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MICHIGAN PUBLIC SERVICE COMMISSION
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Readying Michigan to Make Good Energy Decisions:

Renewable Energy

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September 20, 2013

Presented by

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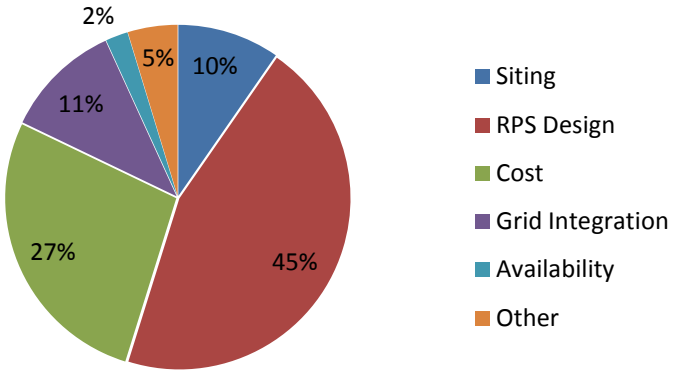
Readying Michigan to Make Good Energy Decisions – Renewable Energy
Executive Summary

The 40 renewable energy questions posted on the Ensuring Michigan's Energy Future website garnered 425 responses. The comment summary pie chart presents an overview of comments received at the website. Many additional renewable energy comments were given at the public energy forums.

Where Michigan Is Today: Michigan's current Renewable Portfolio Standard (RPS) requires electric providers to ramp up their use of renewable energy in order to obtain 10% of their electricity sales from renewable resources in 2015. Those goals are expected to be met in nearly all cases, and the exception has announced plans to wind down service. The RPS has resulted in approximately 1,400 MW of new renewable energy projects operating or currently under development in our state (94% of these new projects are wind energy projects and approximately half are non-utility owned). By the end of 2013, in total, Michigan consumers will have paid approximately $675 million in surcharges supporting this expansion. Due to decreases in renewable energy costs, surcharge collections are expected to be significantly reduced or even eliminated for some electric providers beginning in 2014, because project costs are in some cases essentially equivalent to conventional generation under current conditions.



<u>Comparison of Michigan's Current RPS to Other States</u>

- There are 29 states, Washington DC and 2 territories with renewable portfolio standards. There are 8 states and two territories with renewable *goals*.
- When comparing RPS requirements, there is a simple way of doing so (simply "year" and "number"), which is often used. Michigan's RPS is one of the less aggressive RPS programs when compared to others. With the exception of Michigan and Wisconsin, all other states with renewable energy portfolio standards include targets higher than 10%.
- This type of simple comparison does not take into account differences in the way renewables are defined, the percent of renewables already in a state's supply portfolio, whether the requirement is uniformly mandated, the annual rate of increase to meet the requirement, or the percent of RPS in comparison to load growth.
    - There is no single scale now broadly available that attempts to "normalize" and compare these different RPS standards in apples-to-apples ways.
    - In 2008, when the RPS took effect, Michigan had a very low percentage of renewables in its portfolio (assuming more traditional definitions of renewable power that would exclude nuclear, unlike some states including Ohio). It did

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choose to apply the standard uniformly (unlike Illinois, for example), and it mandated building new generation even if overall demand for electricity was falling.

Technical Feasibility of Increased Renewable Energy Generation

- In the scenarios discussed in the report, from a technical perspective, it would be possible to meet increased RPS targets of as much as 30% (or perhaps higher) from resources located within the State.
- Michigan is part of two multi-state markets, so from a purely technical perspective, Michigan utilities could build or purchase renewable energy generated in a very large geographic area. However, depending on the amount of energy needed, improvements in infrastructure to move that energy could be necessary. Therefore, there is no scenario in which, as a purely technical matter, even very aggressive renewable energy goals could not be met, but more aggressive goals increase the potential need for additional infrastructure improvements.
- Non-technical factors could limit the amount that is available in-state, or could restrict the ability to require generation from in-state regardless of technical feasibility. Two of those factors are legal in nature.
    - From a legal perspective, Michigan's local governments address siting of all types of electrical generation, including renewables, so local governmental rules restricting such items could reduce the available sites.
    - Also as a legal matter, Michigan's current RPS limits on where renewable energy could be located was characterized as unconstitutional in a federal circuit court of appeals decision issued on June 7, 2013. To date, no party has directly challenged the constitutionality of Michigan's current law.

Cost

- The most commonly cited cost estimates for renewables come from the Energy Information Administration's (EIA) levelized cost data from its Annual Energy Outlook 2013 for renewable and conventional generation.
- Under the current RPS, overall costs have been calculated using levelized cost data methods similar to those used by the U.S. Energy Information Administration.
- During the years Michigan's RPS has been in place, the price of the lowest-cost renewable resource, wind, has declined from over $100 per MWh in 2009 to $50 - $60 per MWh now. The predominant reason for the drop is the significant increase in wind farm capacity factors from the high 20s in 2008 to the mid-40s more recently.
- EIA reports current levelized costs for other generation characterized as renewable under Michigan's current RPS:
    - Wind - $87 per MWh
    - Hydro - $90 per MWh

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    - Biomass - $111 per MWh
    - Solar - $144 per MWh
    - Wind (Offshore) - $222 per MWh
- EIA's reports current levelized costs for some generation not characterized as renewable under Michigan's current RPS:
    - Natural gas conventional combined cycle plant is $67 per MWh.
    - Advanced nuclear is $108 per MWh.
    - Advanced coal with carbon capture and sequestration is $136 per MWh.
- Even the entity that develops these estimates notes that levelized cost estimates are not the only way to estimate costs and does not attempt to quantify other costs and benefits that may be applicable. For instance, the EIA has noted that comparing costs only on a levelized basis does not reflect the system value and operational profiles, and others have noted that costs/benefits of reduced emissions may not be reflected. Assumptions regarding the costs/benefits of these and other factors can often lead to disputes regarding the "true cost" of renewables. The report discusses alternatives to levelized cost estimates, none of which have been widely adopted to date.
- Another reason cost estimates of renewables vary is because different estimates may use a different basis for comparison. For instance, if renewable generation is compared to replacing existing generation, it will often appear more expensive. However, if renewable generation is compared as an alternative to building new types of generation, it will often appear to be less expensive.
- Many assumptions regarding future tax treatments, carbon regulations, need for building additional supporting generation and the expected rate of technical improvements can also change cost estimates.
    - One of the most important variables that accounts for different cost estimates for solar and wind generation in the future is estimated fuel costs for other types of generation. Approximately half of the renewable energy in Michigan under the current RPS will come from contracts with prices locked in for 20 years. These prices are not subject to fuel or market price volatility, like other types of generation ranging from biomass to coal to natural gas.
    - The higher the future cost of various fuels is projected to be, the better renewable energy costs will be estimated to be in comparison. Thus, recent estimates of very low natural gas prices are key in the estimated levelized cost of new natural gas generation; usually lower than that of the least expensive renewable, onshore wind.

<u>Grid Reliability (Integration & Generation Diversity)</u>

- Broadly speaking, there is agreement that a diverse generation supply portfolio is a way to minimize risk.

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- In general, Michigan's grid reliability is assured by transmission system operators (MISO and for some of Michigan's southwest, PJM), who work with local operators, who in turn work with the utilities who provide retail power.
- To date, the MISO system portfolio has added more wind power than any other renewable resource. MISO reports that to date, wind has not been a factor in any system-wide reliability problems and has not resulted in any significant reliability concerns, due in part to its ability to manage the system to provide flexibility when resources (both renewable and non-renewable) do not behave as predicted.
- It is difficult at this time to calculate the additional costs that have been undertaken to assure that reliability vs. general reliability. MISO reports that it is not aware of backup capacity costs specifically attributable to the intermittent nature of wind power. However, there has been significant transmission built and planned that has helped facilitate the introduction of wind power where it might not otherwise have been supported. An example of this is the large build in the Michigan Thumb.

<u>Various Scenarios for Comparison Sake</u>

- For purposes of comparison, the report describes a number of possible scenarios for various increased renewable portfolio standards in various years. All scenarios are reliant on a number of assumptions that could change outcomes.
- In order to work in a context familiar to policy makers, the scenarios assume a continuation of PA 295 policies as a general matter, and assumed electric demand growth of between 0% and 1.2% (both scenarios were run to show the range of impact). Additional key assumptions included:
    - Renewable energy costs would be at EIA's current average estimates, however, given Michigan's recent experience with wind contracts coming in at lower prices than EIA estimates, this assumption is considered to be conservative.
    - Costs would be capped at current limits on monthly surcharges (not at current charges, which are typically lower); and an additional scenario considered reducing current surcharge caps by 50%.
    - Current renewable generation costs relative to each other would continue (i.e., wind would continue to be less expensive than solar).
- Under these assumptions, all evaluated scenarios (ranging from 15% by 2020 to 30% by 2035) are achievable.

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Readying Michigan to Make Good Energy Decisions – Renewable Energy Report

In 2008, the Michigan Legislature passed Public Act 295 (PA 295). The purpose of PA 295 is "to promote the development of clean energy, renewable energy, and energy optimization through the implementation of a clean, renewable, and energy efficient standard that will cost-effectively do all of the following: (a) Diversify the resources used to reliably meet the energy needs of consumers in this state. (b) Provide greater energy security through the use of indigenous energy resources available within this state. (c) Encourage private investment in renewable energy and energy efficiency. (d) Provide improved air quality and other benefits to energy consumers and citizens of this state." MCL 460.1001. The Act requires Michigan electric providers to ramp up their use of renewable energy in order to obtain 10% of their electricity sales from renewable resources in 2015.[1] The most recent report prepared by the Michigan Public Service Commission discussing the status of renewable energy in Michigan is *Report on the Implementation of the P.A. 295 Renewable Energy Standard and the Cost-Effectiveness of the Energy Standards* (MPSC RPS Report).

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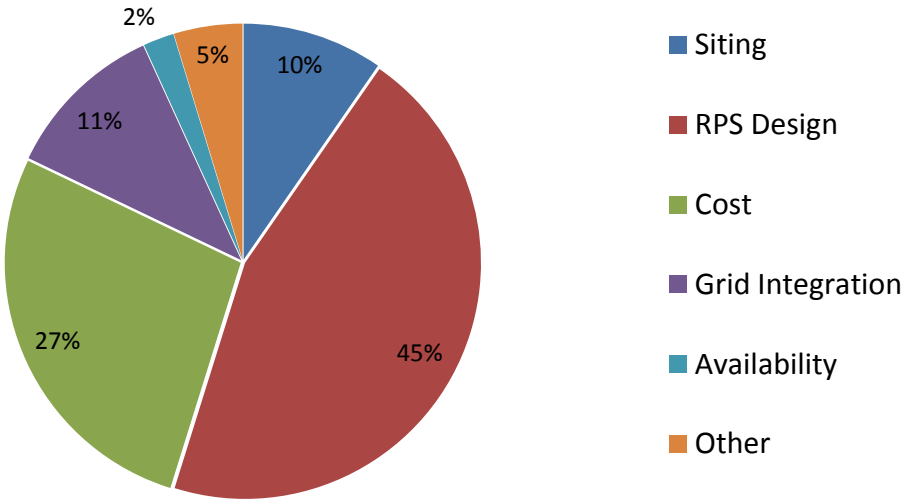
[1] PA 295 defines a renewable resource to include biomass, solar and solar thermal energy, wind energy, hydro, wave energy, geothermal energy, municipal solid waste, and landfill gas. In addition, there is a category called "Clean Energy" provided for within PA 295 via Advanced Cleaner Energy Resources that can qualify for Advanced Cleaner Energy Credits and include gasification facilities, industrial cogeneration facilities, coal-fired electric generating facilities if 85% or more of the carbon dioxide emissions are captured and permanently geologically sequestered, and electric generating facilities or systems that use technologies not in commercial operation on the effective date of the act. PA 295 also includes provisions to allow for excess Energy Optimization Credits to be used to meet the renewable portfolio standard.

As Michigan approaches 2015, policymakers will be considering Michigan's energy future. Governor Snyder asked all of Michigan's citizens to provide input into this critical process. The 40 renewable energy questions posted on the Ensuring Michigan's Energy Future website garnered 425 responses. **Figure 1** presents an overview of comments received at the website. In addition, many people addressed renewable energy at the 7 public forums held throughout the state. This report attempts to provide a look at the current and future possibilities for renewable energy and to address the questions and concerns that were raised by respondents.

Figure 1: Summary of Website Comments



Michigan's Renewable Portfolio Standard (RPS) (Questions 1, 2, 7, 12, 20, 21, 22, 24, 34)

Introduction

Michigan's RPS has been in place four years and has resulted in significant growth in renewables for the State. In addition to the final 10% renewable requirement in 2015, the RPS

includes interim compliance steps for 2012 – 2014. For 2016 and each year thereafter, electric providers are required to maintain the same amount of renewable energy credits (RECs) needed to meet the standard in 2015.[2] Electric provider compliance reports for 2012 have been submitted in 2013. All electric providers expect to meet the standard's 2012 interim step requirement. The 2015 goals are expected to be met in nearly all cases, and the exception, the City of Detroit's system, has announced plans to wind down service.

The RPS has resulted in approximately 1,400 MW of new renewable energy projects operating or currently under development in our state (94% of these new projects are wind energy projects and approximately half are non-utility owned). By the end of 2013, in total, Michigan consumers will have paid approximately $675 million in surcharges supporting this expansion. Due to decreases in renewable energy costs, surcharge collections are expected to be significantly reduced or even eliminated for some electric providers beginning in 2014, because project costs are in some cases essentially equivalent to conventional generation under current conditions. More detail on this can be found in the MPSC RPS Report, which was the most common data source cited by commenters on these topics.[3]

How Compliance Was and Likely Will Be Achieved

A projection of Michigan's renewable energy credits is shown in **Figure 2** for 2012 through 2015 (along with the annual REC compliance requirement and quantity of accumulated RECs). In order to reflect only renewable energy generated or acquired in each year, accumulated RECs from previous years are not included in the renewable energy totals but are

[2] One renewable energy credit is created for each MWh of renewable energy generated. Additionally, Act 295 provides for Michigan incentive renewable energy credits, which are essentially additional credits or fractions of a credit permitted for various factors, including solar power, power generated at times of peak demand, storage of renewably-generated energy, and use of in-state equipment or Michigan workers in the construction of the generating equipment. Renewable energy credits may be sold separately from the energy.

[3] Unless otherwise referenced, this report is the basic information source informing the statements in this section.

shown separately in the line representing accumulated RECs. The projected renewable energy includes baseline renewable energy (renewable energy that was operational prior to the passage of PA 295); an estimate of RECs from PA 295 approved contracts for company-owned renewable energy projects, power purchase agreements and REC-only contracts; and a projection of other RECs from non-rate regulated providers and contracts that do not require Commission approval under PA 295. For 2015, Michigan's renewable energy percentage is projected to reach nine percent based on renewable energy generated during that year and the associated incentive renewable energy credits. Accumulated RECs from previous years that may be banked for up to 36 months and energy optimization credit substitutions for RECs provide additional resources to fill in the gap between annual renewable generation and REC requirements to ensure meeting the 10 percent renewable portfolio standard. The amount of renewable energy generated during each year is expected to continue increasing after 2015 because electric providers' current renewable energy plans show continued development of additional renewable energy projects. The renewable energy projections shown for 2012 through 2015 clearly indicate that providers are on track to meet the renewable portfolio standard.

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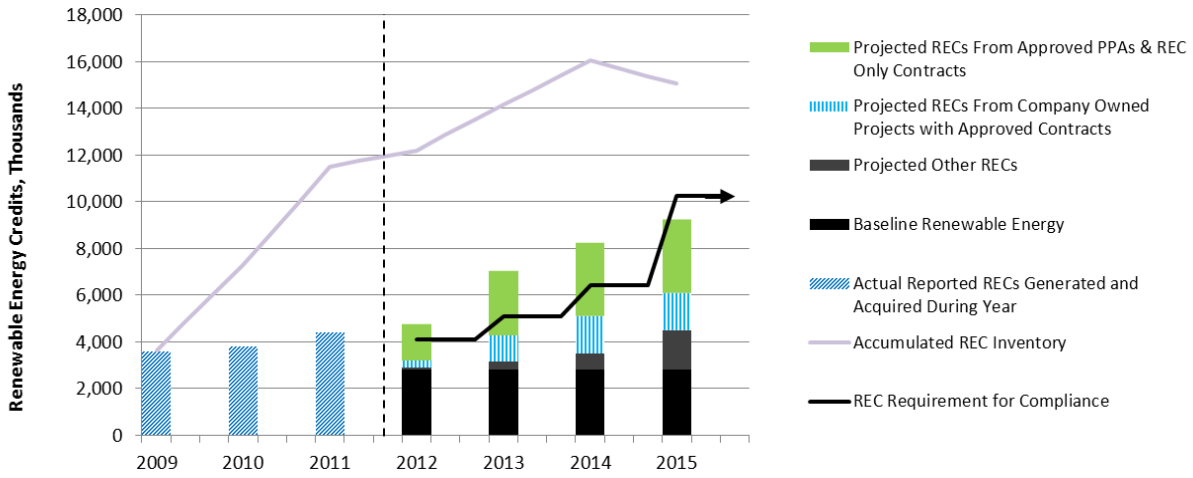
Figure 2: Status of Michigan Renewable Energy[4]



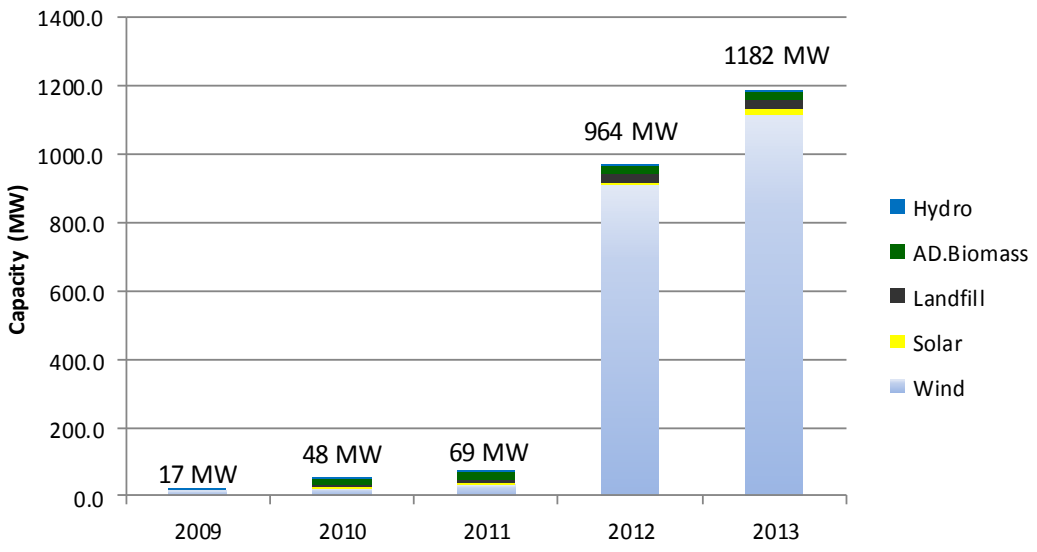
As noted above, Michigan law is structured to create Renewable Energy Credits (RECs) that satisfy the requirements for generation, and to allow trading in these credits. In general, this has created a common valuation scheme for various objectives being pursued (e.g., installation of cost effective renewables projects in Michigan, incentives for the development of renewables technologies not yet known to be at cost parity, use of Michigan content, cost-effective import of renewable power from outside Michigan when allowed by the statute). Michigan's law includes a provision in its RPS to address possible interactions with a potential future federal RPS (there is not one at this time). MIRECS, Michigan's registry established to track and certify energy credits, is able to import and export RECs to other registries. However, users report that due to the tailored nature of the Michigan RECs, that market has not, as a practical matter, extended to other market jurisdictions.[5]

[4] Report on the Implementation of the P.A. 295 Standard and the Cost Effectiveness of the Energy Standards, Michigan Public Service Commission, February 15, 2013, Figure 3. http://www.michigan.gov/documents/mpsc/implementation_of_PA295_renewable_energy_411615_7.pdf?20130729150432

[5] See e.g. Joint response from Consumers and MEGA).

