MTEP14 MVP Triennial Review

A 2014 review of the public policy, economic, and qualitative benefits of the Multi-Value Project Portfolio

September 2014

Contents

Executive Summary

The MTEP14 Triennial Multi-Value Project (MVP) Review provides an updated view into the projected economic, public policy, and qualitative benefits of the MVP Portfolio. The MTEP14 MVP Triennial Review's business case is on par with, if not stronger than MTEP11, providing evidence that the MVP criteria and methodology works as expected. Analysis shows that projected MISO North and Central Region benefits provided by the MVP Portfolio have increased since MTEP11, the analysis from which the Portfolio's business case was approved.

Analysis shows that projected benefits provided by the MVP Portfolio have increased since MTEP11

The MTEP14 results demonstrate the MVP Portfolio:

- Provides benefits in excess of its costs, with its benefit-to-cost ratio ranging from 2.6 to 3.9; an increase from the 1.8 to 3.0 range calculated in MTEP11
- Creates $13.1 to $49.6 billion in net benefits over the next 20 to 40 years, an increase of approximately 50 percent from MTEP11
- Enables 43 million MWh of wind energy to meet renewable energy mandates and goals through year 2028, an additional 2 million MWh from the MTEP11 year 2026 forecast
- Provides additional benefits to each local resource zone relative to MTEP11

Benefit increases are primarily congestion and fuel savings largely driven by natural gas price assumptions.

The fundamental goal of the MISO's planning process is to develop a comprehensive expansion plan that meets the reliability, policy, and economic needs of the system. Implementation of a value-based planning process creates a consolidated transmission plan that delivers regional value while meeting near-term system needs. Regional transmission solutions, or Multi Value Projects (MVPs), meet one or more of three goals:

- Reliably and economically enable regional public policy needs
- Provide multiple types of regional economic value
- Provide a combination of regional reliability and economic value

MISO conducted its first triennial MVP Portfolio review, per tariff requirement, for MTEP14. The MVP Review has no impact on the existing MVP Portfolio cost allocation. MTEP14 Review analysis is performed solely for informational purposes. The intent of the MVP Review is to use the review process and results to identify potential modifications to the MVP methodology and its implementation for projects to be approved at a future date.

The Triennial MVP Review has no impact on the existing MVP Portfolio cost allocation. The intent of the MVP Review is to identify potential modifications to the MVP methodology for projects to be approved at a future date.

The MVP Review uses stakeholder-vetted MTEP14 models and makes every effort to follow procedures and assumptions consistent with the MTEP11 analysis. Metrics that required any changes to the benefit valuation due to changing tariffs, procedures or conditions are highlighted. Consistent with MTEP11, the MTEP14 MVP Review assesses the benefits of the entire MVP Portfolio and does not differentiate between facilities currently in-service and those still being planned. Because the MVP Portfolio's costs are allocated solely to the MISO North and Central Regions, only MISO North and Central Region benefits are included in the MTEP14 MVP Triennial Review.

Public Policy Benefits

The MTEP14 MVP Review reconfirms the MVP Portfolio's ability to deliver wind generation, in a cost-effective manner, in support of MISO States' renewable energy mandates. Renewable Portfolio Standards assumptions[1] have not changed since the MTEP11 analysis.

Updated analyses find that 10.5 GW of year 2023 dispatched wind would be curtailed in lieu of the MVP Portfolio, which extrapolates to 56 percent of the 2028 full RPS energy. MTEP11 analysis showed that 63 percent of the year 2026 full RPS energy would be curtailed without the installation of the MVP Portfolio. The MTEP14 calculated reduction in curtailment as a percentage of RPS has decreased since MTEP11, primarily because post-MTEP11 transmission upgrades are represented and the actual physical location of installed wind turbines has changed slightly since the 2011 forecast.

In addition to allowing energy to not be curtailed, analyses determined that 4.3 GW of wind generation in excess of the 2028 requirements is enabled by the MVP Portfolio. MTEP11 analysis determined that 2.2 GW of additional year 2026 generation could be sourced from the incremental energy zones. The results are the essentially the same for both analyses as the increase in wind enabled from MTEP 2011 is primarily attributed to additional load growth. The MTEP 2011 analysis was performed on a year 2026 model and MTEP 2014 on year 2028.

When the results from the curtailment analyses and the wind enabled analyses are combined, MTEP 2014 results show the MVP Portfolio enables a total of 43 million MWh of renewable energy to meet the renewable energy mandates through 2028. MTEP 2011 showed the MVP Portfolio enabled a similar level renewable energy mandates – 41 million MWh through 2026.

[1] Assumptions include Renewable Portflio Standard levels and fulfillment methods

Economic Benefits

MTEP14 analysis shows the Multi-Value Portfolio creates $21.5 to $66.8 billion in total benefits to MISO North and Central Region members (Figure E-1). Total portfolio costs have increased from $5.56 billion in MTEP11 to $5.86 billion in MTEP14. Even with the increased portfolio cost estimates, the increased MTEP14 congestion and fuel savings and transmission line losses benefit forecasts result in portfolio benefit-to-cost ratios that have increased since MTEP11.

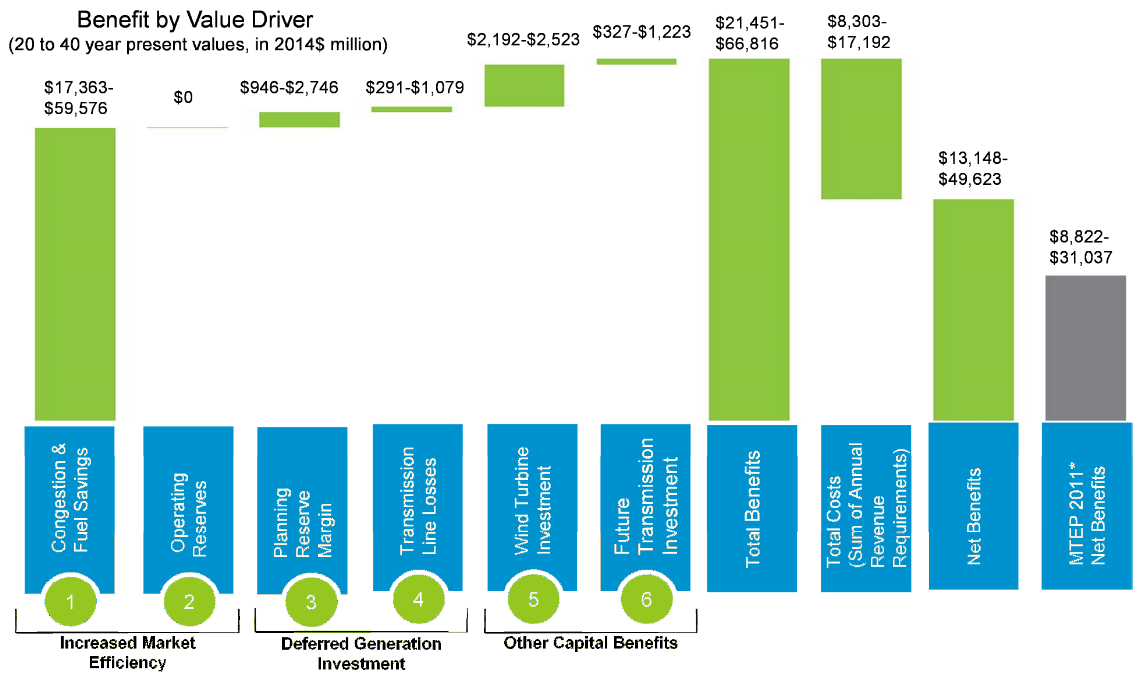


Figure E-1: MVP Portfolio Economic Benefits from MTEP14 MVP Triennial Review

The bulk of the increase in benefits is due to an increase in the assumed natural gas price forecast in MTEP14 compared to MTEP11. In addition, the MTEP15 natural gas assumptions, which will be used in the MTEP15 MVP Portfolio Limited Review, are lower than the MTEP14 forecast. Under each of the natural gas price assumption sensitivities, the MVP Portfolio is projected to provide economic benefits in excess of costs (Table E-1).

Natural Gas Forecast Assumption	Total NPV Portfolio Benefits ($M-2014)	Total Portfolio Benefit to Cost Ratio
MTEP14 – MVP Triennial Review	21,451 – 66,816	2.6 – 3.9
MTEP11	17,875 – 54,186	2.2 – 3.2
MTEP15	18,472 – 56,670	2.2 – 3.3

Table E-1: MVP Portfolio Economic Benefits - Natural Gas Price Sensitivities[2]

Increased Market Efficiency

The MVP Portfolio allows for a more efficient dispatch of generation resources, opening markets to competition and spreading the benefits of low-cost generation throughout the MISO footprint. The MVP Review estimates that the MVP Portfolio will yield $17 to $60 billion in 20- to 40-year present value adjusted production cost benefits to MISO's North and Central Regions – an increase of up to 40 percent from the MTEP11 net present value.

An increase in the natural gas price escalation rate, increases congestion and fuel savings benefits by approximately 30 percent in MTEP14 compared to MTEP11

The increase in congestion and fuel savings benefits relative to MTEP11 is primarily due to an increase in the out-year natural gas price forecast assumptions (Figures E-2). The increased escalation rate causes the assumed natural gas price to be higher in MTEP14 compared to MTEP11 in years 2023 and 2028 - the two years from which the congestion and fuel savings results are based (Figure E-2).

The MVP Portfolio allows access to wind units with a nearly $0/MWh production cost and primarily replaces natural gas units in the dispatch, which makes the MVP Portfolio's fuel savings benefit projection directly related to the natural gas price assumption. A sensitivity applying the MTEP11 Low BAU gas prices assumption to the MTEP14 MVP Triennial Review model showed a 29.3 percent reduction in the annual year 2028 MTEP14 congestion and fuel savings benefits (Figure E-2).

Post MTEP14 natural gas price forecast assumptions are more closely aligned with those of MTEP11 (Figure E-2). A sensitivity applying the MTEP15 BAU natural gas prices to the MTEP14 analysis showed a 21.7 percent reduction in year 2028 MTEP14 adjusted production cost savings.

[2] Sensitivity performed applying MTEP11/MTEP15 natural gas price to the MTEP14 congestion and fuel savings model. All other benefit valuations unchanged from the MTEP14 MVP Triennial Review.

MISO membership changes have little net effect on benefit-to-cost ratios. The exclusion of Duke Ohio/Kentucky and First Energy from the MISO pool decreases benefits by 7.4 percent relative to the MTEP14 total benefits; however, per Schedule 39, 6.3 percent of the total portfolio costs are allocated to Duke Ohio/Kentucky and First Energy, thus there is a minimal net effect to the benefit-to-cost ratio.

The MVP Portfolio is solely located in the MISO North and Central Regions and therefore, the inclusion of the MISO South Region to the MISO dispatch pool has little effect on MVP-related production cost savings (Figure E-2).

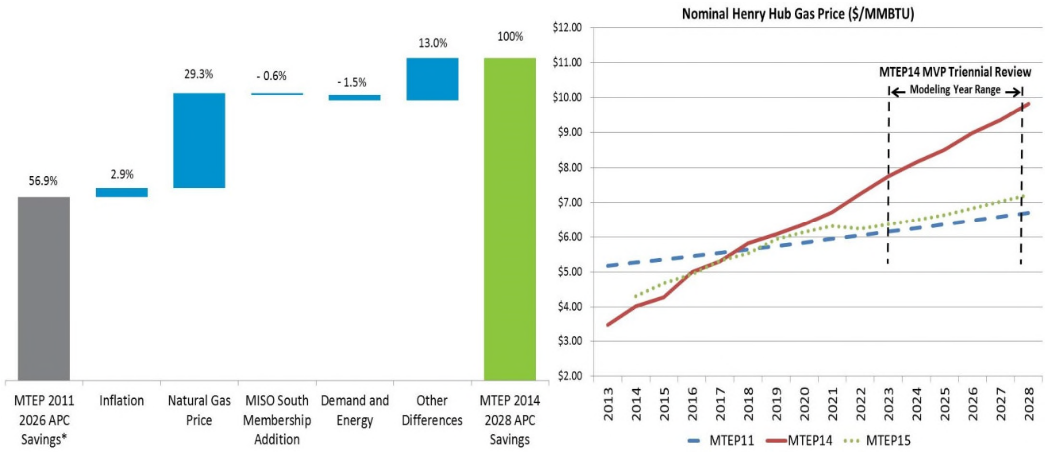


Figure E-2: Breakdown of Congestion and Fuel Savings Increase from MTEP11 to MTEP14

In addition to the energy benefits quantified in the production cost analyses, the 2011 business case showed the MVP Portfolio also reduces operating reserve costs. The MVP Review does not estimate a reduced operating reserve benefit in 2014, as a conservative measure, because of the decreased number of days a reserve requirement was calculated since the MTEP11 analysis.

Deferred Generation Investment

The addition of the MVP Portfolio to the transmission network reduces overall system losses, which also reduces the generation needed to serve the combined load and transmission line losses. Using current capital costs, the deferment from loss reduction equates to a MISO North and Central Regions' savings of $291 to $1,079 million - nearly double the MTEP11 values. Tightening reserve margins, from an additional approximate 12 GW of expected coal generation retirements, have increased the value of deferred capacity from transmission losses in MTEP14. In addition to the tighter reserve margins, a one year shift forward in MVP Portfolio in-service dates since MTEP11 has increased benefits by an additional 30 percent.

The MTEP14 MVP Review estimates the MVPs annually defer more than $900 million in future capacity expansion by increasing capacity import limits, thus reducing the local clearing requirements of the system planning reserve margin requirement. In the 2013 planning year, MISO and the Loss of Load Expectation Working Group improved the methodology that establishes the MISO Planning Reserve Margin Requirement (PRMR). Previously, and in the MTEP11 analysis, MISO developed a MISO-wide

PRMR with an embedded congestion component. The post 2013 planning year methodology no longer uses a congestion component, but rather calculates a more granular zonal PRMR and a local clearing requirement based on the zonal capacity import limit. While terminology and methods have changed between MTEP11 and MTEP14, both calculations capture the same benefit of increased capacity sharing across the MISO region provided by the MVPs; as such, MTEP14 and MTEP11 provide benefit estimates of similar magnitudes.

Other Capital Benefits

Benefits from the optimization of wind generation siting and the elimination of need for some future baseline reliability upgrades remain at similar levels to those estimated in MTEP11. A slight increase in MTEP14 wind turbine investment benefits relative to MTEP11 benefits is from an update to the wind requirement forecast and wind enabled calculations.

Consistent with MTEP11, the MTEP14 MVP Triennial Review shows that the MVP Portfolio eliminates the need for $300 million in future baseline reliability upgrades. The magnitude of estimated benefits is in close proximity to the estimate from MTEP11; however, the actual identified upgrades have some differences because of load growth, generation dispatch, wind levels and transmission upgrades.

