Just & Reasonable? Transmission Upgrades Charged to Interconnecting Generators Are Delivering System-Wide Benefits

September 9, 2021

Submitted to: American Council of Renewable Energy (ACORE)

Submitted by: ICF Resources, LLC. Fairfax, VA

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Additionally, ICF team is grateful for the detailed comments from Daniel Hall, Central Region Senior Director, Electricity & Transmission, American Clean Power Association and Kevin O'Rourke, VP, Strategic Partnerships & Public Affairs, American Council on Renewable Energy.

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LIST OF EXHIBITS

LIST OF ABBREVIATIONS

ACORE	American Council on Renewable Energy
APC	Adjusted Production Cost
ARR	Annual Revenue Requirements
B/C	Benefit to Cost
DFAX	Distribution Factor
DISIS	Definitive Interconnection System Impact Study
DPP	Definitive Planning Phase
GI	Generation Interconnection
ISO	Independent System Operator
IRP	Integrated Resource Plan
ITP	Integrated Transmission Planning
LOIS	Limited Operation Interconnection Study
LRZ	Local Resource Zone
MCPS	Market Congestion Planning Study
MEP	Market Efficiency Project
MISO	Midcontinent Independent System Operator
MTEP	MISO Transmission Expansion Plan
MVP	Multi-Value Project
NPV	Net Present Value
OATT	Open Access Transmission Tariff
RPS	Renewable Portfolio Standards
RRF	Regional Resource Forecast
RTO	Regional Transmission Organization
SCED	Security Constrained Economic Dispatch
SPP	Southwest Power Pool
WACC	Weighted Average Cost of Capital

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1. EXECUTIVE SUMMARY

The American Council on Renewable Energy (ACORE), with support from the Macro Grid Initiative and in collaboration with American Clean Power Association, engaged ICF Resources, LLC (ICF) to evaluate the regional economic benefits of transmission network upgrades necessitated by generation interconnection requests in the Midcontinent Independent System Operator (MISO) and Southwest Power Pool (SPP) wholesale power markets. Both markets have seen a significant uptick in renewable generation interconnection requests over the past few years. Currently, over 92% of the 79 gigawatts (GW) of active requests in the MISO generation interconnection queue are solar, wind, and hybrid resources.[1] In SPP, solar, wind, and hybrid resources make up 95% of the 103 GW active queue requests.[2] Renewable generation is expected to grow even more in the coming years as favorable economics and clean energy goals continue to drive demand.

The lowest cost energy resources, such as solar and wind, are often located far from load centers, thus requiring transmission capacity expansion to move the power from the generation sources to the location it is needed. MISO's MVP and SPP's priority projects have been instrumental in integrating over 20 GW of new renewables across MISO and SPP. The transmission headroom created by these high-voltage expansion plans appears to have been used up and neither of the system operators have current board-approved plans for any significant regional transmission projects to enable new generation. Requests for new wind and solar generation interconnection have increased exponentially to avail the federal tax incentives; this increase is also due to a steady decline in the cost of wind and solar energy as states and corporate buyers seek to meet their renewable standards and goals.

In both markets, the cost of transmission network upgrades has become a significant hurdle for the integration of low-cost new renewable generation. For example, in its most recent Definitive Interconnection System Impact Study (DISIS) for generator interconnection, SPP identified the need for over $4.6B[3] worth of transmission network upgrades to help interconnect 10.4 GW of generation. If developed, these upgrades would have cost approximately $448/kW.[4] Similarly, in its most recent Definitive Planning Phase (DPP) study for generator interconnection, MISO identified the need for nearly $2.5B[5] worth of transmission network upgrades to interconnect 9.2 GW of generation in MISO South that translates to approximately $271/kW. The upgrades assigned to the generators are not limited to direct interconnection costs (akin to a

> Most recent system impact studies from SPP and MISO show network upgrade costs in the range of $270/kW to $448/kW.

[1] MISO GI queue as of August 18th, 2021 – does not include projects from DPP-2021 queue.
[2] SPP GI queue as of August 19th, 2021 – includes projects proposed in DISIS-2021 cluster.
[3] Source: DISIS-2017-001 published on April 28, 2021.
[4] Calculated by dividing the $4.6B in network upgrade costs by 10.4 GW of generator interconnection requests that were allocated the upgrade costs.
[5] Source: DPP-2019 Phase 1 published on July 16, 2020.

driveway) that allow them to access the high-voltage transmission (the highway). Given the over-subscribed power grid, interconnection customers are being allocated the full cost of adding new lanes to the highway and are increasingly responsible for building new highways. For example, SPP in its DISIS -2017-001 included a 165-mile, $1.34B, double circuit 765 kV line.[6]

Adding to the challenge is the fact that both markets allocate most, if not all, of the network upgrade costs to the generation developer. Under MISO's cost allocation process, almost all the costs of network upgrade projects rated 345 kV and higher are assigned directly to generators. Developers are responsible for 90% of the cost, with the remaining 10% allocated regionally on a postage stamp basis. Developers are responsible for all the costs for network upgrades rated below 345 kV. In SPP, the entire cost of network upgrades is assigned directly to generators. This cost allocation fails to consider potential regional economic benefits from these network upgrades.

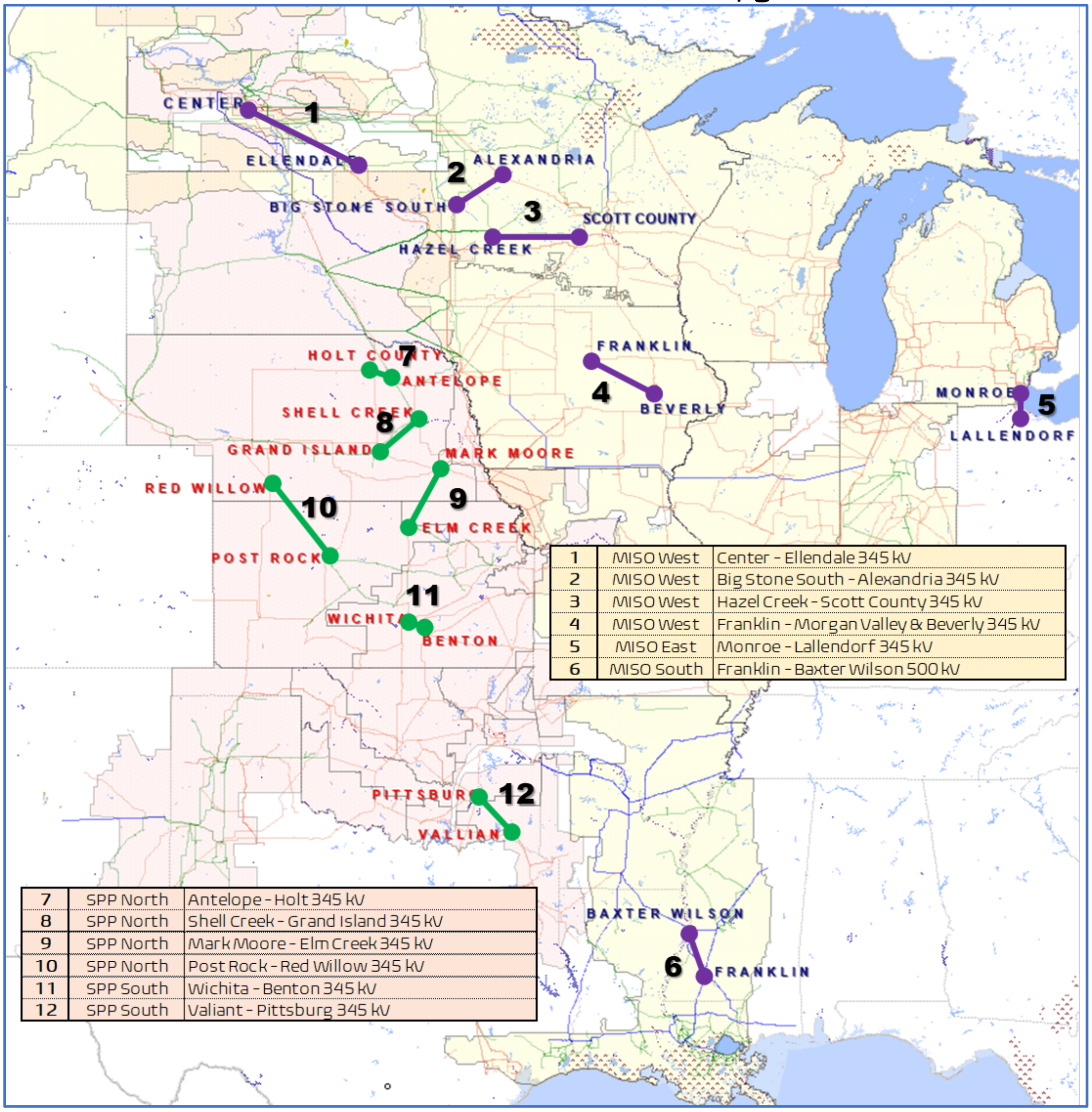
Current Approach	Load	Generator
SPP	0%	100%
MISO	10% (>=345 kV) 0% (<345 kV)	90% (>=345 kV) 100% (<345 kV)

Using very conservative assumptions, this study evaluated the economic benefits of a representative sample of network upgrade projects[7] assigned through the MISO and SPP GI process over the last seven years. ICF screened nearly 230 network upgrades spanning four DISIS studies (2014 – 2017) for SPP and 433 network upgrades spanning four DPP studies (2016 – 2020) for MISO. Informed by a range of factors, including voltage class, location of the upgrades, and level of generation interconnection capacity that were allocated the network upgrades, and in consultation with MISO and SPP staff, the screened network upgrades across both RTOs were shortlisted to six network upgrades in each RTO. In this report, capacity of the set of generators allocated the cost of a network upgrade is referred to as the GI capacity associated with that network upgrade. Exhibit 1 shows the geographic location of the selected projects. The results demonstrate that several of the somewhat randomly selected network upgrades provide significantly more benefits relative to the current costs allocated to the shared system.

To the extent possible, methodologies, assumptions, and processes employed by both MISO and SPP in their respective economic planning processes were followed in the study. The study design, including screening process and criteria to shortlist, was shared with MISO and SPP staff. The final set of shortlisted network upgrades was made after consultation with MISO and SPP.

[6] Crawfish Draw - Seminole 765 kV (165 miles) | Crawfish Draw - Crossroads (95 miles).
[7] ICF relied on past DISIS and DPP studies for SPP and MISO respectively to shortlist a pool of network upgrades that was evaluated as part of the study. The details of the screening processes are described in Study Design section of the report.

Exhibit 1: MISO and SPP Network Upgrades



1.1. *Key Findings*

A summary of the 12 network upgrades (NU) in MISO and SPP and the benefits and costs associated with those network upgrades are shown in Exhibit 2. Benefits of the shortlisted network upgrades are calculated as the Adjusted Production Cost (APC) savings (or "Benefits") to the shared system. APC is one of the key metrics used to calculate economic benefits in both MISO and SPP, as well as in other major electricity markets.

Consistent with the MISO and SPP planning processes, APC savings and costs were assessed over 20-year and 40-year study periods, respectively. In addition, the table provides the percentage of generator interconnection (GI) builds associated with each of the network upgrades that are represented in MISO's and SPP's planning scenarios, which impact the resulting benefits calculation.

Exhibit 2: Summary of Findings

Region	NU #	Network Upgrade	GI Capacity [8] Y2 / Y5 / Y10 / Y15[9]	Cost[10]	APC Savings (Benefits)[11]	B/C[12]
MISO West	1	Center – Ellendale 345 kV	- / 0% / 71% / 71%	$456.2M	$181.9M	0.40
MISO West	2	Big Stone South – Alexandria 345 kV	- / 30% / 97% / 97%	$221.4M	$335.8M	1.52
MISO West	3	Hazel Creek – Scott County 345 kV	- / 10% / 24% / 24%	$236.4M	$85.4M	0.36
MISO West	4	Franklin – Morgan Valley & Beverly 345 kV	- / 33% / 92% / 92%	$597.4M	-$4.8M	-
MISO East	5	Monroe – Lallendorf 345 kV Rebuild	- / 0% / 5% / 5%	$44.9M	$2.9M	0.06
MISO South	6	Franklin – Baxter Wilson 500 kV	- / 21% / 44% / 47%	$350.5M	$41.1M	0.12
SPP North	7	Antelope – Holt 345 kV	0% / 82% / 90% / -	$276.6M	$142.8M	0.52
SPP North	8	Shell Creek – Grand Island 345 kV	0% / 100% / 100% / -	$208.7M	$61.7M	0.30
SPP North	9	Mark Moore – Elm Creek 345 kV	0% / 89% / 96% / -	$259.3M	$10.4M	0.04
SPP North	10	Post Rock – Red Willow 345 kV	0% / 72% / 100% / -	$345.8M	-$8.9M	-
SPP South	11	Wichita – Benton 345 kV 2nd Line	0% / 90% / 97% / -	$32.1M	$59.3M	1.85
SPP South	12	Valiant – Pittsburg 345 kV 2nd Line	0% / 90% / 97% / -	$282.9M	$86.2M	0.30

APC Savings

Ten of the 12 network upgrades assessed in this study provided positive APC benefits. In general, of the network upgrades modeled, those with a higher percentage of interconnection projects represented in the associated future scenario resulted in higher APC savings. Six of the nine network upgrades modeled where 70% or greater of the same or similarly placed GI capacity was matched with RTO planning models resulted in

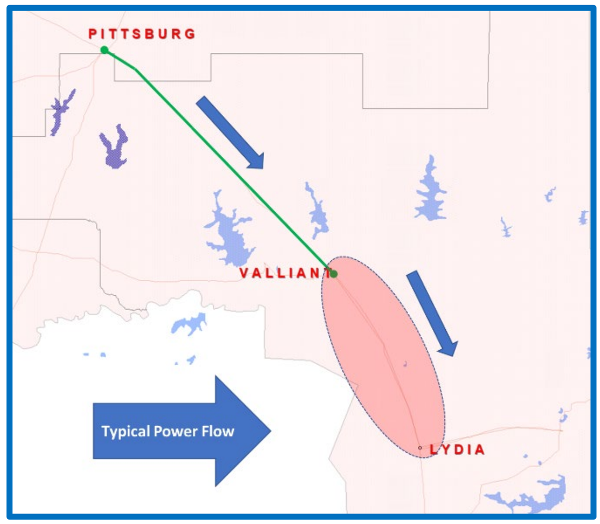
Production cost savings for six network upgrades with greater than 70% percent of GI capacity associated with those represented in the RTO planning models ranged between $59M and $335M.

