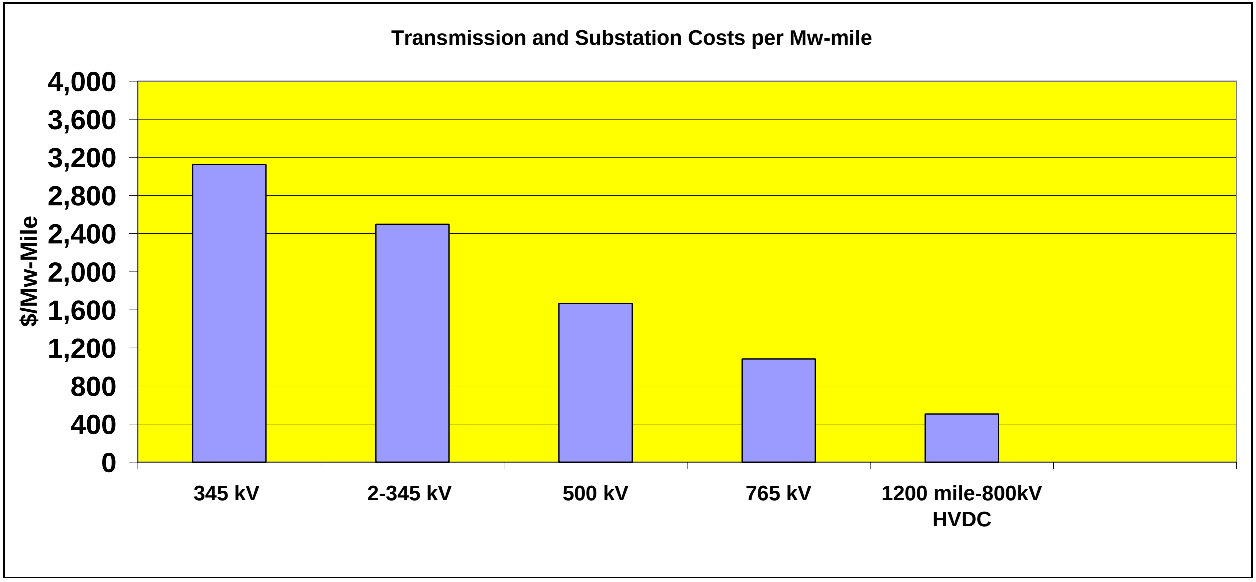


Figure A5-1: Transmission and Substation Costs per MW mile

Typical maximum normal loading levels for a 345 kV line is between 600 MW in the western part of the Midwest ISO to 1000 MW in the central and eastern parts of the Midwest ISO. Western areas have low load densities and long distances between major loads and generation. Central and eastern areas have fairly short distances between major load centers and generation. A loading of 2600 MW is typical for 765 kV and 800 kV HVDC has a rating of 6,400 MW. Later examples will use 345 kV, 765 kV and 800 kV HVDC.

The conclusion to be drawn from Figure A5-1 is that 765 kV AC and 800 kV HVDC are the low cost options for large amounts of power transfer.

HVDC terminals cost more than AC substations. HVDC lines cost less per mile than AC lines for the same capacity. The cross over distance is 600 miles which is the distance from the East Coast of New Jersey to Indiana. So, for the Midwest ISO exports, 765 kV is used for transferring energy from Indiana to the East Coast and 800 kV HVDC is used to transfer energy from the western part of the MAPP and Midwest ISO areas to the East Coast. Figure A3-2 shows a simple example of cross over distances for 345 kV AC, 765 kV AC and 800 kV HVDC. 345 kV is the choice to 225 miles, 765 kV is the choice from 225 miles to 600 miles and 800 kV is the choice from 600 miles plus.

The conceptual JCSP'08 transmission overlay design uses 800 kV HVDC in groups of two or more to transfer energy more than 600 miles west to east. 765 kV or the equivalent in 500 kV or 345 kV is used to provide the contingency backup, collect energy to deliver to the HVDC terminals and interconnect generation. The north-south distances to tie multiple HVDC terminals of the JCSP'08 overlay together to operate as a self contingency grid are less than 600 miles.

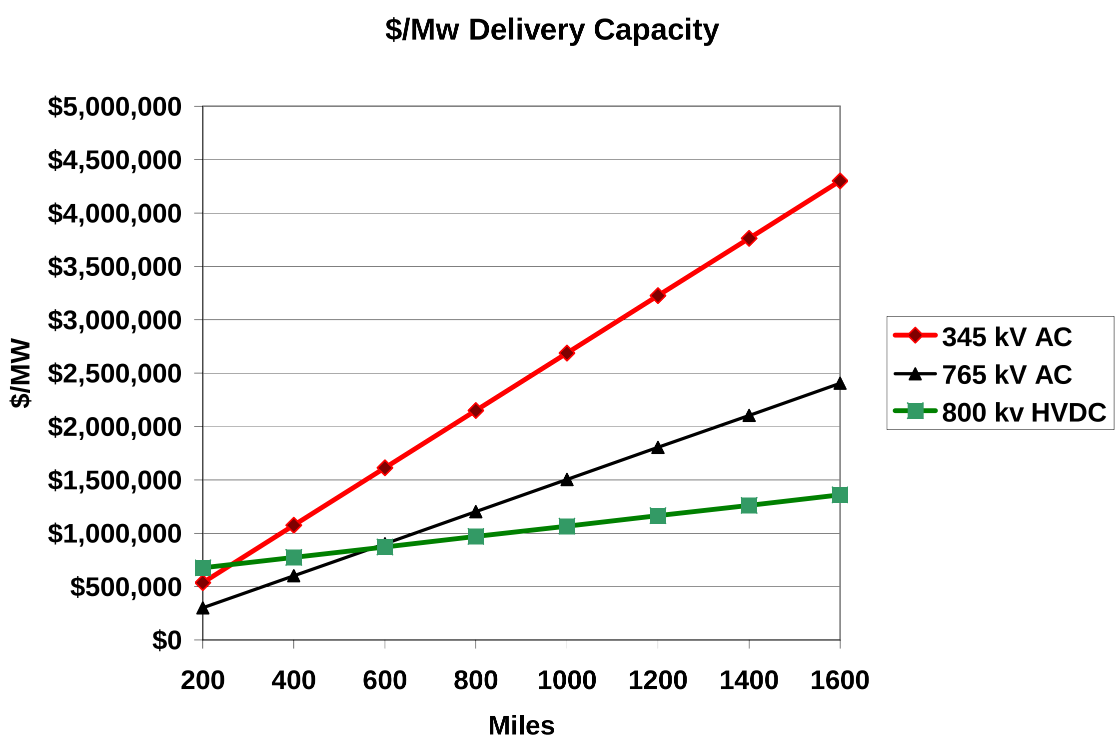


Figure A5-2: $/MW Delivery Capacity

765 kV AC was used to supply the transmission reserve margin between groups of three HVDC terminal locations as these distances were shorter than 600 miles. 765 kV can be expanded to connect future generation and serve the transmission connected to load as load grows. Thus there is no need for future taps of the HVDC lines beyond the initial plan.

For SPP there was already a 765 kV AC collector system planned. The center of the wind resource is located south to north from western Oklahoma to western Kansas. 600 miles from this locus does not connect to Atlanta, Nashville or New Orleans which are locations of energy delivery. 800 kV HVDC was used to connect to Atlanta, the Nashville area and New Orleans for the SPP wind energy deliveries to the east.

The HVDC 6,400 MW transmission lines have two poles or wire bundles of a 3,200 MW rating. Each pole can operate independently or as matched sets of poles called a bipole. The converter stations (HVDC substations) can be configured in different ways. Both poles can be included into one 6,400 MW substation. Multiple 765 kV AC lines would be required to support this level of power concentration. The terminals of one pole can also be physically separated into two series connected 1600 MW converter stations. Figure A5-3 shows a four converter station configuration for a bipolar HVDC transmission. The converter stations of 1,600 MW each can be physically separated geographically and connected with lines or cables. The 400 kV converter stations can be connected by underwater or underground cables; thus some of the terminals can be located in urban areas on the East Coast. Splitting the converter stations allows better utilization of the existing underlying transmission thus keeping the JCSP'08 overall cost low. AC connections between the converter stations provide the contingency backup capability by transferring power from a faulted HVDC line to other HVDC lines.

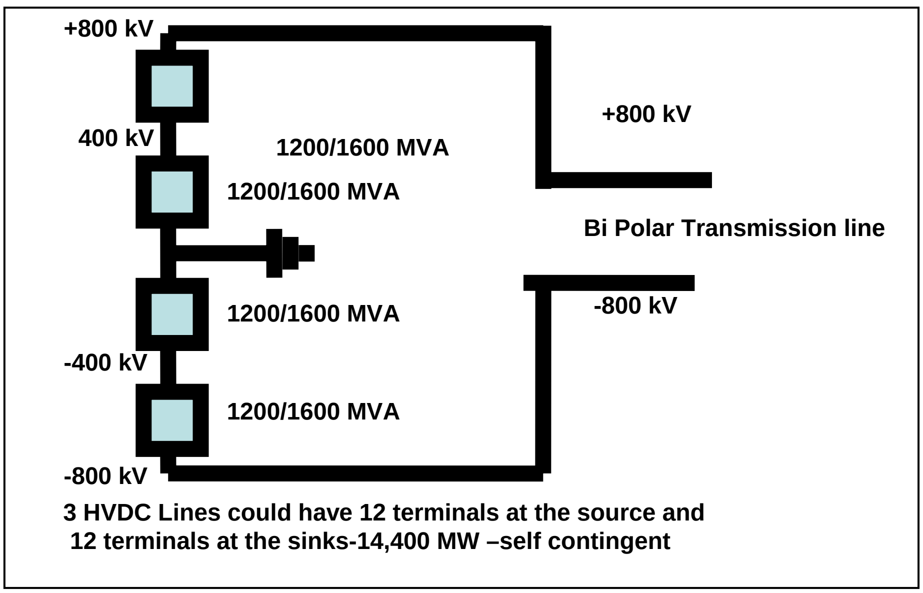


Figure A5-3: A four converter station configuration for a bipolar HVDC transmission

The conceptual JCSP’08 transmission overlays must be reliable as well as economical. The conceptual JCSP’08 transmission overlays are designed to be able to withstand the outage of a line, including an HVDC bipole. The conceptual JCSP’08 transmission overlays are designed so as not to impose any larger contingent flows on the underlying transmission system than what the underlying transmission systems are currently designed to withstand.

Figure A5-4 is a more detailed comparison of the number and rough relative construction cost of 345 kV, 765 kV, and 800 kV HVDC transmission lines to achieve a level of power transfer with transmission reserves. Economic break over points can be estimated using this type of analysis.

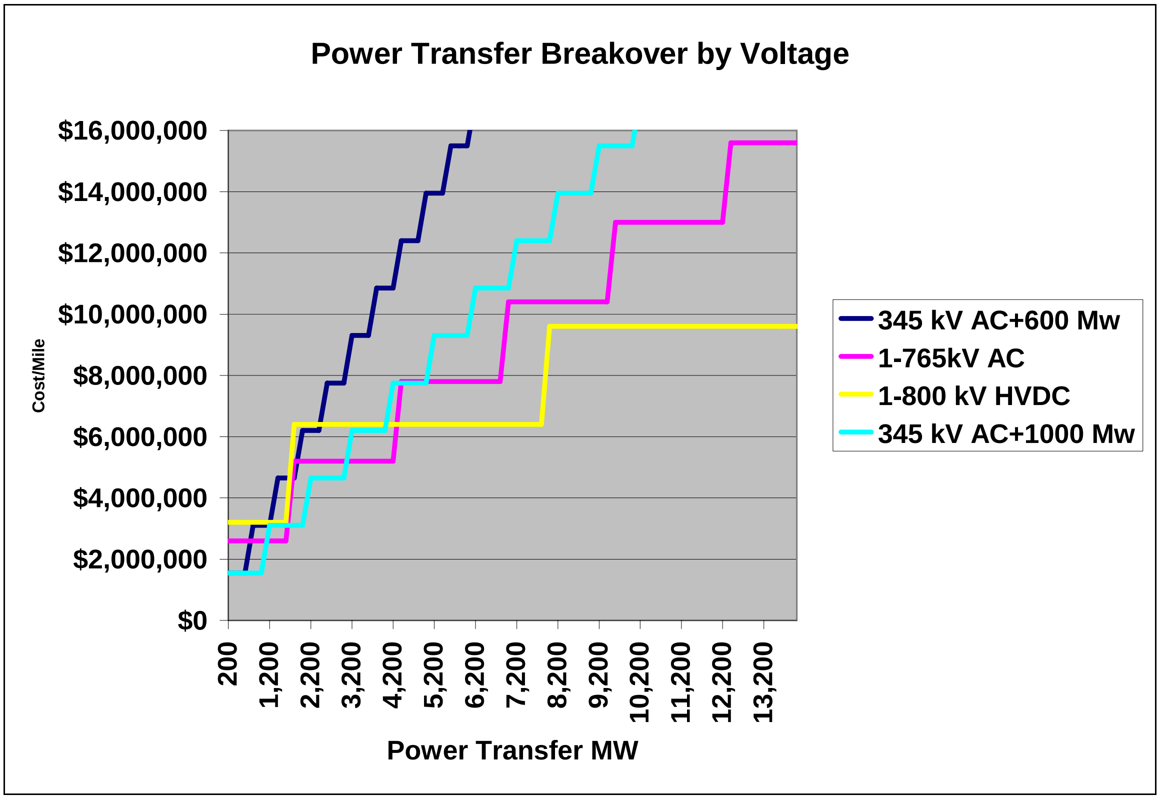


Figure A5-4: Power Transfer Breakover by Voltage

For this example, in the case of adding 345 kV lines, it is assumed that there are already multiple 345 kV lines in the area that would have capacity to withstand an outage of another 345 kV line. A 600 MW and a 1,000 MW incremental power transfer capacity were used. As the power transfer capacity increases and additional 345 kV lines must be added.

For this example, 765 kV lines were assumed to have a 2,600 MW maximum loading capability. The underlying system is assumed to have a 1,500 MW contingency withstand limit. The transmission on the underlying system is capable of withstanding a 1,500 MW loss of generation, as an example. The pre-contingent loading of the system is 1,500 MW plus the number of 765 kV lines added minus one. Each step in the 765 kV price per mile is the addition of one line. All but 1,500 MW is absorbed by the overlay for a contingency. The larger the difference between the capability of the underlying system and the overlay line rating for long distance power transfer, the less utilization of the sum of the power transfer capacity added. AC lines will have more difficulty than HVDC lines in achieving the maximum theoretical power transfer rating increases due to the physics of AC systems. HVDC can schedule the power level if the energy is available.

Lines Added	Pre-contingency power transfer Limit	Utilization
1	1,500 MW	58%
2	4,100 MW	79%
3	6,700 MW	86%
4	9,300 MW	89%
5	11,900 MW	92%
6	14,500 MW	93%

Table A5-1: 765 kV Self Contingent Power Transfer Limit

Lines Added	Pre-contingency power transfer Limit	Utilization
1	1,500 MW	23%
2	7,000 MW	62%
3	14,300 MW	74%
4	20,900 MW	81%

Table A5-2: 800 kV HVDC Self Contingent Power Transfer Limit

Guidelines that can be drawn from this example are:

- 800 kV HVDC is an economically superior choice for power transfer levels greater than 4,100 MW of power transfer. Also the distance to transfer the power has to be greater than 600 miles from Figure A3-2.
- 765 kV becomes the economically superior choice compared to 600 MW rated 345 kV lines at about 1,400 MW of power transfer. Also the distance to transfer the power has to be greater than 225 miles from Figure A3-2. Again distance is a factor. Other factors such as the number of ROW may be the determining factor. The information is used to determine alternatives that might be considered not to make a final decision.
- 765 kV becomes the economically superior choice compared to 1,000 MW rated 345 kV lines at about 5300 MW of power transfer. The same guidelines on distance and ROW considerations might be used for this case also.
- The power transfer contingency level for the conceptual JCSP’08 transmission overlay near the 765 kV system tying the bipole converter sections together is about 4,800 MW. Thus, if generation stations are located near the 765 kV lines near the HVDC collection or delivery points, a station of about 4,000+ MW could be supported on a reliability basis. There may be a transmission service fee to the generator associated with the use of the transmission reserve margin of the conceptual JCSP’08 transmission overlay design.

The Rule of Three is an old guideline that says that three lines are needed to make an economical overlay of a higher voltage. One can also infer that one higher voltage line would not be a superior choice. Thus it is hard to initiate the construction of an overlay in a power system with growth rates of about 2%. Permitting and approval processes one line at a time also limits the initiation of higher voltage, more efficient transmission overlays. Many detailed studies usually are performed to make the final decisions on the selection of voltage levels and type of lines that are to be constructed. The guidelines above help with the understanding of why choices are made. The guidelines may help eliminate the study of alternatives that are not close to being competitive.

