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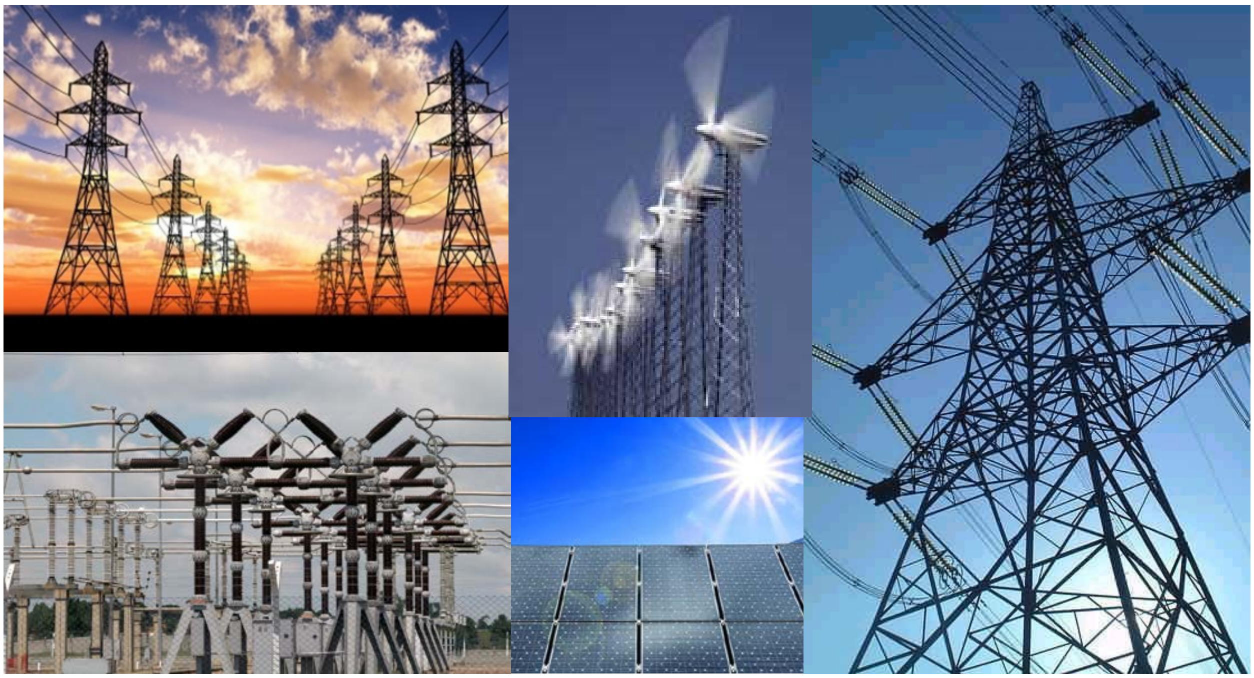
MISO Grid 2033: Preparing for the Transmission Grid of the Future



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Executive Summary

The bulk power system arose over the past century to harness the economies of scale and efficiencies of moving large volumes of electricity over distances that spanned further than a municipality or other small geographic area. However, the geographic scope of these electricity flows was often limited to a utility's service territory or to neighboring utilities in times of emergencies or for a very limited number of opportunity sales. Transmission systems were designed primarily for reliability, not as an interstate highway system to facilitate large scale electricity trades.

Yet, starting in 1996, a series of regulations promulgated by the Federal Energy Regulatory Commission ("FERC") changed almost a century's worth of transmission planning priorities and investment. In the near term, these rules facilitated an open, transparent, and non-discriminatory system for electricity commerce. This commerce was envisioned to be expansive, to go beyond swaps between neighboring utilities to include those that in theory, could span an entire interconnection. More recently, transmission policy priorities have expanded to a set of considerations that go far beyond reliability and commerce and include environmental, technological, social, resiliency and security considerations.

In November 2017, the Searle Center on Law, Regulation and Economic Growth at the Northwestern University Pritzker School of Law, the Louisiana State University Center for Energy Studies, and the Midwestern Governors Association hosted a two-day conference, in St. Louis, Missouri, entitled "MISO Grid 2033: Preparing the Future" (hereafter "the MISO 2033 event"). Consistent with MISO's request, the LSU Center for Energy Studies has prepared this white paper to address each of the important drivers of change identified in the MISO 2033 event and the implications they will have for longer run MISO transmission infrastructure planning. The MISO 2033 event highlighted the irony that, while the development of physical capacity is becoming increasingly more challenging and important, the traditional means of valuating this capacity is coming under assault leading to what can be thought of as a "post-capacity" world.

The antecedents of this post-capacity world are varied. Capacity, both physically and as an economic commodity, has become increasingly devalued by: the deteriorating value in traditional baseload resources (i.e., coal and nuclear); the rise of just-in-time natural gas fired generation; the plethora of zero-marginal cost renewable resources at the bulk power system level (primarily wind); the emergence of distributed generation (mostly solar) and other demand-side resources; and various state and federal policy actions over the past decade. At the same time, electricity customers are becoming increasingly restless as they are being called upon to financially support, through higher rates, the investments (including transmission investments) needed to support these increasingly complicated industry changes. This is forcing some customers to look for ways to potentially bypass the entire system through what they see as more empowering alternatives such as distributed generation and efficiency creating a potential feed-back effect that, if not managed correctly, could itself have even further negative implications for the addition of new transmission capacity and infrastructure.

A consistent public policy theme in U.S. politics is developing and rebuilding infrastructure. The discussion at the MISO 2033 event echoed many of the same themes of urgency and necessity for transmission infrastructure development that are echoed in discussions about upgrading roads, highways, schools, hospitals, transportation, communications and water systems. However, the voices of inertia and the status quo are often heralded as the main barriers to boldness and vision and often the only factor that unfortunately seems to break the logjam between these two opposing forces are large-scale infrastructure failures and catastrophes. The bulk power transmission system is no stranger to this phenomenon as witnessed by numerous large-scale power outages that have occurred since the infamous northeastern black out of 1965. Clearly, this is no way to manage, much less plan for a highly complicated set of critical energy infrastructure.

Technology, in particular, seems to be placing some of the more significant and near-term challenges on transmission system investments. This should come as no surprise since technology, by its very nature, has a disruptive societal impact. What is unique about today's technological innovations, however, is that the scale-orientation of these new technologies are primarily distributed and decentralized in nature; a characteristic that strikes at the very heart of over a century's worth of power industry structural organization. Plus, it should come as no surprise that the financial consequences of getting these infrastructure investments all wrong, are even more prohibitive than in decades past.

However, the MISO 2033 event found that large-scale bulk power system infrastructure investments, and smaller-scale distributed technologies do not have to be mutually exclusive. The value of the bulk power transmission system, while changing, still rests in its integrated nature. The integrated nature of the transmission system will become more important as new technologies, particularly intermittent renewables, becomes more commonplace. The integrated nature of the transmission grid diversifies the supply of resources across traditional and emerging technologies and provides the system reliability important during transition periods like the one currently being witnessed in the industry.

The other pressure point for an organization like MISO, in developing the transmission infrastructure requirements of tomorrow, is understanding what tomorrow's customers want and need. What appears to be increasingly apparent is that customers want more choices: customers want to be able to choose across a variety of environmental attributes; they want to be able choose across a variety of price and service offerings; they want to be able to choose across a variety of different service providers and, increasingly, they want this flexibility provided within a system that is clean, reliable and resilient and one that minimizes costs and maximizes end-user value.

Once again, the MISO 2033 event found that these perceived conflicts are not mutually exclusive and, in fact, can be accommodated within a broad vision for transmission infrastructure development. MISO's transmission planning efforts will likely facilitate these consumer empowerment issues by:

- Integrating new technologies into a larger footprint that facilitates a wide range of customer choices.
- Developing new physical infrastructure investments to strengthen existing reliability requirements and enhance grid resiliency
- Developing market design and market protocols that leverage physical transmission investments to develop framework that provides price signals and creates efficiency.
- Engaging stakeholders in the planning process to ensure adequate feedback on customer needs to ensure minimized costs and maximized value.
- Educating customers about the value proposition of these transmission infrastructure investments, their cost-benefit ratios on both a pre and post development basis.

Lastly, the discussion at the MISO 2033 event highlighted that transparency is one of the most powerful tools in executing a bold transmission infrastructure planning vision.

The event itself was an example of how important and useful a transparent stakeholder meeting can be in understanding differing opinions and positions on transmission planning. This transparency will continue to be important in order to assure confidence in the transmission planning process, to reduce informational asymmetries between market participants, and to ensure resources dedicated to transmission investment development are made in the most efficient manner possible.

1. Introduction

In November 2017, the Searle Center on Law, Regulation and Economic Growth at the Northwestern University Pritzker School of Law, the Louisiana State University Center for Energy Studies, and the Midwestern Governors Association hosted a two-day conference, in St. Louis, Missouri, entitled "MISO Grid 2033: Preparing the Future" (hereafter "the MISO 2033 event"). One of the more poignant moments during the event arose when a rather simple, yet painfully obvious observation was offered that the electric power industry currently operates, and will likely continue to operate, in what could be referred to as a "post-capacity world:" one that recognizes the need for capacity but has an increasing predisposition to discount its full value. The irony of the statement, and its reality, is that while the value of capacity has fallen considerably over the past decade, the cost of continuing to maintain and expand capacity (and supporting infrastructure), across the entire power industry value chain, has not. The capital intensity of the industry continues and, as the MISO 2033 event revealed, the outlook for a continued high level of capital investment into 2033 is highly probable.

The antecedents of this post-capacity world are varied. Capacity, physically and as an economic commodity, has become increasingly devalued by: the deteriorating value in traditional baseload resources (i.e., coal and nuclear); the rise of just-in-time natural gas fired generation; the plethora of zero-marginal cost renewable resources at the bulk power system level (primarily wind); the emergence of distributed generation (mostly solar) and other demand-side resources; and various state and federal policy actions over the past decade. At the same time, electricity customers are becoming increasingly restless as they are being called upon to financially support, through higher rates, the investments (including transmission investments) needed to support these increasingly complicated industry changes. This is forcing some customers to look for ways to potentially bypass the entire system through what they see as more empowering alternatives such as distributed generation and efficiency, creating a potential feed-back loop that, if not managed correctly, could itself have even further negative implications for the development of new capacity.

The changing nature of the power industry, its stakeholder impact, and how to plan for a transmission system of the future are all issues that played directly into the theme of the two-day MISO 2033 event. A wide range of stakeholders, representing the expansive MISO geographic footprint, participated in the MISO 2033 event including regulators, academics, industrial representatives, economic development professionals, policy makers, utilities, non-governmental organizations, among others. The topics discussed at the event were spread across a series of broad areas including advancing transmission development, ratepayer impacts, jobs and economic development, and facilitating future infrastructure investment.

A number of key themes, or “drivers of change” were identified during the course of the event including:

(1) A recognition that MISO is a unique regional transmission organization (“RTO”) and has to plan for that uniqueness.

(2) Natural gas has been, and will continue to be a game changer.

(3) Renewable resources are increasing rapidly and will be an important and permanent part of the grid of tomorrow

(4) Solid fuel resources, while significantly challenged, are not going away.

(5) Distributed resources are becoming more pervasive.

(6) Customer usage trends and the need for customer empowerment is becoming increasingly more important.

Each of these drivers of change are considerable and formidable and have significant implications for a member-driven organization like MISO that is attempting to develop a portfolio of resource solutions to these near-term and longer-term challenges. Member-driven organizations, like MISO, often must rely upon consensus in developing solutions to these longer run challenges, even on exceptionally technical issues. To develop a consensus on these issues, potential stakeholder impacts and concerns need to be addressed candidly and completely in order to support the longer run MISO planning process.

The LSU Center for Energy Studies has prepared this white paper to address each of these important drivers of change and the implications they will have for longer run MISO transmission infrastructure planning. Each section will provide further analysis on each driver of change, how those drivers specifically relate to MISO and its member states, how stakeholders have been, or will likely be impacted by these drivers, and offer some suggestions, as revealed in the MISO 2033 event, on the ways in which the negative impacts associated with these challenges, particularly as they relate to MISO long run planning, can be mitigated. The LSU Center for Energy Studies thanks MISO for the opportunity and financial support to prepare this report.

2. MISO Uniqueness

a. MISO Overview

MISO is a not-for-profit member organization: a regional transmission organization ("RTO") that provides open-access transmission service and monitors the high-voltage transmission system in 15 Midwestern U.S. states, portions of Arkansas, Mississippi, and Louisiana, as well as Manitoba, Canada. MISO undertakes transmission planning and manages the buying and selling of wholesale electricity in one of the world's largest energy markets.[1] MISO's membership includes 48 transmission owners with $37.9 billion in transmission assets as well as 127 non-transmission owners.[2] Currently, MISO oversees the generation capacity of over 174,000 megawatts ("MW") and 65,800 miles of transmission lines.[3]

In addition to managing a wide range of bulk power system assets, MISO also manages one of the world's largest energy and operating reserves markets, which are operated and settled separately, using security-constrained economic generation dispatch.[4] The energy and operating reserves market includes a day-ahead market, a real-time market, and a financial transmission rights ("FTR") market.[5] MISO undertakes an extensive longer term transmission planning process that identifies essential transmission projects that will improve the reliability and efficiency of energy delivery in the region over the next decade and beyond. These projects are identified in the MISO Transmission Expansion Plan ("MTEP"), published annually in collaboration with its

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[1] MISO Fact Sheet.
[2] MISO Fact Sheet.
[3] MISO Fact Sheet.
[4] MISO Fact Sheet.
[5] MISO Fact Sheet.

planning staff and stakeholders. MISO's transmission planning process considers a variety of considerations that include state and federal policies, fuel prices, load patterns and transmission configurations, to name a few.[6]

The guiding principles of the MISO long term planning process include: (1) identifying transmission projects that provide access to electricity and the lowest cost; (2) developing plans that meet NERC and transmission owner planning requirements and ensure reliability; (3) supporting state and federal energy policy requirements by planning for access to a changing resource mix; (4) ensuring cost allocation in a manner roughly commensurate with the projected benefits; (5) analyzing system scenarios to provide context and to inform choices; and (6) coordinating with neighboring transmission systems to eliminate barriers to reliable and efficient operations.[7]

These guiding principles, in turn, must be reconciled with a number of operational considerations that include: (1) aligning collective interests on regional transmission solutions based upon a robust business case for these projects; (2) clearly defining cost allocation methods that closely aligns who pays with who benefits over time; and (3) utilizing cost recovery mechanisms that reduce financial risk.[8]

MISO is unique and differs considerably from other RTOs, even though it performs many of the same daily and longer-term functions as its peers. MISO, for instance, has a large industrial and manufacturing sales mix, something that differs from other RTOs in the Eastern Interconnect. Most of the MISO member states are still retail regulated and

[6] MTEP17, MISO Transmission Expansion Plan, December 2017 p. 1.
[7] MTEP17, MISO Transmission Expansion Plan, December 2017, p. 6.
[8] MTEP17, MISO Transmission Expansion Plan, December 2017, p. 6.

have large vertically-integrated investor-owned utilities ("IOUs"). MISO includes a large rural area where economic development and economic growth issues are important. MISO is also a large renewable energy generator and is seeing increasing levels of distributed generation across its footprint. Understanding this regional uniqueness is important in understanding MISO's distinctive longer-run planning challenges.

b. MISO's Uniqueness

MISO's uniqueness stems from its history and geography. MISO's membership, as shown in Figure 1, spans the entire central portion of North America. The central U.S. has been, and continues to be, home to a considerable amount of industrial and manufacturing capacity. MISO member states account for 38 percent of all U.S. industrial and manufacturing value added.[9] The IOUs that are MISO members, collectively, serve over 490 million megawatt hours ("MWh"). MISO utility members have industrial sales percentages that average around 39 percent of total sales, some 13 percent higher than the U.S. average.[10] Further, in 2016, MISO member states account for 38 percent of all U.S. industrial cogeneration capacity and 40 percent of all U.S. industrial cogeneration production.[11] States with large industrial sales mixes, like the MISO member states, usually have a heightened sensitivity to economic development issues, as well as a heightened sensitivity to large industrial choice opportunities, issues that will discussed in more detail later in the customer empowerment section of this report.

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[9] Bureau of Economic Analysis, GDP by State Regional Data, 2016.
[10] U.S. Energy Information Administration, Form 861, 2016.
[11] U.S. Energy Information Administration, Forms 860 and 923, 2016.

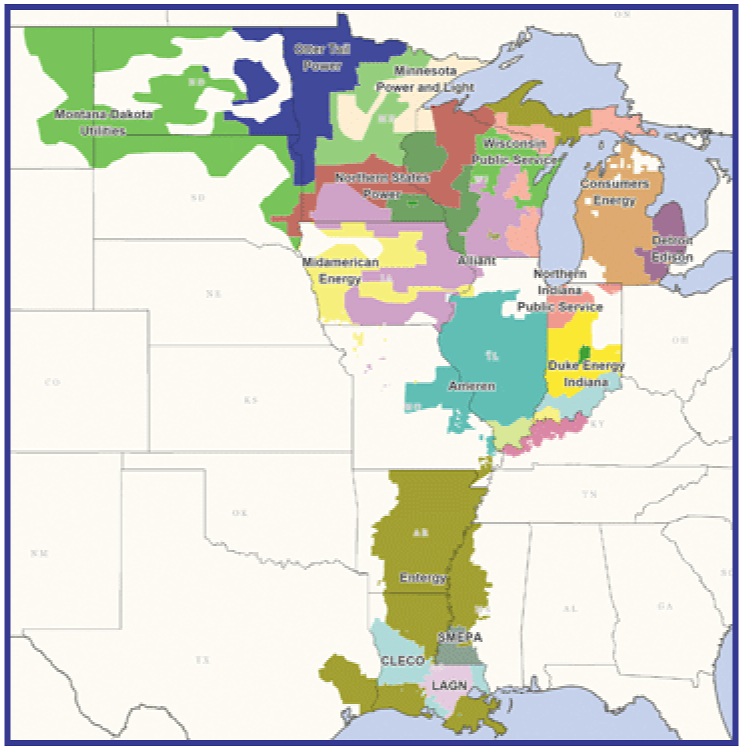

Figure 1: MISO Geographic Footprint
Source: FERC.

MISO states are also large primary energy producers. Consider, for instance, that MISO states produce 14 percent of all U.S. coal, primarily in the states of Illinois and Indiana and, as will be discussed later, utilize a very large share of coal in its power generation activities.[12] Thus, it should come as no surprise that market and environmental policy changes that are driving a retrenchment in U.S. solid fuel generation also have economic development implications that go far beyond just changing the fuel mix of certain generators. MISO states, for instance, employ 14.8 percent of all mining employees in the U.S. and 15.3 percent of all mining employees east of the Rockies.[13] MISO states pay 26 percent of all mining wages in the U.S. and 32 percent of all mining

[12] U.S. Energy Information Administration, Annual Coal Report 2016, Table 1.
[13] U.S. Energy Information Administration, Annual Coal Report 2016, Table 18.

wages east of the Rockies as well.[14] Further, MISO states contain 33 percent of all active U.S. nuclear power plants and 15 percent of all active U.S. nuclear power plant capacity.[15]

MISO states, collectively, are also large natural gas producers. MISO states, for instance, produce 65 percent of all U.S. natural gas and include several important unconventional natural gas basins including parts of the Haynesville shale (in Louisiana), the Fayetteville shale (in Arkansas), the New Albany shale (in Indiana and Kentucky), the Antrim shale (in Michigan), and the Bakken shale (in North Dakota and Montana). Again, while changes in fuel mix are important for MISO's longer-term resource planning, it also needs to be mindful of the economic development implications and sensitivities of its planning decisions.

MISO is also an important source of U.S. solar and wind generation, a fact that will be discussed in greater detail later. However, on a big-picture basis, it is important to recognize that MISO states, collectively, account for nearly 16.5 gigawatts ("GW") of wind generation capacity, accounting for slightly more than 20 percent of all U.S. wind generation. Further, in 2017, over 88.6 percent of the Class 1 renewable energy certifications (RECs) retired in PJM for their respective states' RPS compliance purposes originated in MISO. MISO is also one of the fastest growing areas in the U.S. for solar with the MISO states seeing an average rate of growth of 216 percent per year, on average, over the past five years.

[14] U.S. Census Bureau, 2016.

[15] U.S. Energy Information Administration, Monthly Nuclear Utility Generation (MWh) by State and Reactor, 2017 October, EIA-923 and EIA-860 Reports.

MISO is also unique in its regulatory composition. MISO, unlike other RTOs in New England and the Mid-Atlantic, are dominated by vertically integrated IOUs that are in non-retail choice states (see Figure 2). The heavy concentration of traditional, vertically-integrated power markets makes the political economy of emerging empowerment issues, such as limited industrial choice, or increasing distributed generation, different than say, New England or the Mid-Atlantic. It also raises a host of issues for a part of the country where regulators tend to place a very high priority on promoting economic development.

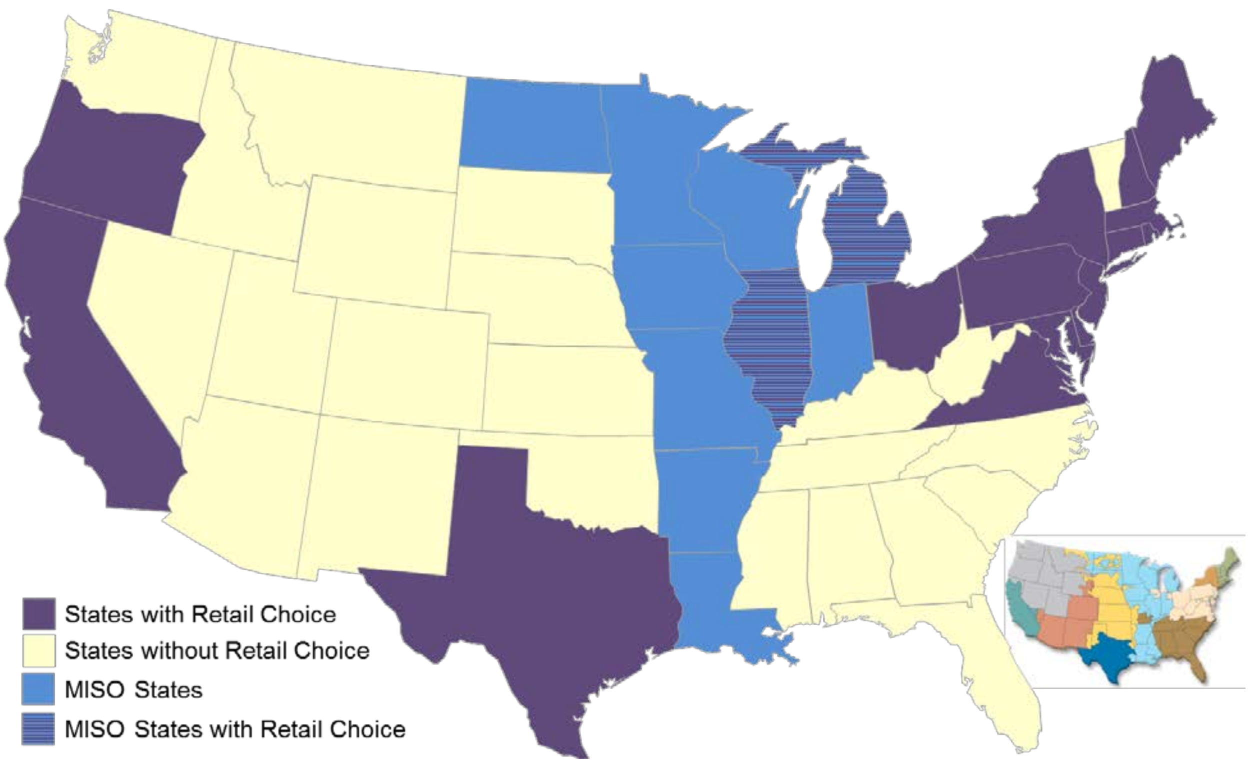

Figure 2: MISO Geographic Footprint and Retail Choice
Source: Author's construct using sources from MISO; U.S. Energy Information Administration; and FERC.

c. Diversity versus Flexibility

Infrastructure planning and development in the electric power industry can be an exceptionally rigid process: it takes talent and creativity to build flexibility into the process.

Power transmission infrastructure is physically large, usually spans broad geographical areas, requires a considerable amount of financial capital, and is long-lived. The process is often multi-year if not multi-decadal. The development of transmission infrastructure can be even more complicated since the permitting and varied approval processes, across a wide range of venues and regulators (economic, safety, environmental, coastal, etc.) is pervasive and requires extensive effort. This is particularly true for MISO which includes, as articulated earlier, a considerable amount of geographical, economical, and political diversity.