[8] Percent capacity of the total GI projects associated with each of the network upgrades that is represented in the RTO Planning Scenarios.
[9] MISO's model run years: Y5 (2025), Y10 (2030), Y15 (2035) | SPP's model run years: Y2 (2023), Y5 (2026), Y10 (2031)
[10] Cost represents the 20-year (for MISO) or 40-year (for SPP) total costs of each network upgrade.
[11] Benefits represent adjusted production cost (APC) savings attributed to the new transmission project. For MISO network upgrades, the APC savings represent the 20-year NPV while the APC savings represent the 40-year NPV for SPP network upgrades.
[12] Calculated as benefits divided by cost for each transmission project. A ratio greater than 0.1 in MISO and 0 in SPP indicates that benefits to the consumer exceeds cost allocated to them.

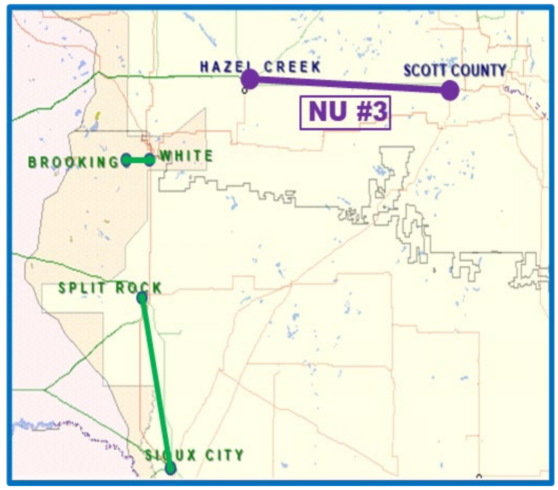
significant benefits—with a range of $59M to $335M in benefits to the shared system. Specifically, Center – Ellendale (NU #1), Big Stone South – Alexandria (NU #2), Antelope – Holt (NU #7), Shell Creek - Grand Island (NU # 8), Wichita - Benton (NU #11), and Valiant - Pittsburg (NU #12) demonstrated high APC savings due to significant share of GI capacity in the planning models. Other upgrades with a lower percentage match, such as Monroe – Lallendorf (NU #5) and Franklin – Baxter (NU #6) with only 5% and 47% of the associated GI capacity respectively, showed diminutive benefits.

Higher GI capacity representation in the planning models was not the only driver of APC savings. Several other factors affected the level of observed APC savings. These are:

- **Increase in congestion on transmission lines in the vicinity of the upgrade after implementation of the upgrade.** For example, nearly all the generation interconnection projects associated with the Valliant – Pittsburg 345 kV (NU #12) network upgrade were represented in the case by the final run year. However, the upgrade provided limited benefits because transmission expansion along the Valliant – Pittsburg corridor created new congestion downstream of the line. With the inclusion of the network upgrade, Valliant – Lydia 345 kV line became congested. Because the scope did not include upgrades to additional facilities identified in the DISIS studies, the impact of the network upgrade was limited. SPP identified Valliant – Lydia 345 kV as a network upgrade in the same DISIS study cluster. Similarly, Mark Moore – Elm Creek (NU #9) resulted in increased congestion on the Columbus 345/138 kV transformer downstream of the network upgrade that resulted in negative APC savings.



- **Upgrades in locations with frequent and persistent congestion provided benefits even with relatively lower percentage of associated generation interconnection projects.** For example, Hazel Creek – Scott County 345 kV (NU #3) showed relatively high benefits with only 24% of the associated generation interconnection projects. Higher APC savings despite a lower level of associated generation was observed due to mitigation of pre-existing chokepoints on Brooking – White and Split Rock – Sioux City 345 kV lines.



B/C Ratio

Of the ten network upgrades with positive APC savings, the benefit-to-cost (B/C) ratios ranged from a low of 0.04 for the Mark Moore – Elm Creek 345 kV network upgrade in SPP to a high of 1.85 for the Wichita – Benton 345 kV network upgrade in SPP. Seven network upgrades had B/C ratios greater than or equal to 0.30. The results show that many projects provide significant regional economic benefits, and some even more than the costs. For example, the Big Stone – South Alexandria 345 kV in MISO and Wichita – Benton 345 kV in SPP have the potential to provide benefits that far exceed the cost to the system.

The network upgrades provide benefits to the system by enabling more low-cost renewable output, which leads to reduction in fossil-fired generation and associated emissions attributed to those generators. On average, the network upgrades enabled 12 TWh of additional renewable output in MISO and nearly 7 TWh of additional renewable output in SPP. The network upgrades also eased existing chokepoints in SPP and MISO, which is beyond their primary purpose of integrating renewables.

1.2. Conservative Aspects of Key Study Assumptions

As noted above, the current cost allocation processes in MISO and SPP largely ignore the economic benefits to the shared system from these network upgrades. This study examined a selection of proposed network upgrades in the two regions to determine their potential to provide benefits associated with APC savings. It assumed network upgrades would be built primarily to interconnect the associated generation resources. Aspects of transmission planning that could enhance market efficiency benefits were not incorporated explicitly. In particular, the study was designed to test the one-off addition of single network upgrades. The only difference between the Reference Case and each of the change cases was the addition of a single transmission network upgrade. As a result, the economic benefits evaluated and described in this report are conservative and may understate the full benefits of the projects to consumers.

Following are other examples of the conservative methods employed in the study. Sensitivity cases, which are described in greater detail below, were conducted to demonstrate the extent of the actual benefits if these factors were taken into consideration.

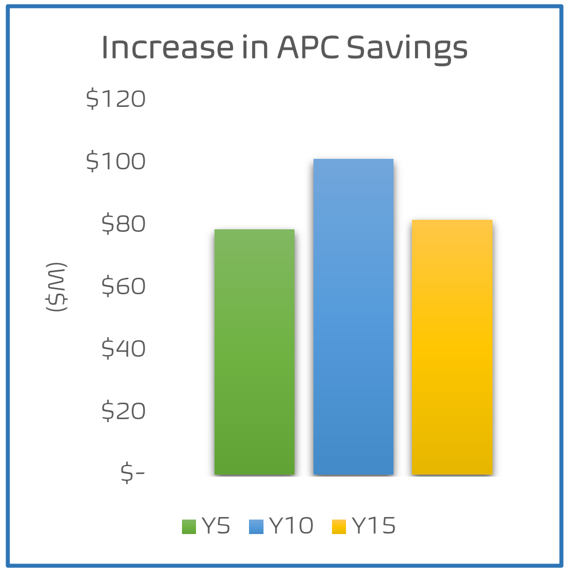
1. **Selection of network upgrade projects.** Unlike typical planning for market efficiency projects, the network upgrades in this study were not selected based on their ability to address persistent congestion. Any economic benefits calculated in this study is incremental to the benefits of interconnecting and delivering low-cost renewable energy to consumers.

2. **Choice of future scenarios.** The study used the most conservative of the MISO and SPP future scenarios. In MISO, the study used Future I, which factored in carbon emissions reduction[16] of 40%. Future II and Future III reflected 60% and 80% carbon emissions reduction respectively and had significantly higher renewable generation. For SPP, the study used Future I that reflected the continuation of current industry trends and environmental regulations. It assumed that solar and wind additions will exceed current renewable portfolio standards due to economics, public appeal, and the anticipation of potential policy changes.[17] Increasing renewable generation increases the benefits of the network upgrades. This also demonstrates another type of unrecognized benefit of network upgrades. Once built, these upgrades would enable additional generation to enter the queue in the future and interconnect at no incremental cost to the future builds or consumers.[18]

Renewable Build-Out (MW)[13]	MISO[14]	SPP[15]
Future 1	48.8 GW	15.5 GW
Future 2	58.4 GW	22.5 GW
Future 3	114.8 GW	N/A

[13] Only wind and solar resources are reflected in the totals.
[14] Futures resource additions through 2035 | source: MISO Futures Report dated April 2021.
[15] Future resource additions through 2031 | source: 2021 Integrated Transmission Planning Resource and Siting Plan
[16] Carbon emissions reduction refer to power sector emissions reduction from 2005 baseline – Source: MTEP21 Futures White Paper dated April 27, 2020.
[17] 2021 Integrated Transmission Planning Assessment Scope document dated August 5, 2020.
[18] FERC ANOPR has acknowledged the issue and raised the concern of potential free-rider problems associated with interconnection customers that later connect to transmission facilities planned for anticipated future generation.

3. **The benefit of the network upgrades therefore includes the ability to enable the full output of the generation interconnection projects.** Because the scope of this study was limited to one-off additions of network upgrades, the associated generation resources were not derated in the Reference Case without the network upgrade. This approach significantly understates the actual production cost savings associated with each network upgrade. A sensitivity was conducted to demonstrate the effect of this assumption on the APC savings associated with Franklin – Baxter Wilson 345 kV line.[19] As discussed above, this line provides relatively low net benefits in the reference scenario. However, in the de-rate scenario, in which 92% of renewables assigned to the network upgrades are excluded from the Base Case and only assumed in the Change Case along with the network upgrade that is being evaluated, APC savings increased by an average of nearly $87M and yielded a B/C ratio to 2.03 (as compared with 0.12 in the reference case).



4. **Absence of associated network upgrades.** MISO and SPP generation interconnection studies usually identify multiple network upgrades to enable the full capacity of each cluster of generation interconnection projects. Because the study was designed to assess one-off additions of single network upgrades, additional projects identified in the interconnection studies were not implemented. This lack of additional upgrades identified in the interconnection studies was observed to be a key factor in the negative APC savings for Franklin – Morgan Valley & Beverly 345 kV (NU#4) and Pittsburg – Valliant 345 kV (NU#12). When simulated as one-offs, these network upgrades led to increased congestion on other transmission facilities that had been identified in the SPP and MISO interconnection studies. For example, the Valliant – Pittsburg 345 kV upgrade created new congestion downstream on the Pittsburg – Valliant 345 kV line. With the inclusion of the network upgrade, Valliant – Lydia 345 kV line became congested. Congestion was observed on Mingo to Post Rock 345 kV, which is one of the eight network upgrades and attributed to be the main driver of negative APC savings for Post Rock – Red Willow 345 kV.

5. **Associated generation interconnection projects.** On average, just under 50% of the builds associated with the network upgrades were represented in the MISO

[19] In MISO, generators that interconnect prior to completion of required network upgrades are subject to quarterly operating limits that ensure they do not cause any reliability violations. SPP performs an annual Limited Operation Interconnection Study (LOIS) to determine the impacts of interconnecting to the transmission system before all required Network Upgrades identified in the DISIS studies can be placed into service.

Future 1, while a higher capacity (above 80%) were found to be associated with the shortlisted network upgrades in SPP. To avoid biasing the study, no additional capacity was added to the ISO models. As a result, some associated generation interconnection projects that could drive the usage and benefits of network upgrades were excluded from the study.

2. INTRODUCTION

The American Council on Renewable Energy (ACORE), with support from the Macro Grid Initiative and in collaboration with American Clean Power Association, engaged ICF Resources, LLC (ICF) to evaluate the regional economic benefits of transmission network upgrades necessitated by generation interconnection requests in the Midcontinent Independent System Operator (MISO) and Southwest Power Pool (SPP) wholesale power markets.

In both markets, the cost of transmission network upgrades has become a significant hurdle for the integration of low-cost new renewable generation. The upgrades assigned to the generators are not limited to direct interconnection costs (akin to a driveway) that allow them to access the high-voltage transmission (the highway). Given the over-subscribed power grid, interconnection customers are being allocated the full cost of adding new lanes to the highway and increasingly building new highways. Adding to the challenge is the fact that both markets allocate most, if not all, of the network upgrade costs to the generation developer. This cost allocation fails to consider potential regional economic benefits from these network upgrades. Using very conservative assumptions, this study evaluated the economic benefits of a representative sample of network upgrade projects assigned through MISO and SPP's GI process over the last seven years.
The remainder of the report is organized into four sections. Section 3 provides a market overview of the SPP and MISO markets. Section 4 details the overall study design and underlying assumptions for the assessment of benefits. Section 5 provides results of the ICF assessment including production cost savings and B/C ratio for each of the twelve projects followed by conclusions in Section 6.