The question as to which interfaces would support power transfers can be obtained from the energy interchange diagram, shown in Figure A5-5 and Table A5-3, that is the translation of the energy flows in the energy interchange diagram. The heaviest flows can support the HVDC according to the guidelines set above. Some of the weaker flows would probably be served better with AC line additions. AC lines are much more difficult to predict their addition's effect on the interface diagram. HVDC lines tend to subtract from the interface flows, Table A3-3, but not on a one to one basis. The reason for this is that HVDC lines are scheduled to transmit power along the paths that the energy flow is shown to travel if it could under the "Copper Sheet" analysis. AC power displacement mechanisms create complex power flows all over the system.

Copper Sheet analysis is shown in Figure A5-5. The paths and quantities of increased energy flow are shown to flow where they would flow if there were no constraints compared to a constrained existing system.

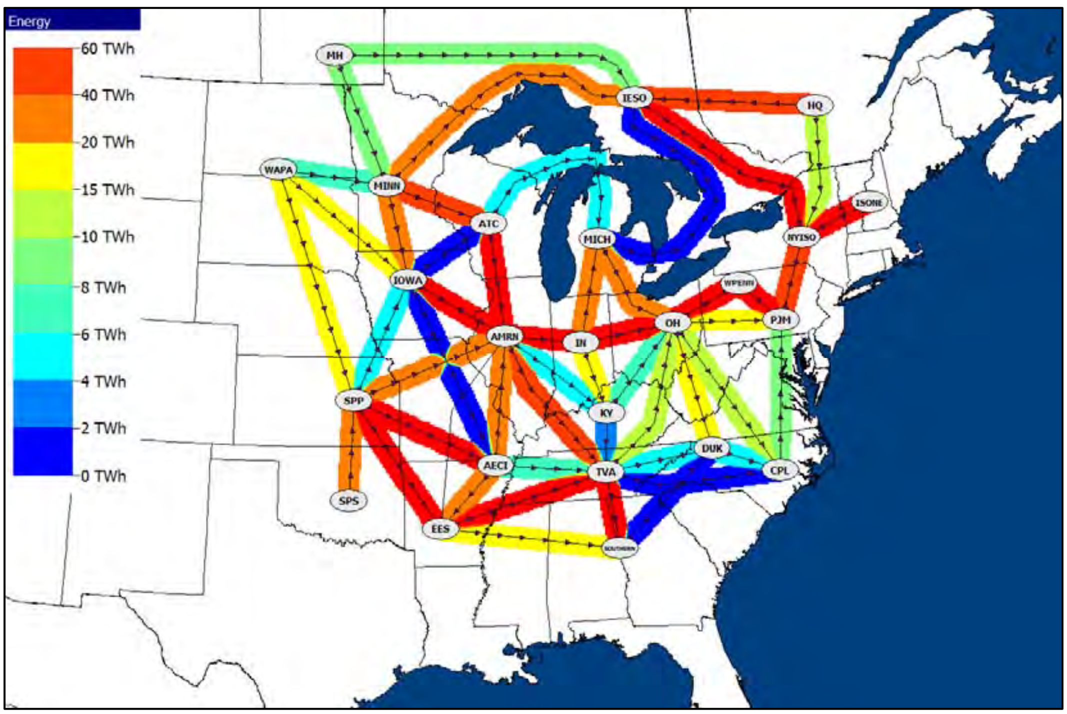


Figure A5-5: Copper Sheet Energy Interchange Diagram

INTERFACE	Additional Transfer Needed to Deliver 80% Energy (MW)	Additional Transfer Needed to Deliver 80% Energy (MW)
AMRN - IN	26,878	15,210
IN - OH	19,334	9,211
OH-E_PJM	16,126	9,998
SPP - EES	12,567	10,743
AMRN - IOWA	12,204	6,087
New England/New York	10,331	6,056
TVA - EES	9,472	7,661
SOUTHERN - TVA	8,860	5,715
IESO - New York	8,678	6,551
New York - E_PJM	8,430	7,558
ATC - AMRN	8,068	4,861
AECI - SPP	7,866	3,519
SPP - SPS	7,174	3,165
IESO - HQ	7,098	6,866
MINN - ATC	6,575	3,320
AMRN - TVA	4,691	2,193
AMRN - AECI	4,618	1,884
MICH - IN	4,568	5,333
MICH - IESO	4,184	5,414
AECI - EES	3,976	916
SPP - AMRN	3,922	2,218
MINN - IOWA	3,424	2,724
MICH - OH	3,128	3,541
PJM - CPL	2,998	1,315
IOWA - SPP	2,926	2,692

Table A5-3: Translation of the energy flows in the energy interchange diagram

Loop flows, and remaining energy flow potential with the conceptual JCSP'08 transmission overlay design, show that there is still some opportunity for west to east transmission. PROMOD runs would have to be performed, with new conceptual lines added, as the benefits diminish as lines are added. There may not be enough benefits to pay for the line since the other lines have already adjusted the East Coast prices downward.

The post JCSP'08 overlay energy power diagram can also confirm whether there is significant loop flow on the interfaces. Alternative sensitivity studies are needed to determine the best economic choice for a particular area of study. Note that the north-south flows are not heavy in the energy flow diagram compared to the Copper Sheet difference case in Figure A5-5.

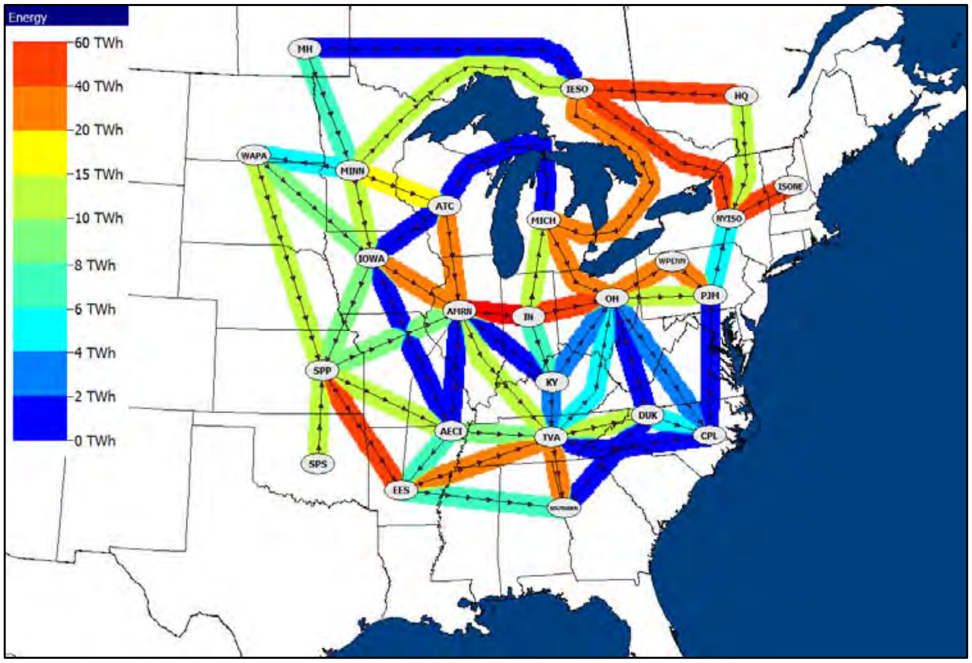


Figure A5-6: Coppersheet Difference Case

2. Ability to Schedule Energy with HVDC

The ability to schedule HVDC allows the wind producing areas of the Midwest ISO and SPP that are exporting energy to east and southeast to also export the diversity of the wind energy. Existing, and forecast, generation in the east and southeast have ramping capabilities that could be used to control the wind diversity. This saves building generation in the Midwest ISO and SPP areas specifically to control the wind energy diversity.

The ability to schedule HVDC also avoids loop flows through the southeastern area of the Eastern Interconnection as HVDC terminals deliver energy directly to the highest priced areas from the lowest priced areas. Comparing Figures A5-5 and A5-6 shows the changes in loop flows due to the conceptual JCSP'08 transmission overlay design. HVDC is an express train. Energy only gets on and off at the terminals. Only the energy scheduled (paid for a ticket) gets on the train. An AC system relies on the honor system. Free ridership is a problem with AC systems. Also, on AC systems, the power flows according to the laws of physics. Energy markets do not send price signals based on the laws of physics. Well designed HVDC systems can perform to work as the market price signals indicate. Power is collected from low cost areas and delivered to high priced areas without taking detours.

3. Simple to understand and of modular design that allows expansion in the future

A well designed overlay with HVDC collection and delivery points distributed over the system provide a transmission system that operates very closely to the way that people think the market should operate. Schedules and market process could determine who received the energy (Regional Transmission Organization (RTO) or utility level) and where the energy was produced. The location of the collector converter stations and delivery collector stations, very near to where the energy market signals indicate that the transactions should take place, limits loop flows and unexpected results.

No energy is displaced from an HVDC line. What goes in comes out minus losses. Losses are a function of the simple DC version of Ohm's Law. Using the DC version of Ohm's Law on AC systems by saying power takes the path of least resistance is less than half right.

Keeping the neighbors energy from flowing on "my" transmission can be accomplished. The reverse can also be accomplished. Free ridership is limited by the ability to schedule the HVDC transactions.

The ability to schedule HVDC greatly simplifies system design on the AC system for power flow analysis. For a given schedule on the HVDC system, the AC system on the source end can be designed locally with the HVDC terminals modeled as a load. For a given schedule on the HVDC system, the AC system on the sink end can be designed locally with the HVDC terminals modeled as a generator. The intervening systems between the HVDC terminals have to plan for the same level of power transfers associated with contingencies that the systems were designed for. The HVDC operation does not significantly affect the design of intervening systems. For example, New England, New York and eastern PJM can continue using their present planning processes once a HVDC schedule is determined for their power flow cases. The JCSP'08 provides the schedules.

4. Financially separable and identifiable from the existing AC grid

The Midwest ISO Vision Exploratory Study is a design of an all AC 765 kV High Surge Impedance Loading (HSIL) transmission design for the Midwest ISO Transmission Expansion Plan 2006 (MTEP 06) with a 20% Midwest ISO footprint Wind Energy Scenario. Transmission was shown to be expanded only in the Midwest ISO and the PJM footprints. The assumption was that the Joint Operating Agreement and the Joint and Common Market Agreement may provide a means to pursue such a conceptual plan. The benefit to cost ratio was 1.1 to 1.0. HSIL construction has double the long range power delivery characteristic of a standard 765 kV line, about 4,500 MW. ROW requirements are 40% less than a standard line. Costs are about 70% of the standard line per MW-mile. China, Brazil and Russia use the HSIL concept with some of their recent lines. Limitations are:

- Spacing is too tight for live line maintenance
- Possible audible noise problems
- HSIL technology is new, about 20 years in use.

The Midwest ISO ran a similar scenario in MTEP 08 with one HVDC line. The power transfer performance of the HVDC line was better than the AC lines and the generator revenue was higher. The benefit to cost ratio was 1.18 to 1.0.

Examining the MTEP 06 and MTEP 08 Exploratory Plans in light of the cost allocation experience with RECB I and RECB II and the expressed views of various Midwestern ISO stakeholders, it became apparent that an all AC system is so complex from the cost allocation aspects that nothing would be constructed.

800 kV HVDC was announced during MTEP 08. China is building a system with fourteen 800 kV HVDC lines with 1,000 kV AC for contingency, distributing bulk power to existing transmission and generation interconnection. The fourteen HVDC lines are to be installed by 2018. China is building factories, test laboratories and training engineers to design, manufacture and construct 1,000 kV AC and 800 kV HVDC facilities. The JCSP’08 process is similar to the Chinese plan, but the Chinese are actually planning to construct major facilities.

The local cost allocation processes that are being used for the AC systems could be used for the AC parts of the overlay. The AC contingent backup and energy delivery systems could be viewed as load or the absolute value of negative load (generation). Allocation of costs on a postage stamp or load ratio share would still be valid. Another way is for the overlay to buy the energy collection, delivery and contingency backup (Transmission Reserve Margin) as transmission network service. The overlay would have to be assured that the cost of services or allocations were not more expensive than building the identified 765 kV. Utilities and RTO’s have processed to design AC systems. AC systems planned across borders are still a work in progress for cost allocation.

HVDC revenue would be recovered from those who used the energy. The revenue requirements of the HVDC line, losses, and generator revenues would be settled by with the RTO by the JCSP’08 HVDC line operations. The JCSP’08 would be an energy market for the RTO markets, and a trading hub an RTO without an energy market, or for a utility in JCSP’08. Line revenue requirements would be paid to the owners of the line. The **ability to schedule** allows the identification of the utility or RTO who was the source or sink and how to settle the transactions. The processes needed to operate and financially settle the JCSP’08 overlay are being used in the energy markets. Trading hubs offer similar functions.

Ownership of transmission facilities could be allocated by the first right to refuse construction of Transmission Owners in an RTO or a utility. Revenue requirements would be collected by the JCSP’08 operator and paid to the transmission owner. Those customers not buying or selling energy would otherwise not be affected. The separation of the conceptual JCSP’08 overlay may also allow third party financing with the construction, operation & maintenance managed by transmission owners along the line. The Sharyland transmission project in Texas is pioneering this concept with Real Estate Investment Trust Financing.

As the JCSP’08 is a voluntary organization and economical energy transactions are also voluntary, it would seem to have some tendency for the conceptual JCSP’08 transmission overlay design to have owners who wish to participate.

5. Summary

The conceptual JCSP'08 transmission overlay designs have the potential to make significant differences in the price of wholesale electric energy in the U.S. Eastern Interconnection. The money on the table may cause someone who is willing to construct the system to surface. The relative cost is only 2% of future incremental energy bills for wholesale power and energy.

The first step is the biggest. Two HVDC lines would cost about $14.4 Billion. The total build-out for a 20% Wind Energy Scenario is $80B. The Midwest ISO has existing Renewable Portfolio Standards and subsequent displaced low cost base load generation sufficient to load the lines and provide the basis for energy transactions. The minimum system would probably come close to breaking even.

The largest risk is a carbon tax or cap and trade. The Midwest ISO analysis of a $25 carbon tax shows that there is little transmission that is required under that scenario. A carbon tax of $25/ton of carbon dioxide is projected to raise the wholesale price of power and energy in the Midwest ISO by 55% compared to the Reference or business as usual case. See MTEP08-Chapter 4-Pages 126 & 127 for a discussion:

http://www.midwestiso.org/publish/Document/279a04_11db4d152b9_-7d8d0a48324a?rev=1

If your browser has a problem using the link above, the path is as follows:

website:	www.midwestiso.org
tab:	Planning
Pull down menu:	Expansion Planning
Select:	Approved Midwest ISO Transmission Expansion Plans (MTEP)
Select:	MTEP 2008

One byproduct of the conceptual HVDC overlay feature is that it may be possible to have a frequency control on the HVDC lines that could spread disturbances over a very large base of generation mitigating the disturbance. This would cost little to implement and may solve some of NERC's[1] concerns about frequency trends in the U.S. Eastern Interconnection. The Midwest ISO has low frequency disturbance damping equipment operating with HVDC lines in Manitoba and a 1,000 MVAR Static VAR System in Forbes, Minnesota coupled with generation stabilizers.

More studies need to be done. The JCSP'08 is just the start.

[1] North American Electrical Reliability Corp. (NERC)

Appendix 6: Wind Transmission Overlay Lines

The information on Wind Transmission Overlay Lines is on an Excel spreadsheet. You can access it here:

- Wind_Transmission_Overlay_Lines.xls

Appendix 7: Value Based Planning

The primary objective of the 2008 Joint Coordinated System Planning Study is the development of the transmission requirements needed to address two specific scenarios that represent the increased use of wind energy throughout the Eastern Interconnection. The first scenario, called the Reference Scenario, effectively represents a 5% wind penetration level while the second represents a 20% wind penetration. These two scenarios are directed toward providing transmission solutions for the economic delivery of large amounts of wind energy, by the year 2024. For the development of the primary objective Value Based Planning is used.

Value Based Planning recognizes that there are numerous value drivers, also known as metrics, which need to be included in the evaluation of projects; these value drivers include both reliability and economic parameters. Such value drivers include:

- adjusted production cost
- NERC TPL[1] standards
- mitigation of congestion
- local and regional economic development
- national security
- greenhouse gas emission reductions
- electricity price considerations

For the JCSP'08 analysis the key metric is adjusted production cost as a result of the mitigation of congestion. Other metrics, such as CO_2 production are tabulated, but were not included, in the transmission development decision making process for this study.

While the two scenarios in the JCSP'08 are credible, and reflect current initiatives being considered, this study should not be considered an exhaustive list of the potential alternatives for the facilitation of renewable wind energy into the grid. The 20% Wind Energy Penetration Scenario is based on sourcing the wind from the highest capacity onshore wind resources which are primarily located in the Midwest and developing the associated transmission requirements to deliver to loads throughout the Eastern Interconnection. Another scenario that is desired is to look at sourcing greater amounts of wind nearer eastern load centers to investigate the tradeoff in the costs associated with using lower quality onshore wind resources plus more offshore wind. The combination of the lower quality onshore wind plus the offshore wind will effectively require more wind turbines for those onshore and higher costs for the offshore turbines. The increase in the costs of the wind turbines to use local wind resources would then be compared to the reduction in transmission related costs. This scenario is a JCSP'09 or EITAG candidate Scenario.