Distribution of Economic Benefits

The MVP Portfolio provides benefits across the MISO footprint in a manner that is roughly equivalent to costs allocated to each local resource zone (Figure E-3). The MVP Portfolio's benefits are at least 2.3 to 2.8 times the cost allocated to each zone. As a result of changing tariffs/business practices (planning reserve margin requirement and baseline reliability project cost allocation), load growth, and wind siting, zonal benefit distributions have changed slightly since MTEP11.

> Benefit-to-cost ratios have increased in all zones since MTEP11

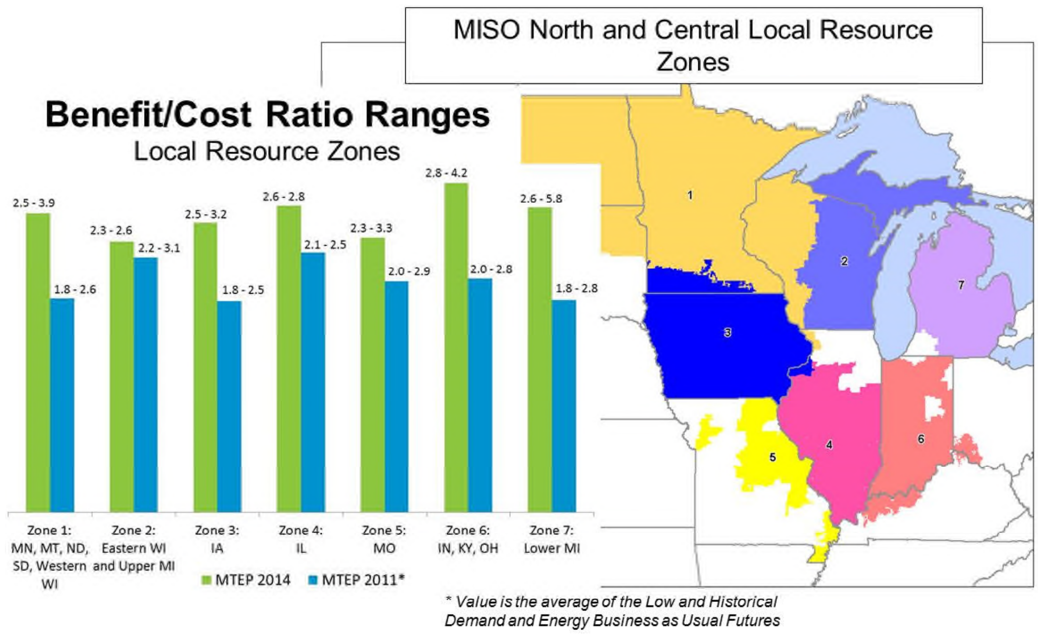


Figure E-3: MVP Portfolio Total Benefit Distribution

Qualitative and Social Benefits

Aside from widespread economic and public policy benefits, the MVP Portfolio also provides benefits based on qualitative or social values. The MVP Portfolio:

- Enhances generation flexibility
- Creates a more robust regional transmission system that decreases the likelihood of future blackouts
- Increases the geographic diversity of wind resources that can be delivered, increasing the average wind output available at any given time
- Supports the creation of thousands of local jobs and billions in local investment
- Reduces carbon emissions by 9 to 15 million tons annually

These benefits suggest quantified values from the economic analysis may be conservative because they do not account for the full potential benefits of the MVP Portfolio.

Going Forward

MTEP15 and MTEP16 will feature a Limited Review of the MVP Portfolio benefits. Each Limited Review will provide an updated assessment of the congestion and fuel savings using the latest portfolio costs and in-service dates. Beginning in MTEP17, in addition to the Full Triennial Review, MISO will perform an assessment of the congestion costs, energy prices, fuel costs, planning reserve margin requirements, resource interconnections and energy supply consumption based on historical data.

1. Study Purpose and Drivers

Beginning in MISO Transmission Expansion Plan (MTEP) 2014, MISO has a triennial tariff requirement to conduct a full review of the Multi-Value Project (MVP) Portfolio benefits. The MTEP14 Triennial MVP Review provides an updated view into the projected economic, public policy and qualitative benefits of the MTEP11 approved MVP Portfolio.

The MVP Triennial Review has no impact on the existing Multi-Value Project Portfolio cost allocation. The study is performed solely for information purposes.

The MVP Review has no impact on the existing MVP Portfolio cost allocation. Analysis is performed solely for information purposes. The intent of the MVP Reviews is to use the review process and results to identify potential modifications to the MVP methodology and its implementation for projects to be approved at a future date. The MVP Reviews are intended to verify if the MVP criteria and methodology is working as expected.

The MVP Review uses stakeholder vetted models and makes every effort to follow consistent procedures and assumptions as the Candidate MVP, also known as the MTEP11 analysis. Any metrics that required changes to the benefit valuation due to revised tariffs, procedures or conditions are highlighted throughout the report. Wherever practical, any differences between MTEP14 and MTEP11 assumptions are highlighted and the resulting differences quantified.

Consistent with MTEP11, the MTEP14 MVP Review assesses the benefits of the entire MVP Portfolio and does not differentiate between facilities currently in-service and those still being planned. The latest MVP cost estimates and in-service dates are used for all analyses.

2. Study Background

The MVP Portfolio (Figure 2-1 and Table 2-1) represents the culmination of more than eight years of planning efforts to find a cost-effective regional transmission solution that meets local energy and reliability needs.

In MTEP11, the MVP Portfolio was justified based its ability to:

- Provide benefits in excess of its costs under all scenarios studied, with its benefit-to-cost ratio ranging from 1.8 to 3.0.
- Maintain system reliability by resolving reliability violations on approximately 650 elements for more than 6,700 system conditions and mitigating 31 system instability conditions.
- Enable 41 million MWh of wind energy per year to meet renewable energy mandates and goals.
- Provide an average annual value of $1,279 million over the first 40 years of service, at an average annual revenue requirement of $624 million.
- Support a variety of generation policies by using a set of energy zones which support wind, natural gas and other fuel sources.

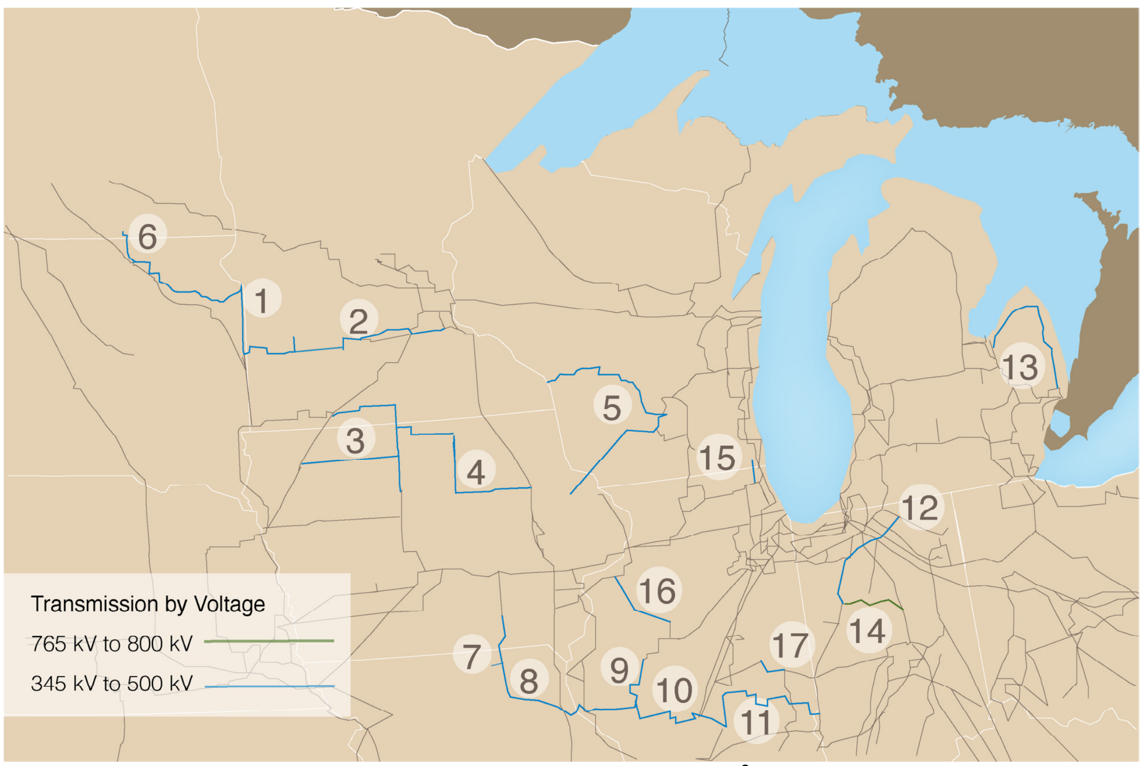


Figure 2-1: MVP Portfolio[3]

[3] Figure for illustrative purposes only. Final line routing may differ.

ID	Project	State	Voltage (kV)
1	Big Stone–Brookings	SD	345
2	Brookings, SD–SE Twin Cities	MN/SD	345
3	Lakefield Jct.–Winnebago–Winco–Burt Area & Sheldon–Burt Area–Webster	MN/IA	345
4	Winco–Lime Creek–Emery–Black Hawk–Hazleton	IA	345
5	LaCrosse–N. Madison–Cardinal & Dubuque Co–Spring Green–Cardinal	WI	345
6	Ellendale–Big Stone	ND/SD	345
7	Adair–Ottumwa	IA/MO	345
8	Adair–Palmyra Tap	MO/IL	345
9	Palmyra Tap–Quincy–Merdosia–Ipava & Meredosia–Pawnee	IL	345
10	Pawnee–Pana	IL	345
11	Pana–Mt. Zion–Kansas–Sugar Creek	IL/IN	345
12	Reynolds–Burr Oak–Hiple	IN	345
13	Michigan Thumb Loop Expansion	MI	345
14	Reynolds–Greentown	IN	765
15	Pleasant Prairie–Zion Energy Center	WI/IL	345
16	Fargo-Galesburg–Oak Grove	IL	345
17	Sidney–Rising	IL	345

Table 2-1: MVP Portfolio

In 2008, the adoption of Renewable Portfolio Standards (RPS) (Figure 2-2) across the MISO footprint drove the need for a more regional and robust transmission system to deliver renewable resources from often remote renewable energy generators to load centers.

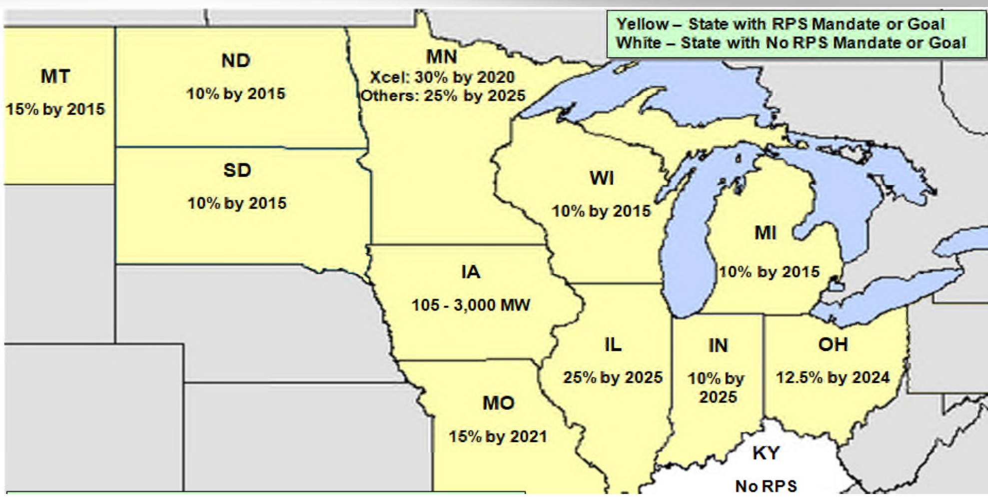


Figure 2-2: Renewable Portfolio Standards - 2011

Beginning with the MTEP 2003 Exploratory Studies, MISO and stakeholders began to explore how to best provide a value-added regional planning process to complement the local planning of MISO members. These explorations continued in later MTEP cycles and in specific targeted studies. In 2008, MISO, with the assistance of state regulators and industry stakeholders such as the Midwest Governor's Association (MGA), the Upper Midwest Transmission Development Initiative (UMTDI) and the Organization of MISO States (OMS), began the Regional Generation Outlet Study (RGOS) to identify a set of value-based transmission projects necessary to enable Load Serving Entities (LSEs) to meet their RPS mandates.

While much consideration was given to wind capacity factors when developing the energy zones utilized in the RGOS and MVP Portfolio analyses, the zones were chosen with consideration of more factors than wind capacity. Existing infrastructure, such as transmission and natural gas pipelines, also influenced the selection of the zones. As such, although the energy zones were created to serve the renewable generation mandates, they could be used for a variety of different generation types to serve various future generation policies.

Common elements between the RGOS results and previous reliability, economic and generation interconnection analyses were identified to create the 2011 candidate MVP portfolio. This portfolio represented a set of "no regrets" projects that were believed to provide multiple kinds of reliability and economic benefits under all alternate futures studied. Over the course of the MVP Portfolio analysis, the Candidate MVP Portfolio was refined into the portfolio that was approved by the MISO Board of Directors in MTEP11.

The MVP Portfolio enables the delivery of the renewable energy required by public policy mandates in a manner more reliable and economical than without the associated transmission upgrades. Specifically, the portfolio mitigates approximately 650 reliability constraints under 6,700 different transmission outage conditions for steady state and transient conditions under both peak and shoulder load scenarios. Some of these conditions could be severe enough to cause cascading outages on the system. By mitigating these constraints, approximately 41 million MWh per year of renewable generation can be delivered to serve the MISO state renewable portfolio mandates.

Under all future policy scenarios studied, the MVP Portfolio delivered widespread regional benefits to the transmission system. To use conservative projections relating only to the state renewable portfolio mandates, only the Business as Usual future was used in developing the candidate MVP business case.

The projected benefits are spread across the system, in a manner commensurate with costs (Figure 2-3).