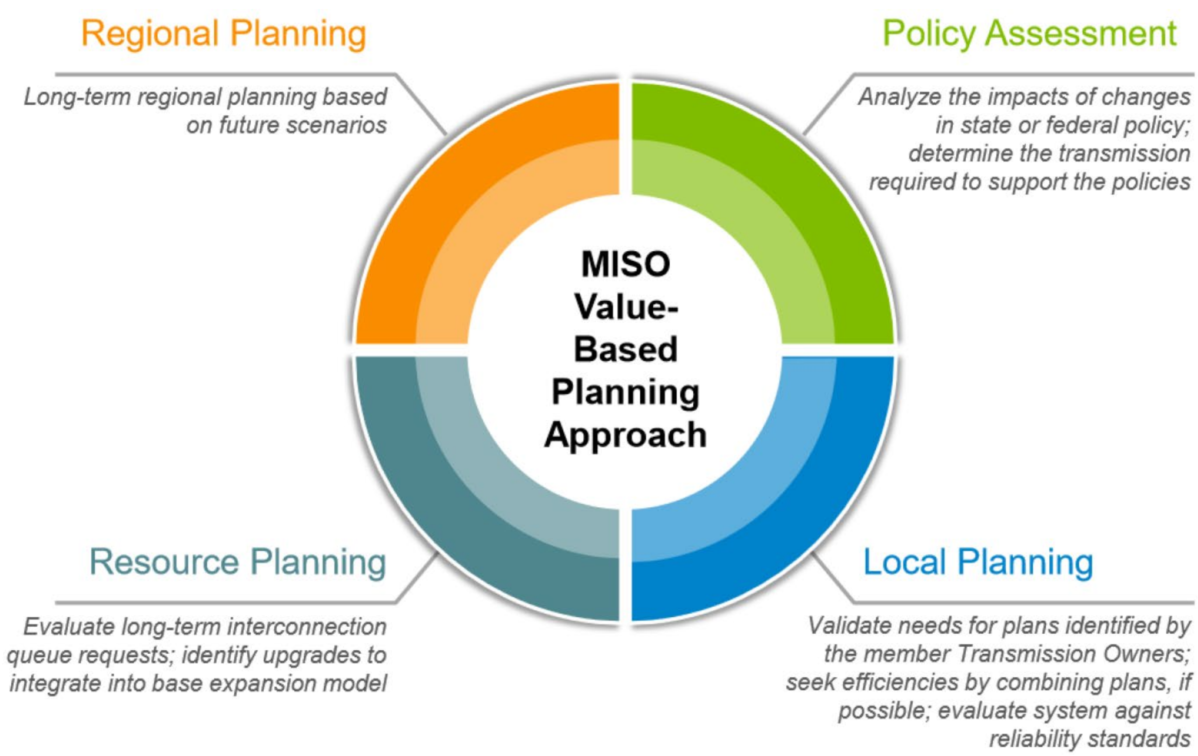
3. MARKET OVERVIEW

3.1. Midcontinent Independent System Operator (MISO)

MISO, the largest wholesale market in North America from a geographical standpoint, is amid an aggressive transition towards a cleaner generation portfolio. MISO has shifted from a coal heavy portfolio in 2014 (57%[20] of the generation mix was comprised of coal) to a current portfolio largely comprised of gas and renewables (over 60%[21] of the generation mix).

As the transition towards a cleaner generation mix continues, it is imperative to focus on a holistic approach to grid planning and management that would enable the greatest benefits to consumers. MISO's value-based planning process incorporates regional planning, local planning, resource planning, and changes in policies that ultimately ensures reliability and minimizes costs to its customers. This switch to a value-based planning could potentially address the deviation between generator interconnection studies versus transmission planning studies. The exhibit below shows MISO's concept of this value-based approach.

Exhibit 3: MISO's Value-Based Planning Approach



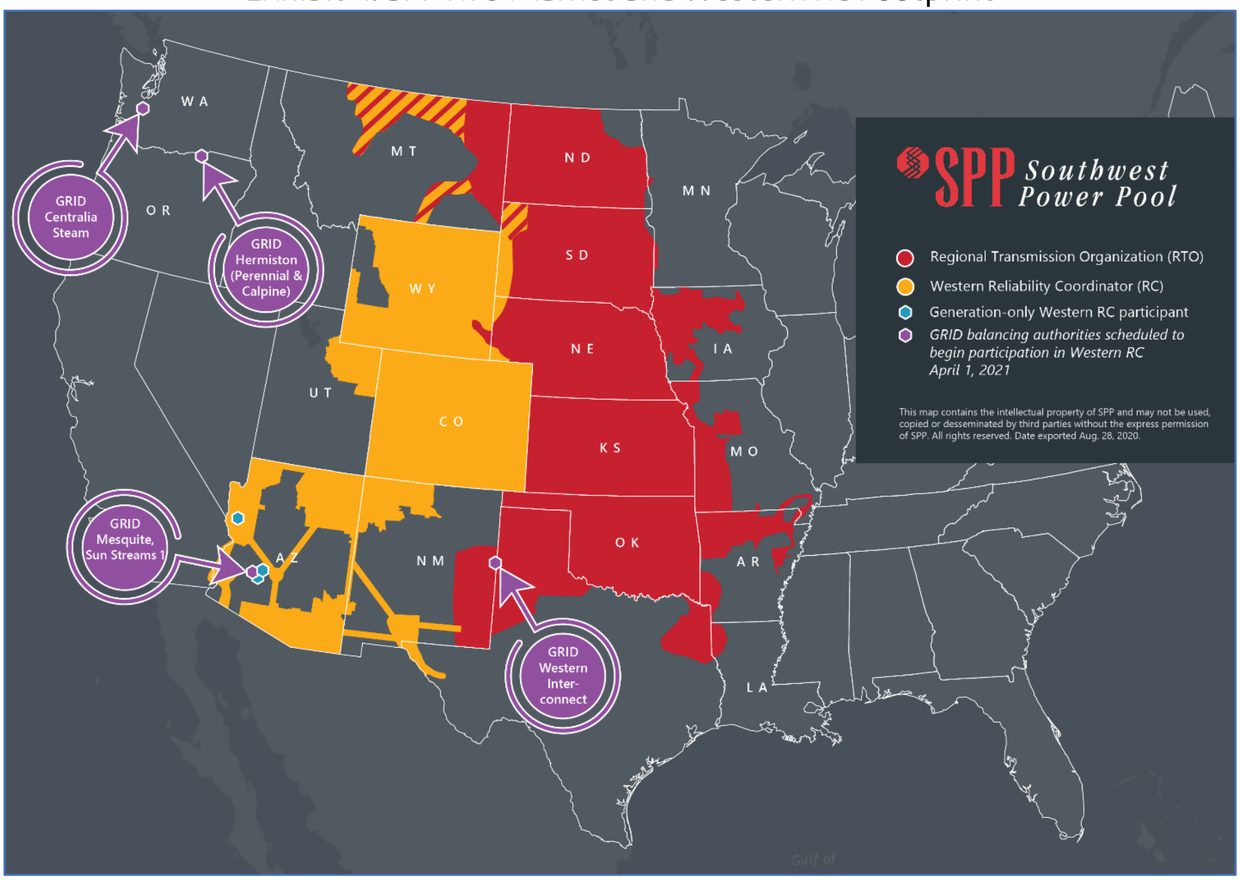
Source: MTEP 2021 Report – Executive Summary

[20] http://timeline.misomatters.org/
[21] https://www.misoenergy.org/about/media-center/corporate-fact-sheet/

3.2. Southwest Power Pool (SPP)

SPP, one of the seven Independent System Operators (ISOs)/Regional Transmission Organizations (RTOs) in the United States, oversees the bulk electric grid and wholesale power market in the central United States on behalf of a diverse group of utilities and transmission companies in 17 states (including 3 states that comprise the Western Energy Imbalance Service market).[22] Through its portfolio of Western Energy Services, SPP also provides contract-based services like reliability coordination and administration of a real-time balancing market to customers in the Western Interconnection.

Exhibit 4: SPP RTO Market and Western RC Footprint



Source: https://spp.org

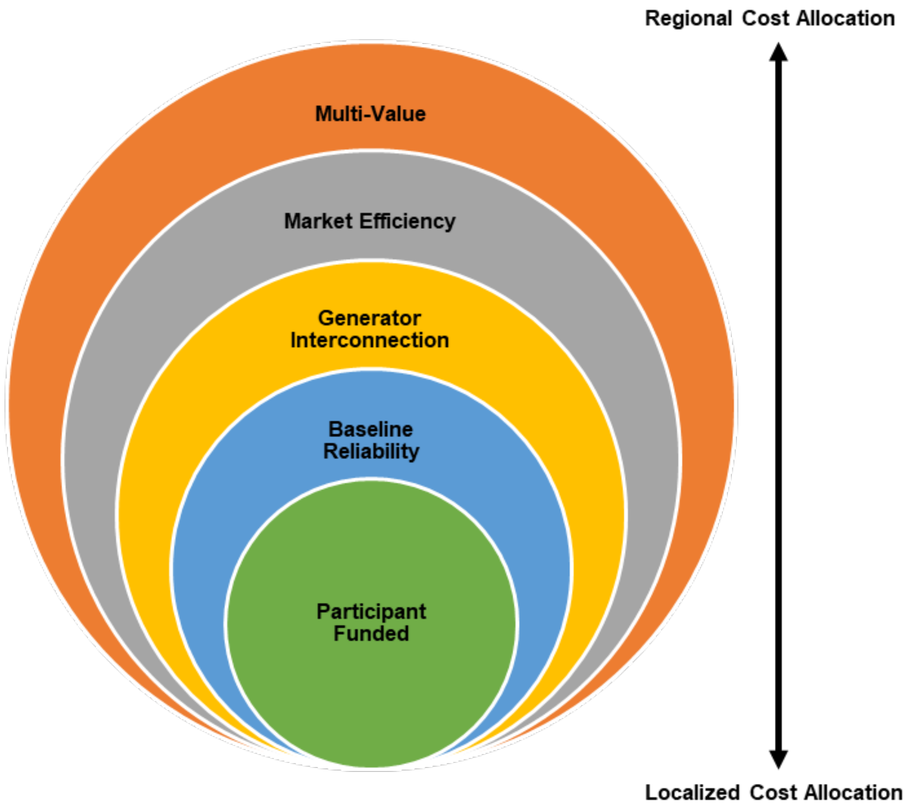
In the Eastern Interconnection, SPP's transmission network consists of approximately 70,000 miles of high-voltage transmission lines and it administers a total generation capacity of over 90 GW. Over the years, SPP's members have harnessed the wind-rich region of the Midwest that has contributed to a shift in the generation mix. As of January 2021, wind comprised 29% of SPP's generating capacity and nearly 30% of its energy production. In March of 2021, SPP saw record wind penetration in real-time at nearly 82%.

[22] https://spp.org

3.3. MISO's Planning Process

MISO's Transmission Expansion Planning (MTEP) process is an annual process that evaluates various types of projects to help support local and regional reliability needs, help facilitate interconnection of generation resources, and offer a platform for developing competitive transmission projects providing regional benefits. MISO's MTEP process classifies projects into several categories, each with its own drivers and needs, and is cost allocated based on the benefits it is intended to provide. Exhibits 7 and 8 below provide an overview of the different categories of MTEP projects and how these projects are cost allocated.

Exhibit 5: MTEP Categories



Source: MISO Tariff – Attachment FF

Exhibit 6: MISO Project Types

Project Type	Description	Cost Allocation Methodology
Multi-Value Projects (MVPs)	Often address one or more of the following three goals and are evaluated as part of a portfolio of projects whose benefits (and costs) are spread across the footprint. • Reliably and economically enable regional public policy needs • Provide multiple types of regional economic value • Provide a combination of regional reliability and economic value	100% postage stamp to load
Market Efficiency Projects (MEPs)	Often provide benefits that span beyond the local zone and is regionally cost-allocated that is commensurate to the load-ratio share of the members	230 kV and above[23]: distributed to Local Resource Zones (LRZs) commensurate with expected benefit
Generation Interconnection (GI) Projects	Help mitigate potential constraints that are caused by interconnecting generator resources to MISO's footprint and is predominantly paid by the interconnection customer.	Primarily funded by the requestor
Baseline Reliability Projects	Projects that are proposed to meet NERC's Transmission Planning Standards and is cost allocated amongst the local zone since the benefits of the project are often localized.	100% allocated to local TPZ
Participant Funded Projects	Often addresses localized constraints	Primarily funded by the requestor

Source: Transmission Planning OMS Cost Allocation Principles Committee (CAPCOM) presentation dated October 19, 2020

3.4. SPP's Planning Process

To meet its Open Access Transmission Tariff (OATT), SPP conducts the Integrated Transmission Planning (ITP) Assessment to plan transmission upgrades needed to maintain reliability, provide economic benefits, and achieve public policy goals over a 10-year planning horizon. In addition, SPP also performs 20-year assessment every five years that focuses on identifying the need for extra high-voltage transmission lines (345 kV and above) for a 20-year planning horizon. The study's success depends on its ability to provide a robust system that enables transmission usage and generation access. The assessment identifies a versatile transmission system capable of providing cost-effective energy delivery for a broad range of possible generation resource futures.[24]

[23] FERC approved MISO's Transmission Cost Allocation reforms in July 2020 that lowered the voltage threshold for MEP projects to 230 kV, added two new metrics in calculating the Adjusted Production Cost (APC) savings, and eliminated the allocation of 20% of the cost of MEPs to the entire MISO footprint on a postage-stamp basis.
[24] Source: spp.org

With the ever-increasing penetration of renewables, SPP updated its renewable forecast in the ITP assessment to allow the region to proactively build the infrastructure needed to alleviate congestion and provide access to cheaper energy.[25] SPP considers three distinct scenarios to account for variations in system conditions over a 10-year period. These scenarios consider requirements to support firm deliverability of capacity for reliability while exploring rapidly evolving technology that may influence the transmission system and energy industry. The scenarios include varied wind projections, utility-scale and distributed solar, energy storage resources, generation retirements and electric vehicles. In addition to the scenarios, SPP also analyzes a wide range of sensitivities that consider changes to natural gas prices, generator retirements, renewables development, battery storage and demand.

