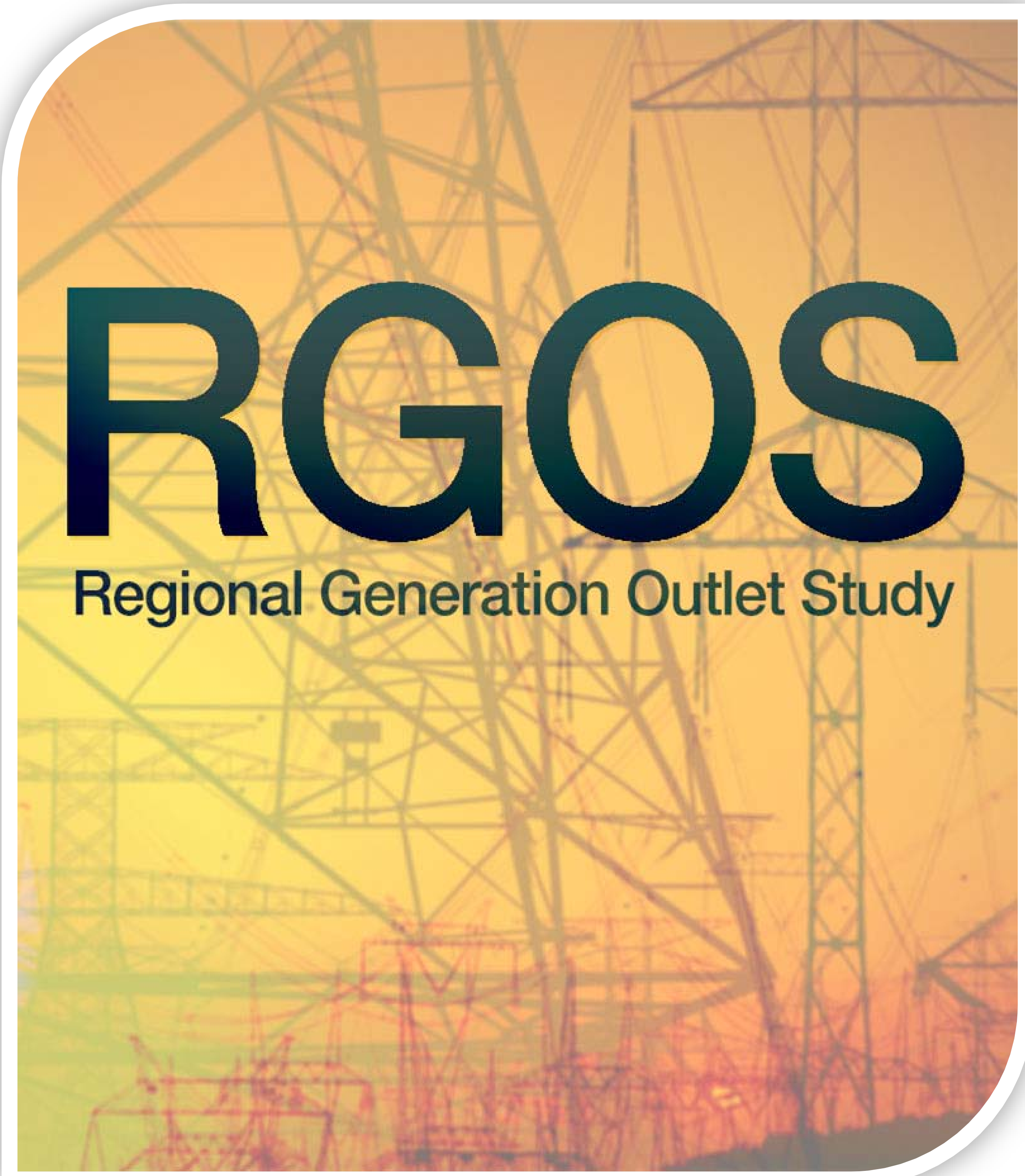
Midwest ISO



November 19, 2010

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Contents

Tables & Figures

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1 Study Overview

Renewable Portfolio Standards (RPS) passed by most Midwest ISO member states mandate meeting significant percentages of total electrical energy with renewable energy resources. To develop transmission portfolios fulfilling these requirements and meeting the objective function of achieving the lowest delivered dollar per MWh cost, Midwest ISO, with the assistance of state regulators and industry stakeholders, conducted the Regional Generator Outlet Study (RGOS).

1.1 RGOS Results Summary

During initial RGOS phases, analysis showed locating wind zones in a distributed manner throughout the system—as opposed to only locating the wind local to load or regionally where the best wind resources are located—results in a set of least-cost wind zones that help to reduce the delivered dollar per MWh cost needed to meet renewable energy requirements. From this earlier work, a combination of local and regional wind zones were identified and approved by the Upper Midwest Transmission Development Initiative (UMTDI). Further solidifying the validity of this methodology, the Midwest Governors' Association affirmed the method employed selecting these wind zones as the best approach to wind zone selection.

- RGOS determined the best fit solution to be a transmission overlay encompassing all Midwest ISO states, premised on a distributed set of wind zones, each with varying capacity factors and distances from load.

RGOS narrowed its focus to the development of three (3) transmission expansion scenarios to integrate wind from the designated zones: (1) a **Native Voltage** overlay that does *not* introduce new voltages such as 765kV in areas where they do not currently exist; (2) a **765 kV** overlay allowing the introduction of 765 kV transmission throughout the study footprint; and (3) **Native Voltage with DC** transmission that allows for the expansion of DC technology within the study footprint.

- All three (3) transmission expansion scenarios meet respective state Renewable Portfolio Standards (RPS) requirements within the Midwest ISO footprint.
- The addition of renewable energy zones with the transmission overlays reduced the Midwest ISO load-weighted LMP between $4.30 to $4.90/MWh (2010 USD).
- The three (3) transmission overlay plans represent potential investment of $16B to $22B in 2010 USD in transmission over the next 20 years and consist of new transmission mileage of 6,400–8,000 miles.
- Total cost for the transmission overlays range from $19/MWh to $25/MWh. The cost of the wind generation is an additional $72/MWh. However, the overlays and generation also produce Adjusted Production Cost (APC) savings of $41/MWh to $43/MWh within the Midwest ISO footprint, creating a net cost of $49/MWh to $54/MWh. This cost does not include the value associated with an additional $20/MWh to $22/MWh of APC savings which would accrue to the rest of the Eastern Interconnect as the result of the RGOS transmission overlays and generation.
- Analyses of these three (3) transmission plan alternatives through the RGOS study, along with additional analytics performed within Midwest ISO planning processes, have identified a sub-set qualifying as inputs into the Candidate Mutli-Value Project (MVP) portfolio analysis.

Because of RGOS, Midwest ISO has identified the next, most immediate step to transmission investment: a set of robust Candidate MVPs designed to address current renewable energy mandates and the regional reliability needs of its members. Viable for near-term development, these projects represent $5.8B (2010 USD) of capital investment, approximately $4.4 billion in the Midwest ISO footprint with the remainder in PJM. These Candidate MVPs will serve as inputs into the 2011 Candidate MVP Portfolio analysis, the first of a cyclical set of MVP Portfolio analyses which will propose and evaluate transmission to meet a changing policy landscape. While none of the overlay scenarios—Native Voltage, 765 kV, Native Voltage with DC—has emerged as the definitive renewable energy transmission solution, it is important to note all selected Candidate MVPs are compatible with all three (3) transmission plans.

1.2 Long-term Transmission Strategies

All three (3) transmission plans were developed to provide reliable delivery of the RPS-identified levels of renewable energy. Reliable delivery assumptions are discussed within Section 5 and focus on transmission system constraints 200 kV and higher. Refer to Figure 1.2-1. The study region consists of Midwest ISO and neighboring facilities including MAPP, Commonwealth Edison, and American Electric Power.

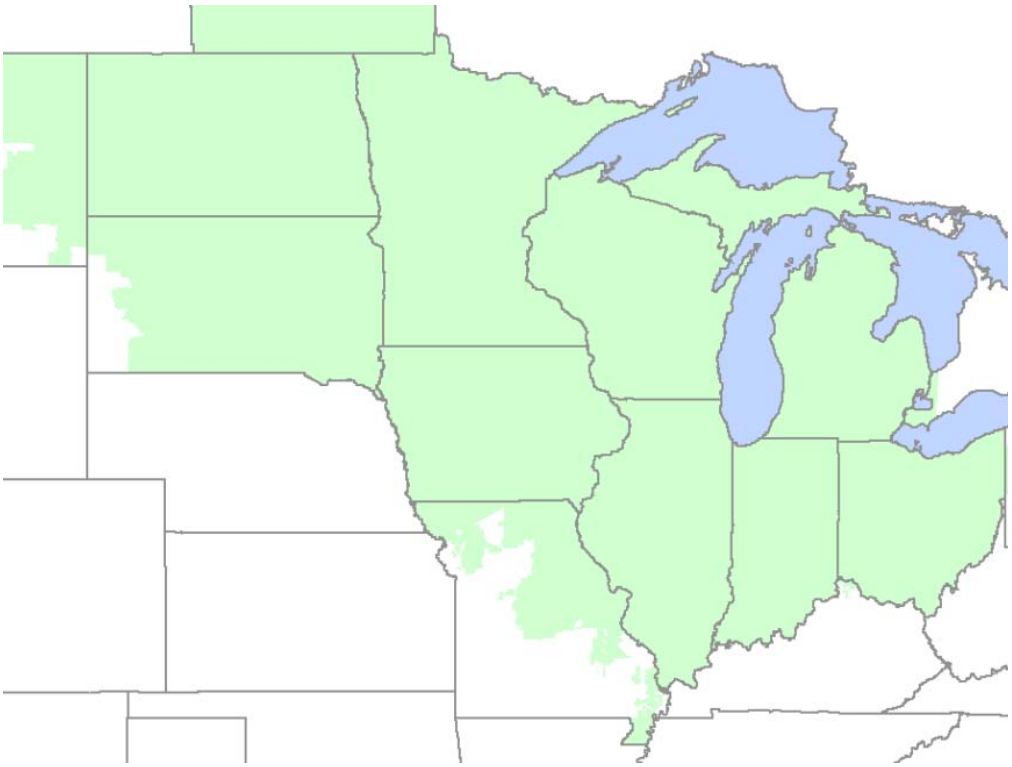

Figure 1.2-1: RGOS Study Footprint

Because RGOS transmission plans impact MAPP and PJM systems, references to these neighboring systems are made whenever RGOS is discussed, the result of necessary assumptions regarding planning practices and strategic assessment. For example, a 765 kV grid logically connects into an already existing 765 backbone on the PJM system, but PJM references are not yet indicative of any projects in the PJM Regional Transmission Expansion Plan. Evaluation of overlays moving forward will continue to require coordination between impacted neighboring entities, including PJM, MAPP, SPP, and TVA.

1.2.1 Transmission Expansion Drivers

The Midwest ISO region observed two significant drivers for transmission expansion: (1) state RPS mandates; and (2) associated generation in the Midwest ISO Generation Interconnection Queue (GIQ). For more detailed information regarding state RPS mandates and goals, refer to section 3 and Appendix 2 of this document. The second major driver for transmission expansion is the Midwest ISO Generation Interconnection Queue (GIQ), which—as of the end of July 2010—held approximately 64,500 MWs of wind requests. After careful examination of the inherently complex issues involved, Midwest ISO staff and stakeholders determined the GIQ process would not be an efficient means for building a cost-effective transmission system either immediately, over the next 5–10 year period or in the foreseeable future beyond that time-frame.

1.2.2 Indicative Zone Selection Rationale

Several different generation siting options were analyzed during previous phases of RGOS. This analysis focused on the relative benefits of local generation, which typically requires less transmission to be delivered to major load centers, and regional generation, which can be located where wind energy is the strongest. A total of fourteen (14) generation siting options were developed, with options ranging from purely local generation siting, purely regional generation siting, or a combination of local and regional generation siting. Transmission overlays were then developed with Transmission Owners (TOs) on a high-level, indicative basis for each generation siting option. Capital costs for each generation siting option and its associated high-level transmission overlay were calculated and plotted against each other to determine the relative cost of each generation siting approach. Refer to Figure 1.2-2.

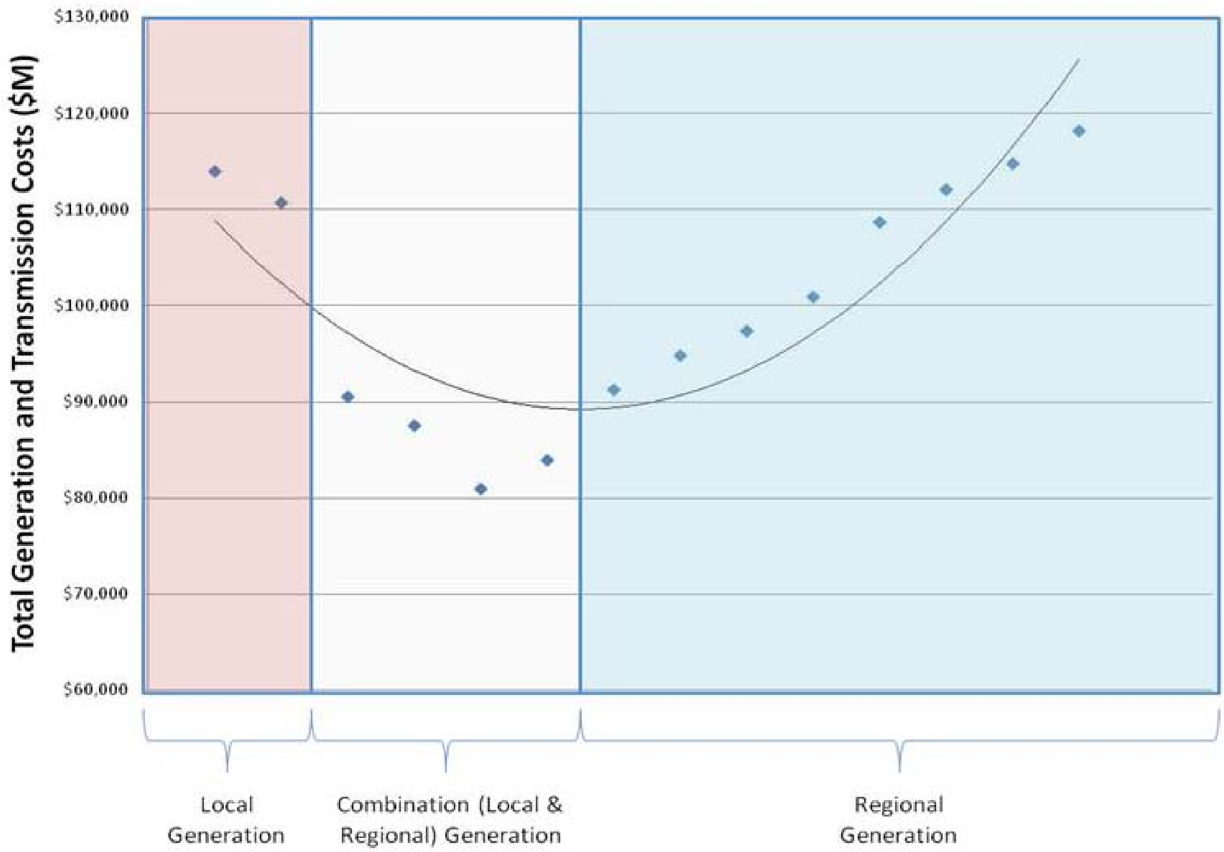

Figure 1.2-2: Zone Scenario Generation and Transmission Cost Comparison

It was determined the least cost approach to generation siting is a methodology containing a combination of local and regional wind generation locations, as shown by the white area on Figure 1.2-2. This was the approach affirmed by the Midwest Governors' Association as the best approach to wind zone selection.

For greater detail regarding the indicative transmission results, design, and optimization, refer to sections 4.1,1, 5.1, and Appendix 3 of this document. Also refer to section 9.1 of the Midwest ISO Transmission Expansion Plan (MTEP) 2009, which more fully describes the rationale driving zone scenario generation.

1.2.3 Comparative Analysis

During the study process, the RGOS group focused on the development of three (3) transmission expansion scenarios mentioned in the previous section: (1) a **Native Voltage** overlay that does *not* introduce new technology or voltages in the area; (2) a **765 kV** overlay allowing the introduction of 765 kV transmission throughout the study footprint; and (3) **Native Voltage with DC** transmission that allows for the expansion of DC technology within the study footprint. Refer to Table 1.2-1, which describes the physical characteristics of the three (3) overlay scenarios. It shows how the number of new lines, total line miles, acres of right-of-way, river crossings, and substations differ between scenarios. It also breaks down each scenario geographically between Midwest ISO, PJM, and Total study footprint. Joint/DC represents AC and DC transmission projects that may constitute shared costs between Midwest ISO and PJM.

The data reveals, for example, that the Native Voltage scenario requires more new lines, more line miles, and more substations than the 765 kV overlay for the total study footprint but does, however, require less acres of right-of-way.

Table 1.2-1: Summary of RGOS Overlay Physical Infrastructure

Overlay	Purview	# of New Lines	Line Miles	Acres of Right-of-way	River Crossings	Substations
Native	**Total**	**122**	**6,795**	**126,637**	**7**	**139**
	Midwest ISO	107	5,938	109,248	7	119
	PJM	13	685	13,197	0	20
	Joint/DC	2	173	4,192	0	0
765	**Total**	**90**	**6,412**	**136,612**	**7**	**124**
	Midwest ISO	69	5,029	104582	7	94
	PJM	17	1,047	23,891	0	30
	Joint/DC	4	336	8,139	0	0
Native DC	**Total**	**113**	**8,033**	**150,094**	**7**	**132**
	Midwest ISO	95	5,340	100,917	7	101
	PJM	17	836	16,289	0	21
	Joint/DC	1	1,857	32,887	0	10

*** Right-of-way widths used in Calculation: 230 kV–100ft ; 345 kV–150ft; Dbl Ckt 345 kV–160ft; 765 kV–200 ft**

Refer to Table 1.2-2, which describes the costs to build new transmission and generation for the three (3) overlay scenarios. Transmission costs were calculated by multiplying line mileage by cost per mile, with cost per mile differentiated by state. These calculations also included substations, transformers, and related infrastructure. Construction cost estimates also attempted to include the regulatory permitting process. The table categorizes these factors by Native Voltage, 765 kV, and Native Voltage with DC scenarios, as well as Midwest ISO, PJM, and Joint/DC geographies.

Based on these factors, RGOS produced total overlay estimates of $16.3 billion (2010 USD) for the Native Voltage system, $20.2 billion for 765 kV, and $21.9 billion for the Native Voltage with DC scenario for the RGOS study footprint.

Generation costs were calculated by multiplying the total amount of RPS required MW by construction cost estimates of $2 million per MW. This cost, at $58.1 billion (2010 USD), does not vary between scenarios.

Table 1.2-2: 2010 Cost Summary - Construction (2010 USD in Millions)

Category	Geographic Purview	Native Voltage	765 kV	Native DC
Transmission	**Total**	$16,301	$20,249	$21,544
	Midwest ISO	$13,865	$15,099	$12,662
	PJM	$1,952	$4,196	$2,138
	Joint/DC*	$484	$955	6,744
Generation	**Total**	$58,100	$58,100	$58,100
	Midwest ISO	$44,737	$44,737	$44,737
	PJM	$13,363	$13,363	$13,363
	Joint/DC*	$ -	$ -	$ -
Total	**Total**	$74,401	$78,349	$79,644
	Midwest ISO	$58,602	$59,836	$57,399
	PJM	$15,315	$17,559	$15,501
	Joint/DC*	$484	$955	$6,744

Refer to Table 1.2-3, which describes 2010 Levelized Annual Costs, which are the total revenue requirements (2010 USD) for the three (3) scenarios. Revenue requirements refer to the total annualized costs for the new transmission and generation. These levelized annual costs are determined through application of proxy Attachment O of the Midwest ISO FERC tariff. Table 1.2-3 breaks these factors down by Native Voltage, 765 kV, and Native Voltage with DC (Native DC) scenarios, and Midwest ISO, PJM, and Joint/DC geographies.

RGOS found total study footprint annual levelized costs vary between $1.7 billion per year for Native Voltage, to $2.1 for 765 kV, to $2.2 for Native Voltage with DC (Native DC), with generation annual costs at $4.9 billion.

Table 1.2-3: Cost Summary - 2010 Levelized Annual Costs***

Category	Geographic Purview	Native Voltage	765 kV	Native DC
Transmission	**Total**	**$1,686**	**$2,064**	**$2,188**
	Midwest ISO	$1,419	$1,537	$1,304
	PJM	$209	$424	$227
	Joint/DC*	$57	$102	$656
Generation	**Total**	**$6,334**	**$6,334**	**$6,334**
	Midwest ISO	$4,931	$4,931	$4,931
	PJM	$1,402	$1,402	$1,402
	Joint/DC*	$ -	$ -	$ -
Total	**Total**	**$8,019**	**$8,397**	**$8,521**
	Midwest ISO	$6,351	$6,469	$6,236
	PJM	$1,612	$1,826	$1,630
	Joint/DC*	$57	$102	$656

Table 1.2-4 describes 2010 Annual Costs $/MWh, which takes total costs from Table 1.2-3 and presents total costs as a per MWh value. This calculation is based on 88.6 TWh of energy delivered from renewable energy zones. Table 1.2-4 describes transmission and generation costs for the modeled RGOS renewable wind zone energy.

These are not incremental costs; rather, these are a comparative measure of total MWh cost if wind served as the only energy source relative to RGOS wind and transmission. This table indicates transmission costs for the modeled RGOS renewable energy wind zone delivered would be $19, $23, or $25 per MWh based on the addition of the various RGOS transmission overlays in the Midwest ISO footprint. On the generation side, MWh cost would increase to $72/MWh for all scenarios. It should be understood that the wind and the subsequent transmission have impacts on the entire system being served. This includes providing additional potential reliability benefits to the system for the transmission additions, as well as providing reductions in the production costs on the system. Within this study, only adjusted production costs were given a value to compare to the costs. Because costs are added to the system infrastructure as a direct result to the renewable energy zones to meet RPS requirements, the energy delivered from those zones was used as a common denominator for the per unit comparsion.

Table 1.2-4: Cost Summary – 2010 Annual Costs ($/MW*)**

Category	Geographic Purview	Native Voltage	765 kV	Native DC
Transmission	**Total**	**$19**	**$23**	**$25**
	Midwest ISO	$16	$17	$15
	PJM	$2	$5	$3
	Joint/DC*	$1	$1	$7
Generation	**Total**	**$72**	**$72**	**$72**
	Midwest ISO	$56	$56	$56
	PJM	$16	$16	$16
	Joint/DC*	$0	$0	$0
Total	**Total**	**$91**	**$95**	**$96**
	Midwest ISO	$72	$73	$70
	PJM	$18	$21	$18
	Joint/DC*	$1	$1	$7

* Joint/DC represents AC and DC transmission projects that may constitute shared costs between Midwest ISO and PJM. Note, too, there is one AC project: the Pioneer 765 kV project in Indiana. The rest represent DC projects.

** Transmission costs include line and substation cost estimates

*** Levelized annual costs determined through application of proxy Attachment O calculation to determine annual revenue requirements

**** Calculation based on energy delivered from renewable energy zones: 88.6 TWh (each overlay effectively delivered the same amount of energy)

Adding wind to the system reduces energy costs. This benefit is captured through the adjusted production cost calculated by dividing total production cost savings by total MWh. Refer to Table 1.2-5, which describes regional per MWh adjusted production savings based on 88.6 TWh of RGOS wind zone delivered energy. Adjusted cost savings within the Midwest ISO footprint for Native Voltage, 765 kV, and Native Voltage with DC (Native DC) scenarios would be $41/MWh, $43/MWh, and $43/MWh (2010 USD), respectively.

Table 1.2-5: 2010 Adjusted Production Cost (APC) Savings ($/MWh)

Entity	Native Voltage	765 kV	Native DC
Midwest ISO	$41	$43	$42
Midwest ISO/MAPP	$56	$57	$57
Midwest ISO/MAPP/PJM	$62	$63	$63
Eastern Interconnect	$62	$63	$63

Table 1.2-6 summarizes net cost. Subtracting 2010 MWh Adjusted Production Cost (APC) benefits from 2010 installed costs results in the following net costs per MWh of delivered RGOS wind zone energy.

Table 1.2-6: 2010 Net Total Cost Summary ($/MWh)

Entity	Native Voltage	765 kV	Native DC
Midwest ISO	$49	$52	$54
Midwest ISO/MAPP	$35	$37	$39
Midwest ISO/MAPP/PJM	$29	$32	$33
Eastern Interconnect	$29	$32	$33

When analyzing the information presented in Tables 1.2-1–1.2-4, it is important to note while overall metrics show some disparity among plans, the Native Voltage and 765 kV overlays are very similar when looking solely at Midwest ISO-only impacts. It is more problematic, however, when comparing either of these two (2) overlays to the Native Voltage with DC option since DC transmission costs are not categorized as solely Midwest ISO or solely PJM because the lines start in one system and terminate in the other.

1.2.4 Native Voltage Overlay

The Native Voltage solution focuses on transmission development that does **not** introduce a new voltage class within areas. This means areas with 345 kV transmission as the native Extra High Voltage (EHV) transmission must be limited to a maximum of 345 kV transmission for new infrastructure expansion. However, those areas with existing 765 kV transmission would be allowed to expand 765 kV infrastructure. Refer to Figure 1.2-3, which depicts the Native Voltage transmission solution meeting the RGOS design criteria. For a large (42 in. x 36 in.), detailed version of the Native Voltage overlay, refer to Appendix 10, attached.

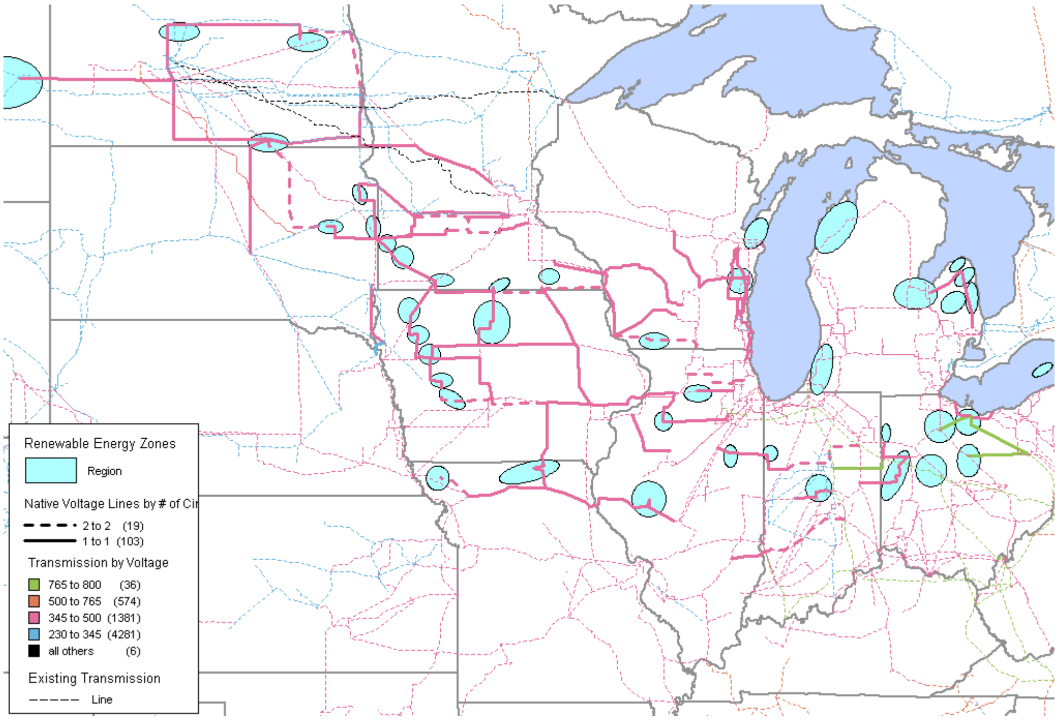

Figure 1.2-3: Native Voltage Transmission Overlay Strategy

As currently designed, the Native Voltage transmission overlay has the lowest construction cost. Although Native Voltage has more line miles than the 765 kV overlay, it requires fewer acres of right-of-way. When considering Midwest ISO alone, although the economic metrics of the Native Voltage overlay may not be as attractive as the metrics for the 765 kV overlay, Native Voltage requires about $1,200M less in capital investment to construct. The Native Voltage plan, like the two other transmission overlays, achieves the reliability objectives of the study. However, this plan does not extend as far south as the other two plans. This is part of the reason the other plans have higher construction/capital costs.

The Native Voltage strategy does have some risks and benefits. If renewable energy mandates are increased within the study footprint, or if there is an increased need for exports, additional transmission may need to be constructed. This would likely require additional right-of-way and more miles of transmission line when compared to the 765 kV and Native Voltage with DC overlays. In the long-term, this may result in escalating costs and environmental impacts that are not accounted for in this study. However, the Native Voltage Overlay has less dependence on the future transmission expansion plans of neighbors. By not introducing new voltages, the Native Voltage strategy readily integrates into the existing Midwest ISO system and may allow for quicker construction and better sequencing with other overlay components compared with the 765 kV overlays. Additionally, this strategy possibly puts less cost at risk if actual wind requirements of the Midwest ISO states are determined to be lower than the amount of wind included in the RGOS study—a determination not yet made. This risk will be minimized by carefully sequencing the construction of whichever overlay is chosen.

1.2.5 765 kV Overlay

The 765 kV solution emphasizes the development of transmission that introduces a new voltage class to much of the RGOS footprint. Figure 1.2-4 depicts the 765 kV transmission solution meeting RGOS design criteria. For a large (42 in. x 36 in.), detailed version of the 765 kV overlay, refer to Appendix 10, attached.

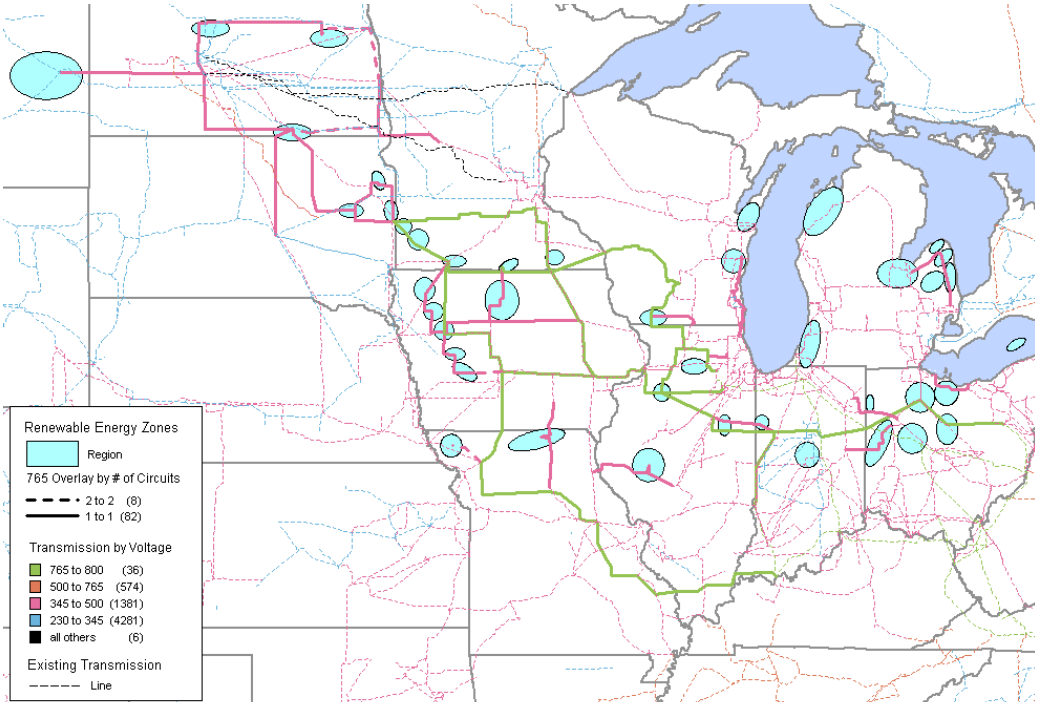

Figure 1.2-4: 765 kV Transmission Overlay Strategy

The 765 kV overlay results in Adjusted Production Cost (APC) savings greater than the Native Voltage overlay. The 765 kV overlay also uses less line miles of transmission lines than the Native Voltage overlay, although the 765 kV overlay does require more acres of right-of-way due to the wider right-of-way needed for 765 kV transmission. However, in the Midwest ISO portion of the overlay, the comparison of transmission costs, mileage, and acreage may favor the 765 kV plan.

Selecting 765 kV as an overall strategy also holds risks. For example, system development may not be achievable without cooperation among the transmission expansion strategies of two RTO regions; e.g., investment in 765 kV construction within Midwest ISO may be more heavily dependent upon the investment of the 765 kV grid within the western PJM region than the Native Voltage overlay. Proper coordination of development within Midwest ISO is also an important consideration. Transmission built in the western portion of the footprint to 765 kV standards may default to 345 kV transmission operation if eastern portions of the Midwest ISO footprint do not commit to the same 765 kV development in the same time-frame, resulting in potential cost risk. Finally, introducing 765 kV into new portions of the footprint will require costs associated with the learning curve required for the development and management necessitated by a new voltage type in the system.

Adopting a 765 kV strategy does, however, offer a number of benefits. For example, the 765 kV overlay demonstrates the need for less miles of transmission than the miles of transmission required by Native Voltage to deliver the same amount of renewable energy. If wind development in the region continues to increase over the future—and it is reasonable to expect this would be a continuing trend—the 765 kV overlay will reduce the amount of environmental impact caused by transmission construction. Although the current 765 kV plan has the potential to create better interconnection access to areas to the south and Southeast of Midwest ISO, additional refinement of the 765 kV plan that results in the same geographical footprint access as the current Native Voltage design could further reduce the line mileage of the strategy while also reducing total costs.

1.2.6 Native Voltage with DC Overlay

The Native Voltage with DC solution focuses on the development of transmission that introduces a new voltage class to much of the RGOS study footprint. Figure 1.2-5 shows the Native Voltage with DC transmission solution that meets RGOS design criteria. For a large (42 in. x 36 in.), detailed version of the Native Voltage with DC overlay, refer to Appendix 10, attached.

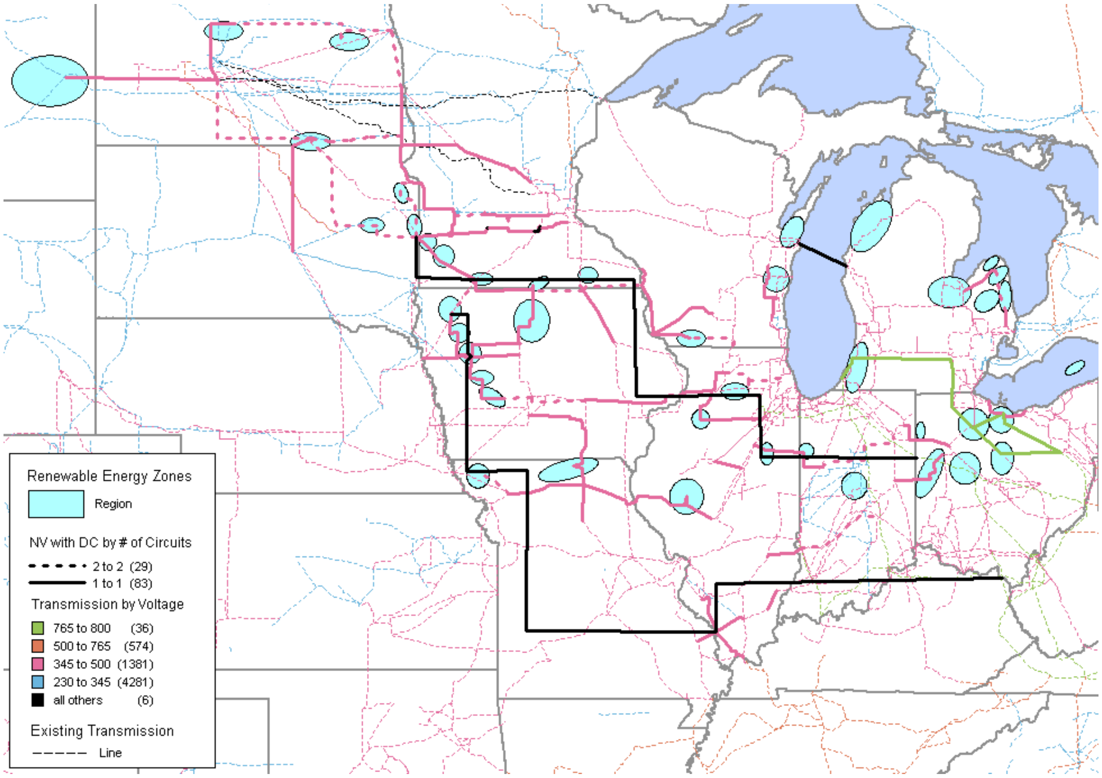

Figure 1.2-5: Native Voltage with DC Transmission Overlay Strategy

The Native Voltage with DC overlay provides benefits to the system—reducing, for example, the amount of AC transmission needed by allowing energy to be gathered in the western region of the study footprint and delivered to points to the east while avoiding potential impacts on the underlying systems. This scenario demonstrates that the crossing under Lake Michigan has the potential to reduce land-based transmission within Wisconsin and along the southern shores of Lake Michigan. Like 765 kV, Native Voltage with DC accesses part of the footprint that the Native Voltage strategy would not.

Land-based High Voltage Direct Current (HVDC) transmission was modeled as conventional HVDC. However, there are other options for the DC design available for future analysis that may provide for operational benefit that could not be captured through this study. For example, HVDC–Voltage Source Control (VSC) provides real power flow control beyond generator dispatch at full range of capability where conventional has limitations at lightly loaded schedules. In addition, HVDC–VSC has voltage control capability independent of the real power flow on the line, whereas conventional design reactive support is dependent on the real power flow. Finally, it is more functional in being able to interconnect at more intermediate locations compared to conventional HVDC which limits intermediate interconnection points.

Unfortunately the costs of adding DC to the system are rather high compared to the AC alternatives at shorter distance needs, and the entries to tap the lines are much more expensive and less integrated than providing AC paths across the system. However, it is difficult to eliminate DC transmission as an option for bulk energy delivery from renewable energy areas across long distances because of not-yet-evaluated option values. Proper evaluation of these other metrics along with improved design of what type of HVDC as well as interconnection locations could improve the case for long-distance DC energy delivery.

1.3 RGOS Candidate Multi-Value Projects

Although RGOS focused on the development of holistic system solutions meeting long-term needs for the integration of renewable resources into the transmission system, it is important to identify an initial group of projects that are compatible with the three overlays that provide a practical first step towards meeting the renewable resource requirements. Midwest ISO staff has developed an analytical framework to identify the best potential transmission projects. These RGOS-identified projects will require more detailed analysis. Because a Midwest ISO long-range transmission expansion strategy has not yet been determined and was not within the scope of RGOS analysis, it is important Candidate Multi-Value Projects (MVPs) not pre-determine Midwest ISO long-range strategic aims and equally important Candidate MVPs prove compatible with all potential strategies.

Refer to the Venn diagram in Figure 1.3-1 conceptualizing RGOS Candidate Multi-Value Project (MVP) selection.

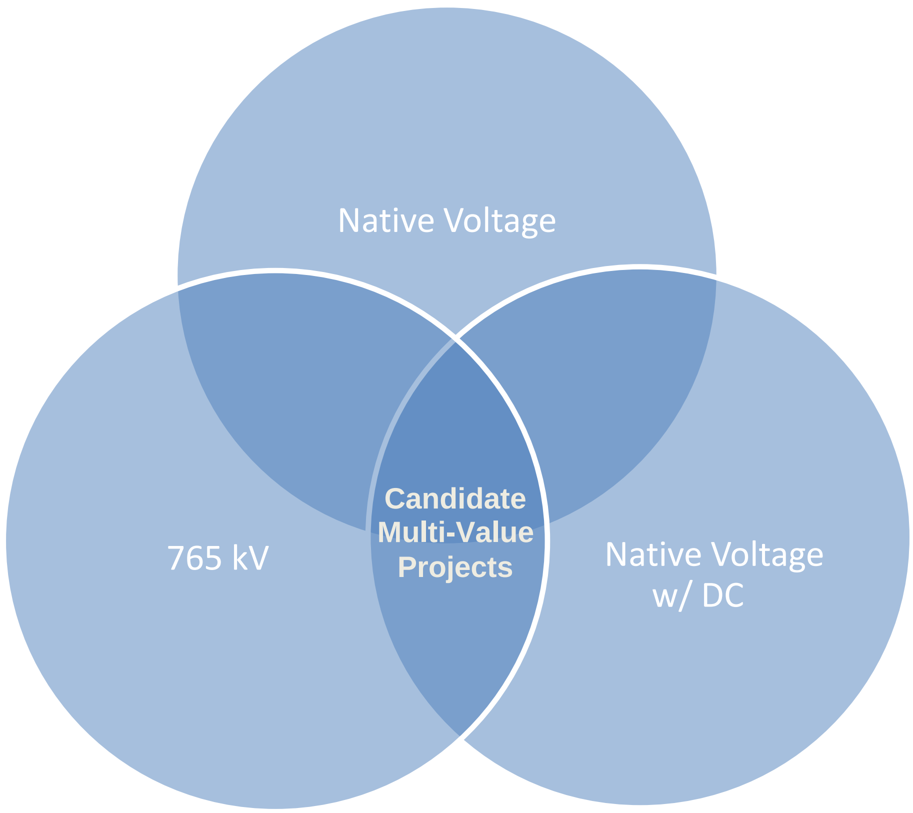

Figure 1.3-1: Candidate MVP Strategy Development Venn Diagram

1.3.1 Identifying RGOS Candidate Multi-Value Projects

The RGOS inputs into the Candidate Multi-Value Projects (MVPs) portfolio were identified by means of the steps outlined below. Please note other studies were considered in collecting the final Candidate MVP portfolio; not all projects in that portfolio are derived from the RGOS study effort. For greater detail regarding the steps comprising the Candidate MVP identification process, refer to section 7 of this document. For a summary of the future ramifications of Candidate MVP portfolio identification, refer to section 8.

- **Step 1:** Identify useful corridors common to multiple Midwest ISO studies.
- **Step 2:** Identify RPS timing needs and synchronize with generation interconnection queue locations.
- **Step 3:** Evaluate constructability of transmission.

An initial set of transmission projects was identified using the inspection steps listed above. These transmission projects served as an input into the overall Candidate MVP portfolio described in section 7.1. The selected Candidate MVPs are compatible with RGOS-developed overlays and provide potential value for other needs identified within the transmission system. Refer to Figure 1.3-2, which depicts Candidate MVPs from the RGOS analysis. Estimated cost for this RGOS Candidate MVP set is approximately $5.8 Billion, with $4.4 billion of that amount within Midwest ISO borders.

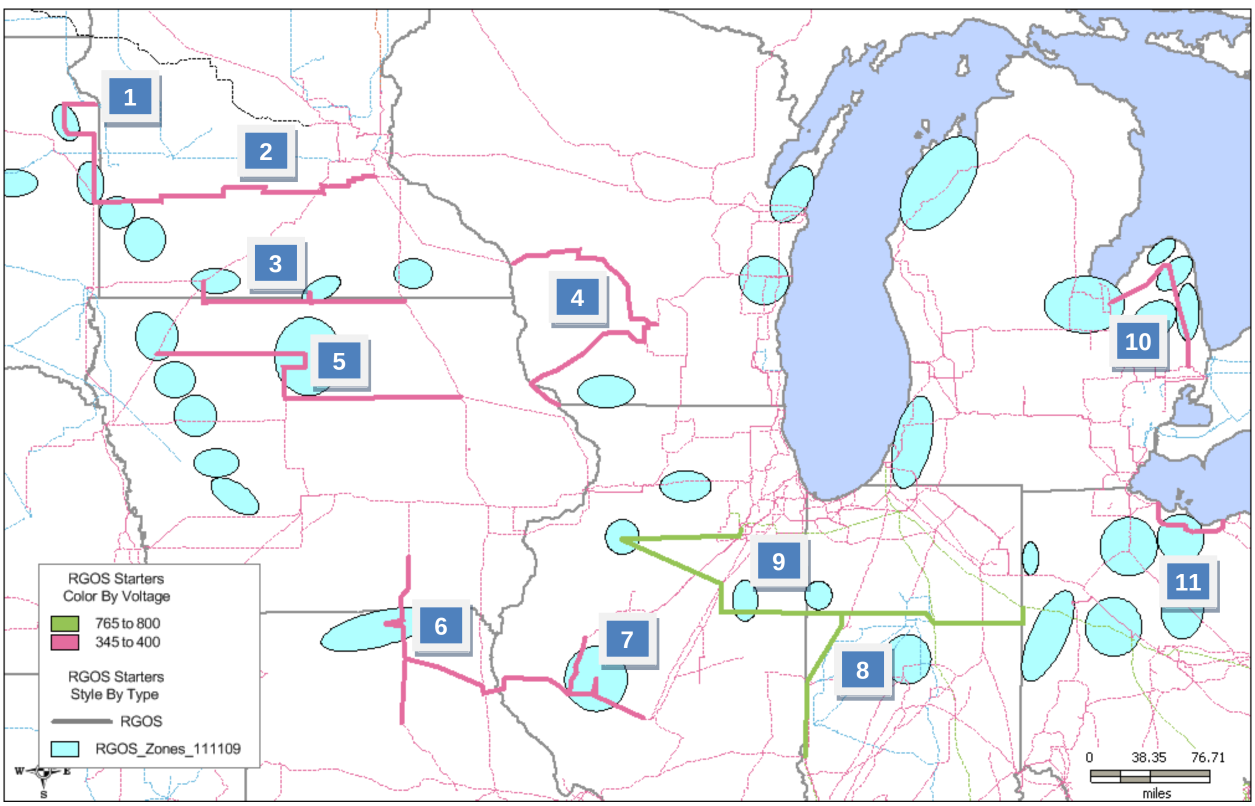

Figure 1.3-2: RGOS-identified Candidate Multi-Value Projects (Midwest ISO and PJM Lines Shown)

The numbered list shown in Table 1.3-1, below, corresponds to the Candidate MVP identifiers depicted in Figure 1.3-2 on the previous page.

Table 1.3-2: Candidate Multi-Value Projects

ID	Candidate MVP	Estimated Installed Cost (2010 USD in millions)
1	Big Stone to Brookings 345 kV line	150
2	Brookings to Twin Cities 345 kV line	700
3	Lakefield Junction to Mitchell County 345 kV line constructed at 765 kV specifications	600
4	North LaCrosse to North Madison to Cardinal, Dubuque to Spring Green to Cardinal 345 kV lines	811
5	Sheldon to Webster to Hazleton 345 kV line	458
6	Ottumwa to Adair to Thomas Hill, Adair to Palmyra 345 kV lines	295
7	Palmyra to Meredosia to Pawnee, Ipava to Meredosia 345 kV lines	345
8	Sullivan to Meadow Lake to Greentown to Blue Creek 765 kV line	908
9	Collins to Kewanee to Pontiac to Meadow Lake 765 kV line	964
10	Michigan Thumb 345 kV transmission loop	510
11	Davis Besse to Beaver 345 kV line	71

The RGOS effort encompassed not only Midwest ISO but also immediate neighbors within PJM. This broadening of the study footprint resulted in development of transmission overlays that also include transmission within the PJM footprint. However, for purposes of Candidate Multi Value Project (MVP) evaluation, only Midwest ISO projects are included.

1.4 RGOS Results Summary

RGOS provides industry stakeholders and policy makers with a regional planning perspective identifying potential investment opportunities and demonstrating the integration of renewable energy policies into electrical system development. The purpose of RGOS has been to explore long-term transmission strategies ensuring study defined reliability objectives in delivery of renewable energy as well as RPS compliance. Aside from developmental considerations and regulatory concerns, determining a long-term transmission expansion strategy also serves to frame and define near-term needs. With these factors in mind, RGOS contributors considered the following when formulating viable long-term transmission strategies:

- **Performance:** Does the proposed strategy perform well under a variety of future scenarios?
- **Developmental Considerations:** Noting many of the more reliable wind resources reside far from large electrical load centers and lack adequate long-distance transmission lines, what is the expectation for further long-term development of wind resources within Midwest ISO?
- **Time Constraints:** Can finalizing a single, long-term strategy decision be deferred long enough to allow continued testing of important assumptions without jeopardizing legal requirements and renewable investment or risking the potential for stranded investment?

The best fit solution is a transmission overlay encompassing all Midwest ISO states, premised on a distributed set of wind zones, each with varying capacity factors and distances from load.

Midwest ISO cannot currently recommend a long-term transmission development strategy employing Native Voltage, 765 kV, or Native Voltage with DC. All three plans meet study objectives. Costs and benefits vary between scenarios, but not significantly. Methodologies for analyzing performance under a variety of possible futures require continued development along with determining 'options value' for each strategy. Detailed construction design analysis is still required.

The best fit solution is a transmission overlay encompassing all Midwest ISO states, premised on a distributed set of wind zones, each with varying capacity factors and distances from load.

No consensus exists regarding the amount of renewable generation ultimately needed to comply with current and future RPS mandates. Predictions vary. Some assert a much higher level of wind generation will be required than those included in RGOS analyses while others, equally confident, claim a lower amount. Regardless of the long-term uncertainty engendered by expansion or reduction of renewable energy standards, states within the Midwest ISO system will need new transmission to meet current and near-term renewable energy requirements, to ensure reliable operation of the transmission grid, and to facilitate the generation interconnection queue process. Midwest ISO will continue to work with policy makers and industry stakeholders to determine a strategy for transmission development within the footprint.