The secondary objective of the JCSP'08 is the development of reliability analysis. The JCSP'08 study recognizes the intertwined nature of traditional planning to meet reliability needs, while at the same time providing long-term expansions that address economic value. Separate reliability and economic studies are performed with an objective to combine the studies next year in JCSP'09 or EITAG.

It is often stated that reliability driven expansions are "mandatory," while economic expansions are "optional," or discretionary. The distinction between reliability and economic transmission is blurred at best and now is the time to bring the two processes together. These two assessment types represent the difference between incremental least-cost planning for reliability compared with total least-cost planning for economics. In the long run the economic least-cost plan will always be less expensive than the incremental least-cost plan for the short-term reliability. While planning to meet reliability needs, and planning for economic expansions, are considered by many to be distinct processes, they ultimately have the same objective - to provide for the efficient, reliable operation of the transmission network, and they must come together into a common process

[1] North American Electric Reliability Corporation (NERC) Transmission Planning (TPL)

Appendix 8: Background on Wind - "Wind Tutorial"

A8.1 Wind Farms/Turbines

This appendix describes the characteristics of wind energy, a brief description of the wind data that is available for studies, the impact of wind on other generation for dispatch purposes for the JCSP'08, and information to evaluate the risk of the assumptions changing for the JCSP'08 study and the possible effects.

The Department of Energy Office of Energy Efficiency and Renewable Energy funded the development of the wind energy data base that was expected to be used for the JCSP'08. The National Renewable Energy Laboratory (NREL) managed the project. The wind data was prepared by AWS TrueWind. Data is prepared using weather data for the years 2004, 2005 and 2006. Mesoscale computer models are used to forecast the wind speed in grids of two km square. The time period of the data is every ten minutes. Maps and movies of the wind database are available at:

http://www.jcspstudy.org

Sets of the grids with the highest potential wind energy are selected for each state in the JCSP'08 footprint. Political diversities as well as the best wind potentials are available in the database. This allows that some wind will be placed in areas for political reasons and not just for economical reasons.

NREL then converts the wind speed data to wind energy using models of the wind turbine similar to that shown in the plot in Figure A8-1.A few wind turbine models are used to forecast the energy production of the area. The turbine type with the best energy output is chosen for that area. A wind energy data set is prepared for about 600,000 MW of wind generation to choose from. The 20% Wind Energy Scenario used 229,000 MW of wind generation.

The wind energy versus speed curve, Figure A8-1, has a minimum cut in speed where the turbine will start to produce energy. There is also a cut out maximum speed where the turbine will shut down. The flatness of the curve is due to pitch control that limits the output of the turbine to a rated value.

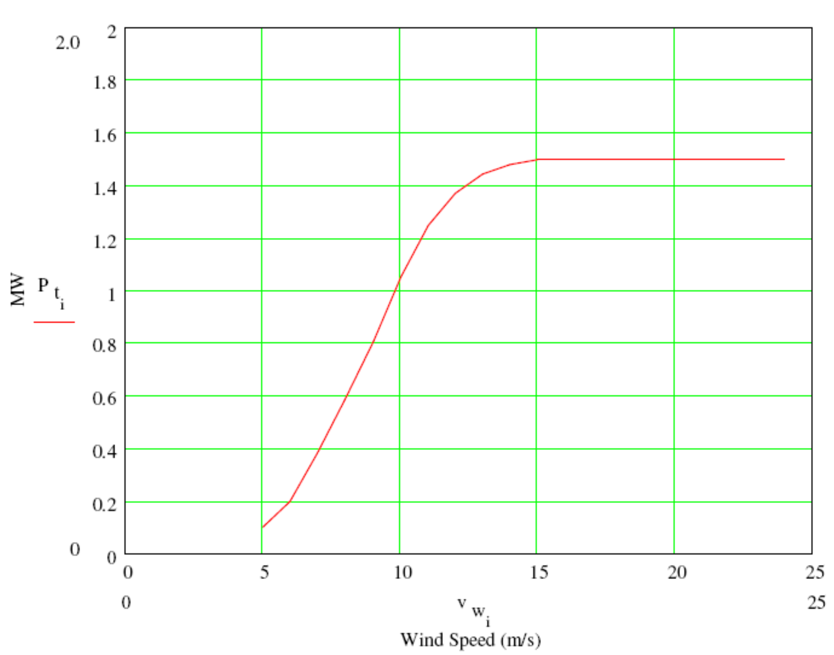


Figure A8-1: Power curve for a variable-speed, pitch-controlled wind turbine. Note the "flatness" of output for wind speeds at or above the rated value

Wind generation technology is nearly a mature technology. Future increases in efficiency and price reductions will be smaller than in the past. Improvements in efficiency and reliability will cost more to obtain the last few percentage points than in the past. Large companies have entered the market place that have the financial, manufacturing, maintenance and technical design knowledge to fine tune the systems as a whole to produce larger volumes of near optimum cost equipment. The economies of scale favor larger manufacturing facilities and larger sites.

Physical limits are being encountered such as tower heights, transportation limits, material stress and weight limits and wind shear from low level jets in areas that are determining the maximum size of wind turbines.

Politically, there is a strong desire to keep economic development within states and ownership of wind plants to local owners. While the economy of scale may produce local jobs also, it is more difficult to assign a local value to a particular wind site. The political will to have smaller systems may restrict the overall economic development of wind. Transmission development depends on economic resources that can be collected and delivered on a large scale to obtain the lowest delivered prices.

Over time, wind turbines have become more efficient at converting wind energy to electrical energy. Increased efficiency raises the MW-Wind Speed curve on the vertical axis for the characteristic curve in Figure A8-1. The efficiency gains are saturating and only about 10% more efficiency is estimated to be left to capture with improved wind turbine designs Wind turbine designers have also been able to increase the cut in and cut out speed to further increase the amount of available energy that is captured. Increased tower heights from 50 meters to 80-100 meters, has increased the wind speed and wind speed durations that are available to recent turbine installations.

The three factors - efficiency of design, larger operating ranges, and increased tower height - have produced wind installations with reduced costs of energy production over the years.

Increases in material costs and shortage of manufacturing capability have lately resulted in increases in the cost of energy production from wind turbines.

Restrictions in crane lifting capability on land, crane availability, tower and blade transportation limitations (due to length and the height of interstate bridges and overpasses) are limits to further reductions in the cost of wind energy.

Wind shear stresses on towers and blades in the western high plains, due to low level jet stream effects, are also being recognized as a tower height limit.

The cost of towers varies as the fourth power of the hub height, and the output of a turbine varies as the wind speed cubed. The economics of tower height on land is also a limit.

Some of the best wind generation sites are already populated with wind turbines. The use of the next best sites, and sites that may have turbulence from existing sites, results in less productive sites that may also limit the improvement in wind generation cost of energy.

Actual wind outputs may vary by 11% from the theoretical outputs estimated by mesoscale modeling. Some of the predictions of wind output may be less than projected.

A8.2 Wind Areas

Figure A8-2 shows the location of the wind generation potential by capacity factors for an eleven year period. The best wind potential is in the western plains states. Pockets of wind potential exist in other areas, such as northern New England, Illinois, and the Virginias. The shorter distance-to-load in some of the states, and the desire for local development of wind resources, may be sufficient to locate wind in other areas as well.

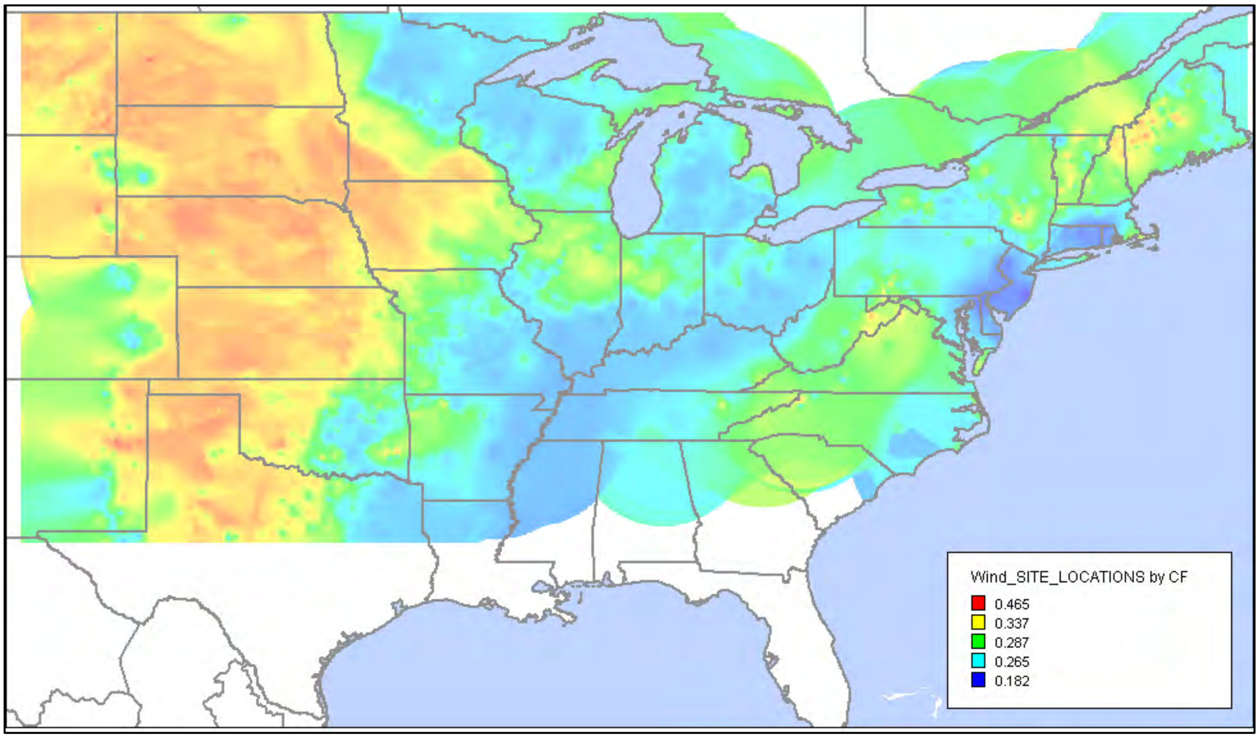


Figure A8-2: Eleven Year Wind Generation Potential by Capacity Factors

Movies of wind production by month for the JCSP'08 area are on www.jcspstudy.org. The colors toward the red end of the spectrum indicate high potential levels of wind output. The blue colors indicate low, or no, potential wind output.

There is a considerable diversity and variability associated with the wind output. There is much more potential wind energy production than what could be used by the power system. Selecting sets of the "best" sites that can produce the needed wind energy for Renewable Energy Standards is a process that was performed by NREL and was an input for the JCSP'08 study. The JCSP'08 study used hourly data for a year for each wind site chosen.

Blending wind outputs from various geographic areas can produce an aggregate wind output that is not as variable and has fewer periods of time with no output. The transmission system is the medium that produces the smoothing by being able to combine the outputs of the wind generation. The plot in Figure A8-3 shows that there is less correlation between wind sites from north to south than there is from east to west. Selecting the mix of sites to meet energy requirements in a north to south direction would produce a smoother aggregated output than choosing sites with a west to east distribution, but not to a large degree.

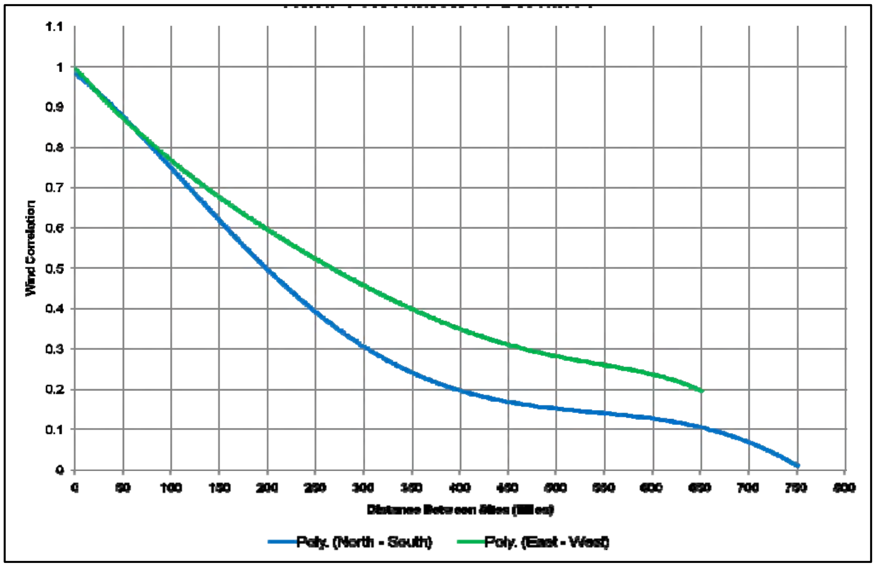


Figure A8-3: Wind Correlation vs. Distance

Wind generation is a variable energy resource as is readily demonstrated in Figure A8-4. The variability of the annual wind production varies by 26% from the lowest year simulated production to the highest year's simulated production for the period 1972-2002. Additional wind generation and possibly additional transmission may be required to meet a Renewable Portfolio Standard (RPS) if the RPS has language which requires a certain percentage of load energy to come from wind generation.

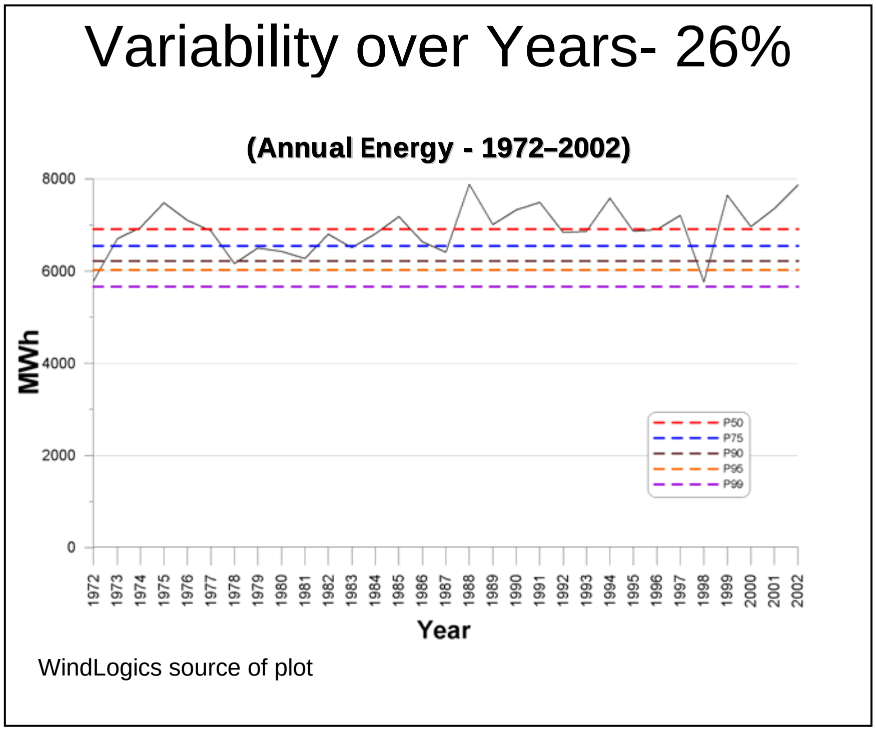


Figure A8-4: Wind Logics Plot

A8.3 Operation

The present process of locating wind turbines is to allow the wind energy developer to choose the site. Sites are chosen with the use of very detailed and complex weather and land contour models plus wind speed measurements over a period of time. The data used for site selection is more detailed than what is used for the JCSP'08 study. Sites are cherry picked to produce the most energy output. The developer may also pick sites with transmission service available in the area. The decisions are based on the benefits to the individual wind plant, or farm, and not necessarily based on the operating requirements of the power system.

Building significant transmission into an area may affect future Generation Queue locations as well as affect the cost of present generation site selections to connect to transmission. The costs of interconnection may be lower near major transmission substations. Any type of generation may be affected and not just wind generation. The JCSP'08 substations near the High Voltage Direct Current (HVDC) terminals have a design contingency level near 5000 MW. This is higher than the typical 1500 MW contingency limit in the Midwest ISO area and other areas. Stronger transmission supports larger generation plants which are generally more efficient to operate than smaller plants.

Power systems need to be able to match the load with generation. Variable generation presents challenges to control the operation of the power system. Generation reserves need to be maintained to supply sufficient generation to manage the load. Load ramps up during the day when wind is ramping down. Wind patterns tend to be in the opposite direction of the load requirements most of the time.