SPP has seen significant wind generation capacity expansion over the last several years, driven by a combination of strong wind resources, production tax credits, and availability of power purchase agreements and hedges. SPP's wind penetration stands at over 23 GW; the 2nd largest market share of wind within the United States, behind ERCOT. There has also been a strong growing interest in solar development in the last few years as evident by the active queue requests. SPP currently has Approximately 46 GW of active solar projects in its Generation Interconnection Queue.[26]

While large load centers in SPP's footprint are in the eastern parts of the market, the southwestern portion comprising the Texas panhandle, western Oklahoma, and southwestern Kansas boast high wind resources. The power often flows from these wind rich regions in the southwest and from the north to load centers in the east.

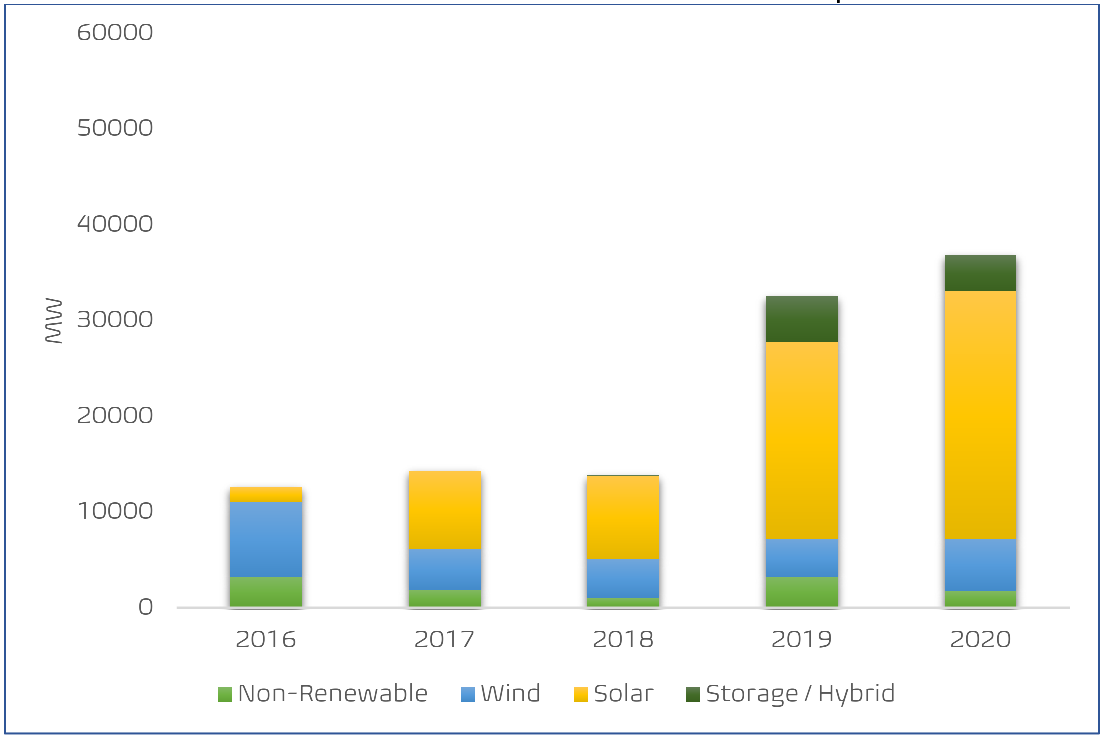
Similar to MISO's MVP, SPP's board approved the construction of a group of "priority" high-voltage electric transmission projects estimated to provide benefits of nearly $4B to the SPP region over 40 years.[27] This group of projects increased the transfer capability and allowed for additional transmission service requests to be granted. In addition, between 3 GW and 5 GW of wind energy (as well as new non-renewable generation) has resulted from this group of projects. However, the incremental transmission capacity created by the "priority" projects are all but used.

3.5. Generator Interconnection Process in MISO and SPP

Over the last few years, generator interconnection queues across the country have seen significant uptick in renewable generation requests. Since 2016, as shown in Exhibits 9 and 10, the Midcontinent Independent System Operator (MISO) has seen renewables comprise of nearly 90% of the interconnection queue on average. While wind interconnection requests have steadily increased over the years in MISO, the solar interconnection requests have increased exponentially.

[25] Source: 2020 ITP Report
[26] SPP Generation Interconnection Queue as of June 2021.
[27] https://www.spp.org/engineering/transmission-planning/priority-projects/

Exhibit : Active and Executed Generator Interconnection Requests (2016-2020)[28]



Source: MISO Generator Interconnection Queue

The significant increase in renewable share brings with it a pressing need for new or expanded transmission grid. The current transmission grid was built years ago to accommodate conventional generators that were often sited close to the load. Renewables, however, are often developed further away from load (largely due to land availability) and rely on transmission reinforcements to help transmit power. This is evident with the ever-increasing transmission network upgrade costs that are seen in markets that eventually leads to several interconnection projects withdrawing their requests.

As the MISO and SPP footprints continue to integrate renewables, there is a growing need to upgrade the existing transmission system to better facilitate the transfer of power from generators to load centers. In its most recent generator interconnection study for example, SPP identified the need for over $4.6B[29] worth of transmission upgrades to help interconnect 10.4 GW of generation. SPP's network upgrades are entirely participant funded, so all these costs will be allocated to the renewable generation developers. The high upgrades costs are sure to deter several interconnection customers from staying in the queue. In addition to the high network upgrade costs, delays to SPP's DISIS process creates uncertainty for interconnection customers. SPP is currently evaluating generators that entered the queue in March 2017. Similarly, in one of its most recent Definitive Planning Phase (DPP) study for generator interconnection, MISO identified the need for nearly $2.5B[30] worth of

[28] Includes only GI projects that are currently active in the queue or have an executed interconnection agreement.
[29] Source: DISIS-2017-001 published on April 28, 2021
[30] Source: DPP-2019 Phase 1 published on July 16, 2020.

transmission network upgrades to interconnect 9.2 GW of generation in MISO South.

The allocation of all network upgrade costs to the developers suggests that the projects do not provide any economic benefits to consumers. As demonstrated in this study, however, some projects provide broader regional benefits.

Currently, MISO's tariff requires majority[31] of the costs for generator interconnection network upgrade costs to be paid by the interconnection customers while the benefits of these network upgrades could potentially accrue to other stakeholders. In particular, the benefits to customers could potentially exceed the costs allocated to customers.

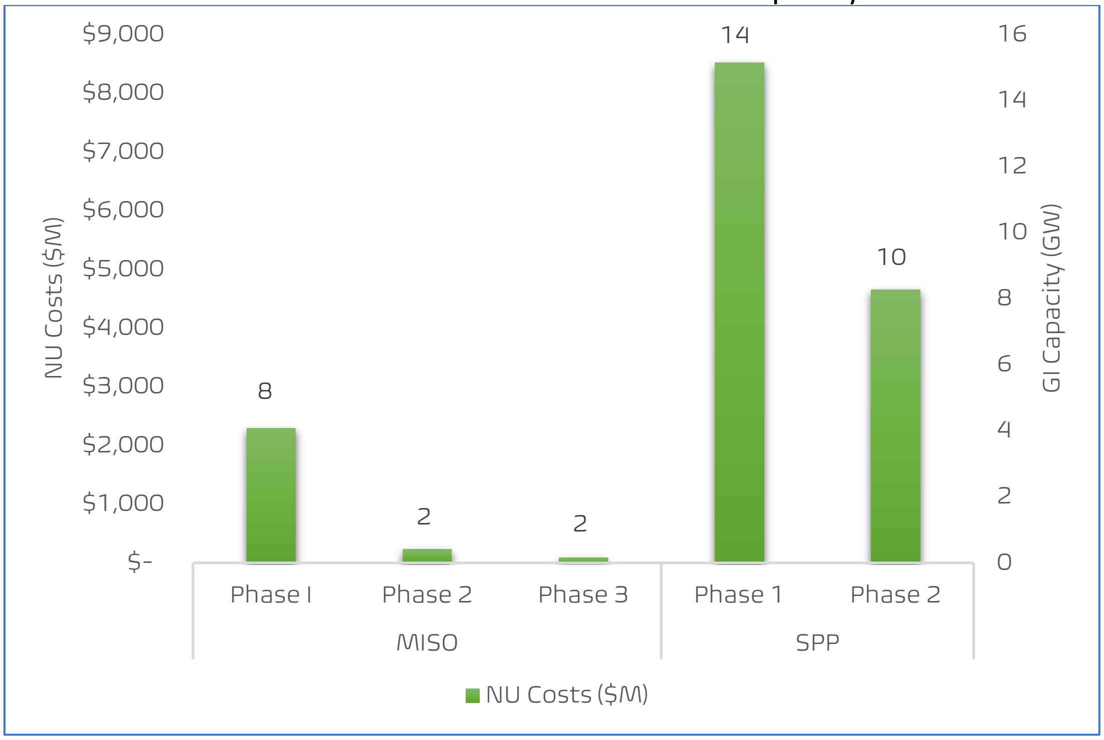
With the level of renewable penetration anticipated over the next several years, MISO's and SPP's focus on value-based planning is ever critical. Early stages of the planning were one of the key drivers in establishing the portfolio of Multi-Value Projects (MVPs) in MISO and priority projects in SPP that have been instrumental in integrating over 20 GW[32] of new renewables across both of their footprints. Since the portfolio of MISO's MVP and SPP's priority projects were proposed, generator interconnection queue in both markets have been flooded with requests for interconnecting proposed renewable resources. As the trend towards incorporating renewable resources to the generation mix continues at almost an exponential rate, it is imperative that the transmission grid is robust enough to help facilitate such penetration levels.

The recently completed DPP studies however indicate that there are certain areas in the transmission system that acts as a bottleneck in enabling renewable buildouts. This is evident by the amount of GI projects that withdraw after phase 1 of the DPP studies due to the high network upgrade costs that are identified. Exhibit 11 below for example, shows the change in network upgrade costs and the number of interconnection requests in the 2018 MISO South DPP cycle. In the 2018 DPP phase 1 study, MISO indicated a total network upgrade costs over $2B[33] to interconnect the projects in the queue. That estimated total network upgrade costs dropped to $230M[34] when MISO completed phase 2 of the 2018 DPP study for MISO South (nearly 75% of the projects that entered the 2018 MISO South DPP cycle withdrew).

SPP is experiencing a similar trend where huge network upgrade costs in the initial phases of the analyses leads to the withdrawal of several GI projects. For example, the DISIS-2017-001 cluster in SPP initially identified nearly $8.5B worth of upgrades to interconnect nearly 14.5 GW of generation while phase 2 of the cluster saw the withdrawal of 4 GW of GI projects from the queue. The withdrawal cut the cost of the interconnection upgrades by half and now stands at $4.7B.

[31] For transmission network upgrades 345 kV and above, MISO allocates 90% of the costs to the interconnection customers while the remaining 10% is assigned to load on a postage stamp basis.
[32] Source: SPP – SPP Priority Projects Phase II Report dated February 1, 2010, | MISO - https://www.misoenergy.org/planning/planning/multi-value-projects-mvps/#t=10&p=0&s=&sd=
[33] Refer to the "Final MISO DPP 2018 April South Area Study Phase I Report"
[34] Refer to the "Final MISO DPP 2018 April South Area Study Phase II Report"

Exhibit 7: MISO's 2018 DPP South NU and Capacity Trends



Source: MISO 2018 DPP South Report and SPP DISIS 2017-001 Report

4. STUDY DESIGN

The Study Design section is structured to provide a brief description of the steps taken in conducting the study. The subsections present details of the assumptions, the determination of network upgrades, and matching of GI projects associated with the shortlisted network upgrades in the modeling database. Ultimately, the assumptions and inputs into the model are evaluated and reported in the form of Adjusted Production Cost (APC) savings that is used as a metric to determine the consumer benefits of the shortlisted network upgrades.

ICF used ABB's PROMOD IV® simulation software to capture the benefits of transmission network upgrades associated with generator interconnection projects. PROMOD is a fundamental electric market simulation solution that incorporates extensive details in generating unit operating characteristics, transmission grid topology, and constraints, and market system operations to support economic transmission planning.

Benefits associated with the shortlisted network upgrades were evaluated by capturing the change in APC across the entire footprint of MISO and SPP individually. To determine the change in APC, ICF modeled a "Base Case" without the proposed transmission network upgrade and a "Change Case" that included the network upgrade. With everything else the same between the two cases, the change in APC can be attributed to the inclusion of the network upgrade.

4.1. Adjusted Production Cost (APC) Methodology

APC is one of the key metrics used by both MISO and SPP in its evaluation of economic benefits of potential transmission upgrades. The APC is the total of production costs of a generation fleet including fuel, operations and maintenance, startup costs, and emissions that is adjusted by the transaction cost. A company's transaction cost includes purchases and/or sales within an ISO's footprint (within pool transaction cost) and purchases and/or sales between a company within an ISO and a company outside of the same ISO (inter-pool transaction cost). The APC is calculated on an hourly basis for each company within the ISO. For example, MISO calculates the APC as:

Adjusted Production Cost

APC is the total of production costs of a generation fleet within a region adjusted by transaction costs. The production cost includes fuel costs, operations and maintenance costs, startup costs, and cost of emission allowances. The transaction cost includes purchases and/or sales within the region and between the region and other regions.

Hourly Company APC = Hourly Production Cost + Hourly Fixed Transaction Cost + Hourly Emergency Energy Cost + Hourly Inter-pool Transaction Cost + Hourly Within Pool Transaction Cost[35]

[35] Source: MISO Adjusted Production Cost Calculation White Paper dated February 1, 2019

Exhibit 8: APC Metric Components

APC Component	Description
Hourly Production Cost	The hourly production cost represents the final cost of operating a company's thermal fleet. The calculation includes fuel costs, startup costs, emission costs, and variable O&M costs.
Hourly Fixed Transaction Cost	The hourly fixed transaction cost represents the production costs of generators without fuel (renewables).
Hourly Emergency Energy Cost	The hourly emergency energy cost represents the cost of injecting power at an existing generator site in addition to the modeled generation capacity to reliably serve load. The emergency energy injection and its pricing are a proxy for deferred reliability transmission investment, generation investment, scarcity pricing, or the loss of load. Emergency energy is priced at $1,000/MWh
Hourly Inter-pool Transaction Cost	The hourly inter-pool transaction cost represents a company's purchases and sales with other companies outside of the ISO.
Hourly Within Pool Transaction Cost	The hourly within pool transaction cost represents the cost of a company's purchases and sales with other companies within the ISO.