Because of RGOS, Midwest ISO has identified the next, most immediate step to transmission investment: a set of robust Candidate Multi-Value Projects (MVPs) meeting current renewable energy mandates and the regional reliability needs of its members.

2 Scope

2.1 Stakeholder Study Participation

Stakeholders reviewed and contributed to RGOS throughout the study process. A Technical Review Group (TRG), composed of regulators, transmission owners, renewable energy developers, and market participants, met monthly with Midwest ISO engineers to provide input, feedback, and guidance. Composed of a smaller group of experienced transmission engineers, a Design Subteam (DST) met bi-weekly to review detailed results. RGOS reported regularly to the Midwest ISO Planning Advisory Committee (PAC) and Planning Subcommittee (PSC). RGOS transmission planners also conferred with the Upper Midwest Transmission Development Initiative (UMTDI), a group of Governor-appointed representatives from Wisconsin, Iowa, Minnesota, South Dakota, and North Dakota.

2.2 Stakeholder Survey Results

In 2008, at the onset of Phase I of the RGOS study, a stakeholder survey was completed for the states of Illinois, Iowa, Minnesota, and Wisconsin. The purpose of the survey was to determine the renewable energy requirements; i.e., the Renewable Portfolio Standards (RPS), of the various Load Serving Entities (LSEs) in those states. The results were published in the RGOS Phase I Executive Summary Report[1]. Likewise, another survey was performed during the summer 2009 to update RGOS Phase I information and to gather LSE renewable requirements from the remaining Midwest ISO states. The surveys also included the PJM members Commonwealth Edison (CE) and American Electric Power (AEP).

This inquiry sought detailed information regarding the plan of each company to meet the requirements of their particular RPS or goal. Each State also received a survey for their perspective. The survey results provided specific and current information on the RPS and wind assumptions within the RGOS study area, such as the following:

- Identifying the RPS mandates and respective plans by each LSE, by state
- Determining how and to what extent each LSE intends to utilize wind generation to meet its RPS obligations
- Calculating the energy projections of each LSE for each year under its RPS

The information obtained from these surveys was vital in determining the amount of renewable energy and capacity to study. Not all the LSE's responded to the survey resulting in some data being determined through a similar survey by the Organization of Midwest States (OMS) Cost Allocation and Regional Planning (CARP) Working Group.

[1] RGOS Phase I Executive Summary Report

Table 3.2-1 below summarizes the results of the RGOS survey, identifying total and net renewable energy requirements, existing and planned renewable energy, and the net renewable capacity for 2027. Table 3.2-1 also identifies the amount (in percent) of each states RPS expected to be served by wind energy. The 'Total Energy Required' column is the net requirement after applying the "% of RPS by Wind" percentages. As can be seen in Table 3.2-1, some states have more existing renewable energy than required by their respective mandates or goals. Existing renewables were only counted towards the requirements of the respective state in which these renewables originate; thus, an excess of existing wind in one state was not counted towards the requirements in another state. In Iowa, for example, it was not fully known where an excess of that state's existing renewable energy is being supplied. Confining source to state also reduced the risk of double counting if an LSE is fulfilling part of its requirements by deriving some of its renewable energy from another state.

Table 2.2-1: RGOS Survey Results

State	% of RPS by Wind	Total Energy Required (GWh)	Existing & Planned (GWh)	Net Needs (GWh)	Wind Zone Capacity (MW)
IA	100%	348	10,272	-	4,650
IL	75%	17,905	5,608	12,297	2,200
IN	-	-	2,263	-	1,000
MI	92%	7,884	365	7,519	3,150
MN	95%	22,786	6,929	15,857	3,875
MO	90%	6,591	439	6,152	1,000
MT	-	-	-	-	400
OH	100%	26,244	3	26,241	5,075
WI	63%	14,630	1,959	12,671	2,325
ND	-	1,453	4,752	-	2,325
SD	-	1,294	626	668	2,325
Total	**-**	**99,135**	**33,215**	**81,406**	**28,325**
RTO					
Midwest ISO	-	78,707	32,165	62,028	21,582
PJM	**-**	20,428	1,050	19,378	6,743

Note the following:

- "Existing & Planned" refers to wind farms or other qualifying renewable energy source currently in operation or holding a signed Generator Interconnection Agreement.
- The Wisconsin RPS is 10% of energy served from renewable; however, it has been adjusted to 25% per direction from the State of Wisconsin.
- Several sources were considered in order to determine the most up-to-date levels of Existing and Planned renewable energy within the study footprint. Those sources included LSE surveys, Midwest ISO Operations data, and data compiled from the SMARTransmission[2] study.

[2] SMARTransmission

2.3 Wind Zone Development

A key assumption of the RGOS study has been the amount and location of wind energy zones modeled within the study footprint. Wind energy zone development was based on stakeholder surveys focusing on expected renewable energy needs over the next 20 years and how much of that need is expected to be met with wind generation.

During RGOS I and RGOS II wind zone development, Midwest ISO staff provided for consideration multiple energy zone configurations that met renewable energy requirements. In this process, study participants identified capital costs associated with generation capacity as well as capital costs associated with indicative transmission that would help deliver the energy to the system. In both RGOS I and II efforts, the most expensive energy delivery options were those options relying solely on the best regional wind source areas (with higher amounts of transmission needed) or those options relying solely on the best local wind source areas (with higher amounts of generation capital required).

As a result of RGOS I and RGOS II zone development efforts as well as interaction with regulatory bodies such as the Upper Midwest Transmission Development Initiative (UMTDI) and various state agencies within Midwest ISO, a set of renewable energy zones was selected. These zones represent the intention of state governments to source some renewable energy locally while also using the higher wind potential areas within the Midwest ISO market footprint. Zone selection was based on a number of potential locations developed by the Midwest ISO utilizing mesoscale wind data supplied by the National Renewable Energy Laboratory (NREL) of the US Department of Energy. Wind zones distributed across the region (1) reflecting local development trends and requirements; or (2) occupying the best regional wind locations, results in a set of distributed wind zones best balancing renewable energy requirements and overall system costs.

Refer to Figure 2.3-1, which depicts this selected set of renewable energy zones, and to Table 2.3-1 and Table 2.3-2, which furnish zone-by-zone UMTDI and non-UMTDI selections, respectively.

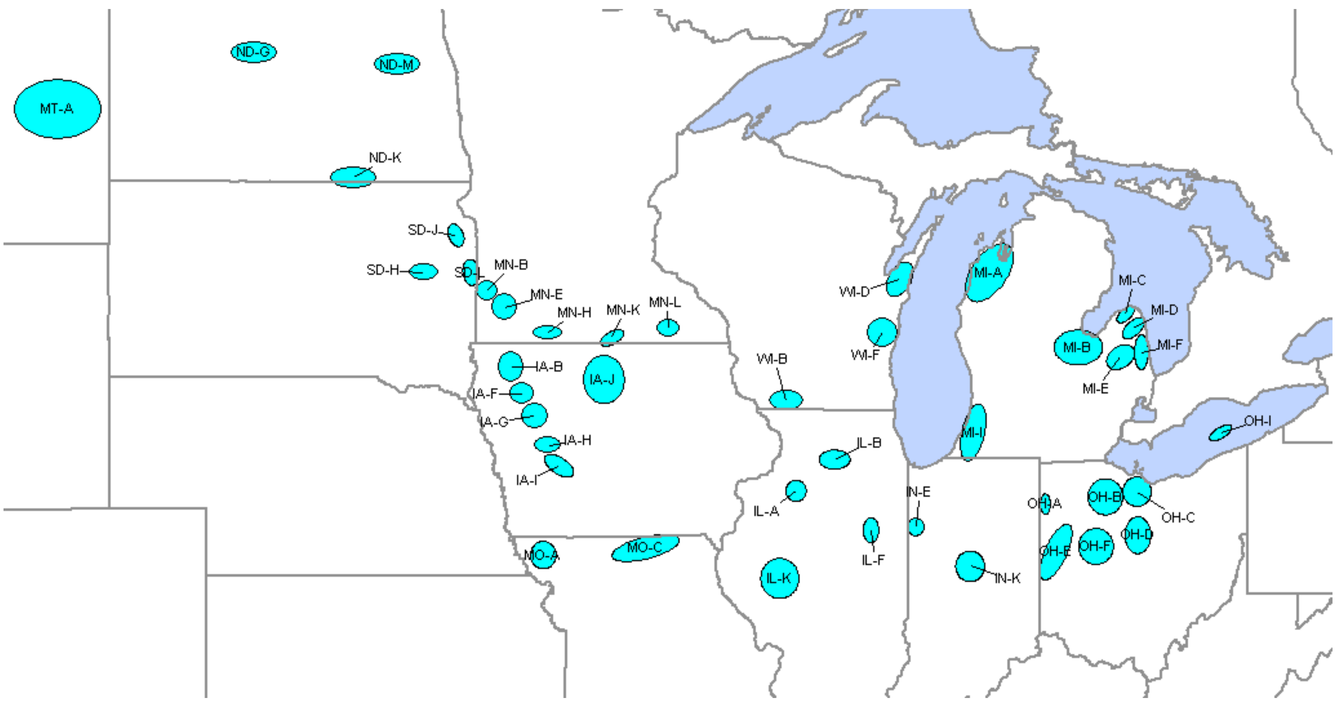

Figure 2.3-1: Renewable Energy Zone Locations

Table 2.3-1: Renewable Energy Zone Information (UMTDI Zone Selection B)

Zone	State	CF	Nameplate (MW)	Energy Output (GWh)	Zone	State	CF	Nameplate(MW)	Energy Output (GWh)
IA-B	IA	0.366	775	2485	MN-L	MN	0.349	775	2369
IA-F	IA	0.362	775	2458	ND-G	ND	0.424	775	2879
IA-G	IA	0.354	775	2403	ND-K	ND	0.373	775	2532
IA-H	IA	0.367	775	2492	ND-M	ND	0.359	775	2437
IA-I	IA	0.356	775	2417	SD-H	SD	0.384	775	2607
IA-J	IA	0.327	775	2220	SD-J	SD	0.407	775	2763
MN-B	MN	0.393	775	2668	SD-L	SD	0.399	775	2709
MN-E	MN	0.382	775	2593	WI-B	WI	0.266	775	1806
MN-H	MN	0.368	775	2498	WI-D	WI	0.283	775	1921
MN-K	MN	0.334	775	2268	WI-F	WI	0.276	775	1874

Table 2.3-2: Renewable Energy Zone Information (non-UMTDI Zone Selections)

Zone	State	CF	Nameplate (MW)	Energy Output (GWh)	Zone	State	CF	Nameplate(MW)	Energy Output (GWh)
IL-A	IL	0.310	550	1494	MI-I	MI	0.259	350	794
IL-B	IL	0.298	550	1436	MO-A	MO	0.358	500	1568
IL-F	IL	0.300	550	1445	MO-C	MO	0.330	500	1445
IL-K	IL	0.252	550	1214	MT-A	MT	0.432	400	1514
IN-E	IN	0.311	500	1362	OH-A	OH	0.272	725	1727
IN-K	IN	0.291	500	1275	OH-B	OH	0.271	725	1721
MI-A	MI	0.264	300	694	OH-C	OH	0.280	725	1778
MI-B	MI	0.274	500	1200	OH-D	OH	0.252	725	1600
MI-C	MI	0.298	500	1305	OH-E	OH	0.255	725	1620
MI-D	MI	0.281	500	1231	OH-F	OH	0.281	725	1785
MI-E	MI	0.272	500	1191	OH-I	OH	0.407	725	2585
MI-F	MI	0.270	500	1183					

The capacity factors used in Table 2.3-1 and Table 2.3-2 are weighted capacity factors (CFs) developed as part of RGOS Phase I analysis. For further information regarding CF calculations, refer to section 9 of MTEP09 and the RGOS Phase I Executive Summary Report. In selecting renewable energy zones, a general methodology was used:

1. UMTDI B zones from the RGOS Phase I were used for the western footprint to meet local needs.
2. Michigan would meet all of its energy needs within the state of Michigan in accordance with state legislation.
3. Ohio, Missouri, and Illinois would meet 50% of their needs with respective in-state resources to reflect state legislation and the desire for local development.
4. UMTDI group B zones, Montana, and Indiana were used to meet the remaining renewable energy needs of Ohio, Missouri, and Illinois.
5. Target energy from renewable energy zones was 81,406 GWh.

2.4 Study Methodology

There were three (3) primary steps utilized in the development of the transmission overlays. These steps include both production cost and Power Flow analysis, with each technique providing its own value to the process. The starting point of this analysis was the indicative transmission developed during RGOS Phase I and Phase II studies in 2008 and 2009. For more information regarding this development process, again refer to MTEP09 report, Section 9.

2.4.1 Production Cost Analysis

Power Flow reliability analysis was conducted using a production cost model as a starting point. This starting point analyzed the energy flow on the system and reduced the indicative transmission to a limited level of transmission to achieve economic energy flow. Production cost modeling uses a limited list of reliability constraints for analysis, and therefore should not be considered an optimal solution without reliability model analysis.

The production cost model included the transmission infrastructure contained within the RGOS peer-reviewed 2019 Power Flow model. The initial production cost analysis was based on the Organization of Midwest ISO States (OMS) Cost Allocation and Regional Planning (CARP) developed Business as Usual with High Demand and Energy Case. Refer to Table 2.4-1, which posits the primary assumptions associated with the development of this case.

Table 2.4-1: Key Assumptions for Economic Model Development

Uncertainty	Value
Demand Source	Module E 2009 Submittal
Demand Growth	1.6% Annual Escalation
Energy Growth	2.19% Annual Escalation
Natural Gas Cost (2010 Henry Hub)	$6.22/MBtu
Carbon Cost/Cap	No Cap nor Cost applied
Reserve Target	15% of Midwest ISO Coincident Peak Demand

Note each overlay was compared to a base run that included new wind zone generation without additional transmission beyond 2019 base case assumptions. The base run included typical flowgates, and was not screened for additional flowgates that might have the potential to severely restrict RPS wind injections resulting in ‘dump’ energy.

The production cost model uses an event file to perform contingencies and system monitoring. This event file was updated with ‘local’ contingencies to capture wind effects, and contains Midwest ISO and NERC flowgates. These flowgates will not show the outlet issues associated with the zones. To add relevant constraints to the modeling, Midwest ISO staff utilized the Power Flow Analysis Tool (PAT).

2.4.2 Linear Power Flow Analysis

The reduced amount of transmission developed through the production cost analysis of the indicative transmission designs was then added to the off-peak (70% of peak load), shoulder Power Flow model. Linear analysis on the off-peak shoulder model identified additional reliability constraints that were addressed. The bulk of the reliability analysis fell within the off-peak shoulder case work effort.

Once all selected criteria violations were identified and solutions proposed, plans were analyzed using an on-peak model as well as a light load (40% of peak load) model.

MTEP09 Power Flow models were used in the development of the 2019 peak and off-peak models. These models were created within the Midwest ISO Model On Demand database and include 2019 summer peak load cases, which were then modified to produce the 2019 off-peak model used in the analysis. The MTEP10 Power Flow model was used to create the light load model employed in analysis. The external representation used for the MTEP models are the NERC ERAG MMWG models. The latest MRO models were used to update non-Midwest ISO Midwest Reliability Organization (MRO) data. Midwest ISO system updates were added through the stakeholder process. Neighboring utility updates were provided by SPP, TVA, and PJM.

The 2019 model contains all projects moving to MTEP Appendix A or Appendix B as well as those MTEP Appendix B projects identified with a “Planned” status designation. Given the uncertainty of their respective status, those projects in MTEP Appendices B and C **not** moving to MTEP Appendix A in the current planning cycle will be removed or not incorporated in RGOS models. Designing RGOS (or any) transmission system dependent on projects not confirmed for development or potentially destined for replacement by an alternative project would adversely impact the final set of transmission projects.

NERC Category A, B and C events were used in Power Flow analysis. A comprehensive Category C evaluation was not performed. Category C events were limited to select events greater than 230 kV supplied by stakeholders, and double branch contingencies within a bus of each zone’s outlet facilities were used. Category C events were tested for energy zone outlet restriction and for potential cascading events. These cascading events were defined as situations in which transmission facilities experience a maximum loading of 125% or higher, as compared to the facility's emergency ratings. All elements greater than 100 kV were monitored during analysis. However, only elements greater than 200 kV in violation were addressed for solutions. All other elements were identified and included within the evaluation of the overlays.

It is understood that evaluating the system reliability for violations on the 230 kV system and above misses constraints on the lower voltage system. This may result in the understatement of the wind curtailment within the economic models as well as the amount of transmission that must be considered for full reliability modeling impact. However, it is a functional screen of the impacts caused by the injection of new resources on the system. Future evaluation of an overall strategy may need to assess the lower voltage concerns in its final decision on the proper transmission expansion strategy for the Midwest ISO footprint.

2.4.3 AC Power Flow Analysis

AC Power Flow analysis was performed on the same peak, off-peak, and light load models used in the linear flow analysis by employing an AC Power Flow solution with the same contingency files used in linear Power Flow work. This analysis helped identify an approximation for reactive and capacitive support on the system, improving the accuracy of cost estimates and providing a more holistic solution to stated RGOS objectives.

2.4.4 Study Objective Change

Initially, the RGOS study was commissioned to develop and analyze multiple transmission overlay solutions that would meet the desire to deliver the RPS requirements in a reliable and economically conscientious way. It was expected that the study would identify a single strategy that would guide transmission investment for the next 20 years. However, during the development and analytics of the overlays, it was determined by Midwest ISO staff and management that none of the overlays stood out as the proper strategy to push forward for all future EHV transmission development.

Because an overall strategy for future transmission development was deemed inappropriate at this time, the RGOS study focused on transmission projects identified within the study that facilitate RPS requirements throughout the study footprint while not predetermining a long-term transmission investment strategy.

3 Renewable Energy Requirements

The bulk of the generation expansion within the RGOS study footprint will consist of resources that will be required to meet legislated renewable energy requirements and goals. Based on RGOS survey results and the current construct of the Midwest ISO Generation Interconnection Queue (GIQ), wind will be relied upon to meet the majority of the requirements. Therefore, the RGOS study focused on the development of a transmission system that would help facilitate the wind contribution to the renewable energy requirements.

3.1 Renewable Portfolio Standards

The Midwest ISO region observed two significant drivers for transmission expansion: (1) state RPS mandates; and (2) associated generation in the Midwest ISO Generation Interconnection Queue (GIQ).

Some states within the Midwest ISO purview; i.e., Montana, Minnesota, Wisconsin, Iowa, Missouri, Illinois, Michigan, Ohio, and Pennsylvania, currently have RPS mandates that require varying percentages of electrical energy be met from renewable energy resources. North Dakota and South Dakota do not have an RPS but do have renewable goals. Kentucky and Indiana currently have neither RPS mandates nor goals. RPS mandates vary from state to state in specific requirements and implementation timing but generally start at or around 2010 and continue into the next decade. Refer to Figure 3.1-1.

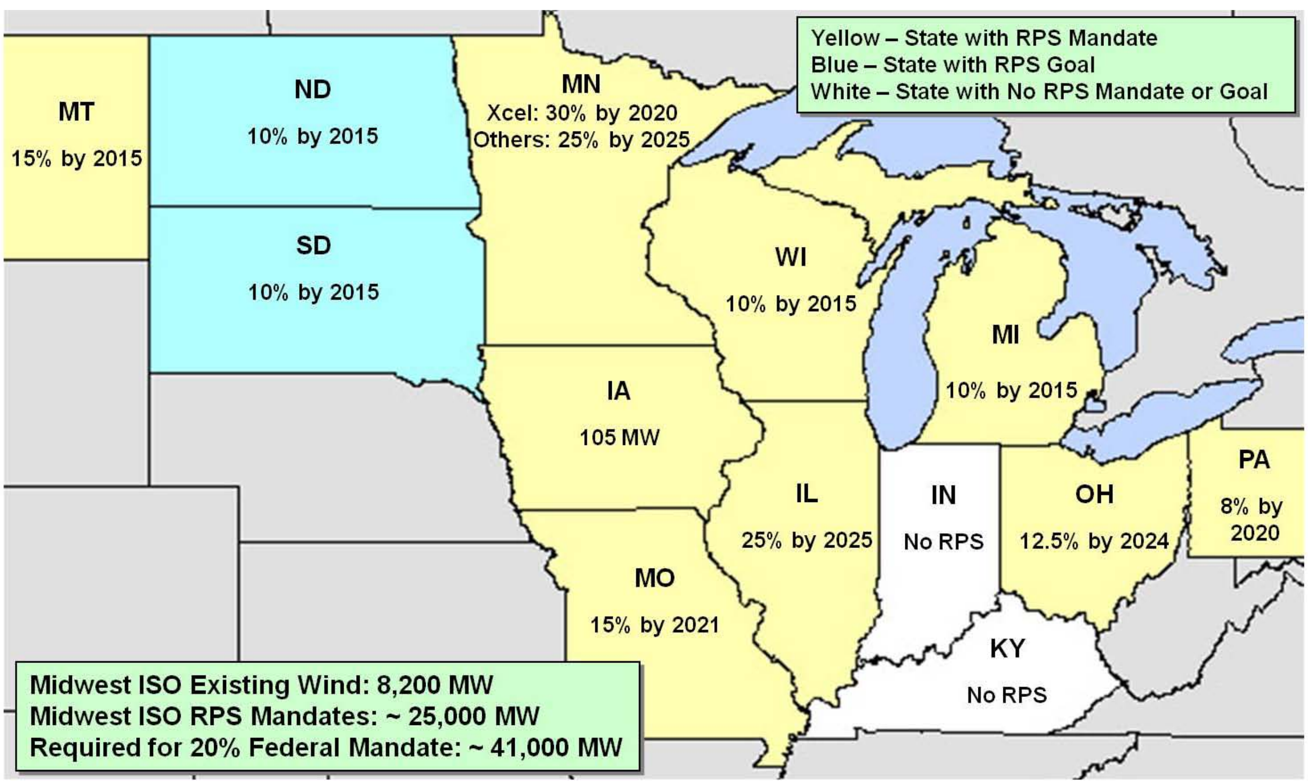

Figure 3.1-1: RPS Requirements within Midwest ISO Footprint

The second major driver for transmission expansion is the Midwest ISO Generation Interconnection Queue (GIQ), which—as of the end of July 2010—held approximately 64,500 MWs of wind requests. After careful examination of the inherently complex issues involved, Midwest ISO staff and stakeholders determined the GIQ process would not be an efficient means for building a cost-effective transmission system over the next 5–10 year period or in the foreseeable future beyond that time-frame.

Each state has specific requirements associated with RPS mandates and goals. Most of the legislated mandates within the study footprint come to maturity between 2015 and 2025. Refer to Table 3.1-1 for a summary of the percentages of energy to be served over time, by year.

Table 3.1-1: 2015–2025 RPS Targets

Year	WI (% of Energy)	MN (w/o Xcel) (% of Energy)	MN (w/Xcel) (% of Energy)	IL (% of Energy)	MI (% of Energy)	OH (% of Energy)	MO (% of Energy)	MT (% of Energy)	PA (% of Energy)	SD (% of Energy)	ND (% of Energy)	IA (MW)
2015	10.00%	12.00%	18.00%	10.00%	10.00%	3.50%	5.00%	15.00%	5.50%	10.00%	10.00%	105
2016	10.00%	17.00%	25.00%	11.50%	10.00%	4.50%	5.00%	15.00%	6.00%	10.00%	10.00%	105
2017	10.00%	17.00%	25.00%	13.00%	10.00%	5.50%	5.00%	15.00%	6.50%	10.00%	10.00%	105
2018	10.00%	17.00%	25.00%	14.50%	10.00%	6.50%	10.00%	15.00%	7.00%	10.00%	10.00%	105
2019	10.00%	17.00%	25.00%	16.00%	10.00%	7.50%	10.00%	15.00%	7.50%	10.00%	10.00%	105
2020	10.00%	20.00%	30.00%	17.50%	10.00%	8.50%	10.00%	15.00%	8.00%	10.00%	10.00%	105
2021	10.00%	20.00%	30.00%	19.00%	10.00%	9.50%	15.00%	15.00%	8.00%	10.00%	10.00%	105
2022	10.00%	20.00%	30.00%	20.50%	10.00%	10.50%	15.00%	15.00%	8.00%	10.00%	10.00%	105
2023	10.00%	20.00%	30.00%	22.00%	10.00%	11.50%	15.00%	15.00%	8.00%	10.00%	10.00%	105
2024	10.00%	20.00%	30.00%	23.50%	10.00%	12.50%	15.00%	15.00%	8.00%	10.00%	10.00%	105
2025	10.00%	25.00%	30.00%	25.00%	10.00%	12.50%	15.00%	15.00%	8.00%	10.00%	10.00%	105

For a tabular breakdown of respective state RPS requirements, refer to Appendix 2 of this document.

4 Renewable Energy Zones Development

4.1 Wind Analysis

Significant work was performed in 2008 and 2009 relating to wind data development and analysis for the RGOS Phase I study, completed in 2009. This work was essential to the RGOS Phase I effort and carried over into further development of renewable resources for current RGOS study work. No consistent source for geographically disparate wind data existed within the RGOS study region at the start of the study. Although basic wind speed information has been available for many years, factors such as wind speed, for example, leave too many unanswered assumptions for the purposes of a detailed statistical and economic study. Other factors include—but are not limited to—wind power output, time correlation with load, turbine class used, terrain, weather, and available capacity. Although data from existing wind farms in the Midwest ISO region could have been used, there were limitations to this data, such as size and quantity, geographic diversity, output history, and future technology or turbine classes.

As identified in the RGOS Phase I Executive Summary Report[3], the Generation Interconnection Queue (GIQ) was not, of itself, an appropriate identifier for wind resources to perform this study. As reported in the RGOS Phase I report in July 2008, the Midwest ISO Queue had 350 wind interconnection requests totaling 67,000 MW, and the PJM Queue had 42,400 MW of wind, of which 27,000 MW was in the RGOS study region. This totaled over 94,000 MW of wind generation which could have been used during the RGOS study. Impartially selecting a subset of queued projects to meet identified state renewable energy requirements without detailed wind data would have been difficult.

Several additional issues made using GIQ data problematic, to include:

- Queue requests for wind had increased in locations with an RPS, which could potentially bias zones towards states with RPS and against potentially higher capacity factor sites in states that do not have such mandates, such as North and South Dakota, and Indiana.
- The location of generation interconnection requests were potentially biased by other criteria not related to the wind capacity factor, such as the generators' location in relation to available transmission, wind turbine transportation, and financing. However, it was recognized that most of the wind interconnection requests do occur in the high wind areas, and that this would be accounted for in any statistical analysis of wind potential in the region.

Midwest ISO worked with the National Renewable Energy Laboratory (NREL) throughout 2007 and early 2008 in a collaborative effort with the Joint Coordinated System Plan (JCSP) and was aware NREL would be performing the Eastern Wind Integration and Transmission Study (EWITS), a comprehensive study of wind in the Eastern Interconnect. In March 2008, NREL engaged AWS Truewind to develop a set of wind resource and plant output data for the eastern United States for EWITS. The statement of work identified five (5) technical tasks to developing high resolution wind power output data in 10-minute increments for years 2004, 2005, and 2006. The methods used and results achieved are described in the following sections. The final results and a study report are available on the NREL website at http://wind.nrel.gov/public/EWITS.

[3] RGOS Phase I Executive Summary Report

4.1.1 Renewable Energy Zone Scenario Development

The information gathered in performing the metrics work discussed in Section 4.1 was used to identify an appropriate weighting system for developing the renewable energy zones. The renewable energy zones were developed on a state-by-state basis taking advantage of the highest eleven (11) year average capacity factor sites in each state. Selected sites were lumped together to achieve an energy zone that had an approximate capacity of 2,400 MW, while maximizing the overall capacity factor of the energy zone. Many energy zones were developed for each state in this manner. Based on the metrics, weighted values were created and used to rank the zones. The four (4) weighted measures and their weighting are as follows, where on-peak hours are 6AM–10PM, afternoon on-peak hours are 3PM–6PM, and summer months are June, July, and August:

- **Weighted Capacity Factor (CF)**
  - 11-Year average CF 50%
  - 3-Year average CF 10%
  - On-peak CF 10%
  - Afternoon On-peak CF 10%
  - Summer On-peak CF 10%
  - Summer Afternoon On-peak CF 10%
- **Distance to Load Center**
- **Weighted Variability**
  - Variance of hourly wind output 25%
  - Standard Deviation 25%
  - Average hourly ramp-up 25%
  - Average hourly ramp-down 25%
- **Distance to Infrastructure**
  - Distance to existing transmission (>300 kV) 33.3%
  - Distance to Railroads 33.3%
  - Distance to major highways 33.3%

For each renewable energy zone developed, weighted metrics were calculated as a composite of the selected sites in that zone. The weighted capacity factor was converted to a $/MWh value based on a capacity of 750MW from each zone and a cost of $2M/MW for wind turbines. Distance-to-load center values were calculated by taking the distance from each selected site to the nearest large load center. Distance to infrastructure was used to help select zones that may otherwise have a similar metrics score to another zone, by giving preference to a zone close to existing infrastructure. Proximity to major railroads and highways aids in the delivery and construction of necessary substations and wind farms.

Wind zones were created in each state once a process methodology was established. Even though North Dakota, South Dakota, and Indiana do not have RPS mandates in accordance with RGOS scope, they do have extensive wind resources and thus were used to provide possible renewable energy to the study. In order to establish local versus regional energy sources—again per study scope—energy zone scenarios were created, each concentrating on local to load center wind (with most of the renewable energy zones located within each state, respectively), remote to load center wind (utilizing higher capacity factors and transporting the wind as needed) and a local and remote combination. A ranking was applied to the four (4) measures described in the last section to create a score from 0-100 for each energy zone. Appropriate renewable energy zones were selected for each scenario based on those rankings. For renewable energy zones in the western part of the footprint, the Upper Midwest Transmission Development Initiative (UMTDI) Zone Scenario B was used.

For each scenario, the top ranking zones were selected as sites for renewable generation until the needed amount of MWh's was sufficient to meet the RPS requirements. Since higher capacity factor areas produce more energy, the regional scenarios had fewer zones than the local scenarios.

The results of this work are shown in Figures 4.1-1–4.1-3, which depict the three (3) scenarios: local, regional, and combination, including the UMTDI Zone Scenario B.

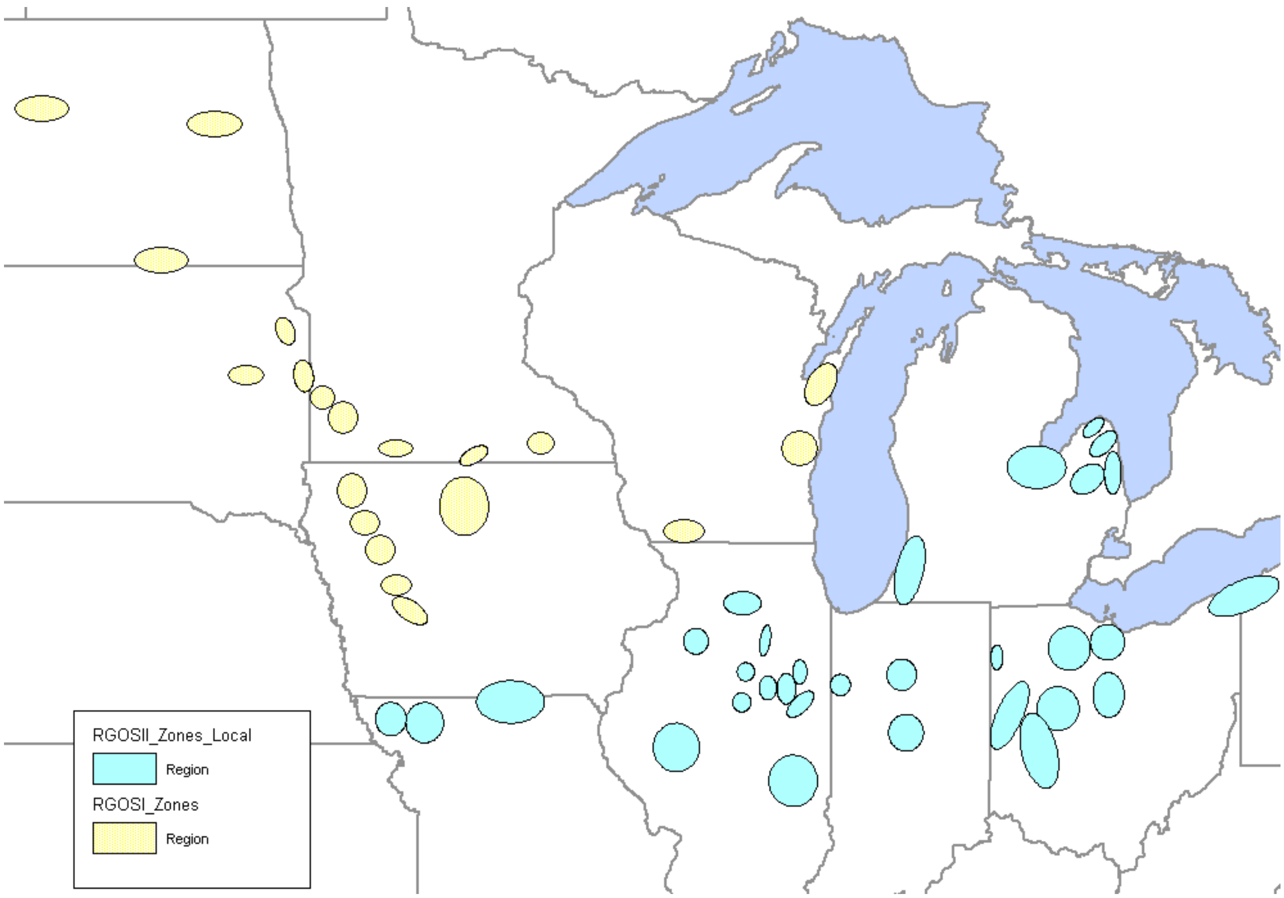

Figure 4.1-1: Local Wind Zone Identification

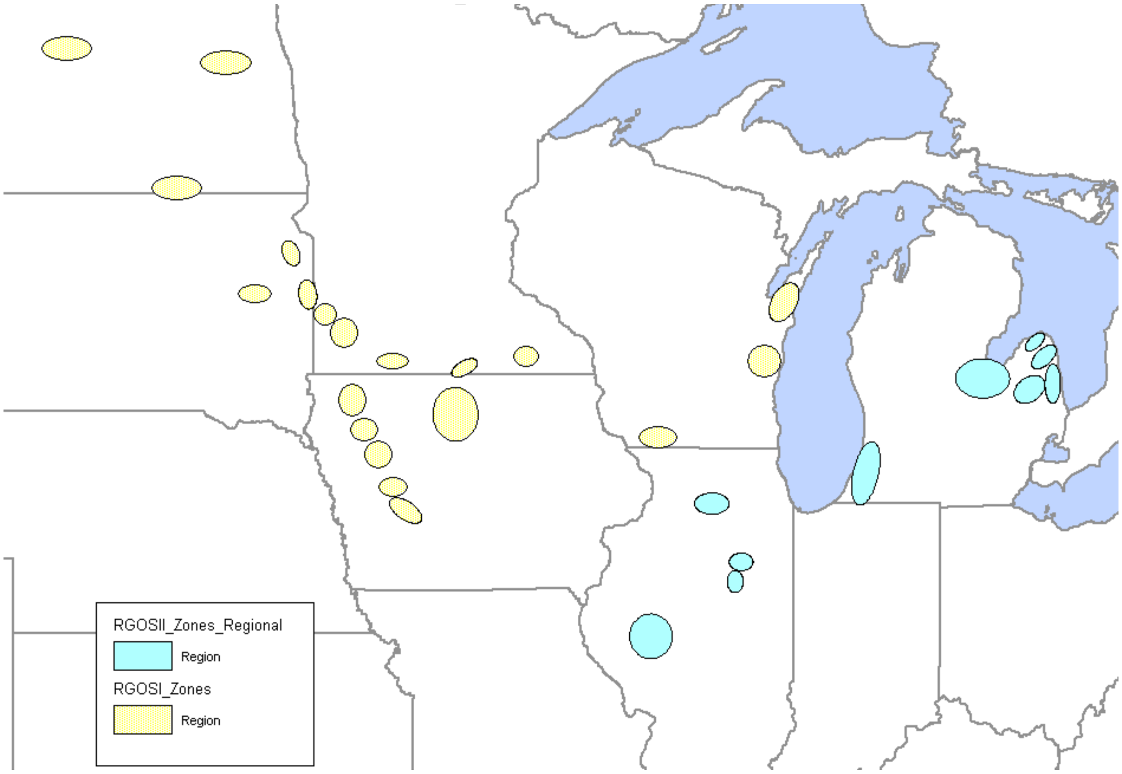

Figure 4.1-2: Regional Wind Zone Identification

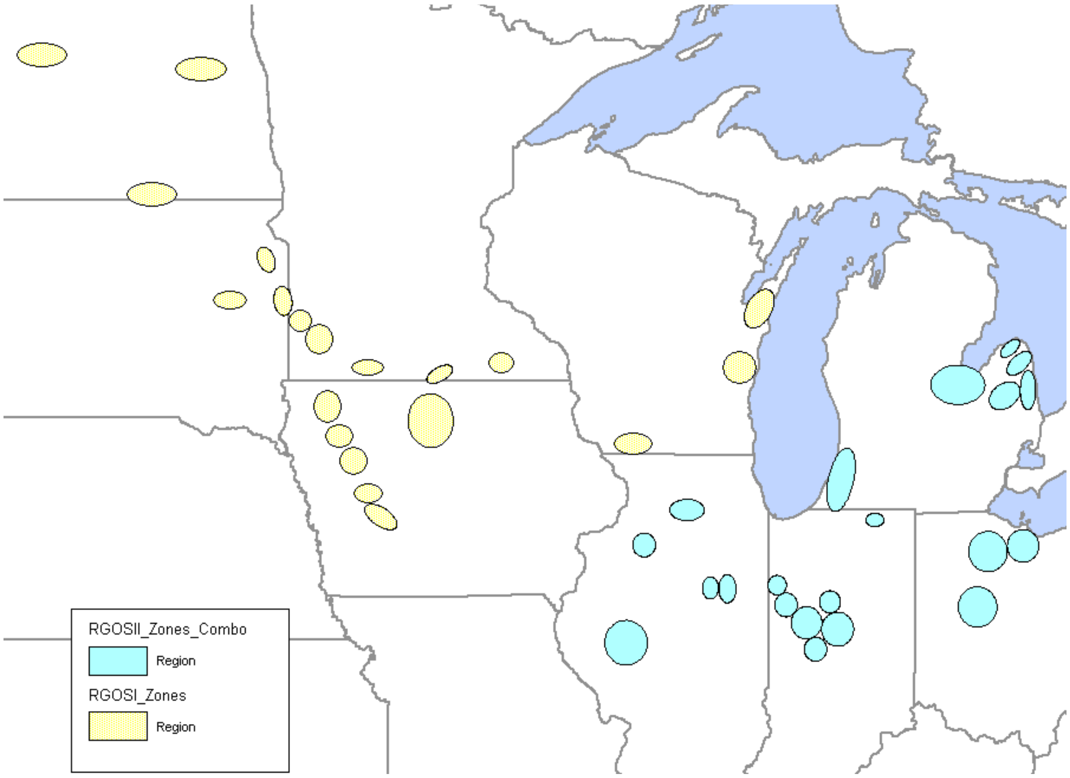

Figure 4.1-3: Combination Wind Zone Identification

To provide for a full range of opportunities in meeting various RPS and goal requirements, these three (3) renewable energy zone scenarios were adjusted to create two (2) additional scenarios. These five (5) scenarios include the following:

- **Local:** In the Local scenario, renewable energy requirements and goals will be met with resources located within the same state as the load.
- **Regional:** In the Regional scenario, renewable energy requirements and goals will be met with resources located in the highest ranking renewable energy zones regardless of respective zone location relative to the RGOS II load. This scenario will utilize the high capacity factor zones recommended by UMTDI from RGOS I.
- **Regional Optimized:** The Regional scenario results in capacity in excess of what is needed to at least cover the renewable requirements/goals. In the optimized case, the capacity in some zones is reduced to the extent there are just enough resources to cover renewable energy requirements/goals.
- **Combination:** In the Combination scenario, renewable energy requirements and goals will be met with a combination of resources located within the RGOS II states and those outside RGOS II states with the highest ranking. Emphasis will be given to state requirements to locate part or all of their resources used to meet renewable energy requirements and goals within those states. Also, distance to load centers will be given more emphasis when determining zones than in the Regional scenario.
- **Combination 75/25:** In this scenario, 75% of RGOS requirements are met with resources in the UMTDI zones and 25% of RGOS requirements are met within the remaining states.

5 Regional Transmission Designs

The goal of the Regional Generation Outlet Study (RGOS) is to develop transmission projects that will facilitate the state renewable energy mandates in the Midwest ISO footprint. The process used to meet this goal consists of detailed transmission design analysis to determine a transmission system that meets RGOS reliability objectives while delivering energy from the generation zones. Refer to Figure 5-1.

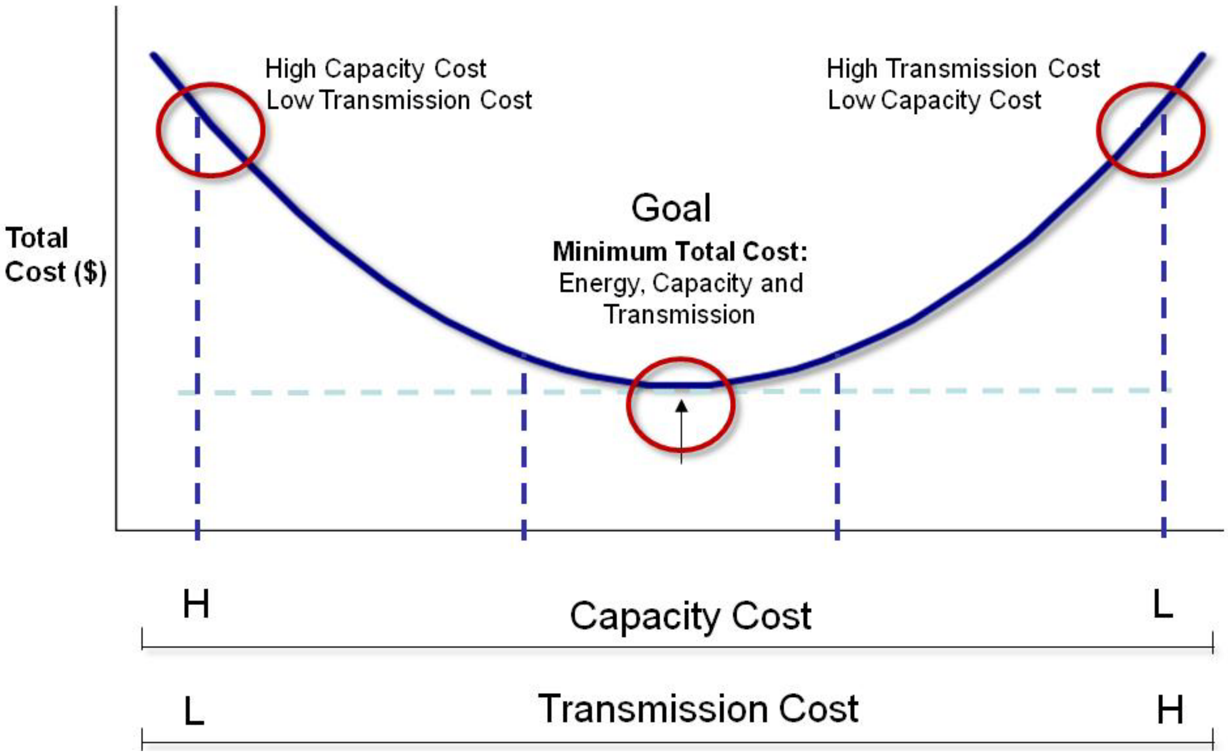

Figure 5-1: Balancing Generation and Transmission Investment

5.1 Indicative Transmission Designs

As in the RGOS Phase I, once candidate renewable energy zone scenarios were established for study, the next step was to design an indicative transmission system for those zones to connect to the grid and deliver energy to load. There were many different transmission designs that could be utilized to achieve this goal, all of which had different costs and benefits associated with them. The purpose of the Indicative Transmission Design phase of the study was to analyze these different alternatives and to quantify costs and benefits of these alternatives. These costs and benefits would then be used to provide information to select a final set of energy zones.

Indicative transmission designs were created with stakeholders by means of a design workshop. Stakeholders, specifically experienced transmission planners from the region, and Midwest ISO staff developed the different transmission alternatives for economic analysis. The process consisted of developing an assumption set to guide the indicative development process, understanding the various renewable energy zone scenarios, and finally developing an indicative set of transmission that could potentially supply the renewable energy. The indicative transmission was developed without the use of system modeling or analysis; rather, the task was achieved by harnessing the collective knowledge of workshop participants, all experienced transmission planners. Again, the point of the exercise was to develop transmission that could “indicatively” provide a solution.

5.1.1 Assumption Set

An assumption set was established by the stakeholders to develop the indicative transmission portfolios and apply costs to them. The indicative transmission portfolios were developed without the benefit of transmission simulations; i.e. Power Flow, so a consistent assumption set had to be employed to compare the transmission portfolio of one energy zone scenario against another.

The primary assumption for the indicative transmission development was that the system would be considered self-healing. It would not depend on the underlying system in the indicative design phase. For this work, Surge Impedance Loading (SIL) ratings were used for new transmission lines. This eliminated the need for Power Flow analysis in the indicative stage since a 'self-healing' plan minimized the impact of new transmission on the existing system. Actual analysis of Power Flow was planned for the conceptual transmission design phase to evaluate the underlying system impacts and would use normal and emergency line ratings. 750 MW of capacity would be exploited from each zone. Other assumptions included the approximate range of capacity for 345 kV and 765 kV transmission using SIL as a limiter. Note economic parameters were also developed for calculating the cost of the transmission. Refer to Table 5.1-1, which shows the capital costs applied to the transmission.

Table 5.1-1: Transmission Line Cost Assumptions used within Indicative Work Efforts (2010 USD in Millions)

kV	MN/Dak	IA	WI	IL	MO	IN	MI	OH/PA
345	2	1.5	2.5	2	1	1.8	1.8	2
2-345	2.5	2.1	3	2.6	1.5	2.3	2.3	2.5
500	3.5							
765	4.8	4.2	4.8	4.2	4.2	4.4	3.6	4
400	0	0	0	0	0	0	0	0
800	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2

Note wind generation at \$2M/MW was used for the wind turbine capital costs.

5.1.2 Indicative Transmission Results

Given the five (5) renewable energy zone scenarios, several indicative transmission overlays were created using 345 kV, 765 kV, and DC transmission options. For additional details regarding Indicative Transmission Design, refer to Appendix 3, which shows the transmission and renewable energy zone maps for the various overlays. Financial results are shown in Table 5.1-2.

Table 5.1-2: Indicative Transmission Costs (2010 USD in Millions Sorted by Total Cost)

Voltage (kV)	Zone Scenario	Generation	Transmission	Total
345	Combination 75/25	$62,300	$18,601	$80,901
345	Combination	$65,300	$18,601	$83,901
765	Combination 75/25	$62,300	$25,193	$87,493
765	Combination	$65,300	$25,192	$90,492
765	Regional Optimized	$60,800	$30,428	$91,228
765/DC	Regional Optimized	$60,800	$33,981	$94,781
765	Regional	$66,900	$30,428	$97,328
765/DC	Regional	$66,900	$33,981	$100,881
765/DC	Regional Optimized	$60,800	$47,855	$108,655
345	Local	$91,400	$19,291	$110,691
345	Regional Optimized	$60,800	$51,260	$112,060
765	Local	$91,400	$22,553	$113,953
765/DC	Regional	$66,900	$47,855	$114,755
345	Regional	$66,900	$51,260	$118,160

As can be seen from Table 5.1-2, all four (4) Combination scenarios demonstrated the lowest overall cost alternative. The "Bathtub Curve" for these scenarios can be seen in Figure 5.1-1 (also refer to section 5 of this document). Hence, a Combination set of zones was selected as the basis for moving forward to select a final set of renewable energy zones. Feeding into the final zone selection for each scenario were other state requirements in addition to energy. For example, the State of Michigan requires the state RPS be served 100% internally to the state. In Ohio, the requirement is 50%, and Illinois has a preference defined in its requirements for local wind. As a result, Missouri, Illinois, and Ohio renewable energy zones were selected based on at least 50% of the wind requirements being served within that respective state. Input on the final zones was gathered from Midwest Governors Association (MGA), the Upper Midwest Transmission Development Initiative (UMTDI), and from stakeholders—including non-Midwest ISO, PJM members Commonwealth and American Electric Power.