As of January 2013, 49 renewable contracts and amendments have been filed with the Commission and all have been approved.[6] **Figure 3** shows the expected commercial operation dates for renewable energy projects. The breakdown by renewable energy technology type for all renewable energy projects based on contracts and solar programs approved by the Commission through 2012 is shown in **Figure 4.** Several renewable energy projects included in **Figure 4** have commercial operation dates beyond 2013.

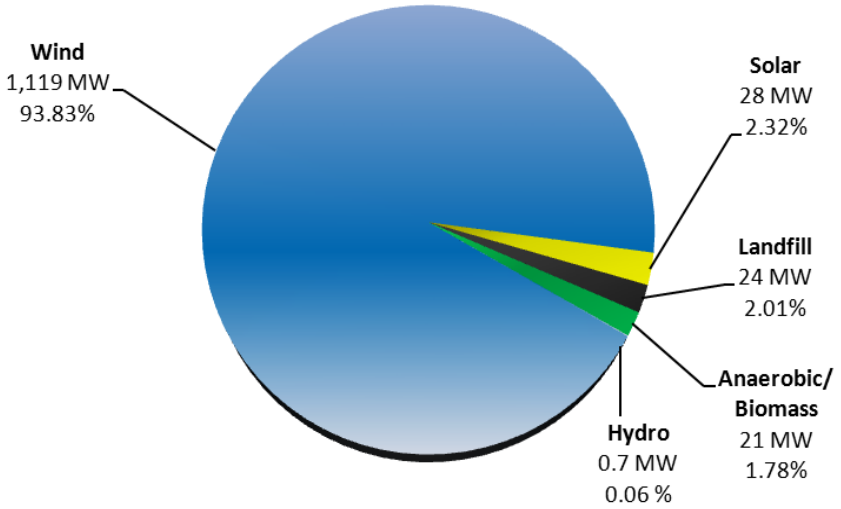
Figure 3: Cumulative Renewable Energy Capacity by Commercial Operation Date[7]



[6] For current contract information please see http://www.michigan.gov/documents/mpsc/ContractSummary_405658_7.pdf?20130723114510

[7] Report on the Implementation of the P.A. 295 Standard and the Cost Effectiveness of the Energy Standards, Michigan Public Service Commission, February 15, 2013, Figure 4. http://www.michigan.gov/documents/mpsc/implementation_of_PA295_renewable_energy_411615_7.pdf?20130729150432

Figure 4: Renewable Energy Capacity by Technology Type[8]

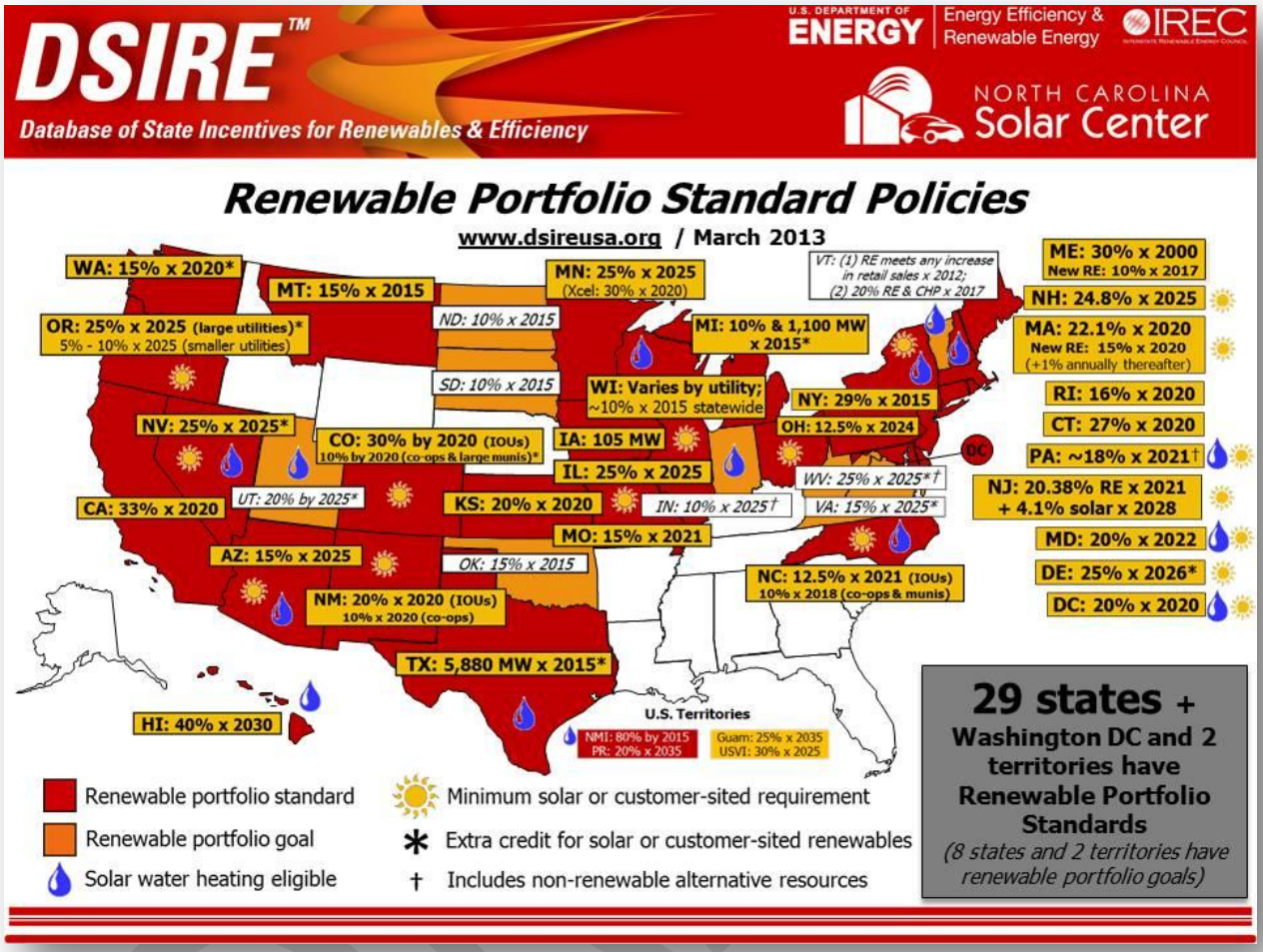


<u>Comparison of Michgan's Current RPS to Other States</u> (Questions 7, 9, 12, 19, 33)

There are currently 29 states, Washington DC and two territories (Puerto Rico and North Mariana Islands) that have Renewable Portfolio Standards. There are eight states and two territories (Guam and United States Virgin Islands) that have renewable energy goals in place. Across the country, there is a large variation in RPS compliance requirements. Many states have higher renewable percentages but with longer time periods to achieve compliance than Michigan. Michigan's 2015 date for the mandate. The 10% requirement, however, is the lowest stated percentage for an RPS in the country, save those states that lack an RPS altogether. **Figure 5** shows a graphical representation of renewable portfolio standards in the U.S. and tabular data is included as Appendix A.

[8] Report on the Implementation of the P.A. 295 Standard and the Cost Effectiveness of the Energy Standards, Michigan Public Service Commission, February 15, 2013, Figure 5. http://www.michigan.gov/documents/mpsc/implementation_of_PA295_renewable_energy_411615_7.pdf?20130729150432

Figure 5: DSIRE Renewable Portfolio Standard Policies Map-March 2013[9]



That said, an "apples to apples" comparison of RPSs is difficult. Variations in how a standard is structured (what resources are included; is standard expressed as % of peak, % of total kwh, % of installed capacity or specific installed MW goal; and the overall timeline for meeting the standard) make state to state comparisons difficult. Some states have established separate compliance requirements for different types of electric providers (municipal utility, cooperative utility, large and small utilities). Many of the state RPS requirements define what qualifies as

[9] DSIRE Website: http://dsireusa.org/summarymaps/index.cfm?ee=1&RE=1

renewable energy to meet the standard differently as well. **Figure 6** includes a state by state comparison of what technologies are eligible to meet renewable portfolio standards.

Figure 6: Eligibility to Meet Renewable Requirements: State by State Comparison

	AZ	CA	CO	CT	DE	DC	HI	IL	IA	ME	MD	MA	MI	MN	MO	MT	NV	NH	NJ	NM	NY	NC	OH	OR	PA	RI	TX	WA	WI
Wind	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●
Solar Photovoltaic	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●
Solar Thermal	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●		●	●	●	●	●	●	●	●
Hydroelectric	ℹ	ℹ	ℹ	ℹ	ℹ	ℹ	ℹ	ℹ	ℹ	ℹ	ℹ	ℹ	ℹ	ℹ	ℹ	ℹ	ℹ	ℹ	ℹ	ℹ	ℹ	ℹ	ℹ	ℹ	ℹ	ℹ	ℹ	ℹ	ℹ
Biomass	ℹ	ℹ	ℹ	ℹ	ℹ	ℹ	ℹ	ℹ	ℹ	ℹ	ℹ	ℹ	ℹ	ℹ	ℹ	ℹ	ℹ	ℹ	ℹ	ℹ	ℹ	ℹ	ℹ	ℹ	ℹ	ℹ	ℹ	ℹ	ℹ
Landfill Gas	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●
Geothermal	●	●	●		●	●	●			●	●	●	●			●	●	●	●	●	●	●	●	●	●	●	●	●	●
Ocean/Wave/Tidal		●		●	●	●	●			●	●	●	●					●	●		●	●		●		●	●	●	●
Fuel Cells - Renewable Energy	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●
Fuel Cells - Non-Renewable Energy				●						●				●							●		●		●				
Combined Heat and Power			●	●			●			●			●				●					●			●				
Conservation/ Energy Efficiency			●	●			●						●				●					●			●				
Co-firing	●		●	●	●	●	●			●	●	●	●	●	●	●	●				●	●		●	●	●	●	●	●
Municipal Solid Waste	●	●		●		●	●		●	●	●	●	●				●		●				●		●				
Other Technologies	●	●		●			●	●		●	●					●	●						●	●	●		●		
Comments / Details	✔	✔	✔	✔	✔	✔	✔	✔		✔	✔	✔	✔	✔	✔	✔	✔	✔	✔		✔	✔	✔	✔	✔		✔		✔

ℹ ✔ For explanations of these icons, click through to UCS Renewable Electricity Toolkit

In general, states that implemented higher standards have historically had higher energy prices than Michigan had (Northeast and California) and/ or higher endemic renewables resources (Western states: more hydro and solar; Plains states: more wind). Taking a closer look at the Midwest, the following data shown in **Figure 7** was supplied in a joint response from the Michigan utilities, with updates made by MPSC Staff shown in italics. It's worth noting that, particularly for Michigan and Ohio, differing sources have presented differing data (Figures 6 and 7).

Figure 7: Comparison of Midwest States

	MI	OH	IL	IA	MN	WI
Standard	10% by 2015	12.5% by 2024 (also 12.5% "alternative energy resources" by 2025 for total of 25%)	25% by 2025	105 MW***	25% by 2025 (30% by 2020 for Xcel)	10% by 2015
Applicability by Utility Type	All	Municipal and cooperatives exempt	Municipal and cooperatives exempt	Municipal and cooperatives exempt	All	All
Eligible technologies						
Biomass	X	X	X*	X	X*	X
Solar PV	X	X	X	X	X	X
Solar Thermal	X	X	X	X	X	X
Solid waste	Limited	X		X	X	X
Geothermal	X	X				X
Hydro	Limited	X	X	X	X	X
Landfill gas	X	X	X	X	X	X
Nuclear		X				
Clean coal	**if 85% or more of the CO_2 emissions are captured and permanently geologically*	X				

	MI	OH	IL	IA	MN	WI
	sequestered					
Energy storage	**Allowed if stored using renewable energy*	X				
Combined heat and power	**Industrial co-gen allowed*	X				
Other waste heat recovery	**Industrial co-gen allowed*	X				
Fuel cells		X				X
Microturbines		X				
Wind	X	X	X	X	X	X
Energy efficiency, demand response	X (capped)	X				
Retrofitted/refueled generation		X				
Co-firing	**Biomass co-firing allowed*				X	
In-state restriction	Yes	Yes, but limited to half of renewables	No**	Unknown	No	Generation can be outside WI but must serve WI customers
Off ramps	Yes	Yes, if costs >3% or force majeure	Yes, must be cost-effective	Not clear	Yes, if in public interest	

* Includes anaerobic digestion and biodiesel
** Previously there was an in-state requirement for investor-owned utilities with an exception if in-state generation was not cost-effective.
*** Governor later set a voluntary target of 1,000 MW.

Broadly speaking, Michigan's RPS is firmly in the middle of states in terms of renewables policy and investment (including those states that have no RPS), with no major issues where Michigan's current policy is out of line with other states' approaches. Reference

data from Sandia National Lab (SNL) and Energy Information Administration (EIA) included by the Union of Concerned Scientists noted that in their comparisons, in 2012, Michigan ranked 34th among 50 states in terms of renewables (including hydro) as a percentage of installed capacity (11%) and 37th in terms of renewables as percentage of total GWh generation (4%).[10]

The following list of considerations was identified by Lawrence Berkeley National Lab as typical considerations in design of renewables portfolio standards, and helps underscore the challenge of simple state to state comparisons (Source: Union of Concerned Scientists comments in response to Question 7):

- Renewable energy targets and timeframes
- Electric service providers obligated to meet the standard, and use of exemptions
- Eligibility of different renewable energy technologies
- Qualification of existing renewable energy projects
- Treatment of out-of-state renewable energy projects
- Whether technology set-asides or other tiers are used
- Use of credit multipliers
- Allowance for renewable energy credits (RECs), and REC definitions
- Methods to enforce compliance
- Existence and design of cost caps
- Compliance flexibility and waivers
- Contract requirements
- Compliance filing and approval requirements
- Compliance cost recovery

[10] Few comments referenced non-US markets, suggesting that stakeholders primary frame of reference is others states/ regions in the US, rather than global energy markets.

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- Role of state funding mechanisms.

The National Renewable Energy Lab report: Including Alternative Resources in State Renewable Portfolio Standards: Current Design and Implementation Experience published November, 2012 has a summary of state programs that include alternative resources (e.g., non-renewables, energy efficiency, and thermal technologies) in state renewable portfolio standards. Michigan is highlighted as one of 16 states that includes alternative resources. Michigan is one of four states that includes non-renewables (coal with >85% sequestration and gasification qualifies for alternative cleaner energy credits), one of nine states that includes energy efficiency, and one of 13 states that includes combined heat and power (industrial cogeneration qualifies for alternative cleaner energy credits) in the state RPS.

Seven of the 29 states with a renewable electricity standard allow energy efficiency to comingle with renewable energy in meeting compliance obligations.[11] In Pennsylvania, up to 10% of the 18% standard can be met with energy efficiency. Connecticut, Nevada and Ohio also permit the use of energy efficiency to meet their goals. Both DTE Electric Company and Consumers Energy Company, Michigan's two largest electric providers, have substituted excess energy optimization (energy efficiency) credits for renewable energy credits to meet the renewable standard.

Carve-Outs/Preferences

Michigan's RPS does not include a "carve-out" to require any particular type of renewable generation, but it does contain "REC multipliers" that give certain types of renewable generation more weight than others. Michigan's REC multipliers provide extra RECs for electricity generated from solar, on-peak generation, use of Michigan materials and Michigan labor in the construction of generating facilities, and advanced storage charged with renewable

[11] See Union of Concerned Scientists Response to Question 2.

generation. A number of states (Nevada, Oregon, Delaware, Utah, Texas, West Virginia, and Washington) have credit multipliers for solar similar to that found in Michigan law, or for specific renewable energy mandates such as non-wind or distributed generation.[12]

Assuming that policy makers wish to stimulate particular types of renewable generation over others, there is some disagreement about the best method for doing so: some advocate carve-outs, and others multipliers. The two approaches are discussed below.

The major advantage of carve-outs is that they provide very tailored and specific ways to achieve a policy goal or recognize the value of natural resource assets. The major disadvantage of carve-outs is that they do not necessarily allow sufficient flexibility should the cost of meeting the carve-out become excessive, or the net benefit of meeting the policy goal through carve-outs is not apparent. However, if the value of RECs is very low, then REC multipliers do not incentivize development. Utility market players tend to support REC multipliers because it gives the investors/program developers flexibility in how best to meet the overall standards. Specific technology supporters and/ or affected market segments tend to favor carve-outs because they are likely to have more direct, predictable impact. **Table 1**, from the Union of Concerned Scientists' answer to Question 24, shows carve-outs in other state RPSs. The majority of the carve-outs are related to solar while several incentivize distributed and customer-sited generation. A carve-out increases demand for a particular type of generation which could lead to higher prices in the near term and caps the particular generation type at the carve-out requirement. The advantage of a carve-out is increased diversity and growth in the specified generation type.

[12] MPSC Renewable Energy Section Staff response to Question 24.

Table 1: RPS Carve-Out Summary[13]

State	Carve-Out or Set-Aside Provision
Arizona	4.5% distributed generation by 2025
Colorado	3% distributed generation by 2020 and 1.5% customer-sited by 2020
Delaware	3.5% photovoltaic by 2026
Illinois	1.5% photovoltaic by 2025 and 0.25% distributed generation by 2025
Maryland	2% solar by 2020
Massachusetts	400 MW photovoltaic by 2020
Michigan	None
Missouri	0.3% solar electric by 2021
Nevada	1.5% solar by 2025
New Hampshire	0.3% solar electric by 2014
New Jersey	4.1% solar electric by 2028
New Mexico	4% solar-electric by 2020 and 0.6% distributed generation by 2020
New York	0.4092% customer sited by 2015
North Carolina	0.2% solar by 2018
Ohio	0.5% solar by 2025
Oregon	20 MW solar photovoltaic by 2020
Pennsylvania	0.5 photovoltaic by 2021

Compliance Approaches

Across states, compliance approaches fall into five broad categories: Alternative Compliance Payments (ACPs) with automatic cost recovery, ACPs with possible cost recovery, explicit financial penalties with no automatic cost recovery, discretionary financial penalties with no cost recovery, and enforcement at PUC discretion. A summary of renewable portfolio standard compliance approaches is included as Appendix B. According to data from the Lawrence Berkeley National Laboratory (LBNL), states currently monitoring compliance report that utilities are meeting about 96 percent of their renewable energy requirements overall. In 2009 and 2010, all but three of the states that had an annual compliance requirement achieved greater than 90 percent compliance, with most states reporting full compliance.