Many attendees at the MISO 2033 event, particularly planners and those engaged in the development of transmission planning policies, argued for "bold visionary approaches," rather than a staggered, reserved and piecemeal methods for the development of future transmission infrastructure in MISO. Bold visions, as recognized by other participants, require considerable commitment, in terms of both effort and capital. These bold and visionary commitments could prove to be misplaced if the future differs considerably from expectations. The risks, and cost recovery burdens of these planning and investment miscalculations, in turn, would fall heavily on the region's ratepayers.

Further, and as highlighted by the MISO 2033 event discussions, some stakeholder requests for greater "diversity" in the planning process will likely lead to an expanding set of resource considerations for the transmission planning process. Expanding resource considerations, however, could also lead to an increase in the uncertainty and riskiness of the overall planning process. For instance, discussions at the MISO 2033 event recognized that many of today's stakeholders, particularly those associated with non-governmental organizations ("NGOs") and environmental interests, advocate for an expanded number of infrastructure planning outcomes that go beyond simple economics (i.e., least cost outcomes) and include those that are more “environmentally neutral,” are more “reliable,” result in greater power “quality,” or lead to more “robust” or “resilient” systems. Contrary to expectations, it could very well be the case that these expanded number of transmission planning considerations will actually lead to an increase, and not a decrease in risk given the additional variability that each new consideration places on the planning process.

d. The Role of Communication and Education

Another major theme throughout the MISO 2033 event was the importance of active stakeholder communication and education, developed through a transparent and accountable process. Each of these concepts (communication, education, transparency, and accountability) has differing meanings and implications for longer-run transmission infrastructure investment and planning.

Communication is the vehicle by which stakeholder interests are conveyed to MISO and serves as the primary feedback mechanism by which the effectiveness of a proposed longer-term transmission infrastructure plan is anticipated to meet stakeholder needs and expectations.

Education, on the other hand, is the process by which MISO makes all of its stakeholders aware of its transmission infrastructure planning goals, resources, and constraints. Education is also the means by which MISO explains the types of challenges it is currently facing, the nature and characteristics of those challenges, and how its proposed transmission plans are designed to address these challenges and mitigate their potentially negative impacts.

Transparency was an equally important topic discussed at the MISO 2033 event. Many stakeholder participants expressed the view that transparency was vital to the longer-run MISO transmission planning process. Transparency assures that all stakeholders are aware of all information, assumptions and data used in the planning process, including all of the non-selected transmission plan alternatives. Transparency is critical in order to ensure the integrity of the transmission planning process, particularly with many non-member stakeholders, who may often feel like they are on the outside, looking in, such as customer groups and state regulators.

Accountability is an equally important concept that was discussed at the MISO 2033 event. Transmission infrastructure planning and development requires a considerable degree of financial capital, and that capital does not come for free. While MISO directly answers to its members, those same members usually, at some point, answer to a customer, or a set of state regulators that represent and protect customer interests. All of these interests are served by comparing past plans to current actions and outcomes to assure results and, to explain deviations from results where possible and how those deviations, particularly if they result in negative outcomes, can be avoided in the future.

e. MISO's Recent Regional Investment Trends and Value Creation

Each year, MISO conducts a transmission planning process that focuses on maximizing value to members while minimizing the total energy, capacity and transmission costs of the MISO system. As part of this process, MISO identifies essential transmission projects that will improve the reliability and efficiency of energy delivery in the region over a ten-year period. This 18-month collaborative process between MISO planning staff and stakeholders culminates with the preparation of an annual report that is referred to as the MISO Transmission Expansion Plan ("MTEP")

Projects included in the MTEP are divided into five separate categories that include:

- ***Baseline Reliability Projects:*** include those required to meet reliability requirements set by NERC.
- ***Generator Interconnection Projects:*** include those required to reliably connect new generation to the transmission grid.
- ***Market Efficiency Projects:*** include those identified as meeting certain criteria and passing regional benefit-to-cost tests.
- ***Targeted Market Efficiency Projects:*** are a relatively new category in the MTEP that is developed with input from neighboring transmission operator PJM, and seeks to identify high value, low cost projects that reduce persistent, historic market-to-market congestion between MISO and PJM.
- ***Other Projects:*** include those that do not fit into any of the above categories.

The most current MTEP is referred to as "MTEP17" and is comprised of 354 new transmission projects representing $2.7 billion in new transmission infrastructure investments and are broken into their component parts shown in Figure 3. The largest project category ("other projects") is comprised of 248 individual transmission projects designed to satisfy a wide range of needs, including support for lower-voltage transmission systems or supporting local economic benefits. Baseline reliability projects represented the second largest category of 35.4 percent and is comprised of 77 separate projects designed to meet ongoing reliability standards set by the North American Electric Reliability Corp. ("NERC").

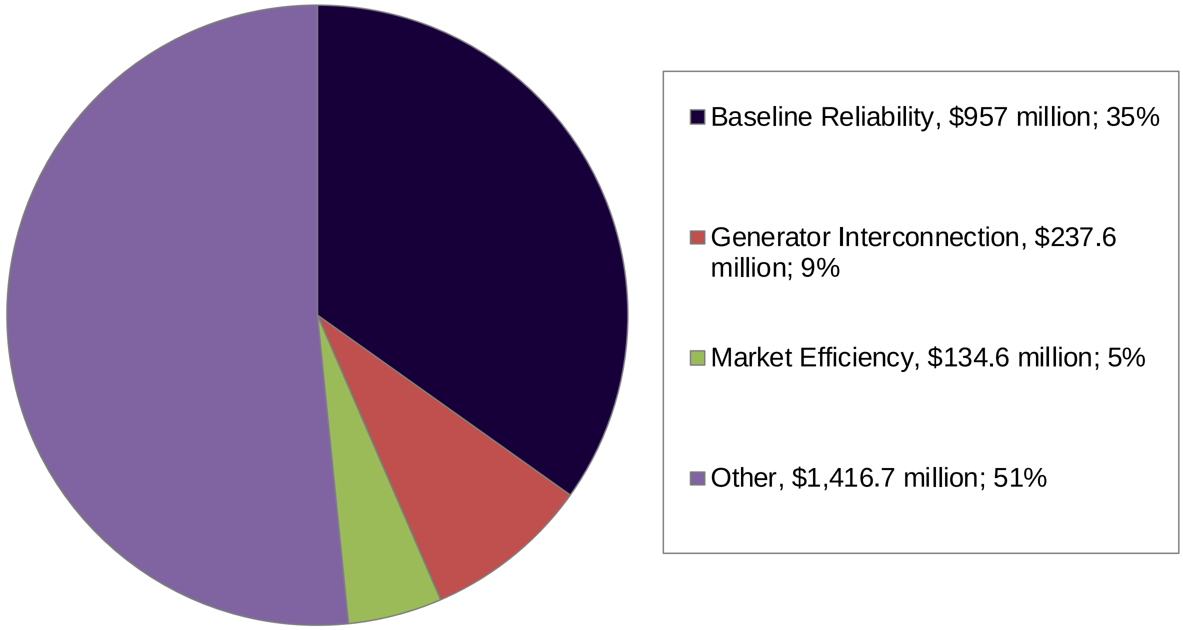

Figure 3: MTEP17 Transmission Projects Investment by Category.
Source: MISO, MTEP17.

Figure 4 shows that the largest 10 projects proposed in MTEP17 represent $756 million in total investment or 28 percent of total costs. A large share of the MTEP17 projects (eight of the ten) are in the MISO South region including the top four investments.

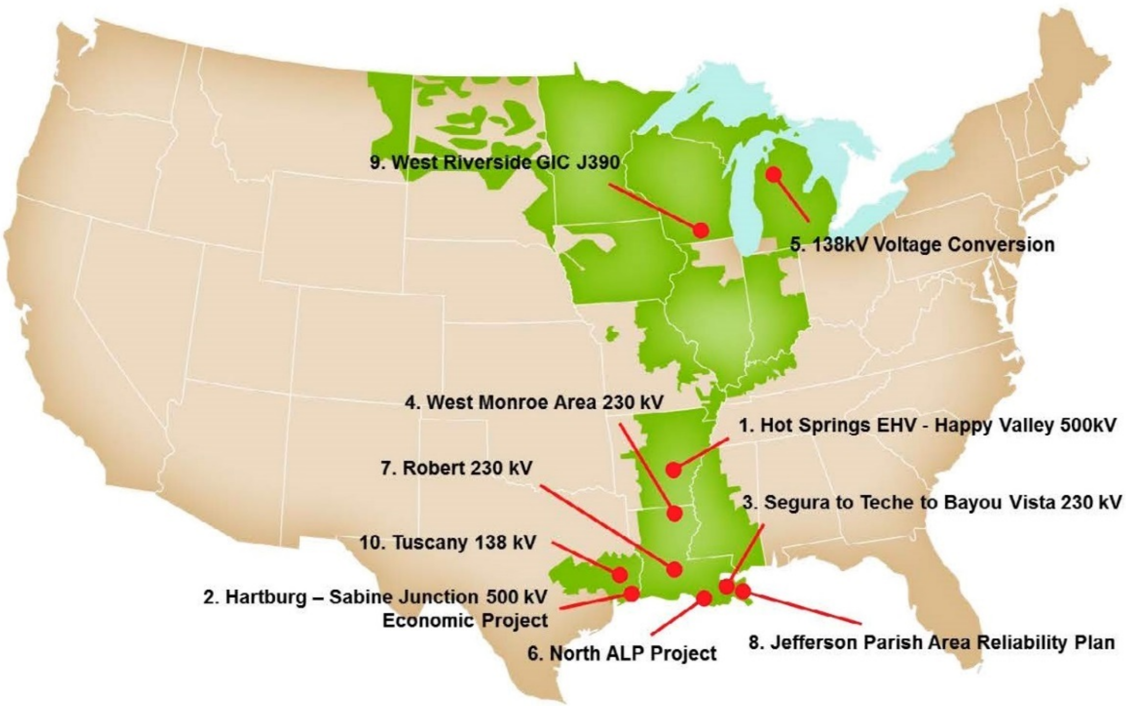

Figure 4: MTEP17 Top 10 New Transmission Projects.
Source: MISO, MTEP17.

Table 1 presents a breakdown in proposed MTEP17 transmission investment. Nearly \$1.8 billion of the \$2.7 billion in total transmission investment (46.5 percent) is associated with investments in the MISO South region and represents MISO's continued efforts to improve the region's transmission capabilities as represented by the \$772.5 million in baseline reliability projects investments.

Table 1: MTEP17 Transmission Investments

MISO Region		Baseline Reliability Project		Generator Interconnection Program		Market Efficiency		Other		Total
		-------------------		-------------------		(million $)		-------------------		
Central	$	65.4					$	320.8	$	386.2
East	$	53.2	$	12.4	$	4.9	$	341.4	$	411.9
South	$	772.5	$	31.4	$	129.7	$	343.6	$	1,277.2
West	$	65.8	$	193.8			$	410.9	$	670.6
Total	**$**	**957.0**	**$**	**237.6**	**$**	**134.6**	**$**	**1,416.7**	**$**	**2,745.9**

Source: MISO, MTEP17.

Table 2 presents MISO's historic transmission investment trends from 2000 (MTEP7) to current (2017; MTEP17) highlighting that the current annual transmission level of $2.7 billion is consistent with the last four-year trends, despite the recent addition of the MISO-South region.

Table 2: Historic Annual MTEP Transmission Investments

		Baseline Reliability Project		Generator Interconnection Project		Market Efficiency		Other		Total
		-------------------		-------------------		(million $)		-------------------		
MTEP6	$	681.6	$	28.8	$	-	$	-	**$**	**710.4**
MTEP7		92.2		16.6		-		-		**108.8**
MTEP8		1,238.3		12.9		-		-		**1,251.2**
MTEP9		170.8		64.6		5.6		-		**241.0**
MTEP10		43.3		2.1		-		510.0		**555.4**
MTEP11		385.3		103.9		-		5,008.4		**5,497.6**
MTEP12		386.1		106.7		14.5		-		**507.3**
MTEP13		-		4.0		-		-		**4.0**
MTEP14		269.5		38.8		-		2,210.2		**2,518.5**
MTEP15		1,227.2		73.6		67.4		1,380.5		**2,748.8**
MTEP16		691.2		142.8		108.0		1,747.5		**2,689.5**
MTEP17	$	957.0	$	237.6	$	134.6	$	1,416.7	**$**	**2,745.9**

Source: MISO, MTEP.

Table 3 presents MTEP17's recommended transmission investment in planned new or upgraded line miles by planned installation year and voltage showing that the majority of MTEP17's proposed investments are expected to be placed in service within the first four years of the analysis (2017 through 2020). Indeed, nearly 80 percent of recommended investment by mile is expected to be installed by 2020. Table 3 also shows that much of the recommended transmission investment in MTEP17 is expected to be lower voltage transmission lines (less than 161 kV).

Table 3: MTEP17 Annual Transmission Investment by Year and Voltage (Miles of New or Upgraded Lines)

	69 kV	115-161 kV	230 kV	345 kV	500 kV	765 kV	Total
	(miles)						
2017	284	446	20	269			1,019
2018	286	477	132	469	7	69	1,440
2019	359	544	26	355			1,284
2020	250	247	67	35	380		979
2021	109	29	128	55	35		356
2022	186	8	27	39			260
2023	96	71	1	109	22		299
2024	60						60
2025	11						11
2026	8						8
2027	211						211
Total	**1,860**	**1,822**	**401**	**1,331**	**444**	**69**	**5,927**

Source: MISO, MTEP17.

3. <u>Natural gas as a game changer</u>

Stakeholders participating in the MISO 2033 event were all cognizant of the paradigm-shifting nature of U.S. unconventional natural gas production, on a general basis, and specifically as it relates to fuel use trends in the MISO footprint. As Figure 5 shows, unconventional natural gas plays are ubiquitous throughout the U.S. arising not only in traditional producing areas, such as Louisiana and Texas, but in areas that are traditionally thought of as "consuming areas" of the country. In fact, several MISO member states have active unconventional natural gas production.

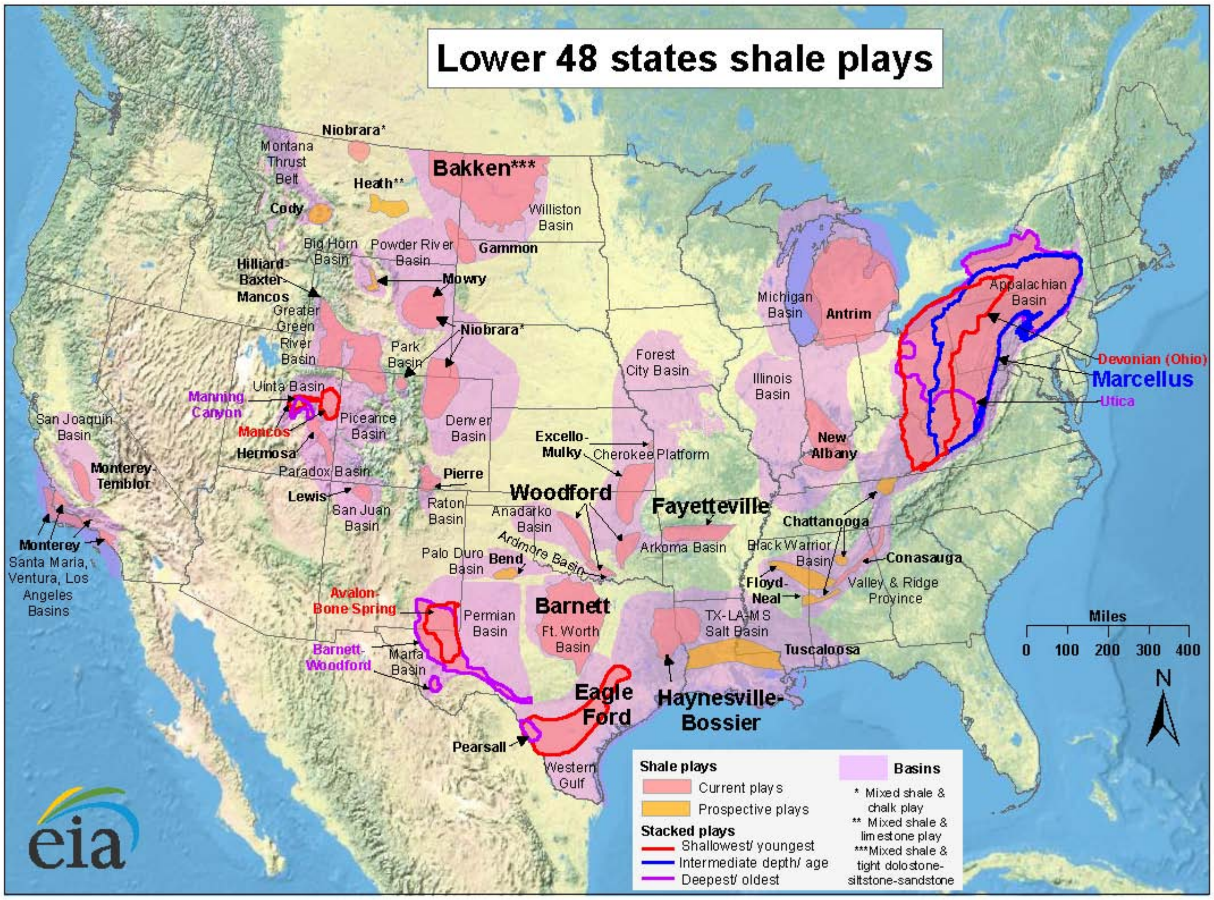

Figure 5: Unconventional Natural Gas Basins and Plays
Source: U.S. Energy Information Administration.

Unconventional natural gas development's impact on natural gas markets began in 2005 and could not have come at a more opportune time given the shifts underway in the industry during that time. The mid-2000s saw the composition of U.S. power generation, due to industry restructuring and environmental concerns, start to shift away from coal-fired generation and toward natural gas fired generation. This resulted in a heavy pull on natural gas supplies from traditional (conventional) basins that, throughout the 1990s, had seen drilling activity stagnate. Natural gas prices began to escalate at alarming rates by 2005, and the use of the resource for continued power generation became somewhat questionable. Figure 6, for instance, shows the Annual Energy Outlook ("AEO") long-term energy forecast developed by the U.S. Energy Information Administration ("EIA"). This forecast clearly shows continued growth in solid fuel generation that includes not only coal, but nuclear as well.

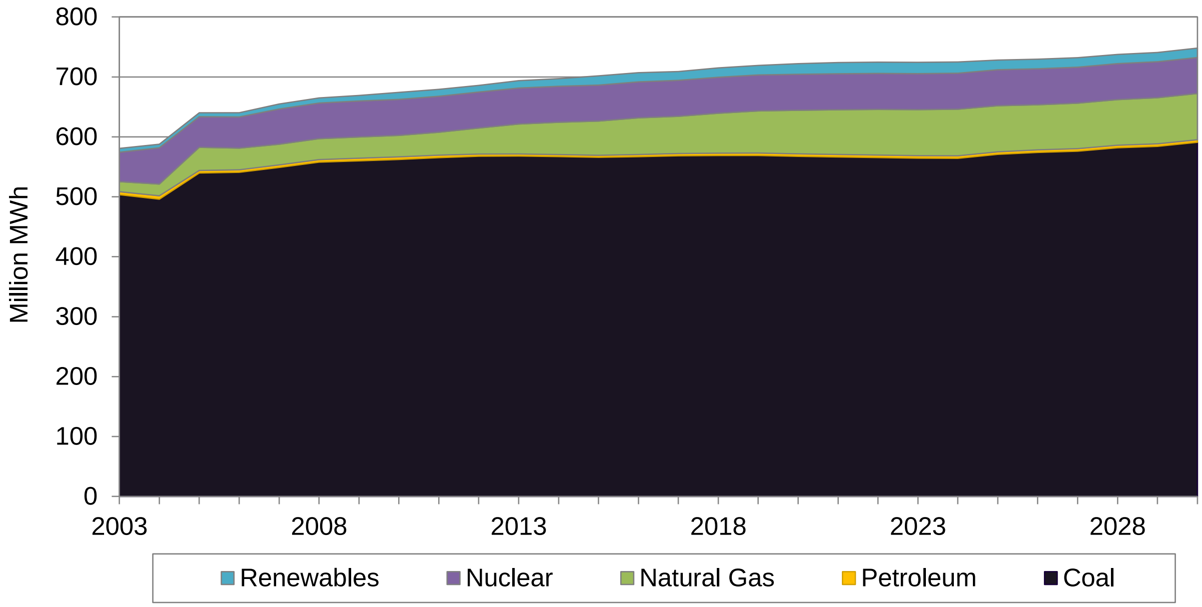

Figure 6: AEO Power Generation Forecast (2005)
Source: U.S. Energy Information Administration.

From 2005 forward, unconventional natural gas production proved to be more than a simple "flash in the pan." Figure 7, for instance, shows that starting in 2005, total U.S. natural gas production, driven almost exclusively by unconventional development, increased each and every year until the 2008-2009 financial crisis. Even at the time of the recession, U.S. unconventional natural gas production did not fall by much and has continued to increase, generally, since that time. Figure 7 also shows that natural gas reserves development, which can be thought of as the longer-run inventory of natural gas from which future production can be pulled, also increased dramatically during this time.

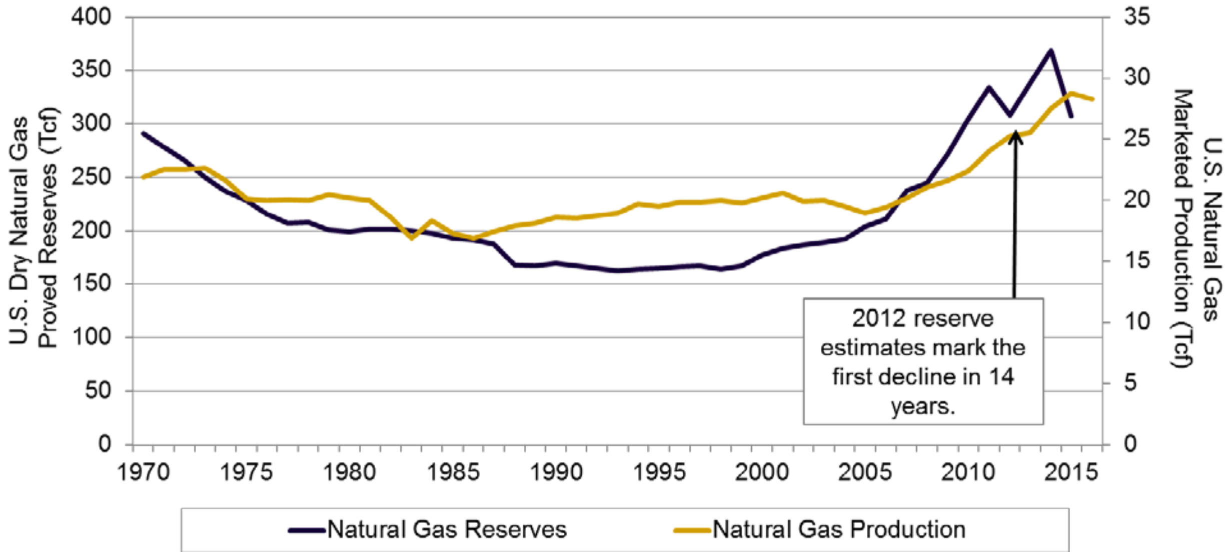

Figure 7: Natural Gas Production and Reserves
Source: U.S. Energy Information Administration.

The forecast for continued natural gas supply growth, in terms of reserve/resource additions, continues to be positive and the debates about the sustainability of the resource base are becoming less frequent. Figure 8 shows the most recent EIA forecast for U.S. natural gas reserves that are anticipated to grow to over 340 trillion cubic feet ("TCF") by 2040. These estimates, however, are conservative relative to some estimates that have reserves/resource potentials growing to as large as 631 TCF (MIT Energy Institute), or 900 TCF (ITG Investment Research) or even as high as 2,750 TCF (IHS Energy).