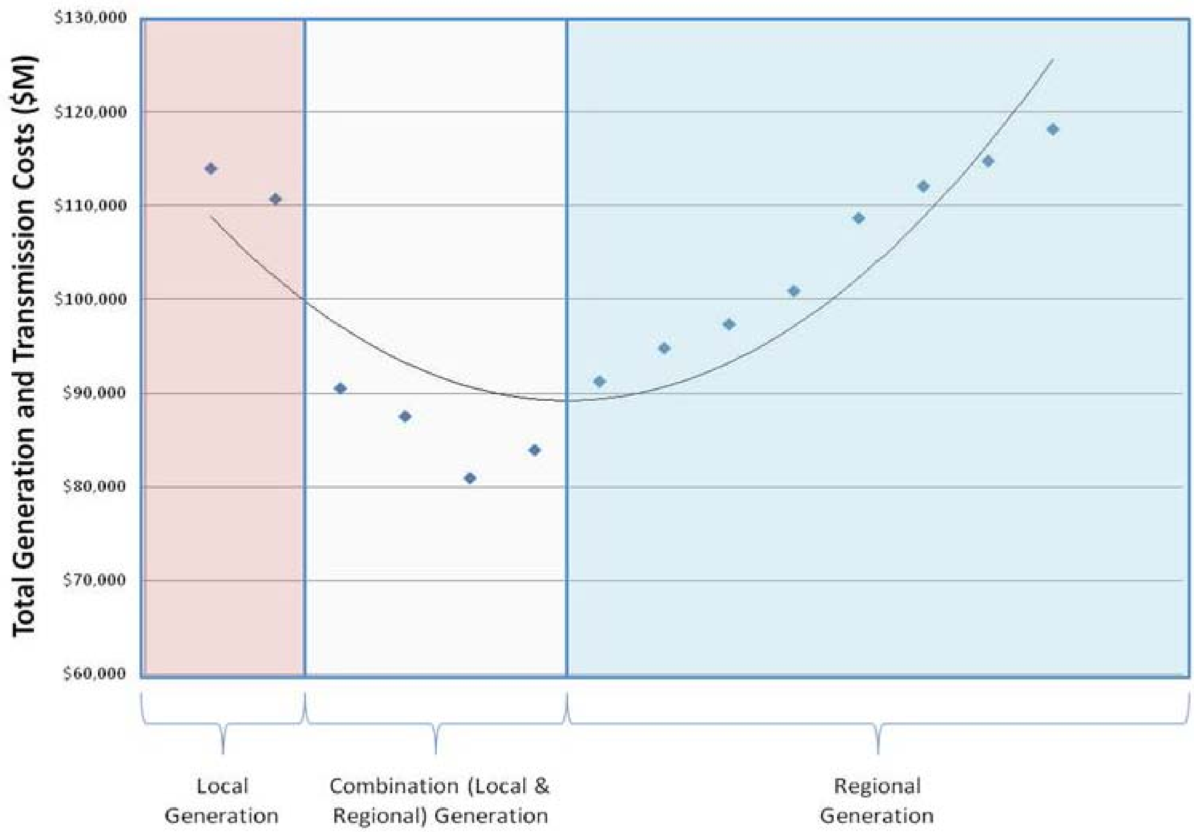

Figure 5.1-1: Zone Scenario Generation and Transmission Cost Comparison

For greater detail regarding indicative transmission results, design, and optimization, refer to Appendix 3 of this document. Also refer to Midwest ISO Transmission Expansion Plan (MTEP) 2009, which more fully describes the rationale driving zone scenario origination.

5.2 Model Development

5.2.1 Power Flow Model Creation

The majority of the transmission design analysis was conducted on a MTEP09 series 2019 summer peak model. This model was developed via the MTEP09 model building effort with considerable stakeholder review. It was used for two sets of analyses: a summer off-peak analysis and a summer peak analysis. For the summer off-peak analysis, the base transmission model was modified to create a shoulder-peak (70% load level) Power Flow model for the RGOS I system analysis in mid-2009 and sent to the stakeholders for additional review. Both the summer peak and summer off-peak models were updated for the full RGOS analysis effort in early 2010 and sent to the stakeholders for a final review. A list of the major transmission upgrades made to this model since the RGOS I study effort is included in the public folder located at:

ftp://mtep.midwestiso.org/mtep10/RGOS/report/Appendices4-6.zip

And includes the following MS Excel .xlsx spreadsheet files:

- A4_1_Native Voltage.xlsx
- A4_2_Native Voltage with DC.xlsx
- A4_3_765 kV.xlsx

A secondary set of analyses were performed on a light load model. This model was converted from a MTEP10 series 2015 light load scenario to a 2019 light load scenario. The model, in addition to being developed and reviewed through the MTEP model building effort, was also provided to the stakeholders for additional review. A list of the major modeling corrections made to this model is also included in the public folder identified above and includes the following MS Excel .xlsx spreadsheet files:

- Modeling Corrections - 765 Modeling Documentation.xlsx
- Modeling Corrections - NV with DC Modeling Documentation.xlsx
- Modeling Corrections - NV wo DC Modeling Documentation.xlsx

External transmission system representation in the MTEP series models was provided by the Eastern Interconnection Reliability Assessment Group (ERAG) Multi-Regional Modeling Working Group (MMWG) North American Electric Reliability Corporation (NERC) models, except for the non-Midwest ISO MRO members, where the latest Midwest Reliability Organization (MRO) models were used. Commonwealth Edison and American Electric Power (AEP) supplied system updates directly to the RGOS study effort for their respective transmission systems.The base MTEP models included all transmission projects moving to MTEP Appendix A or B as well as Appendix B and C projects with a status of Planned. Prior to the start of the RGOS work, any projects in Appendix B or C that were not moving to Appendix A in the MTEP10 planning cycle and have a voltage class greater than 300 kV were removed from the model. These projects could have a significant impact on the transmission network. As such, given the level of uncertainty on whether the projects will be constructed or not, it was determined that designing the RGOS transmission system dependent on these projects adds additional uncertainty to the final RGOS transmission portfolio.

5.2.2 Generation

As part of the MTEP10 model building process, a Regional Merit Dispatch (RMD) was created to aid in dispatching the Midwest ISO generation fleet for the various MTEP10 Power Flow models. This RMD was used to dispatch the wind zones into all the models used for the RGOS analysis. Commonwealth Edison supplied a generation dispatch for its system to enable the wind zones in its control area, and the generation in American Electric Power (AEP) was scaled down to enable the dispatch of the wind zones in its control area. Further information on RMD may be found in the MTEP10 report Appendix E1. Additionally, only existing generators and generators with an executed generator interconnection agreement were included in the Power Flow model.

Consistent with Midwest ISO Planning Subcommittee practices, generation from the energy zones was dispatched to the system at 90% and 20% of capacity for all zones in the shoulder-peak and peak models, respectively. No wind was dispatched in the light load model. Existing and planned wind generation already in the model was dispatched at this same level, respectively, for each model. Data analysis shows load levels between 40% and 80% of peak load, wind output can randomly vary from 0%–90%. The wind levels chosen for analysis represent a majority of the worst case conditions for each scenario—although it could be argued a light load, 90% wind output model should be considered to capture all the worst case scenarios. This light load, high-wind analysis, while initially part of the RGOS effort, was deferred due to time constraints.

Refer to Tables 5.2-1 and 5.2-2, which show the modeled capacity of each wind zone. It is important to note each zone was designed for a potential capacity of up to 2400 MWs even though transmission was not designed for that level of injection. Wind generation in the Midwest ISO footprint was delivered (sunk) to the Midwest ISO market. Generators in the Illinois Commonwealth Edison area are delivered to Commonwealth Edison (PJM), and the wind zones located in American Electric Power (AEP) were sunk to other AEP generation.

Table 5.2-1: Renewable Energy Zone Information (UMTDI Zone Selections)

Zone	State	Nameplate (MW)	Modeled Capacity		
			Off-peak (MW)	Peak (MW)	Light Load (MW)
IA-B	IA	775	698	155	0
IA-F	IA	775	698	155	0
IA-G	IA	775	698	155	0
IA-H	IA	775	698	155	0
IA-I	IA	775	698	155	0
IA-J	IA	775	698	155	0
MN-B	MN	775	698	155	0
MN-E	MN	775	698	155	0
MN-H	MN	775	698	155	0
MN-K	MN	775	698	155	0
MN-L	MN	775	698	155	0
ND-G	ND	775	698	155	0
ND-K	ND	775	698	155	0
ND-M	ND	775	698	155	0
SD-H	SD	775	698	155	0
SD-J	SD	775	698	155	0
SD-L	SD	775	698	155	0
WI-B	WI	775	698	155	0
WI-D	WI	775	698	155	0

Table 5.2-2: Renewable Energy Zone Information (non-UMTDI Zone Selections)

Zone	State	Nameplate (MW)	Modeled Capacity		
			Off-peak (MW)	Peak (MW)	Light Load (MW)
IL-A	IL	550	495	110	0
IL-B	IL	550	495	110	0
IL-F	IL	550	495	110	0
IL-K	IL	550	495	110	0
IN-E	IN	500	450	100	0
IN-K	IN	500	450	100	0
MI-A	MI	300	270	60	0
MI-B	MI	500	450	100	0
MI-C	MI	500	450	100	0
MI-D	MI	500	450	100	0
MI-E	MI	500	450	100	0
MI-F	MI	500	450	100	0
MI-I	MI	350	315	70	0
MO-A	MO	500	450	100	0
MO-C	MO	500	450	100	0
MT-A	MT	400	360	80	0
OH-A	OH	725	652.5	145	0
OH-B	OH	725	652.5	145	0
OH-C	OH	725	652.5	145	0
OH-D	OH	725	652.5	145	0
OH-E	OH	725	652.5	145	0
OH-F	OH	725	652.5	145	0
OH-I	OH	725	652.5	145	0

5.3 Analyses

5.3.1 Initial Energy Model Results

The first transmission analytical step of the RGOS process was the evaluation of the combination ('Combo') indicative overlays with the selected RGOS zones in a production cost model. The analysis consisted of four (4) iterations of PROMOD runs that reduced the indicative overlays that delivered energy and showed utilization of the transmission lines identified in the overlays. Through this process, the RGOS study was able to reduce the inherent overbuild of the indicative work to a set of transmission that provided energy flow based on modeled flowgates, delivered the renewable energy zones, and provided a starting point for the more detailed Power Flow work.

The primary metric to reduce overlay transmission was line utilization. Within the first iteration, all transmission segments with peak line flow less than 20% of the rated limit were removed from the overlay. Iterations 2 and 3 removed all transmission loaded less than 30% of the rated limit was also removed. Iteration 4 removed additional under-utilized transmission while using engineering judgment to ensure overlay circuits were not radial and made general sense in system configuration.

5.3.1.1 Native Voltage Overlay

The Native Voltage overlay saw significant reduction in the process of eliminating under-utilized transmission. Between Iteration 1 and Iteration 4, 128 line segments and autotransformers were removed from the overlay, reducing the high-level generic cost of the overlay used in this stage of the analysis from $18 billion to $10.3 billion. With better engineering judgment on the interconnection of the renewable energy zones, wind curtailment improved with the refinement. However, adjusted production cost savings also decreased—but not at the same rate as the cost to add the transmission to the system. Refer to Table 5.3-1, which provides more detail on the outputs of the energy model iterations.

Table 5.3-1: Native Voltage Overlay Information from Initial Energy Model Analysis

Iteration	Rough Costs (2009 - $M)*	20% ARR (2009 - $M)	APC Savings (annual) 2019 - $M			Wind Curtailment**
			Midwest ISO	RGOS	Eastern Interconnect	
1	18,024	3,605	609	749	716	0.84%
2	16,677	3,335	614	758	718	0.85%
3	9,697	1,939	459	567	547	2.42%
4	10,269	2,054	487	602	558	0.71%

* Costs represent 345 @$1.5/M, 345-2@$2.0/M, 765 @$3.0/M and a 25% adder for station costs
** 10.44% Wind Curtailment prior to indicative transmission additions

Refer to Figures 5.3-1 and 5.3-2, which show the overlay at the beginning and end of the energy model refinement.

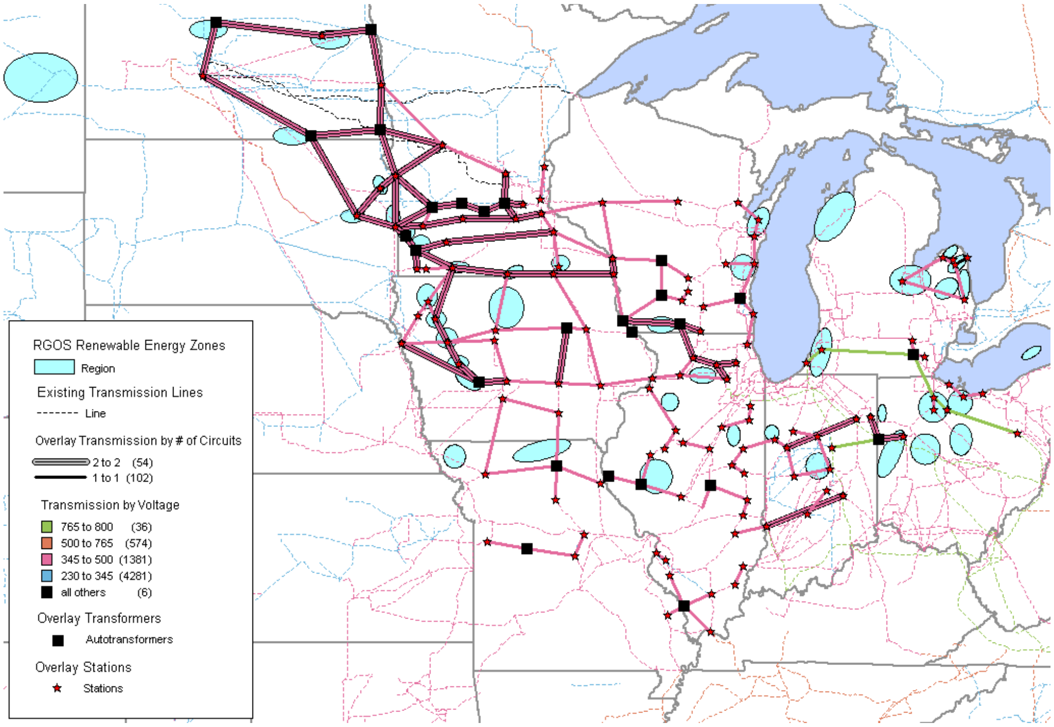

Figure 5.3-1: Native Voltage Indicative Overlay (Iteration 1)

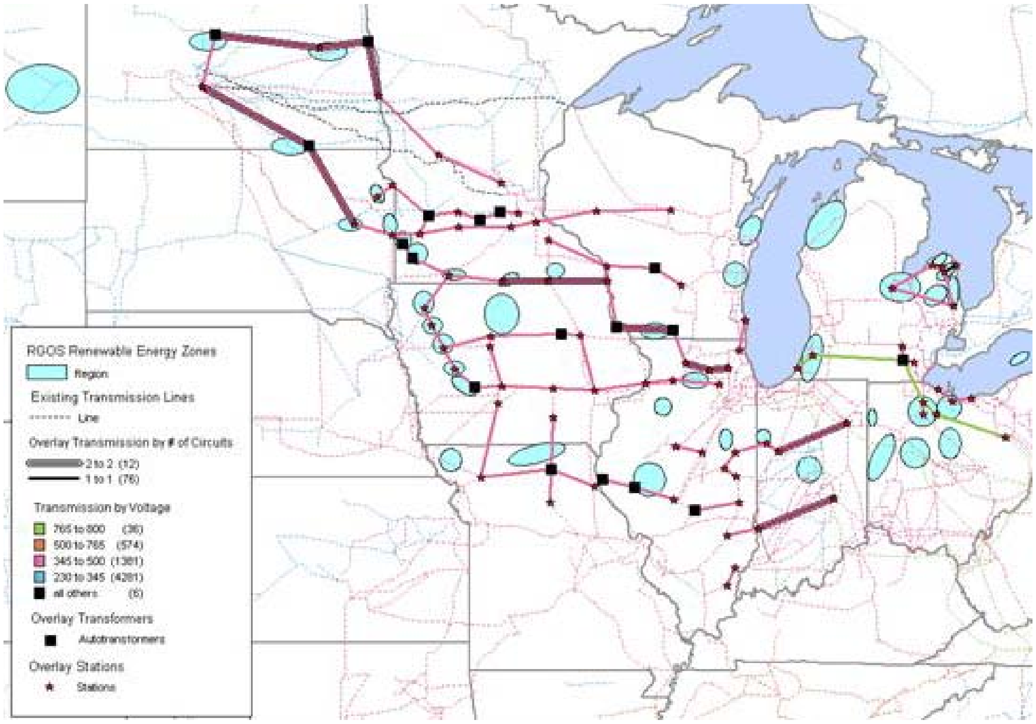

Figure 5.3-2: Native Voltage after Production Cost Modeling Optimization (Iteration 4)

5.3.1.2 765 kV Overlay

The 765 kV overlay saw significant reduction in the process of eliminating under-utilized transmission. Between Iteration 1 and Iteration 4, 124 line segments and autotransformers were removed from the overlay. This reduced the high-level generic cost, used in this stage of the analysis, of the overlay from $23.8 billion to $15.6 billion. With better engineering judgment on the interconnection of the renewable energy zones, the wind curtailment improved with the refinement. However, adjusted production cost savings also decreased but not at the same rate as the cost required to add the transmission to the system. Refer to Table 5.3-2, which furnishes more detail on the outputs of the energy model iterations.

Table 5.3-2: Native Voltage Overlay Information from Initial Energy Model Analysis Annual APC Savings (2019 USD in Millions)

Iteration	Rough Costs (2009 - $M)*	20% ARR (2009 - $M)	Midwest ISO	RGOS	Eastern Interconnect	Wind Curtailment**
1	23,752	4,750	702	926	887	0.89%
2	21,781	4,356	701	922	884	0.90%
3	16,960	3,392	689	924	883	0.14%***
4	15,564	3,113	558	785	737	0.10%

* Costs represent 345 @$1.5/M, 345-2@$2.0/M, 765 @$3.0/M and a 25% adder for station costs
** 10.44% Wind Curtailment prior to indicative transmission additions
*** Primary reduction result of moving some of the wind zones to an indicative overlay station

Refer to Figures 5.3-3 and 5.3-4, which depict the overlay at the beginning and end of the energy model refinement.

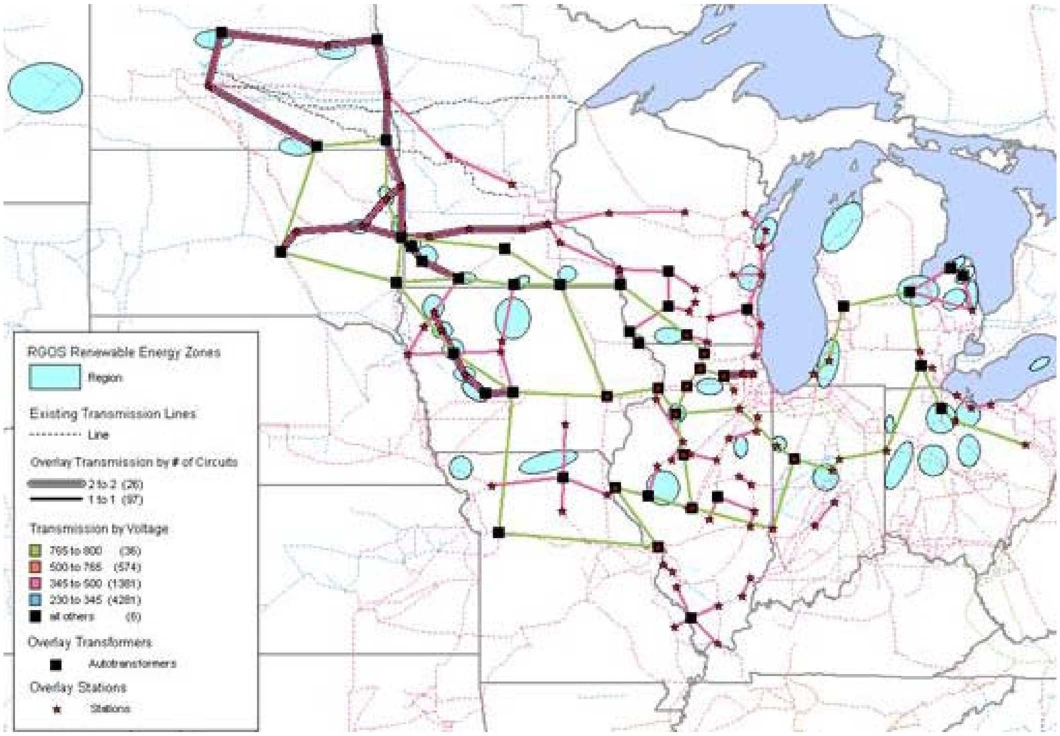

Figure 5.3-3: 765 kV Indicative Overlay (Iteration 1)

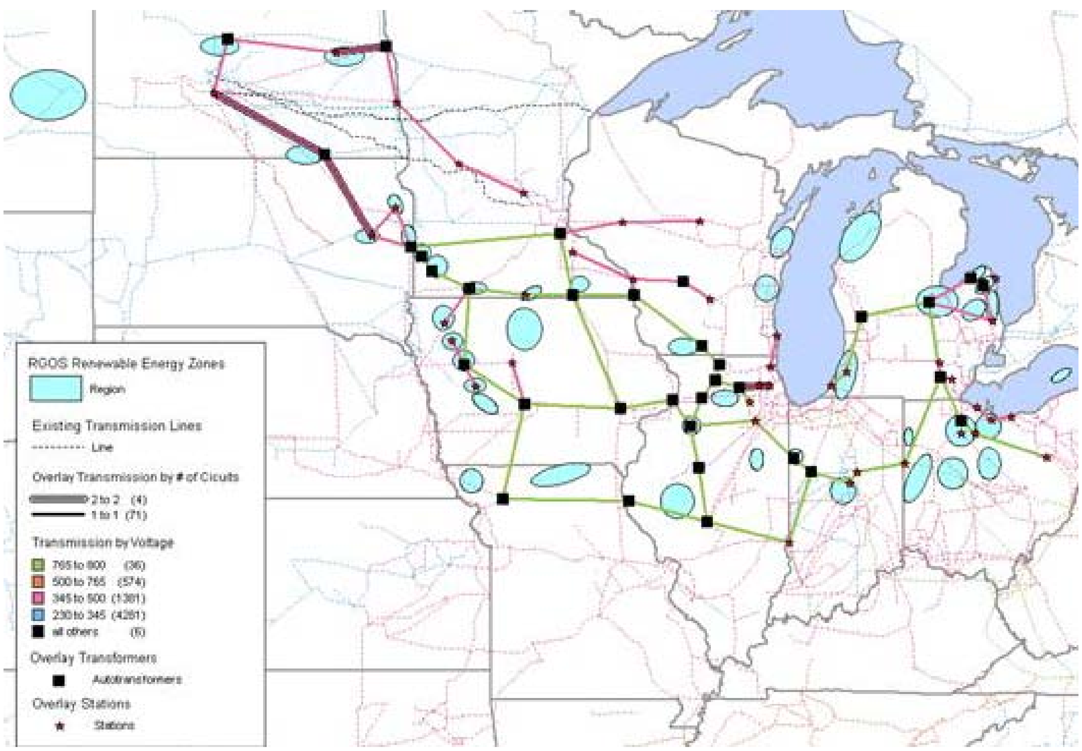

Figure 5.3-4: 765 kV Overlay after Production Cost Modeling Optimization (Iteration 4)

5.3.1.3 Native Voltage with DC Overlay

The Native Voltage with DC overlay saw significant reduction in the process of eliminating under-utilized transmission. Between Iteration 1 and Iteration 4, 123 line segments and autotransformers were removed from the overlay, reducing the high-level generic cost of the overlay used in this stage of the analysis from \$23.5 billion to \$16.1 billion. With better engineering judgment on the interconnection of the renewable energy zones, the wind curtailment improved with refinement. However, adjusted production cost savings also decreased but not at the same rate as the cost required to add the transmission to the system. Refer to Table 5.3-3, which offers more detail on the outputs of the energy model iterations.

Table 5.3-3: Native Voltage Overlay Information from Initial Energy Model Analysis

Iteration	Rough Costs (2009 - $M)*	20% ARR (2009 - $M)	APC Savings (annual) 2019 - $M			Wind Curtailment**
			Midwest ISO	RGOS	Eastern Interconnect	
1	23,524	4,705	734	986	995	0.85%
2	22,457	4,491	734	989	998	0.85%
3	14,654	2,931	673	925	927	0.32%
4	16,109	3,222	734	1023	1035	0.04%

* Costs represent 345 @$1.5/M, 345-2@$2.0/M, 765 @$3.0/M and a 25% adder for station costs and a cost of $5.5B for the DC transmission

** 10.44% Wind Curtailment prior to indicative transmission additions

Refer to Figures 5.3-5 and 5.3-6, which show the overlay at the beginning and end of the energy model refinement process.

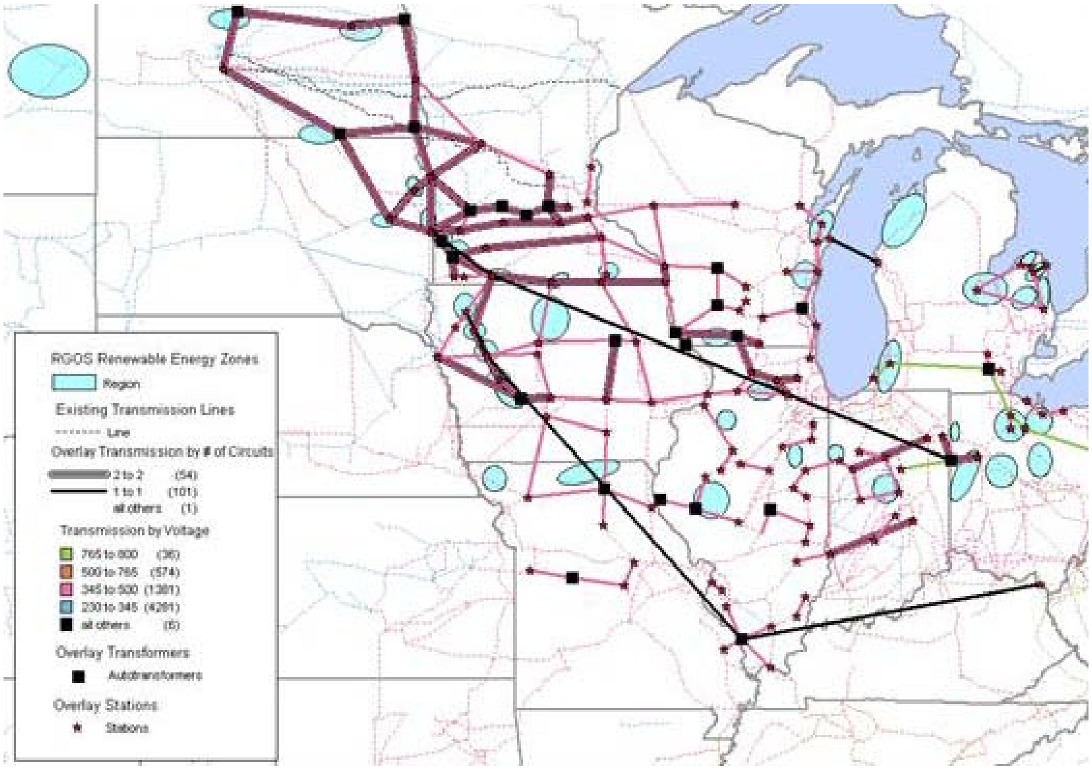

Figure 5.3-5: Native Voltage with DC Indicative Overlay

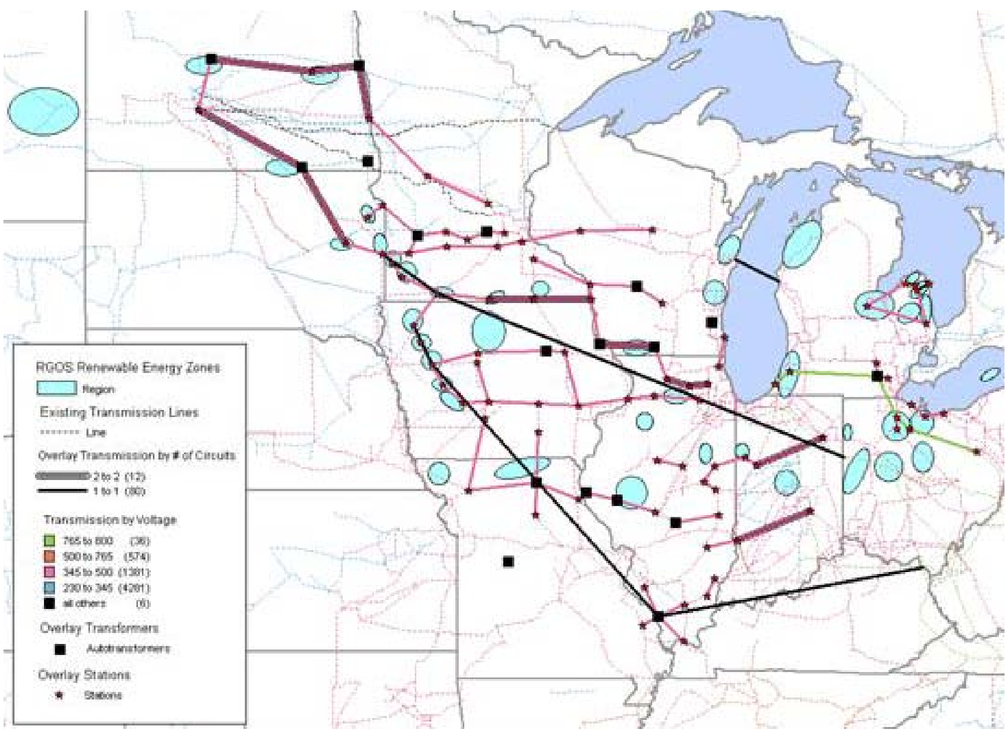

Figure 5.3-6: Native Voltage with DC Overlay after Production Cost Modeling Optimization

5.3.2 Power Flow Analysis Set-up

A set of monitored and contingent elements was created and constraints were defined prior to beginning Power Flow analysis. Voltage and thermal design criteria from each Transmission Owner were applied during the analysis. Voltage limitations were set through the monitored element file and thermal ratings of elements were taken from the Power Flow case. More details on the monitored, contingent elements, and constraint parameters are discussed below.

5.3.2.1 Monitored Elements

The study footprint included the entire Midwest ISO footprint, along with the footprints of American Electric Power, Commonweath Edison, and MAPP. Overloads identified outside of the study footprint were evaluated for their impact; all constraints outside the footprint with a meaningful cause and material impact on the RGOS footprint were mitigated. All elements greater than 100 kV were monitored during analysis, but the primary focus of the study was overloads on transmission elements with a voltage of 230 kV or higher. More details on the monitored elements are shown in Table 5.3-4, below.

Table 5.3-4: Monitored Elements Metrics and Criteria

Metric	Criteria
Thermal Monitoring	1. System Intact 2. All transmission with thermal loadings over 90% of the normal rating (Rate A) was monitored during the analysis. 3. Category B Contingencies: a. All transmission with thermal loadings over 90% of the emergency rating (Rate B) was monitored during the analysis. 4. Category C Contingencies: a. All transmission with thermal loadings over 125% of the emergency rating (Rate B) was monitored during the analysis.
Voltages	1. System Intact 2. All voltages greater than or less than the TO thresholds were monitored during the analysis.

5.3.2.2 Contingency Set-Up

NERC Category A and B events were used for the primary RGOS analysis, including the blanket outage of any 200 kV or higher facilities as well as the implementation of the contingency files provided throughout the MTEP study process. Selected Category C events were also analyzed in the analysis. These events include the double outage of lines surrounding each wind zone, and they also included the 'critical few' double outage contingencies provided by stakeholders. The contingency files used were from the MTEP10 reliability study and consistent with NERC, regional, state, and local planning criteria. These contingency files were screened for compatibility with each model, any discrepancies resolved.

5.3.2.3 Constraint Criteria

All 200 kV or higher transmission with overloads was identified as a constraint and appropriate mitigation was taken. More details on the specific constraint mitigation for each portion of the analysis are shown in Table 5.3-5, below.

Table 5.3-5: Constraint Metrics and Criteria

Metric	Criteria
Thermal Monitoring	1. System Intact: 2. All 200 kV+ transmission with thermal loadings over 100% of the normal rating (Rate A) was considered a constraint. 3. Category B Contingencies: a. All 200 kV+ transmission with thermal loadings over 100% of the emergency rating (Rate B) was considered a constraint. 4. Category C Contingencies: a. All 200 kV+ transmission with thermal loadings over 125% of the emergency rating (Rate B) was considered a constraint.
Voltages	All voltages on a 200 kV+ buses that were greater than or less than the TO thresholds were considered constraints.

5.3.3 NERC Transmission Planning Standards

North American Reliability Corporation (NERC) Transmission Planning standards TPL-001-0, TPL-002-0, and TPL-003-0 specify system performance requirements for the Bulk Electric System (>100 kV) under system intact (Category A), single element events (Category B), and multiple element events (Category C) for a variety of system conditions. Transmission planners must analyze and design the system to meet these system performance requirements or face monetary penalties. The standards specify the type of events to be analyzed and the system performance required for the different categories of events. System intact performance has the most restrictive performance requirements for voltage levels and thermal loadings on equipment. Single element events, loss of any single line or transformer or generator or shunt, must result in system performance within applicable voltage limits and thermal ratings. There should be no loss of load on the system not directly involved in the event. The system must also be stable, with no cascading outages. For multiple element outages, the system must be within limits, stable, and with no cascading outages. However, system adjustments including controlled loss of load or firm transfers are allowed to mitigate contingent performance issues associated with Category C events.

The intent of the RGOS effort was to examine system performance, with NERC TPL standards as a reliability guideline, to determine transmission upgrades to provide system intact and contingent performance standards. The focus of reliability study efforts was fixed on providing adequate capacity to deliver power and energy from wind energy zones.

Refer to Table 5.3-6. NERC Category A, B, and select C events were used in Power Flow analysis. The category C events applied to greater than 230 kV events as supplied by stakeholders, and bus double branch contingencies within a bus of each zone's outlet facilities was used. Category C events tested for energy zone outlet restriction and for potential cascading events. These cascading events were defined as situations in which transmission facilities experience a maximum loading of 125% or higher, as compared to the facility's emergency ratings. All elements greater than 100 kV were monitored during analysis while only elements greater than 200 kV in violation were addressed for solutions. All other elements were identified. NERC and regional entity (RE) planning criteria were applied. Transmission Owners' voltage and thermal design criteria were applied.

Table 5.3-6: Power Flow Solution Criteria

Metric	Criteria
Thermal Monitoring	1. System Intact: 2. Thermal loadings over normal rating (Rate A). All transmission with thermal loadings between 90% and 100% of normal rating will be identified and noted and considered when comparing portfolios. 3. Contingent: 4. Thermal overloads over emergency (Rate B). All transmission with thermal loadings between 90% and 100% of emergency rating will be identified and noted and considered when comparing portfolios.
Thermal Overload	1. System Intact: 2. All transmission greater than 200 kV with thermal loadings greater than 100% of normal rating will be addressed for solution. 3. All transmission less than 200 kV with thermal loadings greater that 100% of normal rating will be identified and noted and considered when comparing portfolios. 4. Contingent: 5. All transmission greater than 200 kV with thermal loadings greater than 100% of emergency rating will be addressed for solution. 6. All transmission less than 200 kV with thermal loadings greater that 100% of emergency rating will be identified and noted and considered when comparing portfolios.
High Voltage	1. System Intact 2. Voltages greater than TO thresholds will be addressed for solution on buses greater than 200 kV. All other buses will be identified and noted. 3. Contingent 4. Voltages greater than TO thresholds will be addressed for solution on buses greater than 200 kV. All other buses will be identified and noted and considered when comparing portfolios.
Low Voltage	1. System Intact 2. Voltages less than TO thresholds will be addressed for solution on buses greater than 200 kV. All other buses will be identified and noted and considered when comparing portfolios. 3. Contingent 4. Voltages less than TO thresholds will be addressed for solution on buses greater than 200 kV. All other buses will be identified and noted and considered when comparing portfolios.

5.3.4 Off-peak Linear Analysis Results

The primary analysis was performed on a 2019, summer off-peak model. This model was chosen due to the likelihood of a high wind output during summer off-peak conditions. This analysis began with the transmission determined in the energy analysis, and it continued in a highly iterative fashion, with between 60 and 110 iterations were performed on each of the Native Voltage, Native Voltage with DC, and 765 kV scenarios. It also contained several different phases, as discussed below. Each of the phases was conducted in an iterative manner, with the transmission refinement relying heavily upon reruns of the Category A, B, and C analyses.

- **Category A and B (System Intact and N-1) analysis** focused upon the identification and mitigation of 200 kV and above Category A and B constraints. A large amount of transmission was added to the model during this period, with the end result being a system without an 200 kV and above constraints under system intact or single contingency conditions.
- **Category C (N-2) analysis** is based upon the results of the Category A and B analysis. It focused on potentially cascading system events, which were simulated in the model as any transmission element which has a 125% or greater loading under a Category C event.
- **Transmission refinement/optimization** was conducted to ensure that the transmission design was not overbuilt. It analyzed the transmission added through the energy and previous off-peak analysis to determine that the lines proposed were used and useful. If any line was found to be lightly loaded, it was removed from the model, and analyses were conducted to ensure that no new constraints occurred without the line.

These analyses resulted in a set of new transmission for each scenario that resolved all the thermal overloads on the system under peak conditions. This transmission was then used as an input for later analysis. Refer to Figures 5.3-7–5.3-9.

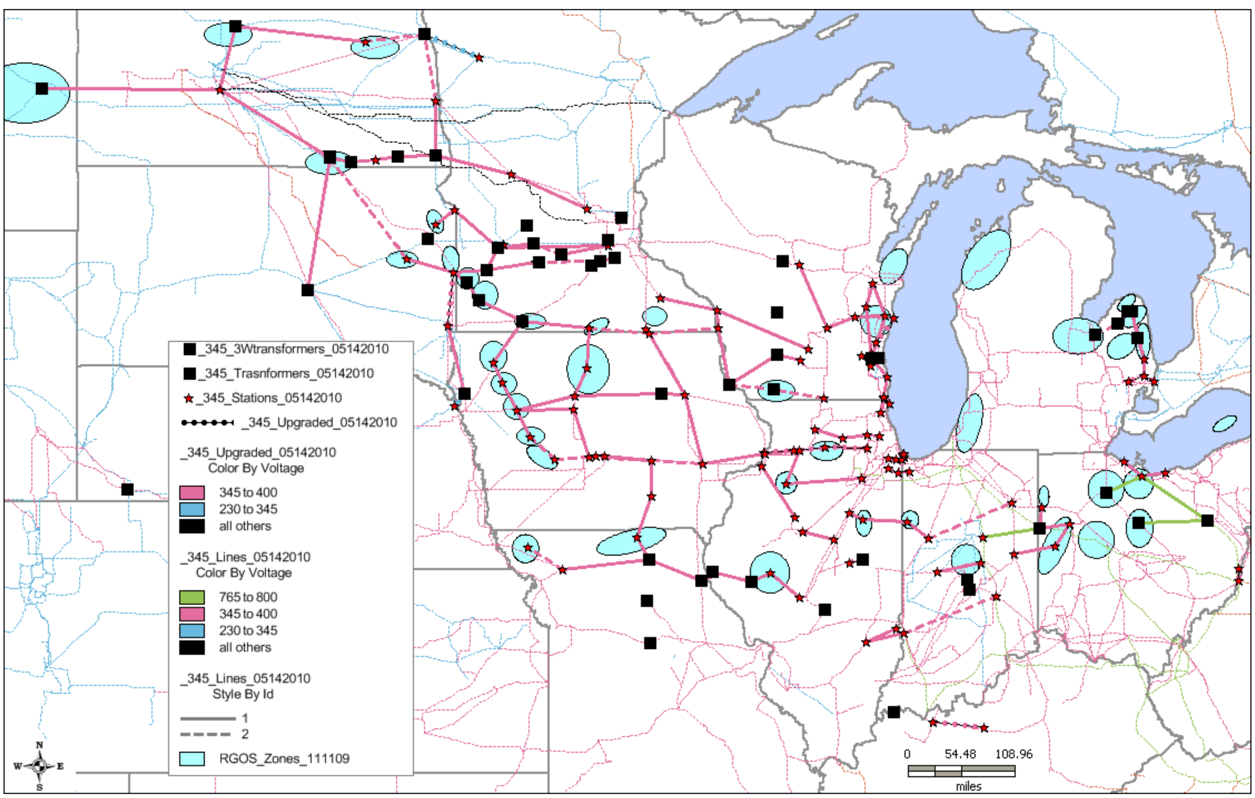

Figure 5.3-7: Native Voltage Off-peak Analysis

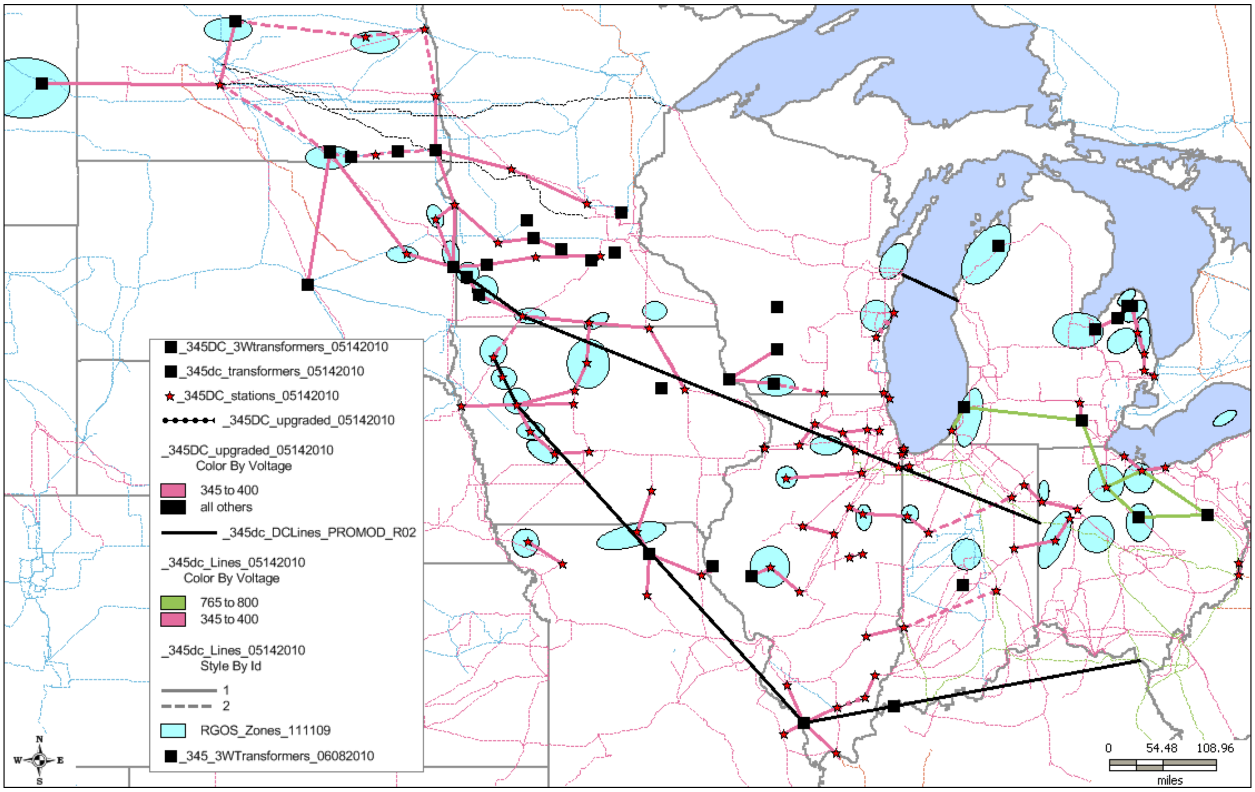

Figure 5.3-8: Native Voltage with DC Off-peak Analysis

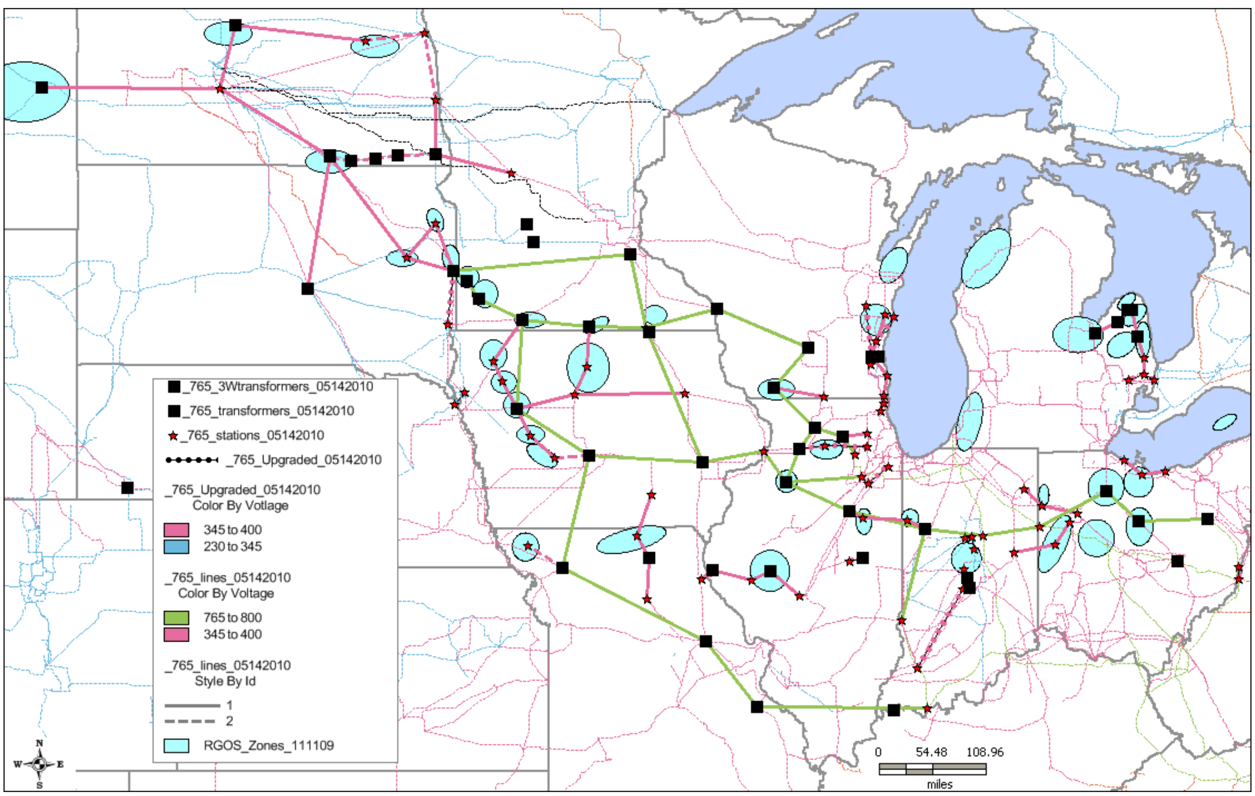

Figure 5.3-9: 765 Kv Off-peak Analysis

5.3.5 Sensitivity Analysis Results

A set of sensitivities were run on a peak and light load case. These sensitivities included both linear and AC analysis, and the results are discussed in more detail below.

5.3.5.1 Peak Sensitivity Analyses Results

Peak sensitivity analyses were conducted to ensure system reliability when the transmission system is experiencing the highest level of loading. Analyses included both linear and AC analysis in order to capture thermal and voltage overloads. Peak sensitivity started with the transmission from the final off-peak linear analysis for each scenario. Refer to Figures 5.3-10–5.3-12.