[13] Union of Concerned Scientists Response to Question 24, http://www.michigan.gov/documents/energy/UCS_Compiled_Responses_on_Michigans_Energy_Future_--_4-25-13_420080_7.pdf

Availability of Renewable Energy (Questions 8, 13, 14, 15)

The National Renewable Energy Laboratory (NREL) issued a report estimating renewable energy potentials for each state. For offshore wind, the Great Lakes Offshore Wind Council estimated Michigan's potential. These estimates are provided in **Table 2**. The greatest amount of potentially available renewable energy is solar, followed by offshore wind. The Estimated Michigan Potential attempts to recognize developmental constraints. For a statewide analysis, it is not possible to consider site specific information to determine where and how much renewable energy generation will actually be developed. The Estimated Michigan Potential shown in **Table 2** reflects wind and solar potential reductions from the Theoretical Maximum Potential and attempts to recognize the significant constraints that could impact development which include local site-specific concerns, community acceptance, technical interconnection and grid integration issues, generation costs, etc.

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Table 2: Estimated Renewable Energy Potential

	NREL Theoretical Maximum Potential for Michigan[1] GW	Estimated Michigan Potential GW
Solar (rural – utility scale)	3,444	34[2]
Solar (urban-utility scale)	34	0.34[2]
Solar (rooftop)	22	0.22[2]
Onshore Wind	59	11-20[3]
Biomass	2	2
Hydro	1	1
	Michigan Great Lakes Offshore Wind Council[4] GW	**Estimated Michigan Potential[4] GW**
Offshore Wind - 30 Meter Depth	97	0-7
Offshore Wind – 45 Meter Depth	131	0-16
Total[5]	**3,700**	**61**

[1]U.S. Renewable Energy Technical Potentials, NREL, July 2012, http://www.nrel.gov/docs/fy12osti/51946.pdf
[2]The solar theoretical potential is reduced by 99% due to lack of siting experience in Michigan.
[3]The theoretical maximum potential for onshore wind is reduced by 66% and 81% to estimate the maximum and minimum Michigan potential. The reduction percentages are based on the analysis done by the Michigan Wind Energy Resource Zone Board described in the Board's final report. http://www.dleg.state.mi.us/mpsc/renewables/windboard/werzb_final_report.pdf
[4]To estimate the offshore wind potential, only the "Most Favorable Area" as described in the Great Lakes Wind Council's September 1, 2009 was included in the estimated Michigan potential. http://michiganglowcouncil.org/GLOWreportOct2010_with%20appendices.pdf
[5]Offshore Wind 45 Meter Depth potentials were included in the Totals.

The theoretical utility scale (rural) solar potential NREL estimated for Michigan is 3,444 GW. To install this quantity of solar, NREL estimates an area of 72,000 square kilometers

would be needed, which is approximately half of Michigan's land area.[14] The minimum quantity offshore wind is assumed to be zero in **Table 2**, as this technology is still in the research stages for the Great Lakes.

Possible Future Demand Under Several Scenarios

Renewable energy targets, like all types of generation planning, are often informed by estimates of future load levels or future sales levels. In particular, it is important to ensure enough energy is available to satisfy the "peak" demand, or widespread instability can result. Michigan's peak load tends to occur during the hottest weekday of the summer. That is based on the confluence of several factors that increase load. First, in a daily cycle, load is higher during the day than at night. Second, load is lower on the weekends. Third, there are also seasonal cycles. Load in Michigan is highest in the summer and lower in the spring and fall. Electricity load is also influenced by the weather.

Table 3 shows estimates of Michigan's peak load at various growth rates, using at the high end the 1.2% rate of load growth that was projected before the most recent recession, as well as lower growth rates. The 0.5% rate was used by Consumers Energy in a recent certificate of need application for a natural gas plant.

[14] Michigan Information Center, 1990 Land and Water Area by County, http://www.michigan.gov/documents/1990_Land_and_Water_Area_by_County_32916_7.pdf?20130729160147

Table 3: Peak Load Estimates (GW)

Year	Peak Load Growth Estimate Percentage		
	1.2%	**1.0%**	**0.5%**
2006	23.8	23.8	23.8
2010	24.9	24.7	24.2
2015	26.4	26.0	24.8
2020	28.1	27.3	25.4
2025	29.8	28.7	26.1
2030	31.6	30.2	26.8

Comparing these numbers to the potential numbers for each type of renewable energy in **Table 2**, shows that there is adequate renewable energy available within the state from a technical perspective to support a wide range of renewable targets.

Therefore, there are no technical or reliability issues that place a hard limit on the amount of renewable energy that could be generated. However, higher levels of requirements may require additional infrastructure to maintain reliability. While from a purely technical view there are no hard limits, non-technical factors could limit the amount that is feasible in-state, or could restrict the ability to require generation from in-state regardless of technical feasibility.

Key Non-Technical Factors Limiting Feasibility

Two key issues were identified during the process that could limit the feasibility of implementing any law that required siting generation within the State, even if the target were technically possible as discussed above.

First, from a legal perspective, Michigan's local governments address siting of all types of electrical generation, including renewables, so local governmental rules restricting such items

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could reduce the available sites. In Michigan, local governments have siting authority for generation. Recently, likely due to concerns like those expressed in some of the public forums regarding possible impacts from large turbines on nearby residents (noise and visual impacts being some of the most common cited), some local governments have restricted siting in ways that reduces the number of turbines that may be able to be sited in certain locations.

There were a number of comments submitted about the negative impacts of siting utility scale wind turbines near structures, particularly near homes. Health and nuisance issues relating to viewscape interference, flickering, audible noise, inaudible noise and vibration were described. One study, Noise and Health Report from Inter-disciplinary International Journal concludes *"our results suggest that utility-scale wind energy generation is not without adverse health impacts on nearby residents"(page 338)* and recommends that *"on the basis of our data, suggest that setback distances need to be greater than 2 km in hilly terrain" (page 339).* Another commenter compared coal-fired power plant siting decisions to wind turbine siting and suggested that greater set-backs may address the siting concerns of adjacent property owners for wind turbines in much the same way as setbacks or buffer zones that are typically used for coal-fired power plants. A 2011 report prepared under a National Association of Regulatory Utility Commissioners grant, Assessing Sound Emissions from Proposed Wind Farms & Measuring the Performance of Completed Projects, found that "…it would be advisable for any new project to attempt to maintain a mean sound level of 40 dBA or less outside all residences as an ideal design goal." (page 2)

There was limited discussion about the tension between the desire for standard setback and other siting requirements vs. the desire for, and essential reality of, home rule and local zoning decisions. Comments were limited to stating preferences rather than a thorough review

of relevant statutes and regulations that would enable or inhibit state-wide siting requirements and/or standards.

Second, Michigan's current RPS provisions regarding where renewable energy could be located were characterized as unconstitutional in a federal circuit court of appeals decision issued on June 7, 2013. The court's rationale was that such restrictions fall afoul of the Commerce Clause of the U.S. Constitution. That decision was not in a case that directly challenged the constitutionality of Michigan's current law, however to date, no such direct challenge has been brought. At least one other state's preferences for in-state renewable generation are before the courts in direct challenge, but no decisions have yet been rendered: Colorado's in *American Tradition Institute v. Colorado*.

Additionally, some states have opted to amend their renewable energy statutes rather than risk having their RPSs declared unconstitutional. When the constitutionality of Massachusetts' RPS was challenged, the Massachusetts Department of Public Utilities removed the in-state locational requirement for long-term renewable energy contracts and the case was settled before a court could rule on the statute's constitutionality. Similarly, Minnesota amended its RPS statute to provide the state's program "shall not give more or less credit to energy based on the state where the energy is generated." California removed location classifications from its RPS in 2006. *The Commerce Clause and Implications for State Renewable Portfolio Standards* report published by Clean Energy States Alliance provides a summary of various approaches for encouraging local economic activity while remaining in compliance with U.S. Constitution. In contrast, some commenters argued that the ability to import renewables from other areas that may be cheaper would have economic benefits overall by lowering the cost of power, and that

these broad benefits could outweigh the direct economic development benefits of restricting generation.

No single source provides a net benefits summary of increased renewable investments in Michigan that addressed the full list of issues identified in this report such as relative costs (with and without consideration for carbon and other environmental impacts), relative risks, regional market approach, or other benefits, so these are unavailable for comparison of various scenarios.

Program Adaptability (Questions 29,32)

Michigan's RPS includes several items that are intended to increase its adaptability. Two key elements that add adaptability is a list of criteria for adjusting or delaying the 10% requirement and a cost cap. Additionally, Michigan's RPS has some provisions regarding how it might fit into a federal RPS were one to be enacted, although not every possible adaptation can be foreseen or addressed through a state law. Other states have employed a variety of provisions to provide alternatives to limit costs under unforeseen circumstances, and some of the more popular provisions are described below, along with the states employing them.[15]

- Alternative compliance payments. These are payments that can be made in lieu of purchasing RECs or building new generation in order to meet RPS requirements. They can serve as an alternative to a cost cap. (CT,DC,DE,IL,MA,MD,ME,NH,NJ,OR,OH,PA,RI,TX)
- Rate impact or revenue cap. These provisions are similar to the per customer cost cap that Michigan employs, but are instead structured as a limit on the overall revenue that can be dedicated to compliance, or the overall rate impact. (CO,DE,IL,KS,MD,MO,NM,OH,OR,WA)

[15] Seven states with RPSs employ none of these cost limitation provisions. (AZ,CA,HI,IA,MN,NV,WI).

- Per customer cost cap. This limits the amount that can be charged to each customer to fulfill the mandate. (MI,NC,NM)
- Renewable Energy fund cap. Under this mechanism, a pre-determined amount of available funding limits the cost of achieving the RPS. (NY, formerly CA)
- Renewable Energy contract price cap. This limits the amount that can be charged per MWh of renewable power in a contract, essentially a way of limiting costs for renewables that is "upsteam" of revenue caps or per customer rate caps. (MT, formerly NM)

An evaluation of the performance of many of these ways of restricting costs can be found at: **http://climatepolicyinitiative.org/wp-content/uploads/2012/06/Limiting-the-Cost-of-Renewables-Lessons-for-California.pdf**.

Generation Costs (Questions 3, 4, 5, 10)

Levelized Cost of Energy (LCOE) for New Build Comparison

The Energy Information Administration (EIA) makes projections of levelized costs for various types of electric generation shown in **Table 4.** The EIA costs are provided in 2011 dollars for plants entering service in 2018 and are overnight cost estimates. EIA provided the levelized cost of renewable and non-renewable energy in its Annual Energy Outlook 2013 Early Release. EIA projects an advanced coal plant levelized cost range of $123.00 per MWh to $135.50 per MWh[16] and a natural gas combined cycle plant cost range of $65.60 per MWh to $67.10 per MWh.

[16] With carbon capture and sequestration.

Table 4: EIA Estimated Levelized Cost of New Generation Resources, 2018[17]

Table 2. Regional variation in levelized cost of new generation resources, 2018

Plant type	Range for total system levelized costs (2011 $/megawatthour) for plants entering service in 2018		
	Minimum	Average	Maximum
Dispatchable Technologies			
Conventional Coal	89.5	100.1	118.3
Advanced Coal	112.6	123.0	137.9
Advanced Coal with CCS	123.9	135.5	152.7
Natural Gas-fired			
Conventional Combined Cycle	62.5	67.1	78.2
Advanced Combined Cycle	60.0	65.6	76.1
Advanced CC with CCS	87.4	93.4	107.5
Conventional Combustion Turbine	104.0	130.3	149.8
Advanced Combustion Turbine	90.3	104.6	119.0
Advanced Nuclear	104.4	108.4	115.3
Geothermal	81.4	89.6	100.3
Biomass	98.0	111.0	130.8
Non-Dispatchable Technologies			
Wind	73.5	86.6	99.8
Wind - Offshore	183.0	221.5	294.7
Solar PV[1]	112.5	144.3	224.4
Solar Thermal	190.2	261.5	417.6
Hydro[2]	58.4	90.3	149.2

[1] Costs are expressed in terms of net AC power available to the grid for the installed capacity.
[2] As modeled, hydro is assumed to have seasonal storage so that it can be dispatched within a season, but overall operation is limited by resources available by site and season.
Note: The levelized costs for non-dispatchable technologies are calculated based on the capacity factor for the marginal site modeled in each region, which can vary significantly by region. The capacity factor ranges for these technologies are as follows: Wind – 30% to 39%, Wind Offshore – 33% to 42%, Solar PV- 22% to 32%, Solar Thermal – 11% to 26%, and Hydro – 30% to 65%. The levelized costs are also affected by regional variations in construction labor rates and capital costs as well as resource availability.
Source: U.S. Energy Information Administration, Annual Energy Outlook 2013,December 2012, DOE/EIA-0383(2012)

Carbon regulation is expected to increase the cost of coal and natural gas generation, but to date has not occurred. EIA levelized cost data shows approximately a $12.50 per MWh cost difference between an advanced coal plant and an advanced coal plant with carbon sequestration technology. The Commission Staff, with input from a group of electric providers, developed a

[17] http://www.eia.gov/forecasts/aeo/pdf/electricity_generation.pdf

combined cycle natural gas plant levelized cost of $66.23 per MWh in 2013 dollars for a plant entering service in 2016.[18]

The EIA's 2012 and 2013 reference case for estimating the levelized costs of different sources of new generation makes an adjustment for greenhouse gas intensive technologies. Specifically, the EIA increases the cost of capital by 3% for coal-fired power and coal-to-liquids plants without carbon capture and sequestration (CCS). The EIA clarified that this 3% is based on a $15 per ton cost of carbon dioxide, which translates to $16 per MWh for new pulverized coal plant and $18 per MWh for Integrated Gas Combined Cycle (IGCC). Recent work on the subject of carbon tax and regulation by the Brookings Institution, Congressional Research Service, MIT, NERA Economic Consulting, and others use a higher estimate in the range of $20 per ton. This would suggest slightly higher levelized cost of energy than the EIA estimates.[19] However, if no carbon tax or equivalent is enacted, then the cost of capital would need to be adjusted accordingly.

Alternative Comparisons (Existing)

Using the most recently approved cost of service data for Consumers Energy and DTE Electric, the weighted average overall power supply cost for both companies is $64 per MWh. This cost includes all existing generated and purchased power with transmission costs removed. Therefore, when comparisons are made to the existing fleet, no new generation of any kind is likely to be lower, with the exception of lower priced wind contracts.[20]

Because new builds of any type are likely to be more expensive than the existing, very mature fleet, comparing the cost of new renewable energy resources to the cost of existing

[18] http://efile.mpsc.state.mi.us/efile/docs/15800/0036.pdf. See also staff answer to question 23.
[19] See: (Utility answer to Q4).
[20] See: http://www.michigan.gov/documents/mpsc/ContractSummary_405658_7.pdf?20130918173106.

generation has been criticized. Further, even comparing the cost of new renewables to other types of new generation should be done with caution.

There is debate about the appropriate methodology for how best to compare the cost of renewables to existing generation and to the cost of new non-renewables generation. For instance, the EIA estimates show only the projected cost of energy. However, planning by utilities and grid operators to ensure long-term supply of generation is done on a capacity basis, meaning taking into account the availability of that energy. Certain types of renewable energy, namely wind and solar, have less capacity value due to their intermittency (although solar is often available at "peak" times), as discussed further below. Additionally, the EIA methodology omits some costs (such as transmission upgrades necessary to integrate new generation resources that will be higher for new resources that are farther from customer load centers).[21] Other factors it omits that some believe should be included are the cost of backup generation and spinning reserves, essentially to "offset" some of the costs of integrating resources with comparatively high intermittency, though this is disputed by others.[22] Similarly, the EIA methodology also omits some pricing benefits that may be available. For instance, the federal production tax credits are not included, which give a credit for 10 years of 2.3¢/kWh for wind, geothermal, closed-loop biomass, and 1.1¢/kWh for other eligible technologies, which can noticeably impact pricing. The EIA methodology also does not attempt to quantify potential health benefits from alternative generation. Levelized costs are presented as "overnight" costs without the cost of interest incurred during construction. Generation types with long construction periods such as nuclear and coal would have higher levelized costs if these interest costs were included in the

[21] Whether additional transmission costs should be allocated to renewables or whether the infrastructure actually reduces costs overall is an area of debate. There is little debate that non-utility-scale solar does not require transmission, and thus may save cost relative to other intermittent generation, but no quantification of such a figure was provided.
[22] Compare the IICCUSA response to ISO/RTO Variable Energy Resources White Paper.

calculation. Finally, EIA costs are only estimates and can vary based on the assumptions and timeframe are used.

Summary of Costs

In general, there is broad agreement that there is significant technical potential for renewables to provide significant supply in Michigan because it's technically possible to meet all of Michigan's needs through renewables. That said, there is significant difference between theoretical technical feasibility of aggressive renewables and the practical ability to deploy it at very high levels within the State. It is also clear that since the Michigan RPS was enacted, the costs of renewable energy, particularly onshore wind and solar, have dropped noticeably.[23]

The most common way to estimate the relative cost for renewables is to compare new renewable builds to new types of other generation. In doing so, natural gas co-generation is one of the only types of conventional fuel generation that might be more economical than the lower-cost forms of renewable energy. However, if compared to existing generation, renewables will often appear more expensive because many of the fixed costs relating to existing generation have already been paid.

While levelized cost is by far the most commonly cited methodology for determining costs, it has drawn criticism from a wide variety of quarters for what it does not include. A long list of potential factors potentially impacting cost estimates and comparisons are not part of the levelized cost calculations, including the system value and operational profiles, the costs/benefits of reduced emissions, future tax treatments, future fuel costs, carbon regulations, the need for supporting generation, and the expected rate of technical improvements. The next section discusses various alternatives, none of which have been widely adopted.*Generation Cost Comparison Methods*

The Levelized Cost of Energy (LCOE) is a methodology for determining an estimated cost of energy from a given generation technology and is often used for screening generation resource options. The following basic input assumptions are required: fixed cost, variable cost, financing costs and expected energy production. The last item is related to how the resource is

[23] Solar cost decreases have been reported by electric providers as part of solar pilot programs.

expected to be dispatched and is the most difficult to estimate. According to EIA, LCOE should not be used to compare renewable and conventional generation options beyond a simple screening comparison because they have different operational profiles and system value. [24] Instead, EIA is developing a new methodology called Levelized Avoided Cost of Energy (LACE). EIA describes LCOE as the revenues required for a type of resource and LACE as the revenues available to a type of resource. When LACE is greater than LCOE, a project is considered to have a positive net economic value. LACE is based on the system value of a generation resource and derived from the cost of displaced energy and capacity which EIA says would be a better value to use for resource selection. EIA's LACE forecasts are shown in **Figures 8a and 8b.**

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[24] EIA Presentation, Assessing the Economic Value of New Utility-Scale Renewable Generation Projects, http://www.fbcconferences.com/e/eia/presentations/c-namowicz.pdf, Jun 17, 2013, Chris Namovicz, U.S. Energy Information Administration, 2013 EIA Energy Conference.