The value of wind generation is that it displaces the use of fossil fuels. Wind energy is a fuels choice that can be used, when it is available, to reduce the use of fossil fuel and to reduce the cost of energy production. This is similar to a decision to use gasoline or E-85 in vehicles designed to use both.

Power systems need to be designed to operate with wind, to benefit from the positive aspects of wind energy, and to tolerate the negative aspects of wind energy. Power systems need to have the ability to ramp up or down to adjust for the load and wind energy variability. The Eastern Wind Integration Transmission Study (EWITS) will address the controllability issues. The conceptual JCSP'08 transmission overlay design will be used in the EWITS study as well as the forecast generation of the JCSP'08 study. EWITS is scheduled to be completed in 2009.

A8.4 General Impact on Systems

A8.4.1 Time Correlation of Wind and Load

Figure A8-5 scales wind and load at their peak value to be 1.0. This allows the comparison of the timing aspects of wind energy supply to the need. Curves are fit through the data to show moving average values.

Wind generation per MW is more variable than load, therefore more reserves and ramping will be required to manage it. EWITS will determine the ramping and reserve requirements of generation; it will use the JCSP'08 transmission models and develop a new model for 30% wind energy for most of the U.S. Eastern Interconnection. EWITS is underway and is expected to finish in 2009.

Wind energy is lowest during the summer peak – 5,000-6,000 hour range. Wind output is heaviest during the spring and fall when it is least needed, and is mostly produced at night. The value of wind energy is not in the capacity to serve load, but as an alternative to burning fossil fuels, thus reducing carbon dioxide.

The question is, if you have wind with all the detracting characteristics, what can be done to use it? Would a transmission solution be economical? The JCSP'08 produces conceptual designs of transmission systems that allow economical use of the power system with scenarios of large amounts of wind generation being modeled in the complete system of generation and transmission.

The present power system was not designed to operate as multi-energy markets over a large geographical area. The existence of transmission constraints being over $20B per year in the unconstrained case is evidence of this. Constraints encountered in every day operation is another indication that the transmission system is not designed to operate efficiently with the present generation mix. The JCSP'08 transmission overlays provide the transmission for both the existing generation to operate efficiently in multi energy markets. Roughly $40B of the $80B of the 20% Wind Scenario is for existing and forecasted conventional generation. The economy of scale of transmission works in favor of combining the conventional generation uses and the wind generation uses into one efficient transmission overlay for energy market use.

The time scale for the plot in Figure A8-5 is expanded so that the hourly variation of wind generation can be seen as in Figure A8-6. Wind energy tends to be available at night while the load is at its maximum during the day. Wind energy is generally, but not always, out of synchronism with the daily and seasonal needs most of the time, as shown in Figure A8-6. The economic value of wind energy is limited due to being available primarily when the demand for energy is low.

Applications, such as pluggable electric vehicles, that would use energy for charging batteries, primarily at night, would be a good match for wind energy. Energy would be stored off-peak during the night and used to power vehicles in the day time. The power system would see an increased load and probably less need to build transmission. Not burning gasoline or diesel fuel would reduce the output of carbon dioxide. Utilities would not have to pay the capital costs of pluggable electric vehicles. Retail rate structures and metering would probably have to be changed to incent the pluggable electric vehicles to charge off-peak at night. Plugging in a vehicle for energy storage during the morning ramp would not be beneficial to the utility as the ramp would increase. Retail tariff changes may be able to use blocking signals or economic signals to avoid worsening ramps, resulting in additional generation being added for control purposes.

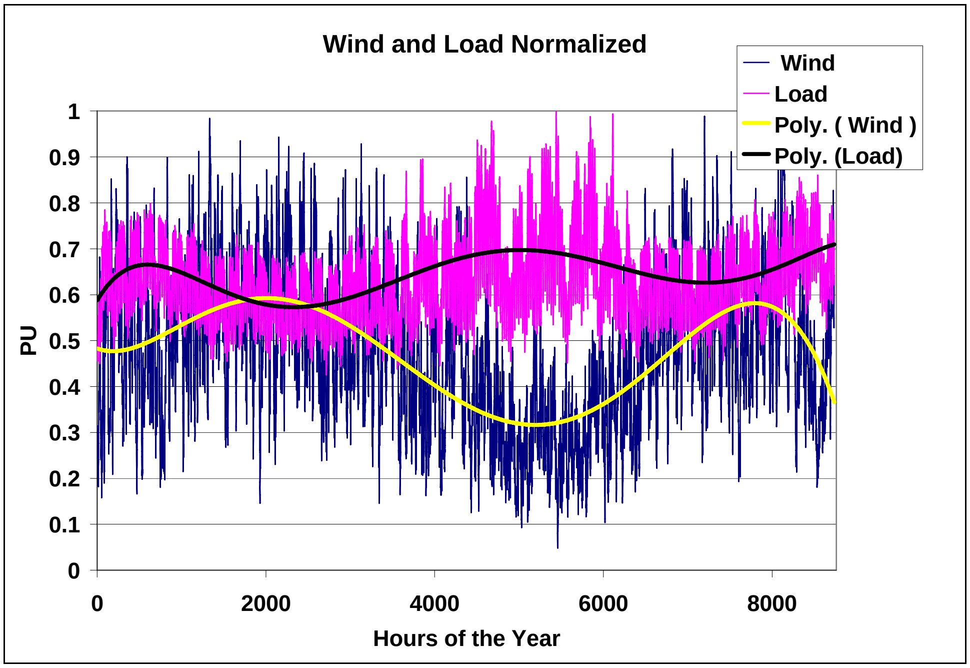


Figure A8-5: Wind and Load Normalized

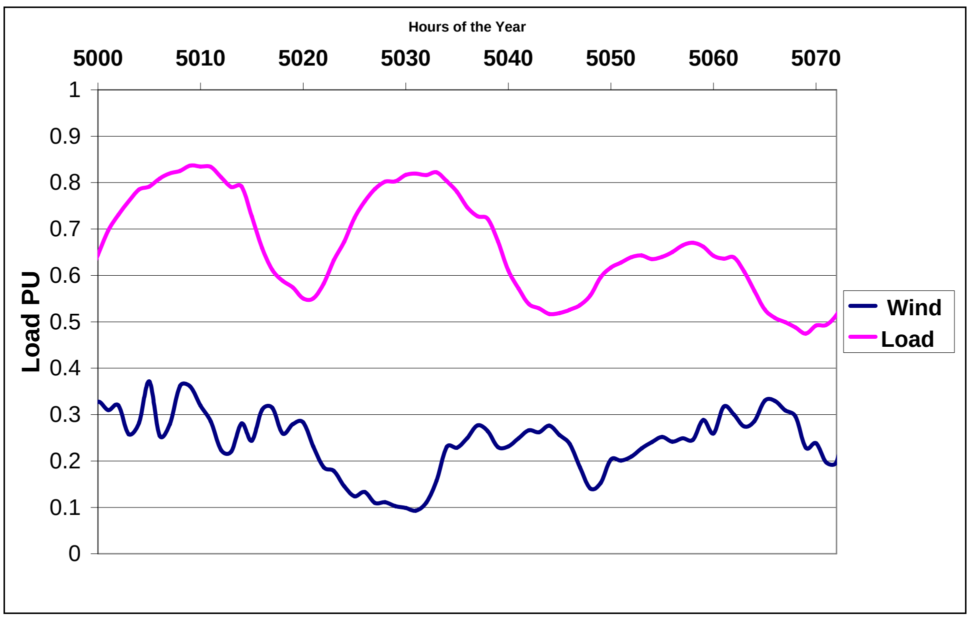


Figure A8-6: Wind and Load Normalized by Hours of the Year

A8.4.2 Wind Generation, Wind Energy Curtailment and Transmission Power Transfer Capacity

Wind generation and transmission interact to deliver an RPS energy provision. Some wind energy curtailment is associated with the economical operation of the power system.

Figure A8-7 is a plot of the installed wind capacity as a percent of peak load versus the renewable energy as a percent of end use load. The horizontal axis is the wind energy requirement in percentage of the energy used by the load in a year that is often stated in the requirements of an RPS. For the JCSP’08, a 20% Renewable Energy Scenario was run. Peak load is an easily identifiable number and the vertical axis is expressed as a fraction percentage of the peak load.

The sloped lines represent the efficiency of the transmission system to deliver the output from a wind generator. This is a capacity number - not an energy number. Some wind energy curtailment is associated with each sloped line as shown in Figure A8-7. Minimum generation output levels and load levels may result in some wind energy curtailment even at a 100% transmission power transfer capacity to wind generation output ratio.

Only the 100% outlet curve is extended to a 50% of wind-energy-to-load energy level. The 100% outlet curve shows that up to 30% wind-energy-to-load energy, the relationship between the wind energy and installed wind capacity is linear. Up to 30% of wind-energy-to-load energy is used as efficiently as at lower levels. Above a 30% wind-energy-to-load energy ratio, progressively more wind capacity is required to produce an increase in the wind-energy-to-load energy ratio. Figure A8-8 is an expanded scale plot of the area of the Figure A8-7 plot with the generator outlet lines in the area of 20% wind-energy-to-load energy used in the JCSP’08 study.

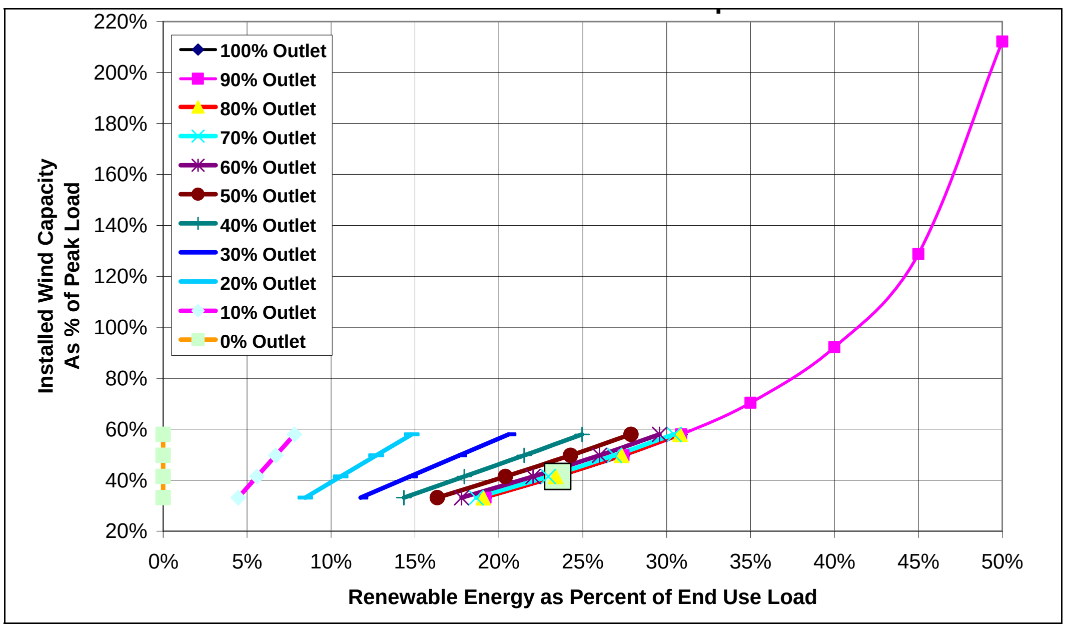


Figure A8-7: Installed Wind Capacity vs. Serving End Use Load Energy at Different Transmission Outlet Capabilities

In conversion of the JCSP'08 energy deliveries to transmission capacity in Step 3, 80% of the energy transmitted amounts to about 60% of the peak power (generator ratings) being transmitted. The plot in Figure A8-8 is used to provide an example of the trade off between adding additional wind generation capacity versus adding additional transmission. The impact of higher voltage lines is also illustrated in the example.

To obtain a 5% more renewable energy-to-load energy, 10% more wind generation capacity as percentage of peak load would be required. If the load factor of the load (similar to a capacity factor for a generator) is 60% and the capacity factor of a wind generator is 30%, then two MW of wind generation must be added to replace one unit of load. As the transmission becomes less efficient (lower outlet percentages) more wind generation is needed to produce the same increase in the wind-energy-to-load energy ratio.

Two methods are possible to increase the wind-energy-to-load energy ratio. One could add 10% more wind-generation-capacity-to-peak load to increase the wind-energy-to-load energy ratio by 5%. Alternatively, one could increase the transmission outlet efficiency from 40% to 80% to increase the wind energy-to-load energy ratio by 5%. 80% and 100% transmission outlet values are practically the same.

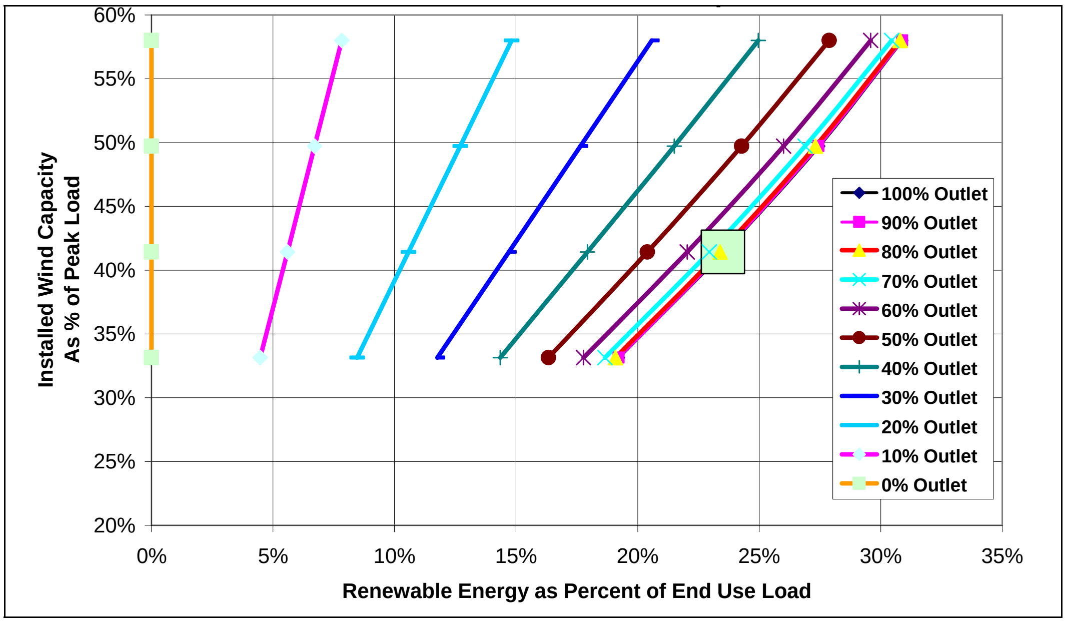


Figure A8-8: Installed Wind Capacity vs. Serving End Use Load Energy at Different Transmission Outlet Capabilities

Which is the most economical means to meet an RPS energy target - adding generation, or adding transmission? The information to perform the economical break even calculation can be obtained from Figure A8-8. As an example, let us use the 20% wind-energy-to-load energy ratio that was used in the JCSP'08 study. The construction to determine the information is displayed in Figure A8-9 with Figure A8-8 as a background. Figure A8-9 shows the intersection of the 20% Energy of End Use Load with the 30% to 70% outlet lines. For 20% energy as a percentage of the load at a transmission capacity of 100% of the wind generation rating, the percentage of wind capacity is 35% of the peak load. The additional wind capacity that must be added for a 60% of installed wind capacity being able to be transmitted is 2% more than having a transmission system than if 100% of the wind capacity can be transmitted. The additional wind capacity that must be added for 50% of the installed wind capacity being able to be transmitted is 6% more than if 100% of the wind capacity could be transmitted. The other values are similarly produced. Assuming:

- Peak Load is 100,000 MW
- Wind generation is 35,000 MW
- Wind generation cost is $1,900,000/MW
- 345 kV transmission cost is $3,200/MW-mile-Figure A3-1 Section 7
- 765 kV transmission cost is $1,000/MW-mile- Figure A3-1 Section 7
- The average distance of wind generation from the load is 150 miles

The interception of the transmission capacity lines with the 20% energy line are extended to the vertical axis to determine the amount of additional wind generation that is needed to maintain 20% energy with transmission capacity/generator ratings of from 70% to 30%.