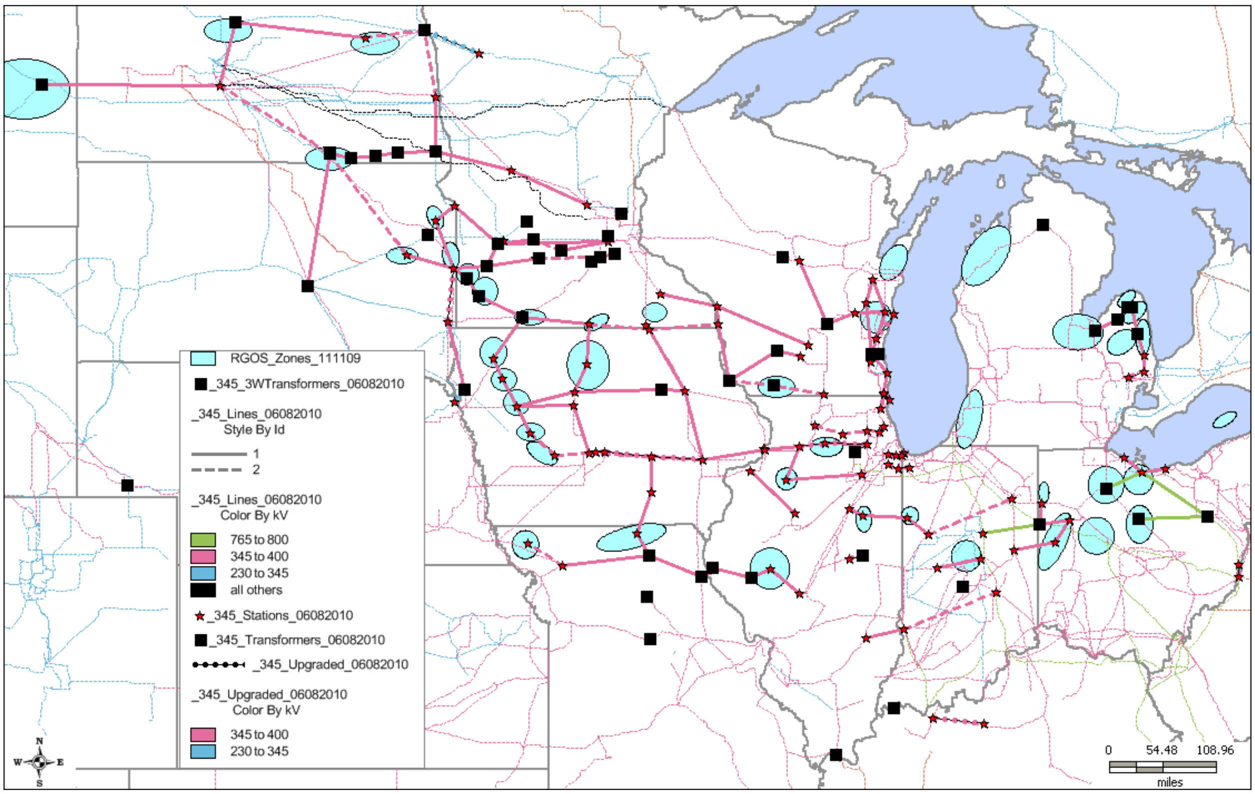

Figure 5.3-10: Native Voltage Peak Analysis

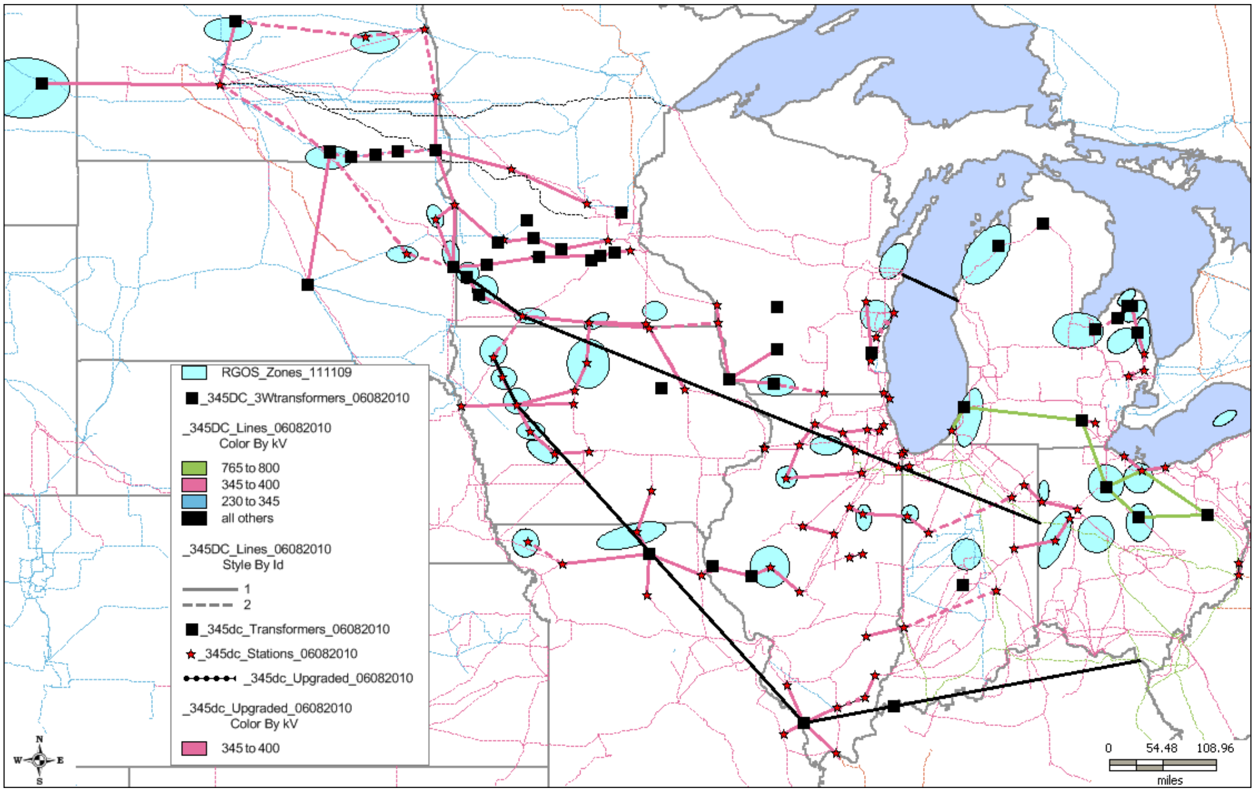

Figure 5.3-11: Native Voltage with DC Peak Analysis

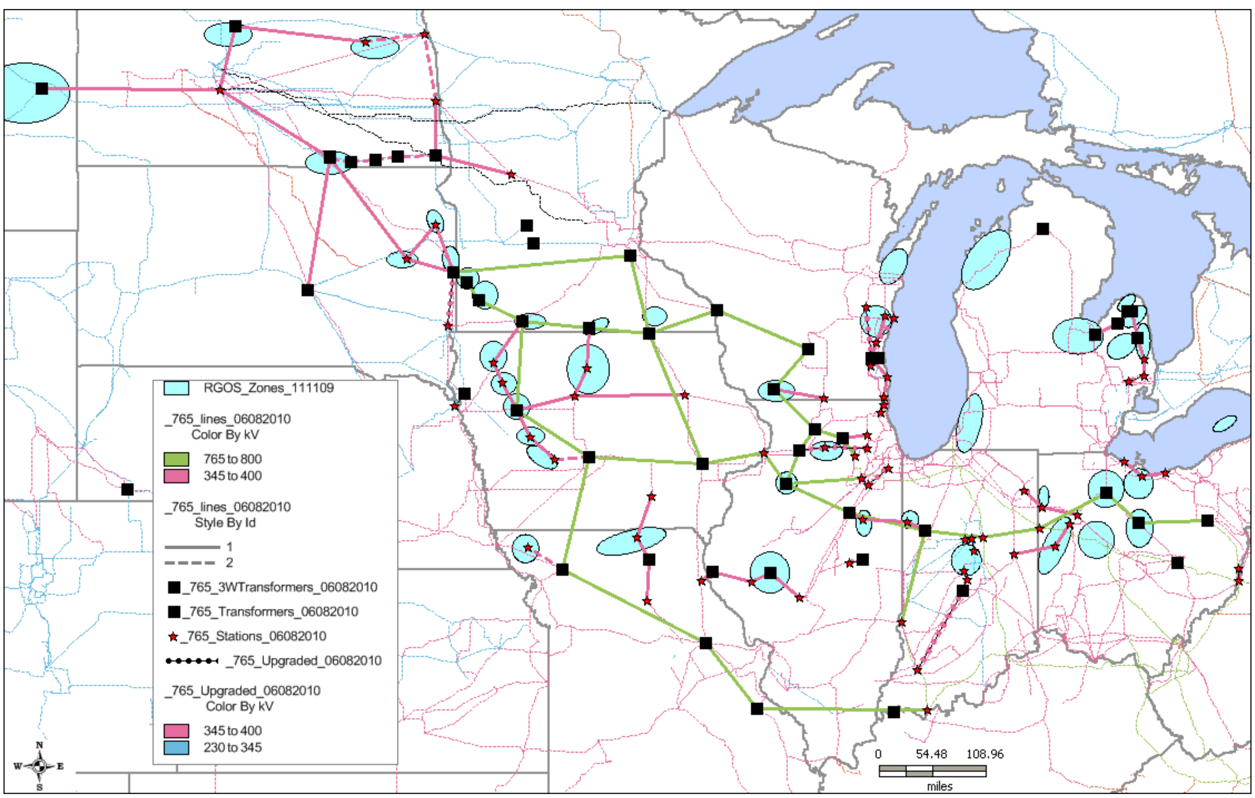

Figure 5.3-12: 765 kV Peak Analysis

5.3.5.2 Light Load Sensitivity Analyses Results

Light load sensitivity analyses were conducted to ensure system reliability with a full transmission buildout, without the support of wind from the wind zones. In particular, this scenario was designed to determine and mitigate any reactive (voltage) constraints which may occur due to the large reactive impact of the lightly loaded new transmission that was added during the off-peak and peak analyses. Light load analysis began with the transmission from the final peak sensitivity and relied upon AC analysis to determine any new thermal or voltage constraints.

5.3.6 Final Off-peak AC Analysis Results

The final step taken during RGOS Power Flow analysis was to run an off-peak AC analysis using transmission developed through the light load sensitivity. Final off-peak AC analysis had two (2) functions:

1. To test the transmission additions added in the peak and light load sensitivity analyses to ensure these additions did not create any reliability violations under off-peak conditions. This provided a final check, under a scenario with the highest wind output, ensuring RGOS plans were not harmful.
2. To find and resolve any lingering voltage violations.

After final off-peak analysis was completed, RGOS transmission scenarios were finalized and economic analyses were performed on each of the scenarios.

5.3.7 Lower Voltage Constraints

Refer to Table 5.3-7. Although RGOS analyses mitigated all constraints on the 200 kV and above transmission system, it did not explicitly attempt to mitigate constraints on the transmission system below 200 kV. These constraints were eliminated from the RGOS scope to minimize the study timeline and—due to the high level of Transmission Owner interaction—mitigate these lower voltage issues. All transmission constraints would require mitigatation prior to any transmission plan or prior to any portion of a transmission plan being moved to MTEP Appendix A for approval and subsequent construction.

Although thermal analysis did not mitigate all sub-200 kV constraints, it did identify and track these constraints throughout the process. The first iteration of the Power Flow analysis, performed on the off-peak model with indicative transmission added from the final energy analysis, contained between 166 and 228 sub-200 kV overloaded lines, depending on scenario. After the final transmission scenarios had been developed and applied to the models, the off-peak model had 76–190 sub-200 kV overloaded lines. These final constraints would have to be mitigated prior to any RGOS plan being moved to MTEP Appendix A.

Table 5.3-7: Sub-200 kV Constraints

Scenario	Initial Sub-200 kV Constraints	Final Sub-200 kV Constraints
Native Voltage	228	190
Native Voltage with DC	147	76
765 kV	166	127

5.3.8 Energy Model Results

The production cost model is also used to evaluate the different strategies refined within the Power Flow reliability work effort. The information in this section was derived from the evaluating the transmission overlays as of the end of the off-peak reliability analysis. Because of this, transmission added because of light load or peak analyses are not included in this production cost model evaluation.

The production cost simulation models reliability at a high level. Unlike Power Flow analysis, which can simulate all possible system contingencies, the production cost model focuses solely upon those contingencies provided by the user that will have significant re-dispatch effects. Within this analysis, contingencies related to RGOS zones were not modeled as completely as the contingencies that may have resulted from adding the new overlay transmission. It is also important to note the events modeled focus primarily on the 230 kV and above transmission system. The ultimate effects of contingency limitations are there are unknown costs and benefits due to re-dispatch that have not yet been explored.

5.3.8.1 Cost Savings

RGOS focuses on the addition of incremental wind to meet the RPS requirements throughout the study footprint and the transmission that facilitates the delivery of the energy. By adding the wind to the system without any RGOS transmission, a reduction in adjusted production costs is recognized within the study footprint as well as some of the defined neighboring regions. This reduction is the result of adding low-cost energy to the system. This can be seen in column 2 of Table 5.3-8, which represents the change in adjusted production cost savings compared to a model that does not include RGOS wind or transmission. Adding the different transmission strategies shows additional benefit can be achieved within the study footprint.

Table 5.3-8: Adjusted Production Cost Savings (2010 USD in Millions)

Pool	+ RGOS Wind	Wind+Native	Wind+765	Wind+Native DC
PJM	$560	$527	$512	$500
MISO	$3,265	$3,664	$3,767	$3,747
TVASUB	($16)	($20)	($28)	($18)
MAPPCOR	$1,222	$1,293	$1,317	$1,339
SPP	($34)	($36)	($17)	$25
SERCNI	$8	$15	$18	$5
IMO	$11	$19	$21	$24
MHEB	($14)	($7)	($5)	$3
NYISO	($13)	($8)	($14)	($13)
RGOS (no mapp)	$3,805	$4,220	$4,317	$4,304
Eastern Int	$4,988	$5,446	$5,571	$5,613

Another metric that can be taken from the production cost model is load cost savings. In Table 5.3-9, it can be seen costs to load reduce with the addition of RGOS wind in most modeled regions, and then reduce even more with the addition of transmission to the system. This potential benefit is recognized more within the RGOS study footprint. However, other regions benefit from the greater availability of cheaper generation due to a greater abundance of low-cost energy within the study footprint.

Table 5.3-9: Load Cost Savings (2010 USD in Millions)

Pool	+ RGOS Wind	Wind+Native	Wind+765	Wind+Native DC
PJM	$865	$1,769	$1,984	$2,021
MISO	$1,688	$2,170	$2,283	$2,021
TVASUB	$212	$307	$296	$360
MAPPCOR	$1,776	$1,591	$1,405	$1,188
SPP	$41	($3)	($66)	$125
SERCNI	$57	$279	$290	$502
IMO	$104	$145	$201	$205
MHEB	$50	$28	$22	$5
NYISO	($38)	($14)	($12)	($17)
RGOS (no mapp)	$2,291	$3,352	$3,533	$3,226
Eastern Int	$4,754	$6,274	$6,404	$6,409

5.3.8.2 RGOS Zone Energy Delivered

RGOS modeled an incremental 28 GW of wind within the study footprint to meet aggregate RPS requirements assumed within the study, resulting in modeling of 88.5 TWh of energy to be delivered to the system. Refer to Table 5.3-10, which shows approximately 8% of the wind was curtailed when adding RGOS-only wind. Curtailment occurred at locational Marginal Prices (LMP) of -$40 defined within the model. The curtailment is a result of LMPs being suppressed due to modeled constraints on the system. It is expected this curtailment may be less than what actually should have been seen because of the lack of appropriately modeled constraints around the wind zones and bulk delivery paths. Refer to Table 5.3-10, which shows this curtailment of RGOS energy zones disappears when RGOS transmission is added to the system.

Table 5.3-10: RGOS Wind Zone Energy Delivered

Overlay	Installed RGOS Wind Zone		Delivered Energy (MWh)	Curtailment
	Nameplate (MW)	Modeled Energy (MWh)		
Base Case (wind added with no transmission)	28,325	88,560,920	81,417,776	8.07%
Native Voltage	28,325	88,560,920	88,533,050	0.03%
765 kV	28,325	88,560,920	88,560,920	0.00%
Native with DC	28,325	88,560,920	88,560,920	0.00%

5.3.8.3 Overlay Line Utilization Summary

Because the production model analyzes every hour within the modeled year, flow information on each of the modeled RGOS lines can be identified. Tables 5.3-11–5.3-13 summarize the max instantaneous loading of the RGOS lines identified in each overlay strategy. This loading is identified as a percentage of the stated rating within the tables. Also, these loadings represent system intact loadings. Because of this, some lines identified within the power flow analysis are primarily needed for reliability and thus load poorly under system intact conditions. More detailed information on each line can be found in the spreadsheet identified as Appendix 6: Production Cost Model Summary Results.

Table 5.3-11: Native Voltage Max Loading Summary

Utilization	Voltage (kV) & Rating (MW)		
	230 kV 340 MW	345 kV 1600 MW	765 kV 5000 MW
Total Lines	4	134	6
Loading at or above 20%	2	123	5
Loading at or above 30%	1	95	2
Loading at or above 40%	1	47	1
Loading at or above 50%	0	27	0

Table 5.3-11: Native Voltage Max Loading Summary

Utilization	Voltage (kV) & Rating (MW)		
	230 kV 340 MW	345 kV 1600 MW	765 kV 5000 MW
Loading at or above 60%	0	10	0
Loading at or above 70%	0	4	0
Loading at or above 80%	0	1	0
Loading at or above 90%	0	0	0
Loading at or above 100%	0	0	0

Table 5.3-12: 765 kV Max Loading Summary

Utilization	Voltage (kV) & Rating (MW)	
	345 kV 1600 MW	765 kV 5000 MW
Total Lines	62	34
Loading at or above 20%	52	34
Loading at or above 30%	31	30
Loading at or above 40%	19	26
Loading at or above 50%	11	14
Loading at or above 60%	3	7
Loading at or above 70%	0	3
Loading at or above 80%	0	3
Loading at or above 90%	0	0
Loading at or above 100%	0	0

Table 5.3-13: Native Voltage with DC Max Loading Summary

Utilization	Voltage (kV) & Rating (MW)			
	345 kV 1600 MW	765 kV 5000 MW	DC 1600	DC 6400
Total Lines	92	9	1	2
Loading at or above 20%	83	9	1	2
Loading at or above 30%	56	6	1	2
Loading at or above 40%	44	5	1	2
Loading at or above 50%	32	3	1	2
Loading at or above 60%	18	2	1	2
Loading at or above 70%	11	2	1	2
Loading at or above 80%	6	1	1	2
Loading at or above 90%	5	0	1	2
Loading at or above 100%	2	0	1	2

5.3.8.4 Interface Flow Summary

Hundreds of lines and autotransformers were modeled for RGOS-developed strategies. More detailed information can be found in Appendix 7: Native Voltage Transmission Detail Flow Information for the Native Voltage strategy; Appendix 8: 765 kV Transmission Detail Flow Information for the 765 kV strategy; and Appendix 9: Native Voltage with DC Transmission Detail Flow Information for the Native Voltage with DC strategy.

Another way to summarize the impact of RGOS transmission strategies is to conceptualize the flow of energy over defined interfaces. For purposes of this study, interfaces were defined as transmission lines crossing state boundaries. Table 5.3-14 provides information for the net energy flow within states containing RGOS lines that cross state borders for the Native Voltage overlay strategy.

Table 5.3-14: Native Voltage Strategy Net State Interface Flow Summary (RGOS Lines Only)

State(s)	Max Export (MW)	Max Import (MW)	# of Hours Exporting	# of Hours Importing
Dakotas Net	1,982	-489	8,376	380
IA Net	2,039	-833	7,729	1,028
IL Net	1,887	-2,546	3,779	4,974
IN Net	329	-2,052	202	8,555
MN Net	919	-2,031	1,399	7,354

Table 5.3-14: Native Voltage Strategy Net State Interface Flow Summary (RGOS Lines Only)

State(s)	Max Export (MW)	Max Import (MW)	# of Hours Exporting	# of Hours Importing
MO Net	1,213	-412	7,571	1,180
MT Net	223	-296	3,047	5,627
OH Net	889	-1,612	898	7,857
WI Net	1,974	-1,079	6,580	2,175

Figure 5.3-13 provides the net energy duration curve for each of the states previously identified with the modeled Native Voltage overlay. Referencing Table 5.3-14 and Figure 5.3-13, it can be seen areas with higher incremental wind penetration tend to be net exporters while states with more load and less wind capability tend to be net importers.

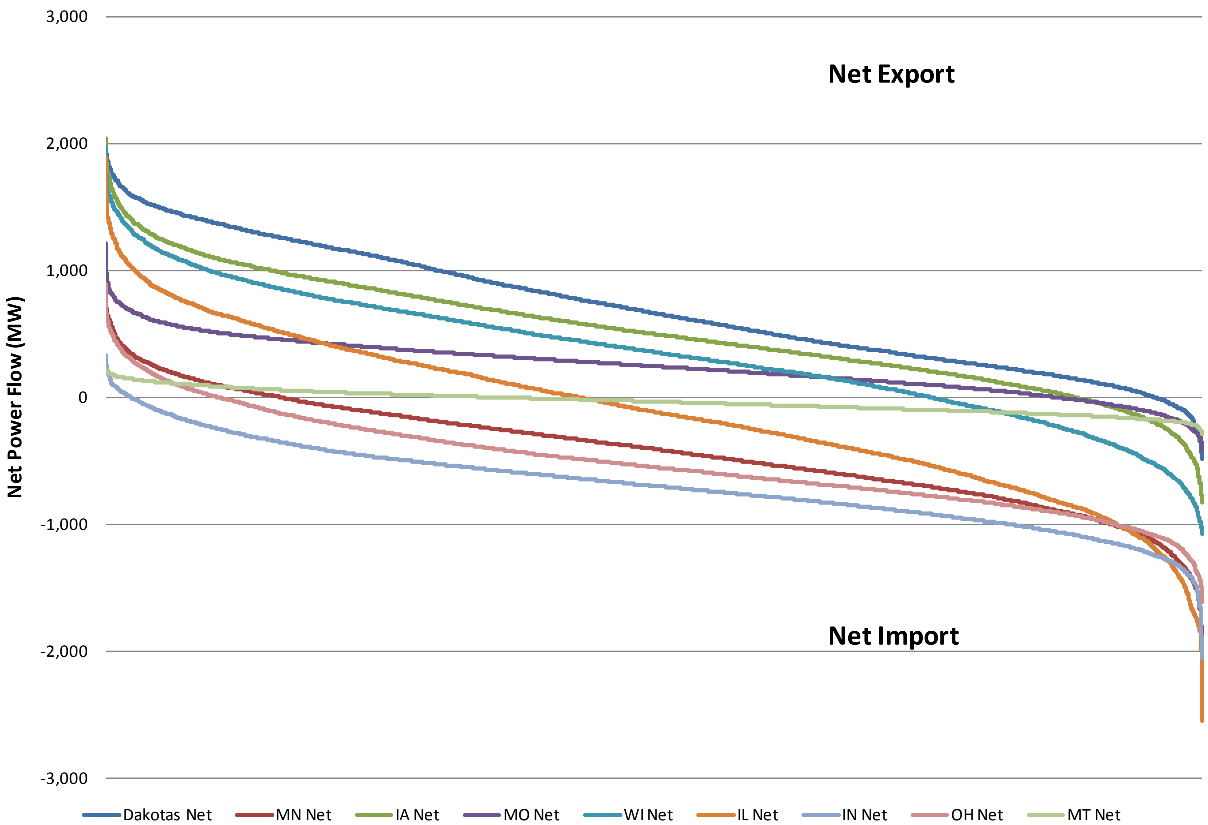

Figure 5.3-13: Native Voltage Strategy Net State Interface Duration Curves (RGOS Lines Only)

Table 5.3-15 and Figure 5.3-14 represent net state energy information for the 765 kV strategy overlay. It is evident more energy flows on the lines with the 765kV overlay than with the Native Voltage overlay. This should be expected because of the higher ratings and lower impedance of 765 kV transmission lines.

Table 5.3-15: 765 kV Strategy Net State Interface Flow Summary (RGOS Lines Only)

State(s)	Max Export (MW)	Max Import (MW)	# of Hours Exporting	# of Hours Importing
Dakotas Net	2,925	-672	8,351	405
IA Net	3,935	-1,401	8,121	639
IL Net	1,752	-6,447	929	7,830
IN Net	1,424	-3,552	537	8,222
MN Net	2,637	-2,184	6,932	1,822
MO Net	4,308	-2,003	7,154	1,604
MT Net	215	-297	2,915	5,789
OH Net	2,073	-3,479	701	8,058
WI Net	2,438	-2,019	5,430	3,326

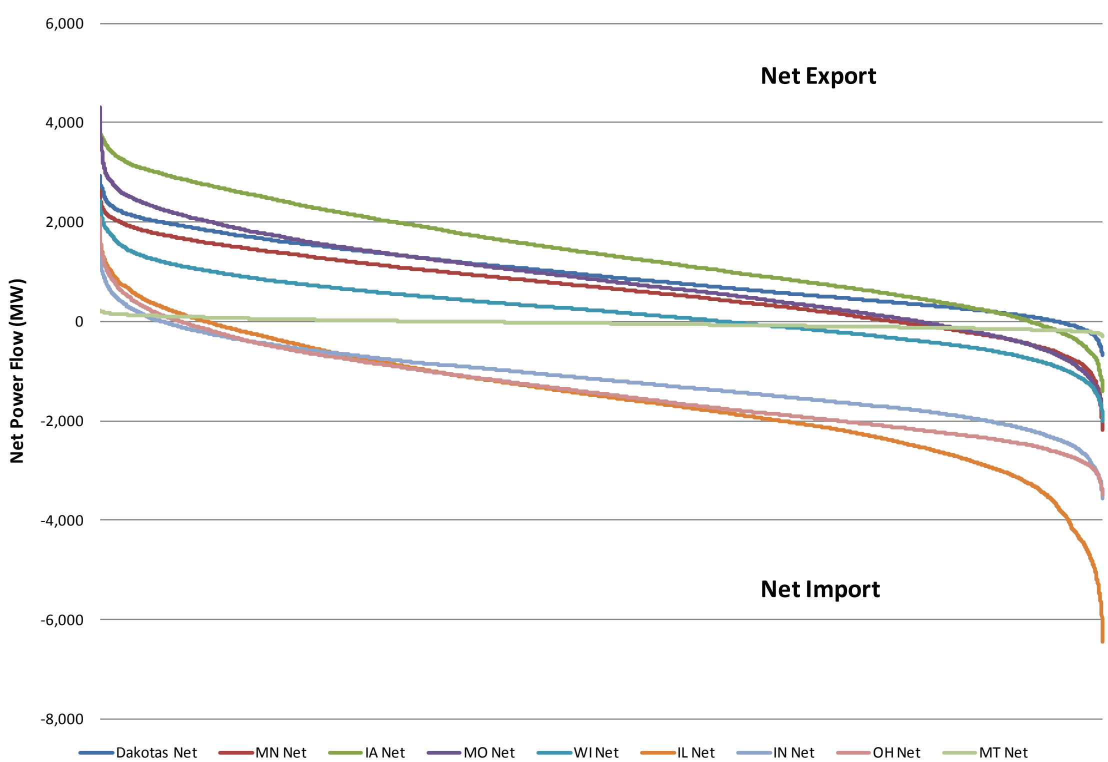

Figure 5.3-14: 765 kV Strategy Net State Interface Duration Curves (RGOS Lines Only)

Table 5.3-16 and Figure 5.3-15 show net state energy information for the Native Voltage with DC transmission strategy. The purpose of DC transmission across the RGOS study footprint is to deliver high levels of energy across the system with minimal impact on existing transmission that it (DC transmission) bypasses. Because of the source and sink locations of the DC lines, the Dakotas, Minnesota, and Iowa see a high impact for net state export while Ohio experiences large imports due to most of the DC transmission sinking within Ohio state boundaries.

Table 5.3-16: Native Voltage with DC Strategy Net State Interface Flow Summary (RGOS Lines Only)

	Max Export (MW)	Max Import (MW)	# of Hours Exporting	# of Hours Importing
Dakotas Net	3,628	-249	8,704	56
IA Net	5,774	-610	8,450	309
IL Net	1,646	-3,622	3,566	5,194
IN Net	-81	-1,806	0	8,760
MI Net	2,485	-3,129	1,321	7,439
MN Net	4,793	-1,290	8,134	625
MO Net	1,100	-1,125	4,437	4,317
MT Net	241	-284	3,627	5,050
OH Net	2,814	-10,222	491	8,269
WI Net	1,600	-1,600	6,970	1,790

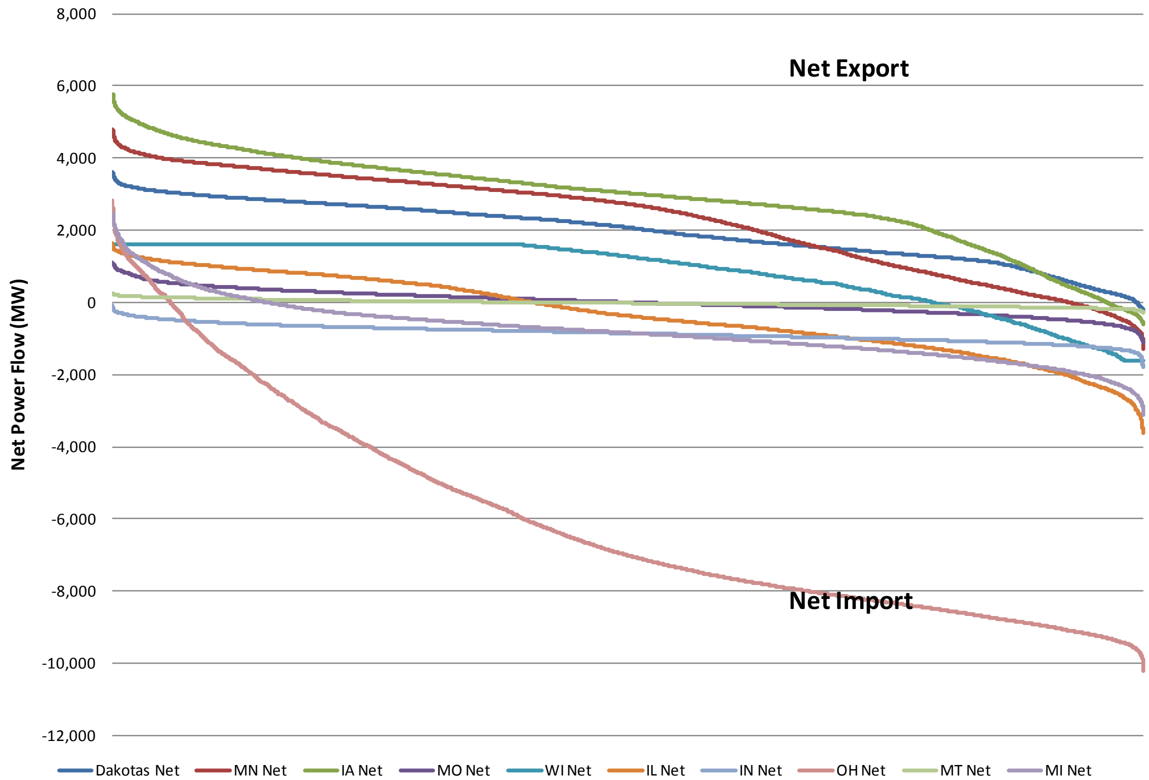

Figure 5.3-15: Native Voltage with DC Strategy Net State Interface Duration Curves (RGOS Lines Only)

To show in greater detail where energy is actually flowing, the following tables and figures show specific state-to-state RGOS line energy flow information. Max power flow and number of positive hours represent "from" to "to" flow while the min power flow and number of negative hours represent the opposite.

Table 5.3-17 and Figure 5.3-16 show the bulk of the energy flow tends to go west to east in the Native Voltage overlay study footprint.

Table 5.3-17: Native Voltage Strategy State Interface Flow Summary (RGOS Lines Only)

Interface	Max Power Flow (MW)	Min Power Flow (MW)	# of Hours Positive	# of Hours Negative
Dak to IA	400	-337	4,759	3,959
Dak to MN	2,042	-298	8,485	272
IA to IL	760	-455	7,835	911
IA to MO	438	-687	4,201	4,517
IA to WI	566	-100	8,674	81
IL to IN	2,060	-166	8,753	6
IN to OH	1,612	-889	7,857	898
MN to IA	980	-1,409	4,515	4,233

Table 5.3-17: Native Voltage Strategy State Interface Flow Summary (RGOS Lines Only)

Interface	Max Power Flow (MW)	Min Power Flow (MW)	# of Hours Positive	# of Hours Negative
MN to WI	462	-284	8,433	322
MO to IL	716	-462	7,802	941
MT to Dak	223	-296	3,047	5,627
NE to IA	42	-157	436	8,240
WI to IL	2,204	-741	8,440	316
* Positive numbers represent flows from A to B (Dakotas to MN) while negative numbers represent flow from B to A (MN to Dakotas).				

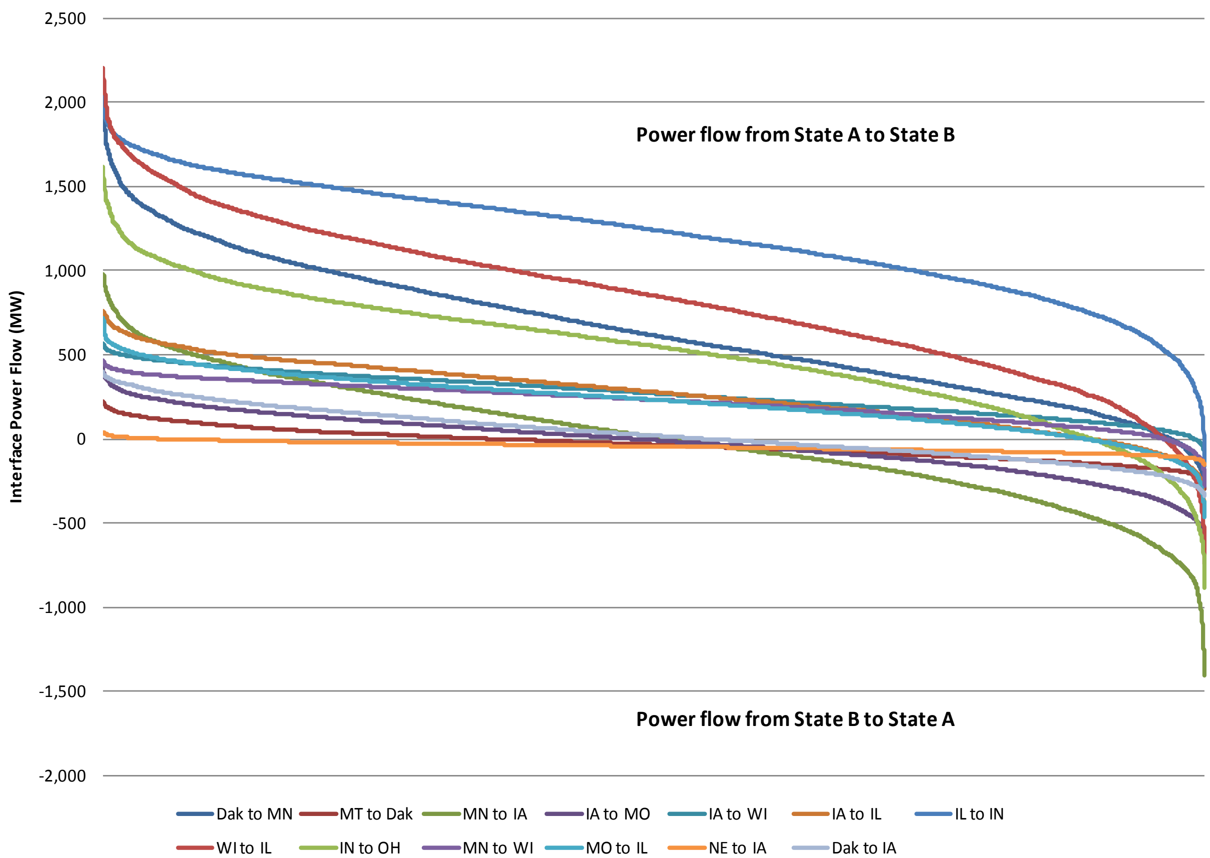

Figure 5.3-16: Native Voltage Strategy State Interface Duration Curves (RGOS Lines Only)

As previously noted, the 765 kV overlay shows many of the same characteristics of the Native Voltage but at higher capacity levels. Table 5.3-18 and Figure 5.3-17 provide energy flow information for this strategy.

Table 5.3-18: 765 kV Strategy State Interface Flow Summary (RGOS Lines Only)

Interface	Max Power Flow (MW)	Min Power Flow (MW)	# of Hours Positive	# of Hours Negative
Dak to MN	2,943	-795	8,218	537
IA to IL	4,103	-993	8,623	137
IA to MO	2,056	-2,639	5,163	3,595
IA to WI	2,773	-372	8,696	63
IL to IN	3,545	-2,021	8,254	505
IN to OH	3,479	-2,073	8,058	701
MN to IA	5,097	-2,468	7,841	917
MO to IL	525	-256	7,417	1,301
MO to IN	2,440	-922	8,194	564
MT to Dak	215	-297	2,915	5,789
WI to IL	3,795	-1,750	8,423	336

* Positive numbers represent flows from A to B (Dakotas to MN) while negative numbers represent flow from B to A (MN to Dakotas).

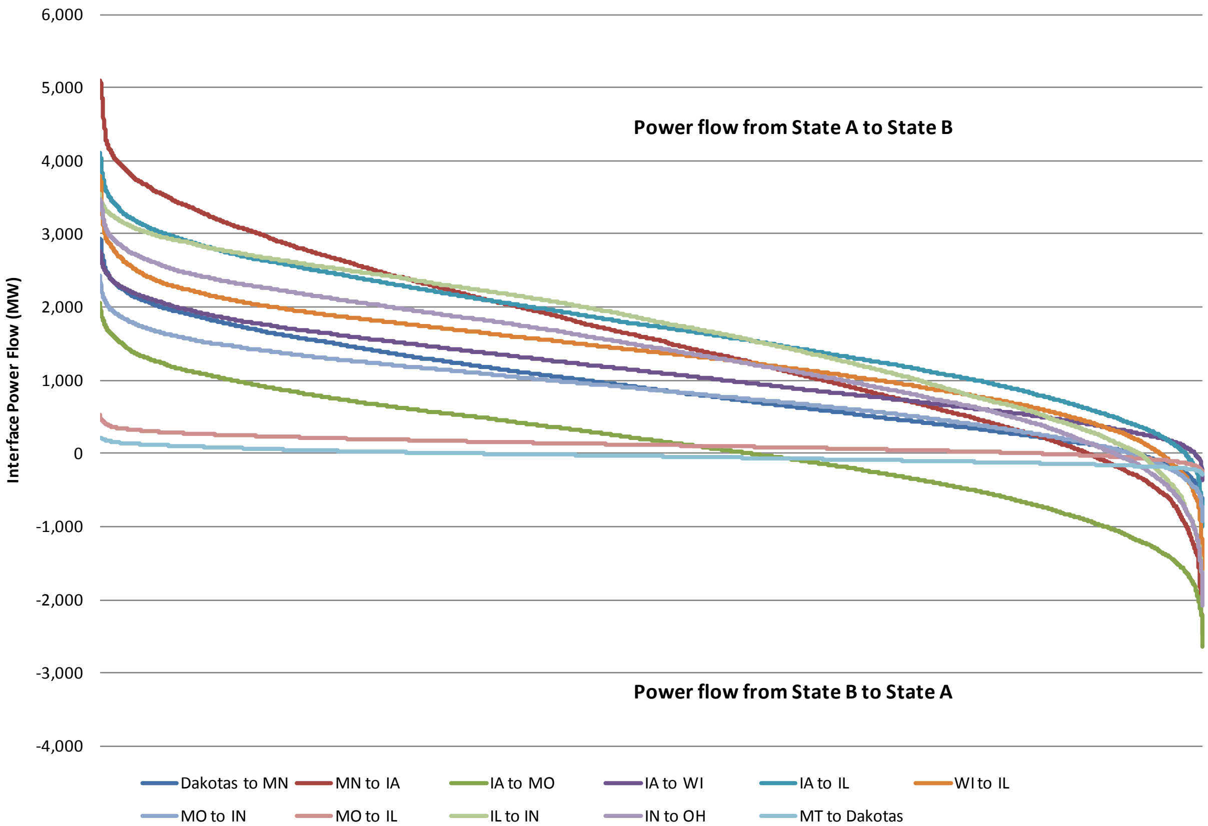

Figure 5.3-17: 765 kV Strategy State Interface Duration Curves (RGOS Lines Only)

Table 5.3-19 and Figure 5.3-18 represent energy flow information for the Native Voltage with DC overlay. Because the DC overlay interconnects into the existing system at only a few points, new state interfaces are developed—the Illinois to Ohio interface, for example. It can also be seen some interface characteristics are different because of where the DC interconnects. For example, the general flow of energy goes from Missouri to Illinois in other overlays. However, with the DC line tying to the system south of a St. Louis in Illinois, the general energy flow of that interface flows from Illinois to Missouri.

Table 5.3-19: Native Voltage with DC Strategy State Interface Flow Summary (RGOS Lines Only)

Interface	Max Power Flow	Min Power Flow	# of Hours Positive	# of Hours Negative
Dak to MN	3,768	-322	8,681	79
IA to IL	6,400	0	8,308	0
IA to MO	324	-922	572	8,166
IL to IN	1,721	-131	8,750	10
IL to OH	8,000	0	8,397	0
IN to OH	493	-687	3,610	5,127
MN to IA	1,664	-1,496	4,531	4,225
MN to IL	6,400	0	8,300	0

Table 5.3-19: Native Voltage with DC Strategy State Interface Flow Summary (RGOS Lines Only)

Interface	Max Power Flow	Min Power Flow	# of Hours Positive	# of Hours Negative
MO to IL	552	-1,180	1,120	7,633
MT to Dak	241	-284	3,627	5,050
OH to MI	2,141	-1,968	4,167	4,589
WI to MI	1,600	-1,600	6,970	1,790
* Positive numbers represent flows from A to B (Dakotas to MN) while negative numbers represent flow from B to A (MN to Dakotas).				

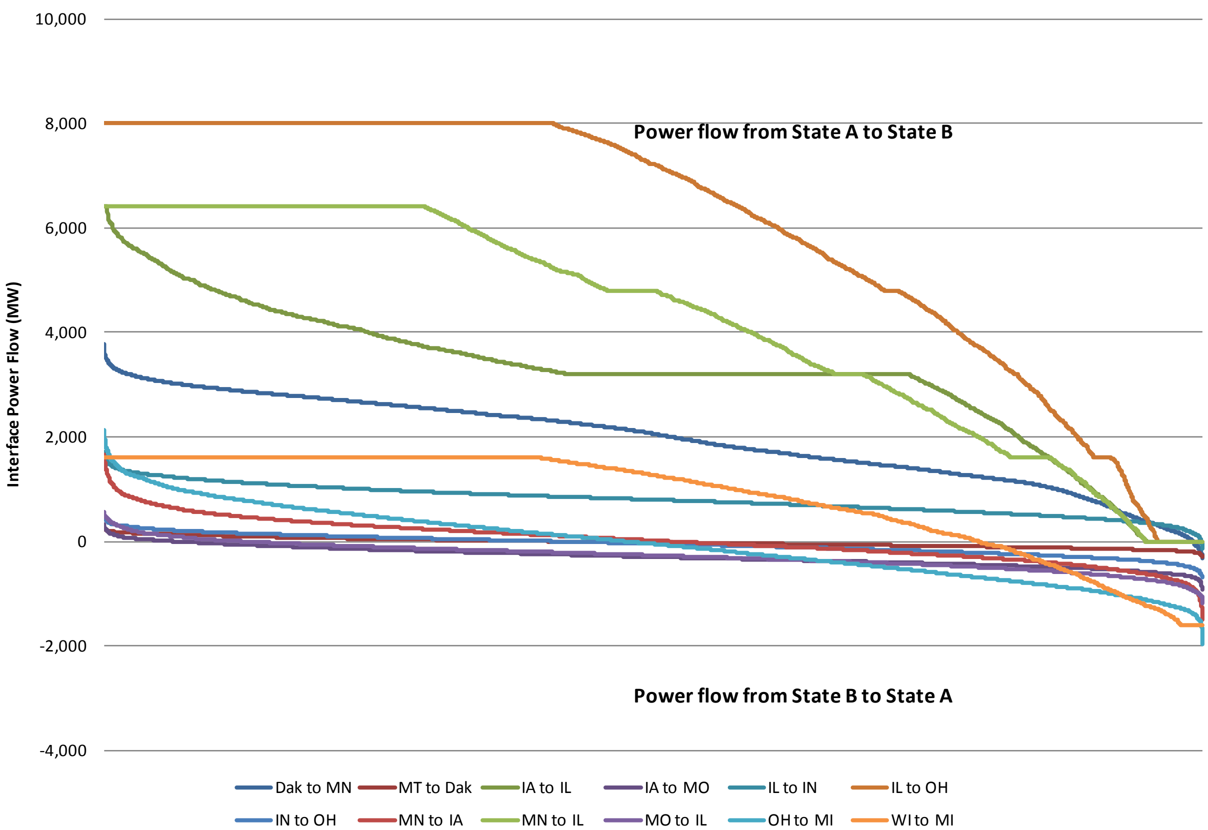

Figure 5.3-18: Native Voltage with DC Strategy State Interface Duration Curves (RGOS Lines Only)

To demonstrate a more integrated look of the impact of the RGOS lines added to the system, the following tables and figures show the interface energy flow summary from state-to-state with RGOS lines as well as existing transmission of 230 kV and greater.

Table 5.3-20 and Figure 5.3-19 represent the state interface flow of the base case. The base case is defined as adding RGOS energy zones to the existing transmission system without adding additional RGOS transmission.

Table 5.3-20: Base Case State Interface Summary (All Lines 230 kV and Greater)

INTERFACE	Max Power Flow (MW)	Min Power Flow (MW)	# of Hours Positive	# of Hours Negative
DK-MHEB	550	-500	1,968	6,771
IA-IL	1,098	-991	6,822	1,931
IA-MO	616	-776	5,194	3,536
IA-NE	1,650	-1,944	5,140	3,615
IA-SD	1,064	-880	4,395	4,350
IL-IN	6,383	-4,308	8,013	746
IL-KT	1,189	-165	8,738	21
IL-MO	1,897	-1,873	4,467	4,290
IN-OH	7,040	-3,390	8,064	695
MI-IN	3,981	-2,355	6,625	2,130
MI-OH	2,599	-1,921	6,571	2,186
MN-DAK	553	-1,514	254	8,504
MN-IA	1,246	-1,670	4,989	3,762
MN-MHEB	834	-855	26	8,734
MN-WI	2,256	-734	8,698	62
OH-PA	1,924	-3,745	2,558	6,198
WI-IL	1,314	-1,682	7,084	1,675
WI-MI	333	-77	8,243	478
* Positive numbers represent flows from A to B (Dak to MHEB) while negative numbers represent flow from B to A (MHEB to Dak).				

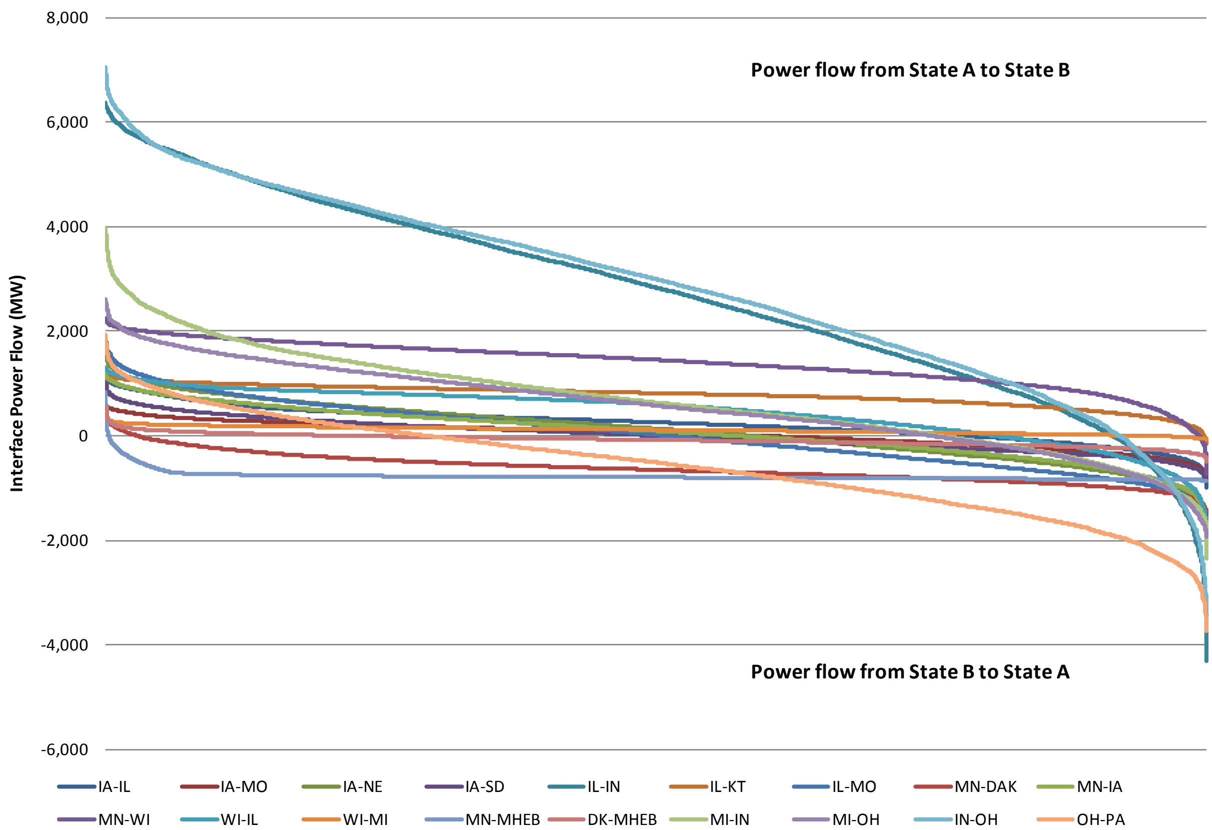

Figure 5.3-19: Base Case State Interface Duration Curves (All Lines 230 kV and Greater)

Table 5.3-21 and Figure 5.3-20 represent the interface information for the Native Voltage overlay with existing transmission added. The impact of adding transmission to one or some of the interfaces may also have an effect on the energy flows of unaltered interfaces.

Table 5.3-21: Native Voltage Strategy State Interface Summary (All Lines 230 kV and Greater)

INTERFACE	Max Power Flow (MW)	Min Power Flow (MW)	# of Hours Positive	# of Hours Negative
DK-MHEB	487	-481	1,790	6,952
IA to WI	566	-100	8,675	81
IA-IL	2,245	-1,407	7,865	890
IA-MO	1,000	-1,321	5,293	3,464
IA-NE	1,859	-1,755	4,458	4,297
IA-SD	909	-1,224	2,889	5,865
IL-IN	8,729	-3,808	8,499	261
IL-KT	1,195	-182	8,724	36
IL-MO	2,138	-2,814	3,050	5,704

Table 5.3-21: Native Voltage Strategy State Interface Summary (All Lines 230 kV and Greater)

INTERFACE	Max Power Flow (MW)	Min Power Flow (MW)	# of Hours Positive	# of Hours Negative
IN-OH	7,882	-2,385	8,531	229
MI-IN	4,148	-2,336	6,302	2,455
MI-OH	2,754	-2,093	6,435	2,323
MN-DAK	811	-3,834	420	8,340
MN-IA	1,481	-2,201	4,789	3,967
MN-MHEB	788	-907	29	8,731
MN-WI	2,861	-1,184	8,664	96
OH-PA	1,989	-3,675	3,256	5,497
WI-IL	4,337	-2,141	8,259	501
WI-MI	341	-70	8,355	370

* Positive numbers represent flows from A to B (Dak to MHEB) while negative numbers represent flow from B to A (MHEB to Dak).