Figure 8a: EIA Net Value Forecasts (LACE – LCOE)

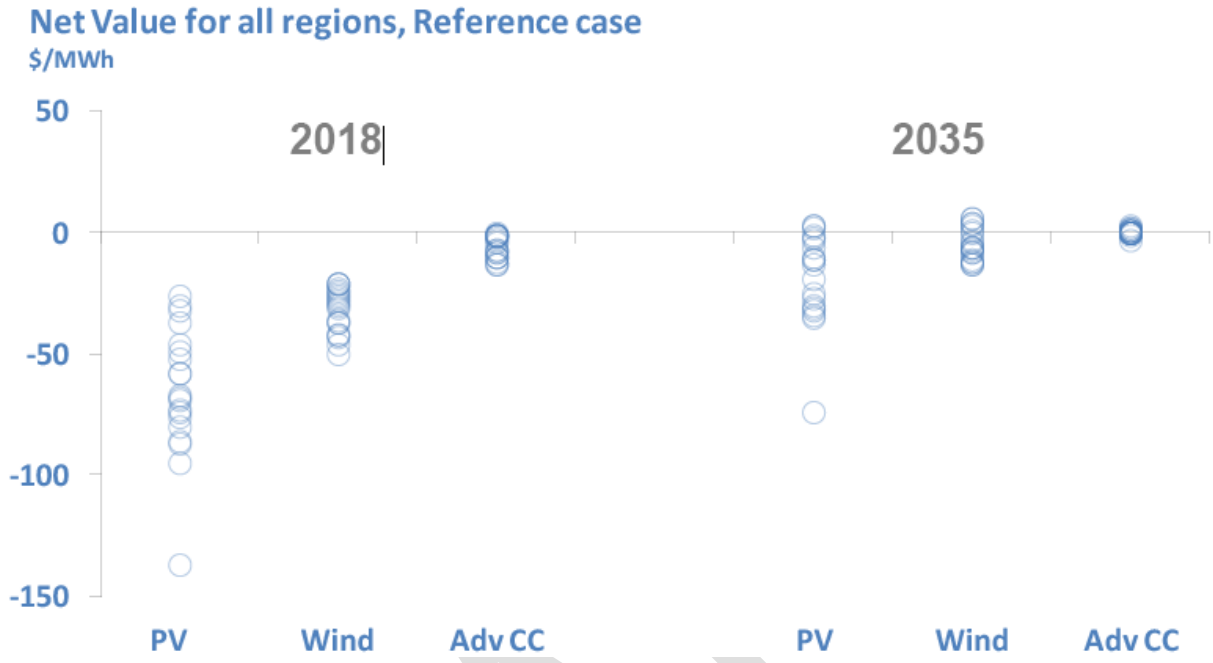
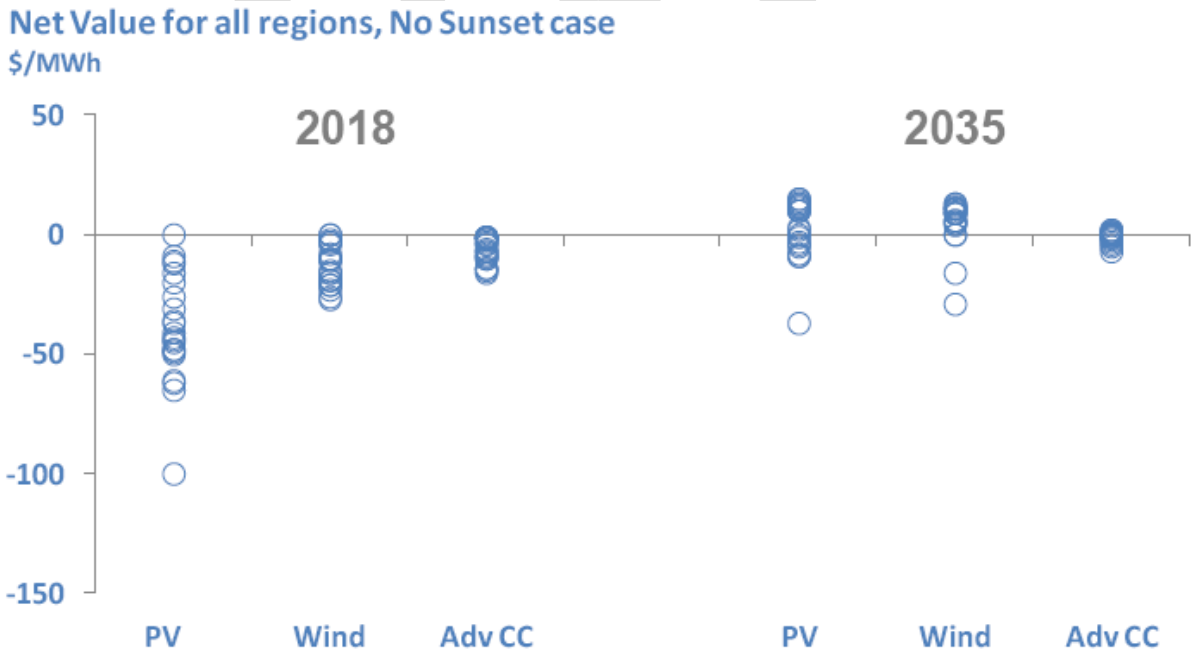


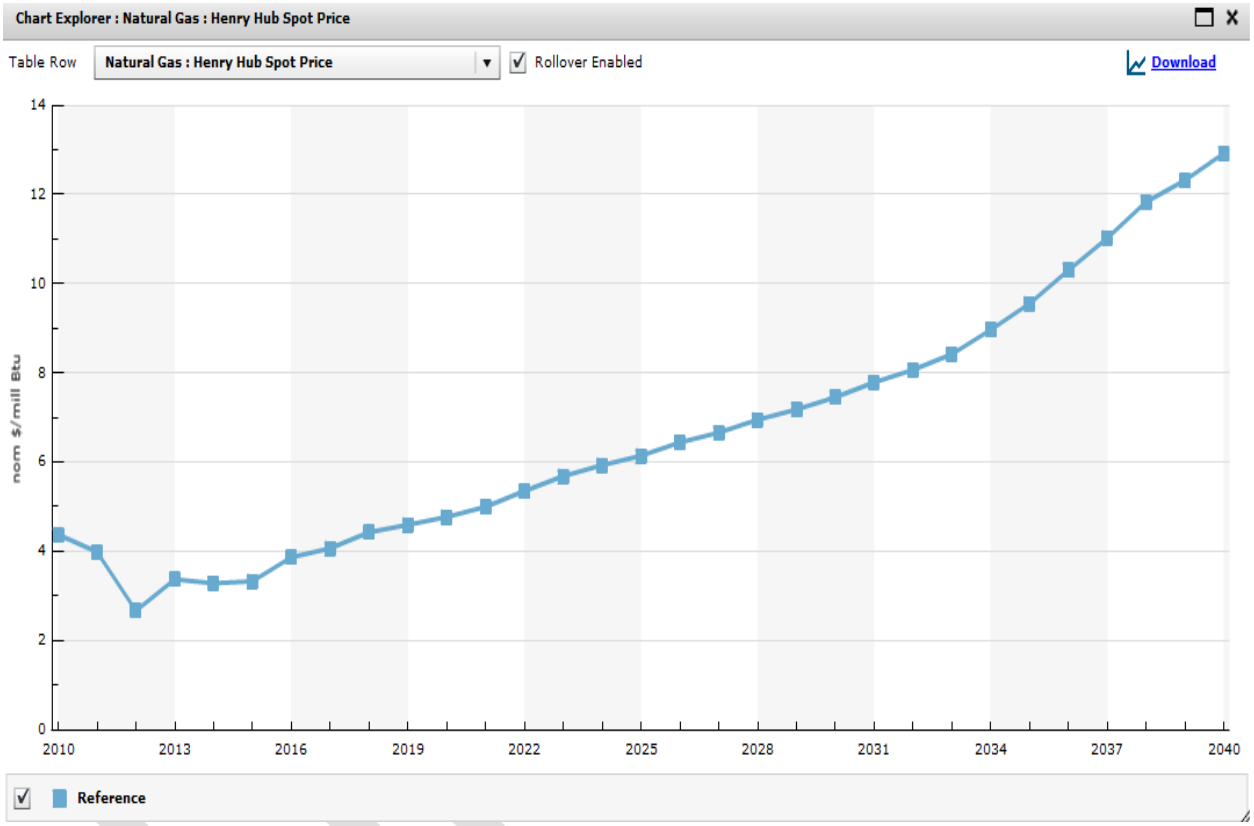
Figure 8b: EIA Net Value Forecasts (LACE – LCOE)
(Assuming Continuation of Current Tax Credits)



Forecasting the value of the avoided energy and capacity into the future for the life of the resource option being considered requires many assumptions – including assumptions that are

forecasted for very long-term time periods. The price of natural gas is a factor in evaluating the advanced combined cycle generation option. **Figure 9** shows EIA's forecast of natural gas prices.

Figure 9: EIA Natural Gas Price Forecast[25]



EIA uses the National Energy Modeling System to generate LCOE and LACE numbers and points out that resource characteristics reflect average values for each region, and may not reflect characteristics at all locations, especially in large, geographically diverse regions. Both LCOE and LACE values are only approximations of model decision making criteria. Similarly, the model on which both LCOE and LACE is based is itself is an approximation of real-world

[25] http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2013ER&subject=3-AEO2013ER&table=13-AEO2013ER&region=0-0&cases=early2013-d102312a

conditions. EIA is expected to begin reporting LACE data in addition to LCOE in the near future.

Other Decision-Making Tools

In addition to generalized estimates like those discussed above, when making specific decisions regarding generation at a point in time, integrated resource planning modeling is often undertaken. Michigan's current law requires such planning as part of a certificate of need application for any new generation not mandated as part of the RPS. Such activities may use Michigan-specific or utility-specific modeling. Some advocate creating a continual modeling process, so that integrated assessments are constantly informing potential decisions that may be considered privately.

Capacity Factors

The capacity factor is a measure of how often an electric generator runs for a specific period of time. It compares how much electricity a generator actually produces with the maximum it could produce at continuous full power operation during the same period. For example, if a 1 MW generator produced 5,000 MWh over a year, its capacity factor would be 0.57 because 5,000 MWh equals 57% of the amount of electricity the generator could have produced if it operated the entire year (8,760 hours) at full capacity and produced 8,760 MWh of electricity. Generators with relatively low fuel costs are usually dispatched to supply baseload power, and typically have average annual capacity factors of 0.70 or more. (No generator has a capacity factor of one, because all types of generation must cease running at times for a variety of reasons, including fuel availability and required maintenance.) Generators with lower capacity factors may indicate they are in operation during peak demand periods and/or have high

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fuel costs, or their operation depends on the availability of the energy source, such as hydro, solar, and wind energy.[26]

The US DOE 2011 Wind Technologies Market Report presents capacity factors for 397 wind power plants built between 1983 and 2010, totaling 37,606 MW (94% of U.S. installed wind generation at the end of 2010). The report found that capacity factors for wind have improved over time, from 25% in 1999 to a high of nearly 34% in 2008. Although factors slipped back to the 30% range during 2009 and 2010, they rebounded to 33% in 2011. The improvement can be credited to the substantial increase in average hub height and rotor diameter. Two factors likely played a role in the 2009 and 2010 decrease: annual wind resource variations (wind speeds) and wind power curtailment. Curtailment of wind generation can occur due to inadequate transmission and/or minimum generation limits which can result in low or negative wholesale electricity prices. Forecasted capacity factors for Michigan's newer wind farms located in the Thumb area are above 40%.[27]

Certain types of renewable energy, namely wind and solar, have less capacity value than most other kinds of generation due to their greater intermittency. This means that system operators cannot count on them during peak periods of high electricity consumption in the same manner as other types of generation. The Midcontinent Independent System Operator,[28] (MISO) studies actual wind generation during periods of peak consumption in order to calculate the maximum "capacity credit" that can be applied to wind generation if it is used by a utility to meet its reserve margin obligation. The capacity credit is influenced by the capacity factor of wind generation and, importantly, *when* that generation occurs relative to peak system usage.

[26] http://www.eia.gov/tools/faqs/faq.cfm?id=187&t=3
[27] http://www.windpoweringamerica.gov/filter_detail.asp?itemid=3207
http://www.windpoweringamerica.gov/pdfs/2011_annual_wind_market_report.pdf
[28] The Midcontinent Independent System Operator (MISO) is the regional transmission operator for the majority of Michigan.

The current wind capacity credit for 2013–2014 in MISO is 13.3%, suggesting that, on average, only 13.3% of the total wind capacity across the MISO system can be counted on to be available at the time of MISO's system-wide peak. (Midwest ISO, Planning Year 2013–2014 Wind Capacity Credit December 2012).[29] For comparison, other types of generation such as coal, nuclear, or natural gas may have values in the range of 80–95 percent, and the capacity credit given to nuclear and fossil generators is unit-specific and based upon the individual unit's historical actual performance.[30]

As a technical matter, electricity can be stored for use at a later time, which could theoretically alleviate intermittency concerns. As a practical matter, however, not much electricity storage has been developed due to its relatively high cost. Michigan is a leader in one of the only large storage technologies used, pumped hydro (located in Ludington, MI). Pumped hydro is essentially an artificial dam, in which water is pumped into the reservoir during times when power is plentiful, and released later when it is needed. Other technologies are not yet ready for full implementation due to technology, economic and operational considerations, such as battery storage and flywheels. If these technologies progress and costs decrease, these technologies may change the calculations regarding intermittency as well as creating other benefits for reliability. At this time, however, they are unlikely to be able to be used at enough scale to influence decision making regarding renewable deployment.

While intermittent, wind output changes tend to be gradual and predictable. When wind turbines are spread over large areas, it typically takes an hour or more for a significant change in wind output to occur. Wind energy forecasters can predict what wind output will be hours and

[29] www.midwestiso.org/Library/Repository/Study/LOLE/2013%20Wind%20Capacity%20Report.pdf
[30] See, e.g., graph on slide 7 of the presentation at: www.midwestiso.org/Library/Repository/Meeting%20Material/Stakeholder/SAWG/2009/20091210%20SAWG/20091210%20SAWG%20Wind%20Capacity%20Credit.pdf and Utility answer to Q3.

days in advance with a high level of accuracy through the use of advanced computers and weather models.[31] Therefore, while it has required new tools and management, the integration of intermittent generation has taken place without a loss of reliability to the overall system.[32]

In summary, the integration of wind and other intermittent renewable energy does require system changes. All types of generation have unique operating characteristics that affect system operations and economics. For example, nuclear and coal plants operate most efficiently at a fairly constant output – i.e., there may be technical and/or economic disincentives[33] to turn the plants "off" and "on." The generation output may exceed electricity demand at night and in low-demand seasons (spring/fall). This characteristic provided an impetus to build Ludington storage to take advantage of that excess generation and store it to be later released at times of higher usage. This improved the capacity factor for baseload units and improved system reliability. Generation diversity and related issues that affect reliability are discussed next.

Diversity of Generation/Impact on Reliability (Questions 6, 39)

A number of factors will require adaptability in the electric utility world: aging electric infrastructure and generation plants, increasing costs for new generation, stricter environmental controls, evolving technologies, and uncertain load growth. In order to understand the wide range of possible adaptation that may be needed, it is important to understand the current landscape of energy generation.

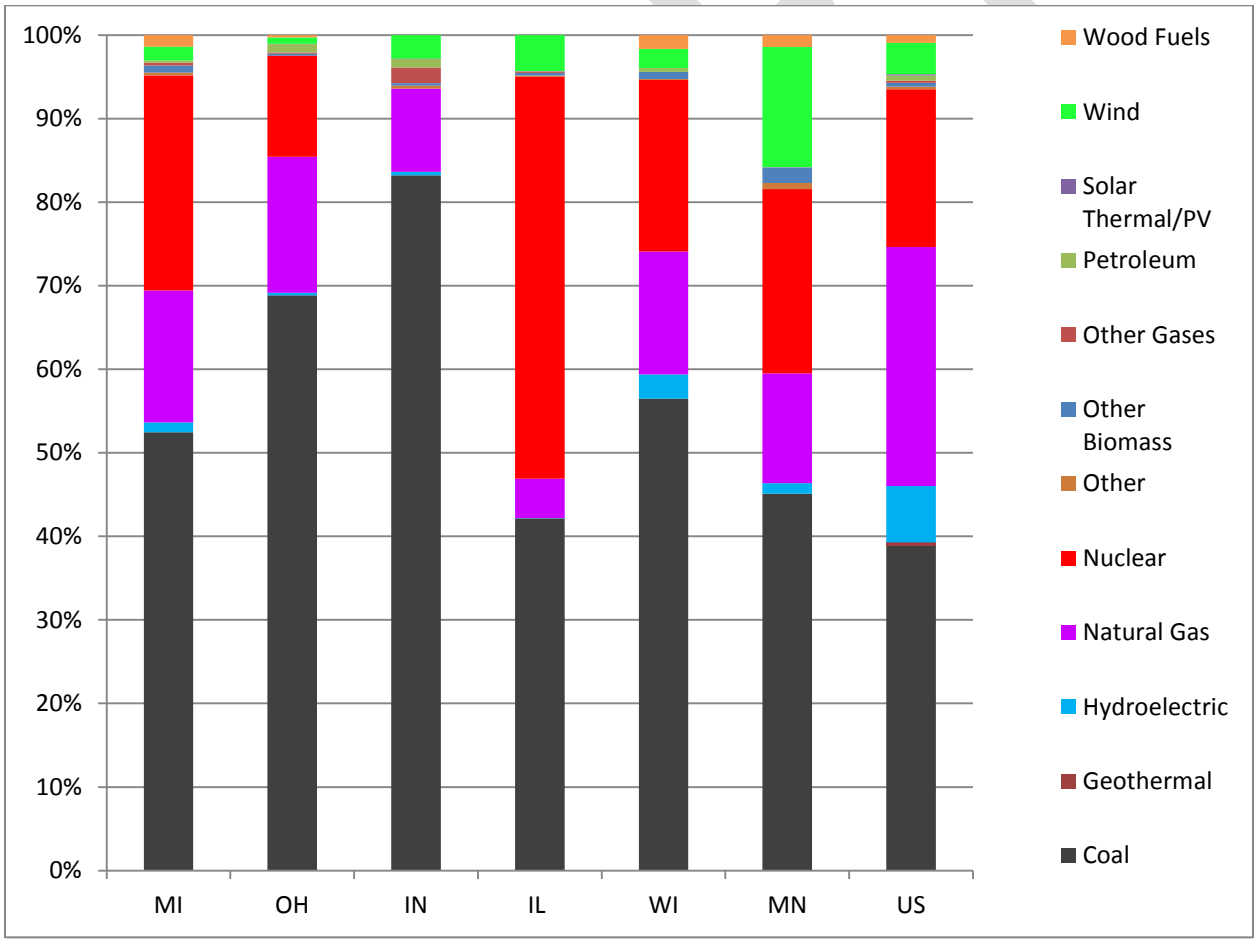
America's electric companies rely on a variety of (largely domestic) fuels to generate electricity. Fuel diversity helps to protect electric companies and their customers from

[31] http://www.awea.org/Issues/Content.aspx?ItemNumber=4544&navItemNumber=680
[32] *See*: Appendix C; MISO's response letter
[33] Conventional coal and nuclear plants may take several days to start up after they have been shut down, and there may be associated start-up costs.

contingencies such as fuel unavailability, fuel price fluctuations, and changes in regulatory practices that can drive up the cost of a particular fuel. Fuel diversity also helps to ensure stability and reliability in electricity supply and strengthens national security.

Similarly, Michigan's fuel generation mix shows a diversity of fuels, although it is more heavily weighted toward coal and has fewer renewables (even with the RPS) than the national average. Michigan's mix, however, is more diverse than many surrounding states. **Figure 10** below shows the fuel mix by generation for Midwestern states compared to Michigan and the United States as a whole.

Figure 10: 2012 EIA Generation Fuel Mix for Midwestern States Compared to the US[34]



[34] http://www.eia.gov/electricity/state/ ; This is based on 2012 data as this is the most recent Energy Information Agency data available..