4.2. *Calculation of Net Present Value (NPV)*

The PROMOD analysis of the three model run years results in nominal APC benefits or costs. Several factors go into the calculation to determine the benefit-to-cost (B/C) ratio such as the APC benefits, cost of the network upgrade, annual revenue requirements (ARR), after-tax weighted average cost of capital (WACC), and inflation rate. These factors are computed over a 20-year period for MISO and a 40-year period for SPP from the start of the assumed in-service date of the network upgrades.

4.3. *Methodology and Modeling Assumptions*

The United States' entire Eastern Interconnect power system is represented in the underlying PROMOD database and reflects a nodal network topology that constitutes transmission lines 69 kV and higher. In addition, the database is updated to reflect generation capacity expected in the three model-run years[36] to reflect MISO's MTEP21 Market Congestion Planning Study (MCPS) process. The network topology and the generation capacities, along with demand, gas prices, coal prices, federal tax credits, renewable mandates, transmission constraints, and hourly profiles, are fed into the PROMOD database. The database is simulated to reflect a security constrained economic dispatch (SCED) of generation over an 8760-hour period based on the inputs

[36] For the analysis, ICF chose to perform the analysis for three model-run years to reflect MISO's MCPS process. ICF performed the analysis for 2025 (5-year out), 2030 (10-year out), and 2035 (15-year out).

provided to capture the impact of transmission constraints on congestion and price formation.

ICF incorporated MISO's Future 1 assumptions for supply, demand, and capacity expansion in the underlying PROMOD database. The Future 1 factors in utility's energy announcements and plans,[37] state mandates, goals, or preferences[38], and an associated carbon emissions reduction of 40% relative to 2005 levels in MISO. In addition, age-based retirements of coal generation are set to 46 years while combined-cycle natural gas plants are set to 50 years. In addition to Future 1, MISO has established two additional futures to capture the different ranges of economic, political, and technological changes over a 20-year period. Future II and III scenarios include significantly higher renewable penetration. As such, ICF's reliance on Future I for assessment of benefits of transmission upgrades should be considered a conservative assumption. All else equal, higher renewable capacity associates with each network upgrade will yield higher system benefits. The exhibit below provides details of all three of the futures.

Exhibit 9: MISO Futures Assumptions Summary

Variables / Futures	Future I	Future II	Future III
Percent of Goals Met	85% goals met 100% IRPs met	100% goals met 100% IRPs met	100% goals met 100% IRPs met
Carbon Emissions Reduction* (2005 baseline)	40% (currently at 22%)**	60%	80%
Retirements-Coal Retirements-Natural Gas- CC Retirements-Natural Gas-Other	46 years 50 years 46 years	36 years 45 years 36 years	30 years 35 years 30 years
Wind and Solar Penetration	No minimum	No minimum	50%
EV Adoption & Charging Technology	Low-Base EV growth Uncontrolled charging	Base-High EV growth Uncontrolled 2020-2035 & V2G 2035 and beyond	Extra-High EV growth Uncontrolled 2020-2030 & V2G 2030 and beyond
Electrification (includes EVs and gas to electric appliances / heating / cooling)	None	19% of technical potential realized representing a 16% energy growth	40% of technical potential realized representing a 34% energy growth
Demand & Energy Growth^	0.59% 0.63%	1.09% 1.23%	1.94% 1.91%
DER Technical Potential by 2040 (GW)^^	DR: 5.2 EE: 13.3 DG: 14.7	DR: 5.9 EE: 14.5 DG: 14.7	DR: 5.9 EE: 14.5 DG: 21.8
Natural Gas Prices	Base starting price determined by GPCM; Future-specific price input to PROMOD	Base starting price determined by GPCM; Future-specific price input to PROMOD	Base starting price determined by GPCM; Future-specific price input to PROMOD

Source: MTEP21 Futures White Paper dated April 27, 2020

[37] Future 1 incorporates 100% of utility integrated resource plan announcements | Source: MISO Futures Report
[38] Unlegislated goals and preferences are applied at 85% of the announcements to hedge for uncertainty | Source: MISO Futures Report

For the SPP market, the database was updated to reflect generation capacities expected during the study period. Consistent with SPP's ITP process, ICF modeled three run years – 2023 (2-year out), 2026 (5-year out), and 2031 (10-year out). The network topology and the generation capacities, along with demand, gas prices, coal prices, federal tax credits, renewable mandates, transmission constraints, and hourly profiles, are fed into the PROMOD database. The database is simulated to reflect a security constrained economic dispatch (SCED) of generation over an 8760-hour period in each year to capture the impact of transmission constraints on congestion and price formation.

Similar to MISO, ICF incorporated the most conservative scenario- Future 1 assumptions for supply, demand, and capacity expansion. Future 1 reflects the continuation of current industry trends and environmental regulation. Solar and wind additions are assumed to exceed current renewable portfolio standards (RPS) due to economics, public appeal, and the anticipation of potential policy changes. In addition, age-based retirements of coal generation are set to 56 years while gas-fired and oil generators are set to 50 years. Battery energy storage resources are included relative to the approved solar amounts [39]. For Future 1, the level of energy storage is 20% of the projected solar capacity. Like MISO, SPP has also established an additional, Future 2 which reflects a scenario driven by the adoption of emerging technologies such as electric vehicles, distributed generation, demand response, and energy efficiency. Age-based retirements of thermal generators are accelerated in Future 2, and it also assumes a more aggressive buildout of solar, wind, and energy storage resources when compared with Future 1.[40] Exhibit 14 below provides an overview of the assumptions that is reflected in SPP's Futures.

[39] Source: 2021 ITP Assessment Scope dated August 5, 2020.
[40] Source: 2021 ITP Assessment Scope dated August 5, 2020.

Exhibit 10: SPP Futures Assumptions Summary[41]

KEY ASSUMPTIONS	YEAR 2	REFERENCE CASE YEAR 5	REFERENCE CASE YEAR 10	EMERGING TECHNOLOGIES YEAR 5	EMERGING TECHNOLOGIES YEAR 10
Peak Demand Growth Rates	As submitted in load forecast	As submitted in load forecast		As submitted in load forecast	
Energy Demand Growth Rates	As submitted in load forecast	As submitted in load forecast		Increase due to electric vehicle growth	
Natural Gas Prices	Current industry forecast	Current industry forecast		Current industry forecast	
Coal Prices	Current industry forecast	Current industry forecast		Current industry forecast	
Emissions Prices	Current industry forecast	Current industry forecast		Current industry forecast	
Fossil Fuel Retirements	Current forecast	Coal age-based 56+, Gas/Oil age-based 50+, subject to generator owner review		Coal age-based 52+, Gas/Oil age-based 48+, subject to GO review and ESWG approval	
Environmental Regulations	Current regulations	Current regulations		Current regulations	
Demand Response[1]	As submitted in load forecast	As submitted in load forecast		As submitted in load forecast	
Distributed Generation (Solar)	As submitted in load forecast	As submitted in load forecast		+300MW	+500MW
Energy Efficiency	As submitted in load forecast	As submitted in load forecast		As submitted in load forecast	
Storage	None	20% of projected solar		35% of projected solar	

Source: 2021 ITP Assessment Scope dated August 5, 2020.

4.4. Determination of Network Upgrades

ICF reviewed MISO's Definitive Planning Phase (DPP) reports published for all cycles from 2016 onwards and SPP's Definitive Interconnection System Impact Study (DISIS) reports published for all clusters from 2014[42] onwards to come up with an initial list of network upgrades that could be evaluated.

[41] Future 1 – Reference Case | Future II – Emerging Technologies

[42] As SPP is currently evaluating GI projects that have entered the queue in 2017, ICF began with DISIS reports for the 2014 cluster as opposed to MISO's DPP reports that were reviewed from 2016 onwards.

The exhibit below presents a set of criteria ICF applied to shortlist the set of network upgrades that would eventually be analyzed.

Exhibit 11: Determination of Network Upgrades[43]

Criteria	Description
Sub-Region	Representations from throughout MISO's and SPP's footprints were considered for the analysis. For MISO, the focus was around the sub-regions (West, Central, East, and South) and for SPP, the focus was around the SPP North and SPP South.
Voltage Threshold	Proposed transmission network upgrades 230 kV and above for MISO and 345 kV and above for SPP were considered for the analysis[44]
Implied Cost Threshold ($/kW) [45]	Proposed transmission network upgrades with a $100/kW or below were considered for the analysis
Repetitiveness	Transmission network upgrades that were identified in multiple DPP cycles (MISO) or DISIS studies (SPP) were given preference

Six network upgrades were subsequently selected from each ISO for the study. The shortlisted projects for both markets are shown in exhibits 16 and 17 with exhibit 18 showing the geographic location of each project in both markets.

Exhibit 12: Shortlisted MISO Network Upgrades

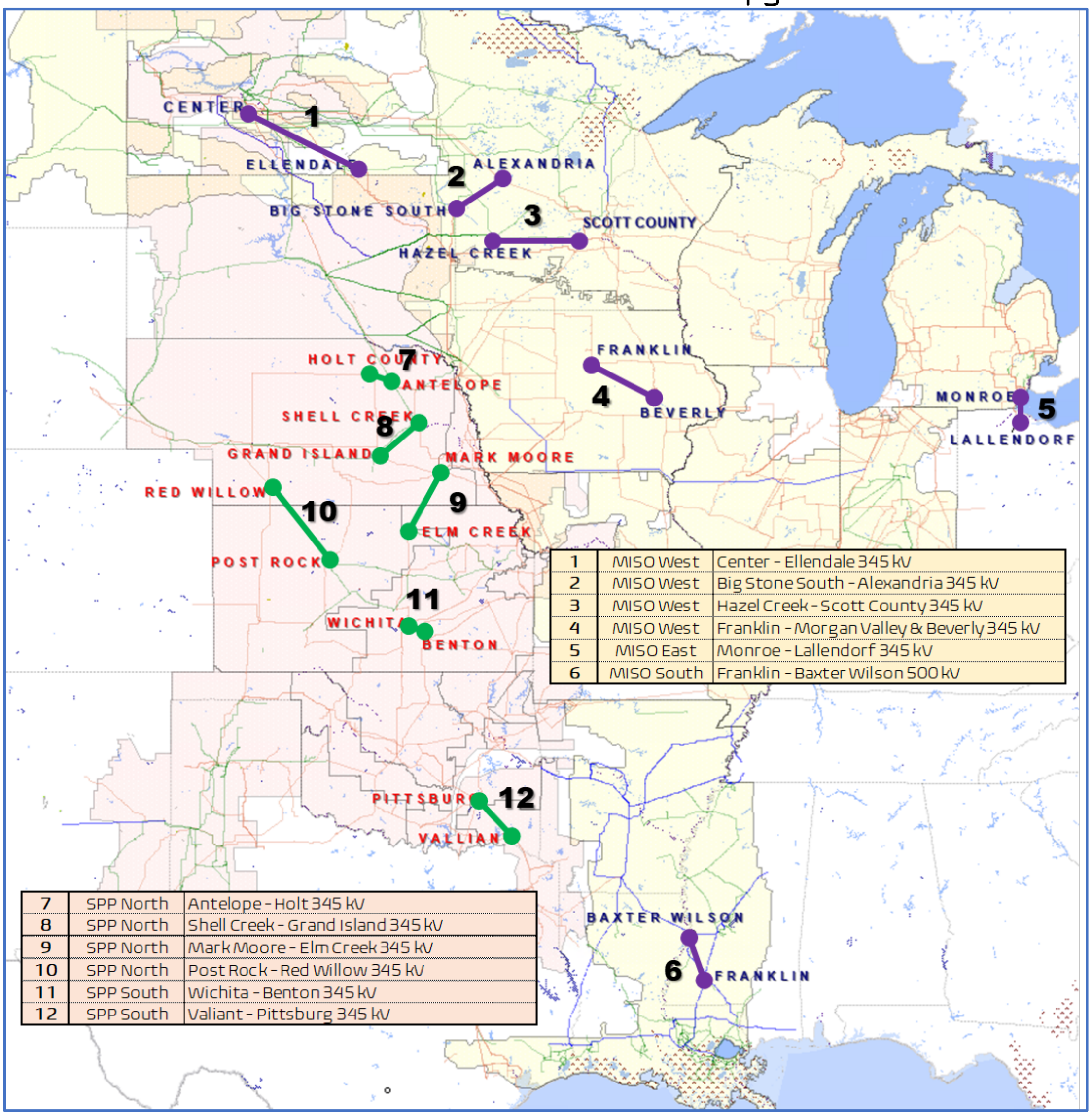
Network Upgrade	Sub-Region	Voltage (kV)	Implied Cost Threshold ($/kW)	Repetitiveness [46]
Franklin – Morgan Valley & Beverly	West	345	$94.83	2
Big Stone South – Alexandria	West	345	$45.05	3
Center – Ellendale [47]	West	345	$332.31	2
Hazel Creek – Scott County	West	345	$47.70	3
Monroe – Lallendorf	East	345	$7.21	2
Franklin – Baxter Wilson	South	500	$58.35	1