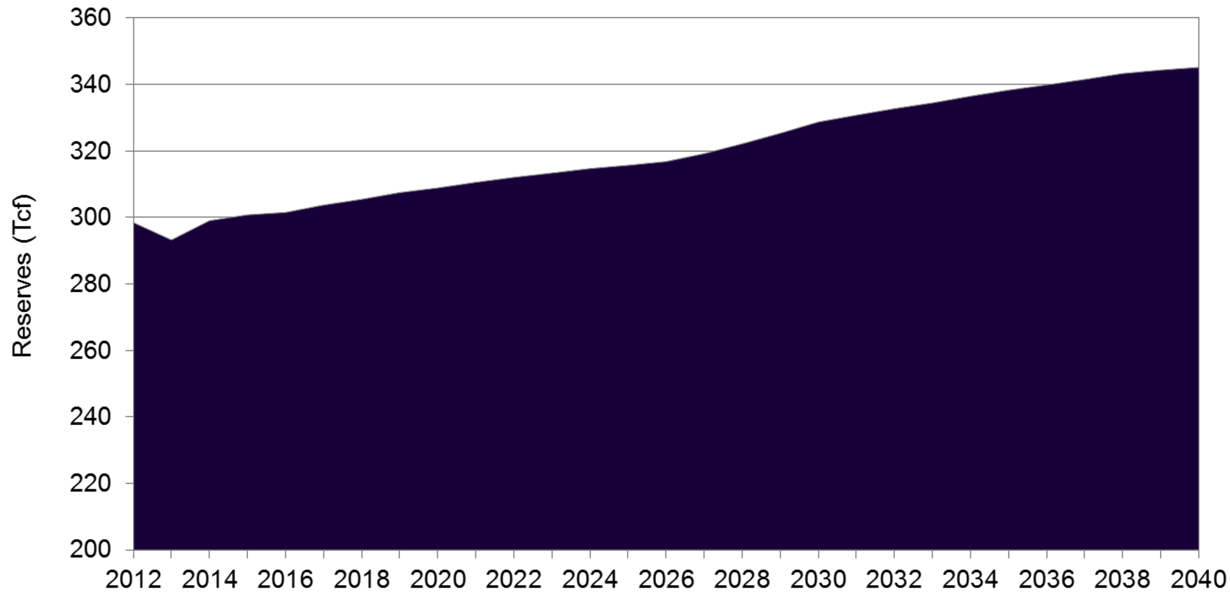

Figure 8: AEO Natural Gas Reserves Forecast (2016)
Source: U.S. Energy Information Administration.

The most significant game changer arising from the new supplies of unconventional natural gas are the impacts these supplies have had on the level and volatility of natural gas commodity prices. Figure 9 presents the historic trends in natural gas prices over the past three decades. In the "pre-crisis" natural gas era (before 2001), natural gas prices averaged $2.89 per MMBtu with a variation, or volatility of about $1.46 per MMBtu. Natural gas prices spiked during the winter of 2000-2001 and generally remained high up to the financial crisis of 2008-2009. During this crisis period, natural gas prices annually averaged $6.24 per MMBtu – some monthly and daily peaks, however, were considerably higher during this time. Annual average natural gas price volatility during this time was also extremely high, at $2.39 per MMBtu.

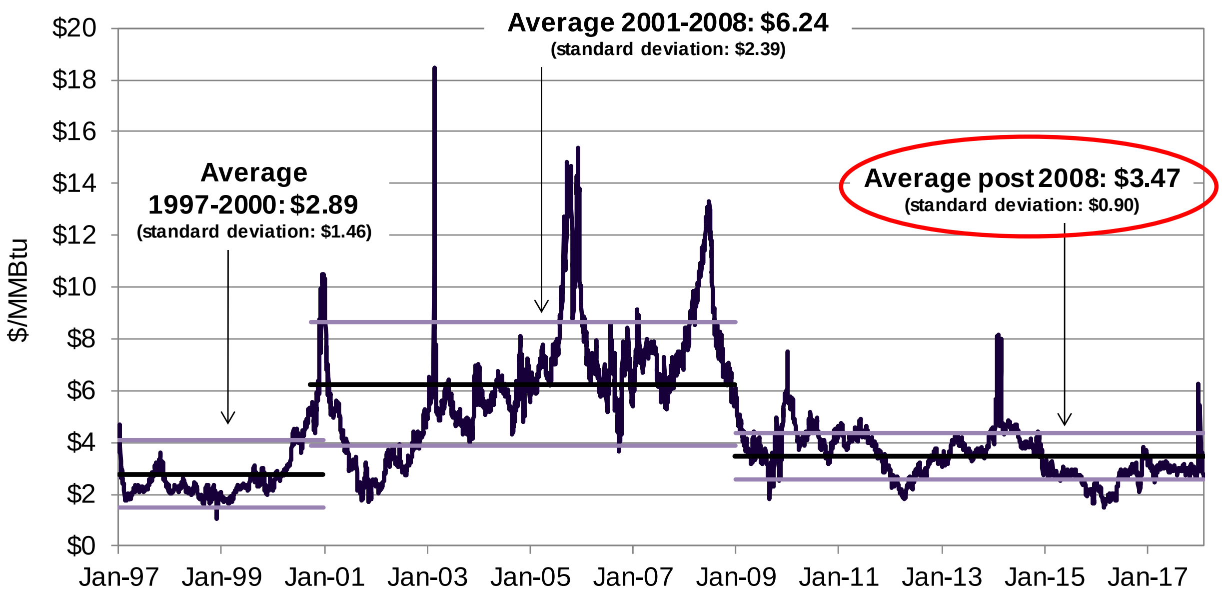

Figure 9: Natural Gas Prices and Volatility
Source: U.S. Energy Information Administration.

Prices and price volatility have fallen considerably in the shale era. Natural gas prices have averaged $3.47 per MMBtu since 2008 and, more importantly, natural gas price volatility has fallen to an annual average of $0.90 per MMBtu. This low price/low price volatility has dramatically impacted power generation since today, natural gas fired generation is quick to plan, develop and install, and very affordable to dispatch on a marginal cost basis.

The development of these resources, and the lack of volatility associated with its pricing has also contributed, in its own way, to the paradox of decreasing capacity value in today's market. The "just-in-time" nature of unconventional natural gas production, for instance, undermines the needs for large capacity investments in gas storage and need for longer term natural gas supply contracting even for large power generation-based customers. The fact that natural gas generation capacity itself can be developed relatively quickly and is dispatched at low marginal costs that is competitive with even solid fuels, helps to support this trend unwinding capacity value in today's energy markets.

4. Natural gas is dramatically changing power generation fuel mixes

Low natural gas prices have dramatically changed U.S. power generation, including the generation occurring within the MISO footprint. The rise of low-cost, abundant natural gas has led to a gradual and steady deterioration of coal-fired generation. Figure 10 shows that coal's relative position in the U.S. fuel mix began falling in 2007 and continued to fall until late 2016 when coal power generation reached 30 percent of overall U.S. power generation. Coal lost its position as the leading fuel source in the U.S. power generation fuel mix to natural gas in 2016 and natural gas continues and is likely to continue to dominate the fuel mix into the future.

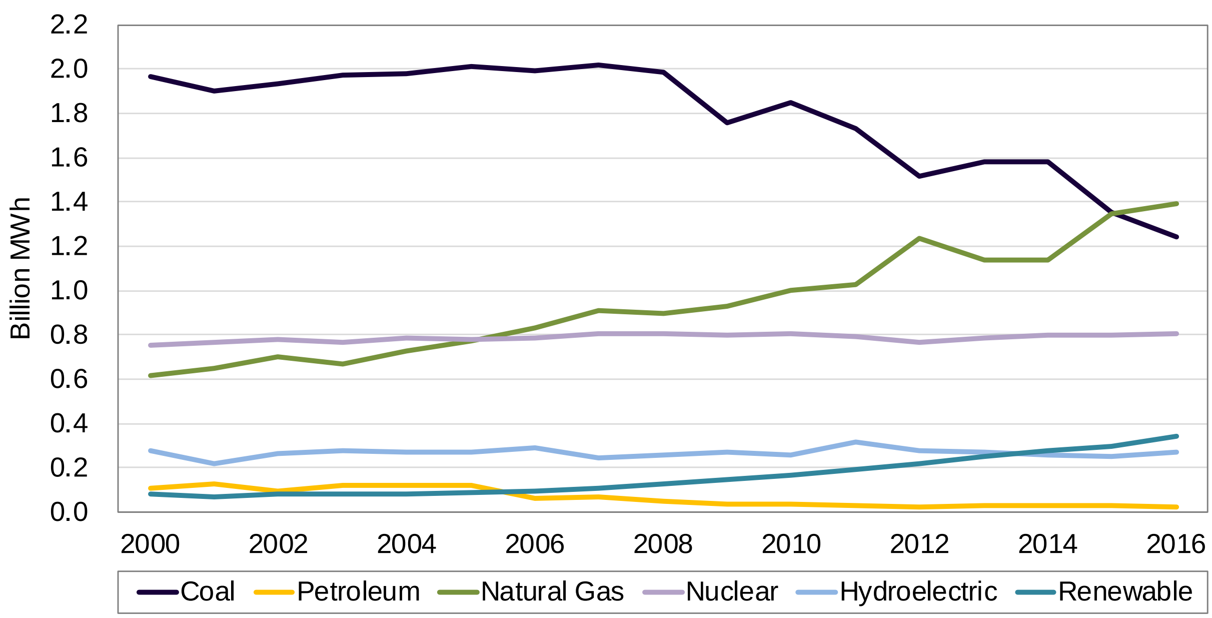

Figure 10: Annual Net U.S. Electricity Generation by Fuel Type
Source: U.S. Energy Information Administration.

The same trends hold for power generation within the MISO footprint. Figure 11 shows the historic predominance of coal-fired generation within MISO's footprint and how that predominance has deteriorated since 2013. Today, even in MISO, natural gas fired generation is at least on par with coal in terms of its use as a generation energy source, and holds a market share that is comparable, if still slightly lower, than the overall U.S. average.

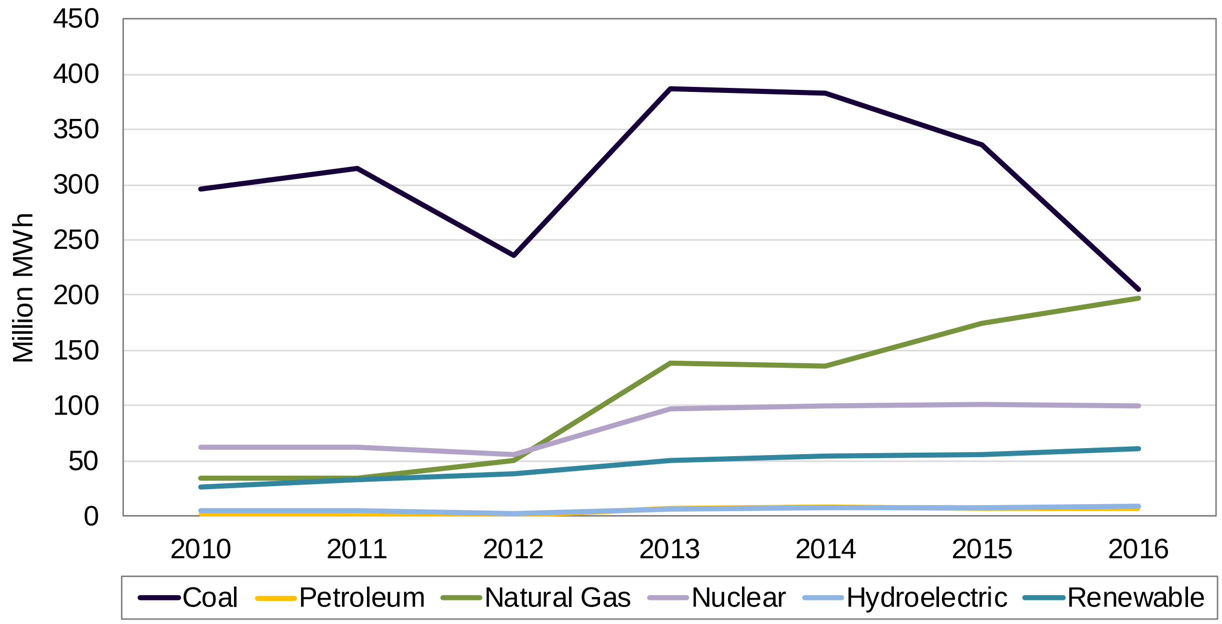

Figure 11: Annual MISO Net Electricity Generation by Fuel Type
Source: U.S. Energy Information Administration.

The National Electric Reliability Council ("NERC") expects the trend in replacing coal-fired generation capacity with natural gas fired generation capacity to continue across North America. Indeed, NERC has been accelerating its projections on the growth on natural gas generation capacity in recent years. Figure 12 presents NERC's forecasted electric generation capacity from natural gas for each NERC forecasted Long-Term Resource Assessment ("LTRA"), 2008 through 2016. Likewise, Figure 13 presents NERC's forecasted electric generation capacity from coal-fired generation capacity across North America.

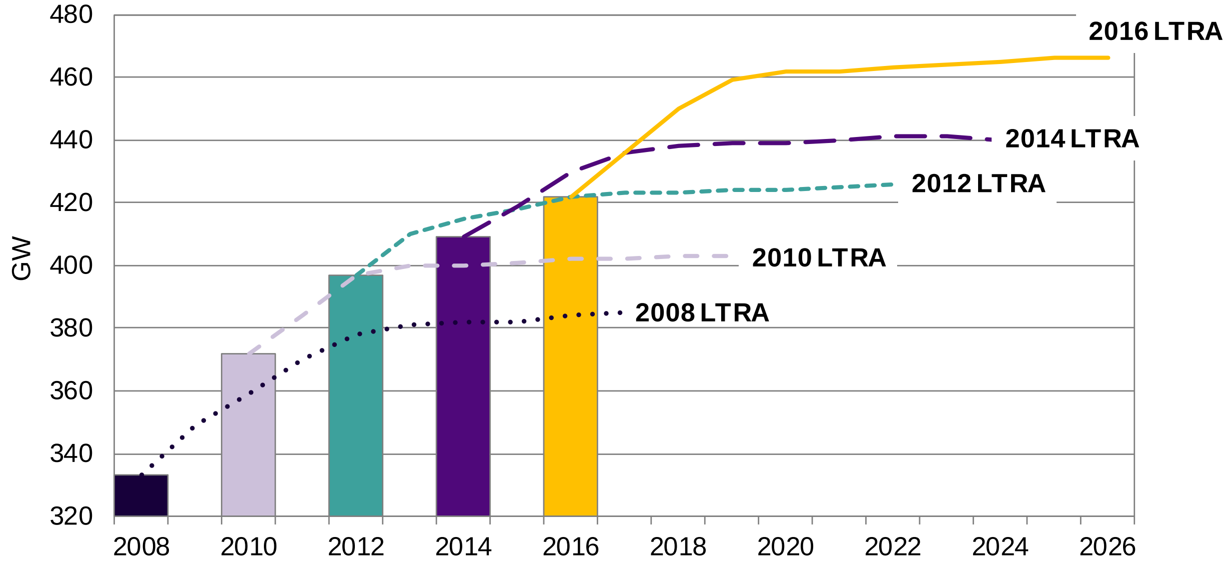

Figure 12: NERC's Anticipated Natural Gas Capacity for LTRA 2008 through 2016
Source: NERC, Long-Term Reliability Assessment.

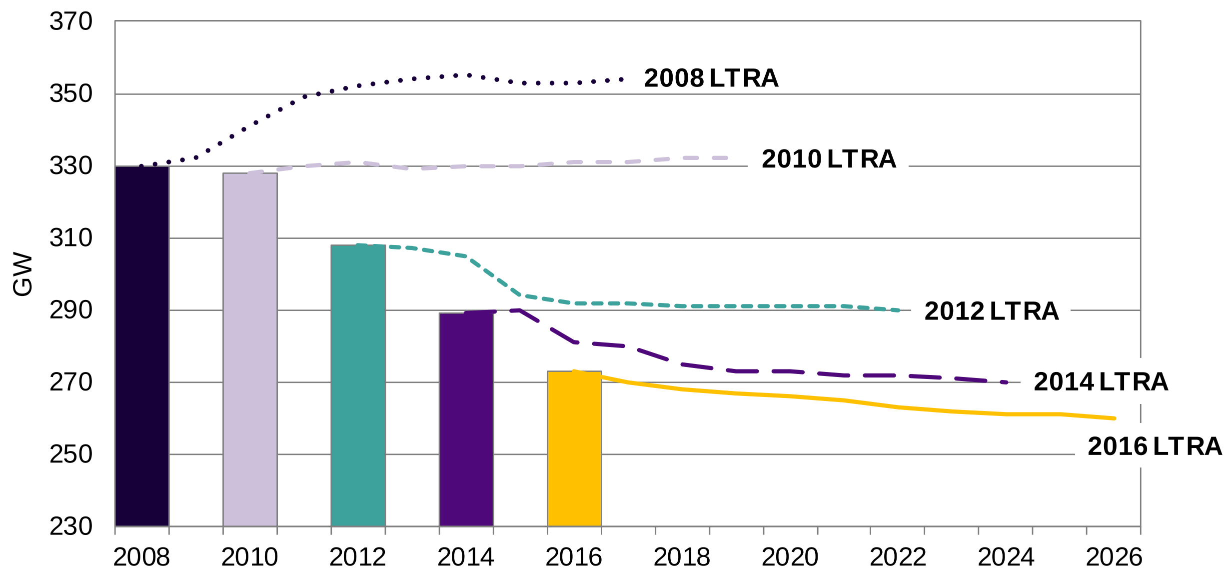

Figure 13: NERC's Anticipated Coal Capacity for LTRA 2008 through 2016
Source: NERC, Long-Term Reliability Assessment.

5. Natural gas is partially responsible for undermining the traditional capacity-value model

Natural gas generation has also, perhaps unwittingly, contributed to the undermining of capacity value of just about any type in regional U.S. power markets. The origins of this deterioration pre-date the shale revolution, and date back to the late 1990s when over 200,000 MW of natural gas fired generation were added. Even in a region like MISO, which has a long and extensive history with solid fuel generation, there were considerable levels of natural gas fired capacity additions. Figure 14 and Figure 15 present the annual gas fired capacity additions for MISO, and the U.S. overall.

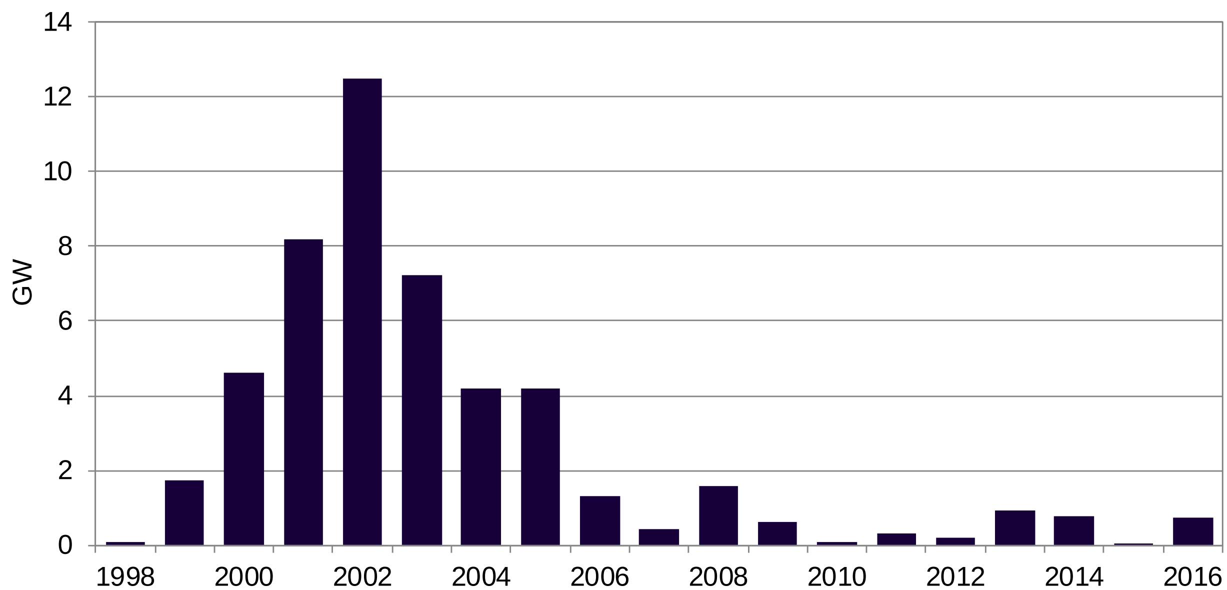

Figure 14: Annual Natural Gas Fired Capacity Additions, MISO Only
Source: U.S. Energy Information Administration.

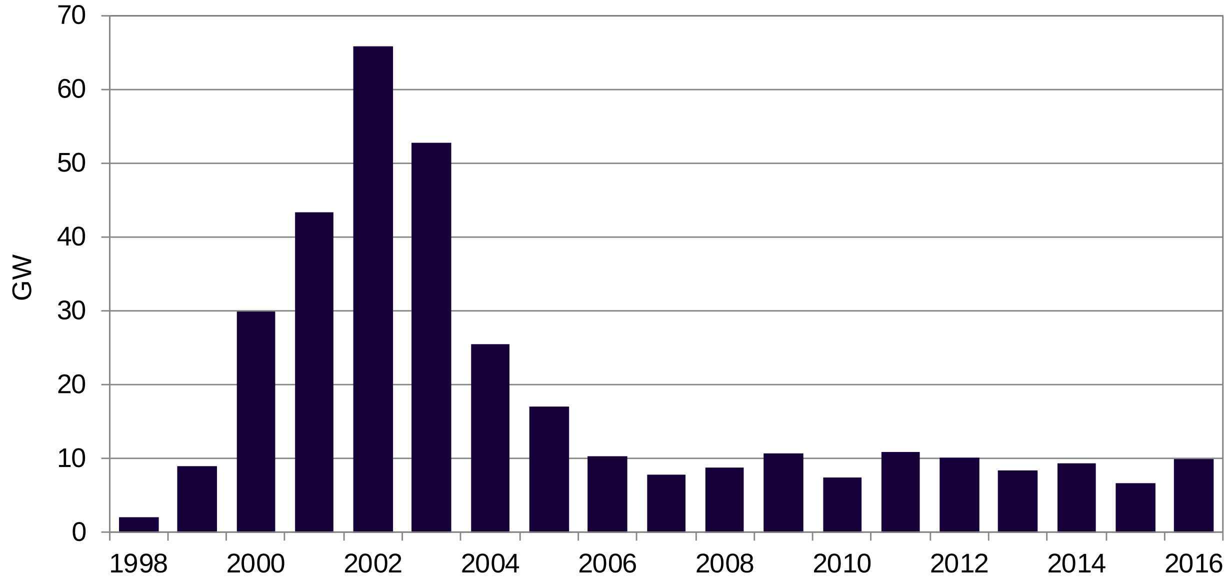

Figure 15: Annual Natural Gas Fired Capacity Additions, U.S.
Source: U.S. Energy Information Administration.

These capacity additions led to the rapid overcapitalization of most generation markets particularly those that were in, or have become part of, the MISO footprint. The rapid rise of capacity and reserve margins in what is now the MISO South region, for instance, drove down the relative price of spot market electricity as shown in Figure 16. Prices during this time period, while upwards of $50/MWh, were primarily based upon high nature gas prices and began to fall to more reasonable levels once natural gas prices fell in 2008. Furthermore, most of the capacity added during this time period was developed on a speculative basis, with little being tied to any form of intermediate or longer-term contract. This considerable amount of unsecured capacity was forced onto short term markets, undermining the value of capacity in a manner that would ultimately have longer run implications for not only generation, but other forms of capacity as well.

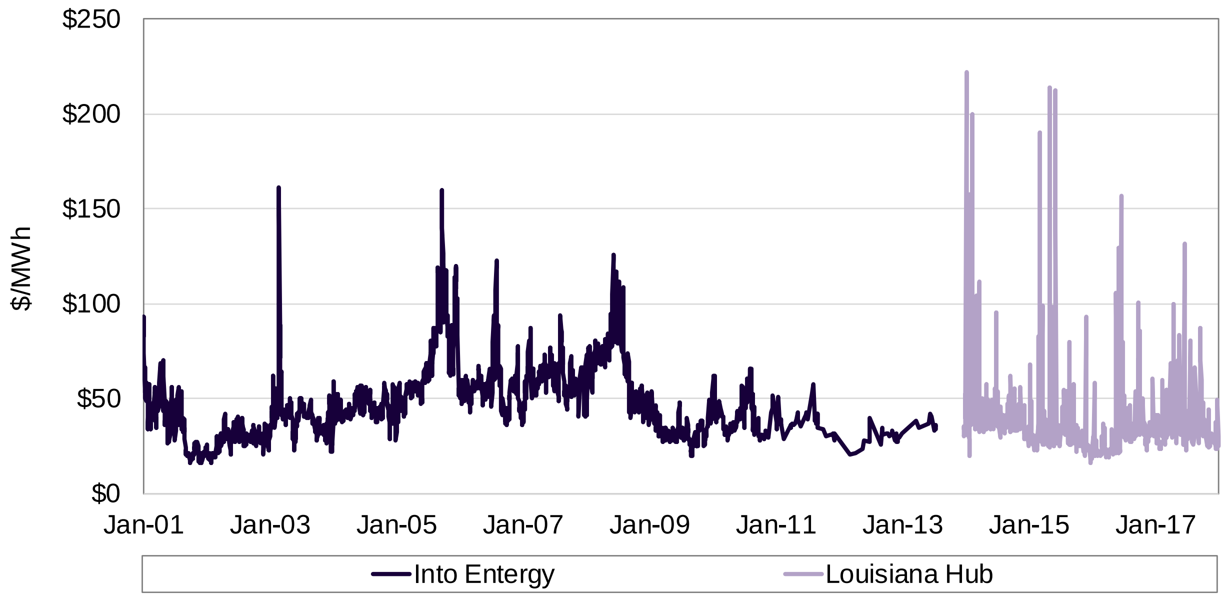

Figure 16: Spot market electricity prices (on peak)
Source: U.S. Energy Information Administration.