That fuel mix has been considered actively in recent years because it is likely to change or at least require reassessment in the near future: more than half of Michigan's coal plants are older than 40 years (built before 1970), nearly a third began operation more than 50 years ago. For instance, Consumers Energy estimates that it will need 1,000 MW of new generating capacity due to suspension of operations at seven of its oldest coal-fueled electric generation plants.

A diversity of fuels can help the overall reliability of the electric grid. Grid operators are adept at dealing with variability and uncertainty on the power system. Factories turning large equipment on and off and millions of people changing their air conditioning and electric heating use can cause large and often unpredictable changes in the demand for electricity. Large changes in electricity supply also occur when large generating plants experience sudden outages due to mechanical or electrical failures and go offline. The loss of a large power plant can happen at any time, forcing grid operators to have reserve generation available 24/7. Therefore, there are advantages to having a mix of plants – some that generate steady amounts of power for long periods of time, some that can turn off and on quickly, and overall, a variety of fuels.

In addition to technical considerations of adaptability, there are considerations of regulatory adaptability. For example, the federal government has enacted a series of emissions rules that have required significant investments in current coal plants and significantly increased the cost of new coal plants. There is also future uncertainty related to climate change and other current and future environmental laws and regulations. Therefore, a diversity of fuels that includes renewable resources could help mitigate rate impacts in the future in the event of increased environmental requirements at the national level. Notwithstanding these benefits, there are attributes to renewable energy that may decrease its value relative to other sources.

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These may include lower capacity value associated with the intermittent power resources, additional transmission costs, integration costs, and the large land footprint necessary for utility-scale wind or (to a lesser extent) solar projects. As with the benefits, these factors can be difficult to quantify and are not typically addressed in economic evaluation of renewable energy projects. Moreover, even when costs or benefits are estimated, they are likely to change over time given the long lifespan of the investments and uncertainty surrounding energy and commodity prices and public policy.

Outside of the context of utility-scale projects, renewable energy sources, primarily solar and (to a lesser extent) wind, as well as combined heat and power projects, can increase overall reliability due to the "distributed" nature of the technologies. In other words, these technologies generally feed power directly to the user on-site and do not require a large transmission structure to operate. Therefore, a large catastrophic weather event is less likely to affect distributed generation as it could with centralized generation.

By the end of 2013, the MPSC RPS Report projects that approximately 1,200 MW of new renewable energy capacity will be operating with just over 1,100 MW in Michigan. According to EIA, during the 2012 – 2016 time period, U.S. planned generator additions are 952 generators with a net summer capacity of 76,616 MW. Renewables comprise about 35% of the planned new capacity.[35]

Ceres, a sustainability leadership advocacy group formed in response to the Exxon Valdez spill, has identified seven essential strategies for minimizing risk: diversify utility supply portfolios; utilize robust planning processes; employ transparent ratemaking practices; use

[35] http://www.eia.gov/electricity/annual/html/epa_04_05.html

financial and physical hedges; hold utilities accountable; operate in active "legislative mode"; and reform and reinvent ratemaking policies.[36]

Fuel Price and Energy Price Volatility (Questions 3, 4, 6, 18)

Renewable energy proponents often point to the volatility and uncertainty of fuel prices as rationale to increase reliance on renewable energy. Approximately half of the renewable resources in Michigan will come from independent power producers who sell their energy to utilities through purchased power agreements (PPA). These contracts are generally for 20 years and lock in the price paid by the utility for that period of time. Moreover, the price of renewable generation does not depend on fuel costs and, therefore, considered to be more predictable. In comparison, while natural gas prices are expected to continue at fairly low levels, the future curve of natural gas prices is sloped upward, making it difficult to lock in a low price for an extended period of time. Thus, wind provides a long term fuel contract with known prices that, when available, can be an attractive alternative to other sources of energy.[37]

The United States has the largest reserves of coal in the world and is a net exporter of coal. Coal has been used to produce electricity for over 60 years but the percentage of total electric generation from coal decreased from 49% in 2007 to 42% in 2011. The cost of generating electricity from coal has historically been less expensive than using natural gas. This changed in 2007, when previously untapped shale deposits led to a decrease in the price of natural gas.[38]

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[36] Practicing Risk-Aware Electricity Regulation: What Every State Regulator Needs to Know, Ron Binz, Richard Sedano, Denise Furey & Dan Mullen, A Ceres Report, April 2012 http://www.ceres.org/resources/reports/practicing-risk-aware-electricity-regulation/view0

[37] Valuing Renewables as a Long-term Price Hedge, Even in an Era of Low Natural Gas Prices, Mark Bolinger, Lawrence Berkeley National Laboratory, June 17, 2013 http://www.fbcconferences.com/e/eia/presentations/m-bolinger.pdf

[38] http://www.eia.gov/energy_in_brief/article/role_coal_us.cfm

In Michigan, coal must be transported to the plant. While the cost of coal tends to remain relatively stable, transportation costs are dependent on market pricing and the cost of diesel fuel, which is used to power the modes of delivery. The national efforts to reduce the environmental effects of burning coal will also have an effect on the cost of coal generation.

During the late 1960s, emission concerns about coal plants and stable crude oil prices resulted in an increase in petroleum generation. Oil price shocks in the 1970s, and the Powerplant and Industrial Fuel Use Act of 1978 (PIFUA) led generators back to coal use. By 1990, repeal of the PIFUA and deregulation of natural gas resulted in more opportunities for interchanging petroleum and natural gas in peaker plants. And, more recently, changes in the production and use of natural gas have seen a heavier reliance on natural gas for electric generation.[39]

In 2009, Michigan produced about 148 billion cubic feet (4.2 billion cubic meters) of natural gas. Most of Michigan's gas production is purchased by Michigan utilities for their customers, but some is also sold to gas marketing companies that sell gas outside of Michigan. Natural gas produced in Michigan represents about 15 - 20% of the total gas consumed in Michigan. Michigan is a net importer of natural gas.[40]

The recent increase in the generation of electricity by natural gas power plants is a result of an increase in the supply of natural gas, focus on reducing power plant emissions and short construction times for natural gas plants. The upsurge in the supply of natural gas is due to gas production from unconventional sources, such as shale gas and tight gas. Natural gas has much

[39] http://www.eia.gov/todayinenergy/detail.cfm?id=7090
[40] http://www.dleg.state.mi.us/mpsc/gas/about1.htm

lower emissions of sulfur dioxide and carbon dioxide than coal. Natural gas plants also have much shorter construction times than coal plants.[41]

A recent article discussed the shift from coal to natural gas as a generation fuel source: [42]

> "Most of the people I know in the electric power industry are building natural gas" plants, said Jay Apt, a professor of technology at Carnegie Mellon University in Pittsburgh. That's because of low prices over the last few years and the relatively low cost of building such plants, compared with coal-fired or nuclear.
>
> But Apt cautions that the trend could stall because the basics of supply and demand mean that if too many plants embrace cheap gas, it won't stay cheap.
>
> "The surest route to $6 or $8 gas is for everybody to plan on $4 gas," Apt said, and if prices do rise, coal will again be the most cost-effective fuel. Natural gas is priced per million BTU.
>
> Apt noted that there was a "huge building boom" in natural gas plants from the late 1990s to 2004, because utilities thought they would get rich from the combination of cheap fuel and plants that were highly efficient and relatively cheap to build. There were predictions that prices would stay low over the long term, too.
>
> But natural gas prices spiked, and the new gas-fired plants around the nation stayed idle much of the time. That trend was also driven by another irony: The gas-fired plants are easier to start and stop compared with coal or nuclear, so many utilities used them just for peak electric demand periods.

In Michigan, fifteen natural gas plants were planned to begin operation around 2004. Most of those plants were never built due to the increasing price of natural gas. Now, primarily because of the discovery of new gas supplies and technologies that allow for drilling in places that could not be accessed before, natural gas plants are again at the forefront. However, natural gas prices have not been stable and an increase in the cost of natural gas could make these plants uneconomic. [43]

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[41] http://www.aep.com/about/IssuesAndPositions/Generation/Technologies/NaturalGas.aspx
[42] http://www.huffingtonpost.com/2012/01/16/electric-plants-coal-natural-gas_n_1208875.html
[43] http://www.dleg.state.mi.us/mpsc/electric/restruct/merchantplants.htm

Coal inventories at power plants dropped below the monthly five-year average in April 2013, the first time this has happened since December 2011. The decline in stockpiles occurred as coal burn increased across much of the nation during a winter that was colder than the previous winter. In addition, rising natural gas prices prompted some gas-fired power plants to run less and some coal-fired power plants to run more to generate electricity. Total coal consumption was up 11% in first-quarter 2013, compared to the same period in 2012. Last spring, when natural gas prices were near ten-year lows, coal consumption for electricity declined and stockpile levels increased. Coal consumption has since increased, but most power plants are burning down the record stockpile levels rather than increase purchases of coal. Because electric power plants appear set to burn down the record coal stocks rather than buy new supply, the weak domestic market for coal producers is expected to continue throughout 2013.[44]

Average on-peak, day-ahead wholesale electricity prices rose in every region of the Lower 48 states in the first-half of 2013 compared to the first-half of 2012. The most important factor was the rise in the price of natural gas (the marginal fuel for generation in much of the nation) in 2013 compared to 10-year lows in April 2012. However, the increase in power prices was not uniform across electric markets as regional natural gas supply issues drove larger increases in the Northeast and Pacific Northwest.[45]

Average spot natural gas prices at most major trading points increased 40% to 60% during the first half of 2013 compared to the same period in 2012, as demand for natural gas rose faster than increases in supply. Price increases were relatively uniform throughout the country, with the exception of New England and New York, where supply constraints caused spot prices

[44] http://www.eia.gov/todayinenergy/detail.cfm?id=12151
[45] http://www.eia.gov/todayinenergy/detail.cfm?id=12211

to spike when demand peaked this winter. Price differences between Henry Hub and most western trading hubs averaged less than 10 cents per million British thermal units (MMBtu).[46]

Grid Integration (Question 6, 25, 35, 37)

The function of managing the reliability of Michigan's electric system is a complex activity spread across a number of entities. The reliability of the distribution system is the responsibility of the individual utility physically providing service to the customer (in other words, this will typically be the entity to which the customer writes their monthly check). The reliability of the transmission portion of the bulk power system primarily falls to the transmission operator. The reliability of the generation portion of the bulk power system is managed by the generator owners, which in some cases are unregulated private entities. The acquisition and maintenance of adequate energy and capacity to meet the customer's energy and capacity requirements is the responsibility of the "Load Serving Entity" or LSE.

The Federal Energy Regulatory Commission (FERC) regulates interstate transmission and wholesale sales of electricity. Regulation of the bulk power system is the responsibility of the North American Electric Reliability Corporation (NERC) a not-for-profit entity (subject to oversight by the FERC) which ensures the reliability of the bulk power system through the development and enforcement of reliability standards.

Entities in Michigan are members of regional transmission operators or RTOs which operate under FERC tariffs and provide reliability coordination for the bulk power system including an energy and ancillary services market and regional transmission planning. MISO is responsible for bulk power system reliability and day to day system operation for the majority of Michigan while PJM has similar responsibilities for a portion of Southwest Michigan.

[46] http://www.eia.gov/todayinenergy/detail.cfm?id=12191

The Michigan Public Service Commission regulates the reliability of the distribution system through its rate making and order issuing process and through the promulgation and enforcement of various rules for the regulated utilities. The reliability of the member-regulated cooperatives and the municipal utilities is the responsibility of their various boards. The Commission participates with FERC, NERC and the RTOs in the process of ensuring the reliability of the Bulk Power System. The Commission also is responsible for the certificate of need process for the regulated entities.

Renewable energy resources interact with ISOs or RTOs when they interconnect with the electric grid system. Because generators operate at high voltage levels, connecting to the transmission system is necessary. Generators must meet requirements established by the regional transmission operator. Regional transmission operators also oversee the energy markets in many areas of the United States, including Michigan. Markets include wholesale energy markets, capacity markets and ancillary services markets. Most generators, including renewable energy resources, are actively pursuing participation in some or all of these markets.

Integrating renewable energy into the electric grid is the primary responsibility of ISOs/RTOs. In Michigan, the Midcontinent Independent System Operator (MISO) oversees most of the state. (AEP, which includes Indiana Michigan Power Co., is a member of PJM LLC.) There have been questions and concerns about how renewable resources would interconnect with the electric grid and how some of the unique aspects of renewable energy could impact the electric grid. But ISOs, including MISO, have been working to adjust their process and protocols to facilitate the inclusion of renewable energy resources into the generation mix.

MISO has taken several actions over the last few years to facilitate the integration of renewable energy. In 2008, MISO made its interconnection queue process more consistent and

predictable for new generators, which have largely been wind resources. This provides developers with more certainty as they seek to finance and build their projects. MISO developed a multi-value project category for transmission projects that meet reliability needs, provide economic benefits and enable public policy goals such as meeting a state-mandated RPS. A new resource designation, Dispatchable Intermittent Resources (DIR), was created by MISO to allow for transparent, timely and precise constraint mitigation, to provide flexibility during minimum load situations and to reduce the need for manual curtailments. Wind owners are able to sell more energy into the MISO market, thus providing buyers with more options for their customers.

Some types of renewable resources are considered to be intermittent because they are not able to run consistently due to needing a resource that is not always available such as wind or sun. This aspect of renewable energy has caused some entities to be concerned about how this will affect the reliability of the electric system. Reliability is a primary concern of the regional transmission operators. MISO indicates that most of the renewable resource generation on its system is wind generation. It is MISO's finding that wind has not been a factor in any system-wide reliability problems. Contingency reserves have never been deployed due to a drop in wind output. The increase in wind has presented localized congestion issues, which have been effectively managed by MISO and have not resulted in any significant reliability concerns. Planned transmission projects such as the Michigan Thumb Loop Expansion are expected to resolve these constraints.

Future growth in renewable resources, particularly wind resources, on the MISO system will be addressed by the multi-value project portfolio that was developed by MISO. The portfolio includes 17 projects across the MISO footprint that are designed to work together to give maximum value. The portfolio will relieve congestion, decrease operating reserve

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requirements, lower planning reserve requirements, lessen transmission line losses and decrease future transmission investment. MISO projects benefit to cost ratios of 1:7 to 3:0 for the Lower Peninsula of Michigan and 2:0 to 3:3 for Michigan's Upper Peninsula and eastern Wisconsin.[47]

MISO's DIR became mandatory on March 1, 2013 and all wind farms in MISO, except for some older or smaller ones, registered and became DIRs. As a result, 78% are now dispatchable by MISO. Manual curtailment of wind has decreased with the DIR tariff allowing more efficient dispatch of resources in the MISO market. The impact of dispatching renewable energy on rates in Michigan has not been quantified, but in theory MISO's DIR tariff may lessen the integration costs attributable to new intermittent resources (i.e., wind) in Michigan's electric rates. (utilities answer to Q35)

Questions 6, 35, and 37` concern the impact of renewables and distributed generation on reliability, cost and MISO dispatch operations. Comments suggest that incremental cost of transmission/ operational impacts of renewables is in the order of $2-$9 per MWh with cited references in the $4.11-$5 range, and that the benefits of these incremental investments more than outweigh costs. The MISO Dispatchable Intermittent Resource Tariff is viewed as effective in reducing the amount of manual or automatic curtailment of wind, and several studies are cited that provide approaches for estimating cost of intermittency, and actual cost impact in different regions of the country (Illinois) or the world (UK). ICCUSA comments suggest that wind intermittency is a major cost and reliability issue, but these comments are contradicted by references provided in comments from Union of Concerned Scientists, the DTE/ CMS/ MEGA joint comments, the Michigan Environmental Council and MISO's July 1, Answers to Questions (Attached as Appendix C). Examples of references include:

[47]See Appendix C: MISO's response to Valerie Brader's Letter.

- Midwest ISO Report describes the first package of 17 Multi-Value Projects as "having benefits in excess of the portfolio cost under all scenarios studied. These benefits are spread throughout the system, and each zone receives benefits of at least 1.6 and up to 2.8 times the costs it incurs." MISO Transmission Expansion Plan 2011, page 1. And an NREL Wind reference report concludes from a scenario where 20% of the Eastern Interconnect electric energy is supplied from wind resources "that although significant costs, challenges, and impacts are associated with a 20% wind scenario, substantial benefits can be shown to overcome the costs".

Wind generation has increased by 30 percent to 3 GW throughout the MISO footprint. MISO's energy market pricing, combined with tax incentives, allowed wind resources to set market prices as low as negative $20.00 per MWh in certain circumstances. Michigan's wind generation continues to contribute to MISO's overall wind capacity with 986 MW of operational wind generation currently. This is expected to increase to over 1,000 MW of operational wind generation in the state by the end of 2013. (2013 MPSC RPS Report)

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Local Impact (Question 13)

Section 29 of Public Act 295 (PA 295) requires that most of the renewable energy needed to meet the requirements of the act be constructed and/or sourced from within Michigan. The MPSC Staff submitted that Michigan companies like Barton Malow, Aristeo, and Nova Consultants have been selected to construct and provide parts for utility scale wind farms and solar PV projects. A coal plant in the Upper Peninsula was converted to use locally sourced biomass fuel. There are manufacturing companies located in Michigan that have obtained certifications to provide utility-scale wind towers and turbine blades. A joint response from the Michigan utilities states that this requirement has yielded economic and environmental benefits to the state.

1. The renewable energy investments of Consumers Energy and DTE Energy to date have created approximately 2,500 jobs, the large majority of which are temporary construction jobs.

2. Communities hosting renewable energy facilities receive increased revenues in industrial personal property taxes. These revenues benefit, among other entities, schools and libraries. Ongoing royalty payments to project participants also contribute additional community benefits and economic activity.

3. Renewable energy manufacturers, suppliers, and service providers have developed in Michigan and created jobs to meet the growing demand for renewable energy. It is estimated that there are over 200 companies now in Michigan's renewable energy supply chain.

4. The owned and contracted renewable energy projects of Consumers Energy and DTE Energy, once fully operational, will displace 4-5 million tons of CO2 annually.

5. These economic benefits do not represent a "net" calculation-that is, they do not factor in the jobs and economic benefits that would have otherwise been created if these expenditures had been made elsewhere in Michigan or saved by utility customers. Any economic benefit resulting from Michigan's current renewable

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portfolio standard (RPS) does not imply that an increase in the target would result in comparable benefits in the future.

While several comments were received outlining benefits to Michigan of the in-state requirement, as previously discussed in this report, many other commenters found the in-state requirement to be restrictive. Some commented that relaxing Michigan's locational requirement would allow cheaper renewable generation from the Northern Plains states to qualify to meet Michigan's RPS. However, data was not submitted detailing the amount of savings that could be expected from sourcing wind from the west.

Net Metering Basics (Question 28)

Net metering enables customers to develop on-site renewable energy electric generation projects to meet some or all of their electric energy needs and reduce their electric bills. Net metering customers may install an on-site renewable energy electric generation project, such as a wind turbine or solar photovoltaic panels. The project must be sized small enough so that it produces no more than what is needed to meet a customer's electric energy needs. The customer will be able to reduce its electricity purchases from the electric provider by using its generated electricity "behind the meter". Any excess energy generated by the customer's net metering project is sent to the electric provider's distribution system and the customer receives net metering credits. **Figure 11** illustrates net metering energy flows between the customer's generator, the customer's on-site usage and the electric provider's distribution system.