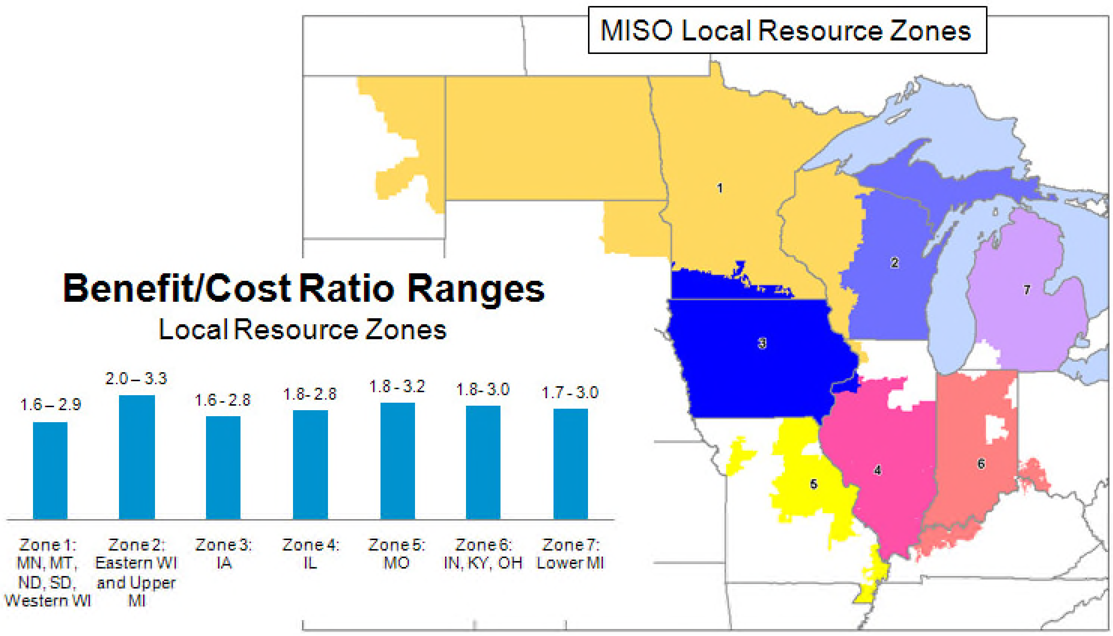


Figure 2-3: MTEP11 MVP Portfolio Benefit Spread

Taking into account the significant economic value created by the portfolio, the distribution of these value, and the ability of the portfolio to meet MVP criteria through its reliability and public policy benefits, the MVP Portfolio was approved by the MISO Board of Directors in MTEP11.

3. MTEP14 Review Model Development

The MTEP14 MVP Triennial Review uses MTEP14 economic models as the basis for the analysis. The MTEP14 economic models were developed in 2012 and 2013 with topology based on the MTEP13 series MISO powerflow models. To maintain consistency between economic and reliability models, MVP Triennial Review reliability analysis was performed with MTEP13 vintage powerflows.

MTEP14 economic models, developed in 2013, are the basis for the MTEP14 MVP Triennial Review.

The MTEP models were developed through an open stakeholder process and vetted through the MISO Planning Advisory Committee. The details of the economic and reliability models used in the MTEP14 MVP Triennial Review are described in the following sections. The MTEP models are publically available via the MISO FTP site with proper licenses and confidentiality agreements.

3.1 Economic Models

The MVP Benefit Review uses PROMOD IV as the primary tool to evaluate the economic benefits of the MVP Portfolio. The MTEP14 MISO North/Central economic models, stakeholder vetted in 2013, are used as the basis for the MTEP14 Review. The same economic models are used in the MTEP14 North/Central Market Congestion Planning Study, formerly known as the Market Efficiency Planning Study.

Consistent with the MTEP11 MVP business case[4], the MTEP14 Review relies solely on the Business as Usual (BAU) future.

The MTEP14 BAU future is most representative of the average of the MTEP11 Low and High BAU futures

The MTEP14 BAU future is defined as: A *status quo environment that assumes a slow recovery from the economic downturn and its impact on demand and energy projections. This scenario assumes existing standards for renewable mandates and little or no change in environmental legislation.*

MTEP11 had two definitions of the BAU future – a typical MTEP Planning Advisory Committee defined future and a slightly modified version from the Cost Allocation and Regional Planning (CARP) process. For the purposes of this report the two MTEP11 BAU futures are identified by their load growth rates – one with a slightly higher baseline growth rate and one with a slightly lower growth rate (Table 3-1). Based on current definitions, the MTEP14 BAU future's demand and energy growth rate is closest to the MTEP11 BAU-Low Demand and Energy, but the natural gas price is closest to the MTEP11 BAU-High Demand and Energy (Table 3-1). The MTEP14 BAU future is most representative of the average of the MTEP11 Low and High BAU futures; as such, all MTEP14 Triennial MVP Review results in this report will be compared to the arithmetic mean of the MTEP11 Low BAU and High BAU results.

[4] The Candidate MVP Analysis provided results for information purposes under all MTEP11 future scenarios; however, the business case only used the Business as Usual futures.

		MTEP14 BAU	MTEP11 Low BAU	MTEP11 High BAU
Demand and Energy	**Demand Growth Rate**	1.06 percent	1.26 percent	1.86 percent
	Energy Growth Rate	1.06 percent	1.26 percent	1.86 percent
Natural Gas Forecast[5]	**Starting Point**	3.48 $/MMBTU	5 $/MMBTU	5 $/MMBTU
	2018 Price	5.81 $/MMBTU	5.64 $/MMBTU	6.11 $/MMBTU
	2023 Price	7.76 $/MMBTU	6.15 $/MMBTU	7.05 $/MMBTU
	2028 Price	9.83 $/MMBTU	6.70 $/MMBTU	8.14 $/MMBTU
Fuel Cost (Starting Price)	**Oil**	Powerbase Default	Powerbase Default	Powerbase Default
	Coal	Powerbase Default	Powerbase Default	Powerbase Default
	Uranium	1.14 $/MMBTU	1.12 $/MMBTU	1.12 $/MMBTU
Fuel Escalations	**Oil**	2.50 percent	1.74 percent	2.91 percent
	Coal	2.50 percent	1.74 percent	2.91 percent
	Uranium	2.50 percent	1.74 percent	2.91 percent
Emission Costs	**SO2**	0	0	0
	NOx	0	0	0
	CO2	0	0	0
Other Variables	**Inflation**	2.50 percent	1.74 percent	2.91 percent
	Retirements	Known + EPA Driven Forecast MISO ~12,600 MW	Known Retirements MISO ~400 MW	Known Retirements MISO ~400 MW
	Renewable Levels	State Mandates	State Mandates	State Mandates
MISO Footprint		Duke and FE in PJM; includes MISO South	MTEP11	MTEP11

Table 3-1: MTEP14 and MTEP11 Key PROMOD Model Assumptions

Models include all publically announced retirements as well as 12,600 MW of baseline generation retirements driven by environmental regulations. Unit-specific retirements are based on a MISO Planning Advisory Committee vetted generic process as the results of the MISO Asset Owner EPA Survey are confidential.

MISO footprint changes since the MTEP11 analysis are modeled verbatim to current[6] configurations, i.e. Duke Ohio/Kentucky and First Energy are modeled as part of PJM and the MISO pool includes the MISO South Region. While the MISO pool includes the South Region, only the MISO North and Central Region benefits are being included in the MTEP14 MVP Triennial Review's business case.

[5] MTEP11 and MTEP13 use different natural gas escalation methodologies
[6] As of July 2014

MTEP13 powerflow models for the year 2023 are used as the base transmission topology for the MVP Triennial Review. Because there are no significant transmission topology changes known between years 2023 and 2028, the 2028 production cost models use the same transmission topology as 2023.

PROMOD uses an “event file” to provide pre- and post-contingent ratings for monitored transmission lines. The latest MISO Book of Flowgates and the NERC Book of Flowgates are used to create the event file of transmission constraints in the hourly security constrained model. Ratings and configurations are updated for out-year models by taking into account all approved MTEP Appendix A projects.

3.2 Capacity Expansion Models

The MTEP14 Triennial Review decreased transmission line losses benefit (Section 6.4) is monetized using the Electricity Generation Expansion Analysis System (EGEAS) model. EGEAS is designed by the Electric Power Research Institute to find the least-cost integrated resource supply plan given a demand level. EGEAS expansions include traditional supply-side resources, demand response, and storage resources. The EGEAS model is used annually in MISO’s MTEP process to identify future capacity needs beyond the typical five-year project-planning horizon.

The EGEAS optimization process is based on a dynamic programming method where all possible resource addition combinations that meet user-specified constraints are enumerated and evaluated. The EGEAS objective function minimizes the present value of revenue requirements. The revenue requirements include both carrying charges for capital investment and system operating costs.

MTEP14 Triennial MVP Review analysis was performed using the MTEP14 BAU future, developed in 2012 and 2013. The capacity model shares the same input database and assumptions as the economic models (Section 3.1).

3.3 Reliability Models

To maintain consistency between economic and reliability models, MTEP13 vintage MISO powerflow models are used as the basis for the MTEP14 MVP Triennial Review reliability analysis. The MTEP14 economic models are developed with topology based on the MTEP13 MISO powerflow models. Siemens PTI Power System Simulator for Engineering (PSS E) and Power System Simulator for Managing and Utilizing System Transmission (PSS MUST) is utilized for the MTEP14 MVP Triennial Review.

Powerflow models are built using MISO's Model on Demand (MOD) model data repository. Models include approved MTEP Appendix A projects and the Eastern Interconnection Reliability Assessment Group (ERAG) Multiregional Modeling Working Group (MMWG) modeling for the external system. Load and generation profiles are seasonal dependent (Table 3-2). MTEP powerflow models have wind dispatched at 90 percent connected capacity in Shoulder models and 20 percent in the Summer Peak.

Additional wind units were added to the MTEP14 MVP Triennial Review cases to meet renewable portfolio standards.

Demand is grown in the Future Transmission Investment case using the extrapolated growth rate between the year 2018 MTEP13 Summer Peak case and the 2023 MTEP13 Summer Peak Case.

Analysis	Model(s)
Wind Curtailment	2023 MTEP13 Shoulder
Wind Enabled	2023 MTEP13 Shoulder with Wind at 2028 Levels
Transmission Line Losses	2023 MTEP13 Summer Peak
Future Transmission Investment	2023 MTEP13 Summer Peak with Demand and Wind at 2033 Levels

Table 3-2: Reliability Models by Analysis

3.4 Capacity Import Limit Models

The MTEP13 series of MISO powerflow models updated for the 2014 Loss of Load Expectations (LOLE) study are used as the basis for the MTEP14 MVP Triennial Review capacity import limit analysis. Siemens Power Technology International Power System Simulator for Engineering (PSS E) and Power System Simulator for Managing and Utilizing System Transmission (PSS MUST) were utilized for the LOLE analyses, which produced results used in the MTEP14 MVP Triennial Review analysis.

Wind modeling and dispatch assumptions for LOLE studies were updated since completion of the 2014 LOLE analysis. These changes were applied to the MVP Triennial Review models so the Triennial analysis is using the up-to-date LOLE study methodology. Consistent with the current LOLE methodology, MISO wind dispatch was set at the wind capacity credit level. Applicable updates to generation retirements or suspensions were applied to the MTEP14 Triennial Review Models.

Zonal Local Clearing Requirements are calculated using the capacity import limits that are identified using PSS MUST transfer analysis. The MTEP14 MVP Triennial Review incorporates capacity import limits calculated using a year 2023 model both with and without the MVP Portfolio.

PSS MUST contingency files from Coordinated Seasonal Assessment (CSA) and MTEP[7] reliability assessment studies were used in the MTEP14 MVP Review (Table 3-3). Single-element contingencies in MISO and seam areas were evaluated in addition to submitted files.

Model	Contingency files used
2014-15 Planning Year	2013 Summer CSA
5-year-out peak	MTEP13 study

Table 3-3: Contingency files per model

PSS MUST subsystem files include source and sink definitions. The PSS MUST monitored file includes all facilities under MISO functional control and seam facilities 100 kV and above.

Additional details on the models used in the Planning Reserve Margin benefit estimation can be found in the 2014 Loss of Load Expectation Report.

3.5 Loss of Load Expectation Models

MISO utilizes the General Electric-developed Multi-Area Reliability Simulation (MARS) program to calculate the loss of load expectation for the applicable planning year. GE MARS uses a sequential Monte Carlo simulation to model a generation system and assess the system's reliability based on any number of interconnected areas. GE MARS calculates the annual LOLE for the MISO system and each Local Resource Zone (LRZ) by stepping through the year chronologically and taking into account generation, load, load modifying and energy efficiency resources, equipment forced outages, planned and maintenance outages, load forecast uncertainty and external support.

The 2014 planning year LOLE models, updated to include generation retirements, were the basis for the MTEP14 MVP Triennial Review models. Additional model details can be found in the 2014 Loss of Load Expectation Report.

[7] Refer to sections 4.3.4 and 4.3.6 of the Transmission Planning BPM for more information regarding MTEP PSS MUST input files. https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=19215

4. Project Costs and In-Service Dates

The MTEP14 MVP Triennial Review cost and in-service data is referenced from the MTEP Quarter One 2014 Report – dated April 11, 2014 (Figure 4-1).

MVP No.	Project Name	State	Estimated In Service Date[1]		Status		Cost[1]	
			MTEP Approved	Q1 2014	State Regulatory Status	Construction	MTEP Approved	Q1 2014
1	Big Stone-Brookings	SD	2017	2017	●	Pending	226.7	226.7
2	Brookings, SD-SE Twin Cities	MN/SD	2011-2015	2013-2015	●	Underway	738.4	640.9
3	Lakefield Jct. - Winnebago-Winco-Burt area & Sheldon-Burt Area-Webster	MN/IA	2015-2016	2016-2018	◑	Pending	550.4	541.1
4	Winco-Lime Creek-Emery-Black Hawk-Hazelton	IA	2015	2015-2018	◑	Pending	468.6	464.3
5	N. LaCrosse-N. Madison-Cardinal (a/k/a Badger-Coulee Project) & Dubuque Co.-Spring Green-Cardinal	WI/IA	2018-2020	2013-2018	◑	Pending	797.5	879.0
6	Big Stone South - Ellendale	ND/SD	2019	2019	◑	Pending	330.7	395.7
7	Adair-Ottumwa	IA/MO	2017-2020	2017-2018	○	Pending	152.3	178.2
8	Adair-Palmyra Tap	MO	2016-2018	2016-2018	○	Pending	112.8	108.1
9	Palmyra Tap-Quincy-Merdosia-Ipava & Meredosia-Pawnee	MO/IL	2016-2017	2016-2017	●	Pending	432.2	524.2
10	Pawnee-Pana	IL	2018	2016-2018	●	Pending	99.4	108.6
11	Pana-Mt. Zion-Kansas-Sugar Creek	IL/IN	2018-2019	2016-2019	●	Pending	318.4	356.2
12	Reynolds-Burr Oak-Hiple	IN	2019	2019	●	Pending	271.0	271.0
13	Michigan Thumb Loop Expansion	MI	2013-2015	2013-2015	●	Underway	510.0	510.0
14	Reynolds-Greentown	IN	2018	2018	●	Pending	245.0	328.7
15	Pleasant Prairie-Zion Energy Center	WI	2014	2013	●	Complete	28.8	33.0
16	Fargo-Galesburg-Oak Grove	IL	2014-2019	2016-2018	○	Pending	199.0	225.5
17	Sidney-Rising	IL	2016	2016	●	Pending	83.2	66.3
						Totals:	*5,564*	*5,858*

Figure 4-1: MVP Cost and In-Service Dates – MTEP11 version MTEP14[8]

For MTEP14, all benefit calculations start in year 2020, the first year when all projects are in service. For MTEP11, year 2021 was the first year when the MVP Portfolio was expected in-service.