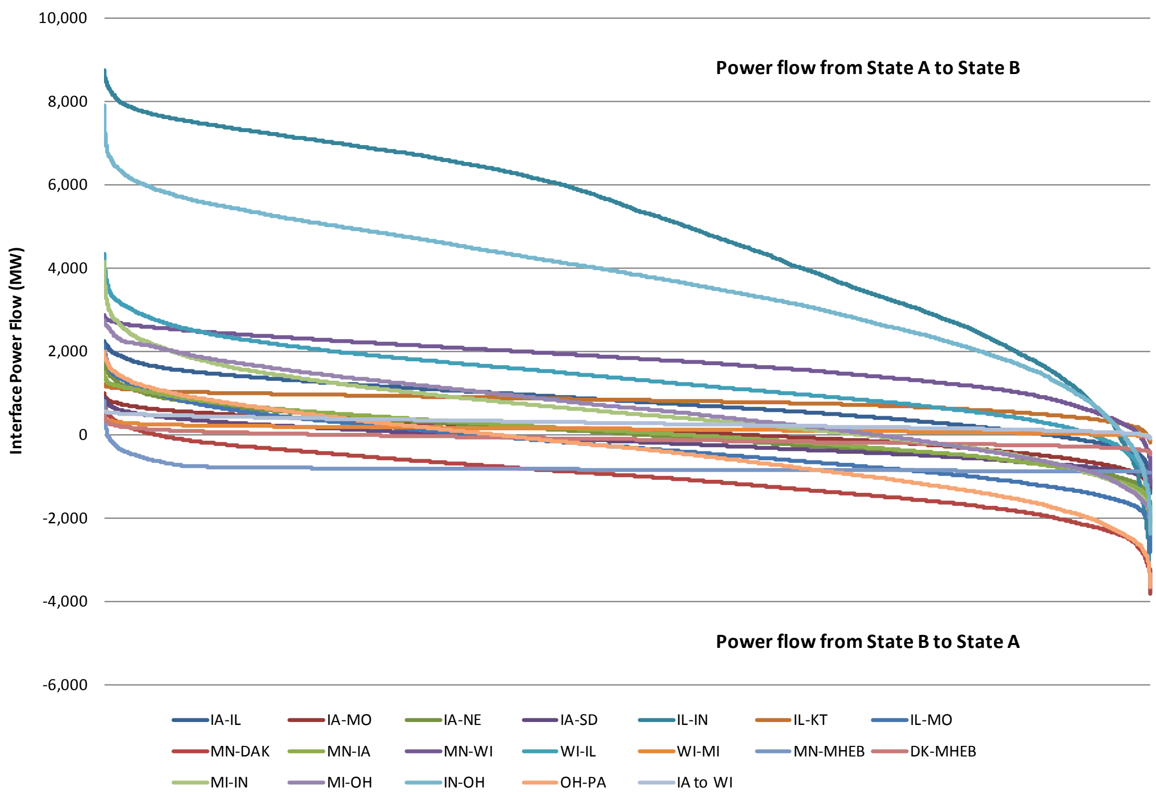

Figure 5.3-20: Native Voltage Strategy State Interface Duration Curves (All Lines 230 kV and Greater)

As mentioned previously, the 765 kV system shows those interfaces with new transmission have higher energy flow impacts than those with the Native Voltage overlay. This can be seen in Table 5.3-22 and Figure 5.3-21.

Table 5.3-22: 765 kV Strategy State Interface Summary (All Lines 230 kV and Greater)

Interface	Max Power Flow (MW)	Min Power Flow (MW)	# of Hours Positive	# of Hours Negative
Dak-MHEB	544	-473	1,476	7,275
IA-IL	5,158	-1,596	8,437	320
IA-MO	2,569	-3,191	5,363	3,395
IA-NE	1,620	-1,467	4,314	4,432
IA-SD	651	-811	3,745	5,001
IA-WI	2,773	-372	8,696	63
IL-IN	11,086	-4,906	8,490	269
IL-KT	1,204	-252	8,716	44
IL-MO	2,258	-2,323	3,995	4,763
IN-OH	12,019	-4,860	8,423	336
MI-IN	4,004	-2,478	5,533	3,225
MI-OH	2,694	-2,277	6,044	2,714
MN-DAK	1,140	-4,299	395	8,363
MN-IA	5,931	-3,450	7,444	1,316
MN-MHEB	819	-902	24	8,736
MN-WI	2,422	-633	8,684	76
MO-IN	2,440	-922	8,194	564
OH-PA	2,453	-3,720	4,027	4,730
WI-IL	4,984	-2,698	8,247	512
WI-MI	343	-71	8,333	393
* Positive numbers represent flows from A to B (Dak to MHEB) while negative numbers represent flow from B to A (MHEB to Dak).				

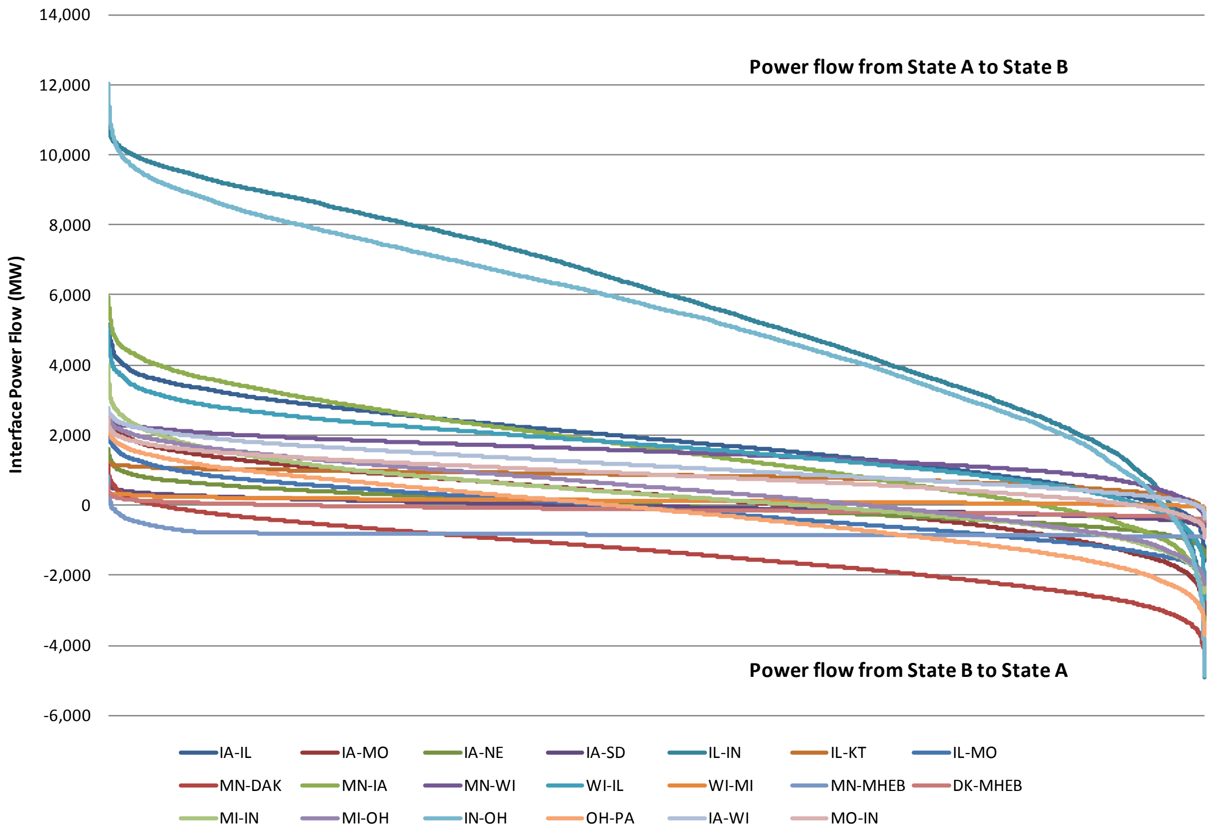

Figure 5.3-21: 765 kV Strategy State Interface Duration Curves (All Lines 230 kV and Greater)

The DC transmission in the Native Voltage with DC overlay shows much of the same impacts with the existing system as without. Native Voltage with DC continues to demonstrate the transfer of large amounts of energy but also shows that selection of locations for the DC terminals can change characteristics of the energy flow across the system. This change in characteristics can be seen on the Iowa and Minnesota interface and the Missouri to Illinois interface. Refer to Table 5.3-23 and Figure 5.3-22.

Table 5.3-23: Native Voltage with DC Strategy State Interface Summary (All Lines 230 kV and Greater)

Interface	Max Power Flow (MW)	Min Power Flow (MW)	# of Hours Positive	# of Hours Negative
DK-MHEB	444	-512	638	8,114
IA-IL	7,508	-1,073	8,448	311
IA-MO	741	-1,687	1,254	7,501
IA-NE	1,046	-2,828	638	8,120
IA-SD	908	-852	6,432	2,322
IL-IN	7,732	-4,287	6,860	1,900
IL-KT	1,263	-233	8,689	68

Table 5.3-23: Native Voltage with DC Strategy State Interface Summary (All Lines 230 kV and Greater)

Interface	Max Power Flow (MW)	Min Power Flow (MW)	# of Hours Positive	# of Hours Negative
IL-MO	3,276	-1,663	6,451	2,304
IL-OH	8,000	0	8,397	0
IN-OH	6,085	-2,977	7,712	1,046
MI-IN	4,813	-3,096	5,020	3,735
MI-OH	4,775	-2,606	6,619	2,138
MN-DAK	716	-5,530	103	8,657
MN-IA	1,854	-2,688	2,013	6,737
MN-IL	6,400	0	8,300	0
MN-MHEB	922	-903	23	8,737
MN-WI	2,119	-1,137	8,233	527
OH-PA	2,309	-3,685	3,974	4,784
WI-IL	1,599	-2,213	3,259	5,500
WI-MI	1,819	-1,655	7,081	1,679
* Positive numbers represent flows from A to B (Dak to MHEB) while negative numbers represent flow from B to A (MHEB to Dak).				

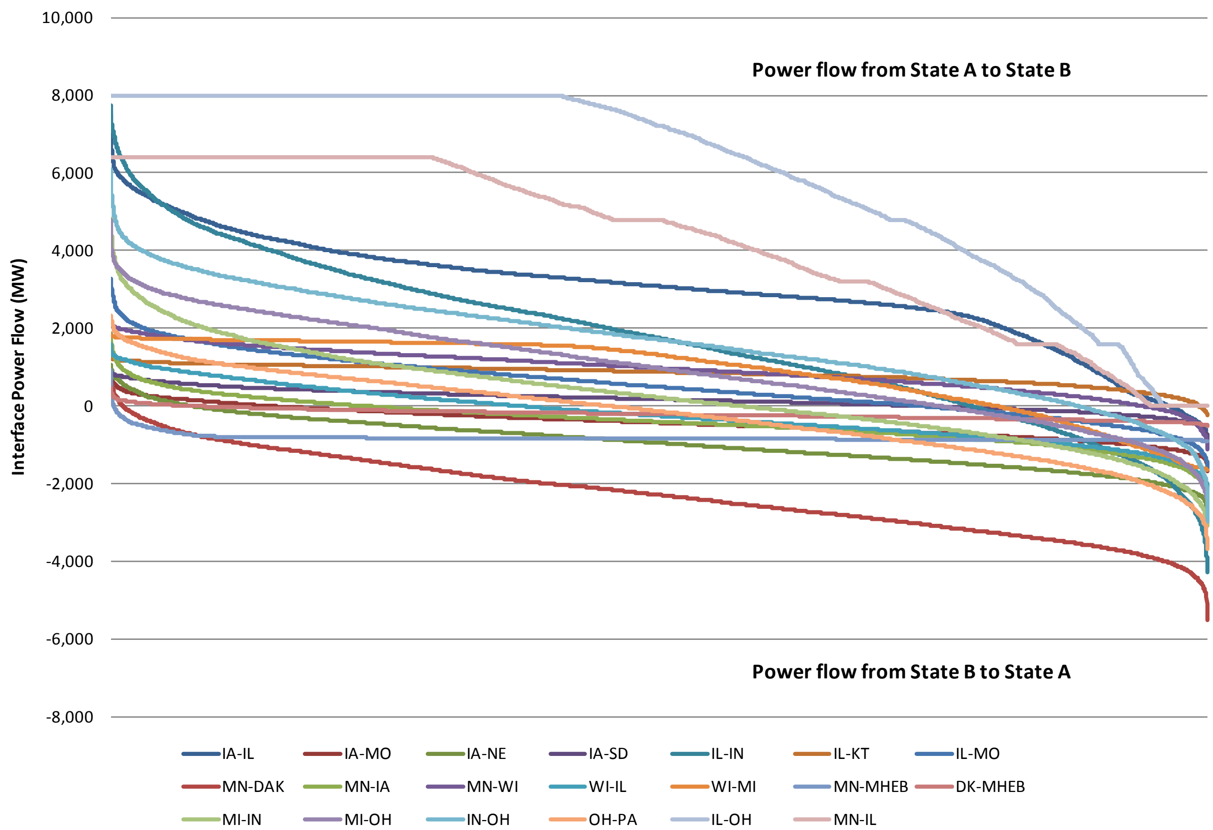

Figure 5.3-22: Native Voltage with DC Strategy State Interface Duration Curves (All lines 230 kV and Greater)

5.3.9 Sensitivity Analysis for RGOS Plans - Robustness Testing

With intensive stakeholder collaboration taking place under the Technical Review Group (TRG), three (3) distinct long-term transmission expansion scenarios have been developed to meet state renewable energy standards and goals encompassing the entire study footprint, as discussed in section 5. In parallel with RGOS study process, a collaborative effort on robust business case development has been undertaken through the MTEP10 planning process to enable a more holistic value assessment of transmission projects or portfolios. The sensitivity analysis for the three (3) RGOS plans has been performed within the context of the MTEP process to facilitate the business case development for new transmission.

The primary focus of sensitivity analysis effort is to determine the total values of the three (3) proposed transmission plans by means of a robustness testing process. To perform robustness testing, each of the three transmission solutions is assessed against a set of value measures across a broad range of plausible future scenarios. As a result, robustness testing under multiple futures provides additional quantifiable benefits to ensure a more complete evaluation on the performance of the three (3) transmission scenarios, and aid in identifying the best-fit long-term strategy which will result in the least future regrets regardless of policy decisions.

Recognizing the need for consideration of additional value measures and further methodology development in transmission business case analysis, the overall benefits of the three long-term strategies identified through the robustness testing process are indicative and are subject to change depending on the assumptions made to quantify the identified value measures and additional value measure inclusion. Without further development of value measure methodology including both financially quantifiable measures and non-financial measures, it will be premature to determine the overall comparative benefits of the RGOS transmission plans and select the definitive long-term strategy. However, with the substantial amount of valuable information resulting from sensitivity analysis, it allows policy makers and stakeholders to recognize that there is a broader set of values beyond satisfying public policy needs to support the implementation of regional plans.

5.3.9.1 Future Scenario Selection and Weights

The Planning Advisory Committee Process (PAC) developed an array of future scenarios (Futures). RGOS used the following:

- **S1: CARP Business As Usual with high Demand and Energy Growth Rates:** Considered the status quo scenario, with a quick recovery from the economic downturn in demand and energy projections. This future scenario models the power system as it exists today with reference values and trends with the exception of demand and energy growth rates.
- **S2: CARP Federal RPS:** Requires that 20% of the energy consumption in the Eastern Interconnect come from renewable resources by 2025. State mandates are the same as those modeled in the Business as Usual Future and any additional renewable energy is met with wind to satisfy the 20% renewable energy requirement.
- **S4: CARP Federal RPS, Carbon Cap and Trade, Smart Grid and Electric Cars:** Combines the impact of multiple future policy scenarios into one future. Smart grid is modeled within the demand growth rate. It is assumed that an increased penetration of smart grid will lower the overall growth of demand. Electric vehicles are modeled within the energy growth rate. Electric vehicles are assumed to increase off-peak energy usage and as such increase the overall energy growth rate.
- **S8: PAC Business as Usual with Mid-Low Demand and Energy Growth Rates:** Considered the status quo future scenario and continues the economic downturn-affected growth in demand, energy, and inflation rates.
- **S10: PAC Carbon Cap and Trade with Nuclear:** Models a declining cap on future CO2 emissions with an aggressive nuclear build out as carbon neutral resources.

The flexibility provided by the multi-dimensional scenario planning analysis allows a more complete robustness analysis around the long-term transmission plans. The weighting of the futures and how a transmission plan performs based on the assigned weights must be taken into account in order to more accurately select the appropriate strategy. To achieve this end, Planning Advisory Committee (PAC) sectors were requested to provide weights for the selected futures based on the possibility of each future relative to the others. The straight sector average weights assigned to each future are tabulated in Table 5.3-24.

Table 5.3-24: Future Scenario PAC Sector Average Weights

Future Scenarios	Weights
S8: PAC Business as Usual Mid-Low D+E	34%
S2: CARP Federal RPS Future	26%
S10: PAC Carbon Future - Carbon Cap with Nuclear	15%
S1: CARP Business as Usual with high growth rate for D+E	14%
S4: CARP Federal RPS + Carbon Cap + Smart Grid + Electric Cars	11%

5.3.9.2 Robustness Testing Process and Value Measures

As illustrated in Figure 5.3-23, robustness testing involves a comprehensive value assessment for transmission solutions utilizing a decision tree based methodology. To perform robustness testing, each transmission solution is tested across multiple future scenarios which it might not be designed for. The value of the transmission for each given future is then evaluated and quantified against a complete set of value measures. By applying the assigned future weights to the values derived from each future, the overall weighted average value is determined for each transmission solution. The ultimate goal of robustness testing is to identify the preferred transmission strategy that can provide the best value under most, if not all, future outcomes in order to minimize the risk associated with the various uncertainties surrounding policy discussions.

The Midwest ISO utilizes PROMOD IV®, a commercial production cost model, to evaluate potential economic benefits of transmission plans. Production cost model simulations are performed with and without each developed transmission scenario. Taking the difference between these two (2) simulation results provides the economic benefits associated with each specific plan.

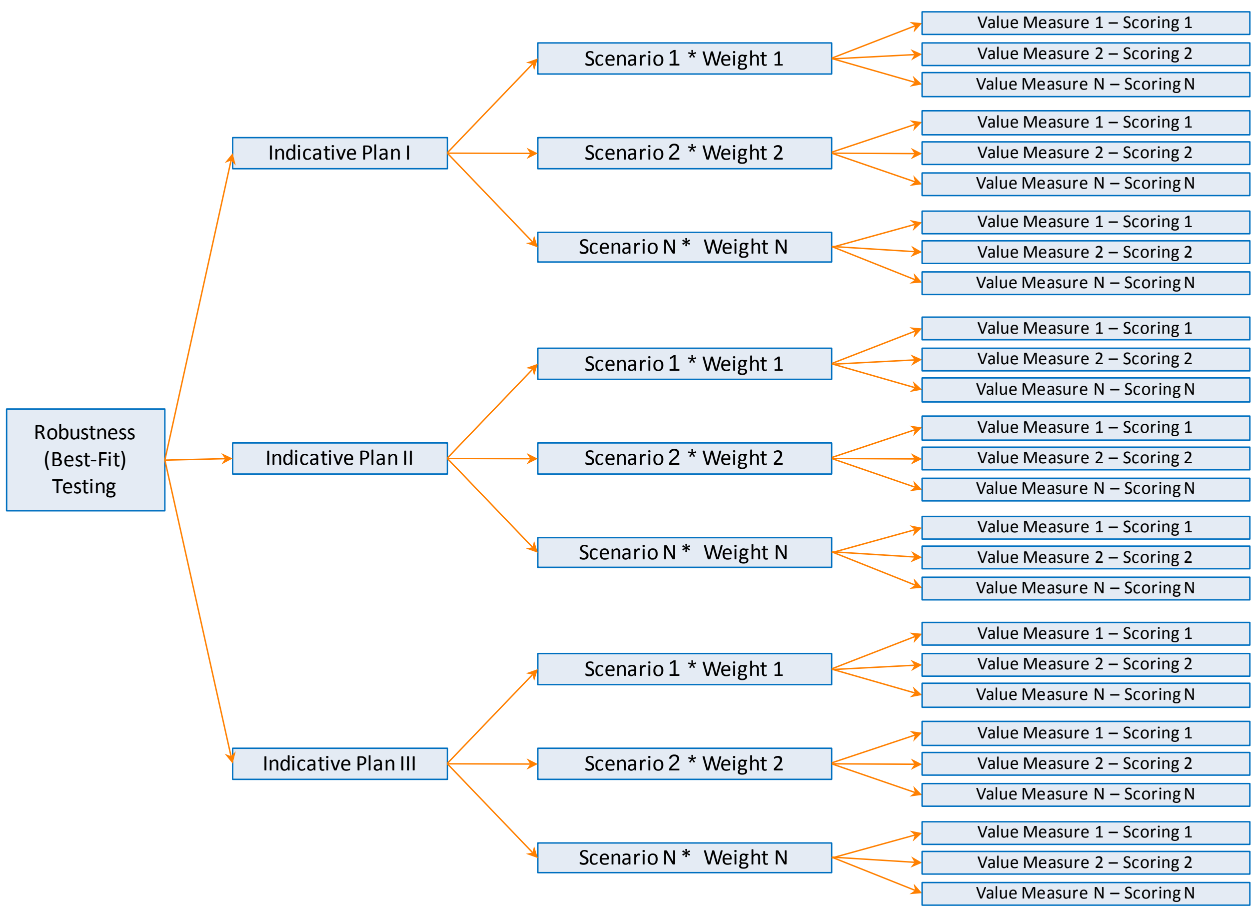

Figure 5.3-23: Indicative Robustness Testing Decision Tree Diagram

As a key component of transmission value assessment, the following financially quantifiable measures have been considered for making comparisons on the performance of the three (3) RGOS plans:

a. **Adjusted Production Cost Savings** where total annual generation production costs include fuel, variable operations and maintenance (O&M) and start up costs, and are adjusted with off-system purchases and sales. The off-system purchases and sales are quantified using load weighted LMP and gen weighted LMP respectively. Adjusted production cost savings can be achieved through reduction of transmission congestion costs and more efficient generation resource utilization.

b. **Load Cost Savings** where load cost represents the annual load payments, measured by projections in hourly load weighted LMP. Load cost savings and adjusted production cost savings are essentially two alternative benefit measures to address the single type of economic value and are not additive measures. Load cost savings is not used to calculate the total value of the RGOS plans in MTEP10.

c. **Capacity Loss Savings** where capacity losses represent the amount of capacity required to serve transmission losses during the system peak hour. The intent is to capture the value of reducing the amount of capacity reserves that are required to maintain system reliability. The avoided capacity investment due to loss reduction is quantified using a generic overnight construction cost of $960,000 per MW.

d. **Capacity Savings Due to Planning Reserve Margin Reduction:** The intent of this measure is to capture the value associated with transmission plans by potentially lowering the overall Planning Reserve Margin requirement through congestion relief. Recognizing a relatively small reduction in reserve requirement would allow a significant amount of benefits to accrue, this measure is under consideration for inclusion in future evaluation of transmission plans/portfolios.

e. **Carbon Emission Reduction Cost Savings:** To address carbon reduction legislation in some future scenarios, a certain cost on carbon is placed combined with uneconomic coal retirement deployment to achieve the high level carbon reductions. The cost of carbon is modeled in a way to only impact the unit dispatch as a penalty and exclude the costs associated with carbon emissions from production costs. The benefits of carbon emission reduction are additive to the adjusted production cost savings described above. The corresponding carbon cost modeled in each scenario is used to quantify the dollar value of carbon emission reductions.

f. **Generation Revenue Due to Wind Curtailment Reduction:** With the new transmission corridors to access the remote wind resources, the curtailment level of wind energy is minimized substantially, particularly for the futures with aggressive RPS requirements. The revenue is quantified using annual generation weighted LMP for the RGOS footprint as an estimate. The intent of this measure is only to provide a standalone value associated with wind curtailment reduction and is not included in the overall value calculation, as this value is embedded in adjusted production cost savings described above.

Robustness testing for the three (3) long-term strategies has been focused on financially quantifiable measures as a starting point. There are other benefit measures including qualitative and risk factors that need to be taken into account to provide a more thorough analysis and allow a more complete value to be captured through the robust business case development process. Midwest ISO will continue to collaborate with stakeholders on further development of value measures as an ongoing effort in the next few planning cycles.

5.3.9.3 RGOS Transmission Plan Value Assessment Results

From the aforementioned list of financially quantifiable measures, only the mutually exclusive or additive measures were used to calculate the total value of RGOS transmission plans to avoid overstating the value of the plans. The straight sum of adjusted production cost savings, capacity loss savings and carbon emission reduction cost savings were used to determine the value of each plan for a given future scenario. Although the capacity savings due to PRM reduction is additive, it has not been evaluated due to time constraints. The overall aggregated financially quantifiable value for each RGOS plan is then determined by applying the PAC-assigned future weights to the value derived for each future. The total financially quantifiable value results for the three (3) RGOS plans are indicative, subject to change depending on the assumptions made to quantify the identified value measures and additional value measure inclusion. In general, the additive financially quantifiable benefits are considered for transmission value assessment. However, for the potential market efficiency projects, the RECBII economic benefit metric, a blend of 70% adjusted project cost benefit and 30% load cost savings, is still in place for transmission value evaluation. Specifically, the financially quantifiable value of each RGOS transmission plan was determined as follows:

Value of transmission plan (per future) = Sum of values of financially quantifiable measures

= Adjusted production cost savings + Capacity loss savings + Carbon emission reductions[4]

Value of transmission plan (overall) = Sum of value of the plan per future * future weights

=34%*Scenario 8 +15%*Scenario 10+14%*Scenario 1+26%*Scenario 2+11%*Scenario 4

For each RGOS transmission plan, the value of each individual financially quantifiable measure under each given future, the total value per future and the overall weighted value are succinctly illustrated through the decision tree diagrams in Figures 5.3-24–5.3-26.

[4] The capacity savings due to PRM reduction is additive and is under development for inclusion in the total value evaluation.

Looking at the results, a wide range of potential benefits are achieved across the five (5) selected futures. Based on the robustness analysis process described above, the three RGOS plans are expected to bring an annual weighted financially quantifiable benefits ranging from $1,064 million to $1,830 million in year 2025 for RGOS study footprint. It is important to reiterate that values derived in this section are indicative and have only been used for the purpose of performance comparison among the three (3) long-term transmission strategies.

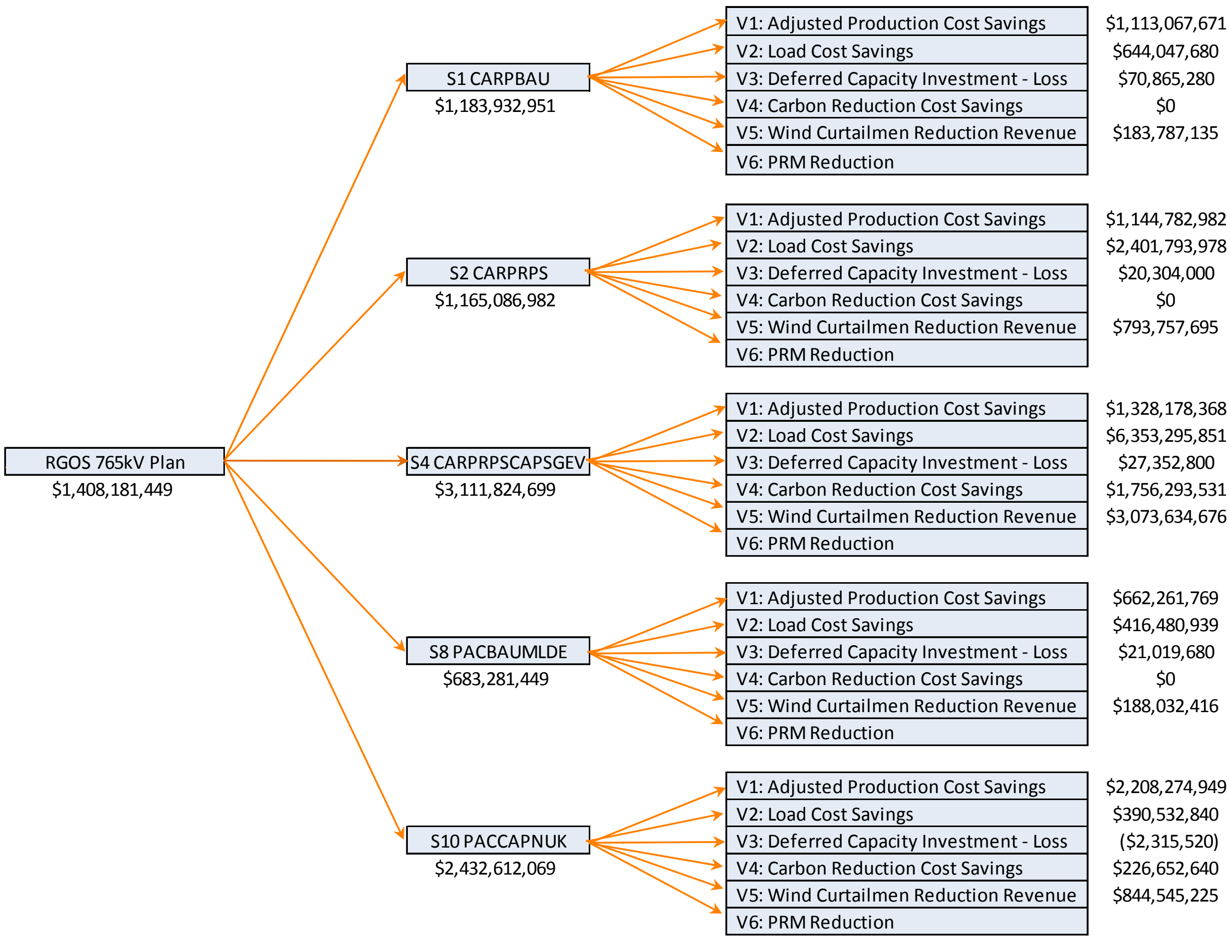

Figure 5.3-24: Indicative RGOS 765kV Plan Robustness Testing Results[5]

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[5] The RGOS transmission plans are still in development and the plan version used for robustness testing is as of May 25, 2010. All the results illustrated in the diagram are **2025 annual benefits** and are calculated for RGOS study footprint.

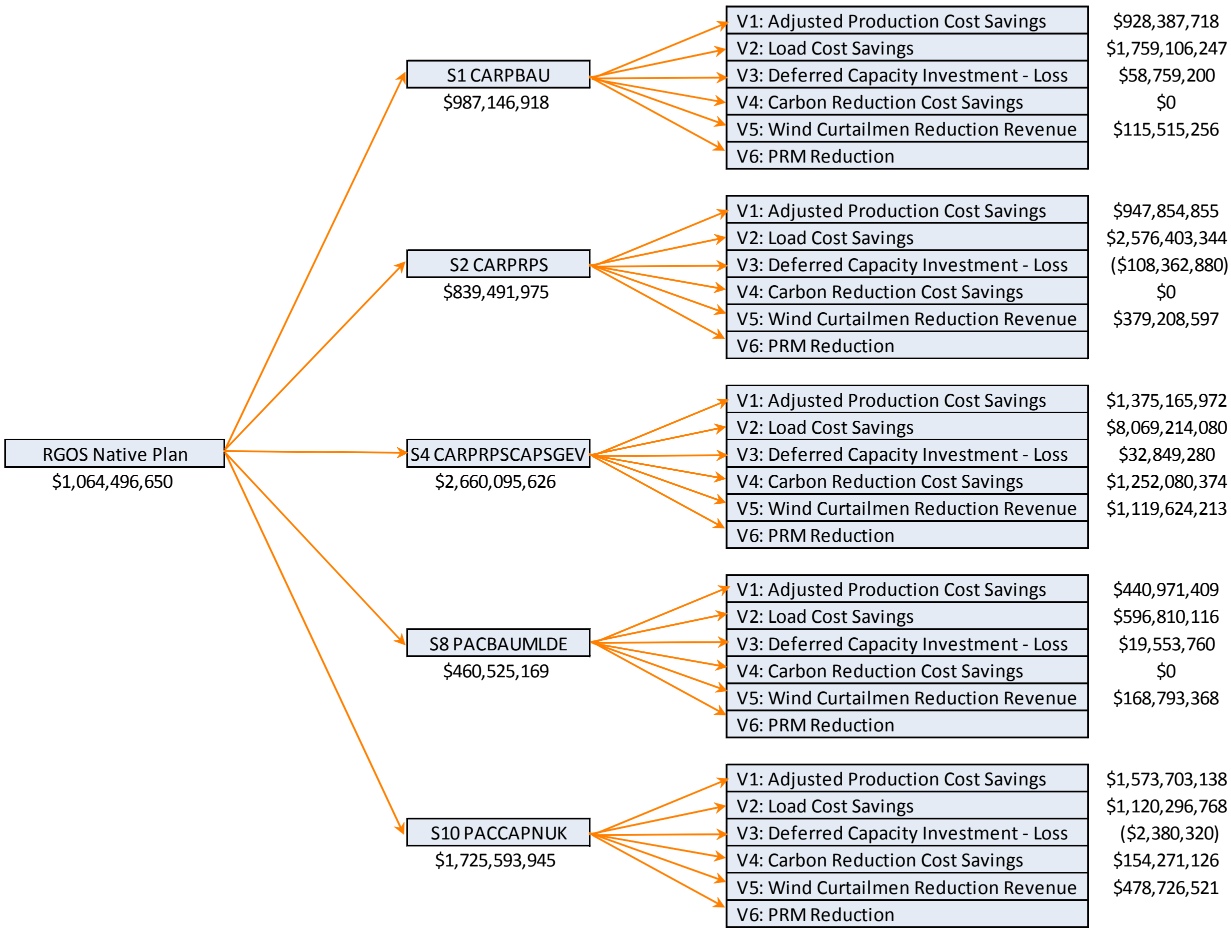

Figure 5.3-25: Indicative RGOS Native Voltage Plan Robustness Testing Results[6]

[6] The RGOS transmission plans are still in development and the plan version used for robustness testing is as of May 25, 2010. All the results illustrated in the diagram are **2025 annual benefits** and are calculated for RGOS study footprint.

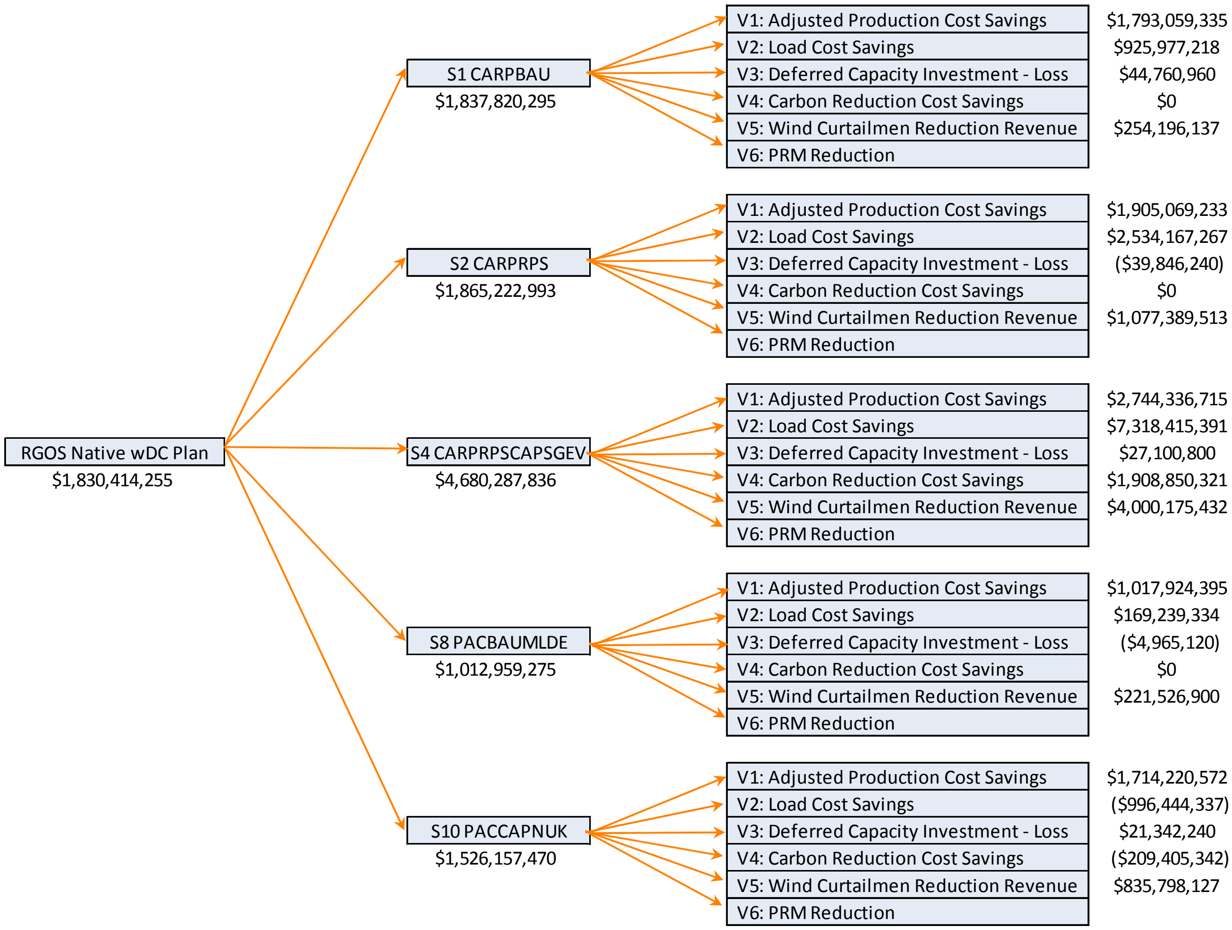

Figure 5.3-26: Indicative RGOS Native Voltage with DC Plan Robustness Testing Results[7]

[7] The RGOS transmission plans are still in development and the plan version used for robustness testing is as of May 25, 2010. All the results illustrated in the diagram are **2025 annual benefits** and are calculated for RGOS study footprint.

Table 5.3-25 summarizes the annual costs, financially quantifiable values, and benefit-to-cost ratios associated with each of the three (3) RGOS transmission plans. It shows the Native with DC option provides the highest benefit-to-cost ratio based on an annual analysis in year 2025. However, before determining an overall definitive long-term transmission strategy, an expanded business case analysis has to be in place with consideration of a more complete list of value measures. Each RGOS plan has its own risks and other pertinent factors that may significantly impact the way the preferred long-term strategy is identified, as described in section 1.

Table 5.3-25: RGOS Transmission Plan Cost and Benefit Comparison - 2025 USD in Millions

Transmission Plan Options	2025 Annual Transmission Cost [8]	2025 Annual Total Financially Quantifiable Value [9]	2025 B/C Ratio [10]
RGOS 765kV	4,684	1,408	0.30
RGOS Native	3,816	1,064	0.28
RGOS Native With DC	4,868	1,830	0.38

Table 5.3-26 shows results of some additional quantifiable benefits, not necessarily financially quantifiable, that can be incorporated into the decision-making process. Moving forward, Midwest ISO will continue to refine the list of value measures and develop a methodology to better utilize non-financially quantifiable value measures, as well as ensure extensive stakeholder involvement throughout the process.

Table 5.3-26: RGOS Transmission Plan Comparison – Other Quantifiable Measures

Transmission Plan Options	Acres of Right-of-way	Hourly Transmission Utilization (%) [11]
RGOS 765kV	136,637	17%
RGOS Native	126,637	16%
RGOS Native With DC	150,094	21%

[8] Annual cost in 2025$ is calculated using 18.3% the Midwest ISO annual average charge rate based 2010 attachment O and 3% escalation rate. The RGOS plans are assumed to be in service at 2019. It is important to note that the cost estimates are used for benefit-to-cost ratio calculation only.

[9] The total financially quantifiable value numbers are indicative and are subject to change depending on the assumptions on how to quantify the identified value measures and additional value measure development.

[10] The benefit-to-cost ratios are indicative and calculated using 2025 annual values only, **not** present values. The results are only intended to provide the comparison between transmission plans relative to each other.

[11] The percentage of hourly new transmission utilization is calculated for the CARPBAU future only, using the straight average of the hourly flows on the new RGOS transmission lines divided by the ratings.

6 Construction Cost Estimates

6.1 Estimating Assumptions

Cost of construction assumptions were developed through the study stakeholder process. Several assumptions were used to determine both capital and present value costs associated with the generation and transmission overlays developed. Table 6.1-1 and Table 6.1-2 summarize capital expenditures. Not shown in the tables is the cost for wind generation, which is $2M per MW (2010 USD).

Table 6.1-1: Line Mile Costs - $M/mile (2010 USD)

kV	IA	IL	IN	MI	MN	MO	MT	ND	OH	SD	WI
345	$1.6	$1.5	$2.0	$1.8	$1.8	$0.9	$1.4	$1.4	$2.0	$1.4	$2.1
2-345	$2.3	$2.0	$2.0	$2.7	$2.5	$2.3	$1.9	$1.9	$2.0	$1.9	$2.7
500	$2.1	$1.8	$1.8	$0.0	$2.4	$1.8	$1.8	$1.8	$1.8	$1.8	$2.8
765	$3.2	$2.8	$2.8	$3.6	$3.5	$3.2	$2.8	$2.8	$2.8	$2.8	$4.0
230	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75
161	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5
138	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5
115	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5
DC (OH)	$2.2	OH - Overhead Construction									
DC (Mar)	$3.0	Mar - Marine									

Table 6.1-2: Substation Costs (2010 USD)

kV	# Bays	($M)
115	2	$9.0
138	2	$9.0
161	2	$9.0
230	2	$9.0
345	2	$11.8
765	2	$25.1
DC Station +/-800 kV - Bi-Pole, 6400 MW		$549.0
DC Station +/- 400 kV - Bi-Pole 1000 MW		$340.0
Two bays (3 CBs)		

Table 6.1-3: Transformer Costs (2010 USD)

kV	($M)
765/345	$28.2
765/161	$20.7
765/138	$20.7
765/115	$20.7
345/230	$6.5
345/161	$5.7
345/138	$5.7
345/115	$5.7
Note 765 Transformers include on-site spare.	

Table 6.1-4: Reactive Costs (2010 USD)

kV	($M/MVAR)
345	$0.0224
765	$0.0560

Other factors used in developing capital costs included using a 50% multiplier for additions to existing substations. Existing substations were costed at half the price of a new substation unless more than two (2) bays were added, in which case no multiplier was applied. All transmission rebuilds were priced as new construction and a 1.1 multiplier was applied to all line mileages to account for adjustments in right-of-way calculations. River crossing costs included $14.0M (2010 USD) for each crossing of the Mississippi River and $7.0M for the Missouri River. Cost factors used to perform net present value calculations are shown in Tables 6.1-5 and 6.1-6.

Table 6.1-5: Net Present Value Factors

Value Factor	Generation	Transmission
Income Tax Rate	40.0%	40.0%
Inflation Rate	3.0%	3.0%
Book Life	20	40
Salvage	0	0

Table 6.1-5: Net Present Value Factors

Value Factor	Generation	Transmission
Tax Life	15	15
Discount Rate	7.0%	7.0%
O&M (% of Investment)	0.20%	0.20%

Table 6.1-6: Net Present Capitalization Cost Factors

Capitalization	Ratio of Fund	Cost of Fund
Bonds	50.00%	6.00%
Preferred	0.00%	7.50%
Common	50.00%	13.38%
Short Term Debt	0.00%	5.00%

6.2 Transmission Scenario Overlay Cost Estimate Results

Cost values were calculated on three levels, 2010 Capital, 2010 Levelized Annual and 2010 $/MWh (2010 USD) for generation and each of the three transmission overlays, Native Voltage (345 kV), 765 kV and Native DC. Capital costs represent the dollar amount if an entire overlay was built and paid for today. The levelized annual cost represents an equal payment to be made each year for the life of the respective overlay if the overlay was financed via typical utility options (represented by Table 6.2-1). A $/MWh value was calculated by dividing the 2010 levelized annual costs by the total annual delivered wind energy from the renewable energy zones.

Important in these calculations was the disbursement of capital dollars across the future investment horizon. An overlay of this magnitude will be constructed across several years. When that money will be spent is not yet known, so assumptions must be made. The assumption used is that the earliest investment would be in 2015 and the latest would be 2025. As noted in Section 1.4 Starter Projects, a set of initial transmission projects have been identified. The total costs for these initial projects were spread over the 2015-2018 horizon. Remaining overlay costs were then equally apportioned through 2025 for each overlay, respectively. For generation investment, the generation capital was rationed from 2015 through 2025 based on RPS requirements.

Line miles and substation costs were calculated on a state-by-state basis as well as Midwest ISO vs PJM. Transmission lines that had end point substations in both the Midwest ISO were considered a Midwest ISO investment and likewise for PJM. Some costs however, such as AC lines where the end substations were in different RTO's were calculated as Joint transmission investment. DC transmission and substations were calculated on a state-by-state basis, however, were also labeled as Joint with respect to Midwest ISO vs PJM.

Refer to Tables 6.2-1 to 6.2-7 on the following pages, which provide a detailed capital cost and net present value summary.