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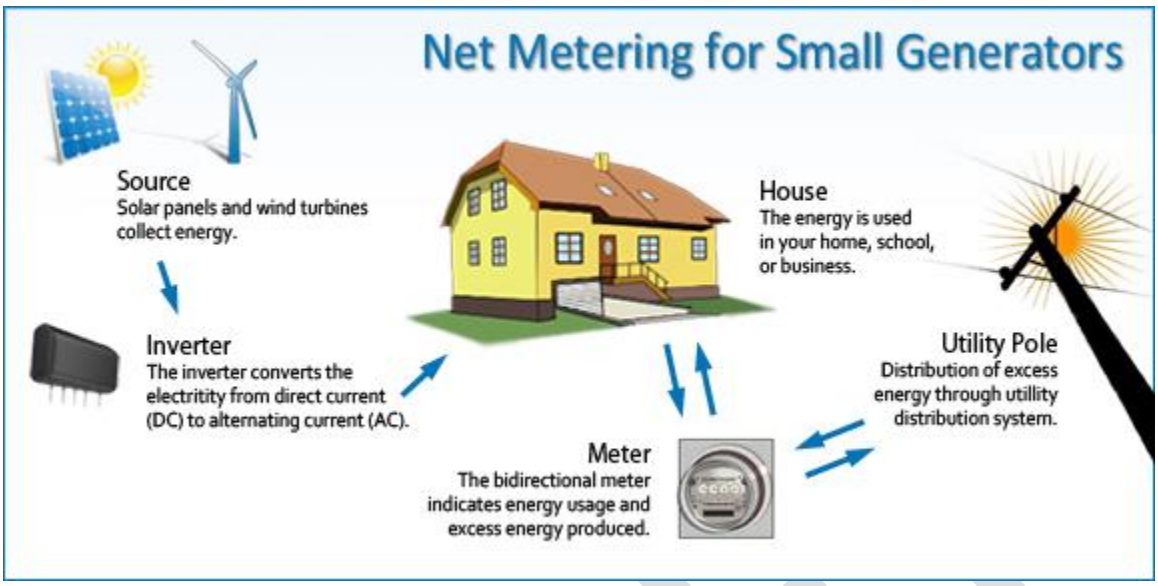
Figure 11: Net Metering Description



Michigan is one of 42 states with some form of a net metering program. Its current statewide net metering program was enacted under Part 5 of Act 295 and administered under the MPSC's Electric Interconnection & Net Metering Standards. The program is offered by all alternative electric suppliers and rate-regulated electric providers. Municipal electric providers and member regulated cooperatives are not required to offer the program, however some of these types of electric providers voluntarily offer a net metering program. Net metering projects with generators that are 20 kW and less qualify for a net metering credit equal to the full retail rate (True Net Metering). Projects larger than 20 kW up to 150 kW receive a net metering credit equal to either the power supply portion of the retail rate or a wholesale market price (Modified Net Metering). The third and final project size category is for methane digesters that are as large as 550 kW. The net metering customer is not required to own the generation project, but the Act 295 net metering provision does not provide for a customer to apply net metering kWh to more than one meter (meter aggregation) and it does not establish a framework for community renewables. Due to more complex billing and meter reading activities, net metering customers

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do create additional costs for a utility. These types of additional costs are not currently tracked by the Commission. However, some of these costs may be considered part of the $75 interconnection and $25 net metering fees that will be discussed below.

According to a recent Crossborder Energy Study, benefits of net metering that are hard to quantify include mitigating negative health impacts, reduced use of scarce water resources, increased local employment, reductions in gas and electric market prices due to reduced demand for these commodities, energy security and reliability benefits from the use of local resources.[48] Other grid based benefits specifically related to solar resources could include blackout prevention, outage recovery, emergency dispatch, managing load uncertainty, retail price hedging, voltage and reactive power control, reduced line losses and deferral of transmission investment as mentioned in a July 2013 report titled "State and Utility Solar Energy Programs: Recommended Approaches for Growing Markets" issued by the National Regulatory Research Institute (NRRI) includes a chart summarizing net metering and value of solar studies.[49] These benefits can all contribute to downward pressure on wholesale energy prices.

A net metering customer's bill, under a True Net Metering billing arrangement, is based on net usage for the month. A kilowatt hour (kWh) generated by the customer's net metering project is exactly equivalent to a kWh delivered by the utility. When the customer's net metering project is sending excess generation to the grid, the excess kWh are "banked" as net metering credits for later usage by the customer. Modified Net Metering bills charge customers the full retail rate for all energy delivered to the customer and provide a credit equal to the power supply portion of the retail rate or a wholesale rate. For methane digester projects that are larger

[48] Crossborder Energy, "Evaluating the Benefits and Costs of Net Energy Metering in California," R. Thomas Beach, Patrick G. McGuire, January 2013. Page 20. http://votesolar.org/wp-content/uploads/2013/01/Crossborder-Energy-CA-Net-Metering-Cost-Benefit-Jan-2013-final.pdf

[49] http://www.nrri.org/documents/317330/f1c96d7d-83ac-4fe3-bf0f-ef8ed343efe8

than 150 kW, the customer pays distribution charges for each kWh they generate and use on site. The value of the banked net metering credits is determined by the customer's utility rate schedule and whether the customer participates in True Net Metering or Modifed Net Metering.

There are three ways the customer's bill is reduced: 1) Utility purchases are reduced by generating and using kWh on-site, 2) Customer generates more kWh than needed at any instant during the month which are delivered to the utility, 3) KWh credits from previous month's excess generation are applied to the bill.

Some electric providers have voiced concern that net metering transfers electric system costs from participating to non-participating ratepayers. For True Net Metering customers, the net metering credit includes the variable components (charges billed on a per kWh basis) for both Energy and Delivery Charges. Under the net metering program, the customer always pays the monthly System Access Charge. The credit is less for Modified Net Metering because distribution charges are not included and even lower for customers on a demand-based rate schedule because those customers pay more of their bill through a demand charge and less in the per kWh charge. Therefore, these net metering customers still contribute toward usage of the electric grid – even if the customer offsets all or more of their monthly kWh usage.

Rates charged by electric providers are established in general rate cases under the ratemaking authority of the MPSC. 2008 PA 286 requires that rates must be equal to the cost of serving each customer class - residential, commercial and industrial. Each rate class's contribution to the utility's peak usage is one factor used to determine cost of service at the customer class level. After costs are allocated to each rate class, individual rate schedules are developed for different types of customers within the rate class.

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Rates are designed to recover costs and encourage desired electricity usage characteristics including conservation and reduced on-peak usage. **Table 5** describes some basic rate schedules for Consumers Energy and shows for different groups of customers the net metering credit and the different charges that are combined to make their total rates.

Table 5: Utility Rate Schedule Example

Utility Rate Schedule Example								
		Energy Charges				**Delivery Charges**		
Rate Schedule	**Net Metering Credit**	**Capacity Charge**	**Energy Charge**	**Power Supply Cost Recovery Factor**		**System Access Charge**	**Capacity Charge**	**Distribution Charge**
	$ per kWh	$ per kW	$ per kWh	$ per kWh		$ per Month	$ per kW	$ per kWh
Residential RS	$0.1295	NA	$0.0838	$0.0019		$7	NA	$0.0438
Secondary GS - energy only	$0.1341 (Modified NM Credit = $0.0971 or wholesale)	NA	$0.0952	$0.0019		$20	NA	$0.0370
Secondary GSD - demand	$0.108 (Modified NM Credit = $0.071 or wholesale)	$9	$0.0691	$0.0019		$30	$1	$0.0267
Primary GP - energy only	Modified NM Credit = $0.088 or wholesale	NA	$0.0861	$0.0019		$50	NA	$0.0136
Based on Consumers Energy's rate schedules. To simplify the rate information, summer/winter price differentials and higher cost rate blocks for high usage customers are averaged together and surcharges are not reflected in the rates.								

Typically, for residential and small commercial customers, utility costs are recovered using a fixed monthly system access charge (sometimes called customer charge) and a per kWh rate that is applied to each kWh used by the customer. Larger customers may have a demand

charge. Fixed costs include costs that are incurred by the utility even if the customer does not use any kWh during the month. These types of costs include the distribution system wires, poles and substations, utility administrative costs, meter reading, billing system, customer call center, capacity charges the utility pays under power purchase contracts, company-owned generation plant costs. If all fixed costs were allocated to customers using a system access charge or demand charge and only variable costs (coal and natural gas fuel costs for example) were recovered using a per kWh charge, the system access charge/demand charge would be significantly higher and the per kWh charge would be significantly lower. One of the key reasons that a rate schedule would be designed to recover fixed costs using a variable charge is to promote conservation. A higher per kWh charge is expected to encourage customers to use less energy to lower their bills.

Within each rate class, there are many factors that influence the cost to serve each customer: high electricity usage (air conditioning), number of miles from the substation, customer density on the distribution system and the type of distribution equipment needed to provide power to larger customers, whether electricity usage is constant or varies. It is not possible to design rate schedules to precisely recover costs from every customer within a rate class that exactly match the cost to serve each individual customer. Instead, costs are averaged and spread over all customers in the rate class with some variations in rate design for more precise recovery.

The cross-ratepayer subsidy question is raised because when a customer reduces monthly kWh usage, they avoid paying some of the utility's fixed costs that the rate design for the customer's rate schedule has placed in the monthly kWh charge. This doesn't impact other customers until the utility files for recovery of these costs in a rate case. The rate design

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establishes how much of the fixed costs will be recovered in the per kWh charge for a particular rate schedule. The new fixed cost amount is divided by the expected number of kWh which has been reduced because a net metering customer purchases less kWh from the utility.

Participation in a net metering program in which the customer generates some or all of their monthly kWh usage is one of several reasons a customer might purchase less kWh from the utility. Other reasons for less customer kWh consumption include vacations, conservation, energy efficiency, and fuel switching from an electric appliance to another fuel such as natural gas. Customers within a rate class that reduce on-peak kWh usage could contribute to less costs being allocated to the rate class since costs are allocated based on each customer class's contribution to the utility's peak usage periods. In the long term, lower on-peak usage will lead to lower fixed cost due to a decreased need for production plant. A net metering customer with a solar project would be expected to reduce the rate class peak. When a non-net metering customer reduces kWh usage, cross-subsidy issues are not typically raised. Reducing energy usage through energy efficiency and conservation is looked at favorably by policy makers. However, some utilities have developed seasonal residential rates to recover more costs in the system access charge if seasonal customers make up a significant part of the customer base. While Michigan's current net metering program is not large enough to have a significant impact on utility rates, the program is continuing to grow. Solar net metering projects are 87% of the total.

Table 6 shows the key parameters and current participation information for Michigan's net metering program based on the MPSC's August 2013 Net Metering &Solar Pilot Program Report.

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Table 6: Michigan's Net Metering Program

	Maximum Program Size As a % of Peak Load	Net Metering Credit	Number of Customers	Participating Projects MW
Small Projects up to 20 kW	0.5%	Full Retail Rate (per kWh charges)	1,310	8
Projects >20 kW and up to 150 kW	0.25%	Power supply component of retail rate or wholesale	19	1
Methane Digesters up to 550 kW	0.25%	Power supply component of retail rate or wholesale (customer must pay a standby rate)	1	0.5
Net metering project size is limited to no more than annual kWh usage or maximum demand in kW during the previous 12-month period. Net metering excess generation rolls over month to month, indefinitely. Renewable energy credits belong to the customer.				

One option that may be used to address the cross subsidy concern is to limit the total size of the net metering program and the size of eligible generators. The net metering program credits net metering excess generation at the full per kWh component of the retail rate which includes both energy and delivery charges. **Table 5** shows that the residential customer net metering credit is about 13 cents per kWh.

A draft white paper by the National Renewable Energy Laboratory (NREL) found that the value of solar in Michigan was 13.8 cents per kWh.[50] The study considered seven main components of solar value:

- Energy and Generation
- Capacity
- Transmission and Distribution

[50] White Paper: The Value of Grid-Connected Photovoltaics in Michigan, Preliminary Draft, January 2012, Sean Ong. http://www.michigan.gov/documents/mpsc/120123_PVvaluation_MI_394661_7.pdf

- Loss Savings
- Reactive Power Support
- Environmental Benefits
- Other (includes hedge value, disaster recovery)

Recent studies evaluating cross subsidy concerns related to net metering programs in other states have compared the value of solar to the net metering credit. The "State and Utility Solar Energy Programs: Recommended Approaches for Growing Markets" includes a chart summarizing net metering and value of solar studies.[51] The chart highlights the many factors that must be considered to fully evaluate net metering and the value of solar considering its unique generation characteristics such as coincidence with peak-demand times. Determining an updated value of solar for Michigan would provide additional information to assist in evaluating possible changes to the net metering program. The Crossborder Energy study compared the amount of the net metering credit to the value of solar.[52] For rate schedules where the net metering credit was less than the value of solar, net metering was considered to provide a benefit to all ratepayers and some researchers characterize this as a cross subsidy from net metering participants to non-participants. A value of solar analysis could be performed for Michigan's net metering program.

Net Metering Program Changes (Question 28)

The net metering question on the Ensuring Michigan's Future website asked for comments on how small and large-scale renewable projects are handled by other states and about policies to encourage community renewables and meter aggregation.

[51] http://nrri.org/research-papers/-/document_library_display/3stN/view/0/7627?_110_INSTANCE_3stN_redirect=http://communities.nrri.org/home;jsessionid=F70B19EFF7321BBF352A0EFF7D96FE31?p_p_id=nrrilatestresearch_WAR_nrrilatestresearchportlet_INSTANCE_F9Le&p_p_lifecycle=0&p_p_state=normal&p_p_mode=view&p_p_col_id=column-2&p_p_col_pos=1&p_p_col_count=4

[52] Crossborder Energy, "Evaluating the Benefits and Costs of Net Energy Metering in California," R. Thomas Beach, Patrick G. McGuire, January 2013. http://votesolar.org/wp-content/uploads/2013/01/Crossborder-Energy-CA-Net-Metering-Cost-Benefit-Jan-2013-final.pdf

The design simplicity of net metering for small generators is a benefit and could be considered for larger projects. For residential and commercial customers without a demand charge, the net metering credits are approximately 13 cents. The net metering credits for customers on large usage rate schedules are lower because rate schedules tend to be designed to collect more costs in system access and demand charges. Because of this rate design element where the net metering credit is less for larger generators, there may not be any cross subsidy and full retail rate net metering may be a more accurate value of the generation. In cases where the net metering credit is less than a value of solar (or other type of renewable generation) that would be determined in the future, a discussion should be held to determine the appropriate accounting methodology and whether there is a cross subsidy issue going either way between net metering participants and non-participants.

The NRRI study found that 16 states offer some kind of group net metering provisions. Under a recent Michigan Energy Office Grant, the Great Lakes Renewable Energy Association studied community solar and prepared "Feasibility of Community Solar in Michigan: A Guidebook for Community Solar" which will be issued in September 2013. A draft of the report defines Community Solar:

> Under a Community Solar program, the actual generation of renewable energy does not occur at the customer's home or business site. Instead, the customer subscribes to a portion of a shared renewable energy facility (much like a resident may invest in a community garden) located elsewhere in the community and the power generated results in each subscriber receiving their portion of the benefit based on their investment.
>
> It has lots of names; community based renewable energy, solar gardens, shared solar, virtual net-metering, community shared solar gardens, and more.

There are 14 states with Community Solar projects – including Michigan. Cherryland Electric Cooperative and Traverse City Light and Power are the first electric providers in

Michigan to offer a joint community solar program – Solar Up North (SUN) Alliance Program. The framework for this program comes from the energy optimization standard of Act 295 and not net metering or the renewable energy standard. Cherryland Electric Cooperative members and Traverse City Light and Power customers can purchase solar shares for a one time investment of $470.00 each. The participants receive a $75.00 Energy Optimization rebate per panel. The electric providers use the wholesale electric market prices to determine the amount of monthly bill credit to provide to the participants. It is estimated that the credit will be an average of $2.00 per month. This amount will be based on total monthly array output and will vary based on weather conditions. The Community Solar program has been very successful initially and is continuing to grow.

Back-up Provisions (Questions 25, 26, 27)

Questions 25, 26, and 27 asked whether Michigan or other jurisdictions included incentives for dispatchable renewables, energy storage or flexible fast ramping non-renewable generation as part of or a complement to the renewable or clean energy standard. The majority of the comments in response to these questions treated all three of these technologies as grid stabilizing technologies to compensate for increased renewables, and provided a number of studies that indicate that these technologies are probably not necessary.

- UCS refers to an ISO/RTO Variable Energy Resource (VER) White Paper from NREL from August 2011 that draws the primary conclusions that "integrating renewable resources is challenging due to the intermittent nature of the fuel source. However ISOs and RTOs are working towards meeting these challenges by developing and implementing tools such as forecasting methodologies and services such as incorporating

VERs into the bidding and dispatch process and developing additional product offerings in the ancillary services markets which will help integrate these resources effectively and efficiently into both system operations and wholesale markets." The white paper specifically concludes specialized technologies are not necessary, and that forecasting and including renewables more broadly into the scheduling protocol will enable ISO/RTOs to effectively manage grid operations with intermittent renewables.

- CMS comments "In 2010, the Independent Market Monitor (IMM), the independent entity responsible for assessing the competitive performance of the Midwest Energy Markets administered by Midwest ISO, recommended a ramp capability product be introduced by Midwest ISO to address the volatility of renewable resources. The ramp capability product consists of establishing ramp capability targets along with economic values for the ramp capability (e.g., a ramp capability demand curve). Midwest ISO agreed with the IMM's concept and has been working on a conceptual design. The current schedule calls for conceptual design to be completed by the second quarter of 2013". This comment suggests that defining ramp capability product and demand curve will provide sufficient option for MISO control so that specific requirements for ramping technologies, energy storage, or dispatchable renewables are not necessary.
- In a letter from MISO responding to questions, (Appendix C), MISO explains that contingency reserves have never been deployed due to a drop in wind output. MISO does not believe the level of fast-ramping generation in our footprint is currently a driver of significant operational issues, but is working with stakeholders on exploring this issue and potential solutions.

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- For energy storage, DTE/CMS/MEGA submitted comments that seven states, including Michigan, consider certain types of energy storage technologies eligible to meet their Renewable Portfolio Standard (RPS) requirements: California, Maine, Massachusetts, Michigan, Montana, Ohio and Pennsylvania. Among the seven states, California, Maine, Michigan and Pennsylvania limit the eligible energy storage technology to pumped hydro storage; Massachusetts limits the eligible technology to flywheel storage (an economic policy priority); Montana limits the technology to compressed air storage; and Ohio permits any storage technology that promotes the better utilization of a renewable energy resource that primarily generates during off peak periods.
- NREL white paper "The Role of Energy Storage with Renewable Electricity Generation" provides a review of energy storage options and concludes "the question (of energy storage) is an economic issue: It involves the integration costs of variable generation and the amount of various storage or other enabling technologies that are economically viable in a future with high penetrations of variable generation. To date, integration studies of wind to about 20% on an energy basis have found that the grid can accommodate a substantial increase in variable generation without the need for energy storage, but it will require changes in operational practices, such as sharing of generation resources and loads over larger areas. Beyond this level, the impacts and costs are less clear, but 30% or more appears feasible with the introduction of "low-cost" flexibility options such as greater use of demand response."
- MISO Energy Storage Study Phase 1 Report "has allowed MISO to become familiar with challenges inherent in modeling energy storage technology in a complex nodal market with an ASM. The study group has gained a good understanding about storage modeling

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using EGEAS, which is the primary MISO tool for transmission resource planning. The study results demonstrate that there is economic potential for energy storage in the MISO footprint. Benefits were observed in cases using both EGEAS and PLEXOS. These benefits will be explored in greater depth during Phase 2." And, per UCS comments, a July 2011 review by MISO staff Ramp Capability for Load Following in the MISO Markets provides a summary of the market's ability to provide the ramping capability associated with growing wind energy on the system. Per UCS comments, "Where a large concentration of wind development creates challenges for balancing, and curtailments are used, a more common solution has been to increase the transmission in the area. This allows the export of wind energy, and the import of additional reserves that provide grid operators the balance of power they need to maintain system reliability." Per National Renewable Energy Laboratory's Renewable Electricity Futures Study, "there is an expectation that at the level of 80 percent renewable energy in the year 2050, a moderate amount of energy storage will be economic and useful".