In theory, capacity overhangs, like the one that developed during the last decade in generation markets, can tend to retreat in the face of sustained market growth and the preliminary retirement of unneeded capacity. This did not happen in spot electricity markets during the past decade for a variety of reasons that include: (1) the considerably large amount of capacity that was developed during this period of time, (2) the increase in natural gas prices that made many of these generators, including those that were of relatively high efficiencies, more expensive, (3) the gradual emergence of policy and financially-supported renewable energy, particularly wind energy and (4) ultimately, the crashing of market demand with the 2008-2009 recession. These factors, collectively, and over time, kept market premiums from being developed for a relatively long and sustained period, as indicated by the relatively low market clearing heat rates for what is now part of the MISO South area as shown in Figure 17. However, those price premiums have started to arise more recently (post 2015) as seen in both Figure 16 and Figure 17.

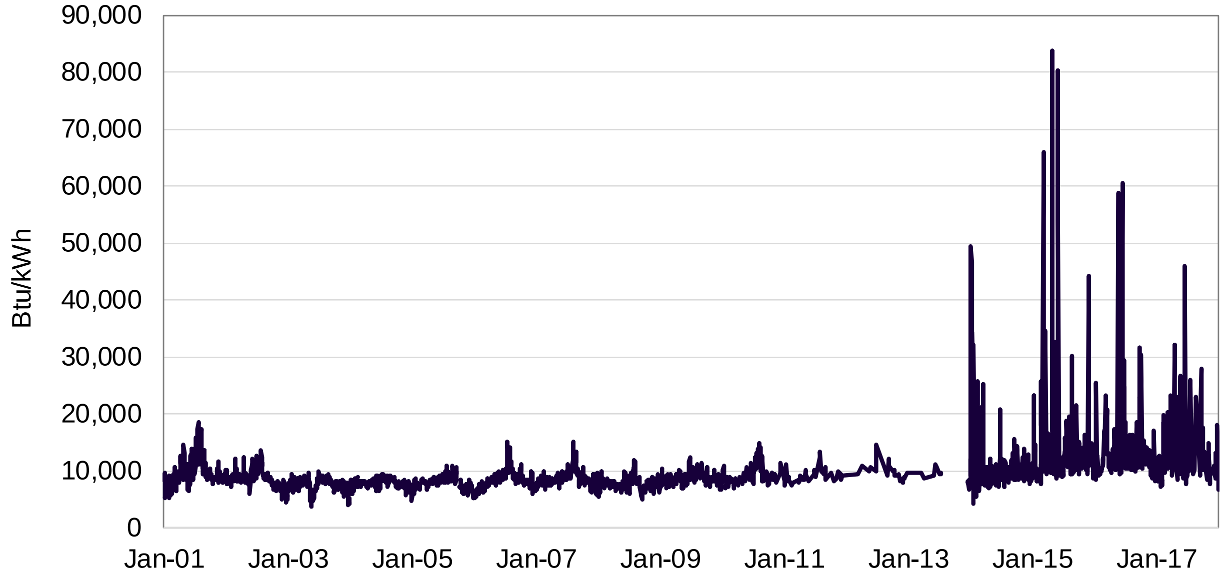

Figure 17: Spot market clearing heat rates (on-peak)
Source: U.S. Energy Information Administration.

6. <u>Renewable energy development challenges</u>

a. Renewable energy development has been rapid and pervasive

Renewable energy ("RE") capacity development over the past decade has been considerable and impressive. Yet this development has not come without costs for many RTOs including MISO. The conversation at the MISO 2033 event focused on the challenges that renewables integration creates now, and in the future. Figure 18, for instance shows the considerable amount of wind capacity that has been developed in the U.S. and in MISO over the past two decades. This capacity development as accelerated rapidly over the past several years, particularly in MISO where many wind generation projects have come on-line.

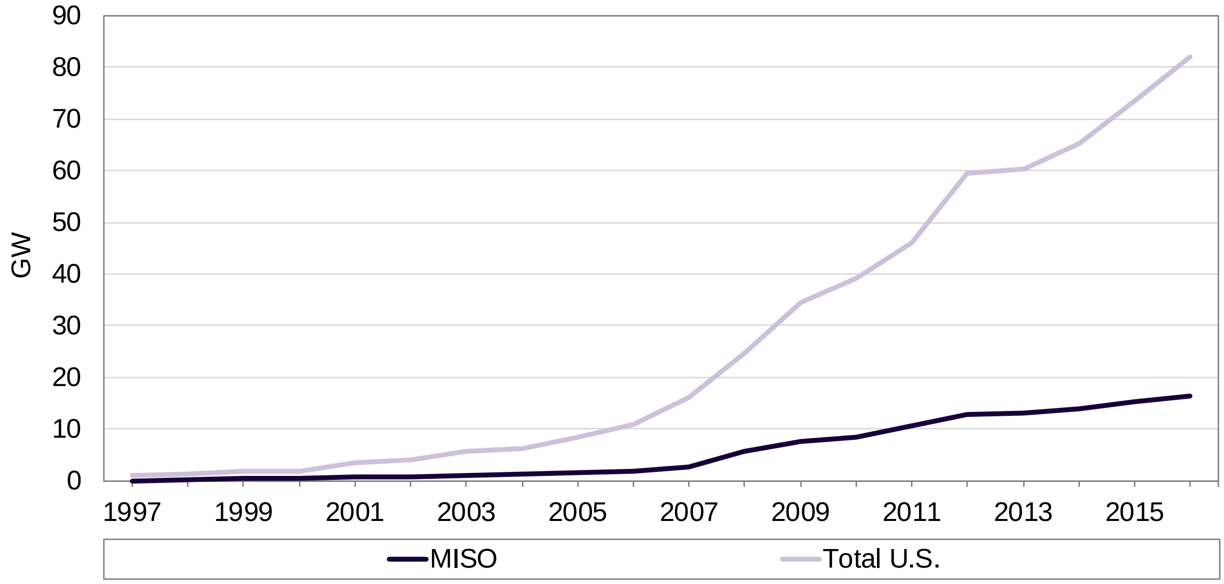

Figure 18: Annual Wind Capacity Development, U.S. and MISO
Source: U.S. Energy Information Administration.

In 2010, MISO-based wind capacity amounted to 8,104 MW. By the end of 2016, this capacity had increased by almost double, to 15,823 MW. The MISO 2033 event clearly noted that this development likely to continue to be considerable. Figure 19, shows that the current MISO interconnection queue has over 22.1 GW of wind capacity requesting to be developed in the MISO footprint over the next three years.

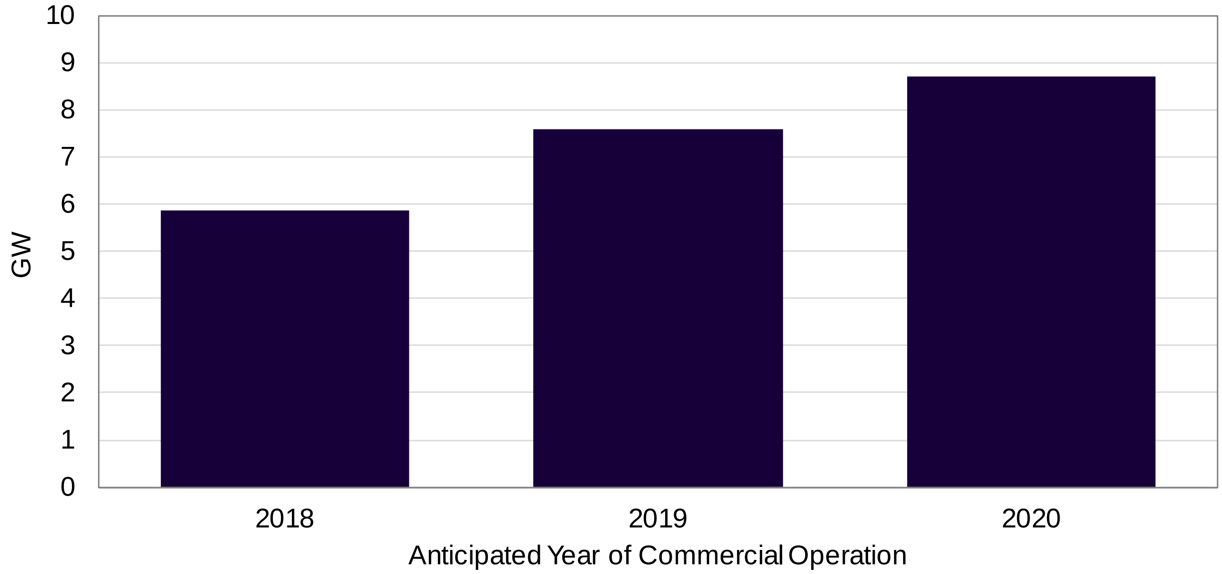

Figure 19: Potential MISO Wind Capacity Development (2018)
Source: MISO Interconnection Queue.

Even more impressive is the amount of solar energy that has been developed throughout the U.S. and in the MISO footprint. Figure 20 shows that U.S. solar capacity growth, for grid-scale (not distributed, behind-the-meter) projects has been considerable and one of the fastest, on a percentage basis, of any power generation resource type. Total U.S. capacity, for instance, was only 420 GW in 2005, but today, has grown to nearly 22,126 GW, and this is only for larger grid-scale type projects. The impact that smaller, distributed, behind-the-meter solar installations are having on transmission planning will be discussed in a later section of this report.

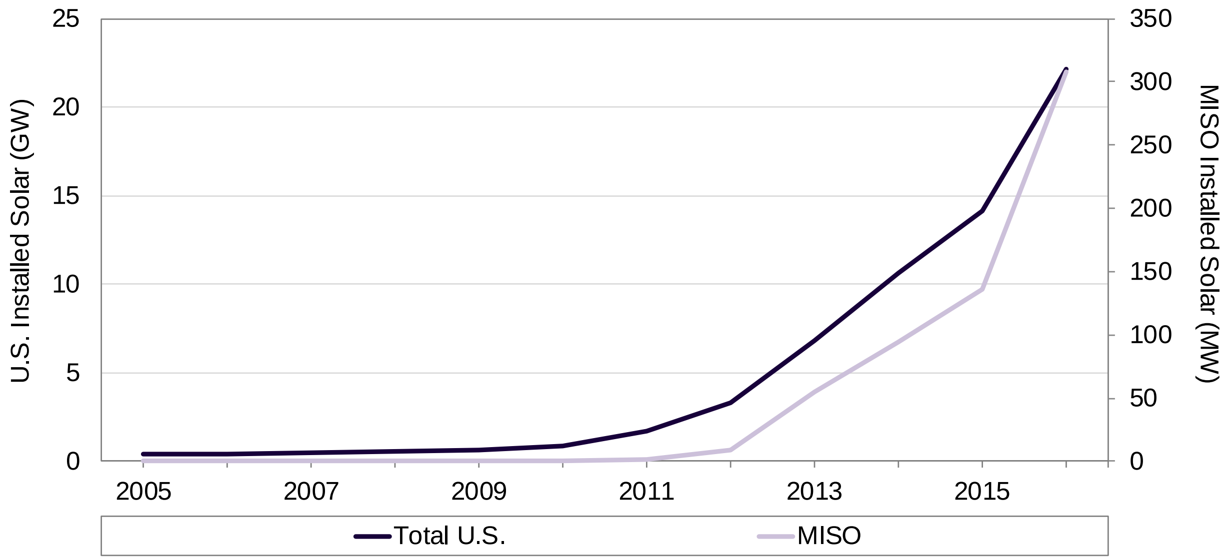

Figure 20: U.S. Grid-Connected Solar Capacity Development (2018)
Note: Chart does not draw MISO installed solar capacity to scale for illustrative purposes.
Source: U.S. Energy Information Administration.

Equally impressive is the amount of solar energy development anticipated for the MISO region. Figure 21 shows the annual proposed solar development that is currently in the MISO interconnection queue. In fact, solar capacity development is larger than any other resource type in the MISO footprint. This solar capacity could amount to nearly 14.4 GW of grid-scale projects by 2021. The average size of each installation currently in the interconnection queue is approximately 120 MW. The bottom portion of Figure 21 shows considerable levels of proposed solar energy development throughout each sub-region within the MISO footprint.

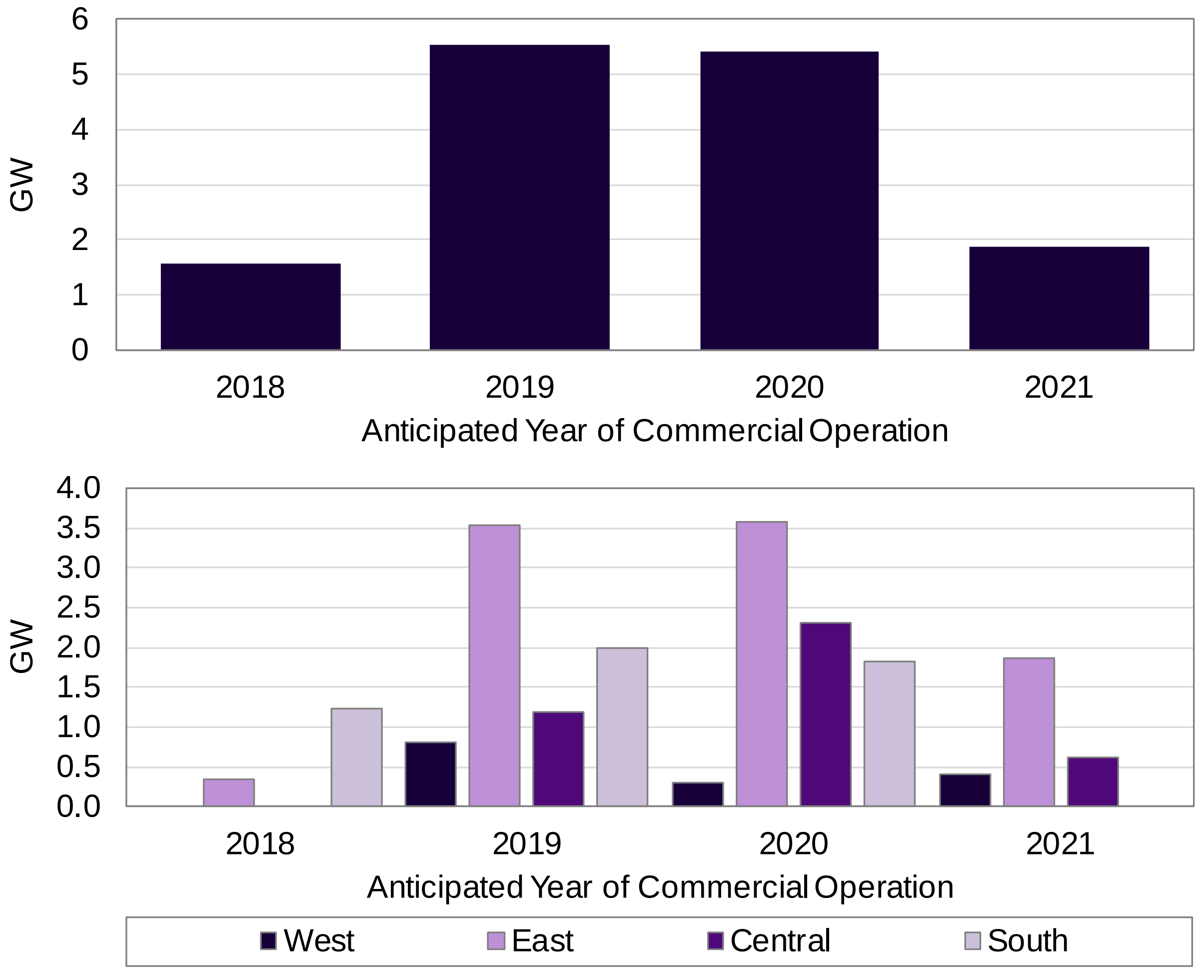

Figure 21: MISO Proposed Grid-Connected Solar Capacity Development (2018)
Source: MISO Interconnection Queue.

The MISO 2033 event noted that these RE capacity developments have raised, and will continue to raise, significant challenges for longer-term transmission planning. Putting aside the obvious intermittency challenges associated with RE, this significant level of RE capacity development will require MISO, as well as many other RTOs, to connect a large amount of RE capacity, in usually very remote areas, to more populous load serving areas. Consider the projects outlined in Table 4 which identify large, expensive transmission infrastructure projects, developed over the past decade, expressly developed to connect often remote RE installations to more populated load-serving areas.

Table 4: Large Transmission Infrastructure Projects

Project	Region	Year of FERC Order	Size	Estimated Cost	ROE Adders[1]	CWIP in Rate Base	Abandoned Plant Cost Recovery	Pre-Commercial Cost Recovery	Hypothetical Capital Structure (Equity/Debt)
MidAmerican Energy Co	Iowa-Illinois-Missouri	2011	546 miles, 161 and 345 kV	$573 million	n.a.	100%	100%	n.a.	n.a.
Dessert Southwest Power	Southern CA	2011	118 miles, 500-kV	$350 million	150 b.p.	100%	Yes	n.a.	50% / 50%
Ameren Services - Illinois Rivers Project	Missouri-Illinois-Indiana	2011	331 mile 345-kV	$739 million	12.38% [2]	100%	Yes	n.a.	56% / 44%
Ameren Services - Big Muddy River Project	Missouri-Illinois	2011	185 mile 345-kV	$383 million	12.38% [2]	100%	Yes	n.a.	56% / 44%
Atlantic Wind Connection	Atlantic Coast / PJM	2011	250 miles of four 320 kV	$5 billion	13.58% (incl. 250 b.p.)	100%	100%	n.a.	60% / 40%
Great River Energy	Minnesota	2010	240-miles, 345 kV; 250-miles, 345 kV;	$310 million	n.a.	100%	100%	n.a.	20% / 80%
Otter Tail CapX2020	Minnesota, North Dakota, South Dakota	2009	568 miles, 230 and 345 kV	~ $1.5 billion	n.a.	100%	100%	n.a.	n.a.
Green Power Express	Midwest	2009	3,000 miles, 765 kV	$10-$12 billion	110 b.p.	100%	100%	100%	n.a.
Pioneer Transmission	PJM-MISO	2009	240 miles, 765 kV	$1 billion	200 b.p.	100%	100%	100%	n.a.
ITC Great Plains	Kansas-Nebraska	2009	210 miles, 345 kV/765 kV; and 180 miles, 765 kV	$787 million	150 b.p.	100%	100%	100%	n.a.
Tallgrass Transmission	Oklahoma	2008	765 kV	$500 million	200 b.p.	100%	100%	100%	n.a.
Prairie Wind Transmission	Kansas	2008	230 miles, 765 kV	$600 million	200 b.p.	100%	100%	100%	n.a.
Central Maine Power and Maine Public Service Co.	Maine	2008	200 miles, 345 kV	$625 million	150 b.p.	n.a.	100%	n.a.	n.a.
Pacificorp - Energy Gateway Transmission Expansion Project [3]	Wyoming-Idaho	2008	300+ miles, 230 and 500 kV	$1.9 billion	200 b.p.	n.a.	100%	n.a.	n.a.

Note: [1]In most cases a specific ROE will be determined when the project makes future filings under FPA section 205 (updating revenue requirement to reflect the fact that the facilities have been placed in service); [2]Ameren did not seek a stand-alone incentive ROE adder
Source: Federal Energy Regulatory Commission; and [3]Two of the eight segments in Pacificorp's Energy Gateway Transmission Expansion Project will connecting transmission-constrained wind resources in Wyoming to westward load centers. The cost reported here pertains to these two segments only.
Source: Federal Energy Regulatory Commission.

b. RE development motivators

There are several reasons for the explosion in RE capacity development over the past several years. Perhaps the most significant stimulus for RE development rests with a variety of public policies, mostly financial support mechanisms that support RE, or actively encourage RE development. Stakeholders participating in the MISO 2033 event activity discussed the important, and yet changing role of public policy in RE support.

Perhaps the most pervasive public policy supporting RE development rests with the widespread utilization of state-level renewable portfolio standards ("RPS"). Figure 22 outlines the number of states with an active RPS and the currently-anticipated terminal RE generation shares mandated by state regulations or legislation. Several of these states, such as Minnesota, Illinois, Missouri and Michigan are within the MISO footprint. RPS policies effectively set a RE capacity development floor and support the anticipated RE capacity development levels discussed earlier.

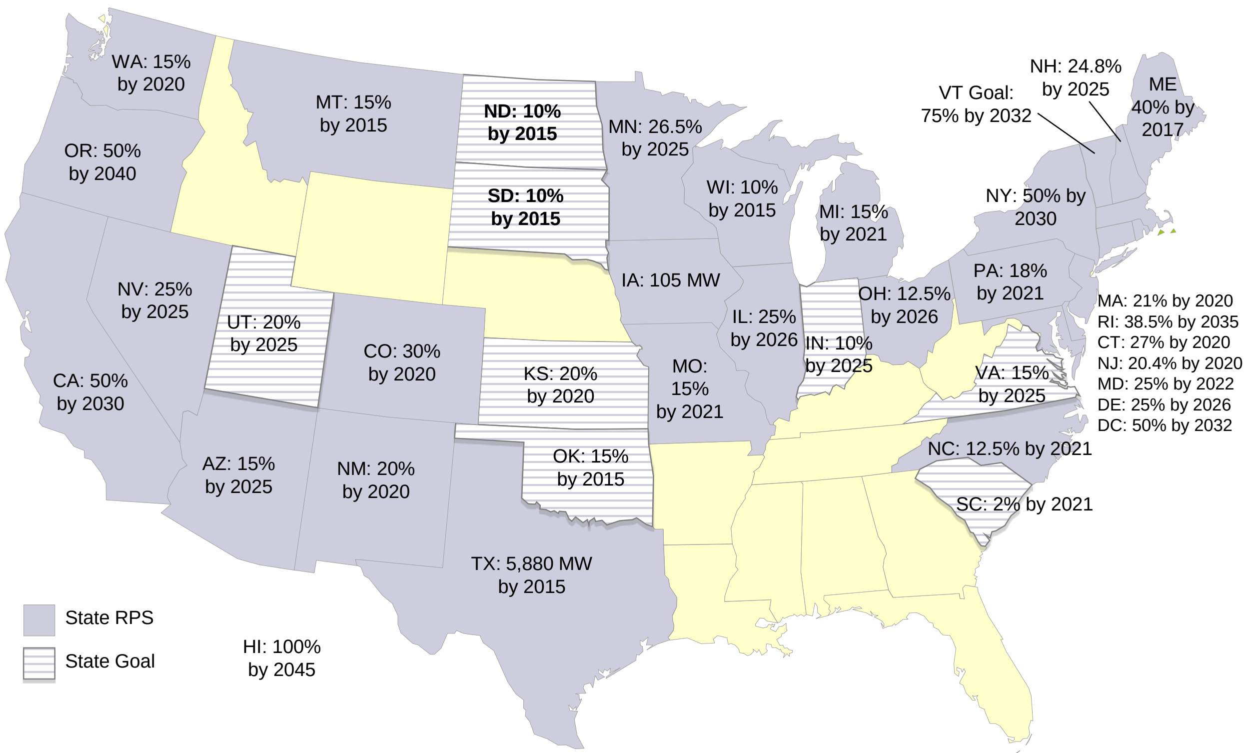

Figure 22: State Renewable Portfolio Standards (2018)
Source: U.S. Energy Information Administration.

Full compliance with these RPS requirements alone will result in a considerable amount of RE being put to the grid by 2035. Figure 23 provides the total renewable capacity and percent of retail sales, in rank order, associated with each state's RPS. MISO states are highlighted in a lighter color. In total, the U.S. is anticipated to add 90.6

GW of capacity, totaling 17.6 percent of all retail sales by 2035. MISO states are anticipated to add 17.9 GW, summing to 8 percent of all retail sales, by the same date.