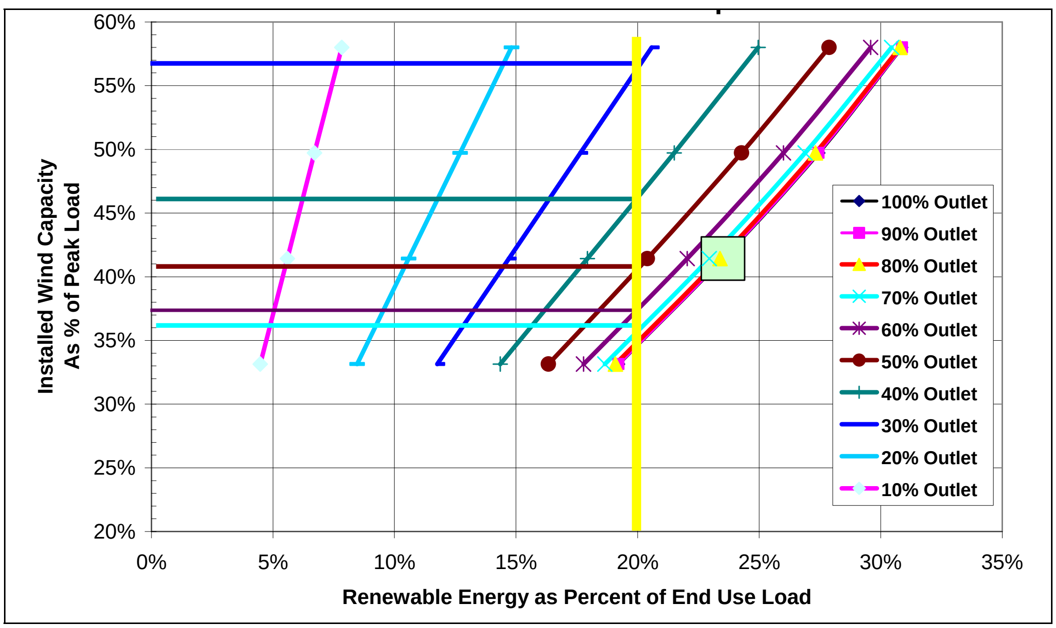


Figure A8-9: Installed Wind Capacity vs. Serving End Use Load Energy at Different Transmission Outlet Capabilities

The wind generation capacity is priced at $1,900,000 per MW and plotted in Figure A8-10. The prices for increasing the transmission capacity/generator rating ratio to 100% for the entire 35,000 MW of wind generation that is necessary to meet the 20% energy requirement.

While it is possible to keep adding generation to a transmission system and increasing the amount of energy that can be delivered from the interconnected generation, it is not the most economical way of supplying the 20% energy requirements as shown in Figure A8-10. If the transmission system is to be expanded at 345 kV, there is a break even point below a 60% ratio of transmission capacity/wind generation rating at which it is more economical to add transmission than to add generation. For 765 kV, it is more economical above a 70% ratio of transmission capacity/wind generator rating to add transmission rather than to add generation. The 765 kV transmission system would have to be configured into a looped system for reliable delivery and the lines would have to be able to carry economical loading levels for this analysis to be valid.

One use of these types of plots, as in Figures A8-7 through A8-10, would be to estimate how much wind capacity could be added to the present transmission system to meet a wind requirement if transmission is delayed.

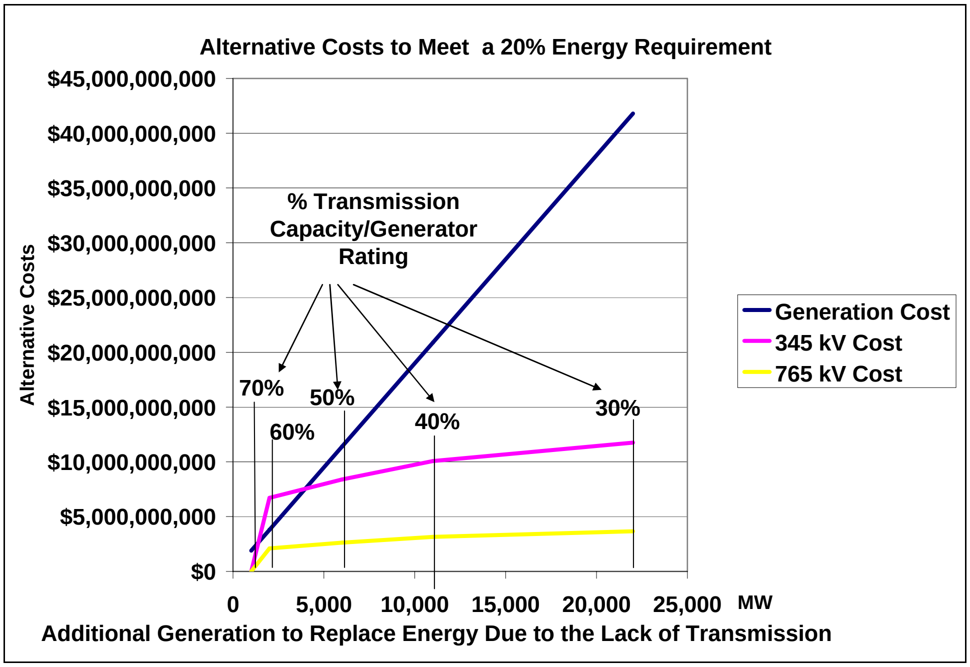


Figure A8-10: Alternative Costs to Meet a 20% Energy Requirement in MW

While the example in Figure A8-10 is used to demonstrate concepts, PROMOD runs simulating the generation and transmission system can produce the curtailment of wind energy for a given transmission configuration as well as the wind energy delivered to meet a requirement. PROMOD can produce a list of the transmission lines that are constrained in order of the descending value of the constraints. Comparing two PROMOD cases can produce the cost difference between two transmission configurations for a year. Thus, the conceptual transmission system design can be changed to minimize overall costs. Just focusing on removing underlying voltage constraints may not be the optimal solution. The focus on wind curtailment in the JCSP'08 analysis is a result of the discussions above on Figures A8-7 through A8-10.

Both PROMOD and Power Flow analysis are required for economic transmission design analysis. PROMOD runs could determine the wind generation energy curtailment and provide a list of wind generators that have enough transmission and wind generators that would need more transmission. A list of constraints for the hours of the wind energy curtailments may help identify transmission expansion options. First Contingency Incremental Transfer Capacity calculations using power flow with an economic dispatch for an appropriate off-peak condition could provide an estimate of transmission options that would bring the transmission to the economic guidelines for power transfer capability. Once the detailed design using power flow was completed, a PROMOD run could be used to confirm if the design produced the desired result for curtailment targets.

The percentage of the transmission capacity to the rating of connected wind generation is on the horizontal axis of the plot in Figure A8-11. Even when there is transmission available, there is a slight curtailment of the wind energy due to not being able to absorb the wind energy by the load with the generation minimums assumed in this example. The curtailment of the wind energy does not start to increase significantly until after a transmission available capacity to wind generation rating of about 70%. The transmission capacity needed by wind generation is off-peak. If power flows are being used to model wind energy deliveries, then a value of 70% or less would be a good guideline for a 765 kV transmission expansion and between 50% and 60% for a 345 kV transmission expansion. Transmission expansions would require multiple lines for higher voltage transmission overlays such as 765 kV.

The amount of wind generation to peak load ratio to meet a 20% wind energy requirement is shown in green in Figure A8-11.

The JCSP’08 study used an 80% energy transmission capability as an initial design parameter which is typically about a 60% expanded transmission capacity to peak energy transfer. All sources of generation are included in the unconstrained versus constrained analysis that produces the maximum area interchange charts and the associated tables of transmission transfer capacity needed. While the example discussed above provides insight to the guidelines that may be the initial conditions to start a study, detailed PROMOD runs as performed in the JCSP’08 are still needed to provide information to make the final decisions.

The significance of the example is that additional wind generation might be added to meet a wind requirement even if the transmission could not provide delivery services for all the energy. Some wind curtailment will occur with any amount of local generation. The best choice economically depends on the transmission voltage that is to be used for the expansion. Higher voltages, if they are loaded to economic levels, would result in the curtailment of less wind energy than lower voltages.

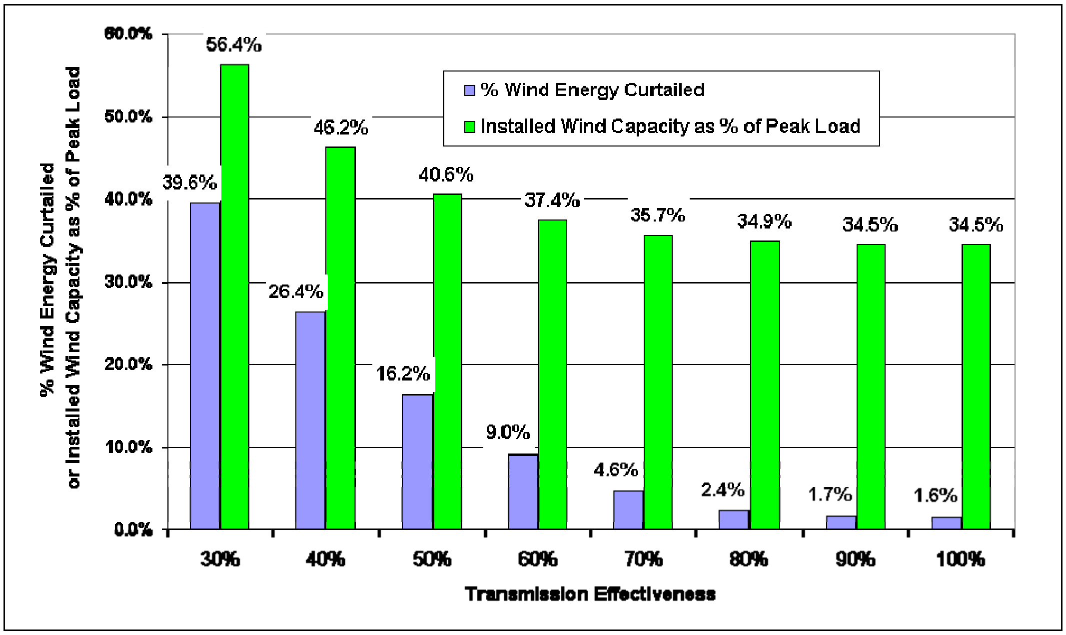


Figure A8-11: Percentage of Wind Energy Curtailed While Sustaining a 20% of Load Served by Wind Energy

A8.4.3 Wind Impact On Gas Generation

The decline in wind generation output near peak load times creates a need for low capacity factor generation that is variable to fill the gap at peak times. Gas generation has this characteristic.

If the load and wind outputs are sorted in descending order of load, the plot in Figure A8-12 is produced. The load curve is often referred to as a load duration curve, or the amount of time that the load is above a certain value. The smooth yellow curve is the average value of wind; the drop off of energy production on-peak can be seen as well as the wide range of probable wind output near peak load. The flatness of the wind average output for most of the year indicates that wind has, on the average, a base load characteristic and will tend to displace energy from base load generation. The variability of wind energy during most of the year is large.

The load duration curve contains more energy (typically 60%) under the curve than a wind duration curve (typically 33% - higher with new installations). Wind energy would not be able to supply the total load needs without substantial curtailment (high cost) or storage (high cost).

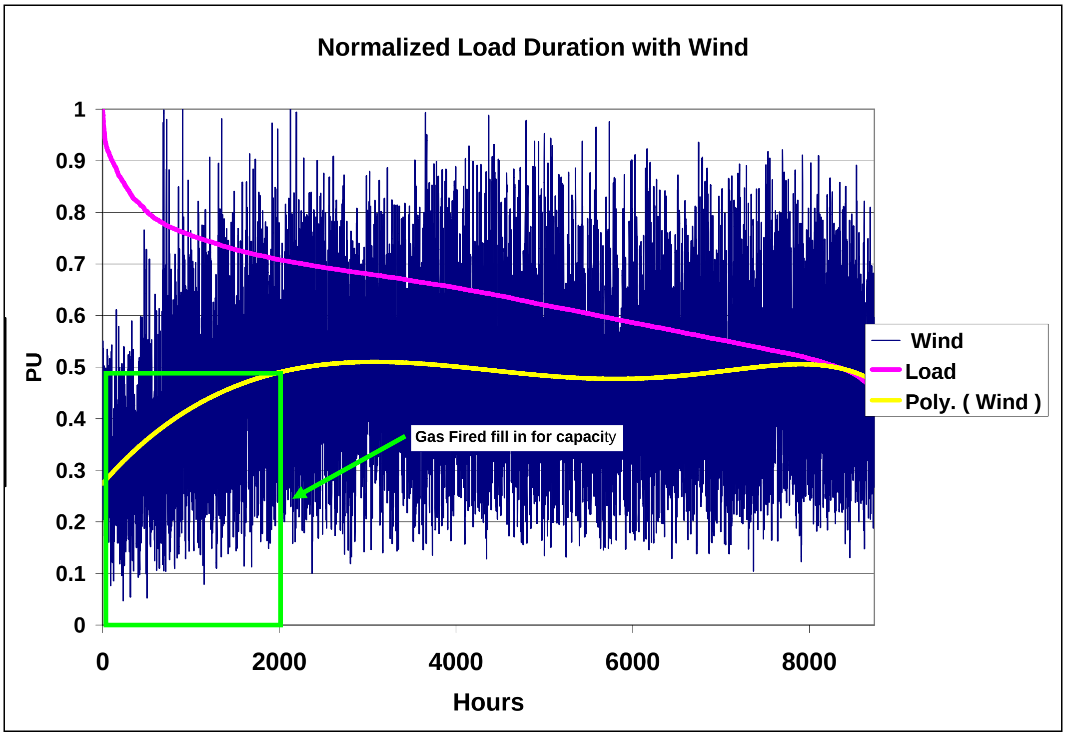


Figure A8-12: Normalized Load Duration with Wind

The decreased contribution on-peak from the wind generation is observable near the left of the plot. The average value decreases and the minimum outputs of the wind generation are experienced near the peak of the load. The minimum values of the wind generation near peak load, account for the tendency to give wind generation a low capacity credit. Other generation that can be dispatched on peak load is added to the generation mix to provide the needed capacity. The period from 0-2,000 hours would probably be filled with gas fired generation for this relatively short time period. From 2,000 hours and greater there is sufficient other generation available to replace wind generation. Adding wind generation tends to increase gas generation whose output can be highly variable.

A8.4.4 Storage and the Use of Wind Energy

A second observation from Figure A8-12 is that the area above the average wind generation output curve and the hourly output is greater than the area under the average generation output curve and the hourly output. This observation could be used to determine the applicability of storage for wind energy to meet the load requirements more fully. The ratio of the area below the average output curve and the hourly output of the wind generation and the area above the average output curve and the hourly output of the wind generation would have to be greater than the efficiency of a storage-generation cycle of the storage device. In practice, some energy may also come from base load generation for the storage cycle.

For this example, energy storage rated at 50% of the installed wind generation ratings, and energy from a wind supply, could possibly supply approximately 50% of the rated capacity of the wind as a base load unit. The period of time from 0 to 2,000 hours would probably have to be supplemented with gas fired generation. While the energy balances appear to have merit with storage, the capital requirements of wind turbines, storage-generation devices, and gas fired generation are probably more expensive than base load alone.

Studies of the JCSP’08 system using PROMOD and the Electrical Generation Expansion Analysis System (EGEAS) would be required to produce quantitative answers to storage scenario questions. The graphical outputs could be used to estimate the initial capacity rating for the storage units in the models. A PROMOD simulation requires about six days of computing time, therefore having information to judge the initial conditions of a study can save a lot of time. Also, one may be able to answer questions as to why a certain alternative was not studied. Producing large amounts of alternatives that produce little information or understanding is not very helpful other than making large reports. One of the advantages of the economic techniques used in the JCSP’08 study is to be able to estimate transmission requirements without having to run exhaustive lists of studies.

One storage option that does not require substantial capital expenditure by the utilities is the pluggable electric vehicle. Just having the vehicles store energy off-peak and not regenerate into the grid would be a positive for wind generation. Pluggable electric vehicles have the potential to be a good match for wind. Smart Grid concepts, with time-of-day metering that would allow the pluggable electric vehicles to obtain the advantage of lower cost energy at night, would be beneficial for the vehicle and for the utility to encourage off-peak consumption during off-peak periods.

The JCSP’08 studies indicate that storage is not needed for up to 20% wind energy penetration levels.

The JCSP’08 generation expansion forecasts showed a greater tendency toward combustion turbines (low capacity factor generation with a high capability to vary the output). The graph section below 2000 hours illustrates the tendency and offers an explanation of the increased combustion turbine capacity associated with increased wind in the generation forecasts.

If the load and wind outputs in Figure A8-12 are sorted in descending order of the wind output the wind generation duration curve and the load at the associated wind outputs plot in Figure A8-13 is produced. Figure A8-13 represents the Figure A8-12 data sorted by load.

The question of whether wind can serve load by itself can be answered as the load above the wind duration curve (pink line) could not be served by wind alone. The choices would be:

1. Not have electric service most of the time and have considerable wind generation curtailments; generation has to match load. Only the load on the wind duration curve (pink line) matches generation and load. Figure A8-14 shows that load above the wind duration curve would have to be curtailed and wind generation would have to be curtailed.
2. Install a storage system associated with the mandatory wind generation. The cost of this option is high due to capital costs for wind generation and capital costs for the storage equipment.
3. Have other generation that would fill in the difference most of the time.

The JCSP'08 considers choice "3" as the viable option and accesses existing generation with conceptual transmission expansion designs.