- There is one example of a state, Massachusetts, including storage in a *clean* energy standard that includes resources other than renewable resources. Massachusetts' Alternative Energy Portfolio Standard includes flywheel energy storage along with alternative technologies such as fossil fuel gasification with capture and permanent sequestration of carbon dioxide, and combined heat and power. To address the challenge of describing the equivalent energy benefits that come from a technology that is providing capacity, the Massachusetts manufacturer of flywheel storage successfully promoted a formula to make an estimate of the benefits of energy passing in and out of the storage, based on the expected use of flywheels for short-term balancing of supply

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and demand. Assumptions about the intended use of new storage are one of the key factors for defining the benefits of new storage investment.

- UCS comments estimate that the impact of the variability introduced by intermittent renewables appears to be approximately half a cent per kilowatt-hour of wind energy. And additional transmission costs needed to increase wind generation to 20-30 percent of electricity use in the Eastern half the country by 2024 would be 2-5 percent of total annual costs (EnerNex 2010). However, the study also showed that most or all of the additional transmission and integration costs would be offset by lower costs for operating coal and natural gas plants.

Electric Choice/ Retail markets/ REC markets (Questions 30, 31, 40, 15)

In general, comments indicate that electric choice and requirements for renewables are compatible, and there is little difference in the magnitude of the renewable standard between jurisdictions with choice and those without retail choice. The average renewable standard for retail choice states is 22.4% vs. 21.1% for states without retail choice. Similarly, there seems to be no difference in renewables standard compliance between retail choice states and those without retail choice. Michigan law is consistent with other jurisdictions with retail choice in requiring all energy providers to comply with the same renewable requirements and establishing Renewable Energy Certificate (REC) Systems to issue, track, and enable retirement and trading of RECs. All 15 jurisdictions with retail choice have renewable standards, and the remaining 15 jurisdictions with renewable standards do not allow retail choice. There is some debate about the cost impact and ultimate market fairness for Alternative Energy Suppliers that meet their renewable obligation by purchasing RECs and, according to The MPSC's 2012 RPS Report,

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have "incurred little or no costs associated with complying with the statute." Utilities are meeting their obligation through purchase power agreements, owning and operating renewable facilities and buying RECs. Utilities comment that "the limit in the level of deregulation in Michigan (the 10% cap) has made it possible for the state's utilities to be confident that the significant investments made in renewable energy will serve the needs of the state and its customers fairly," while major customers in Michigan comment that renewable standards, when combined with caps on retail choice, limit utilities and/ or retail customers from accessing lowest cost supply, though these comments do not include supporting data from Michigan or other jurisdictions.

How Much Renewable Energy is Available Under Current Surcharge Limits (Questions 8, 16, 38)

Since the implementation of Act 295 in 2008, there has been a consistent and considerable decline in renewable energy prices as seen in the figure below. Early contracts for wind were well above $100 per MWh on a levelized basis, while the most recent contracts filed with the Michigan Public Service Commission have been in the $49 per MWh to $59 per MWh range. The contract prices are shown on **Figure 12.**

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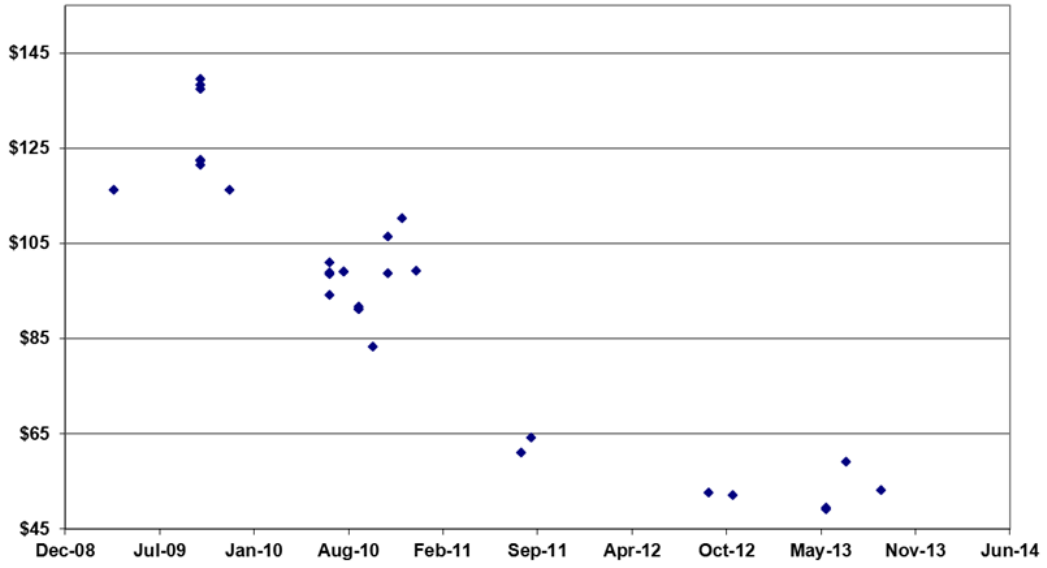
Figure 12: Levelized Cost of MPSC Approved Contracts Over Time[53]



These cost decreases have led to significant reductions in electric provider's customer surcharges as the declining prices have created decreased pressure on revenue requirements. Section 45 (2) of Act 295 provides that electric providers will recover incremental costs of compliance with the Act via surcharges applied to each customer's meter on a monthly basis. Act 295 states that surcharges are not to exceed: $3.00 per month per residential customer meter; $16.58 per month per commercial secondary customer meter; and $187.50 per month per commercial primary or industrial customer meter.

As of the filing of the MPSC 2013 RPS Report, a total of 5 electric providers were utilizing the statutory surcharge caps for recovery of the incremental cost of compliance with the Act. With the continued decrease in renewable energy costs, based on recently filed renewable energy plans, only Detroit Public Lighting and Lowell Power and Light still plan to recover

[53]Updated http://www.michigan.gov/documents/mpsc/implementation_of_PA295_renewable_energy_411615_7.pdf?20130717172545

incremental cost of compliance via capped surcharges, while eighteen providers are below the cap and thirty-nine electric providers charge customers no surcharges at all.[54]

Under the current renewable surcharge on meters, about 68% of the money collected is from residential customers. If renewables costs were recovered through traditional ratemaking, then the money collected would be at cost of service for each customer class, and not set by the surcharge. For both Consumers Energy and DTE Electric, about 44% of total revenue is collected from residential customers in base rates. Changing from a renewable energy surcharge on meters to a volumetric surcharge based on kWh usage could shift costs from residential customers onto commercial and industrial customers.

Act 295 renewable energy costs are recovered in two ways; surcharge revenue is utilized by electric providers to recover the incremental portion of the renewable generation. The remaining energy and capacity portion of the renewable energy is recovered pursuant to Sections 47 and 49 of the Act through the Power Supply Cost Recovery (PSCR) mechanism utilizing a transfer price schedule. PSCR recovery is generally reserved for power purchase agreement recovery, fuel purchases and some Environmental Protection Agency regulation compliance costs. Sections 47 and 49 of the Act expanded the use of the PSCR mechanism to include the projected capacity, energy, and maintenance and operation costs, which is now called the transfer price. Transfer price schedules are representative of what a Michigan electric provider would pay had it obtained the energy and capacity (the non-renewable market price component) through a long term power purchase agreement for traditional fossil fuel electric generation. To best determine the value of the non-renewable component of Act 295 compliant generation, Commission Staff determined, for purposes of developing a uniform Transfer Price Schedule, that the levelized cost of a new natural gas combined cycle (NGCC) plant would likely be

[54] Does not include Alternative Electric Suppliers

analogous to the market price mentioned above.[55] The transfer price used for the scenario analysis is shown in **Table 7**.

Table 7: Transfer Price

Year	Transfer Price	Year	Transfer Price
2016	$66.23	2026	$78.05
2017	$66.39	2027	$79.39
2018	$67.55	2028	$80.68
2019	$68.94	2029	$82.19
2020	$70.29	2030	$81.23
2021	$71.18	2031	$82.62
2022	$73.14	2032	$84.00
2023	$74.45	2033	$86.09
2024	$75.59	2034	$88.31
2025	$76.81	2035	$90.02

Below is a high-level calculation that compares various renewable energy requirements; in order to have an apples-to-apples comparison with uniform, well-understood assumptions, the scenarios below assume the following:

- Retail rate impacts would not exceed limits in current law;
- Rates were assumed as a statewide average and not on a provider-by-provider basis;

[55] For more detailed information on the Staff Transfer Price Schedule see: http://efile.mpsc.state.mi.us/efile/docs/15800/0036.pdf

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- The basic elements of PA 295 would apply to the increased renewables build (including in-state provisions, same allocation among rate classes, and per-meter charges);
- The number of meters would remain stable;
- Levelized cost of $86.60 per MWh for wind,[56] $144.30 per MWh for solar and $111.00 per MWh for biomass (with maximum incremental revenue with the transfer price factored in); [57] and
- Annual load growth would be either 1.2% or zero (to give a range).
- **Table 10** shows the generation mix and capacity given a scenario with 50% of the current surcharge caps.

More specific assumptions are detailed prior to the tables showing the various projections.[58] The EIA levelized cost analysis assumes capacity factors of 30% - 39% for wind and it is anticipated that Michigan wind capacity factors will exceed that. Wind generation technology has advanced rapidly in the last couple of years. Taller towers and larger blade diameters allow for much higher capacity factors and optimized operating characteristics given Michigan's wind resources. Based on third party and electric provider analysis, Michigan wind farms that utilize these new technologies, are anticipated to produce capacity factors well over 40%, meaning that the levelized cost of $86.60 per MWh is probably inflated and actual levelized costs will be lower.

[56] Starting in 2034, all of the costs for wind will be recovered through the PSCR via the transfer price.
[57] The U.S. Energy Information Agency (EIA) has stated an average levelized cost for generation entering the market in 2018 of $86.60 per MWh for wind, $144.30 per MWh for Solar and $111.00 per MWh for biomass. The levelized costs assumed for wind, solar, and biomass are based on an assumption that there will be no federal tax extensions starting in 2015, but that these technologies will continue to benefit from learning curve cost reductions.
[58] http://www.eia.gov/forecasts/aeo/electricity_generation.cfm

Although EIA states an average levelized cost of $144.30 per MWh for solar, the EIA maximum of $244.40 per MWh.is most likely a more reasonable approximation of Michigan's large utility scale solar photovoltaic build-out as it is still in its infancy and while solar is viable in Michigan, capacity factors are not as high as in Southern states. Based on Michigan contracts for Biomass energy, the EIA average levelized cost of $111.00 per MWh seems reasonable. For consistency this analysis uses the EIA averages for all three technologies.

For simplicity, the methodology assumes that recovery for all the renewable energy will be conducted in a manner similar to current electric provider power purchase agreement recovery that is paid for through a schedule of transfer prices for the generation from the plant and a renewable energy surcharge for the incremental cost beyond the transfer price, if any. Additionally, it is assumed that cost recovery through these renewable mechanisms will continue through the twenty year planning period only, which does not account for the electric provider's commitment to company-owned resources after the planning period or obligations to developers for contract terms that extend beyond 2035. Similar to the current renewable standard under the Act, it is assumed that costs beyond the renewable planning period would be recovered utilizing traditional rate making procedures. The modeling also assumes that new capacity will be necessary as current fossil fueled generation will be moth-balled or retired due to age and environmental requirements. These compliance obligations would make renewable generation a much more economical choice when compared to the continued capital investment in generating plants that are close to or already beyond their operational lives.

In developing the scenarios, the sum of the current forecasted renewable energy surcharge revenue is subtracted from the maximum potential surcharge revenue to determine the incremental revenue available each year. This calculation provides the maximum potential

renewable capacity by type shown in **Tables 8 and 9**. The same methodology is used to develop the scenarios in **Table 10** with, but a 50% reduction in surcharge revenues is utilized.

Two different models are presented for each scenario in **Table 8 and 9**. The base scenario adds mostly wind generation because onshore wind generation is cheaper than the other renewable sources. The maximized solar and biomass scenario is added to show that additional amounts of biomass and solar (reducing the amount of wind) could be added while still adhering to the assumption that the current PA 295 renewable energy surcharge cap remained in place. Additionally, a sensitivity to load growth is also provided. **Table 8** shows that lower amounts of new renewables would be required if there is no load growth, as opposed to higher amounts of new renewables that would be required if there was a very robust annual load growth of 1.2%. The scenarios presented in **Table 10** include a 50% reduction in surcharge revenues and show that a 30% renewable standard by 2035 is possible in both the no load and 1.2% load growth scenarios, however the portfolio would have to be primarily wind as this represents the lowest levelized cost source of renewable generation.

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Table 8: Incremental Renewable Energy Constrained by PA 295 Surcharge Caps[59]

Model 1: Base Scenario (No Load Growth)							
Renewable Percentage	Wind Percentage	Wind Capacity MW	Solar Percentage	Solar Capacity MW	Biomass Percentage	Biomass Capacity MW	Incremental Renewables MW
15% by 2020	85.0%	1,246	7.5%	338	7.5%	68	1,651
20% by 2025	85.0%	2,491	7.5%	676	7.5%	135	3,303
25% by 2030	85.0%	3,737	7.5%	1,014	7.5%	203	4,954
30% by 2035	85.0%	4,982	7.5%	1,353	7.5%	271	6,605

Model 2: Maximized Solar and Biomass (No Load Growth)							
Renewable Percentage	Wind Percentage	Wind Capacity MW	Solar Percentage	Solar Capacity MW	Biomass Percentage	Biomass Capacity MW	Incremental Renewables MW
15% by 2020	34.0%	498	33.0%	1,488	33.0%	298	2,284
20% by 2025	67.0%	1,964	16.5%	1,488	16.5%	298	3,749
25% by 2030	75.0%	3,297	12.5%	1,691	12.5%	338	5,326
30% by 2035	77.0%	4,513	11.5%	2,074	11.5%	415	7,002

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[59] Assumptions: Wind capacity factor of 40% and levelized cost of $86.60 per MWh; Solar capacity factor of 13% and levelized cost of $144.50 per MWh; Biomass capacity factor of 65% and levelized cost of $111.00 per MWh

Table 9: Incremental Renewable Energy Constrained by PA 295 Surcharge Caps[60]

Model 1: Base Scenario (1.2% Load Growth)							
Renewable Percentage	Wind Percentage	Wind Capacity MW	Solar Percentage	Solar Capacity MW	Biomass Percentage	Biomass Capacity MW	Incremental Renewables MW
15% by 2020	85.0%	1,544	7.5%	419	7.5%	84	2,047
20% by 2025	85.0%	3,125	7.5%	848	7.5%	170	4,143
25% by 2030	85.0%	4,687	7.5%	1,273	7.5%	255	6,214
30% by 2035	85.0%	6,249	7.5%	1,697	7.5%	339	8,285

Model 2: Maximized Solar and Biomass (1.2% Load Growth)							
Renewable Percentage	Wind Percentage	Wind Capacity MW	Solar Percentage	Solar Capacity MW	Biomass Percentage	Biomass Capacity MW	Incremental Renewables MW
15% by 2020	44.0%	799	28.0%	1,565	28.0%	313	2,677
20% by 2025	73.0%	2,684	13.5%	1,527	13.5%	305	4,516
25% by 2030	80.0%	4,411	10.0%	1,697	10.0%	339	6,447
30% by 2035	82.0%	6,029	9.0%	2,036	9.0%	407	8,472

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[60] Assumptions: Wind capacity factor of 40% and levelized cost of $86.60 per MWh; Solar capacity factor of 13% and levelized cost of $144.30 per MWh; Biomass capacity factor of 65% and levelized cost of $111.00 per MWh

Table 10: Incremental Renewable Energy 50% of PA 295 Surcharge Caps[61]

Model 1: 50% Surcharge Scenario (No Load Growth)							
Renewable Percentage	Wind Percentage	Wind Capacity MW	Solar Percentage	Solar Capacity MW	Biomass Percentage	Biomass Capacity MW	Incremental Renewables MW
15% by 2020	71.0%	1,040	14.5%	654	14.5%	131	1,825
20% by 2025	89.0%	2,608	5.5%	496	5.5%	99	3,203
25% by 2030	93.0%	4,088	3.5%	473	3.5%	95	4,656
30% by 2035	94.0%	5,510	3.0%	541	3.0%	108	6,159
Model 2: 50% Surcharge Scenario (1.2% Load Growth)							
Renewable Percentage	Wind Percentage	Wind Capacity MW	Solar Percentage	Solar Capacity MW	Biomass Percentage	Biomass Capacity MW	Incremental Renewables MW
15% by 2020	76.0%	1,380	12.0%	671	12.0%	134	2,185
20% by 2025	92.0%	3,382	4.0%	452	4.0%	90	3,925
25% by 2030	95.0%	5,239	2.5%	424	2.5%	85	5,748
30% by 2035	96.0%	7,058	2.0%	452	2.0%	90	7,601

Tables 8 and 9 show the potential capacity increases by technology for a Base Scenario that assumes 85% wind, 7.5% solar and 7.5% biomass and a Maximized Solar and Biomass Scenario that varied the two technologies to determine the maximum amount of capacity potential. **Table 8 and 9** assume zero and 1.2% annual load growth, respectively, with the current surcharge caps, while **Table 10** assumes a no load growth and a 1.2% growth rate, but only 50% of the current surcharge caps. Each scenario was run under four compliance goals based on generation of: 15% renewable energy by 2020; 20% renewable energy by 2025; 25% renewable energy by 2030; and 30% renewable energy by 2035. Similar to the current compliance standard, the scenarios above assumed a 20 year planning period in which cost

[61] Assumptions: Wind capacity factor of 40% and levelized cost of $86.60 per MWh; Solar capacity factor of 13% and levelized cost of $144.30 per MWh; Biomass capacity factor of 65% and levelized cost of $111.00 per MWh

recovery would take place through 2035.[62] The incremental capacity numbers provided reflect the amount needed beyond the current 10% standard.

Utilizing the surcharge caps in the current RPS as a maximum allowable cost, and under the assumptions discussed above, it would be possible to increase the renewable portfolio standard by as much as 8,472 MW through 2035, equivalent to approximately a 30% RPS.[63] Additionally, utilizing a 50% reduction in surcharge revenue still allows Michigan as a whole to meet a 30% renewable standard by 2035 as shown in **Table 10.** The scenarios in **Table 10** are only valid if the percentage of wind in the renewable portfolio increases to 95% or above in 2030 and 2035 due to its low cost with respect to solar and biomass.[64]

Using the same assumptions under a less robust renewable portfolio standard of 15% by 2020, Michigan could see an increase of approximately 1,651 MW to 2,677 MW of renewable capacity. These scenarios assume approximately a 1% increase in renewable energy per year which is on par with the pace of Michigan's current standard and several other Midwest states such as Wisconsin, Pennsylvania, Illinois, and Minnesota that all have percentage increase per year of 0.8% to 1.3%.