The costs contained within the MTEP database are in nominal, as spent, dollars. Nominal dollars are converted to real dollars for net present value benefit cost calculations using the facility level in-service dates. To obtain a real value in 2020 dollars from the nominal values in the MTEP database each facility's cost escalates using a 2.5 percent inflation rate from in-service year to 2020.

A load ratio share was developed to allocate the benefit-to-cost ratios in each of the seven MISO North/Central local resource zones (LRZ). Load ratios are based off the actual 2010 energy withdrawals with an applied Business as Usual (BAU) MTEP growth rate applied.

[8] All costs in nominal dollars.

MTEP14 MVP Triennial Review benefit-to-cost calculations only include direct benefits to MISO North and Central members. Therefore it is necessary to exclude costs paid by parties outside of MISO via exports and costs paid by Duke Ohio/Kentucky and First Energy pursuant to Schedule 39. Consistent with MTEP11, export revenue is estimated as 1.94 percent of the total MVP Portfolio costs. Schedule 39 is estimated as 6.24 percent of the total portfolio costs. MISO South Region benefits are excluded from all estimations.

Total costs are annualized using the MISO North/Central-wide average Transmission Owner annual charge rate/revenue requirement. Consistent with the MTEP11 analysis and other Market Efficiency Projects, the MTEP14 MVP Triennial Review assumes that costs start in 2020, such as year one of the annual charge rate is 2020 and construction work in progress (CWIP) is excluded from the total costs.

5. Portfolio Public Policy Assessment

The MTEP14 MVP Triennial Review redemonstrates the MVP Portfolio's ability to enable the renewable energy mandates of the footprint. Renewable Portfolio Standards assumptions[9] have not changed since the MTEP11 analysis and any changes in capacity requirements are solely attributed to load forecast changes and the actual installation of wind turbines.

The MVP portfolio enables a total of 43 million MWh of renewable energy to meet the renewable energy mandates and goals through 2028.

This analysis took place in two parts. The first part demonstrated the wind needed to meet renewable energy mandates would be curtailed but for the approved MVP Portfolio. The second demonstrated the additional renewable energy, above the mandate, that will be enabled by the portfolio. This energy could be used to serve mandated renewable energy needs beyond 2028, as most of the mandates are indexed to grow with load.

5.1 Wind Curtailment

A wind curtailment analysis was performed to find the percentage of mandated renewable energy that could not be enabled but for the MVP Portfolio.
The shift factors for all wind machines were calculated on the worst NERC Category B and C contingency constraints of each monitored element identified in 2011 as mitigated by the MVP Portfolio. The 488 monitored element/contingent element pairs (flowgates) consisted of 233 Category B and 255 Category C contingency events. These constraints were taken from a blend of projected 2023 and 2028 wind levels with the final calculations based on the projected 2028 wind levels.

Since the majority of the MISO West Region MVP justification was based on 2023 wind levels, it was assumed that any incremental increase to reach the 2028 renewable energy mandated levels would be curtailed. A transfer of the 279 wind units, sourced from both committed wind units and the Regional Generation Outlet Study (RGOS) energy zones to the system sink, Browns Ferry in the Tennessee Valley Authority, was used to develop the shift factors on the flowgates.

Linear optimization logic was used to minimize the amount of wind curtailed while reducing loadings to within line capacities. Similar to the MTEP11 justifications, a target loading of less than or equal to 95 percent was used. Fifty-four of the 488 flowgates could not achieve the target loading reduction, and their targets were relaxed in order to find a solution.

[9] Assumptions include Renewable Portflio Standard levels and fulfillment methods

The algorithm found that 9,315 MW of year 2023 dispatched wind would be curtailed. It was also assumed that any additional wind in the West to meet Renewable Portfolio Standard (RPS) levels would be curtailed. This equated to 1,212 MW of dispatched wind. As a connected capacity, 11,697 MW would be curtailed, as the wind is modeled at 90 percent of its nameplate. The MTEP14 results are similar in magnitude to MTEP11, which found that 12,201 MW of connected wind would be curtailed through 2026.

The curtailed energy was calculated to be 32,176,153 MWh from the connected capacity multiplied by the capacity factor times 8,760 hours of the year. A MISO-wide per-unit capacity factor was averaged from the 2028 incremental wind zone capacities to 31.4 percent. Comparatively, the full 2028 RPS energy is 57,019,978 MWh. As a percentage of the 2028 full RPS energy, 56.4 percent would be curtailed in lieu of the MVP Portfolio. MTEP11 analysis showed that 63 percent of the year 2026 full RPS energy would be curtailed without the installation of the MVP Portfolio. The MTEP14 calculated reduction in curtailment as a percentage of RPS has decreased since MTEP11, primarily because post-MTEP11 transmission upgrades are represented and the actual physical location of installed wind turbines has changed slightly since the 2011 forecast.

5.2 Wind Enabled

Additional analyses were performed to determine the incremental wind energy in excess of the 2028 requirements enabled by the approved MVP Portfolio. This energy could be used to meet renewable energy mandates beyond 2028, as most of the state mandates are indexed to grow with load. A set of three First Contingency Incremental Transfer Capability (FCITC) analyses were run on the 2028 model to determine how much the wind in each zone could be ramped up prior to additional reliability constraints occurring.

Transfers were sourced from the wind zones in proportion to their 2028 maximum output. All Bulk Electric System (BES) elements in the MISO system were monitored, with constraints being flagged at 100 percent of the applicable ratings. All single contingencies in the MISO footprint were evaluated during the transfer analysis. This transfer was sunk against MISO, PJM, and SPP units (Table 5-1). More specifically, the power was sunk to the smallest units in each region, with the assumption that these small units would be the most expensive system generation.

Region	Sink
MISO	33 percent
PJM	44 percent
SPP	23 percent

Table 5-1: Transfer Sink Distribution

MTEP14 analysis determined that 4,335 MW of additional year 2028 generation could be sourced from the incremental energy zones to serve future renewable energy mandates (Table 5-2). MTEP11 analysis determined that 2,230 MW of additional year 2026 generation could be sourced from the incremental energy zones. The results are the essentially the same for both analyses as the increase in wind enabled from MTEP11 is primarily attributed to additional load growth. MTEP11 analysis was performed on a year 2026 model and MTEP14 on year 2028.

Wind Zone	Incremental Wind Enabled	Wind Zone	Incremental Wind Enabled
MI-B	250	IL-K	465
MI-C	238	IN-K	70
MI-D	318	WI-B	491
MI-E	264	WI-D	452
MI-F	320	WI-F	144
MI-I	210	MO-C	347
IL-F	167	MO-A	599

Table 5-2: Incremental Wind Enabled Above 2028 Mandated Level, by Zone

Consistent with the MTEP11 analysis, incremental wind enabled was calculated using a multiple pass technique – a first pass where wind is sourced from all wind zones, and a second where wind is sourced from just wind zones east of the Mississippi River. System-wide transfers from west to east across this boundary have historically been limited, and the first transfer limitations are seen along this corridor.

In the MTEP14 Review, no additional wind was enabled in much of the West. The MTEP14 Review power flow model had significantly stronger base dispatch flows from the Western portion of the system compared to the MTEP11 analysis. A first transfer including all zones east of the Mississippi as well as those from Missouri enabled the addition of 2,334 MW nameplate wind, at which point the wind zones in Michigan began meeting system limits. That wind was added to the model, and the analysis repeated for a second pass. The second transfer sourced wind from the Eastern wind zones minus those in Michigan, allowing an addition of 584 MW of nameplate wind, at which point a wind zone in Missouri met a local limit. The last transfer was performed leaving out the Missouri zone, and 1,416 MW of additional nameplate wind was enabled, before meeting a transfer limit in West-Central Illinois.

When the results from the curtailment analyses and the wind enabled analyses are combined, MTEP14 results show the MVP Portfolio enables a total of 43 million MWh of renewable energy to meet the renewable energy mandates through 2028. MTEP11 showed the MVP Portfolio enabled a similar level renewable energy mandates – 41 million MWh through 2026.

6. Portfolio Economic Analysis

MTEP14 estimates show the Multi-Value Portfolio creates $13.1 to $49.6 billion in net benefits to MISO North and Central Region members, an increase of approximately 50 percent from MTEP11 (Figure 6-1). Increases are primarily congestion and fuel savings driven by natural gas prices. Total portfolio costs have increased from $5.56 billion in MTEP11 to $5.86 billion in MTEP14. Even with the increased portfolio cost estimates, the increased MTEP14 benefit estimation results in portfolio benefit-to-cost ratios that have increased from 1.8 to 3.0 in MTEP11 to 2.6 to 3.9 in MTEP14.

> The MTEP14 Triennial MVP Review estimates the MVP benefit-to-cost ratio has increased from 1.8 – 3.0 in MTEP11 to 2.6 – 3.9.

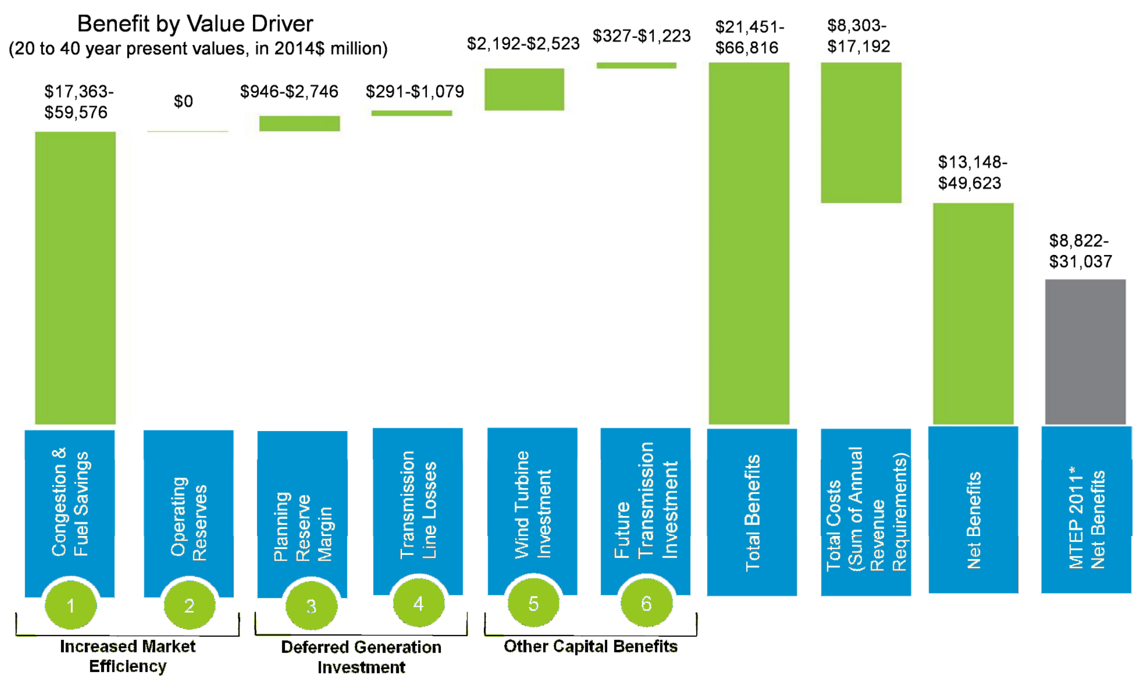


Figure 6-1: MVP Portfolio Economic Benefits from MTEP14 MVP Triennial Review

The bulk of the increase in benefits is due to an increase in the assumed natural gas price forecast in MTEP14 compared to MTEP11. In addition, the MTEP15 natural gas assumptions, which will be used in the MTEP15 MVP Portfolio Limited Review, are lower than the MTEP14 forecast. Under each of the natural gas price assumption sensitivities, the MVP Portfolio is projected to provide economic benefits in excess of costs (Table 6-1).

Natural Gas Forecast Assumption	Total NPV Portfolio Benefits ($M-2014)	Total Portfolio Benefit to Cost Ratio
MTEP14 – MVP Triennial Review	21,451 – 66,816	2.6 – 3.9
MTEP11	17,875 – 54,186	2.2 – 3.2
MTEP15	18,472 – 56,670	2.2 – 3.3

Table 6-1: MVP Portfolio Economic Benefits - Natural Gas Price Sensitivities[10]

The MVP Portfolio provides benefits across the MISO footprint in a manner that is roughly equivalent to cost allocated to each North and Central Region local resource zones (Figure 6-2). MTEP14 MVP Triennial Review results indicate that benefit-to-cost ratios have increased in all zones since MTEP11. Portfolio's benefits are at least 2.3 to 2.8 times the cost allocated to each zone. Zonal benefit distributions have changed slightly since the MTEP11 business case as a result of changing tariffs/business practices (planning reserve margin requirement and baseline reliability project cost allocation), load growth, and wind siting. As state demand and energy forecasts change and additional clarity is gained in to the location of actual wind turbine installation so does the siting of forecast wind.

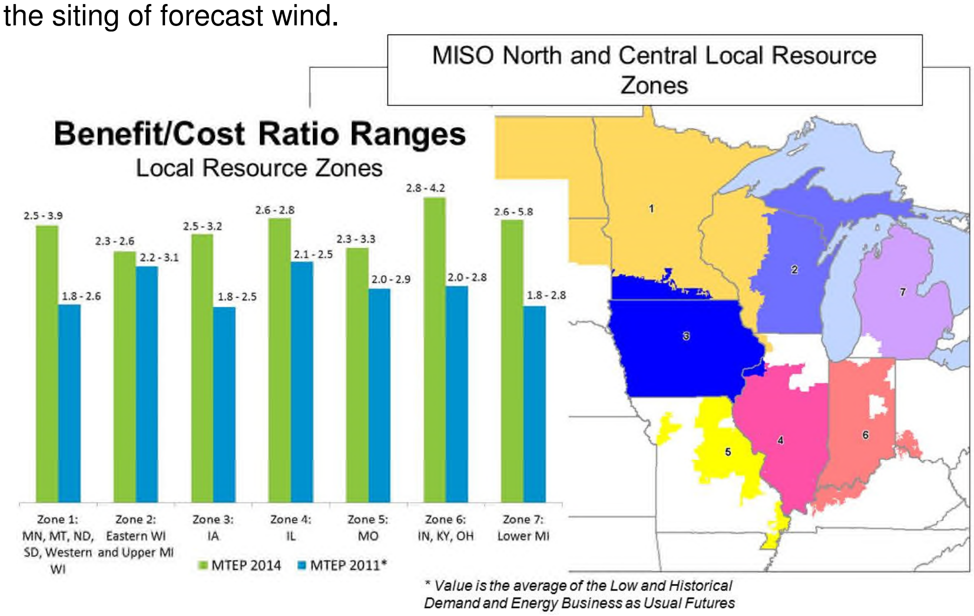


Figure 6-2: MVP Portfolio Production Cost Benefit Spread

[10] Sensitivity performed applying MTEP11/MTEP15 natural gas price to the MTEP14 congestion and fuel savings model. All other benefit valuations unchanged from the MTEP14 MVP Triennial Review.