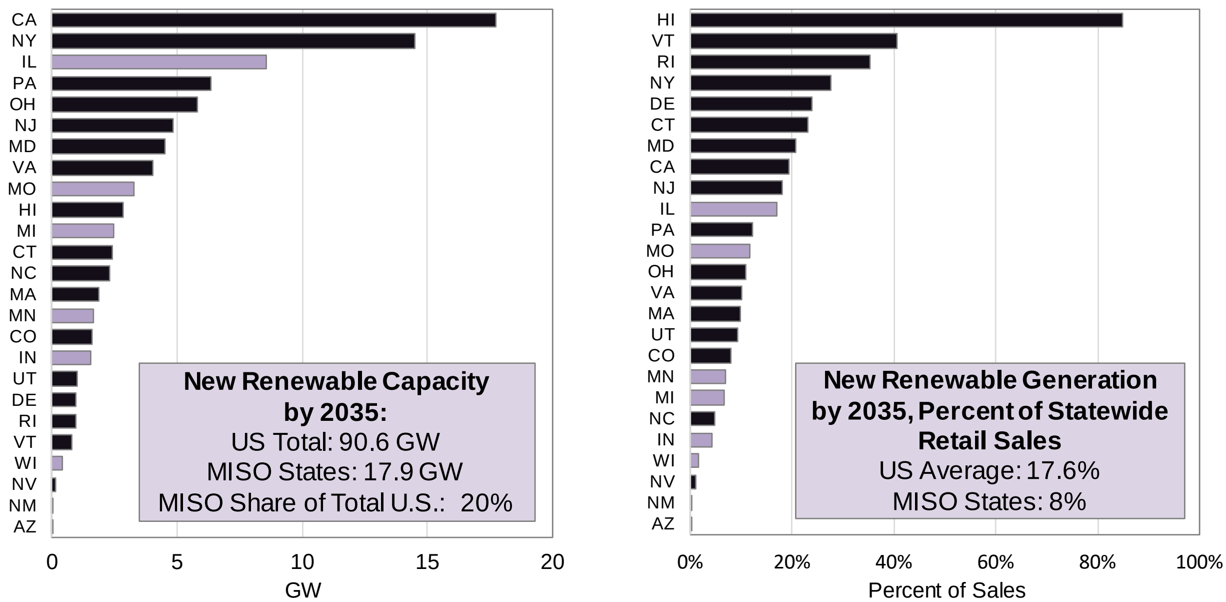

Figure 23: State RPS Compliance by 2035
Source: U.S. Energy Information Administration, Author's construct.

Tax incentives are another form of public policy support that has considerably impacted RE development, for both large scale grid-connected projects, as well as smaller-scale behind-the-meter applications. Perhaps one of the most important, and penultimate tax incentive policies supporting RE development has been the production tax credit ("PTC") which was created as part of the Energy Policy Act of 1992 and provides a per-kWh financial credit for RE power generation from qualifying facilities. This credit has been allowed to expired, and yet later resuscitated several times since 1992 and while its various incarnations have been applicable to several RE resources, the PTC is commonly held as being responsible for stimulating a large amount of wind energy development throughout the U.S. as seen in Figure 24.

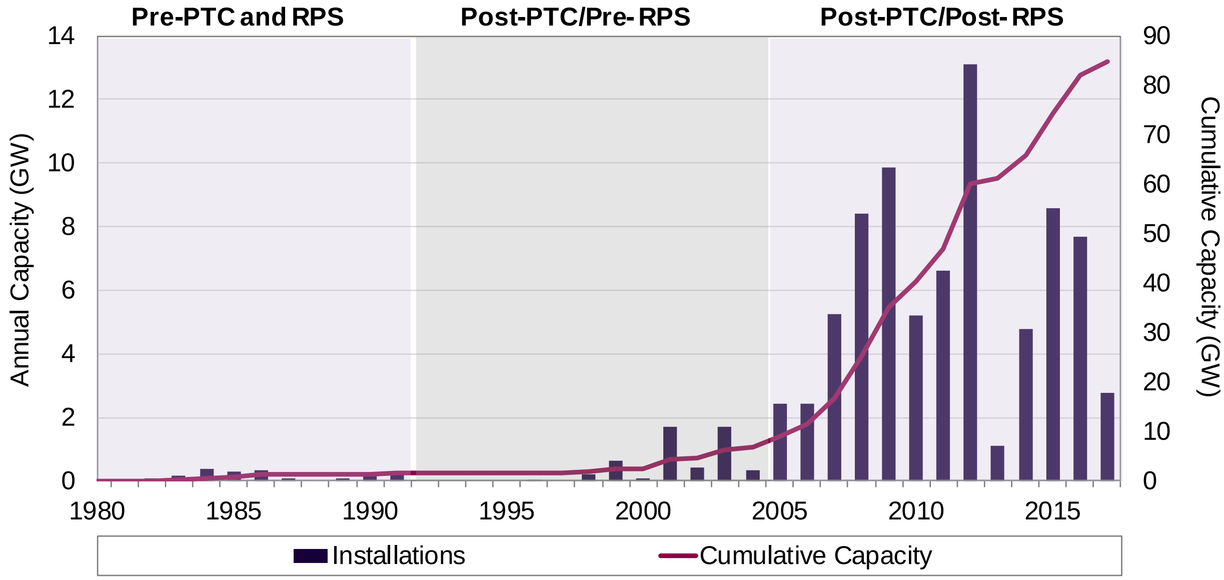

Figure 24: Wind Energy Capacity Development (1980-2017)
Source: U.S. Energy Information Administration, Author's construct.

During the MISO 2033 event, a number of stakeholders noted that corporate attitudes towards RE were changing and that this would likely put further pressure on the transmission planning process since it would result in: (a) ever increasing RE capacity development and its inherent challenges and (b) a possibility that some of this RE capacity development would increasingly be co-located at larger industrial facilities that may require additional transmission infrastructure in order to serve. Many stakeholders, including industrial stakeholders at the MISO 2030 event, noted the corporate sensitivities about climate change, their global footprints that included facilities in many nations that regulate carbon emissions (and are COP21 signees), and activist investor trends are forcing many firms, particularly publicly-traded firms, to utilize "cleaner" and "greener" set of electricity resources.

For instance, 87 companies, such as AB Inbev, General Motors, and Wal-Mart Stores have joined the RE100 and made a commitment to purchase 100 percent RE.[16] In addition, 65 companies have signed onto the World Resources Institute's ("WRI") corporate energy buyers' principles. Further, 94 companies have become members of the business renewables center ("BRC") up from 36 in January 2016.[17] And, some electric utilities, including at least one in the MISO footprint (Xcel Energy in Minnesota), are now offering green tariff offerings to large and residential customers, alike.

Lastly, several large corporations, including such large industrial firms such as Owens Corning, Dow Chemical Company, and General Motors, are all making significant RE capacity purchases that are "off-site" or not co-located at any of their specific industrial facilities. Figure 25 shows a summary of these large off-site purchases over the 2010-2016 time-period by large industrial and other publicly-traded firms.

[16] See, We Mean Business, available online at: https://www.wemeanbusinesscoalition.org/companies/
[17] Romaine, Ted (February 13, 2017), presentation at Gulf Coast Power Association, Invenergy LLC.

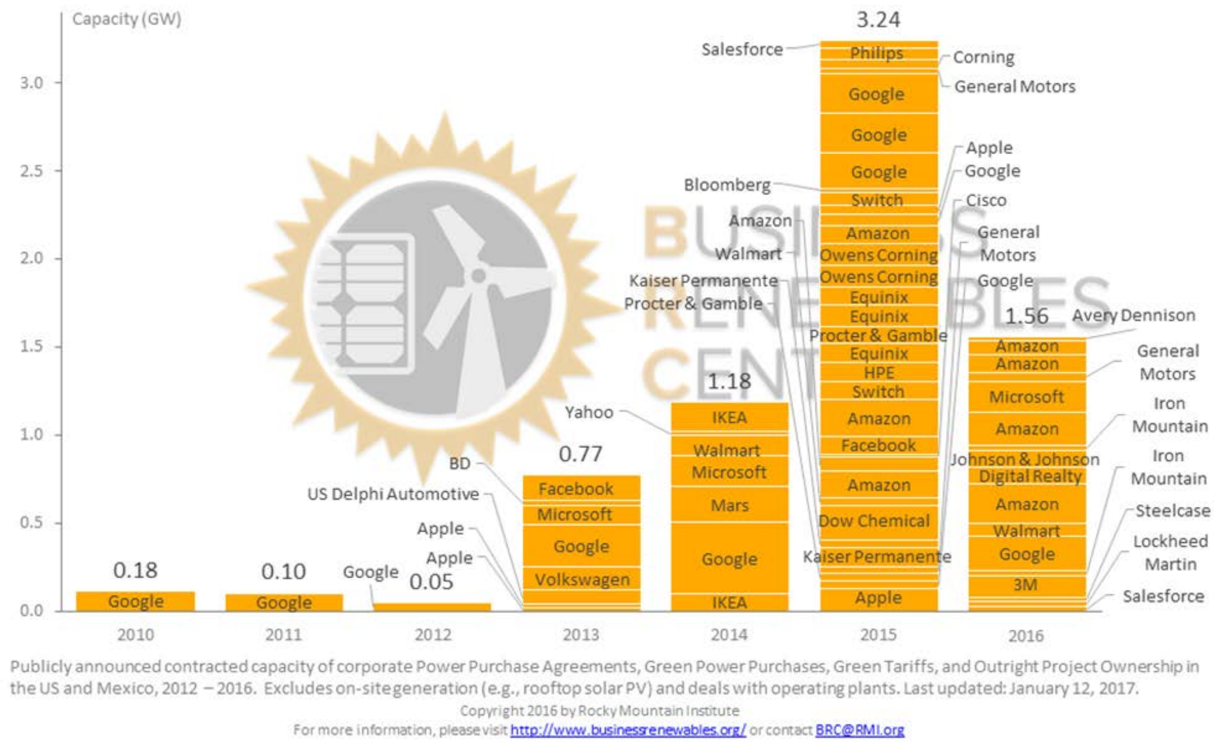

Figure 25: Corporate Off-site renewable energy purchases (2010-2016)
Source: Rocky Mountain Institute, and Invenergy.

c. Movement from policy to markets

Participants at the MISO 2033 event recognized the important role that public policy has played in the development of RE capacity over the past decade. But there was some consensus at the event that future RE development would be conditioned much more by market forces rather than mandates and subsidies. This makes sense for several reasons.

First, as shown earlier in Figure 22, most states have adopted an RPS. Over 75 percent of all U.S. electric retail sales are in states that have some form of RPS or RE goal. At this point, the states that have not adopted an RPS, likely never will, and the possibilities for adopting a national RPS are very small given past unsuccessful attempts.

Thus, from a mandate perspective, the only way RE can grow will be simply through increasing existing state RPS requirements

Second, outside of an RPS, the other predominant means of stimulating RE development has been through tax and subsidy/rebate policies. However, many state governmental agencies, and even the federal government, have started to appreciate the expensiveness of these forms of support. The American Recovery and Reinvestment Act ("ARRA") of 2009, for instance, spent as much as $16.8 billion on a variety of different forms of RE support from tax breaks, to low-interest loans, to other forms of loan guarantees.[18] These programs, however, are mostly one-time in nature (to address the recession) and have been discontinued. The ability to continue funding RE, at the state and federal level, given public budgeting and deficit concerns, falls each year and the likelihood of any new expanded public funding support for new RE development, particularly in a fashion comparable to ARRA and prior state-supported levels, is exceptionally low.

Market forces are already part of RE development and will continue to be important on a forward going basis. Increased RE development appears to have led to increased RE manufacturing development, which in turn, has driven down the costs of a variety of RE technologies, particularly solar and wind. Further, global competition, particularly from Asia, has forced RE development costs to be lower and lower each year. Figure 26 for instance, shows the decreasing average installed cost of a typical wind turbine from 2010

[18] Eber, Kevin (February 18, 2009), Clean Energy Aspects of the American Recovery and Reinvestment Act, Renewable Energy World.

through 2016. Installation costs per unit of capacity, for instance, have fallen by as much as 26.2 percent over this time.

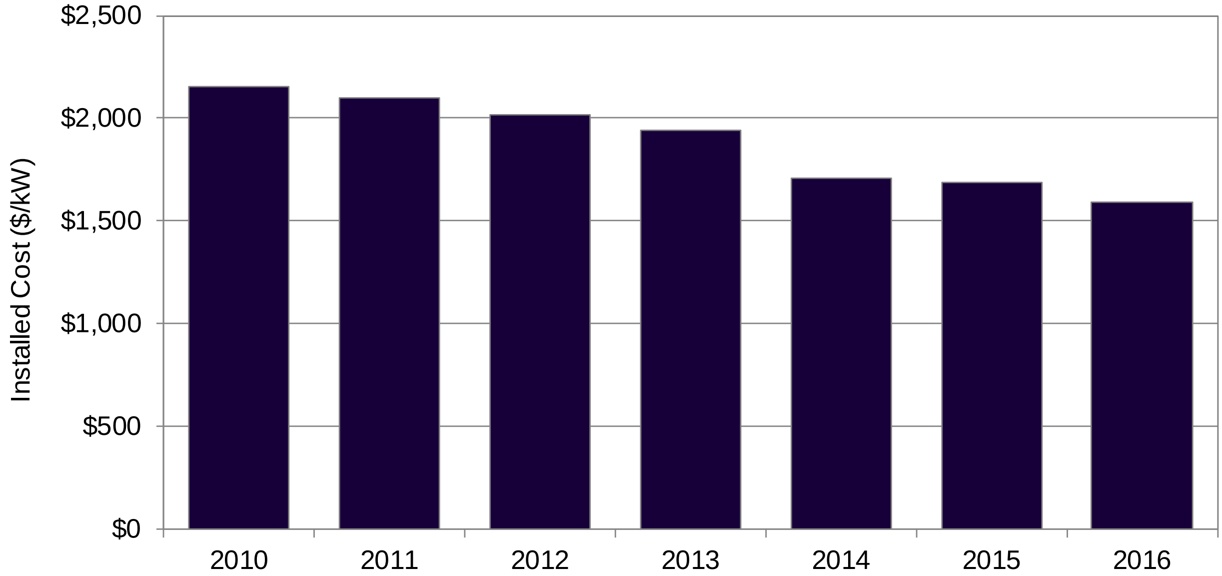

Figure 26: Terrestrial Wind Generation Installed Capital Costs (2010-2016)

Note: 2012 estimated from NREL information by interpolating 2011 and 2013 estimates.
Source: National Renewable Energy Laboratory.

MISO has played, and will continue to play, a large role in facilitating RE capacity development as well as RE market transactions that provide the financial support for this development, not only in the MISO market, but beyond. In 2017 alone, RE capacity located within the MISO footprint is responsible for eight percent of all Class 1 RECs that were retired for RPS compliance purposes in PJM. Thus, the role that MISO and its institutions play in facilitating RE, and in sending appropriate market-based signals for RE development, will continue to be important as direct policy intervention as these RE markets begins to moderate.

d. Increasing intermittency and capacity value challenges

All the MISO 2033 event participants recognize that RE resources are intermittent and typically peak at times of the day that are not coincident with the loads of most MISO LSEs. This is one of the primary challenges associated with imputing any kind of "capacity value" to RE resources and part of the reason why MISO, as well as other RTOs find themselves increasingly operating in a post-capacity world. Wind generation is only available when the wind is blowing and tends to peak in the late evening and early morning hours, at times that are entirely inconsistent with the late afternoon/early evening peaks in MISO. Likewise, solar generation is only available when the sun is shining, and tends to peak around mid-day; again, far earlier than when needed to provide any significant peaking capacity benefit for most MISO LSEs.

The differences between RE peak generation and MISO loads is one of the fundamental disconnects undermining capacity value in many RTOs. This problem becomes more confounded as: (a) additional and considerable levels of RE capacity come on line and (b) additional natural gas fired generation is added to backstop this RE capacity. These factors, in addition to growing challenges associated with many consumers' willingness to pay for capacity, are the rationales and primary foundations for the post-capacity world in which MISO must plan. Few MISO 2033 participants had clear answers as to how to meet this important challenge. But, as noted throughout this paper, it was clear that role of planning, and the processes' underlying principles, will become more important than ever to assure that this new world of resource developments are in line with resource requirements of the future.

7. <u>Solid fuel resources are challenged, but not going away</u>

a. Coal and nuclear retirements are at record levels

Large solid fuel baseload assets have historically supported the longer-run role of capacity in most major regional power markets. In the past, these resources were the first to be dispatched given their relatively high capital costs and low marginal cost of operation. Their marginal costs were often significantly lower than higher cost natural gas steam units, and more importantly peaking units, in the dispatch order. Historically, there were little to no resources competing with these baseload units for their positions at the beginning of the power supply stack. Today, this way of dispatching units has been turned on its head.

Solid fuel resources are threatened from the "top" of the old dispatch order by natural gas units that are now exceptionally efficient and have an abundant, low-cost fuel resource base. Baseload units are also being threatened from the "bottom" of the old dispatch order by a large and ever-growing set of RE resources that have zero marginal cost for generating electricity, if not "negative" dispatch costs once certain subsidies and other financial support mechanisms are take into consideration. The result has been a "squeeze" on these traditional baseload assets that has led to an ever-increasing number being retired and taken out of service.

Table 5 shows the number of coal fired units alone that have been retired between 2011 and 2016 for the U.S. and MISO. The numbers are sobering. All told there have been over 540 units coal-fired units retired in the U.S. since 2011, accounting for over 70,000 MW of capacity. Table 5 also shows that a relatively large share of these retirements occurred in the MISO footprint alone, amount to anywhere from 10.3 percent (2012) to 12.8 percent (2016) over the past several years.

Table 5: U.S. and MISO Coal Generation Retirements (2011-2016)

Year	MISO Number of Units Retired	MISO Capacity (MW)	Total U.S. Number of Units Retired	Total U.S. Capacity (MW)	MISO Retirements as a % of US Total (%)
2011	28	1,207	233	28,775	12.0%
2012	32	1,268	311	36,917	10.3%
2013	44	2,440	368	43,275	12.0%
2014	47	2,392	389	46,087	12.1%
2015	52	2,311	485	61,123	10.7%
2016	69	4,936	540	70,037	12.8%

Source: U.S. Energy Information Administration.

Table 6 also shows that while these coal plant retirements are slowing, in total, they will continue to be considerable through the year 2025.

Table 6: Projected U.S. and MISO Coal Generation Retirements (2018-2025)

Year	MISO Number of of Units Retiring	MISO Capacity (MW)	Total U.S. Number of of Units Retiring	Total U.S. Capacity (MW)	MISO Retirements as a % of U.S. Total (%)
2018	5	909	31	12,457	16.1%
2019	5	359	9	1,584	55.6%
2020	3	190	9	1,698	33.3%
2021	2	138	7	1,496	28.6%
2022	1	682	9	1,901	11.1%
2023	2	490	2	490	100.0%
2024	1	90	1	90	100.0%
2025	2	835	4	1,840	50.0%

Source: U.S. Energy Information Administration.

However, coal generation is not the only set of baseload generation being threatened by the new zero capacity value paradigm. Nuclear power is increasingly being threatened for similar but differing reasons. Table 7 shows that several nuclear facilities that have announced retirement or are considered at risk for retirement with those shaded units representing the ones located in the MISO footprint.

Table 7: Announced and Anticipated Nuclear Generation Retirements

State	Owner	Plant Name	Unit No.	Summer Capacity (MW)	Announcement Year	Retirement Year	Age (Years)
NE	Omaha Public Power District	Fort Calhoun	1	478	2016	2016	43
NJ	Exelon	Oyster Creek	1	608	2018	2018	49
MA	Entergy	Pilgrim	1	678	2016	2019	47
PA	Exelon	Three Mile Island	1	803	2017	2019	45
NY	Entergy	Indian Point	2	1,299	2017	2020	58
NY	Entergy	Indian Point	3	1,012	2017	2021	59
MI	Entergy	Palisades	1	787	2017	2022	51
CA	Pacific Gas and Electric	Diablo Canyon	1	1,122	2018	2024	39
CA	Pacific Gas and Electric	Diablo Canyon	2	118	2018	2025	39
	Total			**6,905**			

Source: U.S. Energy Information Administration; and various trade press.

b. Worst case scenario still has a considerable solid fuel resource base

Participants in the MISO 2033 event recognize that while the role of traditional solid fuel resources is diminishing, these resources will not evaporate completely, but instead will continue to make a sizeable contribution to the overall resource mix, just at lower levels than in the past. Figure 27, for instance, shows three pie charts outlining MISO's past (2010), present (2016), and future (2020) generation fuel mix. In 2010, coal and nuclear generation comprised 45.2 percent and 7.1 percent, respectively, of MISO's overall fuel mix. The coal shares, in recent times, have fallen to 27.9 percent while nuclear has slightly risen to 8.4 percent, in the most recently-available information. In the future, those MISO fuel mix shares are anticipated to be at only slightly lower levels that today, falling to 21.5 percent and 7.6 percent for coal and nuclear, respectively.

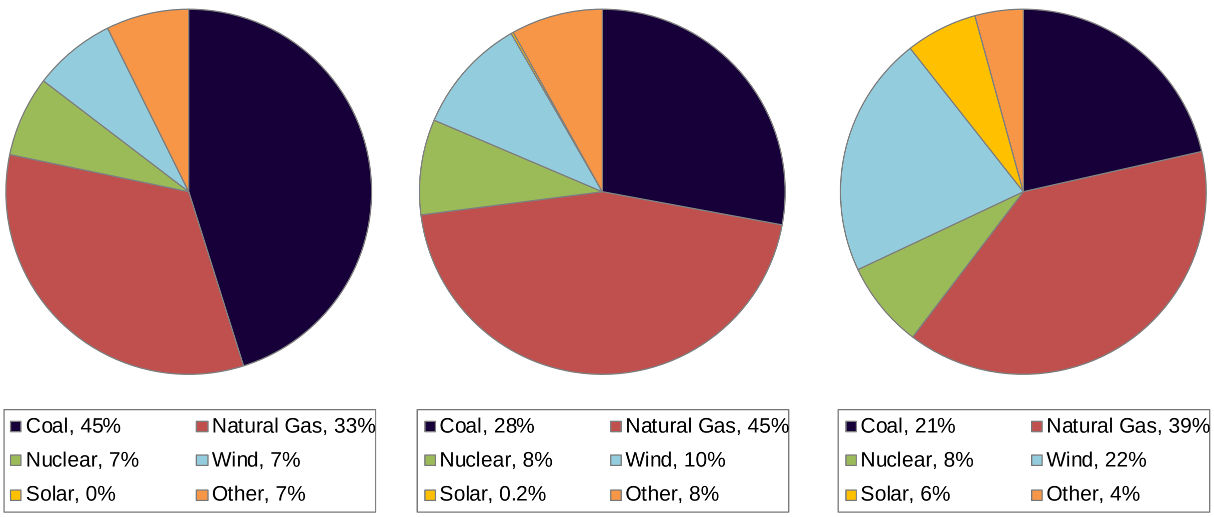

Figure 27: MISO Generation Fuel Mix (2010, 2016 and 2020)
Note: Percentages may not total to 100 due to rounding.
Source: U.S. Energy Information Administration.

So, while nuclear and coal resources will decrease as a share of total MISO generation capacity, each of these solid fuel resources will continue to make, individually and collectively, a major contribution to the overall MISO fuel mix and its generation diversity. Collectively, in 2020, both coal and nuclear will comprise more than 27.9 percent of the overall MISO fuel mix and, in absolute size will still maintain an impressive level of capacity at 42,950 MW, and 15,286 MW, respectively.

c. Solid fuel will need to be integrated and reconciled with the new capacity value realities

The utilization of solid fuel resources in MISO's longer-run planning process will become increasingly more difficult as the value of capacity continues to unwind, as it has over the last decade. MISO will continue to need to evaluate the role of these solid fuel resources into its long-run planning process for a number of reasons.

First, solid fuel resources provide MISO with important fuel diversity benefits that may become important in a world that becomes heavily dominated by natural gas. While there are large scale and abundant natural gas resources, having an additional resource base from which to generate electricity can provide benefits in times of deliverability and availability constraints. While these kinds of constraints do not happen as much as they have in the past, they can arise. Policy, and even markets, are having a difficult time recognizing these benefits. This difficulty however, should not be interpreted as a call for injecting a non-market based support mechanism that unnecessarily insulates these solid fuels, or any resource type for that matter, from fair and open market competition.

Second, solid fuel resources can provide capacity to MISO in average denominations that are far larger than other resource types. Consider that a typical coal plant in MISO has a capacity of 289 MW, while an average nuclear plant in MISO has a nameplate capacity of 917 MW. Compare this to a typical natural gas-fired generator in MISO of 78 MW or a wind farm that has an average capacity of 51 MW. These are capacity denominations that are far smaller than those arising from solid fuel resources.