[43] Due to the differences in modeling methodology and the analytical approach between RTOs, inter-regional network upgrades were not considered as part of the study.
[44] The 230 kV and 345 kV voltage thresholds for MISO and SPP respectively is consistent with how the two ISOs determine transmission projects that would be regionally cost allocated through their economic planning studies.
[45] The set of generators allocated the cost of a network upgrade is referred to as the GI capacity associated with that network upgrade. The implied cost is calculated as the total GI capacity associated with the network upgrade divided by cost of the network upgrade.
[46] The repetitiveness indicates the number of DPP/DISIS cycles the network upgrades were proposed.
[47] Even though Center – Ellendale 345 kV network upgrade did not meet the $100/kW criteria, the upgrade was evaluated to determine complementary nature of this upgrade to Big Stone South – Alexandria 345 kV line which is discussed in the Section 5

Exhibit 13: Shortlisted SPP Network Upgrades

Network Upgrade	Sub-Region	Voltage (kV)	Implied Cost Threshold ($/kW)	Repetitiveness
Antelope – Holt	SPP North	345	$44.90	3
Shell Creek – Grand Island	SPP North	345	$87.90	1
Mark Moore – Elm Creek	SPP North	345	$108.52	1
Post Rock – Red Willow	SPP North	345	$90.50	2
Wichita – Benton (2nd Line)	SPP South	345	$5.30	2
Valiant – Pittsburg (2nd Line)	SPP South	345	$65.70	2

Exhibit 14: MISO and SPP Network Upgrades



4.5. *Matching GI Projects Associated with Network Upgrades*

Because the network upgrades are proposed to enable interconnection of specific generation resources, ICF examined firm and proposed builds in MISO's and SPP's Future I assumptions to determine if the GI projects associated with the shortlisted network upgrades or similarly placed GI projects were included in the model. Firm generation includes projects that are under construction or in advanced stages of development and are very likely to be placed in service. Proposed generation in the MISO Future 1 assumptions include Regional Resource Forecast (RRF) generation, and Integrated Resource Plan (IRP) generation. RRF generation are various resource types that are defined in and selected by MISO's capacity expansion tool, EGEAS, to achieve each of the Futures scenarios. The RRF units used in MISO comprise wind, solar, hybrid resources, 4-hour storage, distributed energy resources (DERs), natural gas resources, and combined cycle & carbon capture sequestration[48]. SPP also includes RRF generation identified through its capacity expansion analysis in its Future 1 assumptions.

For GI projects that were not originally included in the regions' Future I assumptions, ICF determined if similarly placed generators could act as a proxy for the GI builds. Similarly placed generators were determined based on a set of criteria as laid out below.

- **Location of builds.** For MISO, similarly placed generators were determined based on the Local Resource Zones (LRZ). For example, a similarly placed generator could function as a proxy of a GI project associated with a network upgrade if both the generators are intended to be in the same LRZ. With this approach, the overall LRZ level build and the MISO-wide build assumptions in Future I remained the same. For SPP, similarly placed generators were determined by subregion (SPP North and SPP South) while retaining the overall subregional level builds.
- **Impact on the network upgrade.** ICF relied on a distribution factor[49] (DFAX) criteria to determine if a similarly placed generator could function as a proxy for the GI projects. The impact of a similarly placed generator on the network upgrade from DFAX standpoint should tantamount to the DFAX of the GI project on the network upgrade.
- **Resource capacity.** The capacity of the similarly placed GI project should be in line with the GI project associated with the network upgrade.

Based on the above criteria, only a portion of the GI builds associated with the network upgrades were matched in the PROMOD databases of both RTOs. For MISO, the year 5 (2025) database had the least GI builds at 19% while year 10 (2030) and year 15 (2035) databases had just under 50% of the GI builds. The limitations were largely due to the lack of same or similarly placed generators within a specific LRZ and the DFAX methodology that was applied.

For SPP, ICF matched nearly 81% of the GI builds associated with shortlisted network upgrades in year 5 and nearly 92% of the GI builds in year 10. Exhibits 19 and 20 below presents the level of GI builds associated with the shortlisted network upgrades that were matched in the models for MISO and SPP, respectively.

[48] Source: MISO Futures Report dated April 2021
[49] Distribution factor is a measure of the proportion of the output of a generator that will flow on a specified transmission line.

Exhibit 15: Same or Similarly Placed Builds Associated with Network Upgrades in MISO

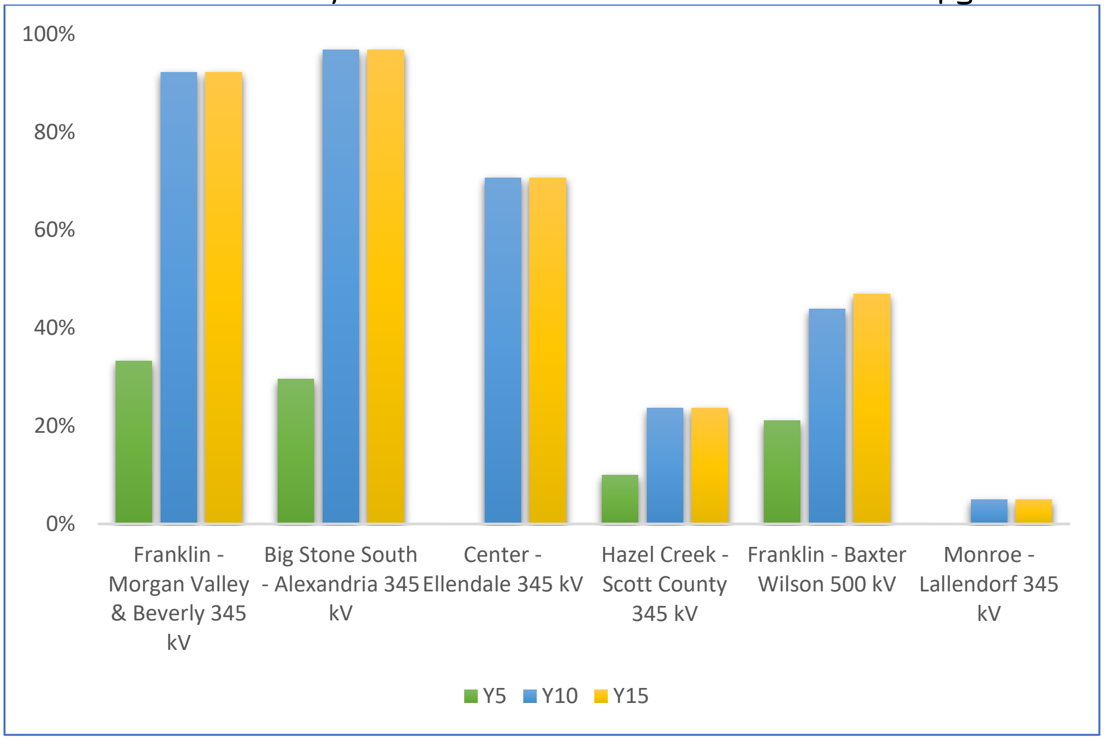
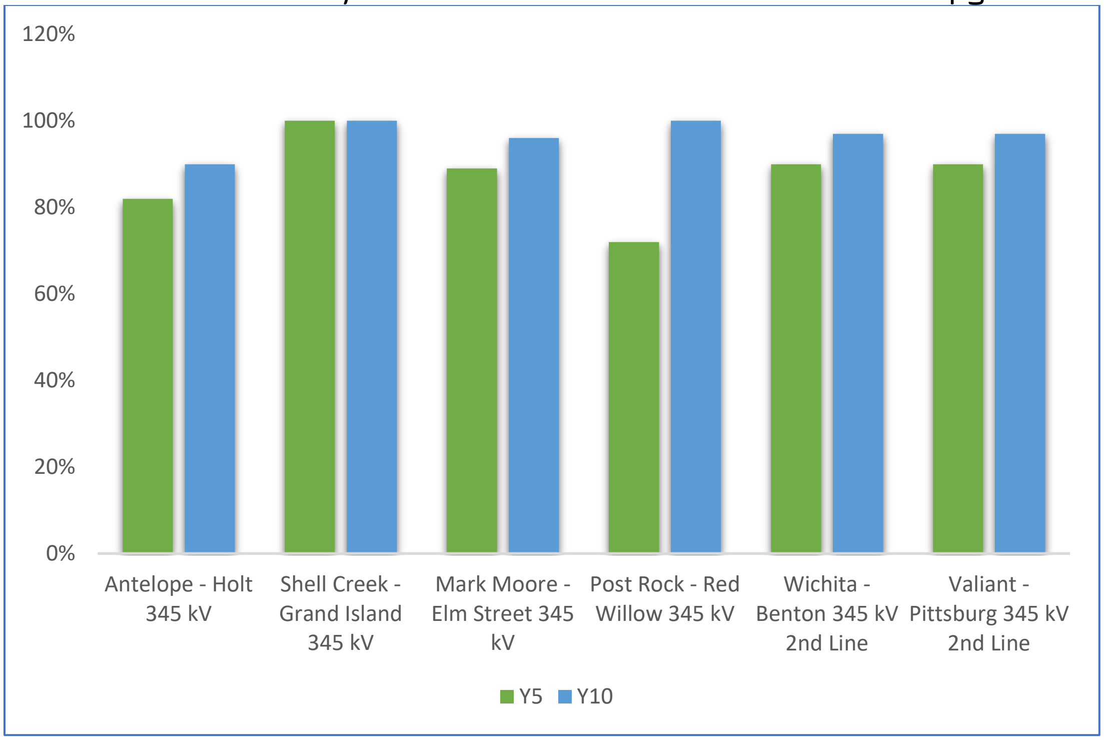


Exhibit 16: Same or Similarly Placed Builds Associated with Network Upgrades in SPP



5. RESULTS

A summary of the 12 network upgrades analyzed in this study is shown in Exhibit 26. The exhibit also summarizes the cost of the network upgrade, the benefits in the form of APC savings calculated from the PROMOD modeling, and the benefit-to-cost ratio. In addition, the table provides a percentage of generator interconnection (GI) builds associated with each of the network upgrades that are represented in MISO's and SPP's planning scenarios, which impacts the resulting benefits calculation.

Exhibit 17: Summary of Findings

Region	NU #	Network Upgrade	GI Capacity [50] Y2 / Y5 / Y10 / Y15[51]	Cost[52]	APC Savings (Benefits)[53]	B/C[54]
MISO West	1	Center – Ellendale 345 kV	- / 0% / 71% / 71%	$456.2M	$181.9M	0.40
MISO West	2	Big Stone South – Alexandria 345 kV	- / 30% / 97% / 97%	$221.4M	$335.8M	1.52
MISO West	3	Hazel Creek – Scott County 345 kV	- / 10% / 24% / 24%	$236.4M	$85.4M	0.36
MISO West	4	Franklin – Morgan Valley & Beverly 345 kV	- / 33% / 92% / 92%	$597.4M	-$4.8M	-
MISO East	5	Monroe – Lallendorf 345 kV Rebuild	- / 0% / 5% / 5%	$44.9M	$2.9M	0.06
MISO South	6	Franklin – Baxter Wilson 500 kV	- / 21% / 44% / 47%	$350.5M	$41.1M	0.12
SPP North	7	Antelope – Holt 345 kV	0% / 82% / 90% / -	$276.6M	$142.8M	0.52
SPP North	8	Shell Creek – Grand Island 345 kV	0% / 100% / 100% / -	$208.7M	$61.7M	0.30
SPP North	9	Mark Moore – Elm Creek 345 kV	0% / 89% / 96% / -	$259.3M	$10.4M	0.04
SPP North	10	Post Rock – Red Willow 345 kV	0% / 72% / 100% / -	$345.8M	-$8.9M	-
SPP South	11	Wichita – Benton 345 kV 2nd Line	0% / 90% / 97% / -	$32.1M	$59.3M	1.85
SPP South	12	Valiant – Pittsburg 345 kV 2nd Line	0% / 90% / 97% / -	$282.9M	$86.2M	0.30

Ten of the 12 network upgrades assessed in this study provided positive APC benefits.

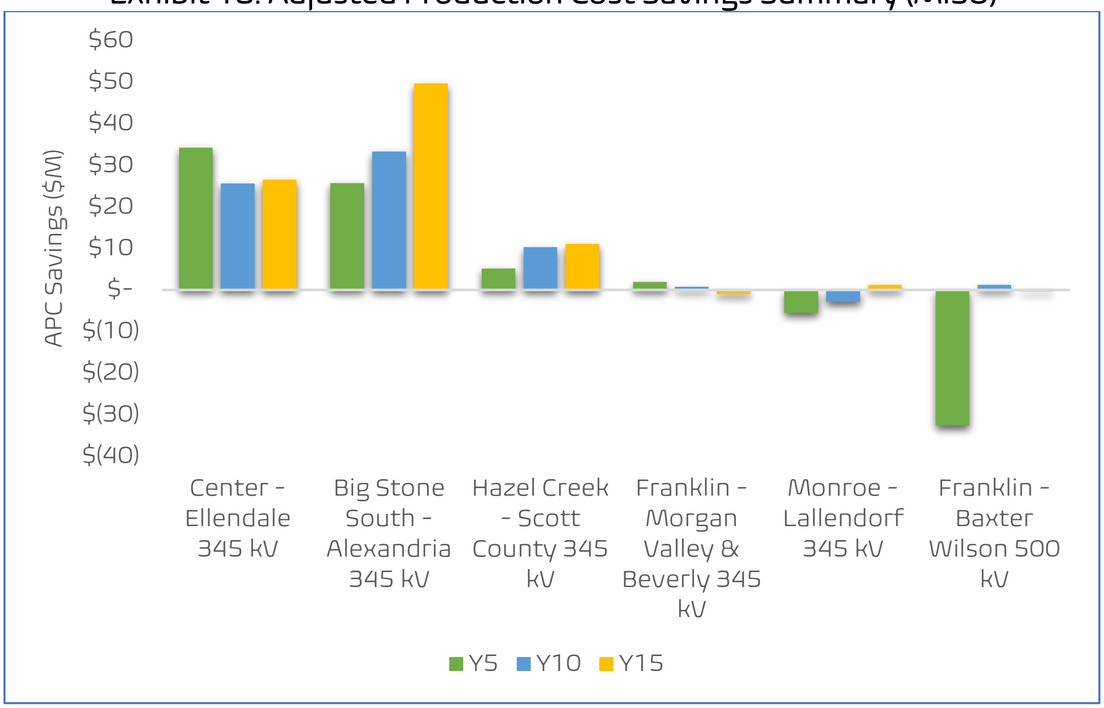
[50] Percent capacity of the total GI projects associated with each of the network upgrades that is represented in the RTO Planning Scenarios.
[51] MISO's model run years: Y5 (2025), Y10 (2030), Y15 (2035) | SPP's model run years: Y2 (2023), Y5 (2026), Y10 (2031).
[52] Cost represents the 20-year (for MISO) or 40-year (for SPP) total costs of each network upgrade.
[53] Benefits represent adjusted production cost (APC) savings attributed to the new transmission project. For MISO network upgrades, the APC savings represent the 20-year NPV while the APC savings represent the 40-year NPV for SPP network upgrades.
[54] Calculated as benefits divided by cost for each transmission project. A ratio greater than 0.1 in MISO and 0 in SPP indicates that benefits to the consumer exceeds cost allocated to them.