Table 6.2-1: Native Voltage (345 kV) 2010 Capital Costs

		IA	IL	IN	MI	MN	MO	MT	ND	OH	SD	WI	Total
New AC Transmission		$2,280	$1,051	$962	$222	$2,211	$317	$52	$1,435	$1,036	$855	$2,073	$12,495
	Midwest ISO	$2,280	$504	$372	$222	$2,211	$317	$52	$1,435	$380	$855	$2,073	$10,702
	PJM	$0	$547	$410	$0	$0	$0	$0	$0	$352	$0	$0	$1,309
	Joint	$0	$0	$180	$0	$0	$0	$0	$0	$304	$0	$0	$484
Upgraded AC Transmission		$196	$261	$165	$75	$0	$0	$0	$48	$40	$91	$116	$993
	Midwest ISO	$196	$56	$165	$75	$0	$0	$0	$48	$0	$91	$116	$748
	PJM	$0	$205	$0	$0	$0	$0	$0	$0	$40	$0	$0	$245
	Joint	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total AC Transmission		$2,476	$1,312	$1,127	$297	$2,211	$317	$52	$1,483	$1,076	$945	$2,190	$13,487
	Midwest ISO	$2,476	$560	$537	$297	$2,211	$317	$52	$1,483	$380	$945	$2,190	$11,449
	PJM	$0	$753	$410	$0	$0	$0	$0	$0	$391	$0	$0	$1,554
	Joint	$0	$0	$180	$0	$0	$0	$0	$0	$304	$0	$0	$484
DC Transmission (Joint)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
River Crossings (Midwest ISO)		$14	$14	$0	$0	$14	$7	$0	$14	$0	$0	$14	$77
AC Substations		$396	$291	$162	$120	$169	$169	$46	$413	$451	$121	$399	$2,737
	Midwest ISO	$396	$215	$96	$120	$169	$169	$46	$413	$195	$121	$399	$2,338
	PJM	$0	$77	$66	$0	$0	$0	$0	$0	$256	$0	$0	$398
DC Substations (Joint)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total		$2,887	$1,618	$1,289	$417	$2,394	$493	$98	$1,910	$1,526	$1,066	$2,603	$16,301
	Midwest ISO	$2,887	$788	$633	$417	$2,394	$493	$98	$1,910	$575	$1,066	$2,603	$13,865
	PJM	$0	$829	$476	$0	$0	$0	$0	$0	$647	$0	$0	$1,952
	Joint	$0	$0	$180	$0	$0	$0	$0	$0	$304	$0	$0	$484
	DC	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Table 6.2-2: Native Voltage (345 kV) 2010 Net Present Value

	Capital Costs in 2010 USD ($M)				NPV of Revenue Requirements (2010, $M)			
Year	**Midwest ISO**	**PJM**	**Joint**	**Total**	**Midwest ISO**	**PJM**	**Joint**	**Total**
2015	$1,047	$257	$121	$1,424	$1,382	$339	$160	$1,880
2016	$1,047	$257	$121	$1,424	$1,330	$326	$154	$1,810
2017	$1,047	$257	$121	$1,424	$1,280	$314	$148	$1,742
2018	$1,047	$257	$121	$1,424	$1,233	$302	$142	$1,677
2019	$1,382	$132	$0	$1,515	$1,567	$150	$0	$1,717
2020	$1,382	$132	$0	$1,515	$1,508	$144	$0	$1,652
2021	$1,382	$132	$0	$1,515	$1,452	$139	$0	$1,591
2022	$1,382	$132	$0	$1,515	$1,397	$134	$0	$1,531
2023	$1,382	$132	$0	$1,515	$1,345	$129	$0	$1,474
2024	$1,382	$132	$0	$1,515	$1,295	$124	$0	$1,419
2025	$1,382	$132	$0	$1,515	$1,247	$119	$0	$1,366
Total	$13,865	$1,952	$484	$16,301	$15,036	$2,219	$604	$17,859
Levelized Annual Cost					$1,419	$209	$57	$1,686
$/MWh					$16.0	$2.4	$0.6	$19.0

Table 6.2-3: 765 kV 2010 Capital Costs

Transmission Type		IA	IL	IN	MI	MN	MO	MT	ND	OH	SD	WI	Total
New AC Transmission		$3,592	$2,206	$1,115	$222	$1,924	$1,732	$52	$1,477	$965	$722	$1,313	$15,322
	Midwest ISO	$3,592	$476	$10	$222	$1,924	$1,514	$52	$1,477	$375	$722	$1,264	$11,629
	PJM	$0	$1,514	$418	$0	$0	$218	$0	$0	$588	$0	$0	$2,738
	Joint	$0	$215	$687	$0	$0	$0	$0	$0	$3	$0	$49	$955
Upgraded AC Transmission		$367	$112	$0	$0	$0	$8	$0	$18	$0	$337	$150	$992
	Midwest ISO	$167	$112	$0	$0	$0	$0	$0	$0	$0	$159	$150	$588
	PJM	$201	$0	$0	$0	$0	$8	$0	$18	$0	$177	$0	$404
	Joint	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total AC Transmission		$3,959	$2,318	$1,115	$222	$1,924	$1,741	$52	$1,495	$965	$1,059	$1,463	$16,314
	Midwest ISO	$3,758	$588	$10	$222	$1,924	$1,514	$52	$1,477	$375	$882	$1,415	$12,217
	PJM	$201	$1,514	$418	$0	$0	$226	$0	$18	$588	$177	$0	$3,142
	Joint	$0	$215	$687	$0	$0	$0	$0	$0	$3	$0	$49	$955
DC Transmission (Joint)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
River Crossings (Midwest ISO)		$14	$14	$0	$0	$14	$7	$0	$14	$0	$0	$14	$77
AC Substations		$435	$718	$214	$146	$584	$344	$41	$447	$379	$205	$346	$3,858
	Midwest ISO	$435	$106	$50	$146	$584	$344	$41	$447	$101	$205	$346	$2,805
	PJM	$0	$612	$164	$0	$0	$0	$0	$0	$278	$0	$0	$1,054
DC Substations (Joint)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total		$4,408	$3,049	$1,329	$367	$2,522	$2,092	$94	$1,956	$1,344	$1,263	$1,823	$20,249
	Midwest ISO	$4,207	$708	$60	$367	$2,522	$1,866	$94	$1,938	$476	$1,086	$1,775	$15,099
	PJM	$201	$2,126	$582	$0	$0	$226	$0	$18	$865	$177	$0	$4,196
	Joint	$0	$215	$687	$0	$0	$0	$0	$0	$3	$0	$49	$955
	DC	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Table 6.2-4: 765 kV 2010 Net Present Value

	Capital Costs in 2010 USD ($M)				NPV of Revenue Requirements (2010, $M)			
Year	**Midwest ISO**	**PJM**	**Joint**	**Total**	**Midwest ISO**	**PJM**	**Joint**	**Total**
2015	$1,047	$257	$121	$1,424	$1,382	$339	$160	$1,880
2016	$1,047	$257	$121	$1,424	$1,330	$326	$154	$1,810
2017	$1,047	$257	$121	$1,424	$1,280	$314	$148	$1,742
2018	$1,047	$257	$121	$1,424	$1,233	$302	$142	$1,677
2019	$1,559	$453	$67	$2,079	$1,767	$513	$76	$2,356
2020	$1,559	$453	$67	$2,079	$1,700	$494	$73	$2,268
2021	$1,559	$453	$67	$2,079	$1,637	$476	$71	$2,183
2022	$1,559	$453	$67	$2,079	$1,576	$458	$68	$2,101
2023	$1,559	$453	$67	$2,079	$1,517	$441	$65	$2,023
2024	$1,559	$453	$67	$2,079	$1,460	$424	$63	$1,947
2025	$1,559	$453	$67	$2,079	$1,406	$408	$61	$1,874
Total	$15,099	$4,196	$955	$20,249	$16,287	$4,494	$1,081	$21,862
				Levelized Annual Cost	$1,537	$424	$102	$2,064
				$/MWh	$17.4	$4.8	$1.2	$23.3

Table 6.2-5: Native DC 2010 Capital Costs

Transmission Type		IA	IL	IN	MI	MN	MO	MT	ND	OH	SD	WI	Total
New AC Transmission		$1,967	$1,271	$735	$1,013	$1,906	$383	$52	$1,684	$1,279	$928	$851	$12,070
	Midwest ISO	$1,967	$681	$255	$1,013	$1,906	$383	$52	$1,684	$419	$928	$851	$10,140
	PJM	$0	$590	$480	$0	$0	$0	$0	$0	$587	$0	$0	$1,657
	Joint	$0	$0	$0	$0	$0	$0	$0	$0	$273	$0	$0	$273
Upgraded AC Transmission		$0	$126	$20	$109	$0	$0	$0	$0	$40	$0	$297	$592
	Midwest ISO	$0	$111	$20	$109	$0	$0	$0	$0	$0	$0	$297	$537
	PJM	$0	$15	$0	$0	$0	$0	$0	$0	$40	$0	$0	$55
	Joint	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total AC Transmission		$1,967	$1,397	$755	$1,123	$1,906	$383	$52	$1,684	$1,319	$928	$1,148	$12,662
	Midwest ISO	$1,967	$792	$275	$1,123	$1,906	$383	$52	$1,684	$419	$928	$1,148	$10,677
	PJM	$0	$605	$480	$0	$0	$0	$0	$0	$627	$0	$0	$1,712
	Joint	$0	$0	$0	$0	$0	$0	$0	$0	$273	$0	$0	$273
DC Transmission (Joint)		$1,079	$719	$837	$121	$269	$539	$0	$0	$239	$11	$121	$3,935
River Crossings (Midwest ISO)		$14	$14	$0	$0	$14	$7	$0	$14	$0	$0	$14	$77
AC Substations		$170	$356	$127	$299	$161	$112	$46	$446	$387	$105	$124	$2,334
	Midwest ISO	$170	$268	$68	$287	$161	$112	$46	$446	$121	$105	$124	$1,908
	PJM	$0	$89	$59	$13	$0	$0	$0	$0	$266	$0	$0	$426
DC Substations (Joint)		$549	$412	$0	$170	$275	$0	$0	$0	$686	$275	$170	$2,536
Total		$3,778	$2,899	$1,719	$1,713	$2,626	$1,042	$98	$2,144	$2,631	$1,319	$1,577	$21,544
	Midwest ISO	$2,150	$1,074	$343	$1,409	$2,082	$502	$98	$2,144	$540	$1,033	$1,286	$12,662
	PJM	$0	$694	$539	$13	$0	$0	$0	$0	$893	$0	$0	$2,138
	Joint	$0	$0	$0	$0	$0	$0	$0	$0	$273	$0	$0	$273
	DC	$1,628	$1,131	$837	$291	$544	$539	$0	$0	$925	$286	$291	$6,471

Table 6.2-6: Native DC 2010 Net Present Value

	Capital Costs in 2010 USD ($M)				NPV of Revenue Requirements (2010, $M)			
Year	**Midwest ISO**	**PJM**	**Joint/DC**	**Total**	**Midwest ISO**	**PJM**	**Joint/DC**	**Total**
2015	$1,047	$257	$121	$1,424	$1,382	$339	$160	$1,880
2016	$1,047	$257	$121	$1,424	$1,330	$326	$154	$1,810
2017	$1,047	$257	$121	$1,424	$1,280	$314	$148	$1,742
2018	$1,047	$257	$121	$1,424	$1,233	$302	$142	$1,677
2019	$1,211	$159	$894	$2,264	$1,372	$180	$1,014	$2,566
2020	$1,211	$159	$894	$2,264	$1,321	$173	$976	$2,470
2021	$1,211	$159	$894	$2,264	$1,271	$167	$939	$2,377
2022	$1,211	$159	$894	$2,264	$1,224	$161	$904	$2,288
2023	$1,211	$159	$894	$2,264	$1,178	$155	$870	$2,203
2024	$1,211	$159	$894	$2,264	$1,134	$149	$838	$2,121
2025	$1,211	$159	$894	$2,264	$1,092	$143	$806	$2,041
Total	$12,662	$2,138	$6,744	$21,544	$13,816	$2,408	$6,950	$23,175
				Levelized Annual Cost	$1,304	$227	$656	$2,188
				$/MWh	$14.7	$2.6	$7.4	$24.7

Table 6.2-7: Generation 2010 Net Present Value

	Capital Costs in 2010 USD ($M)			NPV of Revenue Requirements (2010, $M)		
Year	**Midwest ISO**	**PJM**	**Total**	**Midwest ISO**	**PJM**	**Total**
2015	$22,305	$3,990	$26,289	$28,366	$5,074	$33,434
2016	$3,136	$1,007	$4,144	$3,839	$1,233	$5,073
2017	$2,550	$794	$3,344	$3,005	$936	$3,941
2018	$2,947	$1,055	$4,002	$3,343	$1,197	$4,540
2019	$1,394	$835	$2,230	$1,522	$912	$2,435
2020	$2,828	$1,092	$3,921	$2,973	$1,148	$4,122
2021	$3,871	$871	$4,741	$3,917	$881	$4,797
2022	$1,520	$1,154	$2,675	$1,481	$1,124	$2,606
2023	$1,549	$1,183	$2,734	$1,453	$1,109	$2,563
2024	$1,586	$1,210	$2,797	$1,431	$1,092	$2,524
2025	$1,051	$172	$1,223	$914	$149	$1,063
Total	$44,737	$13,363	$58,100	$52,244	$14,856	$67,098
			Levelized Annual Cost	$4,931	$1,402	$6,334
					$/MWh	
			Native Voltage	$55.7	$15.8	$71.5
			765 kV	$55.7	$15.8	$71.5
			Native DC	$55.7	$15.8	$71.5

7 RGOS 2011 Candidate MVP Portfolio Selection

Although RGOS focused on the development of holistic system solutions meeting long-term needs for the integration of renewable resources into the transmission system, it is important to identify an initial group of projects that are compatible with the three overlays that provide a practical first step towards meeting the renewable resource requirements. Midwest ISO staff has developed an analytical framework to identify the best potential transmission projects. These RGOS-identified projects will require additional, more detailed analysis. Because a Midwest ISO long-range transmission expansion strategy has not yet been determined and was not within the analytical scope of this study, it is important to note that the potential transmission projects do not pre-determine Midwest ISO long-range strategic aims. It is also important to note that these transmission projects prove compatible with all potential strategies.

7.1 Candidate Multi-Value Project Identification Process

The RGOS inputs into the Candidate Multi-Value Projects (MVPs) portfolio were identified by means of the process outlined below. Please note that other studies were considered in collecting the Candidate MVP portfolio; not all of the projects in that portfolio are from the RGOS study effort.

Step 1: Identify useful corridors common to multiple Midwest ISO studies.

Corridors represent general paths for transmission that do not discriminate between voltages or potential intermediate connection points. Studies to be considered when identifying corridors include the following:

- Regional Generation Outlet Study overlay development results
- Generation Interconnection studies:
  - Definitive Planning Phase (DPP)
  - System Planning and Analysis (SPA)
- MTEP related studies:
  - MTEP Appendix B and C projects, which address future reliability concerns
  - Top congested flowgate studies
  - Cross-border top congested flowgate studies
  - Narrowly constrained areas

Step 2: Identify RPS timing needs and synchronize with Generation Interconnection Queue (GIQ) locations.

Refer to Table 7.1-1, which shows renewable portfolio requirements starting in 2015. All states within Midwest ISO with RPS mandates or load-serving entity goals are listed.

Table 7.1-1: Renewable Portfolio Standard Requirements

Year	WI	MN (w/o Xcel)	Xcel MN	IL	MI	OH	MO	MT	PA	SD	ND	IA
	(Of Energy Served)											(MW)
2015	10.0%	12.0%	18.0%	10.0%	10.0%	3.5%	5.0%	15.0%	5.5%	10.0%	10.0%	105
2016	10.0%	17.0%	25.0%	11.5%	10.0%	4.5%	5.0%	15.0%	6.0%	10.0%	10.0%	105
2017	10.0%	17.0%	25.0%	13.0%	10.0%	5.5%	5.0%	15.0%	6.5%	10.0%	10.0%	105
2018	10.0%	17.0%	25.0%	14.5%	10.0%	6.5%	10.0%	15.0%	7.0%	10.0%	10.0%	105
2019	10.0%	17.0%	25.0%	16.0%	10.0%	7.5%	10.0%	15.0%	7.5%	10.0%	10.0%	105
2020	10.0%	20.0%	30.0%	17.5%	10.0%	8.5%	10.0%	15.0%	8.0%	10.0%	10.0%	105
2021	10.0%	20.0%	30.0%	19.0%	10.0%	9.5%	15.0%	15.0%	8.0%	10.0%	10.0%	105
2022	10.0%	20.0%	30.0%	20.5%	10.0%	10.5%	15.0%	15.0%	8.0%	10.0%	10.0%	105
2023	10.0%	20.0%	30.0%	22.0%	10.0%	11.5%	15.0%	15.0%	8.0%	10.0%	10.0%	105
2024	10.0%	20.0%	30.0%	23.5%	10.0%	12.5%	15.0%	15.0%	8.0%	10.0%	10.0%	105
2025	10.0%	25.0%	30.0%	25.0%	10.0%	12.5%	15.0%	15.0%	8.0%	10.0%	10.0%	105

Locations of generation interconnection queue requests to the Midwest ISO transmission system can be seen in Figure 7.1-1. This map represents wind queue locations as of the end of July, 2010.

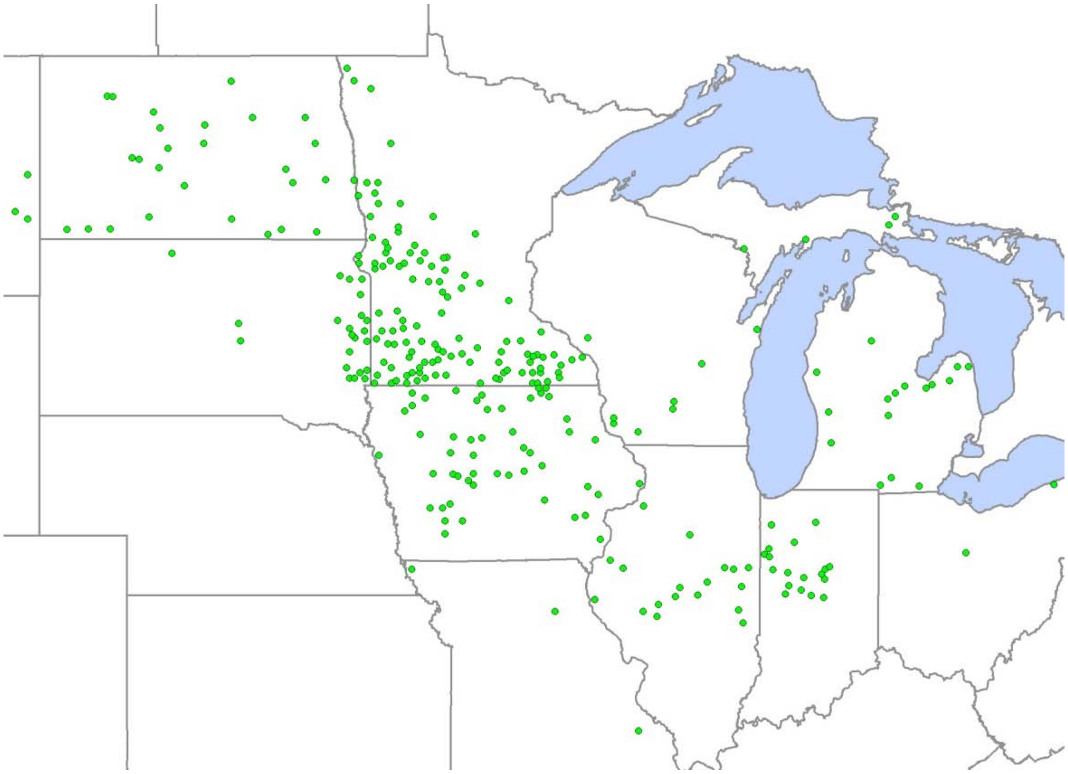

Figure 7.1-1: Location of Midwest ISO Generation Interconnection Queue Requests

Step 3: Evaluate constructability of transmission.

Construction dynamics possibly requiring longer lead times for projects include the following:

- Interstate transmission coordination
- River crossings
- Commonsense coordination of projects; i.e., a group of lines may not make sense until another group is constructed first
- Midwest ISO/PJM cross-border projects

Certain projects may have shorter lead times; for example, when stringing second circuits on “existing” double circuit capable transmission structures.

7.1.1 RGOS-identified Candidate Multi-Value Projects

An initial set of transmission projects was identified using the inspection steps described in section 1, and served as an input into the design of the overall Candidate MVP portfolio. Selected Candidate MVPs are compatible with RGOS-developed overlays and provide potential value for other needs identified within the transmission system, such as congestion relief and mitigation of reliability concerns. Refer to Figure 7.1-2, which depicts Candidate MVPs from the RGOS analysis. Estimated cost for this RGOS Candidate MVP set is approximately $5.8 Billion (2010 USD), $4.4 billion of which is within Midwest ISO borders.

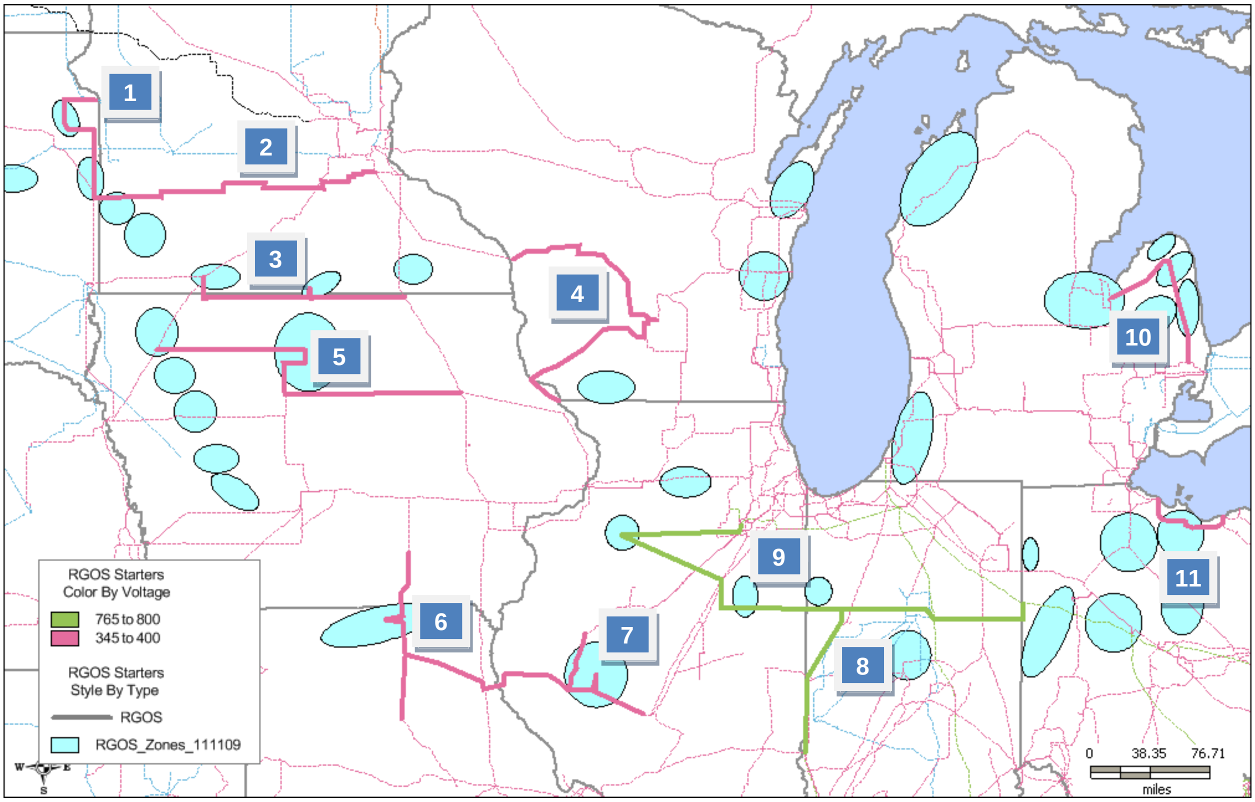

Figure 7.1-2: RGOS-identified Candidate Multi-Value Projects

The following numbered list corresponds to the numbered identifiers in Figure 7.1-2 and furnishes additional details on the rationale guiding specific Candidate MVP selection.

1. **Big Stone to Brookings 345 kV line (2010 estimated installed cost: $150M):** This line provides access to and collection from renewable energy areas located in the eastern South Dakota portion of the Buffalo Ridge area. This corridor is identified in all RGOS overlays at the 345 kV voltage level. The corridor is also compatible with current Generation Interconnection Queue (GIQ) locations.

2. **Brookings to Twin Cities 345 kV line (2010 estimated installed cost: $700M):** This line, as approved the Minnesota Public Utilities Commission, delivers energy from the Buffalo Ridge area to a major load center in the Twin Cities and beyond. This 345 kV project also provides collection points for renewable energy, as well as reliability benefits. This corridor is identified in all RGOS overlay scenarios, although at different voltage levels. Proceeding with 345 kV construction does not negate a long-range 765 kV transmission expansion strategy. The 765 kV strategy can be adjusted to accommodate this selection.

3. **Lakefield Junction to Mitchell County 345 kV line constructed at 765 kV specifications (2010 estimated installed cost: $600M):** This line provides for an additional West to East path for energy delivery from the Buffalo Ridge area. This corridor has been identified in all of the RGOS overlays, as well as in other studies such as the Top Congested Flowgate analysis in the 2009 MTEP process and recent GIQ SPA analysis. This corridor is also compatible to collect resources associated with current GIQ locations. By developing this corridor using 765 kV construction, all potential long-term strategies remain viable.

4. **North LaCrosse to North Madison to Cardinal, Dubuque to Spring Green to Cardinal 345 kV lines (2010 estimated installed cost: $811M):** The development of these corridors will provide for the continuation and extension of the west to east transmission path to provide more areas with greater access to the high wind areas within the Buffalo Ridge and beyond. These corridors are compatible with the RGOS overlays as well as other studies such as the GIQ SPA and DPP studies. These projects can be well-integrated regardless of the long-range transmission expansion strategy adopted by Midwest ISO; e.g., Native Voltage, 765 kV, and 345 kV plus DC.

5. **Sheldon to Webster to Blackhawk to Hazleton 345 kV line (2010 estimated installed cost: $458M):** This set of transmission projects provides both a collection of renewable energy in high wind areas and an additional west to east transmission path for delivery of energy to other parts of the study footprint. This combination of collection and delivery is compatible with the RGOS overlays (with proper adjustments made) and has shown to be compatible with corridors identified within the GIQ SPA studies.

6. **Ottumwa to Adair to Thomas Hill, Adair to Palmyra 345 kV lines (2010 estimated installed cost: $295M):** This set of transmission is compatible with the all RGOS overlays and provides access to quality wind resources within the Midwest ISO footprint in Missouri. This corridor development provides an additional north to south path and begins a new west to east transmission path for energy delivery across the footprint.

7. **Palmyra to Meredosia to Pawnee, Ipava to Meredosia 345 kV lines (2010 estimated installed cost: $345M):** This transmission is compatible with the RGOS overlays and provides access to quality Illinois wind potential located within the Midwest ISO footprint. These lines provide reliability support to the Ipava area with the new 345 kV connections. It also continues the new west to east path that will help bridge some of the market constraints across Illinois.

8. **Sullivan to Meadow Lake to Greentown to Blue Creek 765 kV line (2010 estimated installed cost: $908M):** 765 kV transmission is native to Indiana. This transmission plan is part of the 765 kV overlay but can also be compatible with the other overlays such as the 345 kV lines discussed previously. This transmission provides access to the wind potential in the Benton County area of Indiana and provides an additional west to east energy delivery route. Both Midwest ISO and PJM generation interconnection queues include potential resources in this area. It will also provide the completion of a 765 kV loop within Indiana to help mitigate some of the market constraints associated with the existing Rockport to Jefferson 765 kV line. A similar line was identified as a potential solution to constraints associated with the Southwest Indiana generation energy delivery. Note a version of this project was previously proposed as a joint project between PJM and Midwest ISO. Because of this, costs may be split between Midwest ISO and PJM and would—in the event of a joint project undertaking—also require a coincident PJM analysis.

9. **Collins to Kewanee to Pontiac to Meadow Lake 765 kV line (2010 estimated installed cost: $964M):** 765 kV transmission is native to the PJM system in northern Illinois and Indiana. This corridor is identified primarily within the 765 kV overlay. However, it does have corridor compatibility within the other overlays. As previously discussed, Native Voltage and Native Voltage with DC transmission can both be adjusted appropriately to provide compatibility with any of the strategies. This line provides a second EHV path from the Chicago area to the east. It also provides a potential solution to the Wilton to Dumont related constraints that provides three (3) of the top 20 historical top congested flowgates within the Midwest ISO market. With the increasing pressure of wind within the Midwest ISO and the PJM portion of Illinois, specifically the Kewanee area, this transmission line will help release known and projected congestion associated with the transmission systems along Lake Michigan's southern shore.

10. **Michigan Thumb 345 kV transmission loop (2010 estimated installed cost: $510M):** This loop was evaluated under an Out-of-Cycle process for inclusion in MTEP10 Appendix A and approved by the Midwest ISO Board of Directors (BOD) in its August meeting. This accelerated review was required to meet the near-time needs of the Michigan renewable energy mandate. This transmission is compatible with the all of the strategies within the RGOS analysis and gives access to a high wind potential area within Michigan.

11. **Davis Besse to Beaver 345 kV line (2010 estimated installed cost: $71M):** This transmission provides access to and delivery of wind energy potential located around the shores of Lake Erie within Ohio. There is GIQ generation in the area and the transmission is identified within all of the RGOS-developed transmission strategies.

8 Going Forward

RGOS provides industry stakeholders and policy makers with a regional planning perspective identifying potential investment opportunities and demonstrating the integration of renewable energy policies into electrical system development. The purpose of the RGOS transmission development effort has been to explore long-term transmission strategies ensuring study-defined reliability objectives in delivery of renewable energy as well as compliance with RPS mandates encompassing states within the study footprint.

No consensus exists regarding the amount of renewable generation ultimately needed to comply with current and future RPS mandates. Some assert a much higher level of wind generation will be required than those included in RGOS analyses while others claim a lower amount. Regardless of the long-term uncertainties engendered by expansion or reduction of renewable energy standards, states within the Midwest ISO system will need new transmission to meet current and near-term renewable energy requirements, ensure reliable operation of the transmission grid, relieve current and projected areas of congestion, and facilitate the generation interconnection queue process.

As a result of the RGOS effort, Midwest ISO has identified the next, most immediate step to transmission investment: a set of robust Candidate Multi-Value Projects (MVPs) meeting current renewable energy mandates and the regional reliability needs of its members. This Candidate MVP project portfolio, comprised of results from RGOS, multiple congestion studies, and numerous generation interconnection studies, will undergo rigorous analysis as a first step towards a regional transmission plan to meet the policy driven needs of the states in the Midwest ISO footprint.

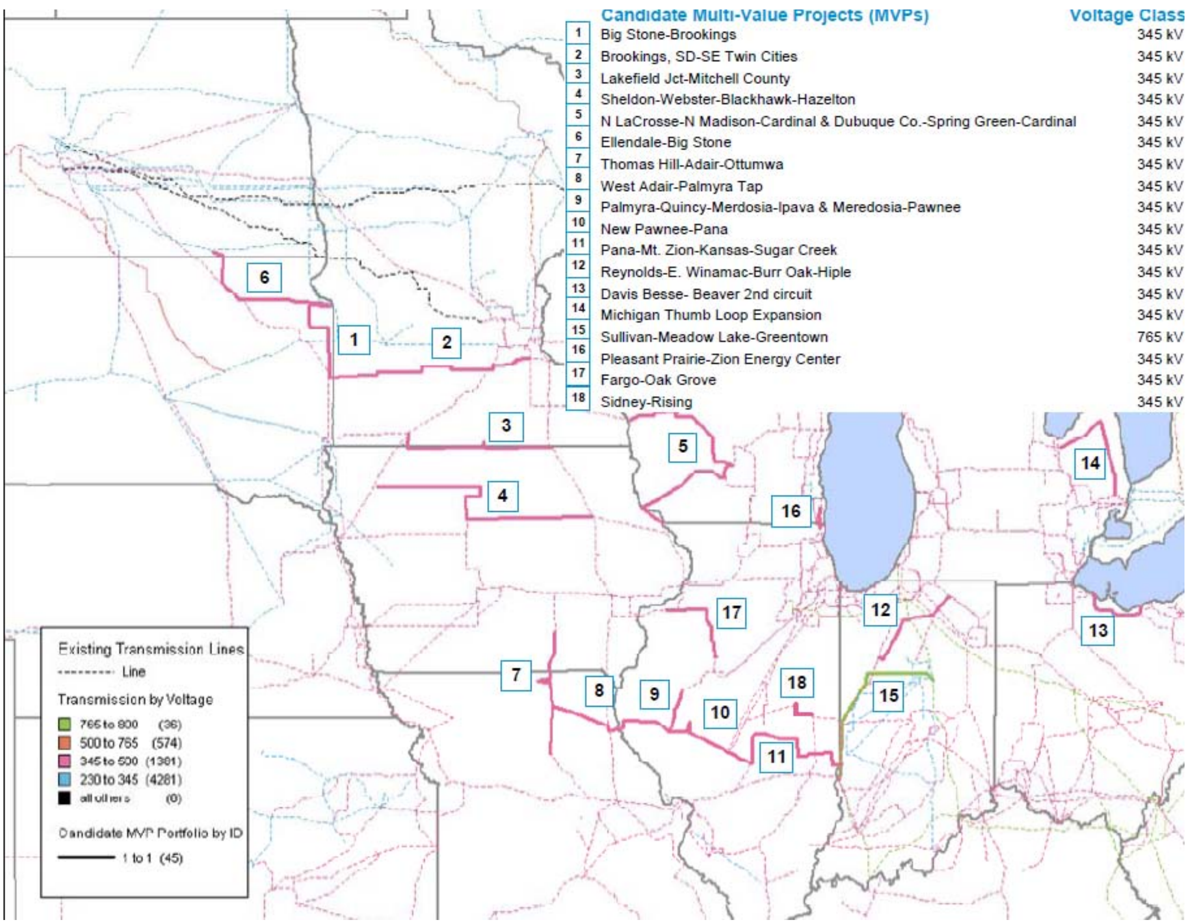

Figure 8-1: Proposed Midwest ISO Candidate Multi-Value Project Portfolio #1

Candidate MVP portfolio analysis is designed to be a fluid, adaptable, and dynamic planning approach based upon the concept of providing a high level of benefits relative to project cost under a number of different future possibilities, culminating in a regional plan that reliably and efficiently delivers value to load. In the MTEP11 study cycle, this portfolio will be thoroughly evaluated to ensure project value and to confirm system reliability with all Candidate MVPs included, with a goal of moving any applicable projects to MTEP Appendix A as MVPs. In 2012 and subsequent years, Candidate MVP portfolio analyses will continue to develop portfolios addressing long-term system value drivers and needs.

A Candidate MVP portfolio has been identified by analyzing transmission needs from multiple transmission and economic studies, which include the following:

- RGOS
- Studies conducted in the generation interconnection process
- Congestion studies such as the Top Congested Flowgate Study and the Cross Border Congested Flowgate Study
- MTEP reliability studies

Transmission solutions from these studies were evaluated for comparability and ability to be built within the near-term. These projects will continue to be evaluated in more detail into 2011, both to ensure project robustness and to confirm system reliability with inclusion of the Candidate MVP portfolio. This analysis was previously referred to as “Starter Project” analysis, but nomenclature was modified to further align its evaluation with the July 15th cost allocation filing at FERC.

Candidate MVP analyses will be used to find the total value of the portfolio of proposed projects, and using reliability and economic analyses, to determine if these projects are eligible for MVP cost allocation. To ensure total value of the projects is accurately captured, Midwest ISO will continue to refine and develop the set of metrics and methodology used to evaluate the total value of a portfolio of projects in the robustness testing step discussed in section 4. This refinement will take place with heavy stakeholder involvement through such forums as the Planning Advisory Committee (PAC) and the Planning Subcommittee (PS).

Appendix 1: Site Selection Methodology

A1.1 Developing Wind Resource Datasets

In this task, high resolution (2km x 2km) mesoscale wind data was developed for years 2004, 2005, and 2006 in 10-minute intervals at various hub heights. Mesoscale is a term used to describe a three dimensional numerical weather model. AWS Truewind determined the best mesoscale model and configuration to use for developing its high resolution wind resource dataset by testing and validating a number of potential modeling configurations. The validation covered one full year of simulations and compared the results with actual wind measurements from ten measurement sites throughout the study region. Results of this model included, temperature, pressure, wind speed, wind direction, wind density, turbulent kinetic energy at five heights, specific humidity, incoming long-wave and short-wave radiation and precipitation. With a validated mesoscale wind dataset it was then possible to model power output for various wind farm configurations at various hub heights.

A1.1.1 Site Selection Process

The goal of this task was to identify potential wind sites in the study region, both on-shore and off-shore, with a combined total rated capacity of at least 3,000 gigawatts (GW). An additional task, through a selection process, was to identify a subset of those wind sites totaling 600,000 megawatts (MW) from which to develop a wind database.

Providing a consistent set of resource estimates for ranking and selecting sites required the preparation of a seamless map of 11-year average wind speeds at 80 meters height for the EWITS region. A representative example wind speed map is shown in Figure A1.1-1. The map has been rendered using Ventyx Velocity Suite[12] and is a representation of wind resources across the United States. The data was compiled from both state and regional sources; thus, level of detail may vary. The scale ranges from Class 1 winds under 12.5 mph to Class 7 winds over 19.7 mph. This image is displayed at 500-meter resolution. While the EWITS and JCSP study regions were the same, wind data was not produced for entirety of the study regions because of time and cost considerations, plus lack of potential wind sites. The map in Figure A1.1.-2 shows the site selection wind development area.

[12] Ventyx®, Velocity Suite© 2008

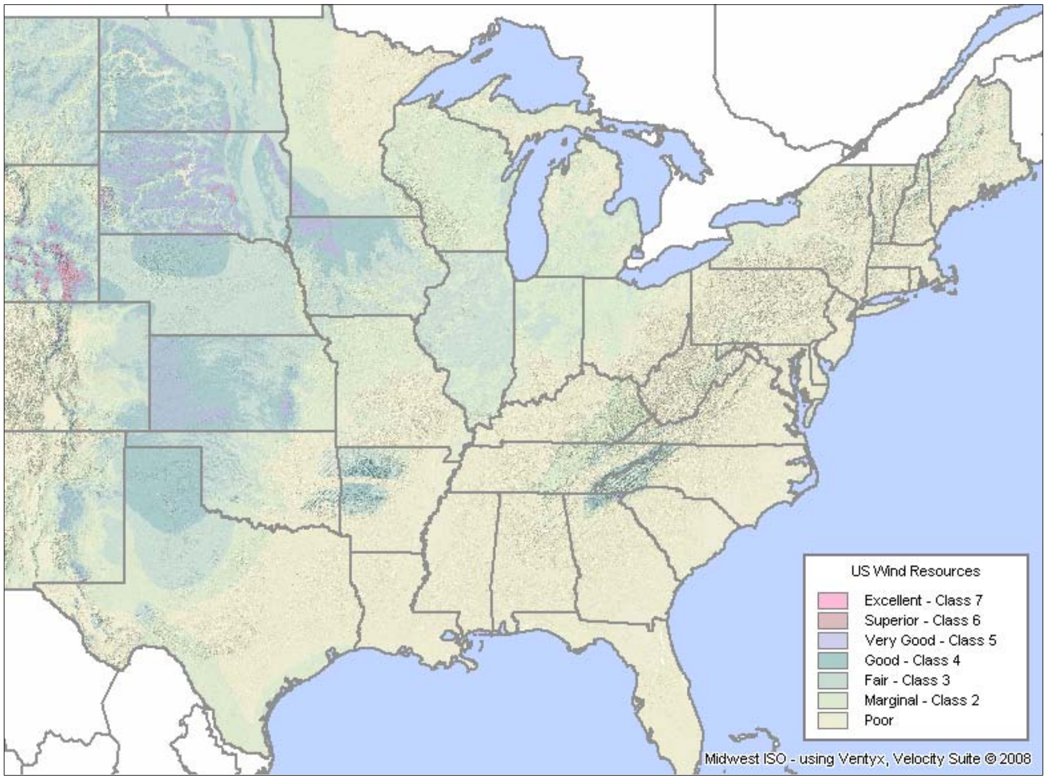

Figure A1.1-1: Example of US Wind Resource Map

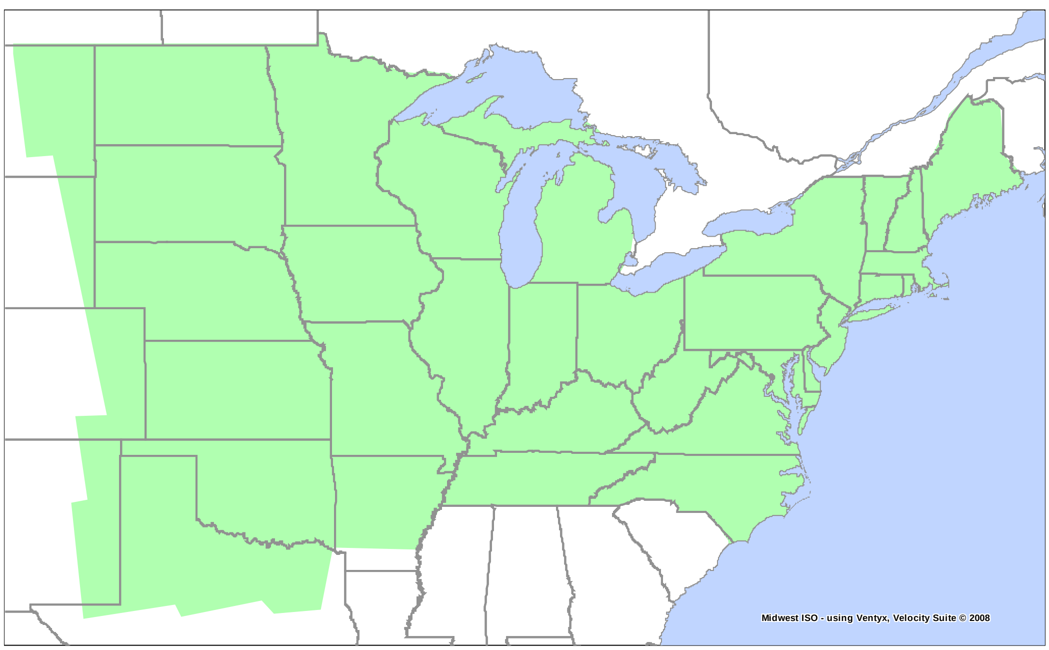

Figure A1.1-2: Site Selection Wind Development Area

Using the 11-year average wind speed at 80 meters, a map of the estimated net capacity factor for a composite IEC Class 2 wind turbine was then created.

These maps are created using Geographic Information System (GIS) software, which allows the spatial representation of the data on a map in unique layers. In addition to capacity factor, other layers such as land area, topography, lakes, rivers, cities, metropolitan areas, state and federal lands, airports, slope, etc. were utilized. Using the capacity factor map and an assumption for how many wind turbines could be placed in a specified area allows estimation of total potential wind capacity and energy in the Eastern United States. Any areas where it is undesirable or impossible for wind turbines to be located were excluded from consideration. With a capacity factor map layer combined with an exclusion map layer, the net potential wind development could be determined for the study region. Maps of exclusion areas to apply to the site selection process were created and the various criteria are listed below.

- Maps Layers from the USGS National Land Cover Database (2001):
  - Open Water
  - 200m buffer of Developed Low Intensity
  - 500m buffer of Developed Medium Intensity
  - 500m buffer of Developed High Intensity
  - Woody Wetlands
  - Emergent Herbaceous Wetland
- Map Layers from the ESRI data base:
  - Parks
  - Parks Detailed
  - Federal Lands (non – public)
  - 10,000ft buffer of small airports (all hub sizes)
  - 20,000ft buffer of large airports (hub sizes medium and large)
- Map Layers from the Conservation Biology Institute:
  - GPACT value of 1, 2, 7 & 8 (Typically these are managed areas, public and private)
- Map Layers from Other Sources:
  - Slopes greater than 20%
  - Areas outside the study region

Several methodologies were used to further prioritize the potential wind farms. The AWS Truewind site-screening program builds wind farms one grid cell at a time with 2km x 2km resolution, adding grids to the farm until an exclusion area boundary is met. A wind farm produced could be as small as 2km x 2 km or extremely large in rural areas. It was therefore necessary to specify a minimum and maximum size wind farm to ensure reasonable site sizes. In addition, to ensure geographic diversity within the sites, if two sites in an area were adjacent the program selected the site with the highest capacity factor and excluded the other. Thus the model logically reduces the amount of wind capacity identified to something less that the total potential capacity. Even this reduction methodology does not reduce the amount of wind sites to the specified 3,000 GW of capacity targeted as the capacity to use in the site selection process. In addition, if the program were to select the top 3,000 GW of wind sites, these sites would then all be in the central part of the country, which is less than ideal. Using previous wind studies and the work done by the JCSP, NREL identified target amounts of wind capacity within each state. These combined methodologies produced over 7800 sites totaling over 3,000 GW of rated capacity. Mesoscale wind data was applied to potential sites identified from this list.

Refer to Figure A1.1-3.

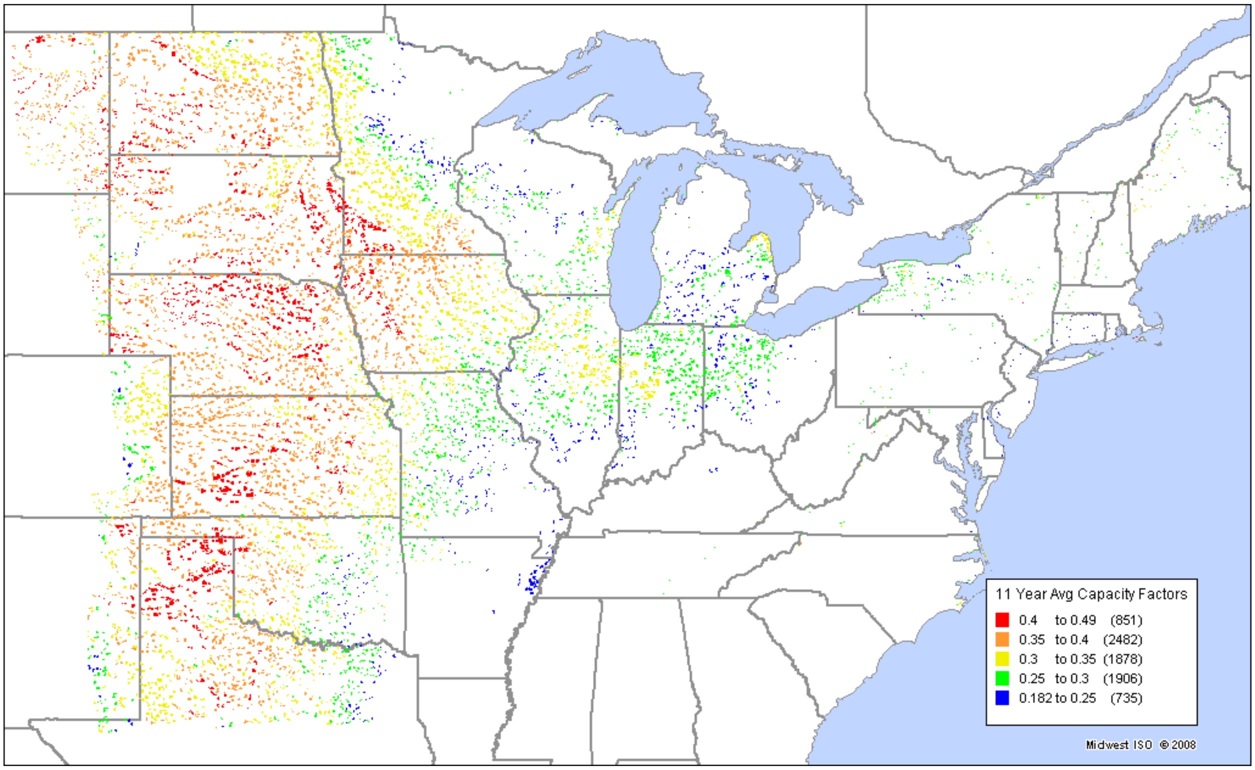

Figure A1.1-3 Potential Sites for Onshore Site Selection by Capacity Factor

From the 7,856 sites in site selection list, NREL identified 1,513 sites totaling 651,091 MW, for AWS Truewind to apply the three (3) years of 10-minute mesoscale wind data. These 1,513 sites are referred to as the "selected sites". These sites are shown in Figure A1.1-4.

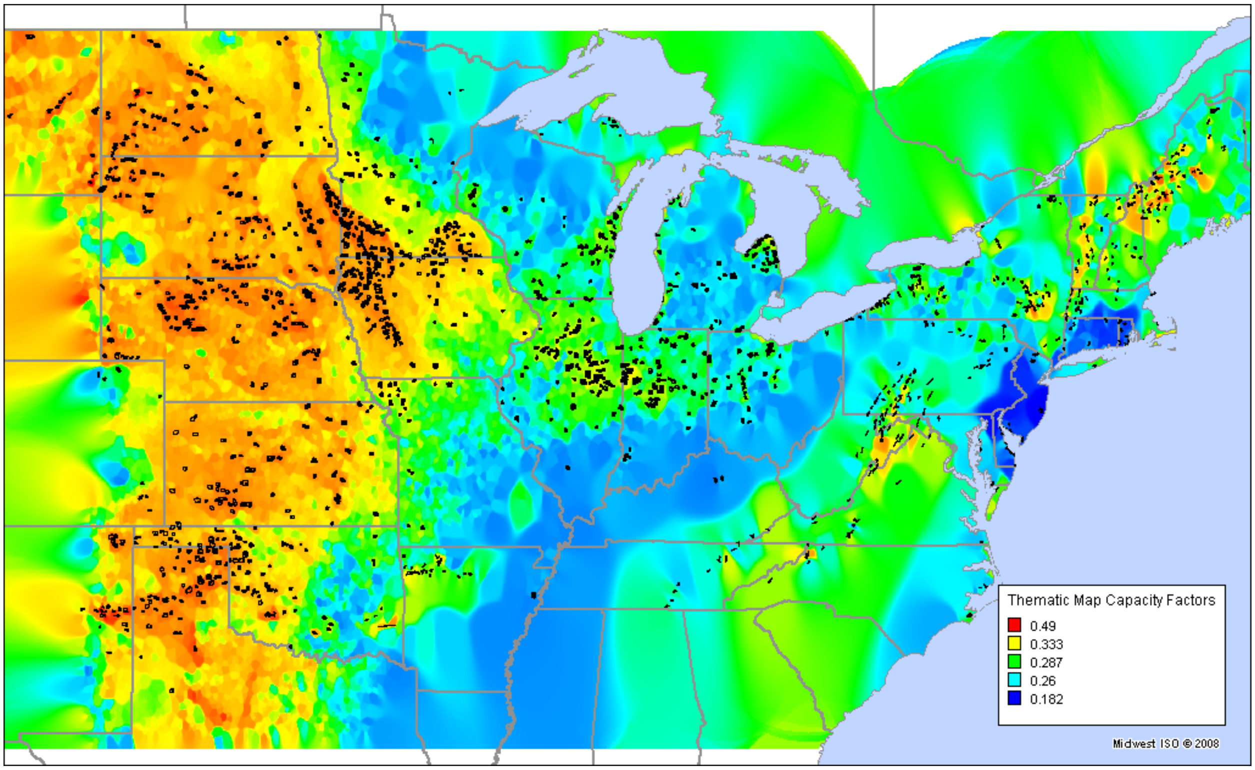

Figure A1.1-4 NREL Selected Site for Mesoscale Wind farm Modeling

The NREL-selected sites with the mesoscale wind modeling are available in on the NREL website for years 2004, 2005, and 2006. Throughout this process, Midwest ISO worked with NREL, reviewing data and providing feedback. Having modeled wind in the past; reviewed numerous wind studies; worked with stakeholders, wind developers, state regulators; conducted the JCSP study, and with a need for wind data in ongoing studies and future studies, Midwest ISO was in a unique position to provide feedback and review the data.

From this reviewing process, Midwest ISO identified an additional need outside of the scope of the original request of AWS Truewind. Midwest ISO performed a gap analysis of the wind sites selected and identified additional sites where it wanted mesoscale wind data developed. NREL was able to work with AWS Truewind to incorporate these additional sites, and the data is included on the NREL website. Refer to Figure A1.1-5.