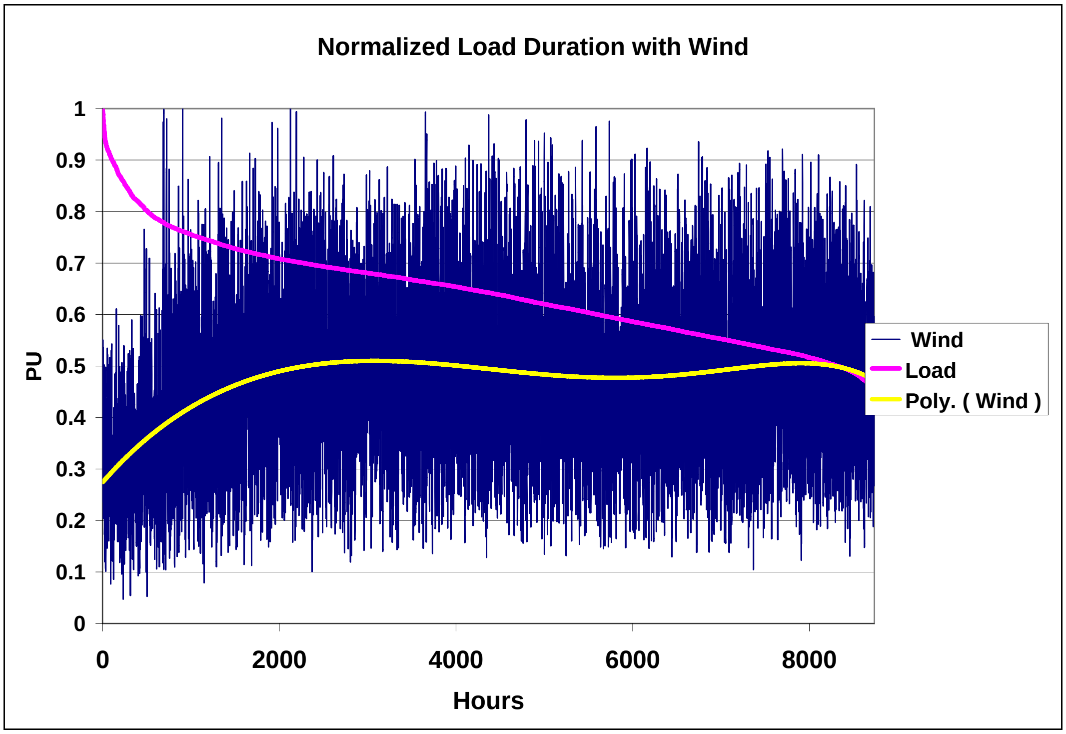


Figure A8-13: Wind Duration and Load

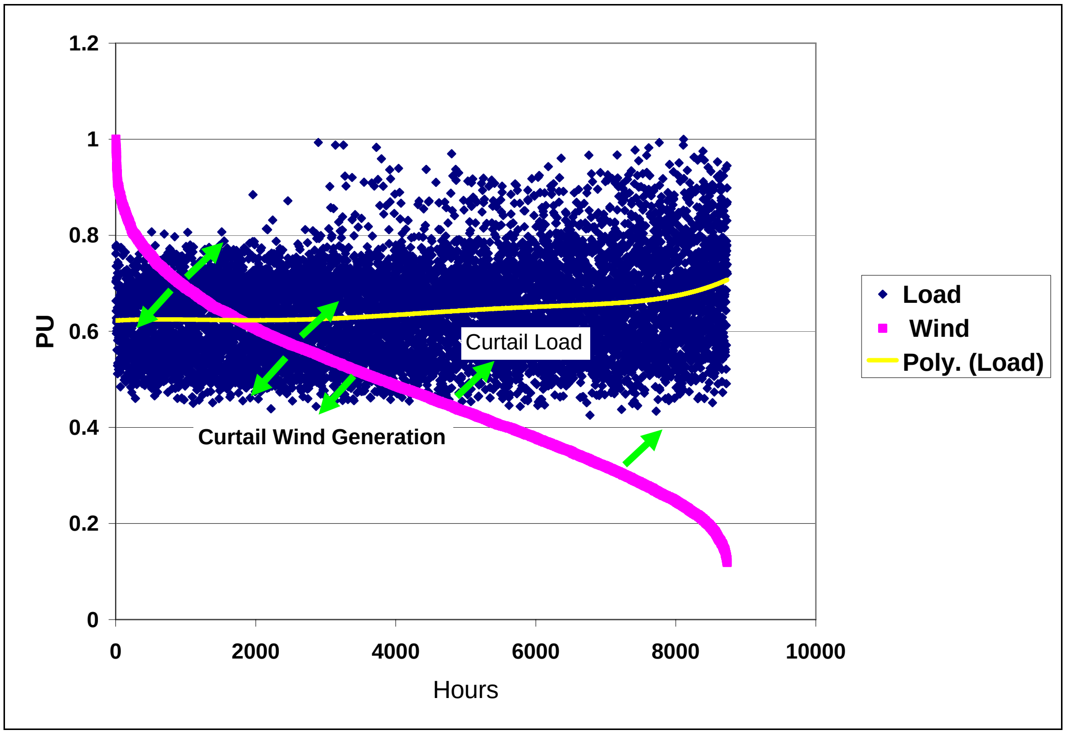


Figure A8-14: Wind Duration and Load

Figure A8-15 provides information about the requirements a wind generation-storage system to be able to serve load without other generation. An 80% energy storage cycle is assumed. A 60% load factor (similar to a capacity factor for generation) is assumed. The wind generation capacity factor is 43%. A storage facility is limited to about eight hours of operation per day, a 33% capacity factor. The MW rating of the storage facility would be about half of the total wind generation installed capacity.

Since the wind generation capacity decision is already made, the incremental capital cost of the energy storage facility is the only capital cost to consider. For areas that have combined-cycle gas-fired generation as a base load option, a storage facility with an installed cost of $2,400/kW versus $1,007/kW for combustion turbine appears to be competitive or nearly competitive with the gas fired generation options. Storage options are not competitive in areas with lower cost base load generation.

Two technologies that can provide eight hours of generation from a storage facility are pumped storage and flow batteries. Pumped storage requires mountains or high hills to be efficient. Combining the reclamation of coal mines with power plant operation and pumped storage development may have some merit. Flow batteries are relatively new and have the advantage of being able to be placed near to loads. Other technologies are under assessment and testing, but may offer opportunities also.

The capital cost of the wind generation would have to be excluded from the economic analysis. Wind generation by mandates would be an existing condition of the analysis.

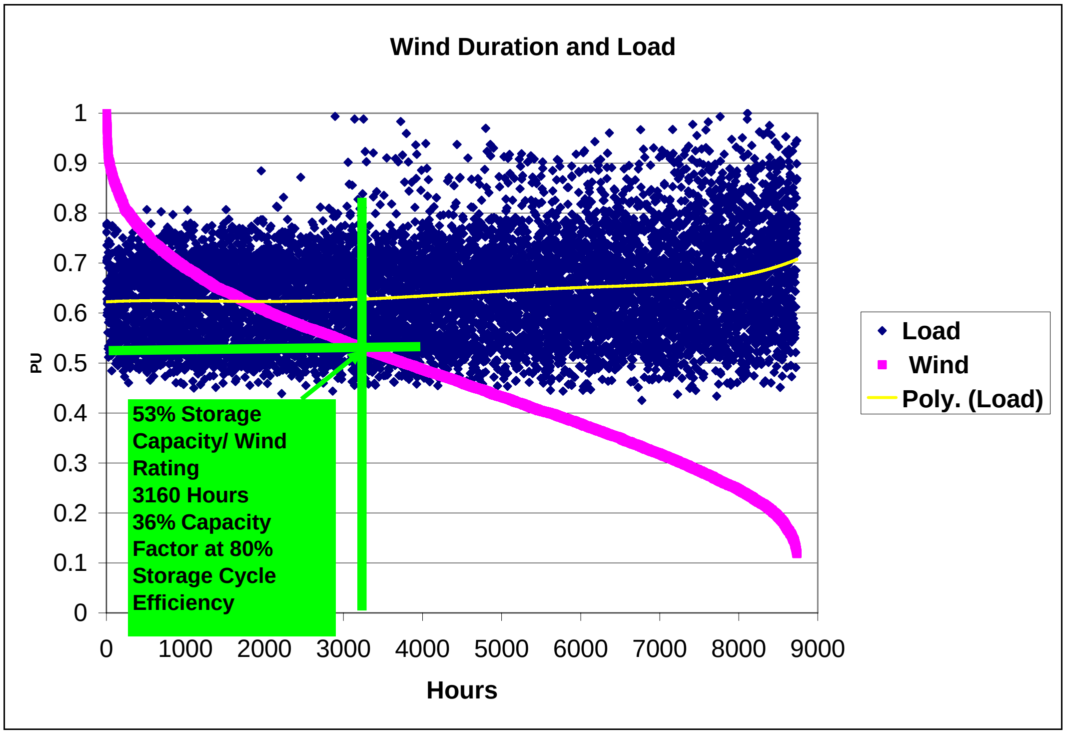


Figure A8-15: Wind Duration and Load

Figure A8-16 represents the total operating costs of a selection of generation types that may be chosen in a generation expansion forecast. Annual fixed cost requirements are on the left hand axis for the various generation options in a generation expansion forecast. The slope of the lines is the variable operating costs. The largest variable operating cost component is fuel.

The optimal mix of generation is obtained by choosing the lowest cost path from the left hand axis (starting with combustion turbines), then combined cycles and then base load steam, if base load steam is an option in the area. The capacity factor range is on the horizontal axis. Each generation type could be inserted into the existing merit order generation mix starting from the lowest cost units working from right to left. Energy sources such as wind generation and the JCSP'08 Transmission Overlay terminals do not provide energy on demand and thus are not included the selection process. Wind energy was given only a 15% capacity credit in the JCSP'08 study.

The storage facility is a capacity resource and has the potential to be a resource in the mid capacity factor range in competition with combined cycle gas fired generation subject to the concerns listed below. Because of the factors that could change the analysis listed below, and risk analysis, combined cycle generation would probably be chosen and it has less capital requirements. Strong environmental reasons would be one reason to consider the storage option. Most tests of the storage options have too low a capacity factor to even approach the economic zone needed to operate.

The conceptual JCSP'08 transmission overlay is modeled by an approximated fixed cost of the transmission and the cost of base load steam energy displaced by wind generation for the slope.

The Ancillary Services Market may provide additional revenue for a storage facility. ASM analysis is beyond the scope of the JCSP'08 as only hourly simulations of the energy markets are performed for the JCSP'08. The EWITS study may be able to identify additional values for storage devices for ASM services shorter than one hour.

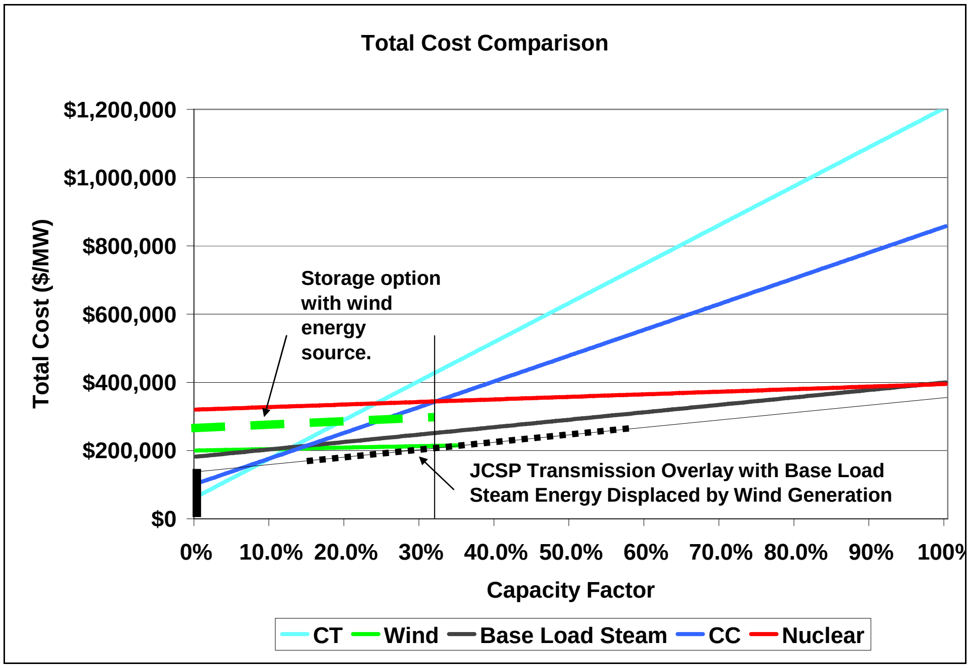


Figure A8-16: Total Cost Comparison

Factors that could change the analysis may be:

- A low price of natural gas may compete with energy storage facilities.
- The capacity factors of the wind generation and availability of low priced energy in the storage facility area.
- The low cost energy from the JCSP'08 conceptual transmission overlays could displace the local use of energy storage for mid range capacity and energy.
- Cap and trade or carbon tax legislation that would reduce load growth so that new capacity would not be needed. Higher fuel prices probably would favor wind generation, but the low capacity factors of wind in areas with the storage facilities may not be sufficient to provide energy storage resources. Transmission would be an additional cost as the low priced base load steam pool of energy would not be available to pay for the transmission.
- Construction costs of storage may be too high compared to better established alternatives.
- High Levelized Fixed Charge Rates could drive solutions to lower initial capital investment options, such as combined cycle and combustion turbine generation.
- Political opposition to everything and anything may be a problem.

More detailed study would have to be made to make a decision on storage. The examples suggest why storage is not needed in the 20% Renewable Scenario. The example also indicates what might be used as the initial assumptions for a study involving storage.

As mentioned before, the pluggable electric vehicle would be a load that could use wind energy directly and initially has little capital requirements on the part of the utilities. The storage in the pluggable electric vehicle displaces fuel that is not part of the present power system mix of generation. Retail rates and metering may have to be changed to incentivize vehicles to use the electricity at the proper time. Having a pluggable electric vehicle start to store energy during the morning ramp toward the days peak load would not be an economic solution.

Another application that may not require a capital investment by the utility, but would use off-peak energy, may be storing energy by making ammonia. Ammonia could be used in agriculture for fertilizers and also as a liquid fuel. Research is being performed to store energy as ammonia.

A8.5 How Wind Interacts With the Rest of the System

A8.5.1 Overview

Generation capital costs, fixed and variable operation & maintenance costs, and fuel cost are considered when choosing the mix of generation that is used to supply the peak demand for a power system.

Generation capital costs and fixed operation & maintenance costs are usually not included in the calculation of the marginal costs of generation for energy markets. Capital costs are paid for by a load in a capacity market or by an integrated utility for generation designated to meet the load and reserve requirements. Marginal costs consist of variable operation & maintenance cost and the fuel costs.

Wind RPS requires the acquisition of generation to meet an energy target. There are some off ramps in most of the RPS if the price becomes too high. Once the wind generation is obtained, the energy is primarily used to satisfy the RPS requirements. Since wind generation is part of the dispatch, it generally appears to the market as a price taker. A price taker will deliver available energy unless there is a transmission constraint on the system that prohibits it.

Merchant generation can also operate in the energy markets. Merchant generation must recover all of its costs of capital, fixed and variable operation & maintenance costs and fuel costs plus some profit if merchant generation is to draw sufficient generator revenue from the energy markets to remain in business. Tax, or other credits such as the production tax credit, can be modeled as negative values which tend to offset costs. A production tax credit can make a wind generation have a negative marginal cost after the variable operation & maintenance costs are netted out.

All AC systems are subject to risk of paying more for transmission than necessary to affect a power transfer over long distances. Loop flow and Free Ridership are two issues that can increase the cost of transmission for long distance transmission of energy.

When a generator injects energy into an AC system, the energy is distributed over the entire AC system. Some lines are more heavily loaded than others. Shift factors determine the percentage of a generators energy flow on each line in the AC system. If energy is transmitted large distances, the flow patterns on transmission lines are altered by displacement of energy. Energy from a generator serves the nearest load. Energy that would normally be from local generation serving the nearest load is then displaced to serve the next nearest load. The displacement of energy in an all AC system forms very complex energy flow patterns. Some of the energy may flow on systems that are not part of the transaction of energy transfer and is called loop flow. Loop flow may cause transmission to be built in areas that are not involved in the energy transfer transaction to relieve transmission overloading. The entire Eastern Interconnection may be affected by loop flow. Some of the transmission lines that are overloaded due to loop flow may have been close to being overloaded already. The allocation of cost to resolve loop flow problems is very complex. The “causer pays” principle subjects the JCSP overlay to the risk of building more transmission than is necessary just to resolve the loop flow issue. The JCSP overlay mitigates 127 flow gates. In an all AC system, this is 127 opportunities to construct more transmission than is needed to solve the problem. No one will pay for problems that are solved that they do not have an obligation to pay. Such benefits are a form of Free Ridership. Transmission lines provide lumps of capacity and not just what is needed. A 10% overload may end up supplying 90% more transmission than needed because the energy transfer “caused” the overload. Paying tribute to pass an area is an example that may apply.