In general, of the network upgrades modeled, those with a higher percentage of interconnection projects represented in the future scenario resulted in higher APC savings. Six of the nine network upgrades with 70% or greater of the same or similarly placed GI capacity represented in the RTO planning models resulted in significant benefits to the system, ranging from $59M to $335M.

Specifically, Center – Ellendale (NU #1), Big Stone South – Alexandria (NU #2), Antelope – Holt (NU #7), Shell Creek - Grand Island (NU # 8), Wichita - Benton (NU #11), and Valiant - Pittsburg (NU #12) provided high APC savings due to significant share of GI capacity in the planning models. Other upgrades with a lower percentage match, such as Monroe – Lallendorf (NU #5) and Franklin – Baxter (NU #6) with only 5% and 47% of the associated GI capacity respectively, showed diminutive benefits. Higher GI capacity representation in the planning models was not the only driver of APC savings.

Consistent with the MISO and SPP planning processes, APC savings and costs were assessed over 20-year and 40-year study periods, respectively. The exhibit below shows the APC savings for the network upgrades in MISO for the three model run years- Year 5 (2025), Year 10 (2030) and Year 15 (2035). The APC values from the PROMOD model run years[55] were interpolated and extrapolated to determine the 20-year present value of the benefits.

Exhibit 18: Adjusted Production Cost Savings Summary (MISO)

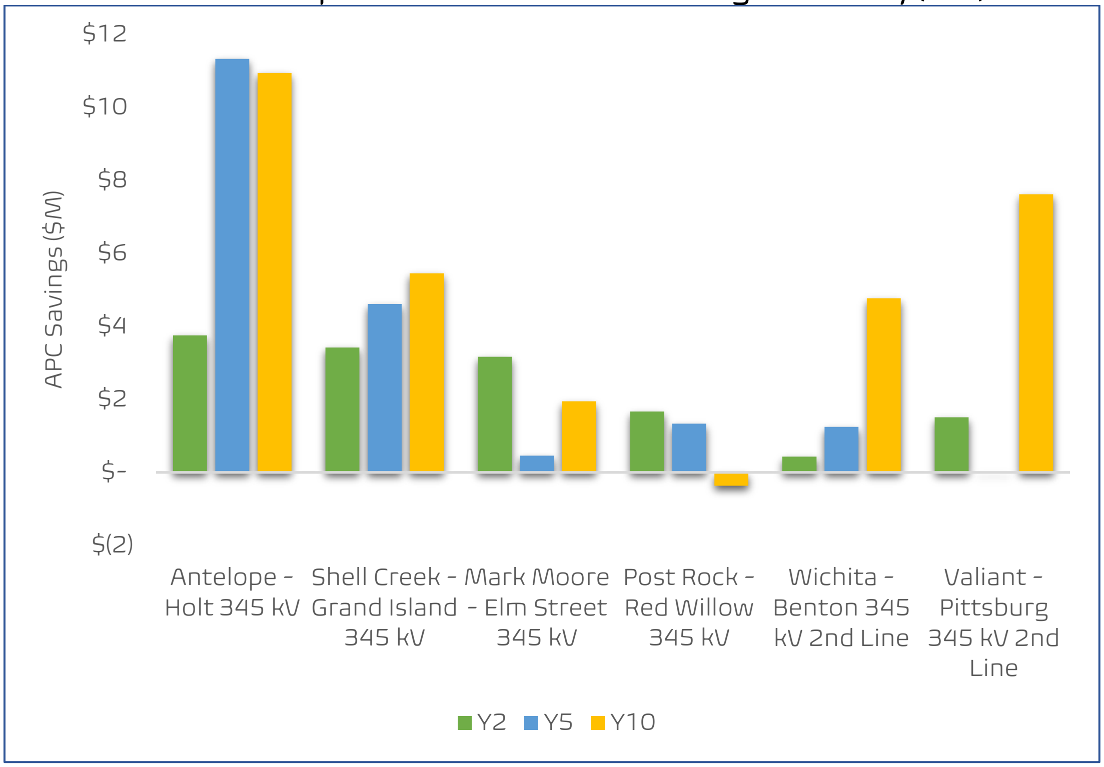


The APC savings for the three run years modeled in SPP, Year 2 (2023), Year 5 (2026), Year 10 (2031), are shown in the exhibit below. The APC values from the PROMOD model run years were interpolated and extrapolated to determine the present value of

[55] MISO's model run years: Y5 (2025), Y10 (2030), Y15 (2035) | SPP's model run years: Y2 (2023), Y5 (2026), Y10 (2031).

the benefits for years 1-15. ICF applied an inflation rate of 2%[56] to capture the benefits for years 16-40. The 40-year value of costs are based on the revenue requirement over the first 40 years of the project. The study uses approaches that are consistent with MISO's and SPP's planning processes.

Exhibit 19: Adjusted Production Cost Savings Summary (SPP)



Several factors affected the level of observed APC savings. These include:

- **Upgrades in locations with frequent and persistent congestion provided benefits even with relatively lower percentage of associated generation interconnection projects.** Regardless of the amount of associated generation represented in the planning model, a network upgrade in an area with frequent and persistent congestion could provide significant benefits to the system through congestion relief.

- **Increase in congestion on transmission lines in the vicinity of the upgrade after implementation of the upgrade.** Implementing the network upgrade could result in congestion moving to other facilities in the vicinity of the network upgrade. For example, congestion could move to a line downstream of the network upgrade and reduce the impact of the project. Because the scope was narrowly focused on single network upgrades, only one upgrade was selected and implemented in each case. Other network upgrades deemed required in the MISO and SPP

[56] Based on SPP's approach in calculating 40-year NPV benefits.

generation interconnection studies to enable the full capacity of each cluster of generation interconnection projects were not implemented. Including these upgrades could result in additional benefits.

5.1. Benefit-to-Cost Ratios

The exhibits below provide details around the benefit-to-cost (B/C) ratios for each of the ten network upgrades with positive APC savings. Exhibit 29 shows the results for the projects in MISO and Exhibit 30 shows the results for SPP. Each exhibit shows the present value of the benefits and costs, as well as the B/C ratio. For example, the present value of benefits of the Big Stone South – Alexandria network upgrade is approximately $335.8M, compared with a present value of cost of approximately $221.4M. The resulting B/C ratio is 1.52.

The B/C ratio for the ten projects shown ranged from a low of 0.04 for the Mark Moore – Elm Creek 345 kV network upgrade in SPP to as high as 1.85 for the Wichita – Benton 345 kV network upgrade in SPP. Seven network upgrades have B/C ratios greater than or equal to 0.30. The results show that many projects provide significant regional economic benefits, and some even more than the costs. For example, the Big Stone – South Alexandria 345 kV in MISO and Wichita – Benton 345 kV in SPP have the potential to provide benefits that far exceed the cost to the system.

Exhibit 22: 20-Year NPV ($M) and B/C Ratio of Network Upgrades (MISO)

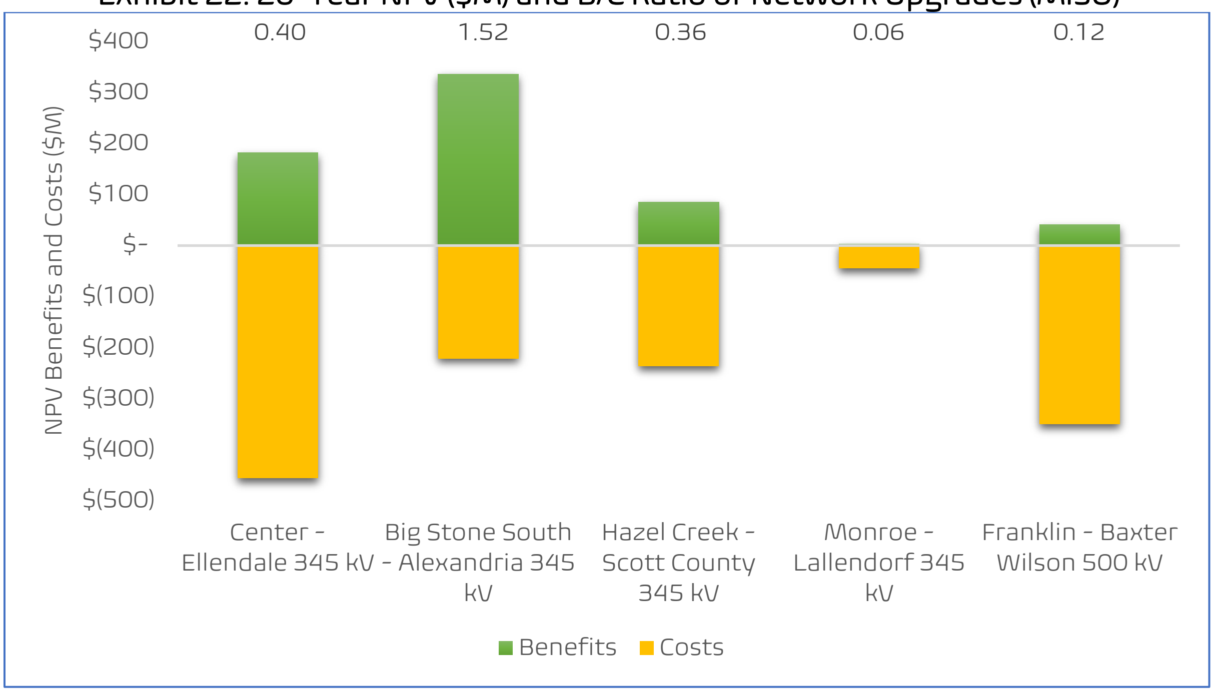
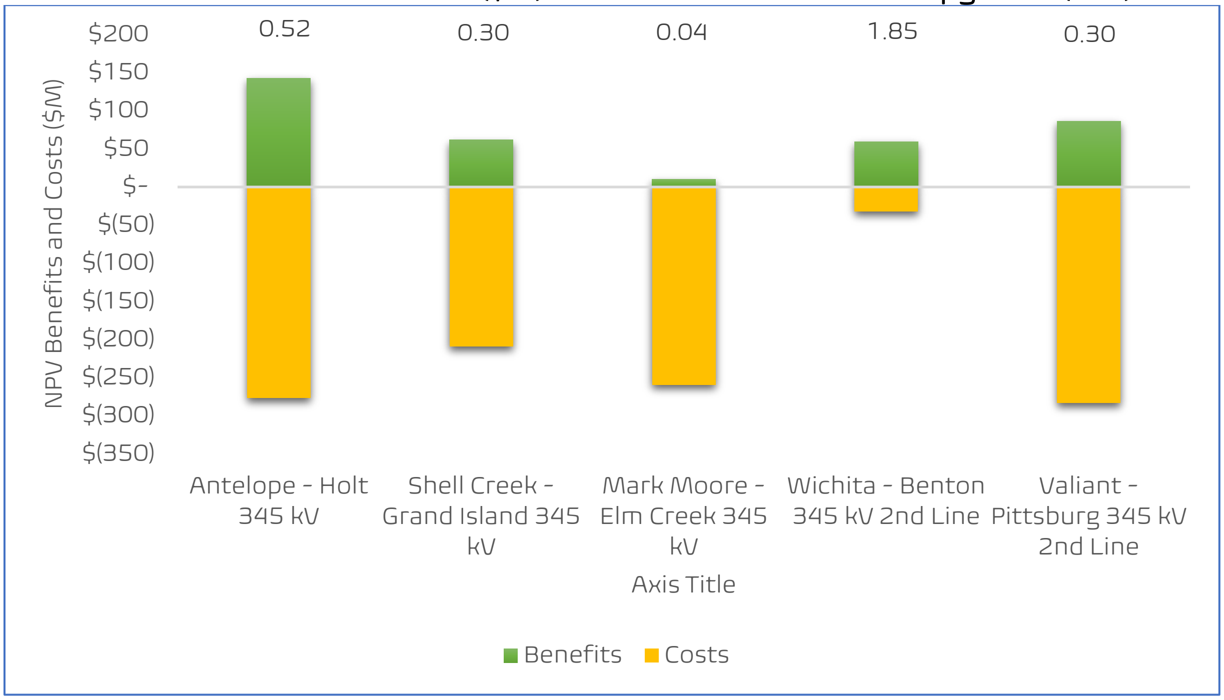
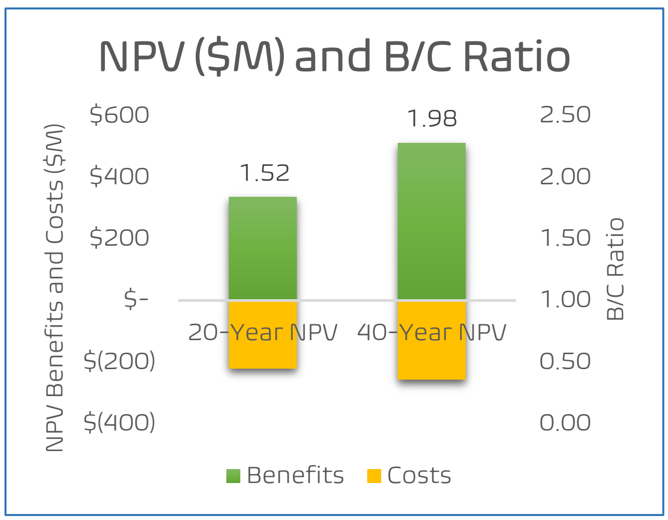


Exhibit 23: 2040-Year NPV ($M) and B/C Ratio of Network Upgrades (SPP)



The 20-year NPV calculation is based on MISO's current Market Congestion Planning Study (MCPS) process. However, understanding that transmission lines are usually far greater than 20-year assets, ICF calculated a 40-year NPV of the benefits and the costs by extrapolating the results from the models. Applying this method to Big Stone South – Alexandria 345 kV network upgrade, for example, yielded a B/C ratio of 1.98 (as compared with the B/C ratio of 1.52 across a 20-year period). This demonstrates that over its service life, the network upgrade could potentially provide even more benefits to consumers than what the 20-year B/C ratio indicates.