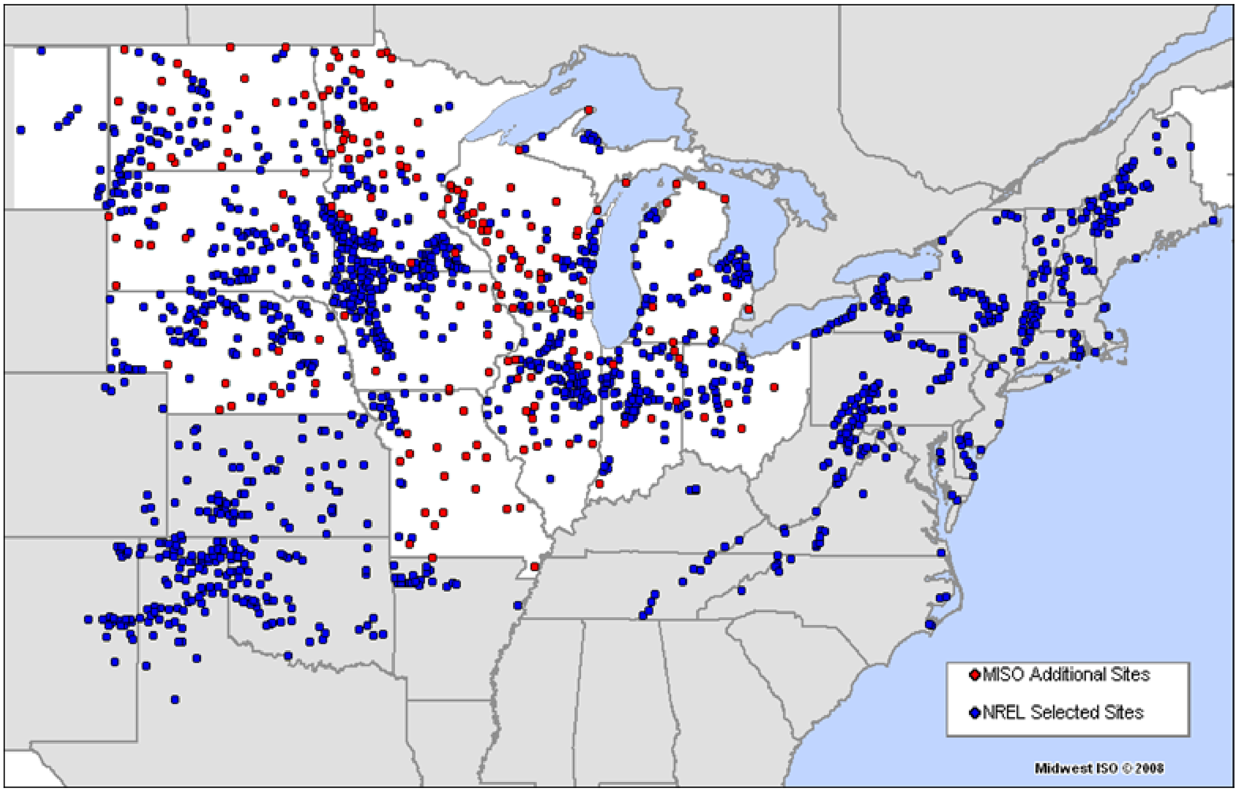

Figure A1-5 NREL and RGOS Study Region Selected Sites

A1.2 Generate Wind Plant Output

A detailed explanation of the procedure to calculate the wind plant output is on the NREL website. AWS Truewind ran a simulation model to convert the mesoscale wind data to the selected sites. Blended power curves were then created and used to calculate the power output of each site. The International Electrotechnical Commission (IEC) 1 and 2 curves were based on a composite of three commercial turbines (GE, Vestas, Gamesa brands). The IEC 3 curve was based on two turbines (GE 1.5xle and Gamesa G90). The IEC 1 and 2 turbines were assumed to have a hub height of 80 m and the IEC 3 turbine 100 m.

A single text file for the output was created for each site. The output included 10-minute simulated wind speed at 80 and 100 meters, with power outputs for IEC class 1 and 2 at 80 meters and IEC class 3 at 100 meters. All outputs were time stamped to Greenwich Mean Time (GMT). In addition, the program selected the most appropriate IEC class based on the maximum mean speed within the site adjusted for air density, for the specific year of study. Since the data was developed for years 2004, 2005, and 2006, the selected turbine class could vary in different years. All turbines in the plant were the same type (1, 2 or 3) as determined from the average wind speed with an adjustment for site altitude. The power output for the selected IEC class is provided in the last column of the file. A header is provided for each site identifying the site number, its rated capacity, the selected IEC class, and the losses for each turbine class. The 10-minute data may be converted to hourly data by taking the average output for each hour. This methodology was accomplished by Midwest ISO and NREL in their studies.

A1.2.1 Forecasts and One Minute Samples

AWS Truewind produced hourly forecasts for three different time horizons: next-day, six-hour, and four-hour for use in hourly production modeling. In addition, they developed one minute samples of wind generation. The procedures are described in depth in the documentation on the NREL website.

A1.2.2 Wind Statistics

- Onshore Site Selection:
  - 7,856 sites considered with a capacity of 3,086,915 MW.
  - Range of selected sites 11 year average capacity factor is 18.2% to 49.0%, the average capacity factor is 33.0 %.
- Mesoscale Data containing the following:
  - Data in Greenwich Mean Time (GMT)
  - 10-minute data for years 2004, 2005, 2006
  - Power output for IEC 1 & 2 turbines at 80 meters and IEC 3 turbines at 100 meters
  - Wind speeds at 80 and 100 meters
  - Max capacity, preferred turbine type and losses provided for each site
  - Onshore NREL Selected Sites
  - 1,326 sites selected by NREL with a capacity of 580,763 MW

Table A1.2-1: Onshore Site Selection Capacity Factors by Year

CF Year	Annual	Minimum	Maximum
2004 Capacity Factor	36.9%	2.4%	81.7%
2005 Capacity Factor	36.3%	2.4%	80.9%
2006 Capacity Factor	37.4%	4.2%	82.1%
3 Year Average Capacity Factor	**36.9%**	**3.0%**	**81.5%**

- Onshore Midwest Additional Sites:
  - 187 additional sites selected by the Midwest ISO with a capacity of 70,328 MW
  - 1,513 total sites totaling 651,091 MW with mesoscale wind data developed
  - Three (3) Year Annual, Min & Max capacity factor for all 1,513 sites of 36.5, 2.3% and 82.5%

Refer to Figure A1.2-1, which shows the distribution of all selected sites by rated capacity. The bulk of the sites fall between 200 MW and 600 MW in size. A small number of "megasites" with rated capacities exceeding 1000 MW were also chosen. All of the megasites are located in the Great Plains.

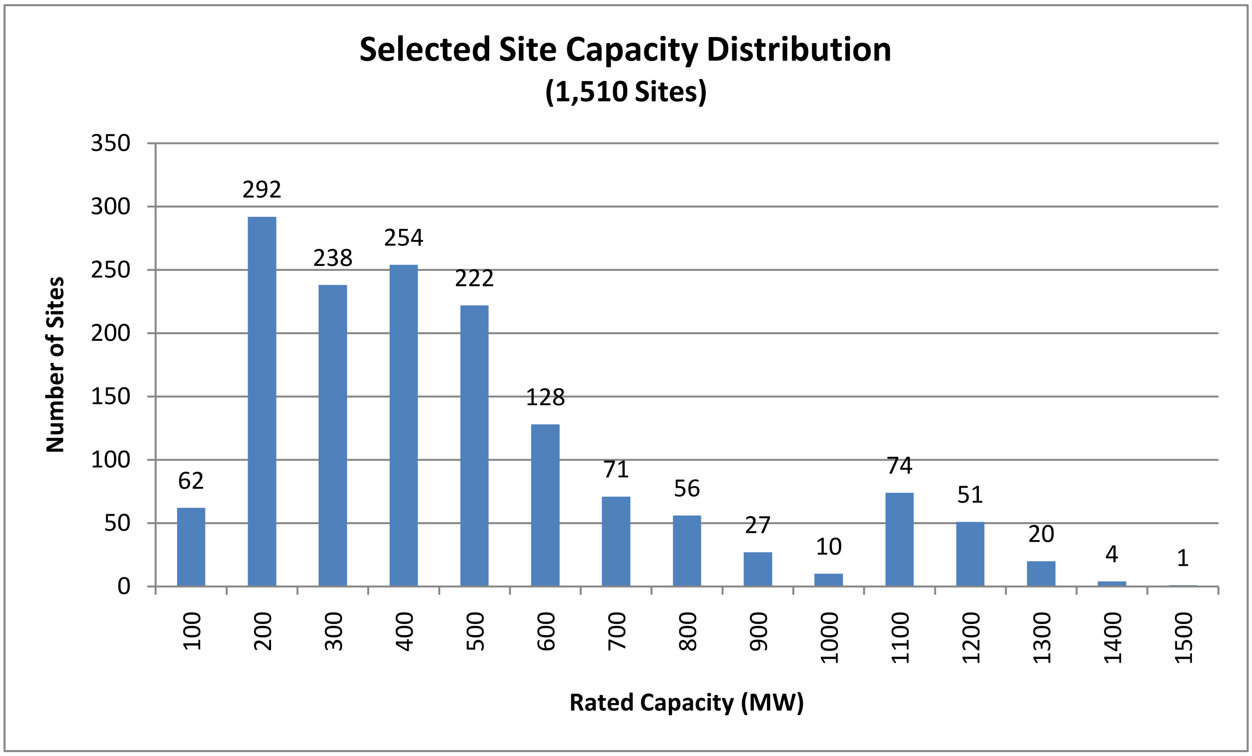

Figure A1.2-1: Distribution of Site Capacity for all 1,513 Selected Onshore Sites

The following figures represent the minimum and maximum system wind for the NREL sites for each year of mesoscale data. To understand and visualize the mesoscale data, Midwest ISO created thematic maps which represented the power output for the eastern interconnect in a color coded map corresponding to the wind power. To illustrate the hourly variance of wind, multiple images were created and combined into 'wind movies' for 2004, 2005, and 2006. These movies represent the mesoscale hourly power output of the NREL selected sites.

The data is presented as per unit power output with red having a value of 0.9 and dark blue with a value of 0.0. These movies are available to download at the following website: http://www.jcspstudy.org/. The Figures A1.2-2 and A1.2-3 showing minimum and maximum system wind were taken from the wind movie.

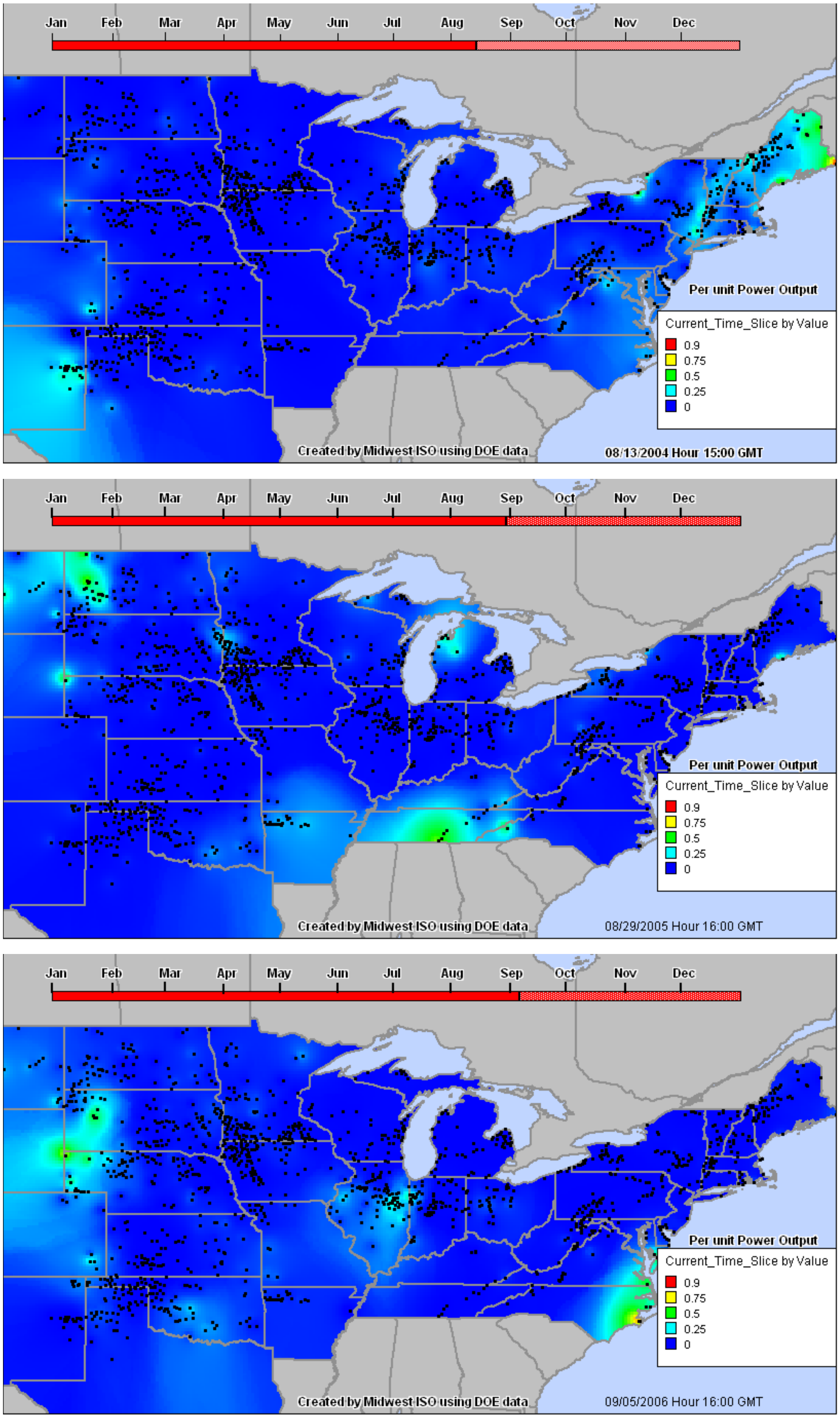

Figure A1.2-2: Minimum Power Output of the NREL Selected Sites for Each Year

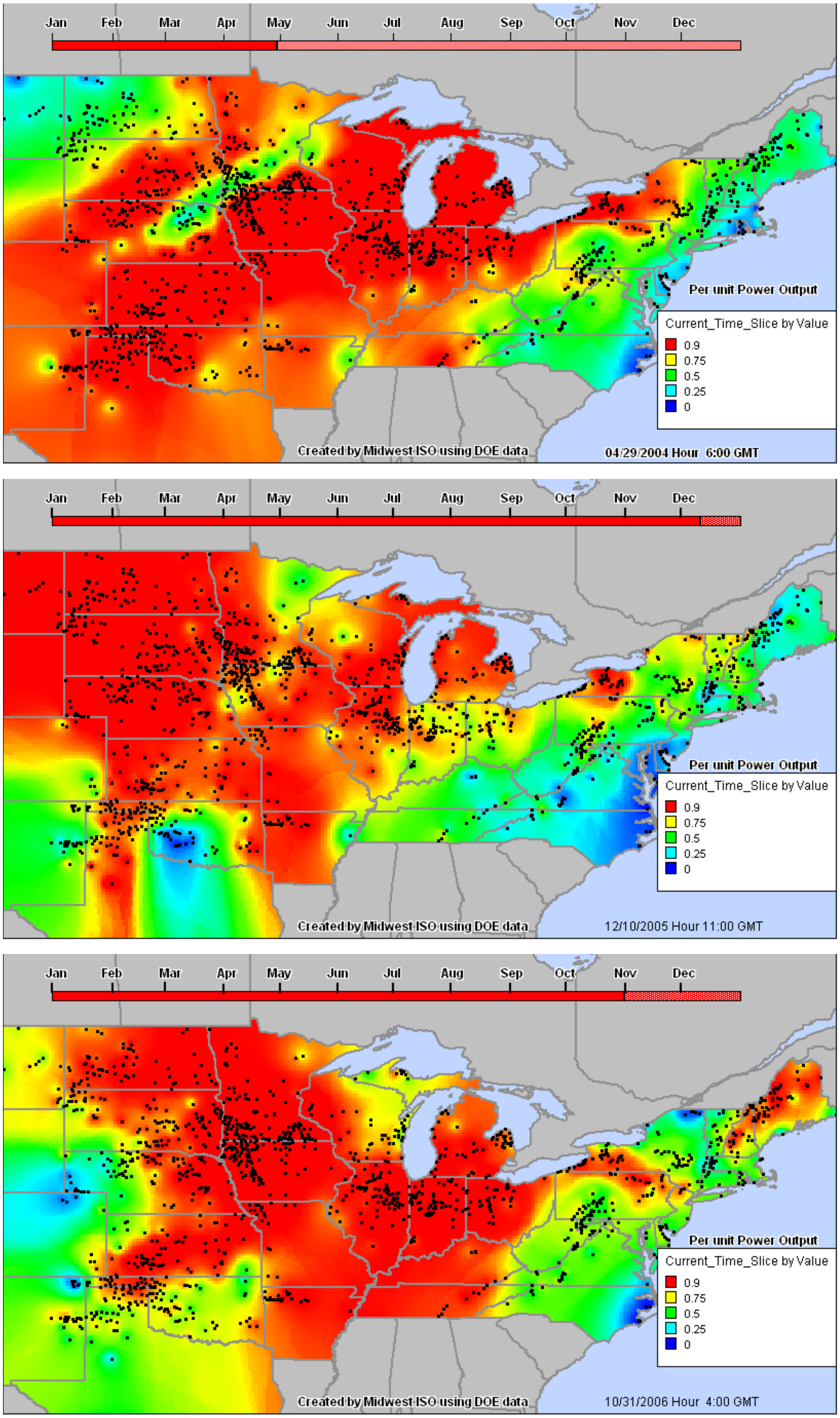

Figure A1.2-3: Maximum Power Output of the NREL Selected Sites for Each Year

A1.3 Renewable Energy Zone Scenario Development

A1.3.1 Wind Analysis

Several capacity factor metrics were calculated to analyze the wind data to determine the appropriate measures for ranking the renewable energy zones. The purpose for examining the various capacity factor metrics was to first answer questions about the variability and timing of wind production and also to determine if there were areas where wind energy performed better. A statistical analysis of the data had to be performed to be able to questions such as the following:

- Is using the three year average capacity factor enough or should the capacity factor for each year be considered a separate criteria?
- How is a site treated which may have a lower capacity factor than another site but tends to produce more energy during on-peak hours?
- Does wind really blow more in the evening than during the day?

To provide answers, a range of statistics was created based on time and applied to each site. The various capacity factor metrics are described in Table A1.3-1, below.

Table A1.3-1 Summary of Capacity Factor Metrics

Metric	Capacity Factor (CF) Metric
11 Year CF	CF based on 11 year average wind speed at 80m
2004 CF	CF for 2004
2005 CF	CF for 2005
2006 CF	CF for 2006
3 Year CF	Average CF for 2004, 2005 and 2006
On-peak CF	3 year CF for hours between 6am to 10pm EST
Afternoon On-peak CF	3 year CF for hours between 3pm to 6pm EST
Summer On-peak CF	3 year CF on-peak hours for June, July and August
Summer Aft On-peak CF	3 year CF for afternoon on-peak hours for June, July & August
Off-peak CF	3 year CF for hours between 10pm to 6am EST

Figures A.3-1 through A.3-3 provide an overview of some of the capacity factor metrics per state. The off-peak average capacity factors were higher than the on-peak and significantly higher than the summer afternoon on-peak hours. A linear relationship can be seen between the average capacity factors and their changes for the different metrics. Spikes or dips in the data indicate the average capacity factors in a given state performed better or worse relative to the other states. This is seen in the afternoon on-peak hours with a slight dip for Missouri and a slight increase for Indiana.

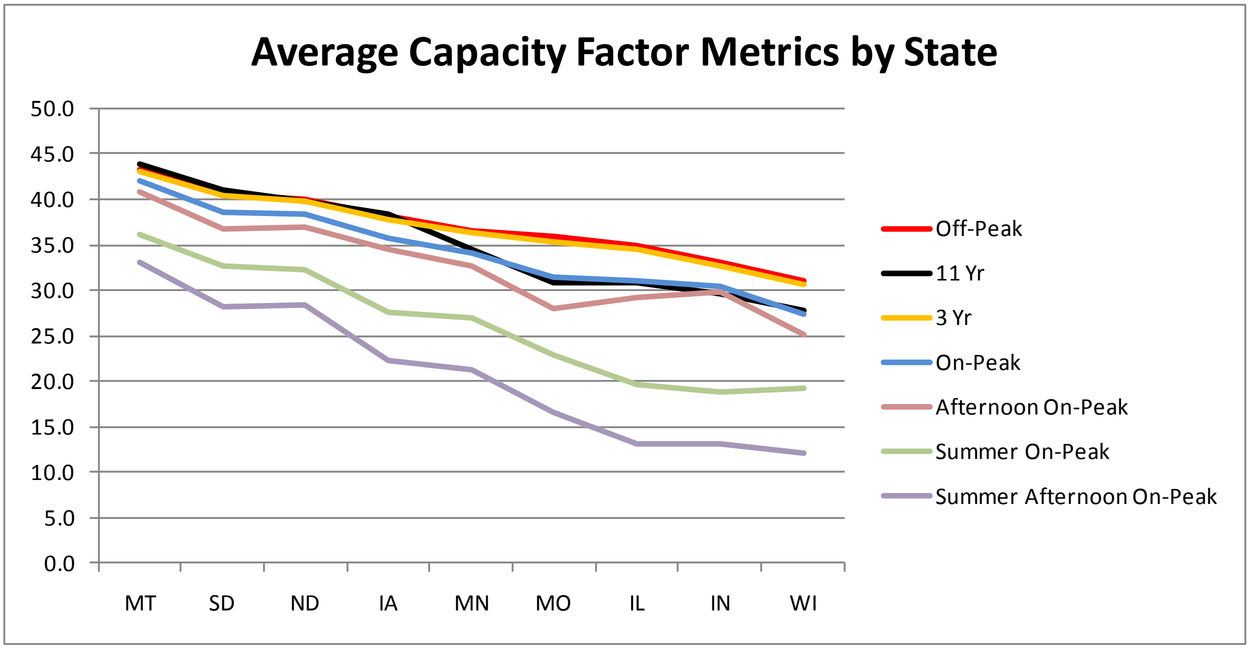

Figure A1.3-1 Average Capacity Factor Metrics by State

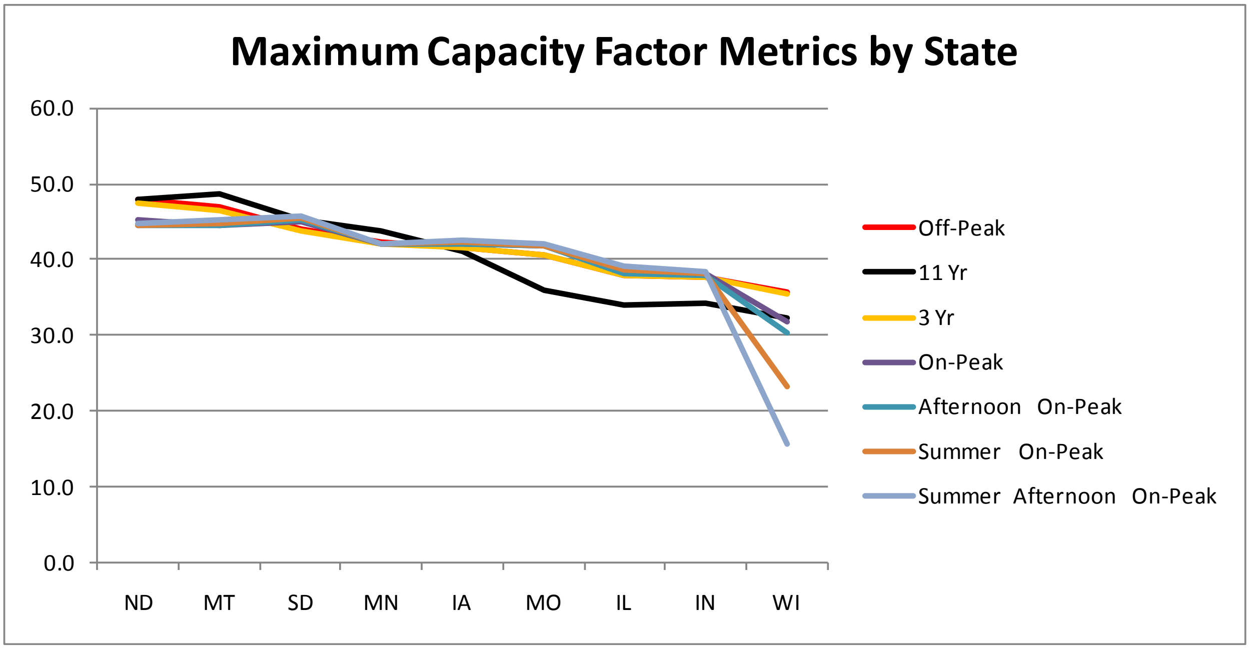

Figure A1.3-2 Maximum Capacity Factor Metrics by State

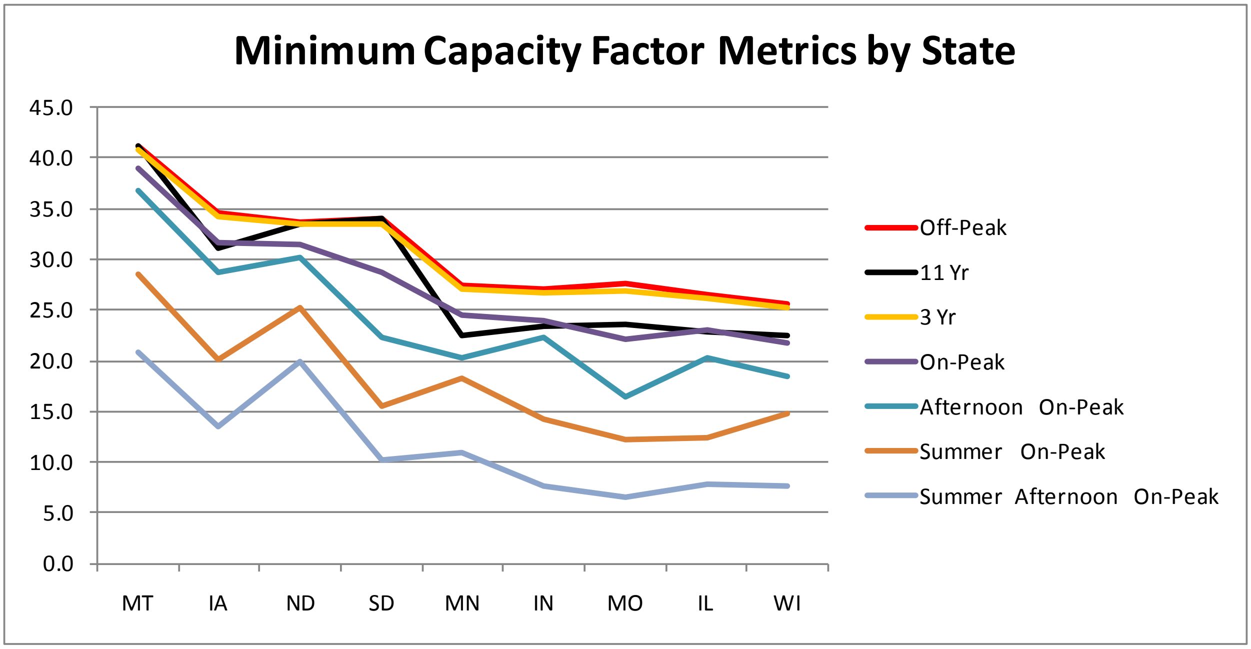

Figure A1.3-3 Minimum Capacity Factor Metrics by State

Some other metrics developed for analysis include correlation of wind to load, ramp, and correlation of wind sites to distance from each other. The following figures demonstrate some of the results from this work.

Figure A1.3-4 represents the wind output correlation to load for Midwest ISO. A correlation of 1.0 is a perfect correlation, meaning load and wind exactly match each other. A correlation of 0.0 represents no correlation, meaning that load and wind act completely independent of each other. The correlation values demonstrate that there was not a strong correlation between wind output and load. In other words, one cannot generally expect a specific wind output based on load levels. However, in general, wind output is typically higher during off-peak hours as opposed to on-peak hours (when load is less) as shown in the previous figures. Similar results hold true on a state by state basis for all the states in Midwest ISO.

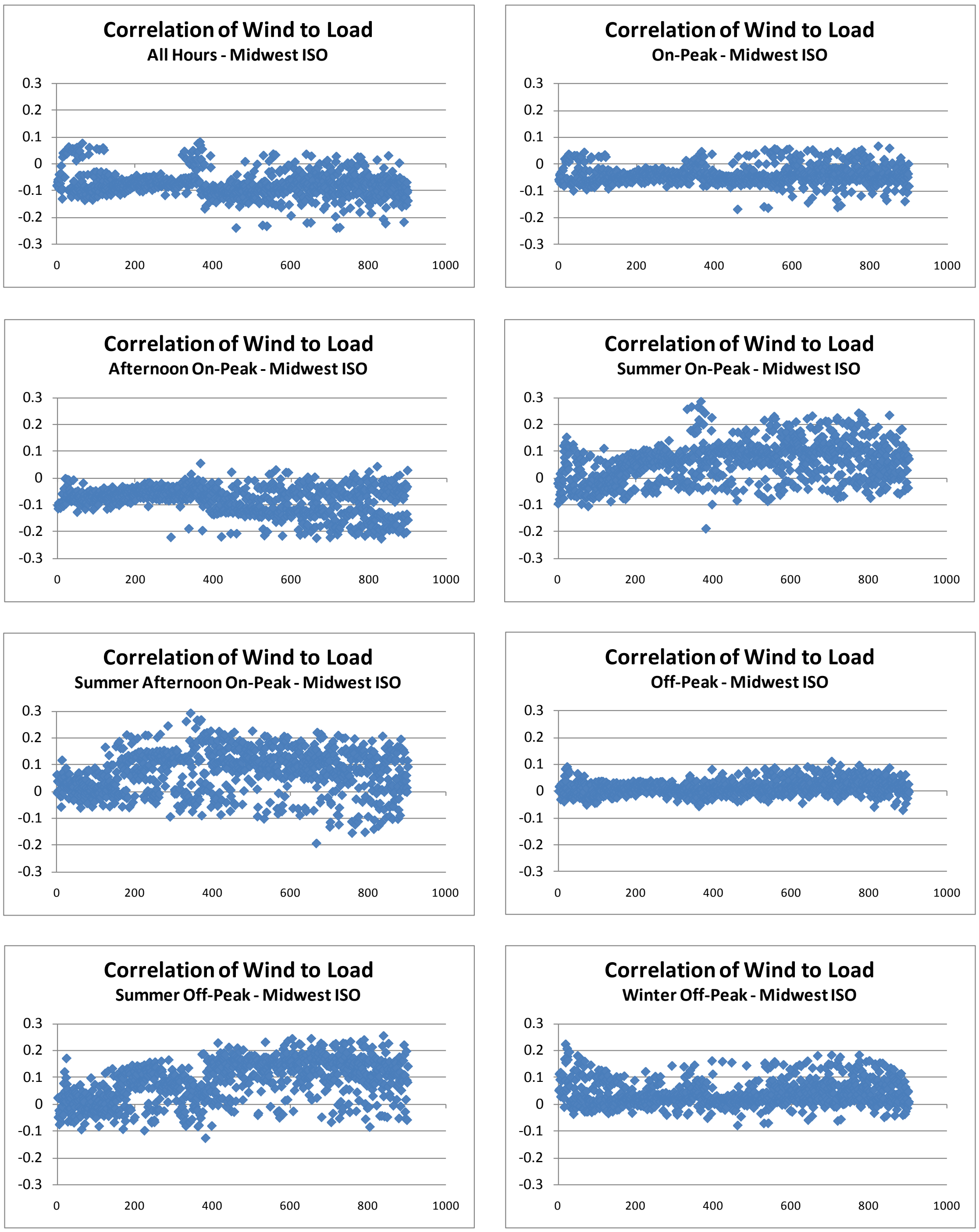

Figure A1.3-4 Correlation of Wind to Load in the Midwest ISO

Hourly ramping of the wind was calculated by looking at the delta of wind output from one hour to the next. A distribution of these values was created and a correlation to load ramp was calculated. As expected, the correlations were relatively close to zero and insignificant. Refer to Figure A.3-5 for results from Iowa (IA), Illinois (IL), Minnesota (MN), and Wisconsin (WI).

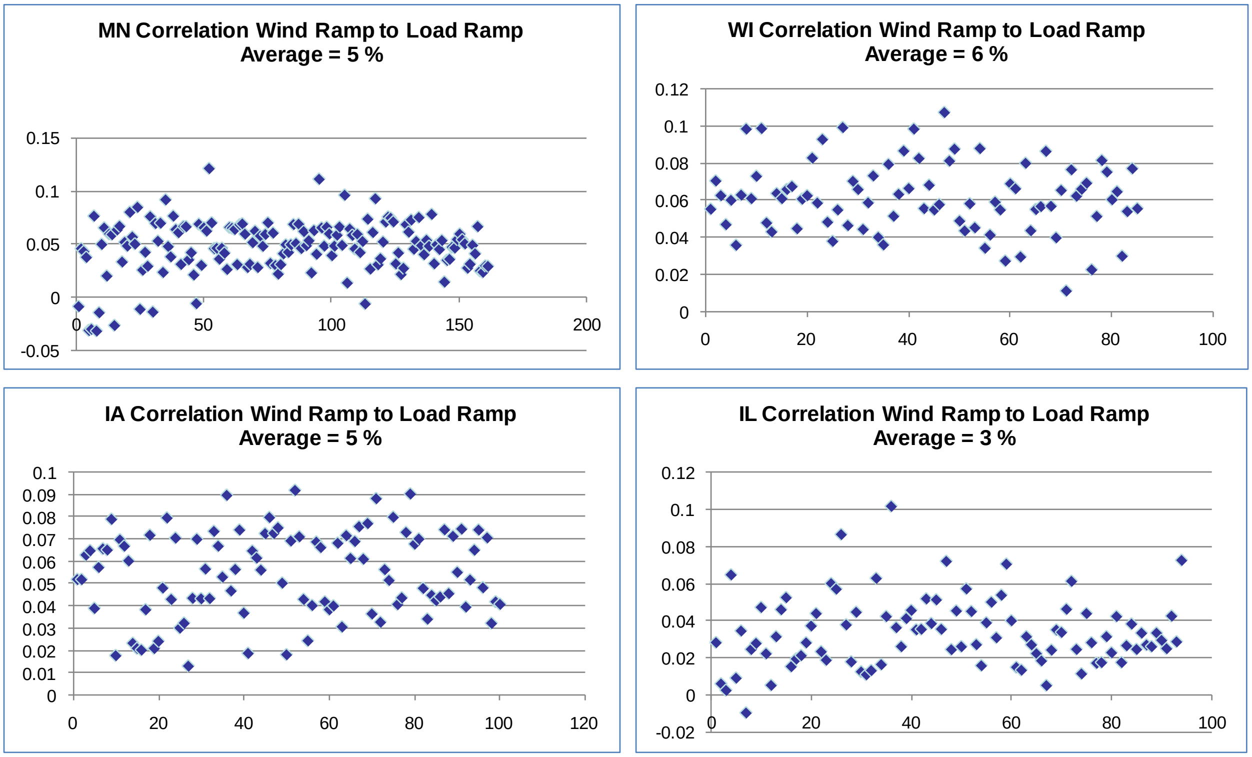

Figure A1.3-5: Correlation of Wind Ramp to Load Ramp

Figure A1.3-6 represents the correlation of individual sites to each other. The green line represents distance separation east to west, the blue line north to south. The figure demonstrates that as the distance between two sites becomes large, the correlation of the wind at those two sites reduces. In other words, the further apart two sites are, the less likely they will have similar wind profiles. This is an obvious expectation since two (2) sites located next to each other would be expected to have similar capacity factor characteristics.

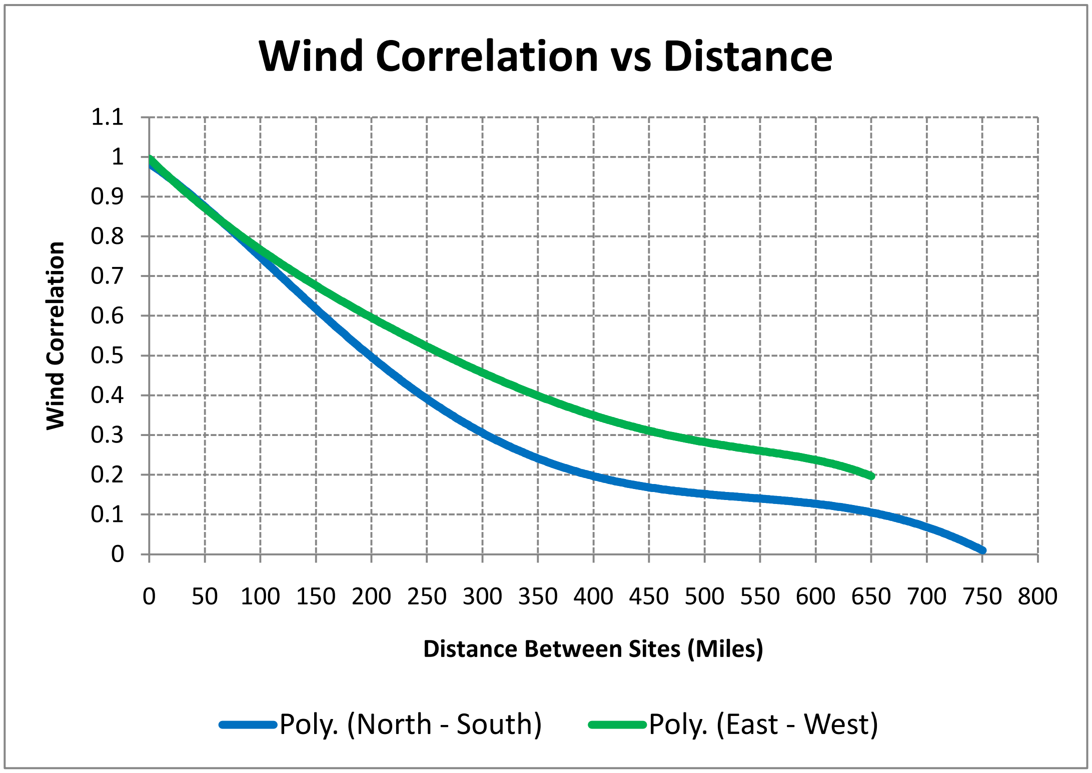

Figure A1.3-6: Correlation of Wind Sites to Distance

Appendix 2: Midwest ISO Member State RPS Requirements

Refer to Table A2-1. The following information, derived from the US Department of Energy's National Renewable Energy Laboratory (NREL) Database of State Incentives for Renewables & Efficiency, highlights general aspects of various state Renewable Portfolio Standards (RPS) legislation within the Midwest ISO purview. The information can be found at http://www.dsireusa.org/.

Note the Ohio mandate is defined differently from most other states. The Ohio mandate focuses on an alternative energy mandate that can include resources such as clean coal and nuclear capacity. The total state mandate is 25% by 2024. However, it has been expressed in this report as that portion that meets the renewable technology minimum of 12.5% by 2024. Note, too, the Pennsylvania mandate is similar to the Ohio mandate, focusing not only on renewable resources but also alternative technologies such as Integrated Gasification Combined Cycle (IGCC). The entire Pennsylvania mandate is approximately 18% of energy served. However, for the purposes of this study, only the Tier I portion of the mandate emphasizing renewable resources is referenced.

Table A2-1: Midwest ISO Region State RPS Requirements

State	Applicable Sectors	Eligible Resources	Technology Minimum	DSIRE Reference Web Address
Wisconsin	Municipal Utility, Investor-Owned Utility, Rural Electric Cooperative	Solar Water Heat, Solar Space Heat, Solar Thermal Electric, Solar Thermal Process Heat, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Geothermal Electric, Geothermal Heat Pumps, Municipal Solid Waste, Solar Light Pipes, Solar Pool Heating, Anaerobic Digestion, Tidal Energy, Wave Energy, Fuel Cells using Renewable Fuels, Geothermal Direct-Use	None	http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=WI05R&re=1&ee=1
Minnesota	Municipal Utility, Investor-Owned Utility, Rural Electric Cooperative	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Municipal Solid Waste, Hydrogen, Co-Firing, Anaerobic Digestion	Wind or Solar (Xcel only): 25% by 2020; maximum of 1% from solar	http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=MN14R&re=1&ee=1
Illinois	Investor-Owned Utility, Retail Supplier	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Biodiesel, Eligible Efficiency Technologies	Wind (IOUs): 75% of annual requirement (18.75% of sales in compliance year 2024-2025); Wind (ARES): 60% of annual requirement (15% of sales in compliance year 2024-2025); PV (All): 6% of annual requirement in compliance year 2015-2016 and thereafter (1.5% of total sales in compliance year 2024-2025)	http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=IL04R&re=1&ee=1

Table A2-1: Midwest ISO Region State RPS Requirements

State	Applicable Sectors	Eligible Resources	Technology Minimum	DSIRE Reference Web Address
Michigan	Municipal Utility, Investor-Owned Utility, Rural Electric Cooperative, Retail Supplier	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Geothermal Electric, Municipal Solid Waste, CHP/Cogeneration, Coal-Fired w/CCS, Gasification , Anaerobic Digestion, Tidal Energy, Wave Energy, Eligible Efficiency Technologies	None	http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=MI16R&re=1&ee=1
Ohio	Investor-Owned Utility, Retail Supplier	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Geothermal Electric, Fuel Cells, Municipal Solid Waste, Waste Heat, Energy Storage, Clean Coal, Advanced Nuclear , Anaerobic Digestion, Microturbines, Eligible Efficiency Technologies	Renewables: 12.5% by 2024 (includes solar-electric minimum) Solar-Electric: 0.5% by 2024	http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=OH14R&re=1&ee=1
Missouri	Investor-Owned Utility	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Municipal Solid Waste, Anaerobic Digestion, Small Hydroelectric, Fuel Cells using Renewable Fuels	Solar-Electric: 2% of annual requirement (0.3% of sales in 2021)	http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=MO08R&re=1&ee=1
Montana	Investor-Owned Utility, Retail Supplier	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Geothermal Electric, Anaerobic Digestion, Fuel Cells using Renewable Fuel	None	http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=MT11R&re=1&ee=1
Pennsylvania	Investor-Owned Utility, Retail Supplier	Solar Water Heat, Solar Space Heat, Solar Thermal Electric, Solar Thermal Process Heat, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Geothermal Electric, Fuel Cells, Geothermal Heat Pumps, Municipal Solid Waste, CHP/Cogeneration, Waste Coal, Coal Mine Methane, Coal Gasification, Anaerobic Digestion, Other Distributed Generation Technologies, Eligible Efficiency Technologies	Tier I: ~8% by compliance year 2020-2021 (includes PV minimum); Tier II: 10% by compliance year 2020-2021; PV: 0.5% by compliance year 2020-2021	http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=PA06R&re=1&ee=1
South Dakota (Goal)	Municipal Utility, Investor-Owned Utility, Rural Electric Cooperative	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Geothermal Electric, Municipal Solid Waste, Hydrogen, Electricity Produced from Waste Heat , Anaerobic Digestion, Eligible Efficiency Technologies	None	http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=SD02R&re=1&ee=1
North Dakota (Goal)	Municipal Utility, Investor-Owned Utility, Rural Electric Cooperative	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Geothermal Electric, Hydrogen, Electricity from Waste Heat, Anaerobic Digestion	None	http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=ND04R&re=1&ee=1
Iowa	Utility	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Municipal Solid Waste, Anaerobic Digestion	None	http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=IA01R&re=1&ee=1

Appendix 3: Indicative Transmission Design

This Appendix depicts and describes the indicative transmission overlays resulting from formulation of five (5) renewable energy zone scenarios. Also refer to section 5 of this document, which provides greater detail on design process background and results. These scenarios include the following:

- **Local:** In the Local scenario the renewable energy requirements and goals will be met with resources located within the same state as the load.
- **Regional:** In the Regional scenario renewable energy requirements and goals will be met with resources located in the highest ranking renewable energy zones regardless of the zones location relative to the RGOS II load. This scenario will utilize the high capacity factor zones recommended by UMTDI from RGOS I.
- **Regional Optimized:** The Regional scenario results in capacity in excess of what is needed to at least cover the renewable requirements/goals. In the optimized case the capacity in some zones reduced such that there is just enough resources to cover the requirements/goals.
- **Combination 50/50:** In the Combination scenario renewable energy requirements and goals will be met with a combination of 50% of the resources located within the eastern states (RGOS II) and 50% from the western states (RGOS I/UMTDI). Emphasis will be given to state requirements to locate part or all of their resources used to meet renewable energy requirements and goals within those states.
- **Combination 75/25:** This scenario is similar to Combination 50/50 except that 75% of the renewable energy requirements will be met from the west states (RGOS I/UMTDI).

The following tables and charts depict results from the indicative transmission workshop whereby the renewable energy zone scenarios above were used to develop indicative transmission overlays to serve the energy and capacity from each scenario. This work was accomplished using several transmission build-out possibilities that included 345 kV, 765 kV, and DC. Each of the various scenarios has a table showing transmission mileage, a table listing transmission capital costs, and a map depicting the transmission overlay.

A3.1 Local 345 kV

Refer to Tables A3.1-1 and A3.1-2.

Table A3.1-1: Local 345 kVSum of Line Lengths (Miles)

Type (kV)	States								Total Line Length
	IA	IL	IN	MI	MN/Dak	MO	OH/PA	WI	
345	1001	999	188	271	230	611	228	880	4408
765				195			268		462
2-345	454	238	187		2701		59	135	3775
Grand Total	**1455**	**1237**	**376**	**466**	**2931**	**611**	**554**	**1016**	**8645**

Table A3.1-2: Local 345 kV Sum of Total Cost

Type (kV)	States								Grand Total
	IA	IL	IN	MI	MN/Dak	MO	OH/PA	WI	
345	$1,501	$1,999	$339	$488	$460	$611	$455	$2,201	$8,054
765				$702			$1,070		$1,772
2-345	$953	$618	$431		$6,753		$148	$406	$9,309
Grand Total	**$2,454**	**$2,616**	**$770**	**$1,189**	**$7,212**	**$611**	**$1,673**	**$2,608**	**$19,135**

Generation

MW of Capacity	Cost (M$)
45,700	**$91,400.00**

Total Costs (2010 USD in Millions)

Transmission	$19,135
Generation	$91,400
Transformers	
Substations	
Reactors	
Total	**$110,535**

Refer to Figure A3.1-1.

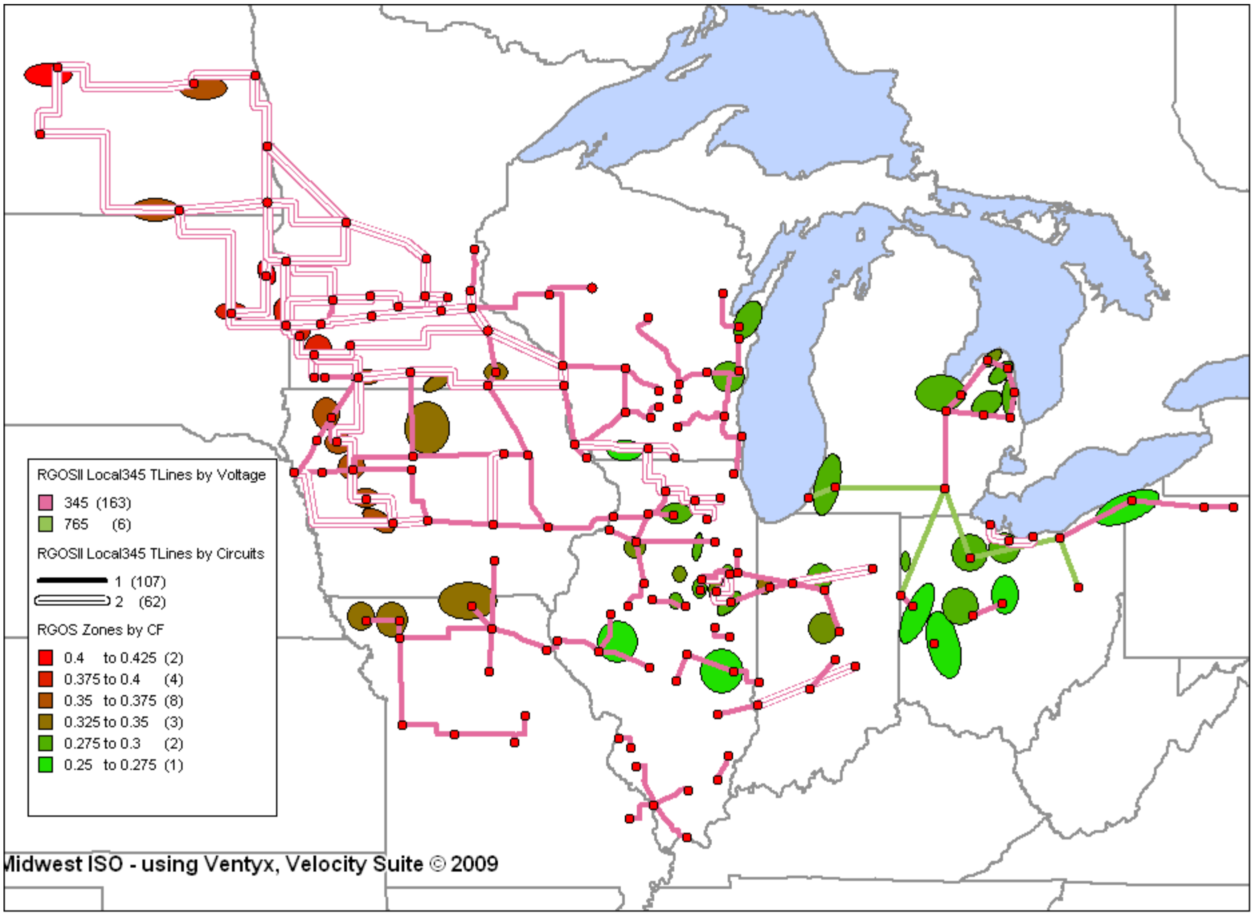

Figure A3.1-1: RGOS Local 345 kV

A3.2 Local 765 kV

Refer to Tables A3.2-1 and A3.2-2.

Table A3.2-1: Local 765 kV Sum of Line Lengths (Miles)

Type (kV)	States								Total Line Length
	IA	IL	IN	MI	MN/Dak	MO	OH/PA	WI	
345	1001	1005	110	196	230	611	228	880	4260
765		432	396	319			269		1416
2-345	454	238			2701			135	3528
Grand Total	**1455**	**1674**	**506**	**515**	**2931**	**611**	**496**	**1016**	**9204**

Table A3.2-2: Local 765 kV Sum of Total Cost

Type (kV)	States								Grand Total
	IA	IL	IN	MI	MN/Dak	MO	OH/PA	WI	
345	$1,501	$2,009	$198	$353	$460	$611	$455	$2,201	$7,788
765		$1,816	$1,741	$1,148			$1,074		$5,779
2-345	$953	$618			$6,753			$406	$8,730
Grand Total	**$2,454**	**$4,443**	**$1,939**	**$1,502**	**$7,212**	**$611**	**$1,529**	**$2,608**	**$22,298**

Generation	
MW of Capacity	Cost (M$)
45,700	**$91,400.00**

Total Costs (2010 USD in Millions)	
Transmission	$22,298
Generation	$91,400
Transformers	
Substations	
Reactors	
Total	**$113,698**

Refer to Figure A3.2-1.