MVP Portfolio benefits under lower natural gas price sensitivities are at least 1.9 to 2.5 times the cost allocated to each zone (Figure 6-3). Under each natural gas price sensitivity benefits are zonally distributed in a manner roughly equivalent to the zonal cost allocation.

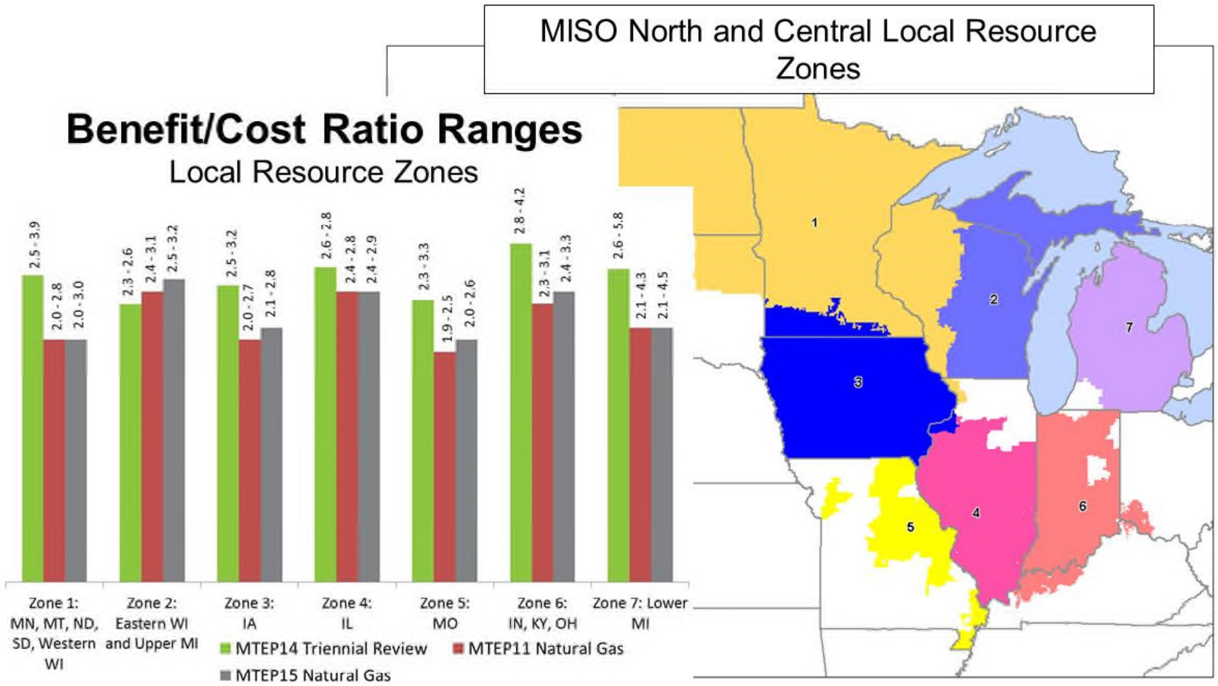


Figure 6-3: MVP Portfolio Production Cost Benefit Spread – Natural Gas Price Sensitivities[11]

[11] Sensitivity performed applying MTEP11/MTEP15 natural gas price to the MTEP14 congestion and fuel savings model. All other benefit valuations unchanged from the MTEP14 MVP Triennial Review.

6.1 Congestion and Fuel Savings

The MVP Portfolio allows for a more efficient dispatch of generation resources, opening markets to competition and spreading the benefits of low-cost generation throughout the MISO footprint. These benefits were outlined through a series of production cost analyses, which capture the economic benefits of the MVP transmission and the wind it enables. These benefits reflect the savings achieved through the reduction of transmission congestion costs and through more efficient use of generation resources.

Primarily because of an increase in natural gas price forecast assumptions, congestion and fuel savings have increased by approximately 40 percent since MTEP11

Congestion and fuel savings is the most significant portion of the MVP benefits (Figure 6-1). The MTEP14 Triennial MVP Review estimates that the MVP Portfolio will yield $17 to $60 billion in 20- to 40-year present value adjusted production cost benefits, depending on the timeframe and discount rate assumptions. This value is up 22 percent to 44 percent from the original MTEP11 valuation (Table 6-2).

	MTEP14	MTEP11[12]
3 percent Discount Rate; 20 Year Net Present Value	28,057	21,918
8 percent Discount Rate; 20 Year Net Present Value	17,363	14,203
3 percent Discount Rate; 40 Year Net Present Value	59,576	41,330
8 percent Discount Rate; 40 Year Net Present Value	25,088	19,016

Table 6-2: Congestion and Fuel Savings Benefit ($M-2014)

The increase in congestion and fuel savings benefits relative to MTEP11 is primarily from an increase in the out-year natural gas price forecast assumptions (Figures 6-4, 6-5, and 6-6). In 2013, as part of the futures development, the MISO Planning Advisory Committee adopted a natural gas price escalation rate assumption sourced from a combination of the New York Mercantile Exchange (NYMEX) and Energy Information Administration (EIA) forecasts. The MTEP14 assumed natural gas price escalation rate is approximately 7.2% per year[13], compared to 1.74% per year in MTEP11. The increased escalation rate causes the assumed natural gas price to be $1.61/MMBTU higher in MTEP14 than MTEP11 in year 2023 and $3.13/MMBTU higher in year 2028 - the two years from which congestion and fuel savings results are based.

[12] Average of the High and Low MTEP11 BAU Futures

[13] 2.5% of the assumed MTEP14 natural gas price escalation rate represents inflation . Inflation rate added to the NYMEX and EIA sourced growth rate.

The MVP Portfolio allows access to wind units with a nearly $0/MWh production cost and primarily replaces natural gas units in the dispatch[14], which makes the MVP Portfolio's fuel savings benefit projection directly related to the natural gas price assumption. A sensitivity applying the MTEP11 Low BAU gas prices assumption to the MTEP14 MVP Triennial Review model showed a 29.3 percent reduction in the annual year 2028 MTEP14 congestion and fuel savings benefits (Figure 6-5). Approximately 68% of the difference between the MTEP11 and MTEP14 congestion and fuel savings benefit is attributable to the natural gas price escalation rate assumed in MTEP14 (Figure 6-6).

Post MTEP14 natural gas price forecast assumptions are more closely aligned with those of MTEP11 (Figure 6-4). A sensitivity applying the MTEP15 BAU natural gas prices to the MTEP14 analysis showed a 21.7 percent reduction in year 2028 MTEP14 adjusted production cost savings.

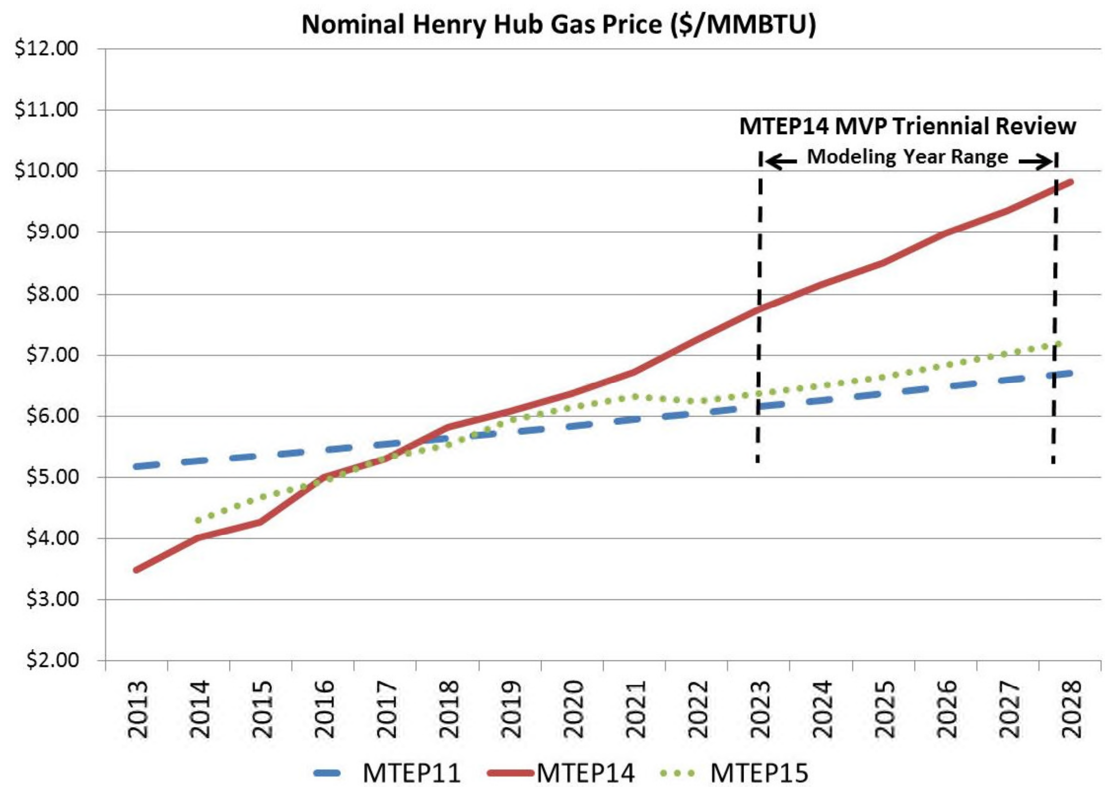


Figure 6-4: Natural Gas Price Forecast Comparison

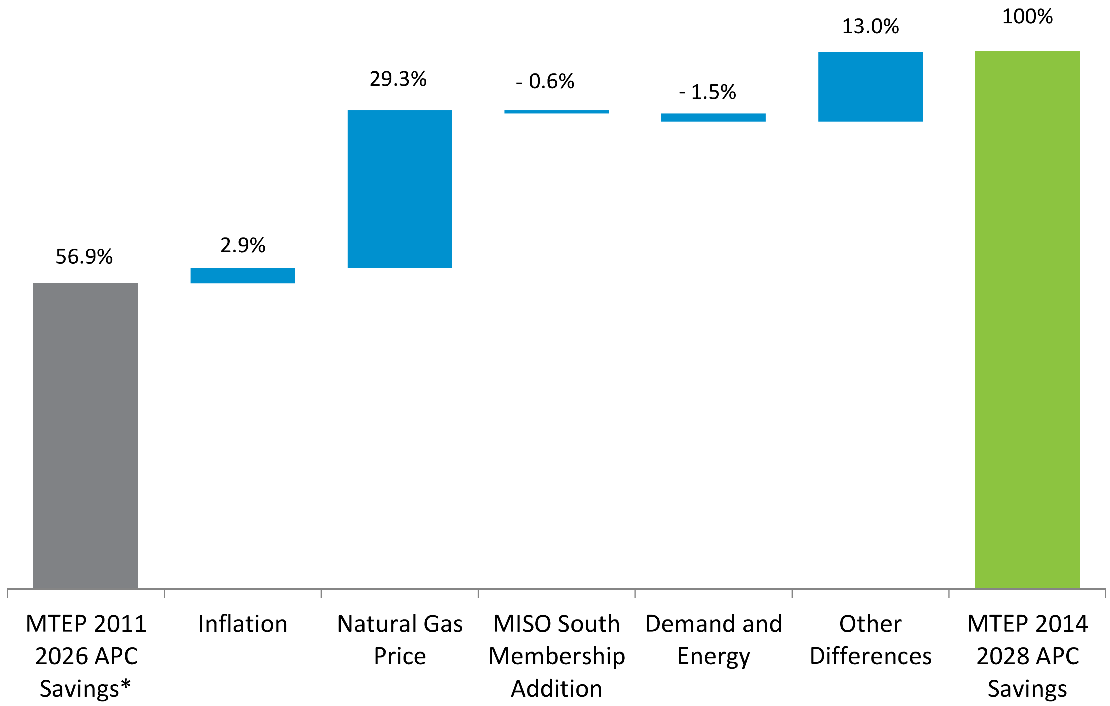
MISO membership changes have little net effect on benefit-to-cost ratios. For example if Duke Ohio/Kentucky and First Energy's benefits and costs are either both included or excluded the benefit-to-cost ratio calculation yields similar results. The exclusion of Duke Ohio/Kentucky and First Energy from the MISO pool decreases benefits by 7.4

[14] In the year 2028 simulation, the MVP enabled wind replaced 66% natural gas, 33% coal, and 1% other fueled units in the dispatch

percent relative to the MTEP14 total benefits; however, per Schedule 39, 6.3 percent of the total portfolio costs are allocated to Duke Ohio/Kentucky and First Energy, thus there is a minimal net effect to the benefit-to-cost ratio.

The MVP Portfolio is solely located in the MISO North and Central Regions and therefore, the inclusion of the South Region to the MISO dispatch pool has little effect on MVP related production cost savings (Figure 6-5).

Because demand and energy levels are similar between the MTEP11 Low BAU and MTEP14 cases, the updated demand and energy assumptions have little relative effect. Other Differences is calculated as the remaining difference between the MTEP14 saving and the sum of MTEP11 2026 APC Savings, Inflation, Natural Gas Prices, Footprint Changes, and Demand and Energy values. The largest modeling assumption differences in the Other Differences category is Environmental Protection Agency driven generation retirements, forecast generation siting, and topology upgrades. Other Differences also includes the compounding/synergic effects of all categories together.