Benefits tend to “leak” in AC systems similar to the loop flows to neighboring systems due to the addition of transmission. Free ridership provides benefits to entities who do not participate in the cost of transmission expansion.

The JCSP’08 higher voltage transmission overlay uses 800 kV HVDC transmission to deliver energy over long distances. HVDC is scheduled by people or programs written by people to pick up injections of energy and to deliver energy to specific locations where there are HVDC terminals for distances of more than 600 miles. The Reference Scenario used two HVDC lines and the 20% Renewable Scenario had seven HVDC lines. HVDC lines simplify the calculation of who the user is and also the AC cost allocation calculations. An injection of energy into a HVDC terminal looks like a load. The HVDC terminal absorbs the energy from the source AC system that is to be transmitted to a distance load at the sink AC system. Thus the major shift factors on the AC system involved in the energy transfer are contained mainly to a local utility or Regional Transmission Organization (RTO). The transmission systems between the HVDC terminals are not significantly affected by loop flow. The “caused” problems are significantly reduced.

HVDC has a schedule. Power that is injected, minus losses, is delivered to the receiving terminal. The scheduled energy is from an area within an RTO or utility. Settlements occur within the utility that the HVDC terminal is located.

The source terminal of an HVDC line appears as a load. There are allocation procedures in most RTO’s to allocate AC transmission costs based on load.

The sink terminal of an HVDC line appears as a generator. There are FERC pro-forma, RTO and utility procedures to allocate transmission cost to generators.

Both source and sink terminals can be located to relieve congestion.

There are multiple ways to operate the HVDC lines. The following is a description of one process that uses most of the current energy market mechanisms.

The RTO energy market at the receiving end of the HVDC line establishes a clearing price on its energy market with the HVDC terminal participating as a generator. The clearing price is paid to the RTO energy market at the source end of the HVDC transmission line. The RTO subtracts the losses and the transmission service for the use of the line. The revenue from the transmission service is paid to the transmission owners. The remainder is paid to the participants in the schedule or blended into the RTO energy market LMP structure.

A8.5.2 Affect on Energy Markets

The HVDC energy injection would shift the operating point of the price-supply curve downward to a new price-supply point, lower by the amount of the power level of the energy injection. If the output of the HVDC terminal was 1,200 MW and there were four terminals, the clearing price with the HVDC terminals would be the price at 4,800 MW less on the supply axis than the clearing price without the HVDC terminals. The price shift concept is illustrated in Figure A8-17. This assumes the HVDC terminal price is less than the clearing price without the HVDC terminals. The reverse would be the case at the source HVDC terminal.

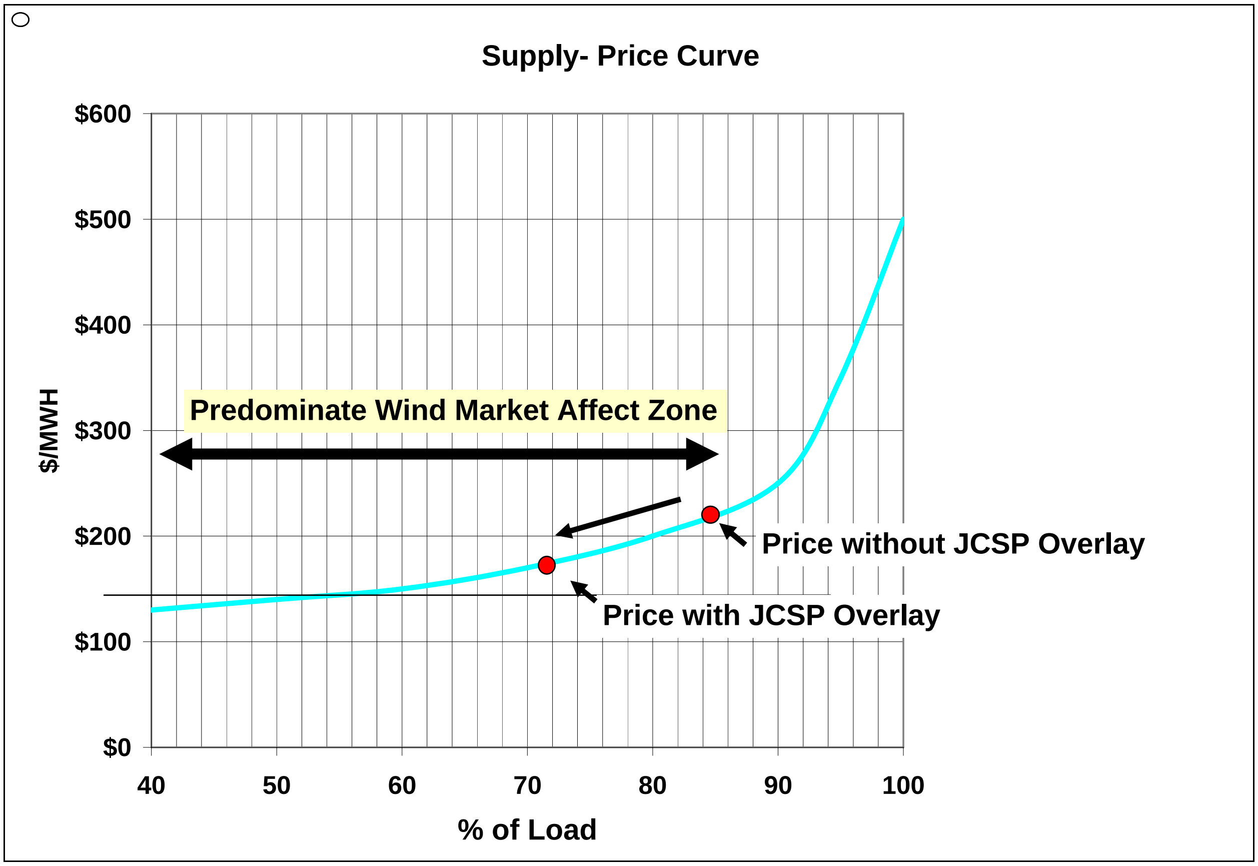


Figure A8-17: Wind Energy Activity Zone

Figure A8-18A uses enlarged scales to demonstrate the interaction of the Western (source) and Eastern (sink) energy markets. The Western Price-Supply curve has transmission service charges and losses added to produce a minimum price bidding curve for the Eastern energy market. If there were enough energy available from the Western energy market and if the Eastern energy market could accept the energy economically, the clearing price would be the same at both the Western + Transmission + Losses price point and Eastern terminals. The energy from the West minus losses must match the energy delivered to the East. The MW difference from the black line to the blue line (East) and the black line to the pink line (West + Transmission Service + Losses) are the same in this example. Losses are ignored. Thus the Eastern price will reduce from the initial operating point (intersection of the red line and blue line). The price in the west would increase from the intersection of the red line and the pink line to the clearing price. At the price equilibrium point there is no profit at the Western side if the prices are cost based. The benefit to cost ratio would be 1:1 for an equilibrium condition.

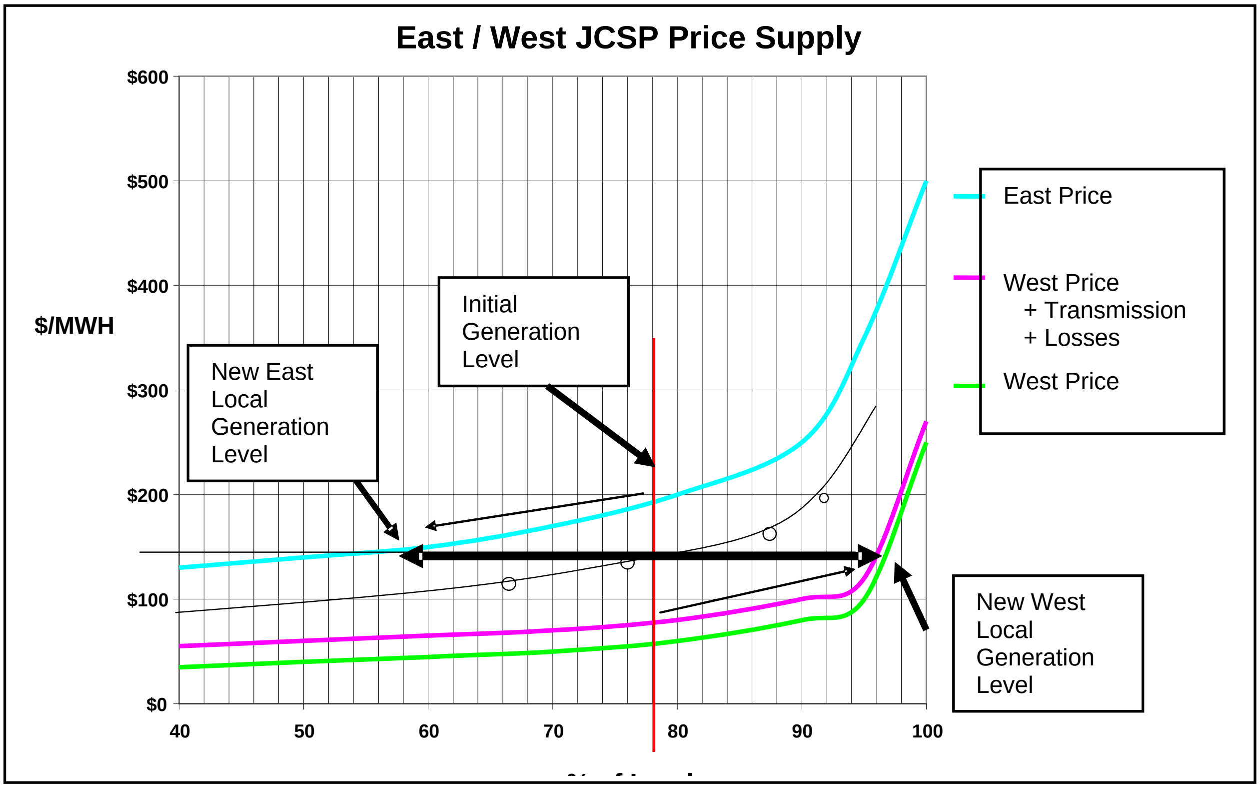


Figure A8-18A: JCSP'08 HVDC Revenue Flow Diagram

The design of the JCSP does not provide enough transmission for the equilibrium condition to be achieved. The JCSP transmission is designed with a benefit to cost ratio greater than 1:1. The incremental benefit, above 1 in the benefit to cost ratio, is the amount of potential generation contribution margin of the generation participating in the HVDC schedule or the RTO energy market as a whole. See Figure A8-18B.

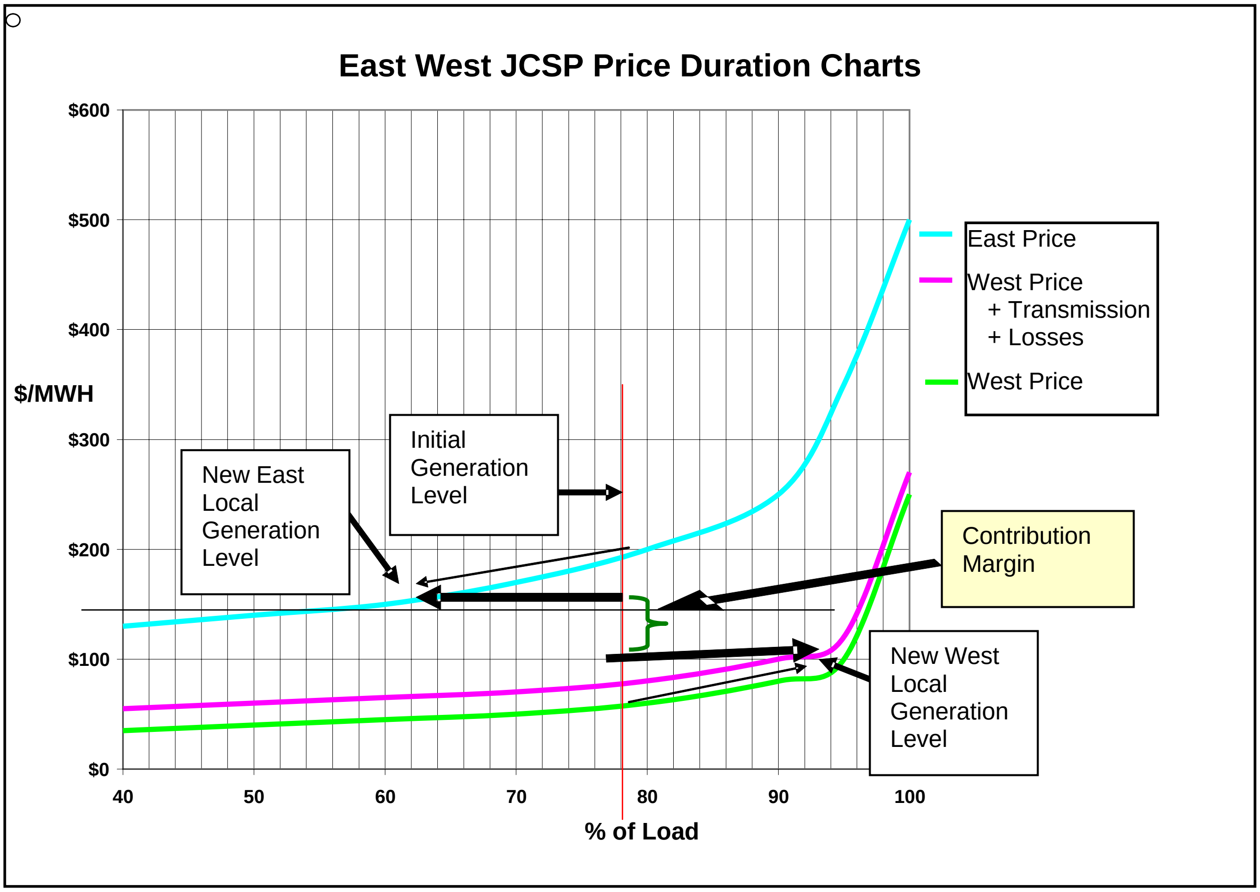


Figure A8-18B: JCSP '08 HVDC Energy Market Mechanism

The AC section of the JCSP '08 overlay has four functions:

1. The JCSP'08 overlay with the HVDC injection terminals uses the AC system for backup of the HVDC terminals and delivery of the energy to the HVDC terminals. The backup and delivery capacity could be supplied by transmission service as long as the transmission service did not exceed the dedicated cost of a 765 kV built out. The RTO, or utility with the HVDC terminal, could design the backup and delivery AC part of the JCSP'08 overlay to connect generation, deliver generation to load, and perform other power transfers as long as it maintained the transmission service requirement of the JCSP'08 overlay without exceeding the cost of the dedicated system. The reason for the "not to exceed" term is so that the transmission capacity is not incremented with 345 kV transmission with a much higher per MW-mile cost and raise the transmission service cost to uneconomical levels. As transmission systems age, load grows, generation is added, and the power transfer capacity and effective delivery distance shrink if no transmission is added. Since transmission is constructed in blocks of capacity, it is easy to incrementally show that lower voltage, much higher cost increments, taken one at a time, is a lower cost option than a long term higher voltage expansion that would maintain the long term transmission service cost. See Figure 5-1.

2. The eastern part of the JCSP'08 overlay from Indiana to the east is an all AC system and the 765 kV and 500 kV overlay is used for multiple purpose. The Midwest ISO-PJM Cross Border or some similar agreement will probably be used to settle this area.

3. Power transfer of purchased wind - the Midwest ISO transfers 40,000 MW of wind generation output to TVA, SERC and PJM in the JCSP'08 model. SPP transfers 62,000 MW to TVA and SERC. The existing AC system, plus the conceptual JCSP '08 transmission overlay, is sufficient to transmit the wind energy. The 765 kV overlay in SPP is part of the overlay for the purposes of collecting energy, backing up the HVDC terminals and some energy delivery through the existing system with the overlay expansions.

4. 180,000 MW of conventional generation in the 20% Renewable Scenario is connected to the AC system. The AC system delivers energy and capacity from this generation. The AC overlay is part of the AC system and thus provides support to the connected generation.

The user, or cost causer, is not able to be determined at the present time as they may not yet exist – therefore allocation is a difficult process. The user of the HVDC transmission can be identified to the utility or RTO level at the time of use, thus the use of the AC system is also identified as discussed above

A8.5.3 Affect on Other Generation

To start the process, existing generation of the lowest cost fuel and variable operation & maintenance costs are placed on the bottom of the curve and then stacked depending on their total fuel plus operation & maintenance cost. Hydro is usually on the bottom, followed by nuclear, base load steam, the combined cycles and then combustion turbines.