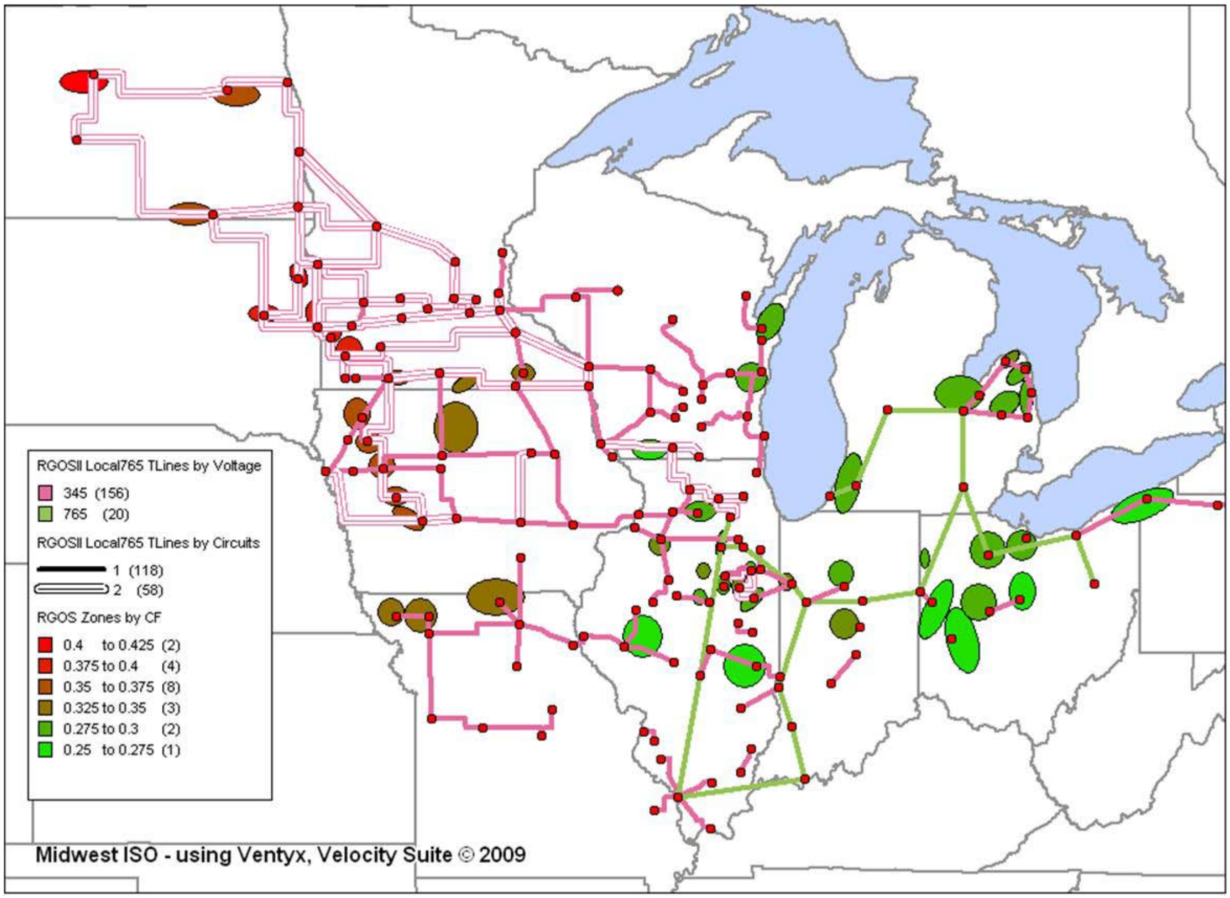

Figure A3.2-1: RGOS Local 765 kV

A3.3 Combo (50/50) 345 kV

Refer to Tables A3.3-1 and A3.3-2.

Table A3.3-1: Combo (50/50) 345 kV Sum of Line Lengths (in Miles)

Type (kV)	States								Total Line Length
	IA	IL	IN	MI	MN/Dak	MO	OH/PA	WI	
345	1162	997	241	196	230	486		880	4192
765			59	165			155		379
2-345	454	152	254		2701		94	135	3790
Grand Total	**1616**	**1148**	**555**	**361**	**2931**	**486**	**249**	**1016**	**8361**

Table A3.3-2: Combo (50/50) 345 kV Sum of Total Cost

Type (kV)	States								Grand Total
	IA	IL	IN	MI	MN/Dak	MO	OH/PA	WI	
345	$1,743	$1,993	$434	$353	$460	$486		$2,201	$7,670
765			$261	$593			$621		$1,474
2-345	$953	$394	$585		$6,753		$234	$406	$9,325
Grand Total	**$2,696**	**$2,387**	**$1,279**	**$946**	**$7,212**	**$486**	**$855**	**$2,608**	**$18,470**

Generation

MW of Capacity	Cost (M$)
32,650	**$65,300.00**

Total Costs (2010 USD in Millions)

Transmission	$18,470
Generation	$65,300
Transformers	
Substations	
Reactors	
Total	**$83,770**

Refer to Figure A3.3-1.

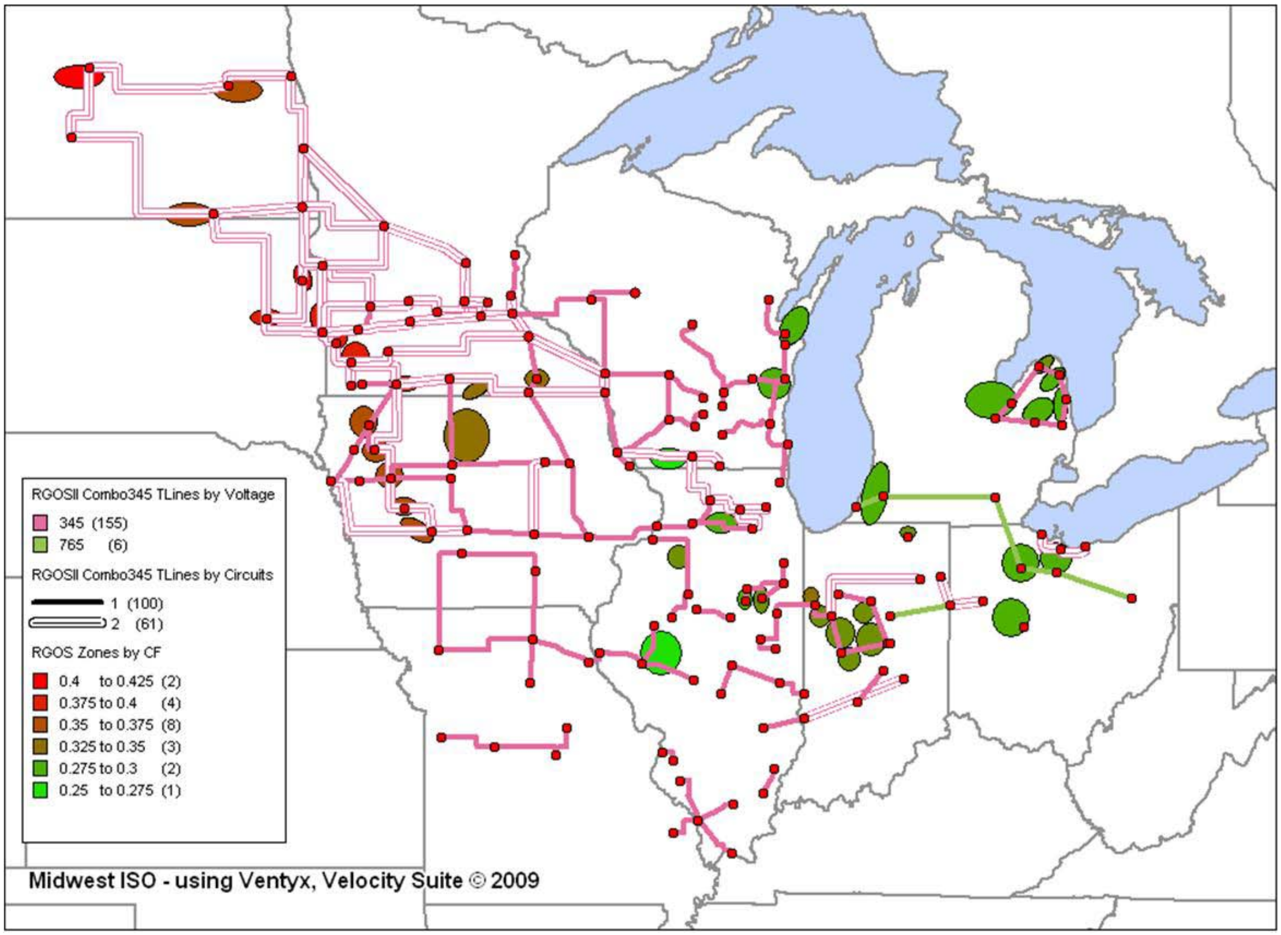

Figure A3.3-1: RGOS Combo (50/50) 345 kV

A3.4 Combo (50/50) 765 kV

Refer to Tables A3.4-1 and A3.4-2.

Table A3.4-1: Combo (50/50) 765 kV Sum of Line Lengths (in Miles)

Type (kV)	States								Total Line Length
	IA	IL	IN	MI	MN/Dak	MO	OH/PA	WI	
345	443	772	93	196	33	277		828	2642
765	650	505	260	319	1166	324	237	162	3623
2-345	197				1338		59	21	1615
Grand Total	**1290**	**1276**	**353**	**515**	**2537**	**601**	**296**	**1011**	**7880**

Table A3.4-2: Combo (50/50) 765 Sum of Total Cost

Type (kV)	States								Grand Total
	IA	IL	IN	MI	MN/Dak	MO	OH/PA	WI	
345	$664	$1,543	$168	$353	$66	$277		$2,070	$5,141
765	$2,731	$2,121	$1,144	$1,148	$5,597	$1,361	$947	$776	$15,826
2-345	$414				$3,346		$147	$62	$3,970
Grand Total	**$3,810**	**$3,664**	**$1,312**	**$1,502**	**$9,008**	**$1,638**	**$1,094**	**$2,909**	**$24,937**

Generation

MW of Capacity	Cost (M$)
32,650	**$65,300.00**

Total Costs (2010 USD in Millions)

Transmission	$24,937
Generation	$65,300
Transformers	
Substations	
Reactors	
Total	**$90,237**

Refer to Figure A3.4-1.

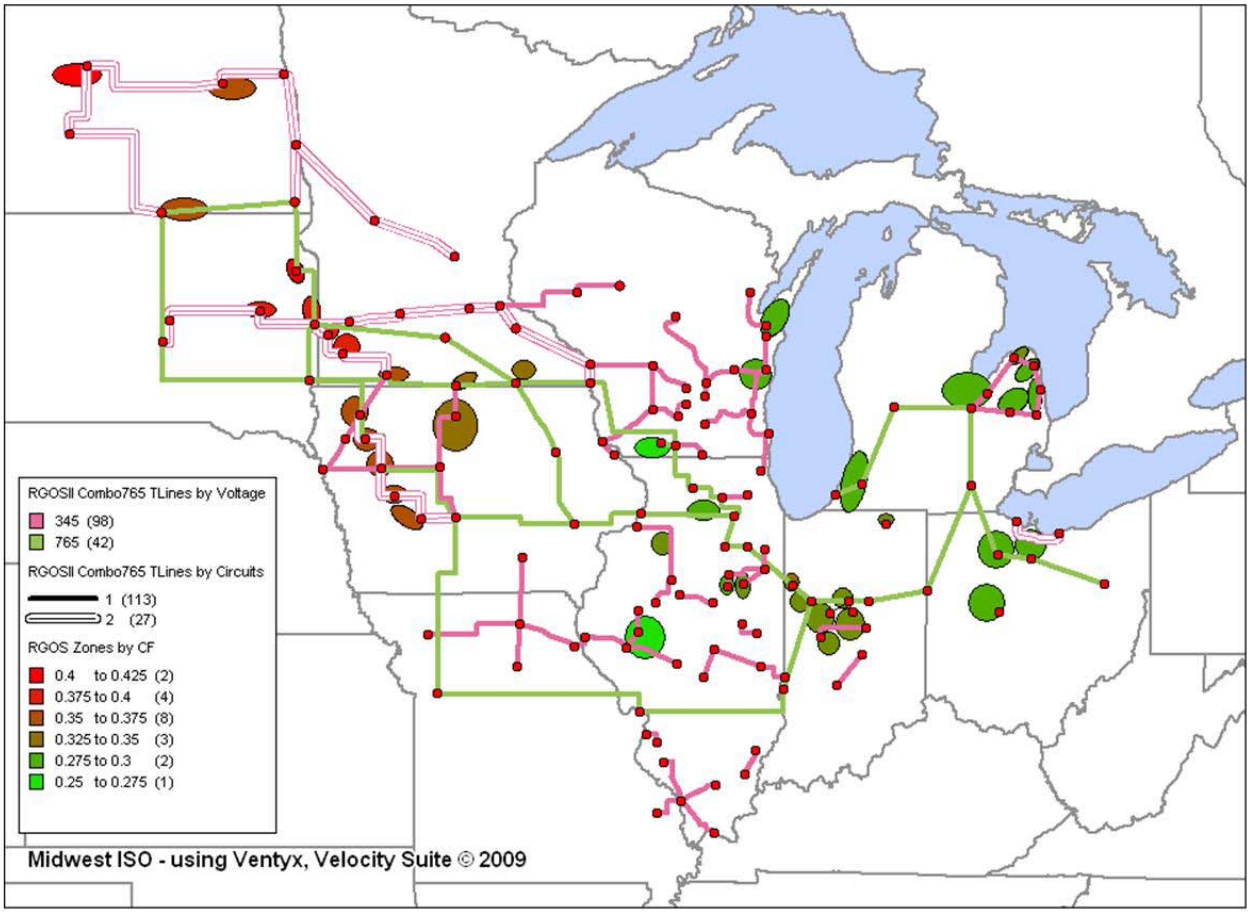

Figure A3.4-1: RGOS Combo (50/50) 765 kV

A3.5 Combo (75/25) 345 kV

Refer to Tables A3.5-1 and A3.5-2.

Table A3.5-1: Combo (75/25) 345 kV Sum of Line Lengths (in Miles)

Type (kV)	States								Total Line Length
	IA	IL	IN	MI	MN/Dak	MO	OH/PA	WI	
345	1162	997	241	196	230	486		880	4192
765			59	165			155		379
2-345	454	152	254		2701		94	135	3790
Grand Total	**1616**	**1148**	**555**	**361**	**2931**	**486**	**249**	**1016**	**8361**

Table A3.5-2: Combo (75/25) 345 kV Sum of Total Cost

Type (kV)	States								Grand Total
	IA	IL	IN	MI	MN/Dak	MO	OH/PA	WI	
345	$1,743	$1,993	$434	$353	$460	$486		$2,201	$7,670
765			$261	$593			$621		$1,474
2-345	$953	$394	$585		$6,753		$234	$406	$9,325
Grand Total	**$2,696**	**$2,387**	**$1,279**	**$946**	**$7,212**	**$486**	**$855**	**$2,608**	**$18,470**

Generation

MW of Capacity	Cost (M$)
31,150	**$62,300.00**

Total Costs (2010 USD in Millions)

Transmission	$18,470
Generation	$62,300
Transformers	
Substations	
Reactors	
Total	**$80,770**

Refer to Figure A3.5-1.

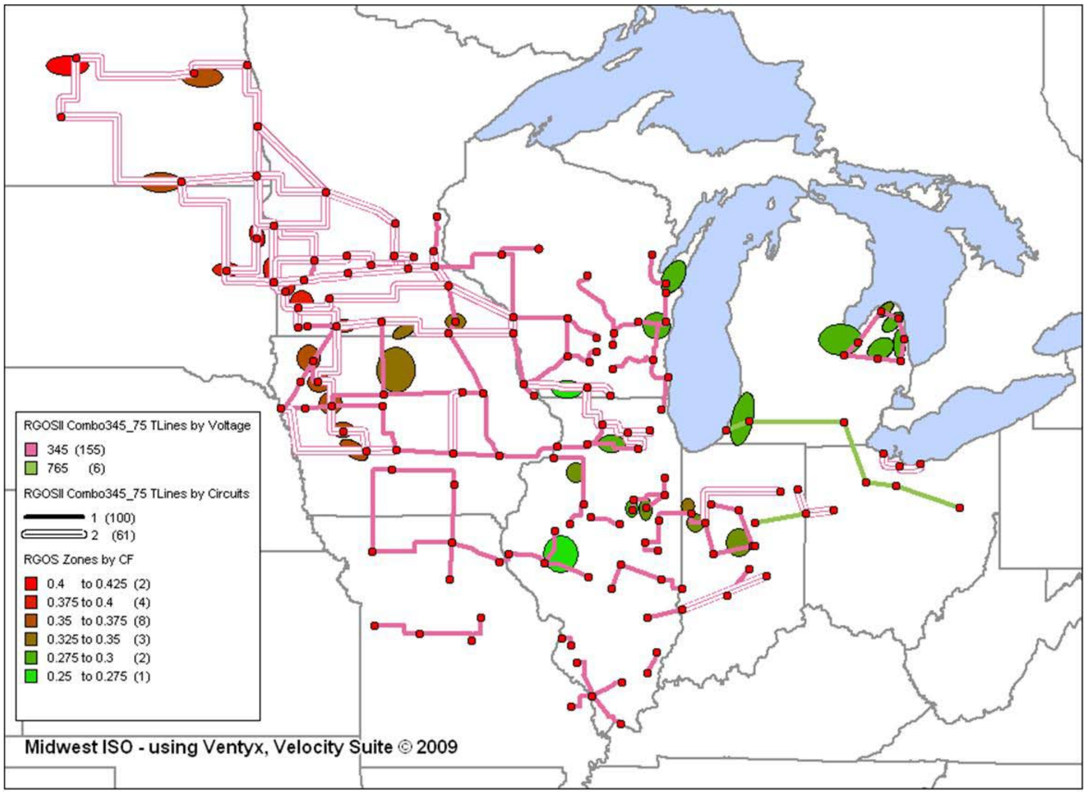

Figure A3.5-1: RGOS Combo (75/25) 345 kV

A3.6 Combo (75/25) 765 kV

Refer to Tables A3.6-1 and A3.6-2.

Table A3.6-1: Combo (75/25) 765 kV Sum of Line Lengths (in Miles)

Type (kV)	States								Total Line Length
	IA	IL	IN	MI	MN/Dak	MO	OH/PA	WI	
345	443	772	93	196	33	277		828	2642
765	650	505	260	319	1166	324	237	162	3623
2-345	197				1338		59	21	1615
Grand Total	**1290**	**1277**	**353**	**515**	**2537**	**601**	**296**	**1011**	**7880**

Table A3.6-2: Combo (75/25) 765 kV Sum of Total Cost

Type (kV)	States								Grand Total
	IA	IL	IN	MI	MN/Dak	MO	OH/PA	WI	
345	$664	$1,543	$168	$353	$66	$277		$2,070	$5,141
765	$2,731	$2,121	$1,144	$1,148	$5,597	$1,361	$947	$776	$15,826
2-345	$414				$3,346		$147	$62	$3,970
Grand Total	**$3,810**	**$3,664**	**$1,312**	**$1,502**	**$9,008**	**$1,638**	**$1,094**	**$2,909**	**$24,937**

Generation

MW of Capacity	Cost (M$)
31,150	**$62,300.00**

Total Costs (2010 USD in Millions)

Transmission	$24,937
Generation	$62,300
Transformers	
Substations	
Reactors	
Total	**$87,237**

Refer to Figure A3.6-1.

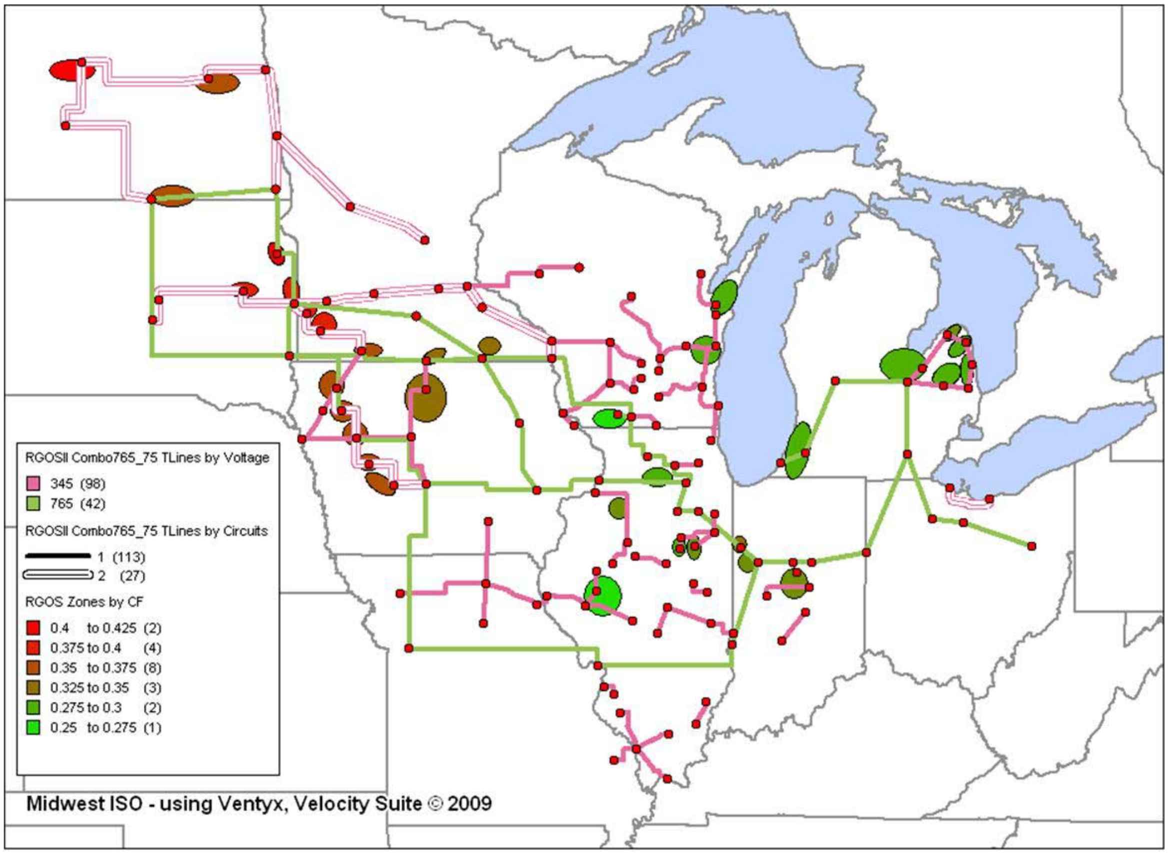

Figure A3.6-1: RGOS Combo (75/25) 765 kV

A3.7 Regional 345 kV

Refer to Tables A3.7-1 and A3.7-2.

Table A3.7-1: Regional 345 kV Sum of Line Lengths (in Miles)

Type (kV)	States								Total Line Length
	IA	IL	IN	MI	MN/Dak	MO	OH/PA	WI	
345	887	869	39	196	214	486		797	3488
765	150				67		269		487
2-345	729	152			3439			286	4606
400								60	60
800	335	532	489		280	229	363	103	2332
Grand Total	**2101**	**1553**	**528**	**196**	**4000**	**715**	**632**	**1247**	**10973**

Table A3.7-2: Regional 345 kV Sum of Total Cost

Type (kV)	States								Grand Total
	IA	IL	IN	MI	MN/Dak	MO	OH/PA	WI	
345	$1,330	$1,739	$71	$353	$427	$486		$1,993	$6,399
765	$631				$324		$1,076		$2,031
2-345	$1,532	$394			$8,598			$859	$11,382
400								$887	$887
800	$3,159	$7,225	$7,131		$3,039	$1,716	$6,854	$1,437	$30,561
Grand Total	**$6,652**	**$9,358**	**$7,202**	**$353**	**$12,388**	**$2,201**	**$7,930**	**$5,176**	**$51,260**

Generation

MW of Capacity	Cost (M$)
33,450	**$66,900.00**

Total Costs (2010 USD in Millions)

Transmission	$51,260
Generation	$66,900
Transformers	
Substations	
Reactors	
Total	**$118,160**

A3.8 Regional 345 kV Optimized

Refer to Tables A3.8-1 and A3.8-2.

Table A3.8-1: Regional 345 kV Optimized Sum of Line Lengths (in Miles)

Type (kV)	States								Total Line Length
	IA	IL	IN	MI	MN/Dak	MO	OH/PA	WI	
345	887	869	39	196	214	486		797	3488
765	150				67		269		487
2-345	729	152			3439			286	4606
400								60	60
800	335	532	489		280	229	363	103	2332
Grand Total	**2101**	**1553**	**528**	**196**	**4000**	**715**	**632**	**1247**	**10973**

Table A3.8-2: Regional 345 kV Optimized Sum of Total Cost

Type (kV)	States								Grand Total
	IA	IL	IN	MI	MN/Dak	MO	OH/PA	WI	
345	$1,330	$1,739	$71	$353	$427	$486		$1,993	$6,399
765	$631				$324		$1,076		$2,031
2-345	$1,532	$394			$8,598			$859	$11,382
400								$887	$887
800	$3,159	$7,225	$7,131		$3,039	$1,716	$6,854	$1,437	$30,561
Grand Total	**$6,652**	**$9,358**	**$7,202**	**$353**	**$12,388**	**$2,201**	**$7,930**	**$5,176**	**$51,260**

Generation	
MW of Capacity	Cost (M$)
30,400	$60,800.00

Total Costs (2010 USD in Millions)	
Transmission	$51,260
Generation	$60,800
Transformers	
Substations	
Reactors	
Total	**$112,060**

Refer to Figure A3.8-1.

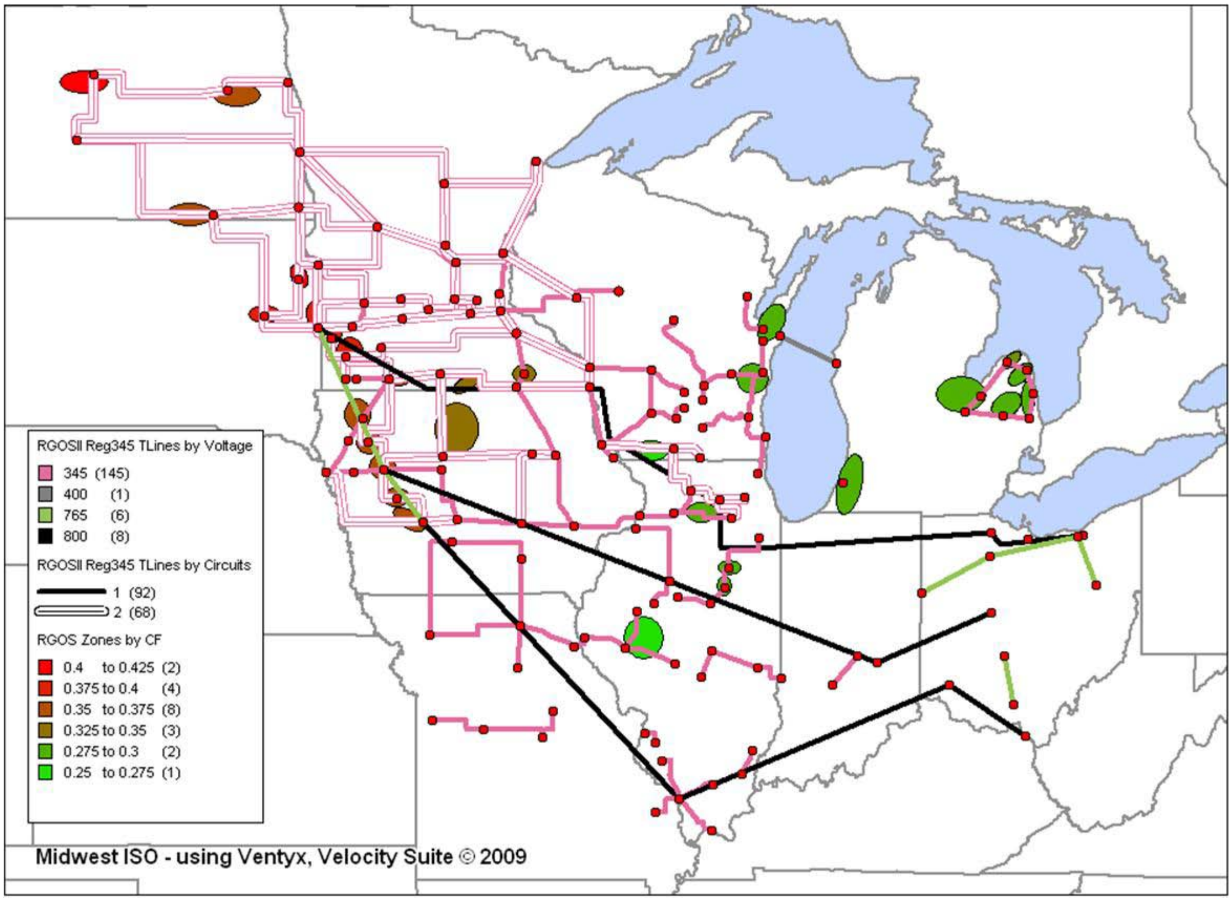

Figure A3.8-1: RGOS Regional 345 kV (with Optimized)

A3.9 Regional 765 kV with DC

Refer to Tables A3.9-1 and A3.9-2.

Table A3.9-1: Regional 765 kV with DC Sum of Line Lengths (in Miles)

Type (kV)	States								Total Line Length
	IA	IL	IN	MI	MN/Dak	MO	OH/PA	WI	
345	350	781	39	196	32	277		842	2517
765	651	505	354	319	1656	324	317	148	4274
2-345	337				1232			21	1590
400								60	60
800	166	297	437		280	222	3	101	1506
Grand Total	**1504**	**1583**	**830**	**515**	**3200**	**823**	**320**	**1172**	**9947**

Table A3.9-2: Regional 765 kV with DC Sum of Total Cost

Type (kV)	States								Grand Total
	IA	IL	IN	MI	MN/Dak	MO	OH/PA	WI	
345	$524	$1,563	$71	$353	$63	$277		$2,105	$4,957
765	$2,735	$2,121	$1,559	$1,148	$7,948	$1,361	$1,269	$708	$18,850
2-345	$707				$3,080			$62	$3,849
400								$887	$887
800	$1,577	$4,286	$4,594		$3,039	$1,699	$2,428	$1,434	$19,057
Grand Total	**$5,544**	**$7,970**	**$6,224**	**$1,502**	**$14,129**	**$3,337**	**$3,696**	**$5,197**	**$47,600**

Generation

MW of Capacity	Cost (M$)
33,450	$66,900.00

Total Costs (2010 USD in Millions)

Transmission	$47,600
Generation	$66,900
Transformers	
Substations	
Reactors	
Total	**$114,500**

A3.10 Regional 765 kV with DC Optimized

Refer to Tables A3.10-1 and A3.10-2.

Table A3.10-1: Regional 765 kV with DC Optimized Sum of Line Lengths (in Miles)

Type (kV)	States								Total Line Length
	IA	IL	IN	MI	MN/Dak	MO	OH/PA	WI	
345	350	781	39	196	32	277		842	2517
765	651	505	354	319	1656	324	317	148	4274
2-345	337				1232			21	1590
400								60	60
800	166	297	437		280	222	3	101	1506
Grand Total	**1504**	**1583**	**830**	**515**	**3200**	**823**	**320**	**1172**	**9947**

Table A3.10-2: Regional 765 kV with DC Optimized Sum of Total Cost

Type (kV)	States								Grand Total
	IA	IL	IN	MI	MN/Dak	MO	OH/PA	WI	
345	$524	$1,563	$71	$353	$63	$277		$2,105	$4,957
765	$2,735	$2,121	$1,559	$1,148	$7,948	$1,361	$1,269	$708	$18,850
2-345	$707				$3,080			$62	$3,849
400								$887	$887
800	$1,577	$4,286	$4,594		$3,039	$1,699	$2,428	$1,434	$19,057
Grand Total	**$5,544**	**$7,970**	**$6,224**	**$1,502**	**$14,129**	**$3,337**	**$3,696**	**$5,197**	**$47,600**

Generation	
MW of Capacity	Cost (M$)
30,400	**$60,800.00**

Total Costs (2010 USD in Millions)	
Transmission	$47,600
Generation	$60,800
Transformers	
Substations	
Reactors	
Total	**$108,400**

Refer to Figure A3.10-1.

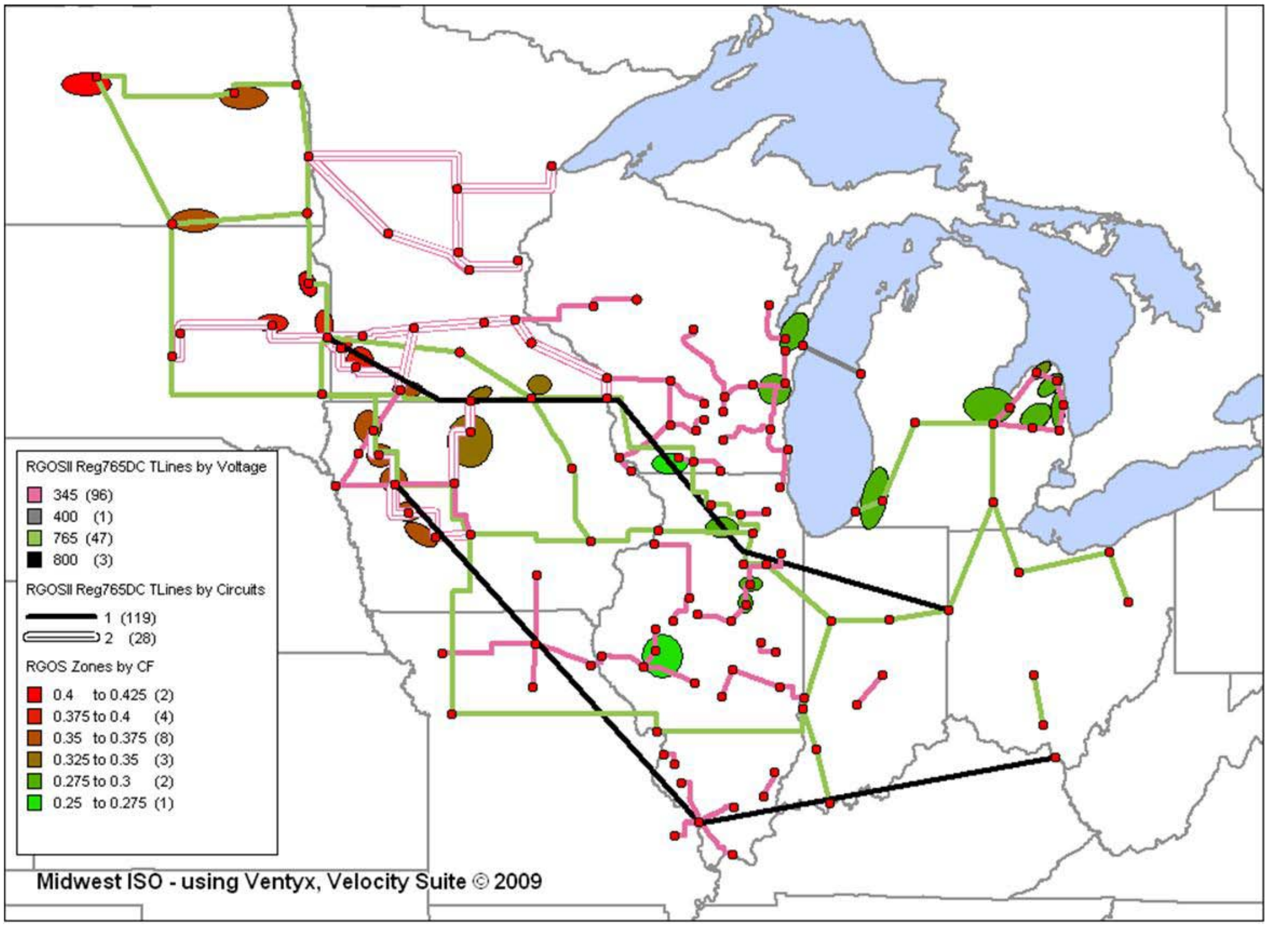

Figure A3.10-1: RGOS Regional 765 kV with DC (with Optimized)

A3.11 Regional 765 kV DC West

Refer to Tables A3.11-1 and A3.11-2.

Table A3.11-1: Regional 765 kV DC West Sum of Line Lengths (in Miles)

Type (kV)	States								Total Line Length
	IA	IL	IN	MI	MN/Dak	MO	OH/PA	WI	
345	350	755	39	196	32	277		842	2491
765	410	495	393	319	1169		317		3102
2-345	337				1232			21	1590
400								60	60
800	166	166			280	222		99	934
Grand Total	**1263**	**1415**	**432**	**515**	**2712**	**499**	**317**	**1022**	**8176**

Table A3.11-2: Regional 765 kV DC West Sum of Total Cost

Type (kV)	States								Grand Total
	IA	IL	IN	MI	MN/Dak	MO	OH/PA	WI	
345	$524	$1,509	$71	$353	$63	$277		$2,105	$4,903
765	$1,723	$2,077	$1,728	$1,148	$5,610		$1,269		$13,555
2-345	$707				$3,080			$62	$3,849
400								$887	$887
800	$1,577	$2,788			$3,039	$1,699		$1,429	$10,531
Grand Total	**$4,532**	**$6,374**	**$1,798**	**$1,502**	**$11,791**	**$1,976**	**$1,269**	**$4,483**	**$33,726**

Generation

MW of Capacity	Cost (M$)
33,450	**$66,900.00**

Total Costs (2010 USD in Millions)

Transmission	$33,726
Generation	$66,900
Transformers	
Substations	
Reactors	
Total	**$100,626**

A3.12 Regional 765 kV DC West Optimized

Refer to Tables A3.12-1 and A3.12-2.

Table A3.12-1: Regional 765 kV DC West Optimized Sum of Line Lengths (in Miles)

Type (kV)	States								Total Line Length
	IA	IL	IN	MI	MN/Dak	MO	OH/PA	WI	
345	350	755	39	196	32	277		842	2491
765	410	495	393	319	1169		317		3102
2-345	337				1232			21	1590
400								60	60
800	166	166			280	222		99	934
Grand Total	**1263**	**1415**	**432**	**515**	**2712**	**499**	**317**	**1022**	**8176**

Table A3.12-2: Regional 765 kV DC West Optimized Sum of Line Lengths (in Miles)Sum of Total Cost

Type (kV)	States								Grand Total
	IA	IL	IN	MI	MN/Dak	MO	OH/PA	WI	
345	$524	$1,509	$71	$353	$63	$277		$2,105	$4,903
765	$1,723	$2,077	$1,728	$1,148	$5,610		$1,269		$13,555
2-345	$707				$3,080			$62	$3,849
400								$887	$887
800	$1,577	$2,788			$3,039	$1,699		$1,429	$10,531
Grand Total	**$4,532**	**$6,374**	**$1,798**	**$1,502**	**$11,791**	**$1,976**	**$1,269**	**$4,483**	**$33,726**

Generation

MW of Capacity	Cost (M$)
30,400	**$60,800.00**

Total Costs (2010 USD in Millions)

Transmission	$33,726
Generation	$60,800
Transformers	
Substations	
Reactors	
Total	**$94,526**

Refer to Figure A3.12-1.

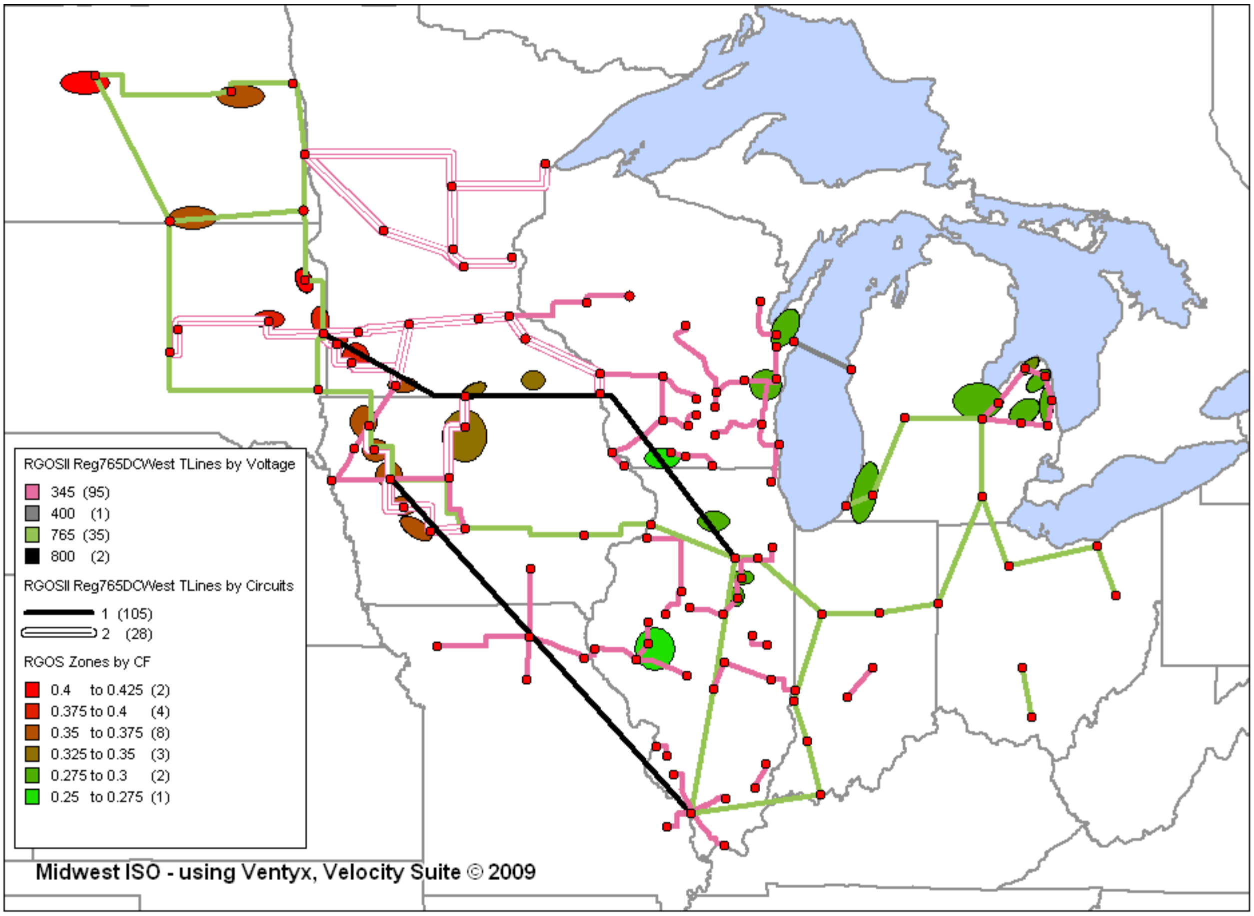

Figure A3.12-1: RGOS Regional 765 kV DC West (with Optimized)

A3.13 Regional 765 kV

Refer to Tables A3.13-1 and A3.13-2.

Table A3.13-1: Regional 765 kV Sum of Line Lengths (in Miles)

Type (kV)	States								Total Line Length
	IA	IL	IN	MI	MN/Dak	MO	OH/PA	WI	
345	350	781	39	196	32	277		842	2517
765	651	834	411	319	1656	324	317	148	4660
2-345	337				1232			21	1589
400								60	60
Grand Total	**1338**	**1615**	**450**	**515**	**2919**	**601**	**317**	**1071**	**8827**

Table A3.13-2: Regional 765 kV Sum of Total Cost

Type (kV)	States								Grand Total
	IA	IL	IN	MI	MN/Dak	MO	OH/PA	WI	
345	$524	$1,563	$71	$353	$63	$277		$2,105	$4,957
765	$2,735	$3,503	$1,807	$1,148	$7,948	$1,361	$1,269	$708	$20,480
2-345	$707				$3,079			$62	$3,849
400								$887	$887
Grand Total	**$3,967**	**$5,066**	**$1,877**	**$1,502**	**$11,090**	**$1,638**	**$1,269**	**$3,763**	**$30,173**

Generation

MW of Capacity	Cost (M$)
33,450	**$66,900.00**

Total Costs (2010 USD in Millions)

Transmission	$30,173
Generation	$66,900
Transformers	
Substations	
Reactors	
Total	**$97,073**

A3.14 Regional 765 kV Optimized

Refer to Tables A3.14-1 and A3.14-2.

Table A3.14-1: Regional 765 kV Optimized Sum of Line Lengths (in Miles)

Type (kV)	States								Total Line Length
	IA	IL	IN	MI	MN/Dak	MO	OH/PA	WI	
345	350	781	39	196	32	277		842	2517
765	651	834	411	319	1656	324	317	148	4660
2-345	337				1232			21	1589
400								60	60
Grand Total	**1338**	**1615**	**450**	**515**	**2919**	**601**	**317**	**1071**	**8827**

Table A3.14-2: Regional 765 kV Optimized Sum of Total Cost

Type (kV)	States								Grand Total
	IA	IL	IN	MI	MN/Dak	MO	OH/PA	WI	
345	$524	$1,563	$71	$353	$63	$277		$2,105	$4,957
765	$2,735	$3,503	$1,807	$1,148	$7,948	$1,361	$1,269	$708	$20,480
2-345	$707				$3,079			$62	$3,849
400								$887	$887
Grand Total	**$3,967**	**$5,066**	**$1,877**	**$1,502**	**$11,090**	**$1,638**	**$1,269**	**$3,763**	**$30,173**

Generation

MW of Capacity	Cost (M$)
30,400	**$60,800.00**

Total Costs (2010 USD in Millions)

Transmission	$30,173
Generation	$60,800
Transformers	
Substations	
Reactors	
Total	**$90,973**

Refer to Figure A3.14-1.

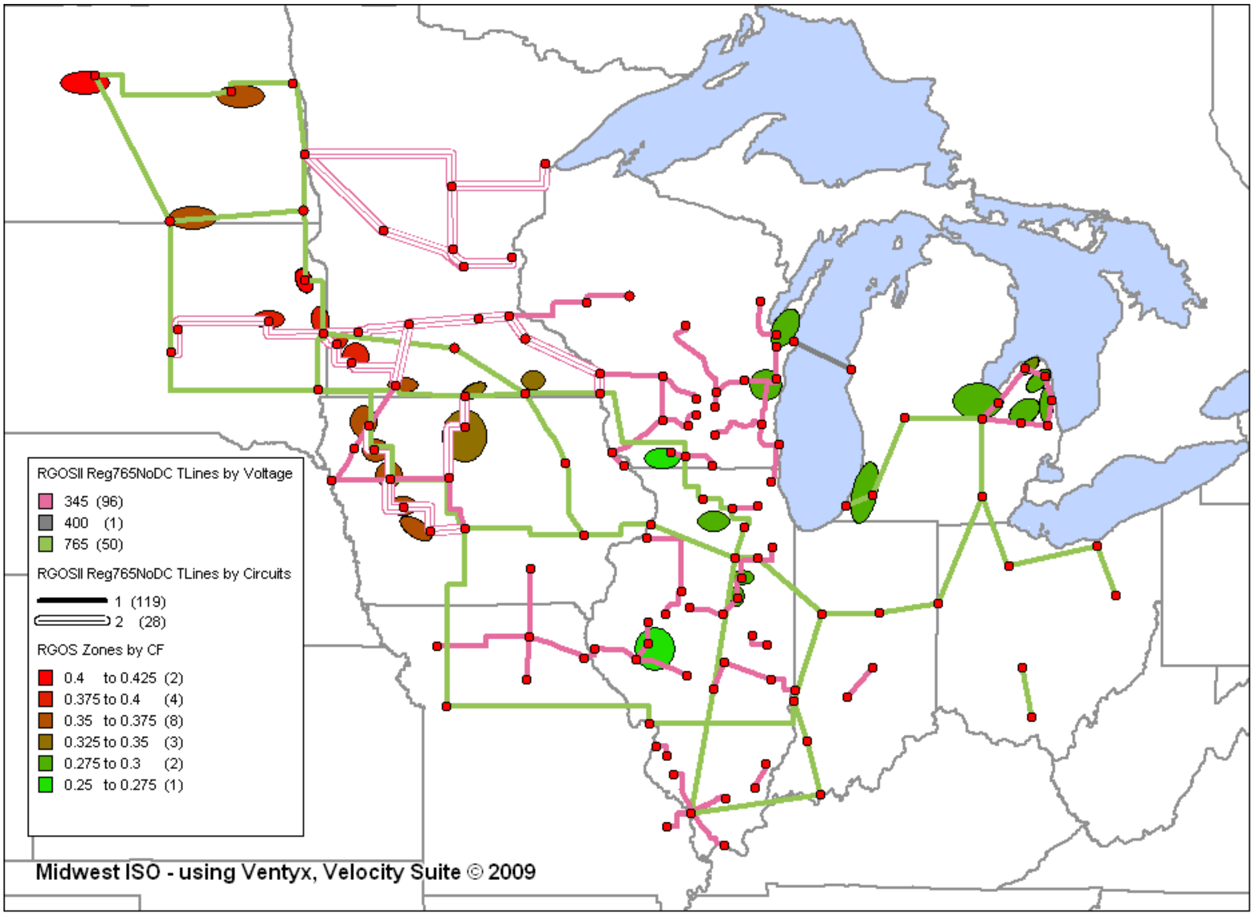

Figure A3.14-1: RGOS Regional 765 kV Optimized