**Excludes Duke Ohio/Kentucky - MTEP 2011 Business Case included Duke Ohio/Kentucky but excluded First Energy*

Figure 6-5: Breakdown of Annual Congestion and Fuel Savings Benefit Increase from MTEP11 to MTEP14 – Values a percentage of MTEP14 year 2028 Adjusted Production Cost (APC) Savings

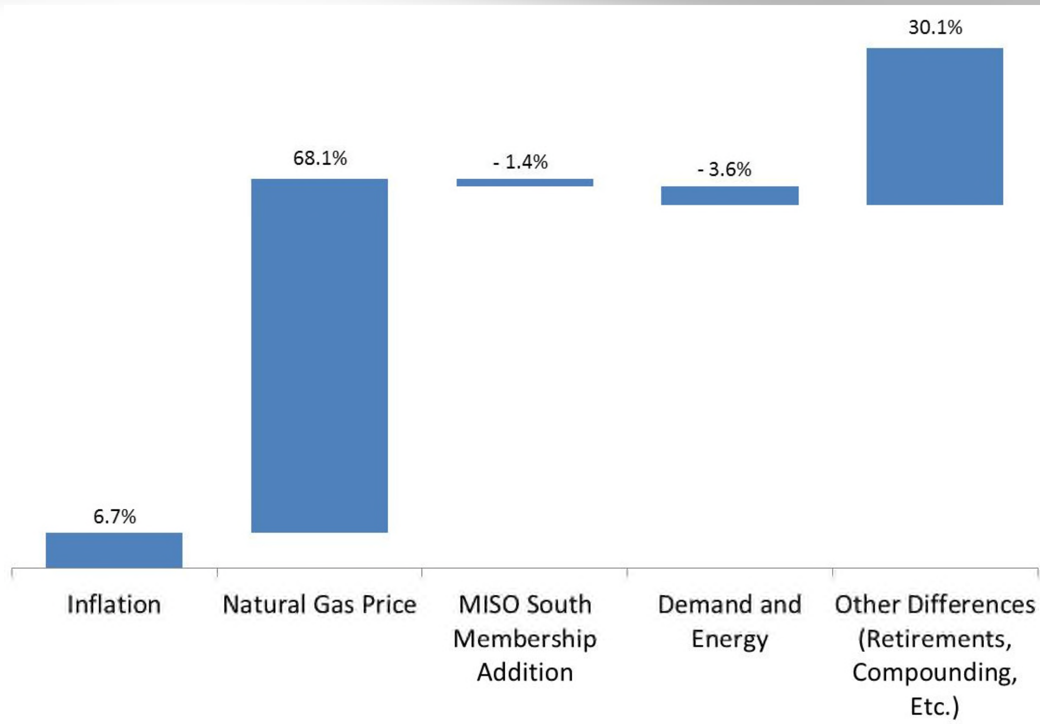


Figure 6-6: Breakdown of Annual Congestion and Fuel Savings Benefit Increase from MTEP11 to MTEP14 – Values a percentage of difference between MTEP14 year 2028 and MTEP11 year 2026 Adjusted Production Cost (APC) Savings

The MTEP14 MVP Triennial Review economic analysis was performed with 2023 and 2028 BAU future production cost models, with incremental wind mandates considered for 2023, 2028 and 2033. The 2033 case was used as a proxy case to determine the additional benefits from wind enabled above and beyond that mandated by the year 2028 (Section 5.2).

6.2 Operating Reserves

In addition to the energy benefits quantified in the production cost analyses, the 2011 business case showed the MVP Portfolio also reduce operating reserve costs. The 2011 business case showed that the MVP Portfolio decreases congestion on the system, increasing the transfer capability into several areas that would otherwise have to hold additional operating reserves under certain system conditions. While MTEP14 analysis shows the MVP Portfolio improves flows on the flowgates for which the reserves are calculated (Table 6-3), as a conservative measure, the MTEP14 Triennial MVP Review is not estimating a reduced operating reserve benefit. Since MTEP11, a reserve requirement has been calculated only a limited number of days (Table 6-4).

As a conservative measure, the MVP Triennial Review does not estimate a reduced operating reserve benefit in MTEP14.

Zone	Limiter	Contingency	Change in Flows
Indiana	Bunsonville - Eugene 345	Casey - Breed 345	-15.0 percent
Indiana	Crete - St. Johns Tap 345	Dumont-Wilton Center 765	3.0 percent
Michigan	Benton Harbor - Palisades 345	Cook - Palisades 345	-9.4 percent
Wisconsin	MWEX	N/A	-11.6 percent
Minnesota	Arnold-Hazleton 345	N/A	23.9 percent

Table 6-3: Change in Transfers; Pre-MVP minus Post-MVP

Zone	MTEP11 (June 2010 – May 2011)			MTEP14 (January 2013 – December 2013)		
	Total Requirement (MW)	Days with Requirement (#)	Average daily requirement (MW)	Total Requirement (MW)	Days with Requirement (#)	Average daily requirement (MW)
Missouri/Illinois[15]	95	1	95.1	0	0	0
Indiana	14966	53	282.4	0	0	0
Northern Ohio	9147	15	609.8	N/A	N/A	N/A
Michigan	4915	17	289.1	0	0	0
Wisconsin	227	2	113.4	0	0	0
Minnesota	376	1	376.3	32	2	16

Table 6-4: Historic Operating Requirements

MTEP11 MVP analysis concluded that the addition of the MVP Portfolio eliminated the need for the Indiana operating reserve zone and the reduction by half of additional system reserves held in other zones across the footprint. This created the opportunity to locate an average of 690,000 MWh of operating reserves annually where it would be most economical to do so, as opposed to holding these reserves in prescribed zones. MTEP11 estimated benefits from reduced operating reserves of $33 to $82 million in 20 to 40 year present value terms (Table 6-5).

	MTEP14	MTEP11[16]
3 percent Discount Rate; 20 Year Net Present Value	-	50
8 percent Discount Rate; 20 Year Net Present Value	-	34
3 percent Discount Rate; 40 Year Net Present Value	-	84
8 percent Discount Rate; 40 Year Net Present Value	-	42

Table 6-5: Reduction in Operating Reserves Benefit ($M-2014)

As operating reserve zones are determined on an ongoing basis, by monitoring the energy flowing through flowgates across the system, the benefit valuation in future MVP Triennial Reviews may provide a different result.

[15] The Missouri Reserve Zone was changed to Illinois in 2012. The Illinois Reserve Zone was eliminated in September 2013
[16] Average of the High and Low MTEP11 BAU Futures

6.3 Planning Reserve Margin Requirements

The MVPs increase capacity sharing between local resource zones which defers more than $900 million in future capacity expansion

MTEP14 MVP Triennial Review analysis estimates the MVPs annually defer more than 800 MW in capacity expansion by increasing capacity import limits thus reducing the local clearing requirements of the planning reserve margin requirement. Local clearing requirements are the amount of capacity that must be physically located within a resource zone to meet resource adequacy standards. The MTEP14 Review estimates that the MVPs increase capacity sharing between local resource zones (LRZ), which defers $946 to $2,746 million in future capacity expansion (Table 6-7).

In the 2013 planning year, MISO and the Loss of Load Expectation Working Group improved the methodology that establishes the MISO Planning Reserve Margin Requirement (PRMR). Previously, and in the MTEP11 analysis, MISO developed a MISO-wide PRMR with an embedded congestion component. The Candidate MVP Analysis showed the MVP Portfolio reduces total system congestion and thus reduces the congestion component of the PRMR. The MVP Portfolio allows MISO to carry a decreased PRMR while maintaining the same system reliability. The post-2013 planning year methodology no longer uses a single congestion component, but instead calculates a more granular zonal PRMR and a local clearing requirement based on the zonal capacity import limit. While terminology and methods have changed between MTEP11 and MTEP14, both calculations are capturing the same benefit of increased capacity sharing across the MISO region provided by the MVPs; as such, MTEP14 and MTEP11 provide benefit estimates of similar magnitudes (Table 6-6).

	MTEP14	MTEP11[17]
3 percent Discount Rate; 20 Year Net Present Value	1,440	2,846
8 percent Discount Rate; 20 Year Net Present Value	946	1,237
3 percent Discount Rate; 40 Year Net Present Value	2,746	3,760
8 percent Discount Rate; 40 Year Net Present Value	1,266	1,421

Table 6-6: Local Clearing Requirement Benefit ($M-2014)

[17] Average of the High and Low MTEP11 BAU Futures

Loss of load expectation (LOLE) analysis was performed to show the decrease in the local clearing requirement of the planning reserve margin requirement due to MVP Portfolio. This analysis used the 2014-2015 Planning Reserve Margin (PRM) 10-year out (2023) case. Capacity import limit increases from the MVPs were captured by comparing the zonal capacity import limits of a case with the MVP Portfolio to a case without inclusion of the MVP Portfolio. The 2023 Local Reliability Requirement (LRR) for each LRZ was determined by running GE MARS. Local clearing requirements were calculated for both the "with" and "without" MVP cases by subtracting the CIL values from the LRR values (Table 6-7).

Local Resource Zone	1	2	3	4	5	6	7	Formula Key
2023 Unforced Capacity (MW)	17,583	14,592	9,646	10,664	8,135	19,735	24,833	[A]
2023 Local Reliability Requirement Unforced Capacity (MW)	21,515	15,737	11,696	12,754	10,998	21,222	25,793	[B]
No MVP Capacity Import Limit (CIL) (MW)	5,326	2,958	1,198	4,632	5,398	5,328	3,589	[C]
MVP Capacity Import Limit (MW)	5,576	3,387	2,925	9,534	4,328	5,761	3,648	[D]
No MVP CIL Local Clearing Requirement (MW)	16,189	12,779	10,498	8,122	5,600	15,894	22,204	[E]=[B]-[C]
With MVP CIL Local Clearing Requirement (MW)	15,939	12,351	8,771	3,220	6,670	15,461	22,145	[F]=[B]-[D]
Excess capacity after LCR with No MVP CIL (MW)	1,394	1,813	-852	2,542	2,535	3,841	2,629	[G]=[A]-[E]
Excess capacity after LCR with MVP CIL (MW)	1,644	2,242	875	7,444	1,465	4,274	2,688	[H]=[A]-[F]
Deferred Capacity Value ($M-2014)			$75.8					[I]=[G]*CONE

Table 6-7: Deferred Capacity Value Calculation

The MTEP14 MVP Triennial Review analysis shows the MVP Portfolio allows 852 MW of capacity expansion deferral in LRZ 3. The deferred capacity benefit is valued using the Cost of New Entry (CONE) (Table 6-8). It's important to note that the capacity expansion deferral benefit may or may not be realized due to future market design changes around external resource capacity qualification.

The MTEP14 MVP Triennial Review methodology does not capture the MVP benefit to the capacity import of LRZ 5. This limitation is driven by the selection of generation used to perform import studies. MISO's LOLE methodology defines the selection of generation used as the source for a transfer study based on a zone's Local Balancing Area (LBA) ties. Based on its LBA ties, import studies indicate LRZ 5 primarily uses generation from the MISO South Region since its LBA ties in the North and Central Regions have very limited available capacity. The MVP facilities are not used to transfer power from the South Region so a benefit for LRZ 5 is not quantified.

Local Resource Zone	Cost of New Entry ($/MW-year)
1	89,500
2	90,320
3	88,450
4	89,890
5	91,610
6	89,670
7	90,100

Table 6-8: Cost of New Entry for Planning Year 2014/15[18]

[18] From MISO Business Practice Manual 011 Resource Adequacy – January 2014

6.4 Transmission Line Losses

The addition of the MVP Portfolio to the transmission network reduces overall system losses, which also reduces the generation needed to serve the combined load and transmission line losses. The energy value of these loss reductions is considered in the congestion and fuel savings benefits, but the loss reduction also helps to reduce future generation capacity needs.

Reflective of MISO's tighter reserve margins, the value of MTEP14 capacity deferment benefits from reduced losses has increased

The MTEP14 Review found that system losses decrease by 122 MW with the inclusion of the MVP Portfolio. MTEP11 estimates that the MVPs reduced losses by 150 MW. The difference between MTEP11 and MTEP14 results is attributed to decreased system demand, the MISO North and Central Regions membership changes, and transmission topology upgrades in the base model.

Tightening reserve margins, from an additional approximate 12 GW of expected generation retirements due mostly to emissions compliance restrictions, have increased the value of deferred capacity from transmission losses in MTEP14. In MTEP11, baseload additions were not required in the 20-year capacity expansion forecast to maintain planning reserve requirements. In MTEP11, the decreased transmission losses from the MVP Portfolio allowed the deferment of a single combustion turbine. In MTEP14, the decreased losses cause a large shift in the proportion of baseload combined cycle units and peaking combustion turbines in the capacity expansion forecast.

In addition to the tighter reserve margins, a one-year shift forward in the MVP Portfolio expected in-service date relative to MTEP11, has increased benefits by approximately 30 percent. In MTEP11, the MVP Portfolio's expected in-service date was year 2021. In MTEP14, the MVP's Portfolio's expected in-service date has shifted to year 2020. Given current reserve margins, additional capacity is needed as soon as year 2016 to maintain out-year reserve requirements. The in-service date shift forward allows earlier access to the 122 MW of reduced losses which allows earlier and less discounted deferment of capacity expansions.

The combined result of the tighter reserve margins and in-service date shift has caused the estimated benefits from reduced transmission line losses to more than double compared to the MTEP11 values (Table 6-9). Using current capital costs, the deferment equates to a savings of $291 to $1,079 million ($-2014), excluding the impacts of any potential future policies.

	MTEP14	MTEP11[19]
3 percent Discount Rate; 20 Year Net Present Value	734	227
8 percent Discount Rate; 20 Year Net Present Value	291	287
3 percent Discount Rate; 40 Year Net Present Value	1,079	315
8 percent Discount Rate; 40 Year Net Present Value	401	327

Table 6-9: Transmission Line Losses Benefit ($M-2014)

The benefit valuation methodology used in the MTEP14 Review is identical to that used in MTEP11. The transmission loss reduction was calculated by comparing the transmission line losses in the 2023 summer peak powerflow model both with and without the MVP Portfolio. This value was then used to extrapolate the transmission line losses for 2018 through 2023, assuming escalation at the business as usual demand growth rate. The change in required system capacity expansion due to the impact of the MVP Portfolio was calculated through a series of EGEAS simulations. In these simulations, the total system generation requirement was set to the system PRMR multiplied by the system load plus the system losses (Generation Requirements = (1+PRMR)*(Load + Losses)). To isolate the impact of the transmission line loss benefit, all variables in these simulations were held constant, except system losses.

MVP benefits from the optimization of wind generation siting remain similar in magnitude since MTEP11

The difference in capital fixed charges and fixed operation and maintenance costs in the no-MVP case and the post-MVP case is equal to the capacity benefit from transmission loss reduction, due to the addition of the MVP portfolio to the transmission system.

6.5 Wind Turbine Investment

During the Regional Generator Outlet Study (RGOS), the pre-cursor to the Candidate MVP Study, MISO developed a wind siting approach that results in a low-cost solution when transmission and generation capital costs are considered. This approach sources generation in a combination of local and regional locations, placing wind local to load, where less transmission is required; and regionally, where the wind is the strongest (Figure 6-7). However, this strategy depends on a strong regional transmission system to deliver the wind energy. Without this regional transmission backbone, the wind generation has to be sited close to load, requiring the construction of significantly larger amounts of wind capacity to produce the renewable energy mandated by public policy.