Wind generation sufficient to supply the energy of the RPS is inserted into the stack just above nuclear generation. The reason for the placement is that a nuclear plant's output is not reduced, if at all possible, due to operation constraints. Otherwise wind generation would probably be placed just above hydro. For this example the average value of wind is shown, but in actual operation the widely varying profile in Figure A8-12 would be used.

The wind section differs from other generation types on the left hand or capacity axis. Wind generation produces what it does on-peak and cannot be relied upon to produce more. Wind generation has a capacity credit of only 15% on-peak for the JCSP'08 study. Wind generation has higher average capacity contributions off-peak. The annual capacity factor of the wind energy is the area encased by the wind output curve.

The wind output is wedged under base load steam generation in the stack, thus pushing the base load steam segment under the load duration curve upward, and distorting the shape of the base load steam capacity versus hours of operation. The result is a reduction of the amount of base load steam generation that would be added to produce an economical mix of generation and also increasing the amount of base load steam energy that is on the margin, available for sale to an energy market. Potential energy available for sale is to the right of the load duration.

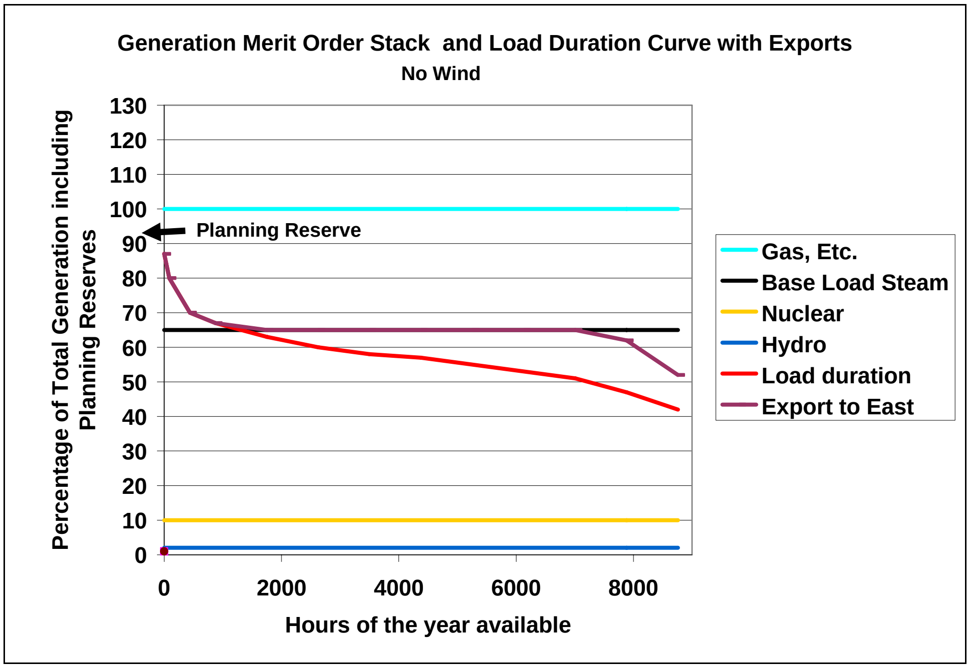


Figure A8-19: Generation Merit Order Stack and Load Duration Curve with Exports No Wind

The base load steam energy on the margin (available for sale) without wind generation is highlighted in green in Figure A8-20.

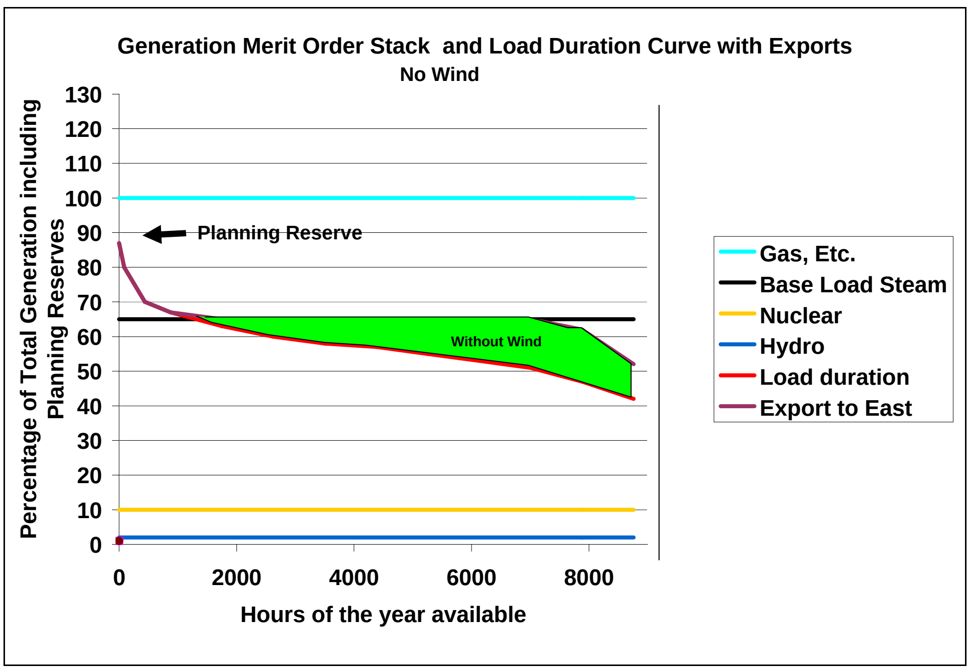


Figure A8-20: Generation Merit Order Stack and Load Duration Curve with Exports No Wind

Comparing a case without wind and a case with wind shows more base load steam capacity available for sale. The increased base load steam on the margin is shown by the lighter green shading in Figure A8-21. The total pool of base load steam on the margin represents significant quantities of low cost energy that could be sold to higher priced areas. The difference in prices in the two areas could possibly pay for the transmission, in benefits to the load in the higher priced area, and the generation in the lower priced area.

The JCSP'08 study identified conceptual transmission expansion overlays that for the assumptions used in the study showed there is a possibility that the transmission designs could possibly pay for themselves in benefits from the energy market operations linked by the JCSP'08 overlay designs.

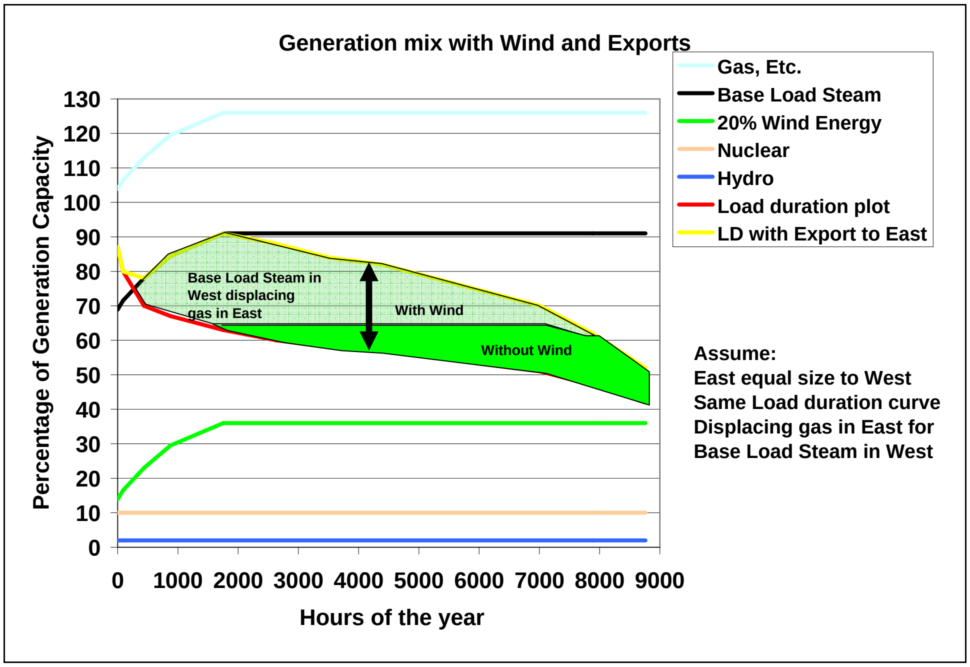


Figure A8-21: Generation Mix with Wind and Exports

Note the reduction of the minimum generation space for the base load steam generation on the right hand axis. Generation has minimum output levels. If there is not enough room for the generators to operate at a minimum output, either the wind is curtailed or some of the base load steam generation must be taken offline. Base load steam generation may be difficult to restart if it is needed for meeting peak load the next day. Not having sufficient generation when it is needed is a reliability concern. Turning generation off and on or cycling the generation creates thermal stresses that can lead to equipment failure, higher maintenance costs and lower availability.

Having a transmission outlet to areas with high concentrations of gas fired generation that can cycle more readily, allows the base load steam plants to run and the wind generation not to be curtailed. There are financial benefits associated with having more low cost generation available.

Note the example in Figure A8-22 that there is still substantial potential base load steam energy for sale that cannot be accommodated by the other system example. Wind energy displaces base load steam and the base load steam is not used up.

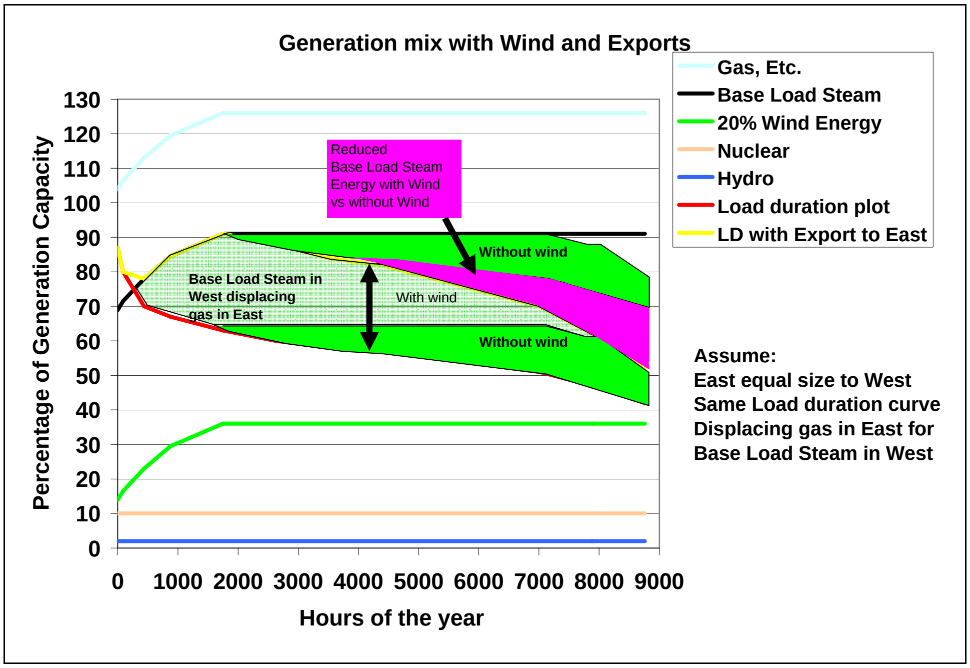


Figure A8-22: Generation Mix with Wind and Exports

The solid shaded blue area in Figure A8-23 shows the gas which was displaced by base load steam which was displaced by wind energy.

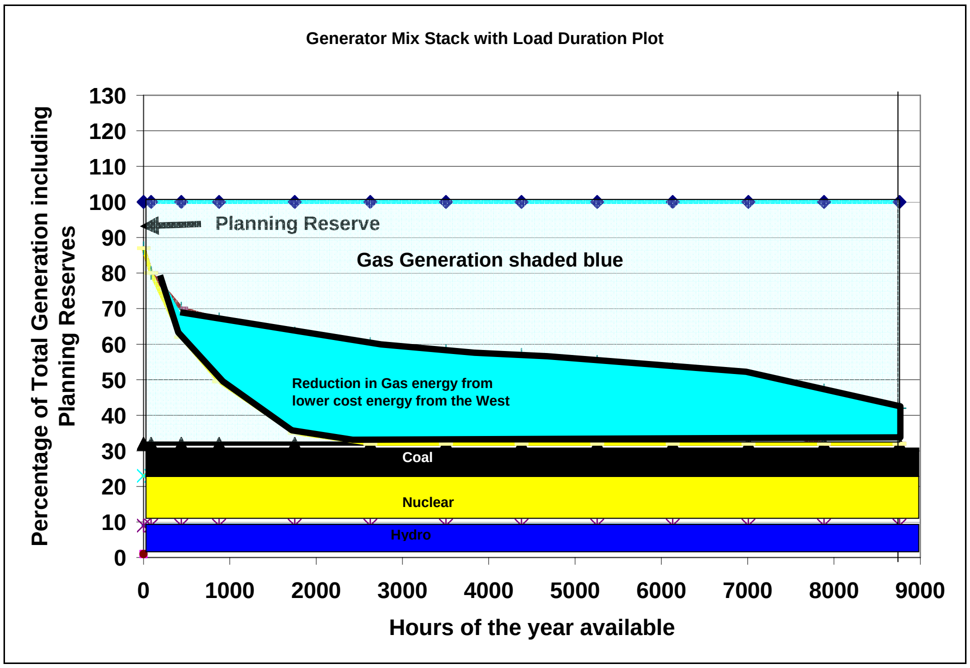


Figure A8-23: Generation Mix Stack with Load Duration Plot

Natural gas has about the same price across the country and, when gas is available for sale, any sales would be from a combined cycle plant with a lower production cost than a combustion turbine. The price difference would be lower than a base load steam to gas transaction. There are few transactions between areas when both areas are on gas. This condition exists near peak conditions and can be seen on the plot in figure 5-23 as not having an export at the peak hours.

For this example, we will focus only on the base load steam to gas transactions.

Just because the base load steam energy that is available for sale is lower in price than gas fired generation elsewhere, the lower cost base load steam energy can be used only if there is a place under another area's load duration curve being served by gas that the low cost base load steam energy can displace.

Putting two load duration curves, and their associated merit order generation stacks, side-by-side provides an example of how two energy markets might enter into a combined dispatch that would lower the overall price of energy.

When wind generation is added to the eastern systems, the wind displaces the base load steam energy in the west which was replacing gas. The eastern systems must pay the capital costs for this wind energy which is higher than the cost of the displaced base load steam energy and transmission costs. The most economical mode of operation would be to use as much of the low cost energy as possible and then add additional wind generation in the east. The optimum case falls between the JCSP'08 Reference 5% Wind Energy Scenario and the JCSP'08 20% Renewable Scenario. Perhaps, optimizing the wind benefits could be a future study.

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Acronyms and Definitions

AC	Alternating Current
APC	Adjusted Production Cost
B/C	Benefit to Cost
Brownfield	An area that has previously been developed, such as the site of a gas station, a paved parking lot or the site of a demolished building
BRP	Baseline Reliability Project
CC	Combined Cycle
CNF	Capacity Need Forum
CREZ	Competitive Renewable Energy Zone
CT	Combustion Turbine
DFAX	Distribution Factor
DOE	Department of Energy
EGEAS	Electrical Generation Expansion Analysis System
EHV	Extra High Voltage
EIA	Energy Information Administration
EITAG	Eastern Interconnection Transmission Assessment Group
EPRI	Electrical Power Research Institute
ERAG	Eastern Interconnection Reliability Assessment Group
ES&D	Electricity Supply & Demand
EWITS	Eastern Wind Integration and Transmission Study
GADS	Generator Availability Data System
Greenfield	A piece of previously undeveloped land, in a city or rural area, either currently used for agriculture, landscape design, or just left to nature
GIS	Geographic Information System
HSIL	High Surge Impedance Loading
HVDC	High Voltage Direct Current
IGCC	Integrated Base Load Steam Gasification Combined Cycle
JCSP'08	Joint Coordinated System Plan 2008
JOA	Joint Operating Agreements
LCRIF	Location Constrained Resource Interconnection Facility
LFCR	Levelized Fixed Charge Rate
LMP	Locational Marginal Pricing
LODF	Line Outage Distribution Factor
LOLE	Loss of Load Expectation
LSE	Load Serving Entity
MAPP	Mid-Continent Area Power Pool
METU	Market Efficiency Transmission Upgrade
MBTU	Million British Thermal Units
MMWG	Multi-area Modeling Working Group
MTEP	Midwest ISO Transmission Expansion Plan
MW	Megawatt
MWh	Megawatt Hour
NERC	North American Electrical Reliability Corporation
NREL	National Renewable Energy Laboratory
O&M	Operation and Maintenance
PJM	Pennsylvania – New Jersey – Maryland Interconnect
PROMOD	PROMOD IV – Ventyx software program for Generator and Portfolio Modeling System with Nodal LMP Forecasting and Transmission Analysis
PTF	Pool Transmission Facility
RPS	Renewable Portfolio Standard
RSC	Regional State Committee
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Organization
RTU	Reliability Transmission Upgrade
SERC	South-Eastern Reliability Corporation
SPP	Southwest Power Pool
TAC	Transmission Access Charge
TO	Transmission Owner
TPL	Transmission Planning
TVA	Tennessee Valley Authority
TWH	Terawatt Hours
WAC	Wheeling Access Charge