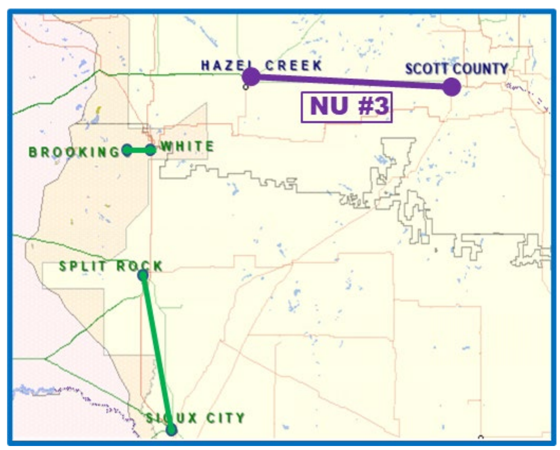
The drivers of benefits and B/C ration for each of the network upgrades is described in more detail below.

__MISO Network Upgrades__

- **Center – Ellendale 345 kV (NU #1),** located in North Dakota, helps deliver power from the wind-rich region to load centers in MISO West. Up to 71% of the GI projects associated with NU #1 were represented in the planning model, resulting in significant benefits from the network upgrade. Over the 20-year study period NU #1 provided $181.9M in APC savings, compared to a cost of $456.2M, and resulting in a B/C ratio of 0.40. The network upgrade eases congestion on the 230 kV line from West Oakes to Ellendale. However, inclusion of this upgrade increases congestion on the downstream Big Stone South to Browns Valley and White to Brookings County transmission lines.

- **Big Stone South – Alexandria 345 kV (NU #2)** provides the highest benefits of the projects in MISO. Up to approximately 97% of the GI projects associated with NU #2 were represented in the planning model. The result was $335.8M in APC savings relative to a cost of $221.4M, and a B/C ratio of 1.52. NU #2 also relieves congestion on 230 kV line from Big Stone South to Browns Valley and significantly reduces wind curtailment. Much like NU#1, increased flows enabled by NU#2 also increases congestion on West Oakes to Ellendale, likely limiting the overall benefits. Inclusion of associated network upgrades such as the West Oakes – Ellendale 345 kV line upstream of Big Stone South – Alexandria could increase the value proposition of the network upgrade. The constraints affected by NU #1 and NU #2 suggest some synergies between the two network upgrades and a portfolio comprising of the two projects may potentially result in significantly higher benefits. Additional analysis will be required to determine the potential for the projects to be developed as a portfolio.

- **Hazel Creek – Scott County 345 kV (NU #3)** is located between wind-rich areas in MISO West and load centers in MISO Central. Unlike NU #1 and NU #2, NU #3 had only 24% of the associated GI projects represented in the planning model. Despite that, NU #3 provided significant benefits to the system – approximately $85M in APC savings and a B/C ratio of 0.36. The reason for the relatively high APC savings is the fact that NU #3 is located in an area with frequent and persistent congestion. It helps reduce congestion on lines southwest of Hazel Creek, such as White – Brookings County 115 kV and Aurora – Flandreau 115 kV. The network upgrade is also a critical path that transfers power into the city of Minneapolis.



- **Franklin – Morgan Valley & Beverly 345 kV (NU #4)** was the only project with a net cost in MISO. This was despite the high percentage (92%) of associated GI projects that were represented in the planning model. The primary driver for the negative savings attributed to this upgrade was increased congestion on the Tiffin – Hills 345 kV line. It is likely that additional network upgrades associated with GI projects in the DPP studies, which also highlighted the need for NU#4, may alleviate these chokepoints and potentially yield higher benefits. For example, MISO identified the need for new Webster – Franklin 345 kV line and Beverly – Sub92 345 kV lines in the same DPP study cycles as Franklin-Morgan Valley & Beverly. Additional analysis will be required to determine the potential for the projects to be developed as a portfolio.

- **Monroe – Lallendorf 345 kV (NU #5)** had the lowest percentage (5%) of associated GI capacity in the planning model and therefore had a very low APC savings of approximately $2.9M.

- **Franklin – Baxter Wilson 500 kV (NU #6)** network upgrade, located in Mississippi (MISO South) resulted in relatively low benefits compared to some of the MISO West network upgrades mentioned earlier. However, comparing the results from the model run years indicate that the benefits are somewhat suppressed due to the lack of higher levels of associated GI projects in the models. The APC of the network upgrade for year 5 resulted in incurred costs of over $30M. However, increase in associated GI builds between year 5 and year 10 resulted in APC savings of over a $1M (a change of nearly $34M). By year 10, only 47% of the GI capacity associated with this network upgrade was represented in the planning models. Inclusion of higher renewable builds could potentially yield significant benefits.

<u>SPP Network Upgrades</u>

- Located in Nebraska, the **Antelope – Holt 345 kV (NU #7)** network upgrade helps address congestion on transmission elements that serve the Lincoln and Omaha load centers and further east and southeast. Over the 40-year study period NU #7 provided $142.8M in APC savings at a B/C ratio of 0.52. In addition to high percentage of GI capacity match, this upgrade also eases pre-existing constraints on the Gentleman interface which leads to reduction in curtailment of wind energy that can be transferred from Nebraska and the Dakotas into the load centers in the east and south.

- Despite $61.7M in savings, the B/C ratio of **Shell Creek – Grand Island (NU #8)** was low due to higher upgrade cost. Much like NU#4, savings attributed to NU#8 were restricted due to increase in congestion on the Sweetwater – Grand Island 345 kV line. SPP identified the need for a 2nd Hoskins – Shell Creek 345 kV line that was not factored into the analysis. This is another example where a portfolio assessment may yield higher savings in addition to primary goal of reliably interconnecting large amounts of renewables. However, additional analysis will be required to determine the potential for the projects to be developed as a portfolio.

- **Mark Moore – Elm Creek 345 kV (NU #9)** network upgrade had the least B/C ratio of all the network upgrades that were evaluated. The inclusion of this network upgrade resulted in increased congestion on downstream elements such as the Columbus 230/115 kV transformer that limited the value proposition of this upgrade. The mitigation for the constraint however is the Shell Creek – Grand Island 345 kV line that was evaluated on a standalone basis. Similar to the potential synergies between Big Stone South – Alexandria 345 kV and Center – Ellendale 345 kV network upgrades in MISO, this region in Nebraska could benefit from a holistic solution that considers NUs #7, 8, and 9.

- Located in the southern portion of Nebraska, **Post Rock – Red Willow (NU #10)** was the only project with a net cost in SPP. This was despite the high percentage of associated GI projects that were represented in the planning model. The upgrade led to significant increase in congestion on the upstream Gentleman – Red Willow 345 kV line which yielded negative savings for this upgrade. In the same DISIS study cluster, SPP identified keystone – Red Willow 345 kV as a mitigation for several constraints including Gentleman – Red Willow 345 kV line.

- The **Wichita – Benton 345 kV (NU# 11)** network upgrade relieves congestion on lines such as the existing Wichita – Benton 345 kV transmission line and Wichita 345/138 kV transformer. In addition to that, the upgrade has significant GI capacity associated with it which leads to B/C ratio of 1.85, the highest for SPP and all twelve projects across both markets. The high B/C is in part driven by the low cost of the upgrade (of $59.2M). The upgrade pushes more power into load centers such as Wichita and Kansas City and increasing congestion on Benton – Rose Hill 345 kV and Butler – Altoona 138 kV transmission lines. However, these factors are not sufficient to restrict the immense value provided by this network upgrade.

- Located in the southeastern portion of Oklahoma, near the Oklahoma/Texas border, the **Pittsburg – Valliant 345 kV (NU# 12)** network upgrade helps facilitate the transfer of power from the North and West towards Arkansas and Louisiana. This network upgrade eliminates congestion on the existing Pittsburg – Valliant 345 kV line circuit 1 and reduces congestion on Hugo – Valliant 345 kV line. However, the inclusion of the upgrade creates new congestion on the Valliant – Lydia 345 kV line that offsets some of the savings discussed above and leads to lower B/C ratio of 0.3. SPP identified Valliant – Lydia 345 kV 2nd circuit as a network upgrade in the same DISIS study cluster. Incorporating this upgrade would potentially increase the benefits ($86.2M) that the line currently provides.

5.2. Conservative Aspects of Key Study Assumptions

ICF's reliance on Future I assumptions for assessment of benefits of transmission upgrades should be considered a conservative assumption. All else equal, higher renewable capacity associates with each network upgrade will yield higher system benefits. As observed for NU#4, the APC savings attributed to the network upgrade increased by nearly $34M as the percentage of GI capacity associated with the network increased from 21% in year 5 to 47% in year 10. Inclusion of higher renewable builds could potentially yield significant benefits.

This study examined a selection of proposed network upgrades in the two regions to determine their potential to provide benefits associated with APC savings. It assumed network upgrades would be built primarily to interconnect the associated generation resources. Aspects of transmission planning that could enhance market efficiency benefits were not incorporated explicitly. In particular, the study was designed to test the one-off addition of single network upgrades. The only difference between the Reference Case and each of the change cases was the addition of a single transmission network upgrade. As a result, the economic benefits evaluated and described in this report are conservative and may understate the full benefits of the projects to consumers.

As discussed above, ICF observed increased congestion on existing corridors after the network upgrade was incorporated as the main driver lower savings. Some of the observed chokepoints were identified in the DPP/DISIS studies along with the network upgrade of interest. While additional sensitivity analysis needs to be performed, it is likely that if assessed as a portfolio, these upgrades may yield significantly higher APC savings in addition to reliably integrating the renewables.

In addition, the associated generation resources were not derated in the Reference Case without the network upgrade. In real world operations the output of generators may be limited by the operator in the absence of required network upgrades. This approach significantly understates the actual production cost savings associated with each network upgrade. A sensitivity was conducted to demonstrate the effect of this assumption on the APC savings associated with Franklin – Baxter Wilson 345 kV line. As discussed above, this line provides relatively low net benefits in the reference scenario. However, in the de-rate scenario, in which 92% of renewables assigned to the network upgrades are excluded from the Base Case and only assumed in the Change Case along with the network upgrade that is being evaluated, APC savings increased by an average of nearly $87M and yielded a B/C ratio to 2.03 (as compared with 0.12 in the reference case).

Finally, as noted some network upgrades yielded substantial savings in spite of GI capacity match rate. This was attributed to the ability of the network upgrade to mitigate some of the existing transmission bottlenecks. ICF did not select projects based on their ability to relieve existing constraints. As shown in Section 4, the criteria for screening and shortlisting the upgrades was to ensure that all regions within both markets are represented, the voltage class, level of GI capacity that was identified as potentially limited in its ability to deliver its output to the load and persistence of the issue. The benefits could have been higher if the selection process included consideration for addressing persistent congestion.

6. CONCLUSION

The cost of transmission network upgrades in MISO and SPP have become a significant hurdle for the integration of low-cost new renewable generation. In addition to the direct interconnection costs, generators are being required to fund increasingly more expensive network upgrades because the network is over-subscribed. Both markets allocate most, if not all, of the network upgrade costs to the generation developer.

Using very conservative assumptions, this study evaluated the economic benefits of a representative sample of network upgrade projects assigned through the MISO and SPP GI process over the last seven years. The results show that the network upgrades provide benefits to consumers that can exceed their allocated costs, resulting in an inconsistency between the payments and the benefits received. Of the 12 network upgrades reviewed, ten provided positive benefits to consumers, with eight having benefits that exceeded 10% of the costs.

Because of the conservative nature of the study, the economic benefits evaluated and described in this report may understate the full benefits of the projects to consumers. A sensitivity analysis on one of the network upgrades demonstrated that under real world operating conditions, the network upgrades could provide significantly higher benefits to the system.

The study shows that the network upgrades identified through the DPP and DISIS studies provide broader regional benefits resulting in real value to consumers. Understanding these potential areas of consumer benefits can help policy makers and other stakeholders to determine how to leverage such projects to the advantage of customers, while ensuring that costs are allocated equitably.