[19] Average of the High and Low MTEP11 BAU Futures

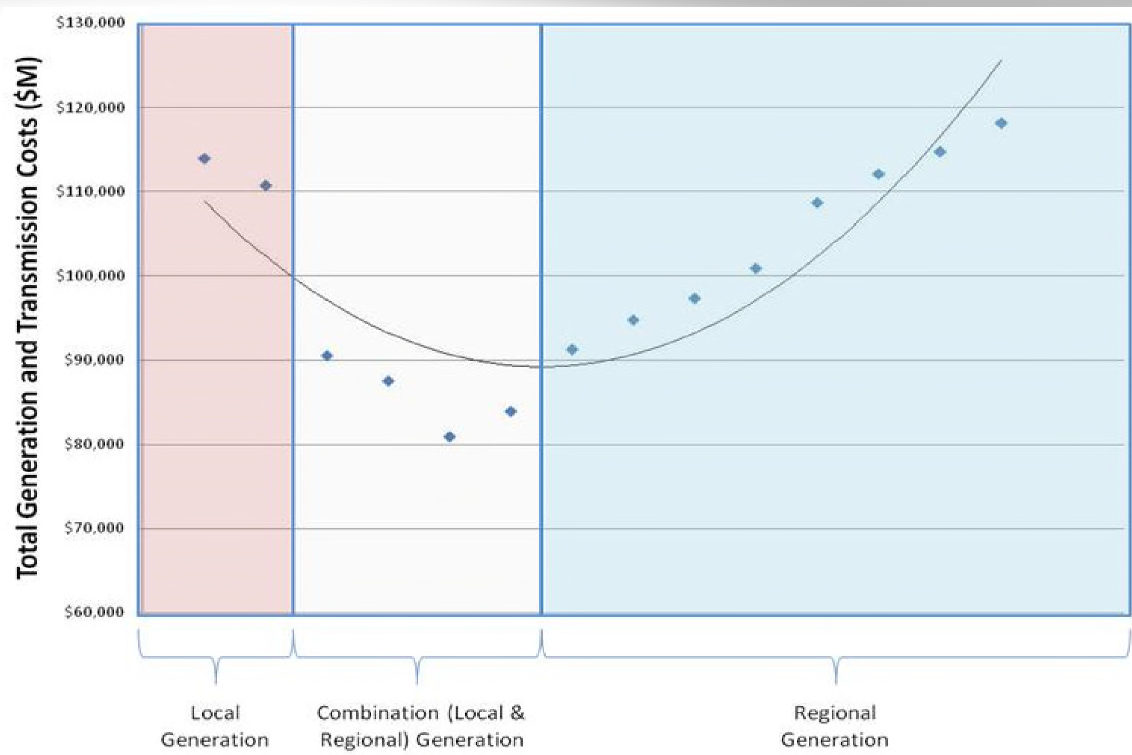


Figure 6-7: Local versus Combination Wind Siting

The MTEP14 Triennial MVP Review found that the benefits from the optimization of wind generation siting remain similar in magnitude since MTEP11 (Table 6-10). The slight increase in MTEP14 benefits relative to MTEP11 is from an update to the wind requirement forecast and wind enabled calculations. The MTEP14 Review found that the MVPs reduce turbine capital investments by 3,262 MW through 2028, compared to 2,884 MW through 2026 in MTEP11.

	MTEP14	MTEP11[20]
3 percent Discount Rate; 20 Year Net Present Value	2,192	1,850
8 percent Discount Rate; 20 Year Net Present Value	2,523	2,222
3 percent Discount Rate; 40 Year Net Present Value	2,192	1,850
8 percent Discount Rate; 40 Year Net Present Value	2,523	2,222

Table 6-10: Wind Turbine Investment Benefit ($M-2014)

[20] Average of the High and Low MTEP11 BAU Futures

In the RGOS study, it was determined that 11 percent less wind would need to be built to meet renewable energy mandates in a combination local/regional methodology relative to a local only approach. This change in generation was applied to energy required by the renewable energy mandates, as well as the total wind energy enabled by the MVP Portfolio (Section 5). This resulted in a total of 3.2 GW of avoided wind generation (Table 6-11).

Year	MVP Portfolio Enabled Wind (MW)	Equivalent Local Wind Generation (MW)	Incremental Cumulative Wind Benefit (MW)
Pre-2018	16,403	18,246	1,843
2018	20,289	22,568	2,279
2023	22,946	25,524	2,578
2028	24,702	27,477	2,775
Full Wind Enabled	29,037	32,299	3,262

Table 6-11: Renewable Energy Requirements, Combination versus Local Approach

The incremental wind benefits were monetized by applying a value of $2 to $2.8 million/MW, based on the U.S. Energy Information Administration's estimates of the capital costs to build onshore wind[21]. The total wind enabled benefits were then spread over the expected life of a wind turbine. Consistent with the MTEP11 business case that avoids overstating the benefits of the combination wind siting, a transmission cost differential of approximately $1.5 billion was subtracted from the overall wind turbine capital savings to represent the expected lower transmission costs required by a local-only siting strategy.

[21] Value as of November 2013

6.6 Future Transmission Investment

Consistent with MTEP11, the MTEP14 MVP Triennial Review shows that the MVP Portfolio eliminates the need for $300 million in future baseline reliability upgrades (Table 6-12). The magnitude of estimated benefits is in close proximity to the estimate from MTEP11; however, the actual identified upgrades have some differences because of bus-level load growth, generation dispatch, wind levels and transmission upgrades.

MTEP14 analysis shows the MVP Portfolio eliminates the need for $300 million in future baseline reliability upgrades.

	MTEP14	MTEP11[22]
3 percent Discount Rate; 20 Year Net Present Value	674	521
8 percent Discount Rate; 20 Year Net Present Value	327	286
3 percent Discount Rate; 40 Year Net Present Value	1,223	931
8 percent Discount Rate; 40 Year Net Present Value	452	394

Table 6-12: Future Transmission Investment Benefits ($M-2014)

Reflective of the post-Order 1000 Baseline Reliability Project cost allocation methodology, capital cost deferment benefits were fully distributed to the LRZ in which the avoided investment is physically located; a change from the MTEP11 business case that distributed 20 percent of the costs regionally and 80 percent locally.

A model simulating 2033 summer peak load conditions was created by growing the load in the 2023 summer peak model by approximately 8 GW. The 2033 model was run both with and without the MVP Portfolio to determine which out-year reliability violations are eliminated with the inclusion of the MVP Portfolio (Table 6-13).

[22] Average of the High and Low MTEP11 BAU Futures

Avoided Investment	Upgrade Required	Miles
New Carlisle - Olive 138 kV	Transmission line, < 345 kV	2.0
Reynolds 345/138 kV Transformer	Transformer	N/A
Lee - Lake Huron Pumping Tap 120 kV	Transmission line, < 345 kV	8.5
Waterman - Detroit Water 120 kV	Transmission line, < 345 kV	2.9
Dresden - Electric Junction 345 kV	Transmission line, 345 kV	31.1
Dresden - Goose Lake 138 kV	Transmission line, < 345 kV	5.8
Golf Mill - Niles Tap 138 kV	Transmission line, < 345 kV	2.5
Boy Branch - Saint Francois 138 kV	Transmission line, < 345 kV	7.1
Newton - Robinson Marathon 138 kV	Transmission line, < 345 kV	34.3
Weedman - North Leroy 138 kV	Transmission line, < 345 kV	3.6
Wilmarth - Eastwood 115 kV	Transmission line, < 345 kV	4.6
Swan Lake - Fort Ridgely 115 kV	Transmission line, < 345 kV	13.2
Black Dog - Pilot Knob 115 kV	Transmission line, < 345 kV	10.3
Lake Marion - Kenrick 115 kV	Transmission line, < 345 kV	3.5
Johnson Junction - Ortonville 115 kV	Transmission line, < 345 kV	24.7
Maquoketa - Hillsie 161 kV	Transmission line, < 345 kV	12.0
New Iowa Wind - Lime Creek 161 kV	Transmission line, < 345 kV	10
Lore - Turkey River 161 kV	Transmission line, < 345 kV	19.6
Lore - Kerper 161 kV	Transmission line, < 345 kV	7.0
Salem 161 kV Bus Tie	Bus Tie	N/A
8th Street - Kerper 161 kV	Transmission line, < 345 kV	2.6
Rock Creek 161 kV Bus Tie	Bus Tie	N/A
Beaver Channel 161 kV Bus Tie	Bus Tie	N/A
East Calamus - Grand Mound 161 kV	Transmission line, < 345 kV	2.6
Dundee - Coggon 161 kV	Transmission line, < 345 kV	18.1
Sub 56 (Davenport) - Sub 85 161 kV	Transmission line, < 345 kV	3.8
Vienna - North Madison 138 kV	Transmission line, < 345 kV	0.2
Townline Road - Bass Creek 138 kV	Transmission line, < 345 kV	11.8
Portage - Columbia 138 kV Ckt 2	Transmission line, < 345 kV	5.7
Portage - Columbia 138 kV Ckt 1	Transmission line, < 345 kV	5.7

Table 6-13: Avoided Transmission Investment

The cost of this avoided investment was valued using generic transmission costs, as estimated from projects in the MTEP database and recent transmission planning studies (Table 6-14). Generic estimates, in nominal dollars, are unchanged since the MTEP11 analysis. Transmission investment costs were assumed to be spread between 2029 and 2033. To represent potential production cost benefits that may be missed by avoiding this transmission investment, the 345 kV transmission line savings was reduced by half.

Avoided Transmission Investment	Estimated Upgrade Cost
Bus Tie	$1,000,000
Transformer	$5,000,000
Transmission lines (per mile, for voltages under 345 kV)	$1,500,000
Transmission lines (per mile, for 345 kV)	$2,500,000

Table 6-14: Generic Transmission Costs

7. Qualitative and Social Benefits

Aside from widespread economic and public policy benefits, the MVP Portfolio also provides benefits based on qualitative or social values. Consistent with the MTEP11 analysis, these benefits are excluded from the business case. The quantified values from the economic analysis may be conservative because they do not account for the full potential benefits of the MVP Portfolio.

> The MVP Portfolio also provides benefits based on qualitative or social values, which suggests that the quantified values from the economic analysis may be conservative because they do not account for the full benefit potential.

7.1 Enhanced Generation Flexibility

The MVP Portfolio is primarily evaluated on its ability to reliably deliver energy required by renewable energy mandates. However, the MVP Portfolio also provides value under a variety of different generation policies. The energy zones, which were a key input into the MVP Portfolio analysis, were created to support multiple generation fuel types. For example, the correlation of the energy zones to the existing transmission lines and natural gas pipelines were a major factor considered in the design of the zones (Figure 7-1).

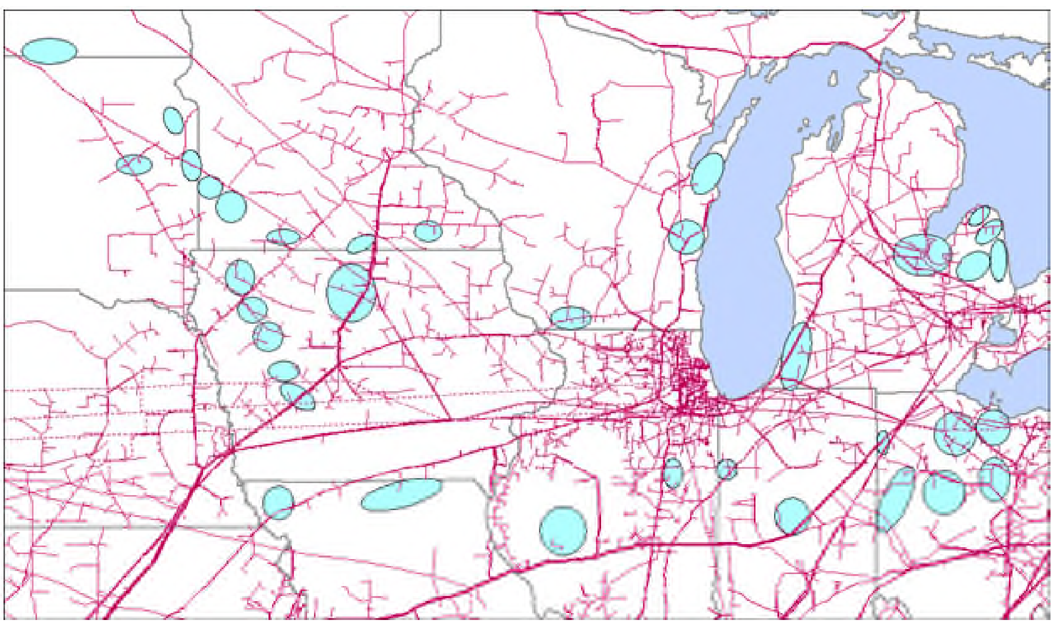


Figure 7-1: Energy Zone Correlation with Natural Gas Pipelines

7.2 Increased System Robustness

A transmission system blackout, or similar event, can have wide spread repercussions and result in billions of dollars of damage. The blackout of the Eastern and Midwestern United States in August 2003 affected more than 50 million people and had an estimated economic impact of between $4 and $10 billion.

The MVP Portfolio creates a more robust regional transmission system that decreases the likelihood of future blackouts by:

- Strengthening the overall transmission system by decreasing the impacts of transmission outages
- Increasing access to additional generation under contingent events
- Enabling additional transfers of energy across the system during severe conditions

7.3 Decreased Natural Gas Risk

Natural gas prices vary widely (Figure 7-2) causing corresponding fluctuations in the cost of energy from natural gas. In addition, recent and pending U.S. Environmental Protection Agency regulations limiting the emissions permissible from power plants will likely lead to more natural gas generation. This may cause the cost of natural gas to increase along with demand. The MVP Portfolio can partially offset the natural gas price risk by providing additional access to generation that uses fuels other than natural gas (such as nuclear, wind, solar and coal) during periods with high natural gas prices. Assuming a natural gas price increase of 25 percent to 50 percent, 2014 analysis shows the MVP Portfolio provides approximately a 24 to 45 percent higher adjusted production cost benefits.

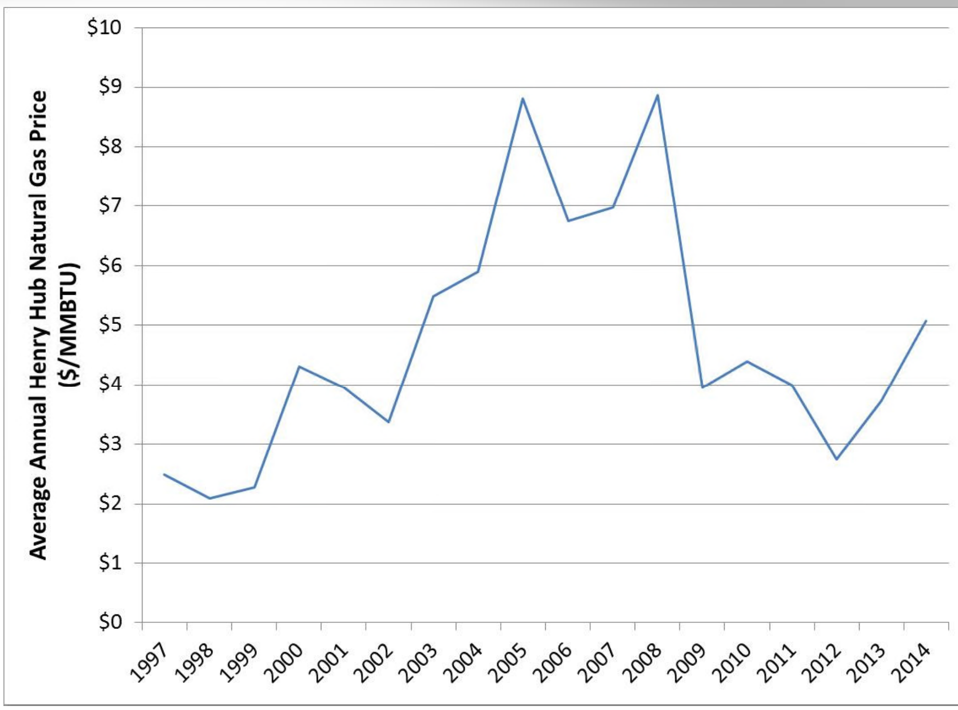


Figure 7-2: Historic Henry Hub Natural Gas Prices

A set of sensitivity analyses were performed to quantify the impact of changes in natural gas prices. The sensitivity cases maintained the same modeling assumptions from the base business case analyses, except for the gas prices. The gas prices were increased from $3.50 to $4.35 and $5.22/MMBTU and then escalated to year 2028 using MTEP14 rates.