Third, these solid fuel resource can provide important local economic development benefits, and this was a topic discussed at length during the MISO 2033 event. These solid fuel resources can be important local employers, hiring a large work force that is usually paid considerably higher-than-average wages and higher-than-average benefits. Further, these resources, given their capital-intensity, usually are the source of considerable local property taxes and other local governmental revenues. All told, these resources can play an important role, particularly at the local level, for economic development.

8. <u>Distributed energy resources are become more pervasive</u>

a. Factors stimulating distributed generation growth

The growth of distributed generation, or distributed energy resources ("DER"), over the past several years, particularly the growth of behind-the-meter solar generation growth, has been considerable. This has been particularly true in the MISO footprint. Figure 28 provides a map showing this rapid growth, as it applies to states that allow net energy metering ("NEM") for behind-the-meter systems. Several MISO states, such as Louisiana, parts of Texas, and Missouri have seen growth of these system that are over a ten-fold increase. Several other states, such as Wisconsin, Arkansas and Iowa have seen equally impressive percentage growth.

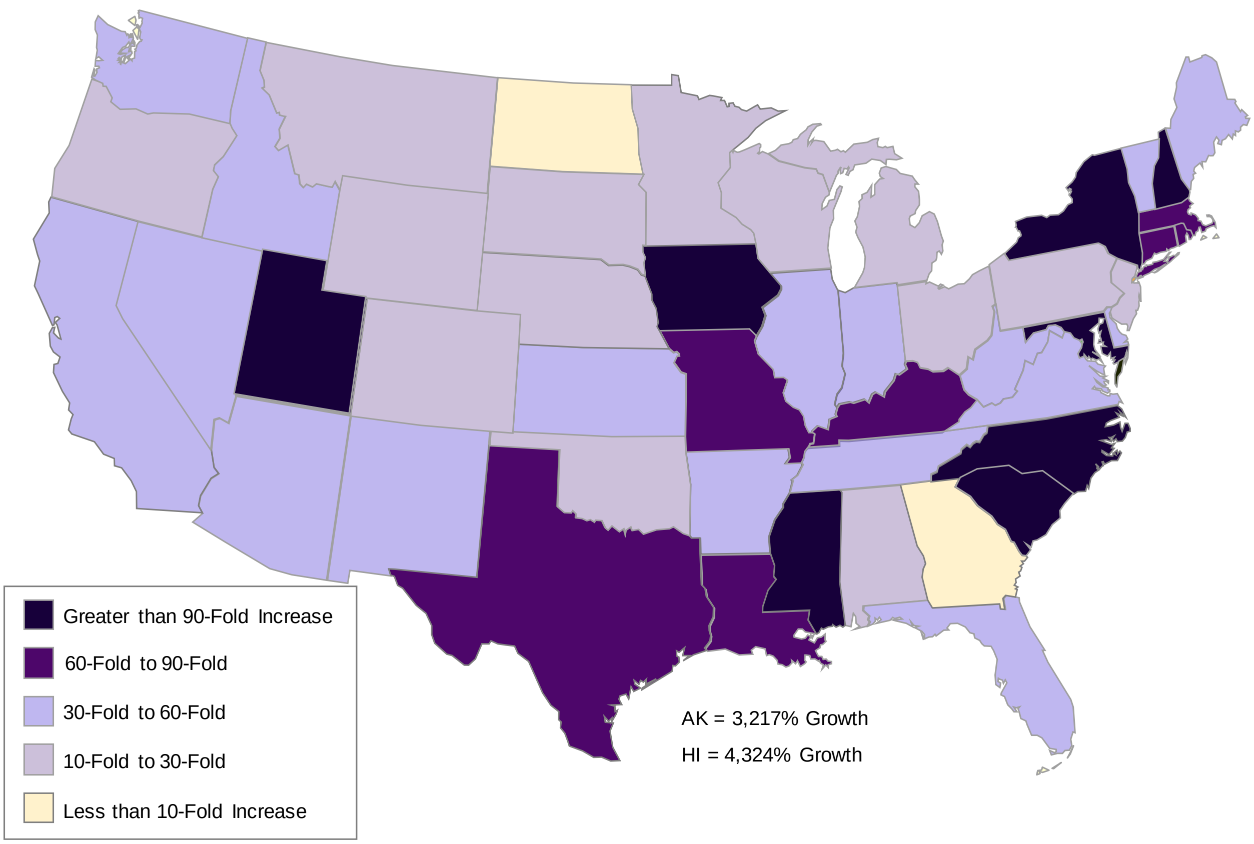

Figure 28: U.S. Net Metering Capacity Growth (2013-2017)
Source: U.S. Energy Information Administration.

The motivations for this DER growth are multi-faceted and similar, in many ways, to the factors impacting RE capacity growth overall. For instance, tax policies, government rebates and subsidies, and other set-asides like solar preferences within state RPS requirements, all represent considerable incentives for DER development, and solar development in particular. For some states, like Louisiana, there were several years between 2008 and 2015 where solar DER installations received both a 50 percent state tax credit and a 30 percent investment tax credit ("ITC"), thereby reducing the overall installed cost of solar installation by 80 percent.

Market forces over the past decade, however, have also provided considerable motivation for DER installations, particularly solar. The past several years have seen declines in the installed cost of solar installations. For instance, the installed cost for a typical residential system in 2011 was $6,340 per kW, but by 2016, had fallen below $3,000 per kW. Most types of solar installations (residential, commercial, grid connected) have seen installed cost decreases by over 50 percent over the past eight years. Figure 29 shows those trends and how these installed costs have fallen, particularly for larger, grid-connected projects, over the past several years.

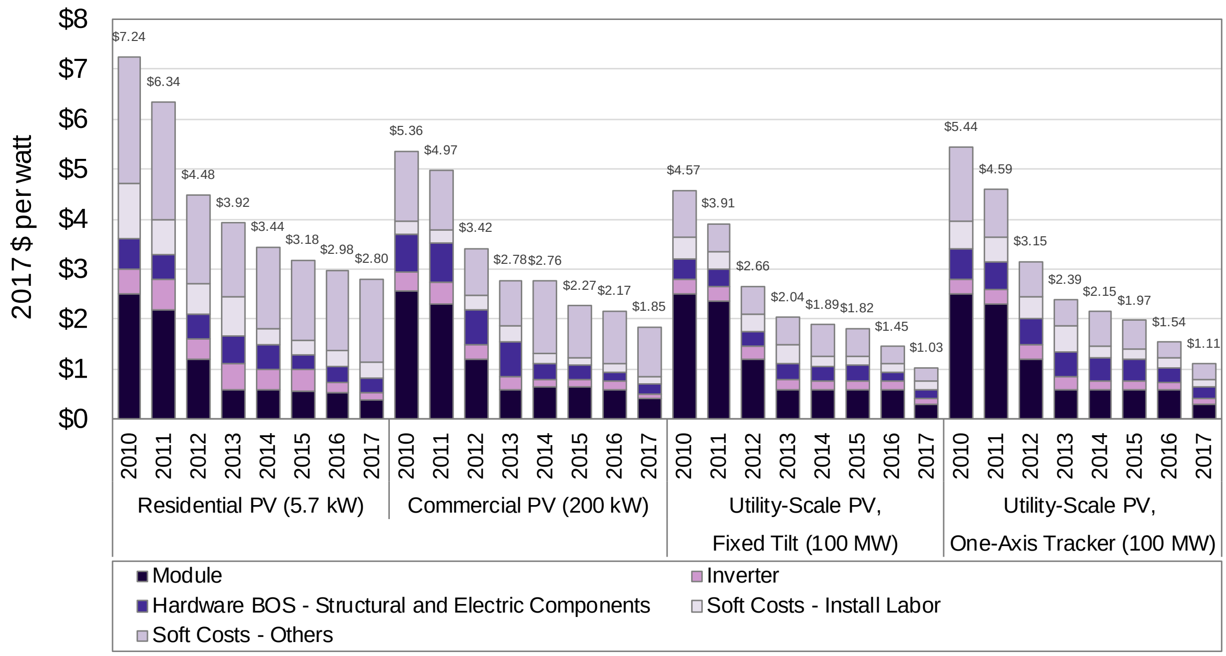

Figure 29: Trends in Installed Solar Generation Costs (2010-2017)
Source: Fu, Ran et. al. (September 2017), U.S. Solar Photovoltaic System Cost Benchmark: Q1 2017, U.S. Department of Energy National Renewable Energy Laboratory, Figure ES-1.

While solar growth has been considerable, the current capacity level for all types of solar in the MISO footprint is still somewhat moderate, at least as compared with many other regions of the country that have pursued more aggressive solar energy policies. Table 8 includes all solar capacity developed between 2012 and 2016 including grid connected and NEM installations.

Table 8: MISO Solar Capacity (2012-2016)

	Total Solar Capacity 2012	2013	2014	2015	2016	Cumulative Growth Rate (%)
	------(MW)------					
MISO States						
Louisiana	-	46.6	82.9	111.8	126.7	172%
Mississippi	-	0.1	0.1	0.1	1.4	1455%
Arkansas	-	2.1	2.4	2.8	3.4	60%
Missouri	7.2	19.7	50.0	55.6	57.3	700%
Illinois	2.4	3.1	4.7	7.1	9.9	320%
Indiana	4.4	52.2	93.7	136.5	155.4	3472%
Iowa	1.6	5.8	20.0	29.8	43.2	2602%
Minnesota	8.1	12.9	19.0	29.2	184.3	2173%
Wisconsin	7.0	10.3	14.7	18.6	30.4	335%
Michigan	8.6	10.9	13.7	18.7	29.8	247%
North Dakota	0.2	0.2	0.3	0.2	0.3	-
South Dakota	0.0	0.0	0.0	0.0	1.0	-
Montana	-	-	-	-	-	-
Kentucky	-	0.0	0.1	0.2	0.4	-
Texas	-	0.9	0.9	1.2	2.3	165%
US Total	**4,237.3**	**5,775.8**	**7,894.9**	**10,727.8**	**13,790.4**	**225%**
MISO States as Share of Total US	**0.9%**	**2.9%**	**3.8%**	**3.8%**	**4.7%**	

Source: U.S. Energy Information Administration.

Table 9 provides similar information on solar installations but is limited to just distributed, behind-the-meter solar installations that are net metered. The table shows that on average, MISO states collectively only account for 2.2 percent of all U.S. solar NEM installations. Iowa, Mississippi and Missouri however, have seen considerable percentage growth in solar NEM installations between 2012 and 2016 at 2,439 percent, 1,455 percent and 686 percent, respectively.

Table 9: MISO Solar NEM Capacity (2012-2016)

	Total Solar Capacity					Cumulative Growth Rate
	2012	2013	2014	2015	2016	
	(MW)					(%)
MISO States						
Louisiana	-	46.6	82.9	111.8	126.7	172%
Mississippi	-	0.1	0.1	0.1	1.4	1455%
Arkansas	-	2.1	2.4	2.8	3.4	60%
Missouri	7.2	19.7	50.0	54.6	56.3	686%
Illinois	2.4	3.1	4.7	5.9	8.7	270%
Indiana	0.9	3.0	4.7	9.0	12.1	1320%
Iowa	1.6	5.8	20.0	29.8	40.6	2439%
Minnesota	8.1	11.2	17.3	25.2	36.9	355%
Wisconsin	7.0	10.3	13.7	17.6	27.3	290%
Michigan	8.6	10.9	13.7	16.7	21.9	155%
North Dakota	0.2	0.2	0.3	0.2	0.3	-
South Dakota	0.0	0.0	0.0	0.0	0.0	-
Montana	-	-	-	-	-	-
Kentucky	-	0.0	0.1	0.2	0.4	404%
Texas	-	0.9	0.9	1.2	2.3	165%
US Total	**4,231.8**	**5,724.9**	**7,803.2**	**10,591.1**	**13,482.9**	**219%**
MISO States as Share of Total US	**0.8%**	**2.0%**	**2.7%**	**2.6%**	**2.5%**	

Source: U.S. Energy Information Administration.

b. DER outlook and transmission planning

The anticipated growth of all types of solar, both behind-the-meter and grid connected, will lead to considerable transmission infrastructure planning challenges. Figure 30 provides the most recent outlook for U.S. solar installations as estimated by the solar industry's primary trade association, the Solar Energy Industries Association ("SEIA"). This forecast shows slower, yet considerable growth in solar capacity development across all segment types: residential; commercial; and utility (grid-connected).

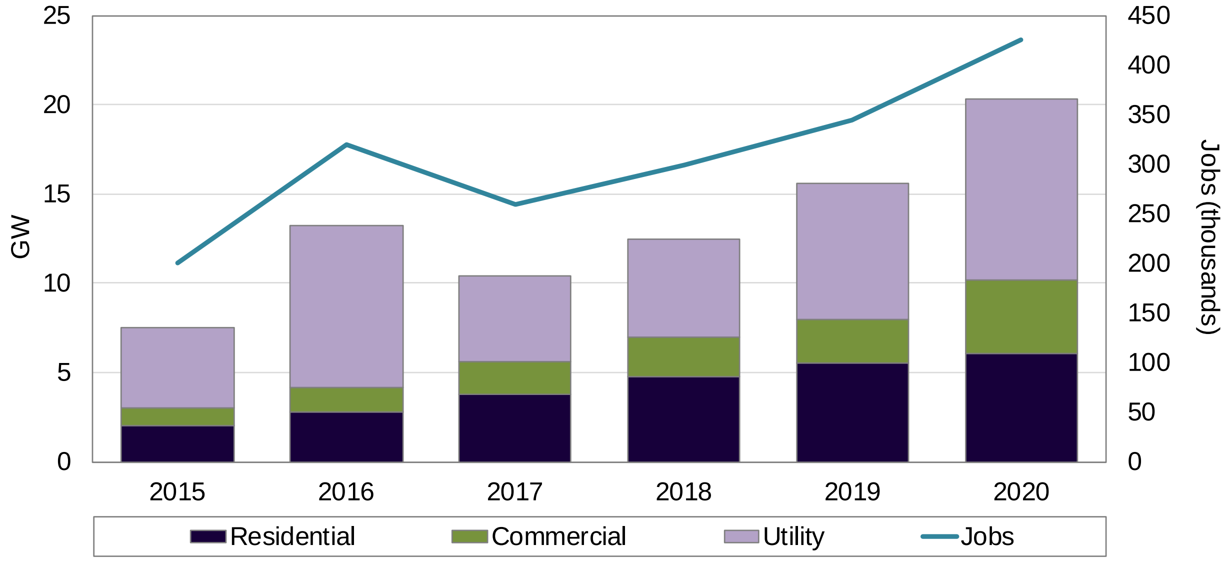

Figure 30: Forecast U.S. Solar Capacity by Market Segment (2015-2020)
Source: Solar Energy Industries Association.

Currently, solar capacity development is dominated by grid-scale projects (60%) followed by residential installations (26.7%), and then commercial installations (13.3%). SEIA estimates the installation share across market segments will increasingly shift away from grid-scale applications towards more distributed residential and commercial applications. Figure 31 combines the information provided earlier in Figure 30 and Table 9 to develop a projection of potential solar installations in MISO given current SEIA national projections. This projection simply assumes that current levels of MISO solar capacity will grow by the same percentages, across the same market segments, as those projected on a national basis by SEIA.

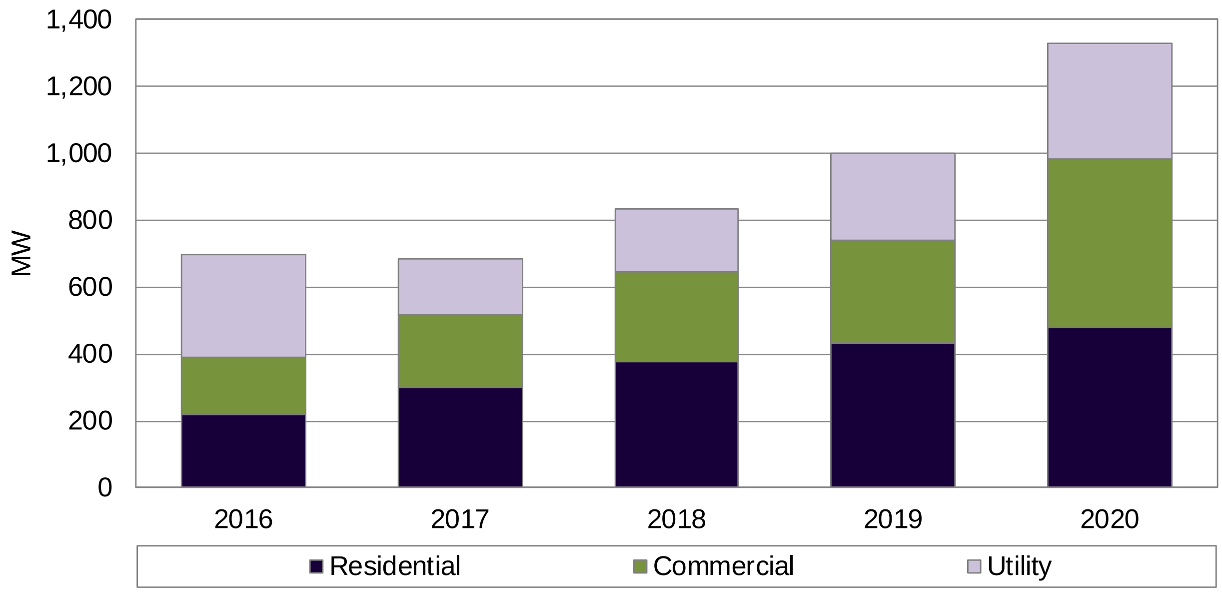

Figure 31: MISO-Based Projection, Solar Capacity by Market Segment (2016-2020)
Source: Solar Energy Industries Association, Author's construct.

Assuming MISO follows national trends, it could see solar capacity growth move from current moderate levels of capacity development toward a level that requires special transmission planning attention. Region-wide, MISO could see as much as 3,846 MW of new solar capacity by 2020, with 1,589 MW being associated with residential installations, 1,300 MW being associated commercial installations, and 957 MW being allocated to grid-scale projects.

One potential test of the projection outlined above would be to simply evaluate the solar installations that are already in the MISO interconnection queue which, as shown in Table 10, are considerable. As of year-end 2017, the MISO interconnection queue has as much as 14,025 MW of capacity requesting interconnection. Most of that capacity (86 percent) is anticipated to be on-line by 2020, at least for the capacity that provided commercial operation date information. Likewise, the average capacity of those proposed facilities seeking interconnection is 122 MW.

Table 10: MISO Solar Interconnection Requests

Installation Year	Less than 20 MW	20-50 MW	50-100 MW	More than 100 MW	Total	Share of Total (%)
	---------- (Number of Interconnection Requests) ----------					
2018	0	2	7	2	**11**	**10%**
2019	1	12	19	20	**52**	**45%**
2020	0	4	15	20	**39**	**34%**
2021	0	0	7	6	**13**	**11%**
Total	**1**	**18**	**48**	**48**	**115**	**100%**
Share of Total (%)	**1%**	**16%**	**42%**	**42%**	**100%**	

Source: MISO Interconnection Queue.

c. Other considerations

While policy, incentives, and decreasing costs are important in stimulating solar development, participants at the MISO 2033 event clearly recognized that a large part of this interest, particularly for behind the meter installations, is being motivated by customers' desire to control their own electricity decisions. This is particularly true for residential customers taking advantage of state NEM programs.

However, NEM is not without its share of controversy, motivated in large part by the considerable increase in behind-the-meter solar installations and capacities. Over the past several years, many states have begun to re-assess their NEM policies and retail rate structures in response to rapid behind-the-meter generation growth and the concerns this growth has created regarding cross-subsidization and lost base revenues. One of the particularly contentious issues surrounding these NEM tariff and rule modifications has been on how to value behind-the-meter generation (primarily solar generation) that is put to the distribution grid.

Historically, most NEM generation has been valued at full retail rates primarily due to what was considered administrative ease in an era when NEM installations were few and far between. Today, what started as administrative ease is now seen by many as a regulatory burden since policies valuing NEM at full retail rates effectively reimburse a generation-only product at a vertically-integrated utility cost. This has led some state regulators to the conclusion that a different set of price signals needs to be utilized to reimburse this NEM generation. These price signals need to be more accurate and consistent with the opportunity cost of the behind-the-meter generation being put to the grid.

Participants at the MISO 2033 event noted that this valuation challenge could be ameliorated, at least in part, through the MISO longer run planning process and through continued development of institutions and markets that can send signals about the value of a variety of electricity products being offered across a variety of geographical areas, for various durations, by a differing set of market participants. Further, MISO's planning process can reveal the "upstream" implications of "downstream" solar installations for regulatory purposes. This includes providing education and information about the benefits and cost of distributed generation on the transmission system and longer-term transmission infrastructure investment.

9. <u>Customers Issues: Usage, Prices and Empowerment</u>

a. Customer issues

Customer interests in greener and more advanced technologies are growing in importance. However, the MISO 2033 event clearly underscored the fact that, despite an expanding set of customer interests into issues like renewables and resiliency, the top three customer concerns continue to be the "old-fashioned" ones of cost, reliability and market transparency. The MISO 2033 event included a roundtable discussion focused exclusively on customer issues comprised of residential, commercial, and industrial representatives. The discussion of costs, and how those costs are passed down from the transmission level to retail, was of predominate concern. As noted earlier, one of the unique aspects of the MISO footprint is the predominance of member states that continue to be vertically-integrated and have not adopted retail choice policies. LSEs operating in these states pass along the costs of their transmission infrastructure investments directly to customers through their various state-level ratemaking processes. Thus, changes in transmission costs, other things being equal, can have a direct implication on retail electricity rates.

MISO member states are fortunate in that most have relatively affordable retail electricity rates. For instance, Figure 32 shows that the central part of the U.S., the area predominantly served by MISO, as well as the SPP, have some of the lowest retail electricity rates in the U.S. Overall, in 2017, the MISO region averaged $0.0959 per kWh for total retail electric service. Those average rates are estimated to $0.1003 per kWh for MISO North while they are $0.084 for the MISO South states. Another interesting fact about rates in the MISO footprint is that the variation in rates, from the highest cost, to lowest cost, in member states is relatively low, particularly compared to other RTOs in the mid-Atlantic or northeastern part of the U.S.

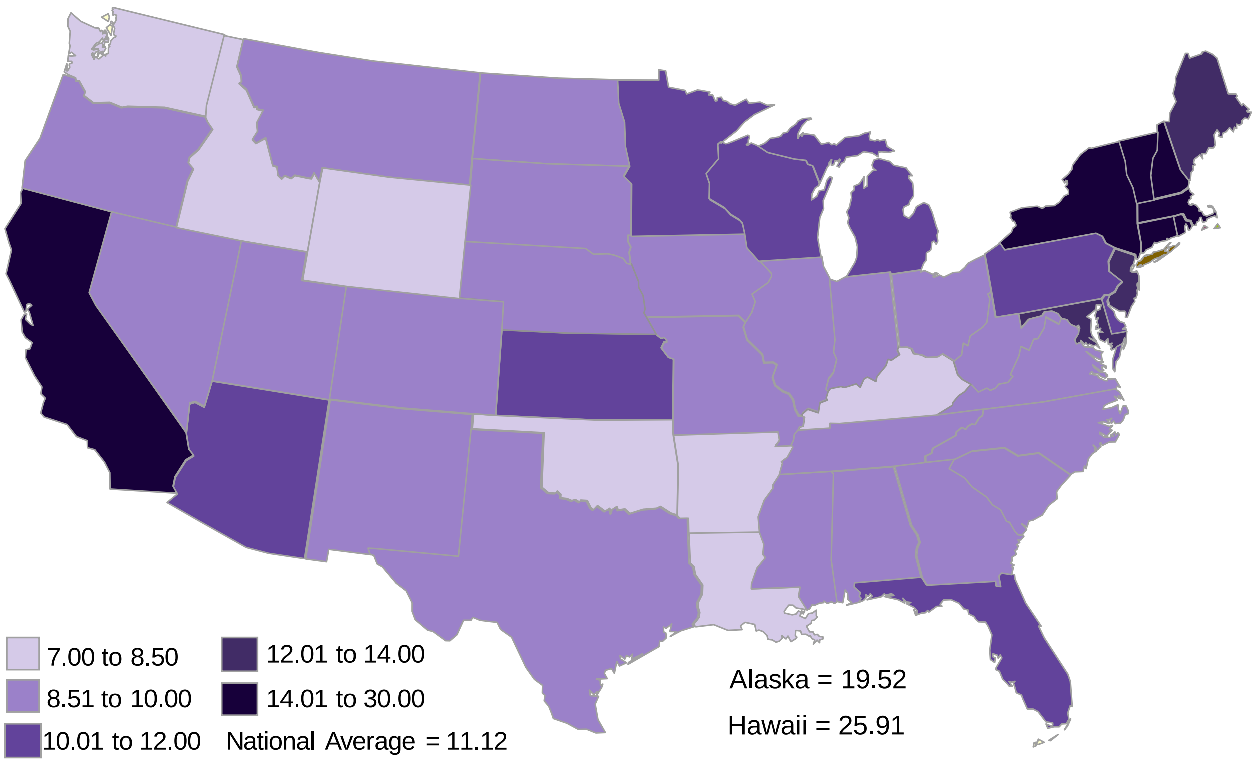

Figure 32: U.S. Estimated Electricity Rates (Retail Revenue cents per kWh)
Source: U.S. Energy Information Administration.