Some have commented that all of the renewable energy costs should be considered incremental cost (and therefore recovered entirely through surcharge) in cases where a utility does not need new generation but for the RPS. This approach is inconsistent with the PA 295 framework and would require detailed utility-specific analyses to determine the projected impact. Each utility is situated differently with projected load growth rates, the amount of existing

[62] 30% by 2035 assumes a 21 year plan period while the other scenarios assume a 20 year plan period

[63] Other constraints need to be further analyzed when determining the amount of renewable energy potential such as: available land suitable for renewable development when setbacks are considered; and that do not disrupt migratory fly zones or have other negative effects on flora and fauna; effects on the transmission system; availability of transmission in a particular area; etc.

[64] Under the current renewable standard of 10% by 2015, Michigan will see an increase of approximately 1,500 MW of renewable capacity with over 95% from wind resources.

utility-owned generation, purchased generation capacity and projected retirements due to aging fleets. If this projected policy change was enacted, the amounts of renewables that are identified in **Tables 8, 9 & 10** to meet the various potential future targets would be reduced, but at the same time, it's likely that the renewable requirements would vary utility by utility. In addition, PA 295 already includes "off ramps" in the event the requirements exceed the cost caps in the statute for an individual provider. Thus, flexibility is built into the statute to ensure cost effectiveness, although other approaches could be taken to achieve the same goal.

Summary

This report discusses the current situation for renewable energy in Michigan and offers a glimpse into the potential for the future inclusion of renewable energy in Michigan's energy policy. Michigan is on track to meet its current legislated RPS of 10% by 2015. Electric Providers have been working diligently to make this happen. As more renewable resources have been added, the prices of these resources has decreased, particularly for wind energy, and are now competitive with some new sources of non-renewable energy. Renewable energy has also increased the diversity of Michigan's energy sources, adding to the usual mix of coal, natural gas and nuclear. Michigan's RPS has improved the transmission system in Michigan, especially in the Thumb region; led to a more transparent and efficient grid integration methodology; and made people reconsider the way that they analyze new generation alternatives. The statewide net metering program has encouraged net metering in Michigan, particularly for residential and small commercial customers.

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APPENDIX A: Summary of State Renewable Portfolio Standards

State RPS Requirements

	Standard	Date	% Load	Adjusted Standard - State Equivalent
Arizona	15%	2025	58.5%	8.8%
California	33%	2020	98.2%	32.4%
Colorado		2020		21.2%
IOUs	*30%*	*2020*	*58.7%*	*17.6%*
Co-ops and large munis	*10%*	*2020*	*35.6%*	*3.6%*
Connecticut	27%	2020	93.4%	25.2%
Delaware	25%	2026	70.0%	17.5%
District of Columbia	20%	2020	100.0%	20.0%
Hawaii	40%	2030	100.0%	40.0%
Illinois		2025		16.5%
IOUs	*25%*	*2025*	*43.2%*	*10.8%*
AES [1]	*12.5%*	*2025*	*45.7%*	*5.7%*
Iowa[2]	1%	2000	75.7%	0.8%
Kansas	20%	2020	81.5%	16.3%
Maine[3]	10%	2017	98.3%	9.8%
Maryland	20%	2022	93.4%	18.7%
Massachusetts[4]	22.1%	2020	86.0%	19.0%
Michigan	10%	2015	100.0%	10.0%
Minnesota		2020/2025		27.4%
Xcel	*30%*	*2020*	*47.8%*	*14.3%*
Other	*25%*	*2025*	*52.2%*	*13.1%*
Missouri	15%	2021	70.0%	10.5%
Montana	15%	2015	66.6%	10.0%
Nevada	25%	2025	88.2%	22.1%
New Hampshire	24.8%	2025	98.2%	24.4%
New Jersey	20.4%	2021	98.3%	20.0%
New Mexico		2020		15.6%
IOUs	*20%*	*2020*	*67.7%*	*13.5%*
Co-ops	*10%*	*2020*	*20.8%*	*2.1%*
New York	29%	2015	84.7%	24.6%
North Carolina		2018/2021		11.9%
IOUs	*12.5%*	*2021*	*75.2%*	*9.4%*
Co-ops and munis	*10%*	*2018*	*24.8%*	*2.5%*
Ohio	12.5%	2024	88.6%	11.1%
Oregon		2025		20.4%
Large utilities	*25%*	*2025*	*74.6%*	*18.7%*
Small utilities	*10%*	*2025*	*10.2%*	*1.0%*

	Standard	Date	% Load	Adjusted Standard - State Equivalent
Small utilities (<1.5% state's load)	*5%*	*2025*	*15.2%*	*0.8%*
Pennsylvania	18%	2021	97.3%	17.5%
Rhode Island	16%	2020	99.3%	15.9%
Texas[5]	5%	2015	n/a	5.0%
Washington	15%	2020	84.7%	12.7%
Wisconsin	10%	2015	100.0%	10.0%

SOURCE: Public Sector Consultants, 2013, based on data from Database of State Incentives for Renewables and Efficiency, January 2013.
NOTES:
[1] AESs are only required to meet 50% of standard but can elect to do 100%.
[2] Electricity sales in Iowa are 45,445,269 MWh; 105 MW in high-quality wind area (40% capacity factor) would be expected to produce 367,960 MWh per year, equivalent to 1% renewable energy. Iowa has over 4,000 MW of installed capacity, far exceeding the 105 MW minimum.
[3]This applies only to new renewable energy projects. Maine had standard of 30% by 2020, which included existing renewable resources. Maine had large percentage of existing hydro-electric that qualified.
[4] Massachusetts has goal of 15% by 2020 for new renewable resources, and this increases 1% annually thereafter.
[5] Texas' requirement of 5,880 MW by 2015 equates to approximately 5% of the state's electric load. Texas has already surpassed this goal with over 10,000 MW installed.

*Provided in a joint response from Michigan utilities

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APPENDIX B: Summary of Renewable Energy Compliance Approaches

State	Type of Enforcement	Description of Penalty/Alternative Compliance Payments
Arizona	Discretionary Financial Penalties with no cost Recovery	
California	Explicit Financial Penalties with no automatic cost recovery	
Connecticut	Explicit Financial Penalties with no automatic cost recovery	$55/MWh
Colorado	Discretionary Financial Penalties with no cost recovery	
Delaware	Alternative Compliance Mechanisms with possible cost recovery	
Hawaii	Discretionary Financial Penalties with no cost recovery	
Kansas	Explicit Financial Penalties with no automatic cost	Failure to comply with the renewable energy requirements results in a minimum penalty equal to
	Recovery	twice the market value of RECs that would have been required to meet the requirement.
Maine	Alternative Compliance Mechanisms with automatic cost recovery	$62.10/MWh
Maryland	Alternative Compliance Mechanisms with possible cost recovery	$40/MWh for non-solar Tier 1, $15/MWh for Tier 2, and $45/MWh for solar (declining to $50/MWh in 2023)
Massachusetts	Alternative Compliance Mechanisms with automatic cost recovery	ACP is $64/MWh for Class I sources, $27/MWh for Class II sources, and $550/MWh for solar. It is adjusted for upwards inflation each year, and the Department of Energy Resources can adjust it downward based on market conditions.
Michigan	Explicit Financial Penalties with no automatic cost Recovery	

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Minnesota	Discretionary Financial Penalties with no cost recovery	If the PUC finds a utility is non-compliant, the commission may order the utility to construct facilities, purchase eligible renewable electricity, purchase RECs or engage in other activities to achieve compliance. If a utility fails to comply, the PUC may impose a financial penalty on the utility in an amount not to exceed the estimated cost of achieving compliance.
Missouri	Explicit Financial Penalties with no automatic cost recovery	Utilities that do not meet their renewable and solar portfolio are subject to penalties of at least twice the market value of RECs or SRECs.
Montana	Explicit Financial Penalties with no automatic cost recovery	$10/MWh
Nevada	Discretionary Financial Penalties with no cost Recovery	
New Hampshire	Alternative Compliance Mechanisms with automatic cost recovery	Class I: $55.00/MWh, Class I Thermal: $25.00/MWh in 2013, Class II: $55.00/MWh, Class III: $31.50/MWh, Class IV: $26.50/MWh in 2013 (adjusted annually for inflation.
New Jersey	Alternative Compliance Mechanisms with automatic cost recovery	ACP is $50/MWh, and the solar ACP was $641/MWh in 2013, declining to $239/MWh in 2028.
New Mexico	Enforcement at PUC Discretion	
North Carolina	Enforcement at PUC Discretion	
Ohio	Explicit Financial Penalties with no automatic cost recovery	ACP initially set at $45/MWh (with the possibility of upwards adjustment each year). The Solar ACP is set at $450/MWh in 2009, reduced to $400/MWh in 2010 and 2011, and will be reduced by $50 every two years thereafter to a minimum of $50/MWh in 2024.
Oregon	Alternative Compliance Mechanisms with possible cost recovery	ACP = $50/MWh
Pennsylvania	Explicit Financial Penalties with no automatic cost recovery	ACP of $45 per megawatt-hour for shortfalls in Tier I and Tier II resources. A separate ACP for solar PV is calculated as 200% times the sum of (1) the market value of solar AECs for the reporting period and (2) the levelized value of up-front rebates received by sellers of solar AECs.
Rhode Island	Alternative Compliance Mechanisms with automatic cost recovery	$64.02/MWh
Texas	Explicit Financial Penalties with no automatic cost recovery	

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Washington	Explicit Financial Penalties with no automatic cost recovery	ACP = $50/MWh (adjusted annually for inflation)
Wisconsin	Explicit Financial Penalties with no automatic cost recovery	

*Provided in a joint response from Michigan utilities

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July 1, 2013

Ms. Valerie Brader
Deputy Legal Counsel and Senior Policy Advisor
Governor Rick Snyder's Office
George W. Romney Building
111 South Capitol Avenue
Lansing, MI 48909

Dear Ms. Brader,

Thank you for the opportunity to provide information to assist Governor Snyder in developing his energy plan for Michigan. Attached please find responses to the five questions specifically addressed to MISO. We are excited about the opportunity to participate in Readying Michigan to Make Good Energy Decisions. Should you have any further questions, or need additional information, please do not hesitate to contact me.

Appendix C: MISO Response Letter

On a further note, please know MISO continues to work on addressing transmission issues in the Northern area of our footprint. On June 17, 2013 MISO conducted a successful first meeting between policymakers and regulators from the states of Michigan, Wisconsin, Minnesota, South Dakota, North Dakota and the Province of Manitoba. As a result of this meeting, several issues were identified for further discussion with this group to continue working on these issues. MISO believes these discussions will also provide additional information to Governor Snyder as he develops his energy plan.

Again, thank you for the opportunity to participate in the Governor's plans for Michigan's energy future.

Sincerely,

Rob Berntsen
Vice President
Government & Regulatory Affairs

cc: Steven Bakkal, Michigan Energy Office
John D. Quackenbush, MPSC Chair
Paul Proudfoot, MPSC Electric Reliability Division Director

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Readying Michigan to Make Good Energy Decisions
Renewable Energy Questions for MISO

1. **Recognizing that MISO has been actively involved in the integration of renewable resources throughout the MISO footprint, could you summarize actions MISO has taken to address the integration of renewable resources?**

   MISO Response:

   Current registered wind capacity in the MISO footprint is approximately 12,200 MW, which is a 60% increase from just three years ago. MISO anticipates continued additions of wind capacity as states continue to comply with Renewable Portfolio Standard (RPS) goals and mandates set by policy makers in the MISO states. Given the amount of renewable generation in our footprint, MISO has had to make enhancements in both the planning and operations functions in order to ensure our ability to effectively integrate these resources. Some of these enhancements are outlined here.

   Queue Reform. In 2008, a significant change was made to the MISO generation interconnection queue, which is the process that generators use to connect new generation facilities to the transmission grid. The changes were driven by the need to have a more consistent and predictable process to integrate new generation facilities, which have largely been wind generators. The revised queue process provides a more efficient and transparent process for evaluating interconnection requests. MISO's queue process now provides more certainty for developers as they move to finance their projects and more certainty for transmission planners.

   Multi-Value Projects. RPS goals and mandates set by state policy makers also drove a need for a more regional and robust transmission system that would provide many benefits to the MISO system, including enabling the delivery of renewable resources, which are typically sited in areas that are far away from customers. In response to this situation, MISO worked with stakeholders to identify transmission projects (and corresponding cost allocation) that would fulfill combinations of the following purposes: (1) meet reliability needs; (2) provide economic benefits, and (3) enable public policy goals to be met. The result of this process was the development of the first Multi-Value Project (MVP) portfolio of projects that was approved by the MISO Board of Directors in 2011.

   Dispatchable Intermittent Resources. From an operational aspect, integrating wind generation presents unique challenges. The wind-rich areas in the MISO system are in rural areas where significant transmission capacity has historically

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not been needed. As significant generation has been developed in these areas, the transmission system is not always able to handle the full output of these new resources. To manage this situation, manual curtailments of wind generation were necessary. To reduce the need for those manual actions, enable more efficient congestion management, and place wind generation on par with other generators on the system, MISO created a new resource designation – Dispatchable Intermittent Resources (DIR). DIRs were implemented in June of 2011, allowing for more transparent, timely and precise constraint mitigation. DIRs also provide the additional benefit of providing flexibility during minimum load situations. Wind generation owners have welcomed DIRs as this new tool benefits the generators by allowing them to sell more energy into the MISO market without threat of full (manual) curtailment. Energy purchasers in the MISO market have also recognized the benefit of having more lower-priced wind generation in the market to purchase for their customers.

2. **There has been concern that the integration of renewable resources into the MISO system could negatively impact reliability of the system. Has MISO experienced any negative impact to grid reliability caused by the integration of renewable energy sources and/or distributed generation?**

   MISO Response:

   Reliability of the system is the primary concern of MISO's planning and operations. To date, wind has not been a significant contributor to any system-wide reliability issues or threats, including operating reserve deployments. Wind has historically had a small impact on the use of regulating reserves. Contingency reserves have never been deployed due to a drop in wind output. Any issues with wind have primarily been limited to localized congestion and generation outlet concerns, which have not caused system reliability issues. Reliability is a primary concern as additional wind resources are planned for and integrated onto the MISO system.

3. **As Michigan nears the 10 percent RPS requirement, there is interest in increasing the standard. Does MISO have an estimate of how much additional renewable energy capacity could be added in the Michigan footprint without negatively impacting system reliability? Have Michigan customers been allocated back-up capacity/integration costs as a result of the current Michigan renewable standard?**

   MISO Response:

   MISO has not yet worked with Transmission Owners in Michigan to estimate the amount of renewable capacity that could be added in Michigan without negatively impacting reliability. A number of factors could impact this determination, thus making an accurate

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prediction very difficult. The incremental increase of wind generation in recent years has, at certain times and under certain local load and energy supply conditions, introduced localized congestion on the transmission system. However, these issues (which have not caused any significant reliability issues) have been effectively managed through the use of operating guides and congestion management procedures. Also, it is expected that these constraints would be mitigated or entirely resolved by future transmission projects, including the Michigan Thumb Loop Expansion project, which is part of MISO's Multi-Value Project portfolio.

In terms of costs of backup capacity or integration costs, MISO is not aware of any backup capacity costs specifically attributable to supporting the increase of wind generation in Michigan. With respect to integration costs, $74,096,830 of transmission network upgrades have been made to interconnect wind resources in the state of Michigan to the MISO system. This figure reflects the costs associated with "in-service" generators that have a signed interconnection agreement with MISO.

Additionally, as identified in the previous answer, to support the renewable portfolio standards, to ensure future system reliability, and to make the benefits of an economically efficient market available to all customers, the MISO Multi-Value Project (MVP) portfolio was developed. The portfolio includes 17 projects across the MISO footprint, developed as a portfolio to provide maximum value through the synergies among and between the projects. The portfolio was approved by the MISO Board of Directors in 2011, and included the 345kV Michigan Thumb Loop Expansion.

The MVP portfolio is forecasted to provide the following benefits:

- Relieve Congestion and fuel savings
- Decrease operating reserve requirements
- Lower planning reserve requirements
- Decrease transmission line losses
- Lower future transmission investment

The estimates of savings from the MVP portfolio range from $15,540M - $49,204M ($-2011). In Michigan these benefits are estimated at $3,072M – 9,952M for Lower Michigan and $2,124M - $6,580M for Upper Michigan/Eastern Wisconsin[1] in net present value benefits over a 20/40 year period (the ranges of these estimated benefits depend on the modeling assumptions).

The most recent MVP portfolio cost estimate is approximately $5.5 billion. These costs would be allocated to Michigan as follows: $8,789M – $16,407M ($-2011) (Lower Michigan: $1,785M – 3,333M and Upper Michigan/Eastern Wisconsin: $1,067M -

[1] Upper Michigan and Eastern Wisconsin are calculated together because they make up a single pricing zone in the MISO footprint.

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$1,992M). These figures represent the net present value of sum of annual revenue requirements over a 20/40 year period depending on future assumptions.

When comparing estimated costs to estimated benefits, the MVP portfolio provides benefit to cost ratios ranging from 1:8 to 3:0. Specific to Michigan, the MVP portfolio benefit to cost ratio for Lower Michigan is 1:7 – 3:0 and 2:0 – 3:3 for the Upper Peninsula and Eastern Wisconsin. Additionally, the MVP portfolio provides benefits not reflected in the quantified benefits including enhanced generation policy flexibility, increased system robustness, decreased natural gas risk, decreased carbon output, decreased wind generation volatility, and local investment and job creation.

4. **MISO recently introduced an improved Dispatchable Intermittent Resource (DIR) tariff. Has the dispatch of renewable generation changed since the implementation of the DIR tariff and has dispatching of renewable energy impacted locational marginal prices within the MISO footprint? What thoughts do you have on the benefits of the current DIR tariff since its resent onset?**

   MISO Response:

   DIRs have improved MISO's ability to respond to and mitigate congestion on the transmission system – as evidenced by the reduced level of manual curtailments of wind generation.

   In an unconstrained system, we would expect wholesale energy prices to trend lower with higher wind penetration, since the result would reduce the need to commit higher cost resources. This outcome would be the result of the changing generation mix rather than the DIR specifically. When congestion is present, having additional resources, including intermittent resources, available to set prices and manage congestion allows for greater transparency and would have the effect of depressing wholesale energy prices in areas where the amount of generation exceeds the current transmission capability in the area.
   With respect to the benefits of the DIR tariff, operations have become much more efficient as the monitoring and dispatching of wind generation has become an automated process, rather than a manual one.

5. **Intermittent resources may require flexible, fast-ramping generation, does MISO believe there are operational issues resulting from the lack of this type of generation and does the MISO market provide an incentive for this type of generation?**

   MISO Response:

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MISO does not believe the level of fast-ramping generation in our footprint is currently a driver of significant operational issues. Forecasted wind changes are effectively managed through MISO's economic dispatch of generation to meet demand. Unexpected changes in wind output is also be managed through the MISO dispatch, but could also result in the use of fast-start resources and the utilization of reserve capacity. A benefit of our large single Balancing Area is that changes in intermittent generation tend to be relatively small compared to the ability of the system to respond In addition, the geographical diversity of wind resource locations reduces the impact of a weather change on the combined output of those units. However, as we integrate additional wind capacity into our footprint, ramp capability will become increasingly important. MISO is currently engaged with stakeholders on exploring this issue and potential solutions.

Finally, the MISO market does not incentivize any particular type of generation.

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