The system production cost is driven by many variables, including fuel prices, carbon emission regulations, variable operations, management costs and renewable energy mandates. The increase in natural gas prices imposed additional fuel costs on the system, which in turn produced greater production cost benefits due to the inclusion of the MVP Portfolio. These increased benefits were driven by the efficient usage of renewable and low cost generation resources (Figure 7-3).

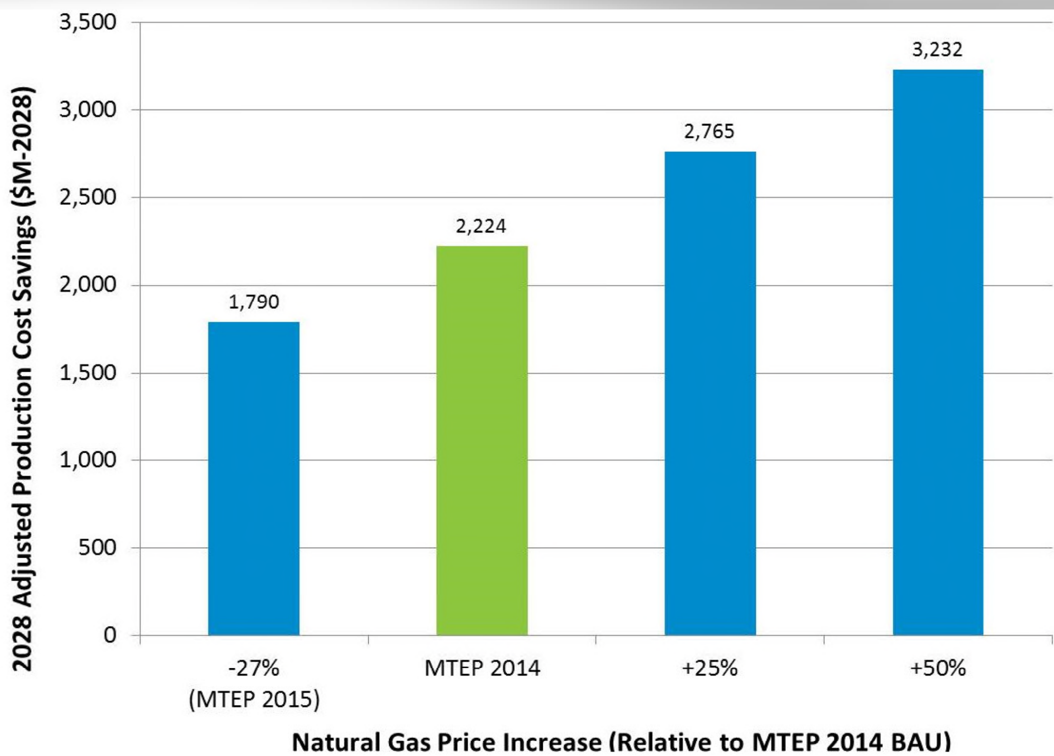


Figure 7-3: MVP Portfolio Adjusted Production Cost Savings by Natural Gas Price

7.4 Decreased Wind Generation Volatility

As the geographical distance between wind generators increases, the correlation in the wind output decreases (Figure 7-4). This relationship leads to a higher average output from wind for a geographically diverse set of wind plants, relative to a closely clustered group of wind plants. The MVP Portfolio will increase the geographic diversity of wind resources that can be delivered, increasing the average wind output available at any given time.

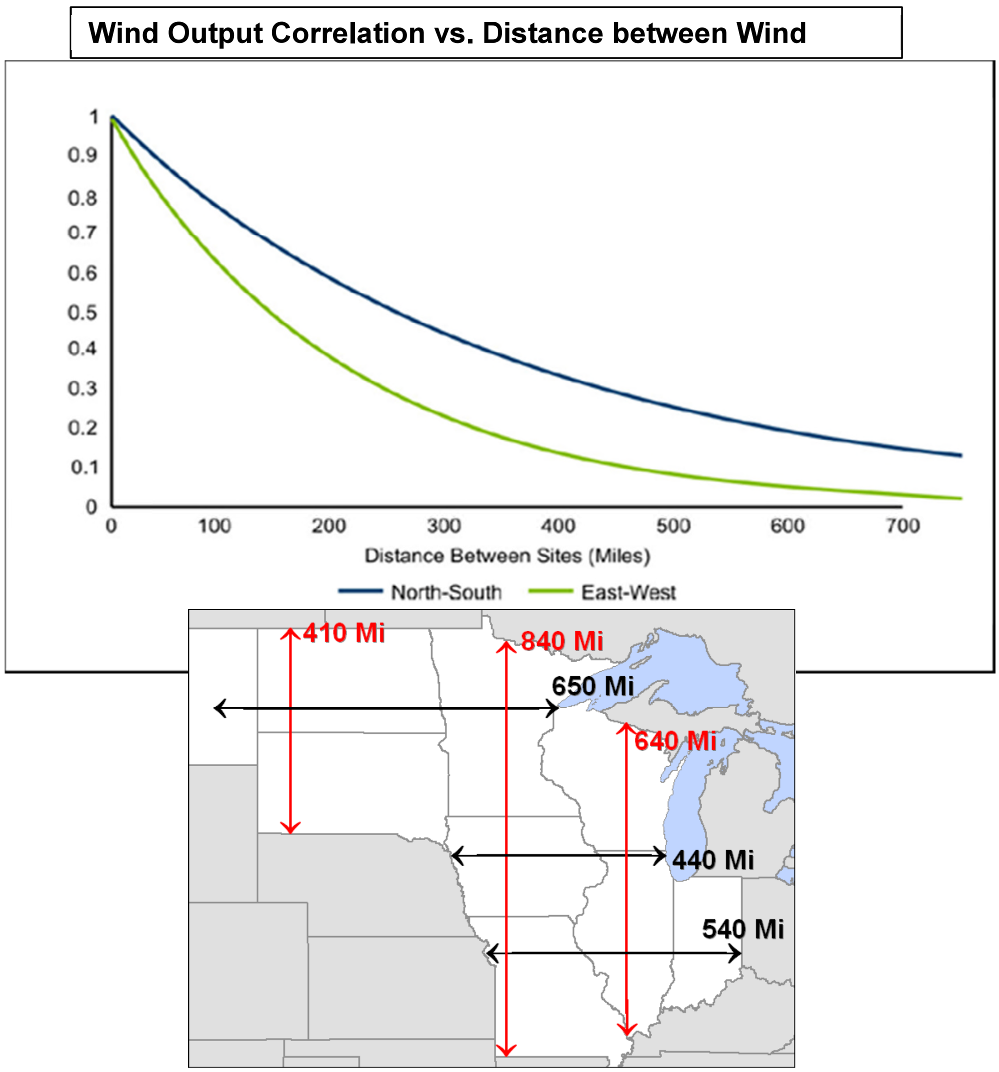


Figure 7-4: Wind Output Correlation to Distance between Wind Sites

7.5 Local Investment and Jobs Creation

In addition to the direct benefits of the MVP Portfolio, studies performed by the State Commissions have shown the indirect economic benefits of the MVP transmission investment. The MVP Portfolio supports thousands of local jobs and creates billions in local investment. In MTEP11, it was estimated that the MVP Portfolio supports between 17,000 and 39,800 local jobs, as well as $1.1 to $9.2 billion in local investment. Going forward, MISO is exploring the use of the IMPLAN model to quantify the direct, indirect, and induced effects on jobs and income related to transmission construction.

7.6 Carbon Reduction

The MVP Portfolio reduces carbon emissions by 9 to 15 million tons annually (Figure 7-5).

The MVP Portfolio enables the delivery of significant amounts of wind energy across MISO and neighboring regions, which reduces carbon emissions.

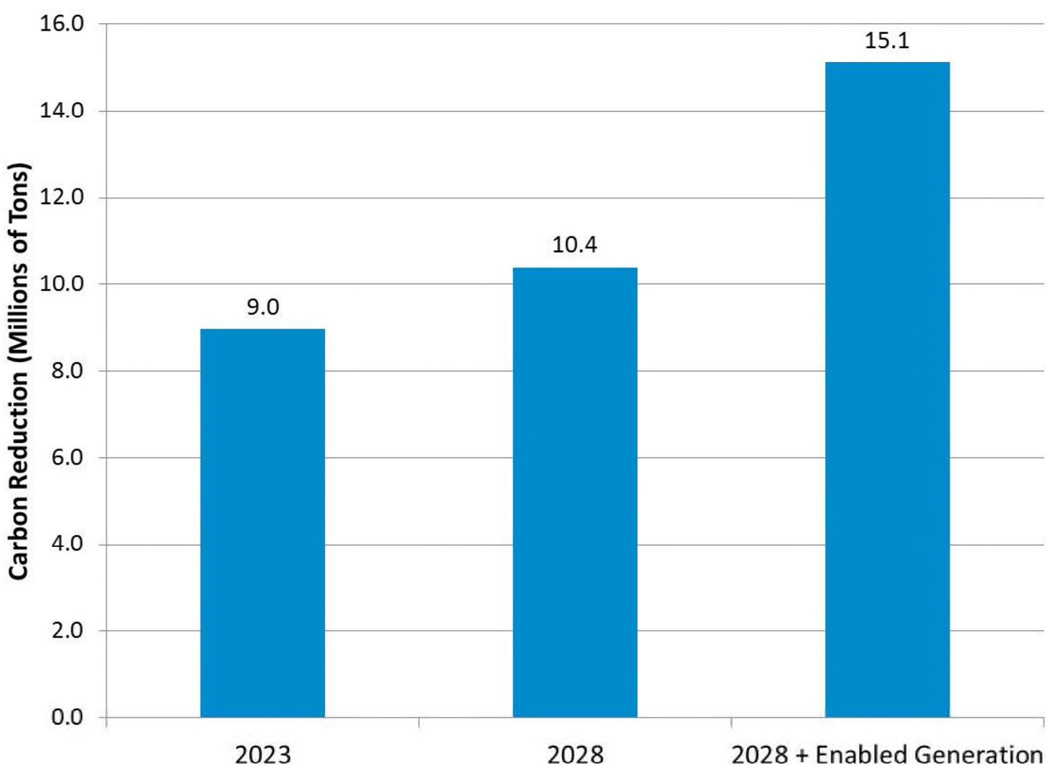


Figure 7-5: Forecasted Carbon Reduction from the MVP Portfolio by Year

8. Conclusions and Going Forward

The MTEP14 Triennial MVP Review provides an updated view into the projected economic, public policy and qualitative benefits of the MTEP11 MVP Portfolio. Analysis shows Multi-Value Project benefit-to-cost ratios have increased from 1.8 to 3.0 to a range of 2.6 to 3.9 since the MTEP11 analysis. Benefit increases are primarily congestion and fuel savings largely driven by natural gas prices.

The MTEP14 MVP Triennial Review's business case is on par with, if not stronger than, MTEP11 providing proof that the MVP criteria and methodology is working as expected. While the economic cost savings provide further benefit, the updated MTEP14 assessment corroborates the MVP Portfolio's ability to enable the delivery of wind generation in support of the renewable energy mandates of the MISO states in a cost effective manner.

Results prepared through the MTEP14 Triennial Review are for information purposes only and have no effect on the existing MVP Portfolio status or cost allocation.

MTEP15 and MTEP16 will feature a Limited Review of the MVP Portfolio benefits. Each Limited Review will provide an updated assessment of the congestion and fuel savings (Section 6.1) using the latest portfolio costs and in-service dates. Beginning in MTEP17, in addition to the Full Triennial Review, MISO will perform an assessment of the congestion costs, energy prices, fuel costs, planning reserve margin requirements, resource interconnections and energy supply consumption based on historical operations data.

Appendix

Detailed Transfer Analysis Results

LRZ	FCITC	Import Limit (CIL in MW)	Monitored Element	Contingency
1	-209	5,576	631115 OTTUMWA5 161 631116 BRDGPRT5 161 1	C:631115 OTTUMWA5 161 631134 TRICNTY5 161 1
2	-146	3,387	270810 LOCKPORT; B 345 274702 KENDALL; BU 345 1	C:270811 LOCKPORT; R 345 274703 KENDALL; RU 345 1
3	810	2,925	630388 WINCOR 8 69.0 630395 WNTRSET8 69.0 1	C:635631 BOONVIL5 161 635632 EARLHAM5 161 1
4	9,913	9,534	Limited by generation in tiers 1 and 2 - resulting limit considering Tier 1 and 2 available capacity and base interchange	
5	3,027	4,328	337651 8WHT BLUFF percent 500 337957 8KEO percent 500 1	C:P1_2-1312
6	2,002	5,761	243212 05BENTON 345 243250 05BENTON 138 1	C:P1_2_EXT_31
7	987	3,648	256290 18TITBAW 138 256542 18REDSTONE 138 1	C:b|18BULOCK-18SUMRTN 138-1

Table A-1: With MVP Capacity Import Limits

LRZ	FCITC	Import Limit (CIL in MW)	Monitored Element	Contingency
1	-204	5,326	699211 PT BCH3 345 699630 KEWAUNEE 345 1	C:ATC_B2_NAPL121
2	-237	2,958	270810 LOCKPORT; B 345 274702 KENDALL; BU 345 1	C:345-L10806_R-S
3	-564	1,198	300049 7THOMHL 345 300120 5THMHIL 161 1	C:345088 7MCCREDIE 345 345408 7OVERTON 345 1
4	4,429	4,632	256026 18THETFD 345 264580 19JEWEL 345 1	C:b|19BAUER-19PONTC 345-1
5	3,917	5,398	337651 8WHT BLUFF percent 500 337957 8KEO percent 500 1	C:P1_2-1312
6	1,277	5,328	256026 18THETFD 345 264580 19JEWEL 345 1	C:b|19BAUER-19PONTC 345-1
7	470	3,589	264522 19MENLO1 120 264947 19BUNCE2 120 1	C:x|19GRNEC 345-120-1

Table A-2: Without MVP Capacity Import Limits