The competitiveness of the region's electricity rates, however, should not over shadow the fact that many consumer groups, particularly those closely engaged in the ratemaking process, have expressed concerns about the ever-increasing utility transmission investments, many of which reflect investments or allocation of investments, associated with MISO-related upgrades. Table 11 for instance, shows the changes in net transmission plant in service on a per customer basis for MISO's IOU members. These investment trends are compared on a per customer basis and over a comparable time period to show why the acceleration of these costs are becoming so important to many consumer groups.

Table 11: Net Transmission and Distribution Plant in Service per Customer (MISO IOUs)

Net Transmission Plant per Customer

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
	($/Customer)									
Ameren Illinois Company				$ 719	$ 772	$ 838	$ 989	$ 1,187	$ 1,445	$ 1,717
Cleco Power, LLC	857	950	962	1,058	1,290	1,426	1,656	1,692	1,814	1,992
Duke Energy Indiana, LLC	689	712	775	812	871	957	1,084	1,221	1,264	1,354
Entergy Arkansas, Inc.	1,034	1,116	1,173	1,215	1,381	1,542	1,637	1,767	1,886	2,293
Entergy Louisiana, LLC	845	1,222	1,367	1,401	1,568	1,701	1,837	2,005	1,572	2,412
Entergy Mississippi, Inc.	1,062	1,107	1,128	1,158	1,274	1,465	1,632	1,677	1,735	1,937
Entergy New Orleans, Inc.	167	165	205	171	171	214	216	302	445	475
Entergy Texas, Inc.		1,941	1,976	2,019	2,134	2,180	2,236	2,296	2,357	2,854
Indianapolis Power & Light Company	193	183	185	250	249	270	284	306	355	522
MidAmerican Energy Company	518	561	629	723	771	1,142	1,173	1,275	1,479	2,018
Northern Indiana Public Service Company	938	793	882	947	987	1,012	1,066	1,161	1,250	1,311
Northern States Power Company (Minnesota)	699	807	881	965	1,051	1,145	1,236	1,613	1,929	2,041
Northern States Power Company (Wisconsin)	851	977	1,013	1,240	1,444	1,682	1,926	2,262	3,164	3,414
Northwestern Wisconsin Electric Company	615	665	741	854	860	887	1,044	1,076	1,109	1,115
Otter Tail Power Company	878	1,027	1,069	1,083	1,169	1,414	1,480	1,881	2,398	2,531
Superior Water, Light and Power Company	301	358	371	371	372	384	405	407	790	951
Union Electric Company	311	357	370	407	459	470	526	629	648	787
MISO Average	**$ 664**	**$ 809**	**$ 858**	**$ 906**	**$ 990**	**$ 1,102**	**$ 1,202**	**$ 1,339**	**$ 1,508**	**$ 1,748**

Net Distribution Plant per Customer

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
	($/Customer)									
Ameren Illinois Company				$ 3,756	$ 3,835	$ 3,962	$ 4,120	$ 4,309	$ 4,592	$ 4,824
Cleco Power, LLC	1,952	2,072	2,338	2,498	2,743	2,920	3,129	3,287	3,469	3,643
Duke Energy Indiana, LLC	1,534	1,630	1,749	1,815	1,870	1,984	2,101	2,201	2,348	2,482
Entergy Arkansas, Inc.	2,076	2,185	2,310	2,382	2,556	2,700	2,895	3,113	3,277	3,534
Entergy Louisiana, LLC	1,733	2,493	2,791	2,697	2,817	3,063	3,083	3,202	2,408	3,416
Entergy Mississippi, Inc.	2,109	2,219	2,387	2,526	2,677	2,870	3,029	3,192	3,360	3,563
Entergy New Orleans, Inc.	2,024	1,973	1,995	2,049	2,056	2,251	2,311	2,457	2,760	2,655
Entergy Texas, Inc.		2,848	2,926	3,018	3,141	3,250	3,426	3,559	3,674	3,856
Indianapolis Power & Light Company	718	803	869	920	994	1,052	1,117	1,191	1,280	1,395
MidAmerican Energy Company	1,631	1,800	1,858	1,854	1,973	1,745	1,869	2,017	2,152	2,281
Northern Indiana Public Service Company	1,292	1,621	1,689	1,775	1,852	1,965	2,075	2,206	2,368	2,594
Northern States Power Company (Minnesota)	1,264	1,318	1,368	1,447	1,508	1,545	1,638	1,736	1,817	1,932
Northern States Power Company (Wisconsin)	1,167	1,245	1,324	1,443	1,654	1,788	1,907	2,078	2,232	2,380
Northwestern Wisconsin Electric Company	1,365	1,469	1,566	1,634	1,749	1,889	1,991	2,067	2,137	2,219
Otter Tail Power Company	1,445	1,593	1,717	1,837	1,970	2,083	2,201	2,323	2,416	2,517
Superior Water, Light and Power Company	871	1,253	1,293	1,347	1,406	1,457	1,632	1,712	1,733	1,860
Union Electric Company	1,713	1,880	2,136	2,275	2,402	2,573	2,714	2,877	3,017	3,219
MISO Average	**$ 1,526**	**$ 1,775**	**$ 1,895**	**$ 2,075**	**$ 2,188**	**$ 2,300**	**$ 2,426**	**$ 2,560**	**$ 2,649**	**$ 2,845**

Source: FERC Form 1s.

b. MISO Cost Allocation Practices

MISO's current cost allocation procedures vary by infrastructure project type, but in general, the costs are allocated across local resource zones and throughout the MISO footprint. For instance, the allocation of costs associated with a high voltage market efficiency projects that have a voltage rating of 345 kV and above, are typically based on a split of 80 percent to local resource zones (based on benefit of the project), and 20 percent to the remaining loads flowing throughout the footprint.

Transmission upgrades associated with individual generator interconnection requests are primarily paid for by the interconnecting generator, except for investments made on projects of voltage ratings of 345 kV and larger. The costs of these larger transmission infrastructure projects are allocated 90 percent to the interconnecting generator, with the balance (10 percent) allocated to the remaining loads in the system.

MISO also makes transmission infrastructure investments that are referred to as "multi-value projects" (or "MVPs"). While these MVPs can be limited to a fixed geographic area, they are typically designed to provide widespread benefits across the MISO footprint and not just in the geographic area in which they are located. Since these MVPs have widespread benefits, their costs are allocated across the system as a whole (across all loads) and not just to an individual local resource zone.

Likewise, MISO makes "baseline reliability projects" that are defined as those projects that are used to ensure that its transmission system is in compliance with NERC reliability standards, Regional Entities reliability standards, and Local Transmission Owner planning criteria[19]. MISO allocates the investment costs associated with these baseline reliability projects entirely to the local resources zones in which they are located.

A "transmission service delivery project" generally originates with a transmission customer and not MISO or a transmission owner. Ultimately, the investment costs

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[19] MTEP17, MISO Transmission Expansion Plan.

associated with of these types of projects are paid for by the customer or rolled-into local pricing zone rates. Likewise, “participant-funded projects” originate with the requestor and are entirely paid for by that customer; they are not included in the zonal rates nor the rate base of the transmission owner.

Lastly, transmission infrastructure projects that do not fit into one of the above categories are referred to as “other projects” and are recovered from the local pricing zone. Some examples of these “other projects” include those associated with reliability issues, economic benefits, public policy initiatives, or projects that are not a part of the bulk electric system under MISO functional control[20].

c. Stakeholder Cost Allocation Issues

The MISO 2033 event addressed and underscored the need for “bold visions” in setting transmission infrastructure plans for the future. However, bold visions, particularly those for the future, come with risk and ramifications that are not easily undone if the future does not play out in an expected manner. Many participants at the MISO 2033 discussed the risks and potential conflicts between “bold visions” and what could be characterized as “playing it safe.” The inherent implications for the cost of providing transmission service to the region’s customers, was perhaps one of the more, if not the most pervasive at the MISO 2033 event.

A particular concern expressed by several regulators participating in the MISO 2033 event, was that taking “bold” transmission planning “visions” could lead to proverbial “bridges to nowhere.” While advanced planning was recognized as being important, the

[20] MTEP17, MISO Transmission Expansion Plan.

risk associated with this planning, particularly given the potential dollars involved in large MVP-type projects, is sobering and can lead to pause in such initiatives. No firm solutions to this challenge were offered at the MISO 2033 event other than underscoring the need for a vigorous and robust planning process that actively engaged all stakeholders in a transparent fashion that afforded ample time for stakeholder analysis, comment, and feedback.

The other challenge raised in the discussion on “bold planning visions” was that of cost allocation. These cost allocation issues can often represent a prodigious bugaboo in the planning and development of large infrastructure projects which are often characterized by difficult to assign public benefits. For instance, transmission infrastructure investments, whether associated with upgrades or the development of new facilities, that are designed to move electricity from remotely-sourced renewable generation to more centralized load centers, tend to provide a variety of regional, not necessarily localized benefits. This suggests that the investment cost of such projects should be allocated on a regional or system-wide basis, not a localized basis.

Further, the wide-spread allocation of these investment costs often takes on the somewhat pejorative moniker of being “socialized” which, in turn, can raise issues about longer term capital investment, pricing efficiencies, and even equity considerations. An example for instance, was raised regarding recent transmission investment requirements for Otter Tail Power. Discussants noted that Otter Tail was being forced to make considerable localized transmission investments to facilitate RE capacity development that was being utilized far outside its local resource area requirements.

The “socialized” nature of certain types of transmission infrastructure investments also raises several public policy issues relative to transmission siting and local economic development. For instance, some state siting statutes require that the adjudicating authority reviewing any transmission siting request assure that there are clear local benefits that outweigh local costs. As noted earlier, it can increasingly be the case in today’s growing transmission system that many localized transmission infrastructure projects, particularly those designed to alleviate congestion in other parts of the grid (like MISO’s MVPs), can have system-related benefits that span beyond state boundaries which could be deemed potentially ineligible (or can be more difficult to incorporate) in any strictly-interpreted state-specific siting review.

This same type of transmission planning/investment issue can also have implications for state or local economic development since some types of localized transmission infrastructure investments made in one location may, unintentionally, transport a considerable amount of economic development benefits to other regions. Consider as a hypothetical, a localized transmission system upgrade made in one state that alleviates transmission congestion in another state, and in alleviating this congestion, opens up a large RE investment opportunity that would otherwise be unavailable, but-for this localized transmission investment. In this case, the localized transmission investment made in one state potentially skews the location in which the investment is made, and in doing so, potentially skews the direction of regional economic development.

Again, while these problems seem quite problematic and difficult, there are solutions and many of those were discussed during various panel discussions at the MISO 2033 event. The predominant solution was: (a) ensuring a transparent and open transmission infrastructure planning process; and (b) educating stakeholders about the various constraints, options and alternatives associated with various transmission infrastructure options. What became clear in this discussion is that part of this education process should including making clear, to a wide range of stakeholders, the results of planning and post-development cost-benefits ratios regarding large and multi-regional (multi-value) projects.

d. Education and Communication regarding Transmission Infrastructure Benefits

Retail customers, and entities representing these customers such as consumer counsels, trade, and user associations, have been increasingly concerned about the rapid increase in transmission-related costs and how those are entering retail rates. What often goes unnoticed however, is that these increases in transmission investment represent a "cost" which must be compared to the "benefit" of securing more efficient electricity from wholesale power. While the transmission investment "cost" is often seen by many consumers, the wholesale benefits and how those are translated into lower bills, is often not as easily identified.

Figure 33 summarizes the "all-in price" of wholesale electricity that is calculated as the load-weighted average real-time energy price plus capacity, ancillary services, and real-time uplift cost per MWh of real-time load in the region. Figure 33 also charts this all-in price against natural gas prices as measured at the Chicago Citygate. As is expected, electricity prices in the MISO footprint are heavily correlated with wholesale natural gas prices so as natural gas prices have fallen, so too have wholesale electricity prices. However, while 2015 prices have fallen relative to 2014 prices, 2016 all-in wholesale prices are up somewhat given increases primary in the cost of capacity over the better part of last year.

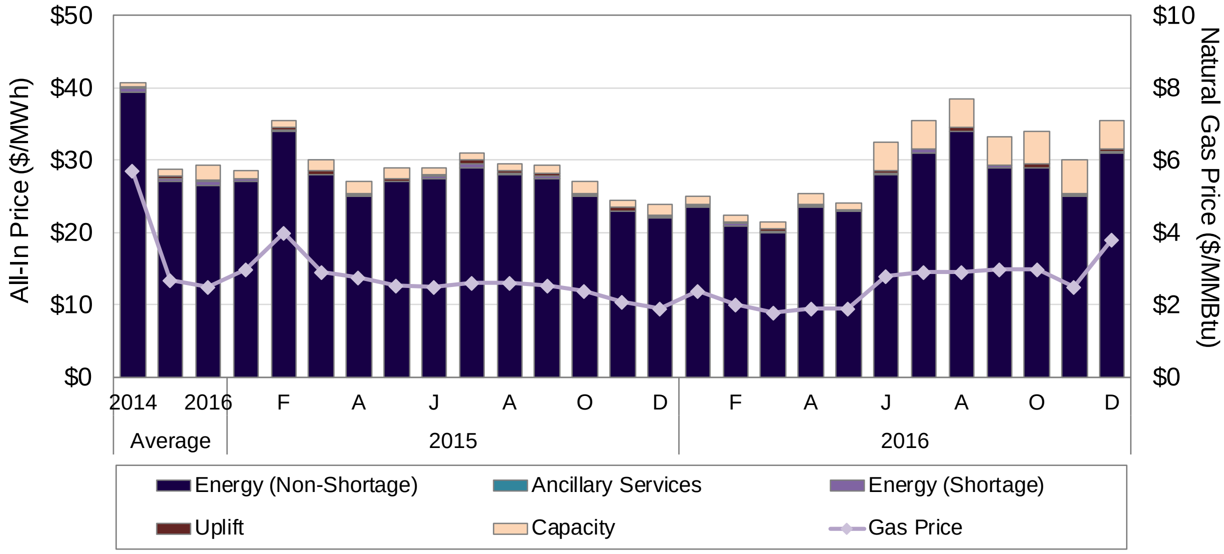


Figure 33: MISO "All-In" Wholesale Electricity Price vs. Natural Gas Price
Source: Potomac Economics, 2016 State of the Market Report for the MISO Electricity Markets.

While Figure 33 presents a generally positive outcome for MISO customers (i.e., generally lower wholesale rates) there are other benefits, such as a reduction in price volatility, that should be considered as well. Figure 34, for instance, presents a price duration curve for 2014 through 2016. This curve shows the percentage of time in which wholesale prices (presented in terms of locational marginal prices, or "LMPs"), are above certain fixed levels; in this instance, about $200 per MWh, above $100 per MWh and in instances when prices are negative (below $0 per MWh). The chart and inset tables show significant benefits across all the major MISO hubs with the share of prices being above an extreme level (such as $200 per MWh) falling every year, and in some instances, dramatically from 2014 to 2016. The one exception is Louisiana, which registered a slight increase in prices that reached extreme levels ($200 per MWh) but was still decreasing in the moderately high price rate (those about $100 per MWh).

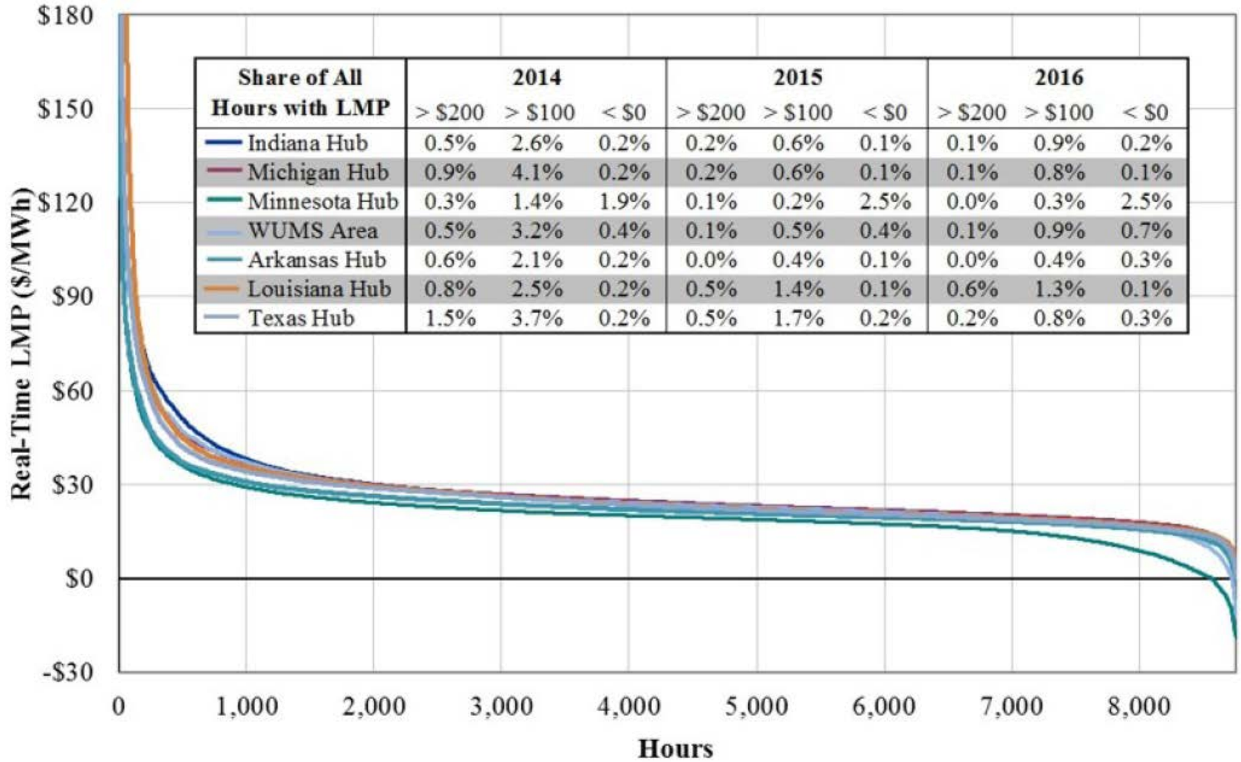


Figure 34: MISO Real-Time Energy Price-Duration Curve (2014-2016)
Source: 2016 State of the Market Report for the MISO Electricity Markets, Analytic Appendix

The improvement in MISO wholesale price volatility compares well to other similar RTOs. Figure 35, for instance, presents the fifteen-minute average price change in real-time markets in 2016 and shows that:

- MISO's wholesale price volatility is relatively and consistently low across all of its hubs as compared to other RTOs.
- MISO's wholesale price volatility is relatively stable as compared with 2015 prices across the same hubs and as compared to other RTOs and their respective hub prices.
- Price volatility is relatively consistent across all MISO hubs and does not vary like, for instance, the pricing variability across hubs that is observed in NYISO.

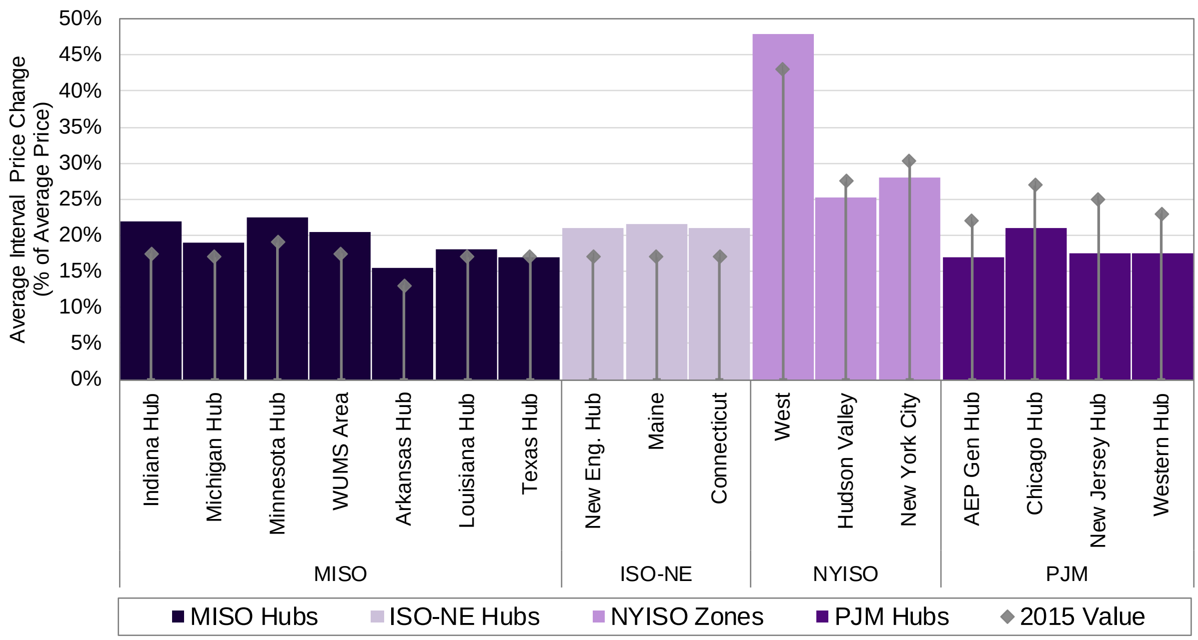


Figure 35: Comparison of RTO Pricing Volatility
(2015-2016, Fifteen-Minute Real-Time Price Variation)

Source: Potomac Economics, 2016 State of the Market Report for the MISO Electricity Markets, Analytic Appendix.

MISO's relatively low prices and low pricing volatility, however, should not be interpreted as recommendation to ignore current and emerging transmission congestion issues, or that somehow, these issues have gone away. Over the past several years, MISO has seen a gradual up-tick in congestion which suggests additional value, and customer benefits, from improving transmission capabilities both within MISO and MISO's interconnections with other RTOs.

Figure 36 presents the value of real-time congestion in MISO power markets on an annual basis from 2014 to 2016, and then monthly for 2015 and 2016. Overall, the value of congestion in MISO in both 2015 and 2016 is down considerably from 2014 levels. This reduction has occurred across all three planning areas (north, central, south), with particularly strong reductions in the north and central areas.

Transfer constraints between neighboring markets adjacent to MISO also fell considerably from 2014 to 2015, and again from 2015 to 2016. Part of this price decrease can be attributed to a recent (January 2016) agreement between MISO and SPP that allowed MISO to capture substantial dispatch savings in balancing across the two systems[21]. While the value of congestion was slightly up in 2016 (4.3 percent), it was still down considerably from 2014 levels (42 percent reduction). Overall congestion revenues were lower in 2016 and there was a surplus in firm transmission rights ("FTRs") in 2016 as well.

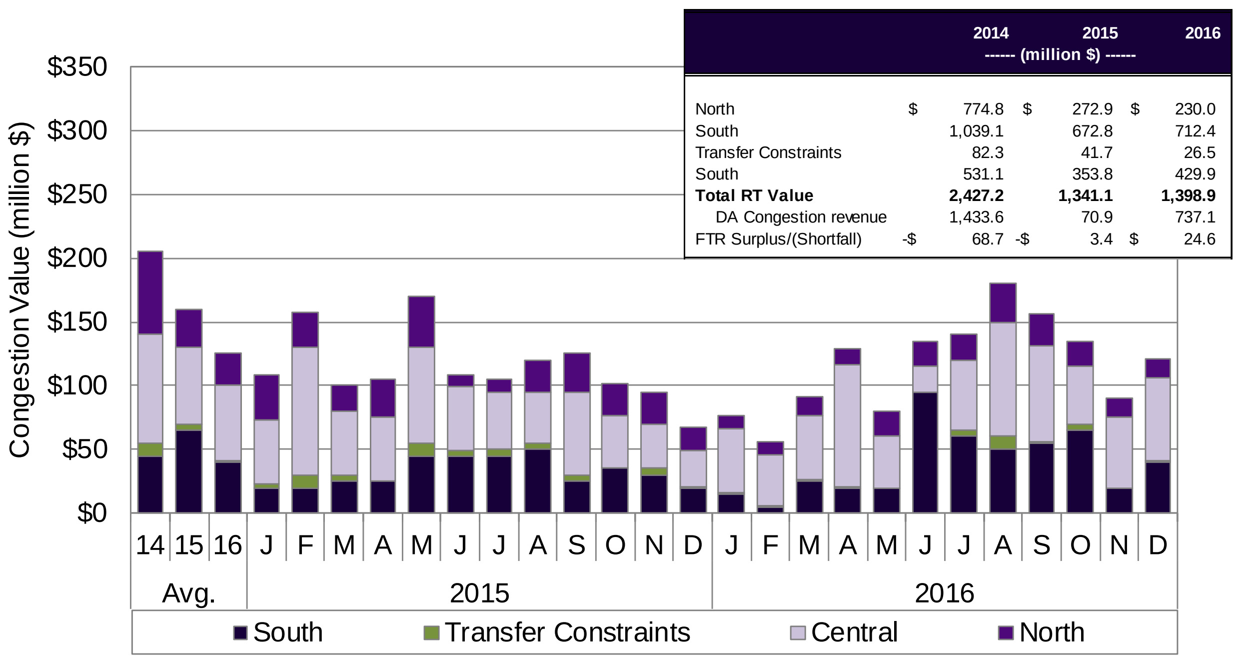


Figure 36: MISO Real Time Congestion Value (2014-2016)
Source: Potomac Economics, 2016 State of the Market Report for the MISO Electricity Markets, Analytic Appendix.

[21] Docket No. ER 16-65-000, Federal Energy Regulatory Commission Order Accepting Tariff Revisions, Subject to Condition (Issued January 21, 2016).

Figure 37 presents the value of real-time congestion by type of market constraint for both MISO North and MISO South. Market constraints in this analysis are divided into two categories, internal and market-to-market. Internal market constraints are constraints set by MISO as the reliability coordinator for the MISO footprint. Market-to-market constraints are those associated with energy transfers from MISO to neighboring markets such as SPP or PJM. Figure 37 shows that, while the price of transmission constraints has fallen since early 2014 for both MISO North and MISO South, the last few quarters of 2016 saw increased congestion costs in the footprint, especially in MISO South.

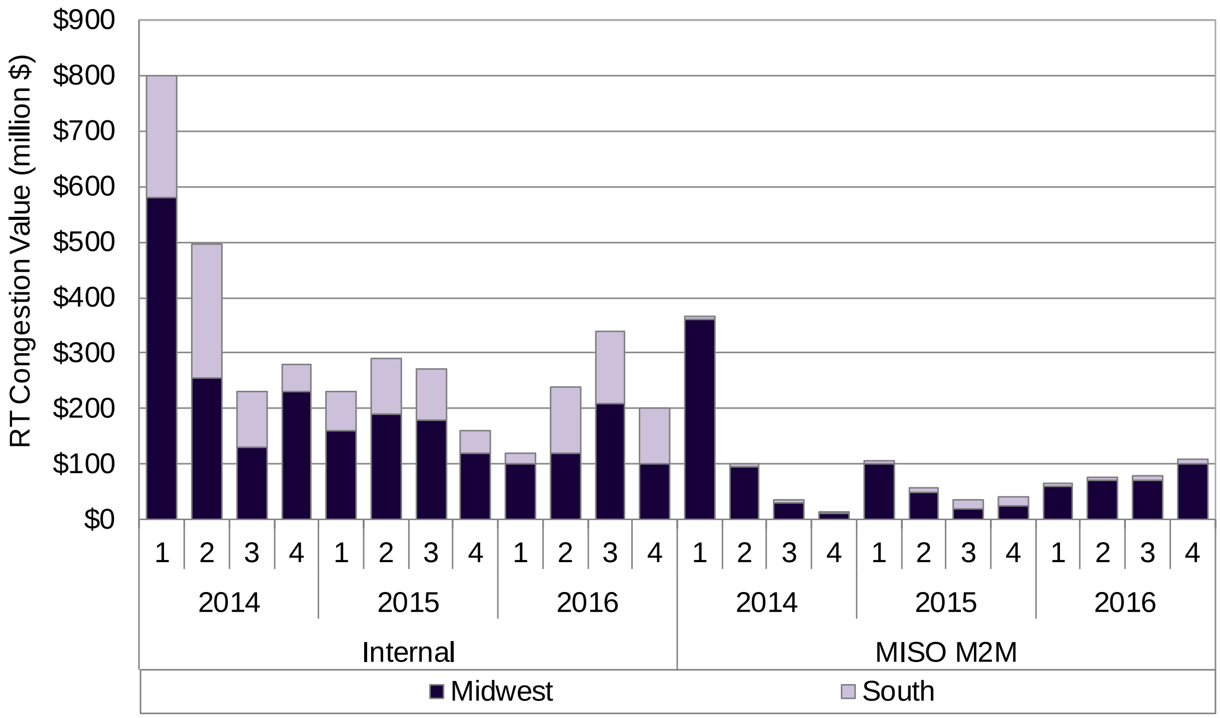
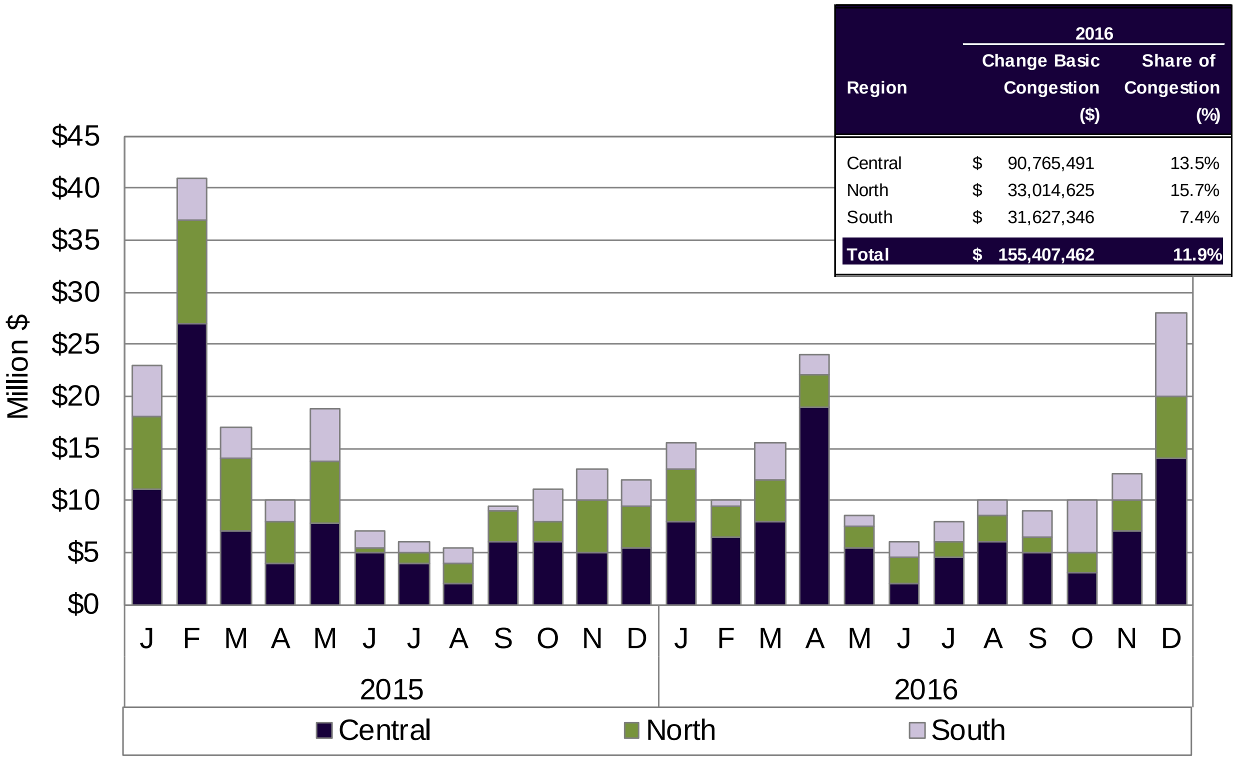


Figure 37: MISO Real-time Congestion Value by Constraint Type (2014-2016)
Source: Potomac Economics, 2016 State of the Market Report for the MISO Electricity Markets, Analytic Appendix.

Figure 38 estimates the monthly value of alleviating transmission constraints across the three MISO planning regions as a proxy for the estimating value of new transmission capacity.[22] The analysis shows that additional transmission in the MISO Central region would have provided approximately $90.8 million in benefits in 2016. Additional transmission in the remainder of MISO North and in MISO South would have provided approximately $33 and $31.6 million in benefits, respectively.



Region	2016 Change Basic Congestion ($)	2016 Share of Congestion (%)
Central	$ 90,765,491	13.5%
North	$ 33,014,625	15.7%
South	$ 31,627,346	7.4%
Total	**$ 155,407,462**	**11.9%**

Figure 38: Potential Value of Additional Transmission Capability (2015-2016)
Source: 2016 State of the Market Report for the MISO Electricity Markets, Analytic Appendix

Lastly, Figure 39 presents the cost-benefit analysis of proposed transmission investments for the MISO North area as an example of the considerable value customers are anticipated to see from the recent increases in their transmission costs. In all instances, the value of projects in each of these zones far in excess of 1.0 and in many instances, in excess of 2.5 or even 3.0, indicating that benefits are anticipated to be 2.5

[22] 2016 State of the Market Report for the MISO Electricity Markets, Analytic Appendix.

to 3.0 times the original costs associated with transmission infrastructure investments in each of these zones across the various MISO planning processes.

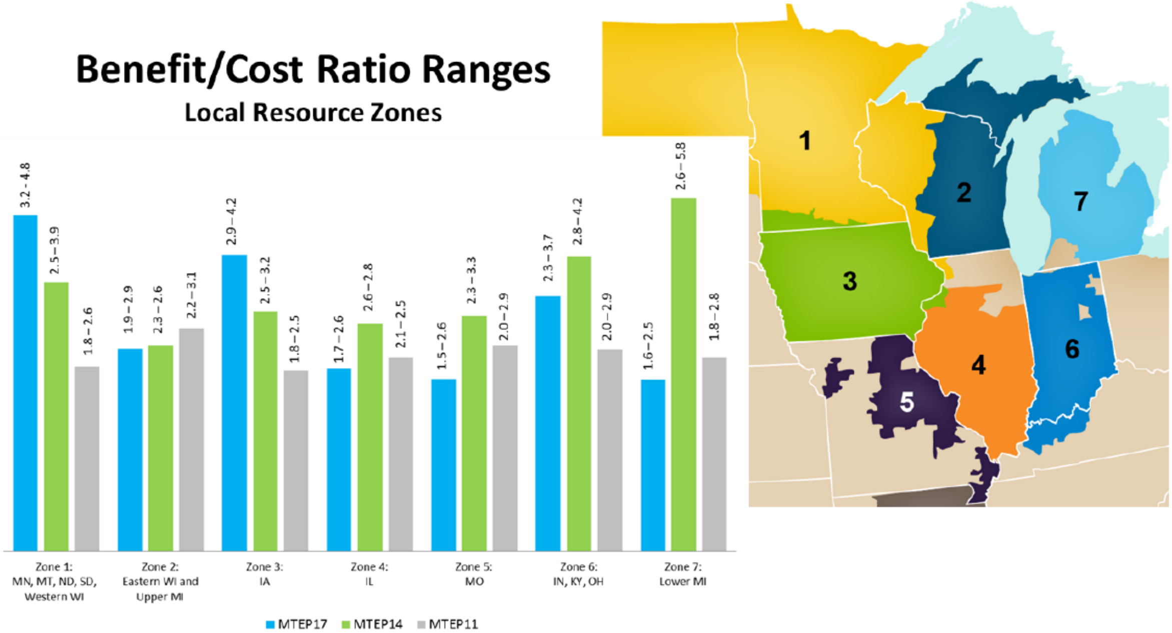


Figure 39: Estimated Transmission Investment Cost-Benefit Ratios (MTEP11, MTEP14, and MTEP17)
Source: MTEP17, MISO Transmission Expansion Plan.

e. Customer Empowerment and Choice

Competition and competitive markets are important across the MISO footprint and while most of the MISO member states do not allow for retail choice, this has not diminished the interest of some customer groups, primarily large industrial customers, for securing their own power supplies from either themselves or from parties other than LSEs. Industrial customers are often diverse and do have many competitive alternatives. Many of these industrial customers, particularly those in the MISO South region, have been securing their own competitive supplies of natural gas, directly from a variety of suppliers, often directly off the interstate natural gas transmission system, for decades. Many would like to see this ability extended to electricity.

There are a few ways in which industrial customers could alter how they secure electricity. Most industrial customers, for instance, are also large producers of electricity themselves. MISO has over 65 generation facilities within its footprint that are considered industrial cogeneration facilities. A map of those facilities and their in-state capacity (for 2016) is provided in Figure 40. As of 2016, there were over 9,418 MW of active industrial cogeneration in the MISO footprint, accounting for 60.4 percent of the total active generation capacity in the region (the states in which MISO is present).

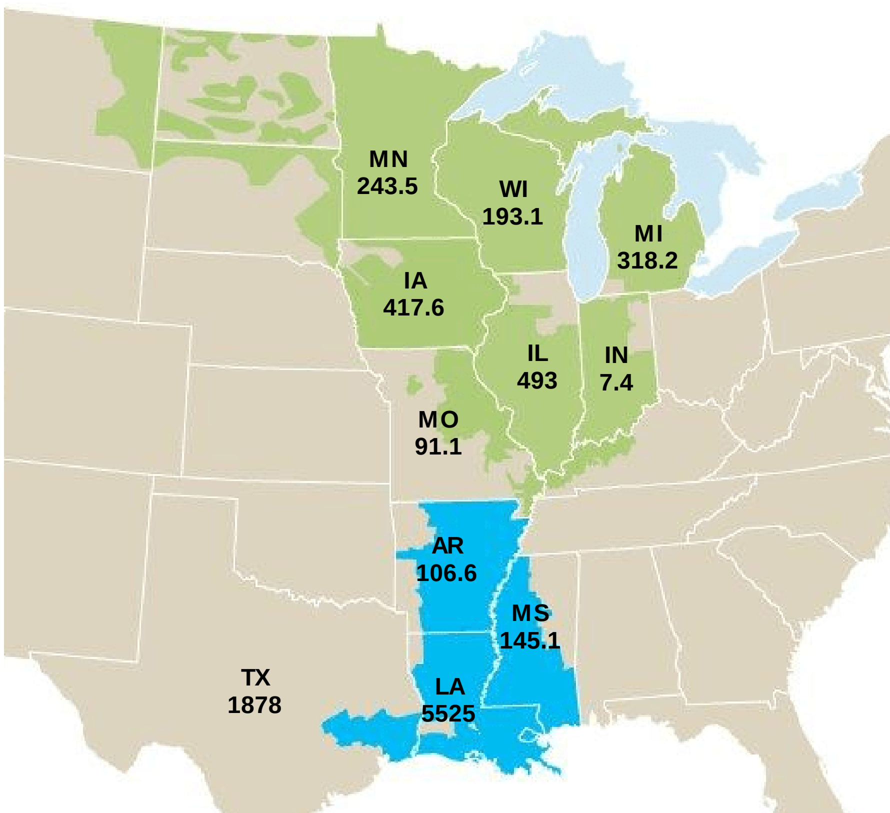


Figure 40: 2016 MISO Industrial Cogeneration/On-site Generation (MWh)
Source: U.S. Energy Information Administration.

One important option that could be available to industrial generators could incude what can be referred to as "affiliate wheeling:" allowing an industrial generator to use the MISO transmission assets (including those owned by its host utility) to "wheel" excess power from one location to another location, provided that the plants at the two locations are part of the same company. So, as an example, an affiliate wheeling transaction would allow a company like the Dow Chemical Company to contract to transport electricity across the transmission system to its affiliate at another location either within, or even potentially across a state line. The ability to engage in this activity would be strictly limited to affiliates and the amount of on-site generated electricity at affiliate locations. Figure 41 shows that, at least based upon recent trends, there has been steady and what appears to be relatively reliable trend of on-site industrial generation (at least from an aggregate perspective) across the region over the past decade.

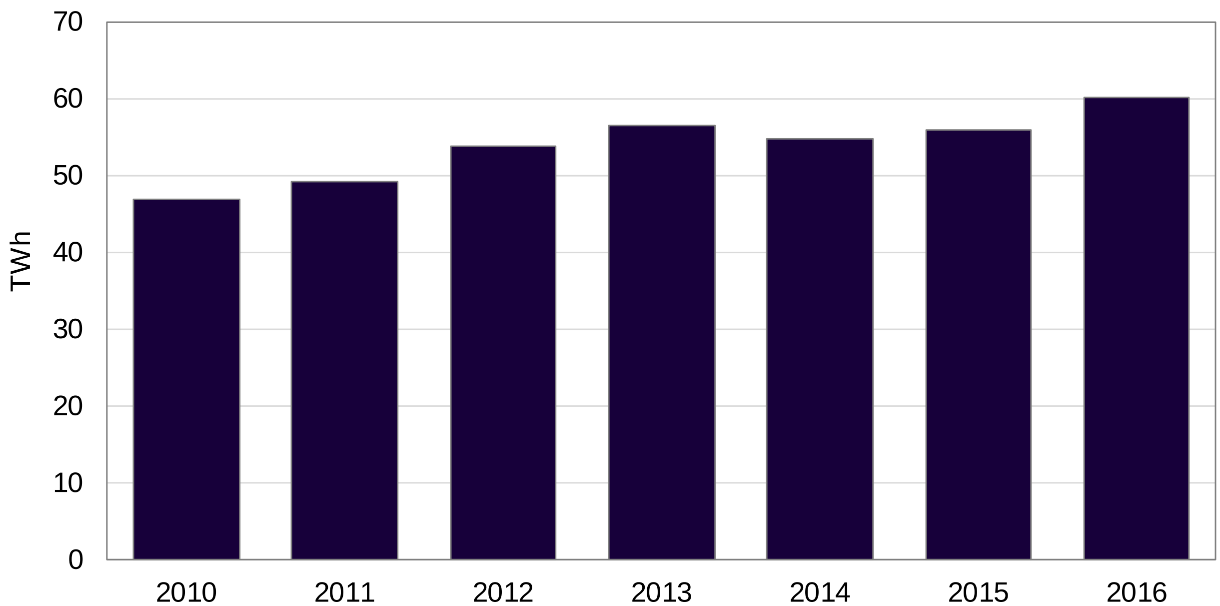


Figure 41: MISO Industrial Cogeneration/On-site Generation (2010-2016)
Source: U.S. Energy Information Administration.

The ability to facilitate some limited amount of industrial choice is often tied to economic development, particularly over the past several years which has seen a "renaissance" in industrial project development announcements, particularly in the MISO South region. Small differences in electricity rates, in theory, can potentially influence siting location decisions for large industrial users. Thus, having the ability to offer some form of limited retail industrial choice, such as affiliate wheeling, or some other restricted process, could represent an important tool for economic developers.

Ultimately, the issue of limited retail choice for industrial customers is a state legislative and/or regulatory issue. For MISO, these considerations are important because they underscore the increasing desire for customers to seek greater levels of empowerment, either through the use of technology or policy, or both. This pressure for greater levels of choice and empowerment will influence the long-run transmission infrastructure planning process including the location, scope, and nature of future transmission investment projects. This type of variation plays to concerns regulators expressed, which were discussed earlier, about potential unanticipated shocks to the system which could lead to various projects becoming "bridges to nowhere" or "white elephants." Ultimately, this is an issue for which MISO needs to be mindful, but one that clearly will have to percolate up from the state regulatory process.

10. Conclusions

The U.S. bulk power system arose over the past century to harness the economies of scale and efficiencies associated with the large-scale movement of alternating current ("AC") over long distances. The vision of Westinghouse, Tesla, and Stanley trumped that of Edison in winning the war of the currents and the standardization of the industry we have today. The links between various vertically integrated utilities and the regions in which they operate were focused primarily on developing a system that could be tapped upon for reliability-related purposes: to share electricity during extreme weather events, outages and to manage other unforeseen crises. This system, and most importantly its component transmission infrastructure, was not developed to facilitate a high level of commerce at a regional, and particularly a sub-region basis.

Order 888 was issued by the FERC over two decades ago and established a framework and vision for a new industry organization, one that was less fragmented and balkanized and more integrated, diversified, seamless and efficient. This Order also envisioned a system that would facilitate the development of markets and an expansive set of physical and financial transactions that would lead to better resource optimization and efficiencies. At the time, RTOs were established as the focal institution that would facilitate and maintain this dramatic market transformation on both a commercial and physical basis.

Infrastructure development was at the heart of the industry transformation started by Order 888 since, at that time, the bulk power system of the past was clearly neither adequate nor sufficient to sustain any extensive degree of commercial activity. While a considerable amount of infrastructure development has been completed over the past two decades, there is considerably more work that needs to be done to reach this vision.

A consistent public policy theme in U.S. politics is developing and rebuilding infrastructure. This theme dates back to the early days of the Republic and continues even today as engineers, economists, and other pundits lament the current status of U.S. infrastructure and the need to upgrade this infrastructure to meet modern needs. Boldness and vision are often cited as the standard prerequisites for infrastructure development success. The electric power industry is not immune to these calls, and the MISO 2035 echoed many of the same themes of urgency and necessity for transmission infrastructure development that are echoed in discussions about upgrading roads, highways, schools, hospitals, transportation, communications and water systems.

The voices of inertia and the status quo are often heralded as the main barriers to boldness and vision and often the only factor that unfortunately seems to break the logjam between these two opposing forces are large-scale infrastructure failures and catastrophes. The bulk power transmission system is no stranger to this phenomenon as witnessed by numerous large-scale power outages that have arisen in the industry dating back to the infamous northeastern black out of 1965. Clearly, this is no way to manage, much less plan for a highly complicated set of critical energy infrastructure.

Transmission Infrastructure development is no easier today, in 2018, than it was in decades past, and is now confounded by dramatic changes in not only technology, but customer usage and preferences. Technology, in particular, seems to be placing some of the more significant and near-term challenges on transmission system investments. This should come as no surprise since technology, by its very nature, has a disruptive impact on society and particularly market institutions. What is unique about today's technological innovations, however, is that the scale-orientation of these new technologies are primarily distributed and decentralized in nature; a characteristic that strikes at the very heart of over a century's worth of power industry structural organization. Plus, it should come as no surprise that the financial consequences of getting these infrastructure investments all wrong, are even more prohibitive than in decades past.

However, as the MISO 2033 event found, large-scale bulk power system infrastructure investments, and smaller-scale distributed technologies do not have to be mutually exclusive. The value of the bulk power transmission system, while changing, still rests its integrated nature. The integrated nature of the transmission system will become more important as new technologies, particularly intermittent renewables, becomes more commonplace. The integrated nature of the transmission grid diversifies the supply of resources across traditional and new technologies and provides the system reliability important during transition periods like the one currently being witnessed in the industry.

The other pressure point for an organization like MISO, in developing the transmission infrastructure requirements of tomorrow, is understanding what tomorrow's customers want and need. What appears to be increasingly apparent is that customers want more choices: customers want to be able to choose across a variety of environmental attributes; they want to be able choose across a variety of price and service offerings; they want to be able to choose across a variety of different service providers and, increasingly, they want this flexibility provided within a system that is clean, reliable and resilient and one that minimizes costs and maximizes end-user value.

Once again, the MISO 2033 event found that these perceived conflicts are not mutually exclusive and, in fact, can be accommodated within a broad vision for transmission infrastructure development. MISO's transmission planning efforts will likely facilitate these consumer empowerment issues by:

- Integrating new technologies into a larger footprint that facilitates a wide range of customer choices.
- Developing new physical infrastructure investments to strengthen existing reliability requirements and enhance grid resiliency

- Developing market design and market protocols that leverage physical transmission investments to develop framework that provides price signals and creates efficiency.
- Engaging stakeholders in the planning process to ensure adequate feedback on customer needs to ensure minimized costs and maximized value.
- Educating customers about the value proposition of these transmission infrastructure investments, their cost-benefit ratios on both a pre and post development basis.

Lastly, the discussion at the MISO 2033 event highlighted that transparency is one of the most powerful tools in executing a bold transmission infrastructure planning vision. The event itself was an example of how important and useful a transparent stakeholder meeting can be in understanding differing opinions and positions on transmission planning. This transparency will continue to be important in order to assure confidence in the transmission planning process, to reduce informational asymmetries between market participants, and to ensure resources dedicated to transmission investment development are made in the most efficient manner possible.