Union of Concerned Scientists
Citizens and Scientists for Environmental Solutions

April 25, 2013

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Lansing, MI 48913

John Quackenbush
Chairman, Michigan Public Service Commission
4300 W. Saginaw Hwy.
Lansing, MI 48917

Director Bakkal and Chairman Quackenbush,

Thank you for the opportunity to provide information to you and your staff as you prepare policy recommendations to chart Michigan's energy future.

On behalf of the Union of Concerned Scientists (UCS) and the undersigned organizations, I am pleased to submit responses to twenty-eight of the forty Renewable Energy questions posted on the Michigan.gov website as well as two questions from the "Additional Areas" section. For your convenience, the attached document compiles all responses as well as a response to renewable energy question #28 that was prepared by Vote Solar.

UCS drafted these responses based on rigorous research and analysis as well as a thorough review of available literature. Resources for additional information on specific topics are provided as links to online documents or as a PDF in the document's appendix. In addition to this compendium, we posted our response to each question online through the Michigan.gov website.

We appreciate the opportunity to provide input into this important process and look forward to working with you to develop sound policies for Michigan's energy future. Please do not hesitate to contact us with any questions or for more information about any of these or related topics.

Sincerely,

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Organizations Endorsing UCS's Responses:
5 Lakes Energy, LLC
Climate Change and Earth Care Task Force
Interfaith Council for Peace and Justice
Ecology Center
Environmental Law and Policy Center
Michigan Air, Michigan Health Coalition
Michigan Clean Water Action
Michigan Environmental Council
Michigan Interfaith Power & Light
Michigan Land Use Institute
Michigan League of Conservation Voters
Moms Clean Air Force
National Wildlife Federation, Great Lakes Regional Center
West Michigan Environmental Action Council

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Question 1:

Renewable Energy Question #1: How much RE will be operational in MI by the end of 2015? What is the total dollar amount of MI renewables investment to date and expected when the 10% goal is reached in 2015?

According to Appendix H of the February 2013 MPSC report on the implementation of P.A. 295, there is currently 1,192 MW of renewable energy capacity online or expected to be online by end of 2013 to meet P.A. 295 compliance. According to Appendix I, an additional 133 MW of wind pre-dates P.A. 295. In addition, according to the Energy Information Administration, there are 212 MW of biomass, 236 MW of hydropower and 152 MW of landfill gas capacity that are in service but not applied to P.A. 295 requirement. In all, the total amount of renewable energy in Michigan either online or expected to be by the end of 2013 is 1,925 MW.

Looking ahead to 2015, DTE expects to add an additional 330 MW of renewable energy (nearly all of which will be wind resources) through either self-build or power purchase agreements. Consumers Energy also has plans to bring online a 150 MW wind power facility by 2015. SNL Financials, which tracks energy projects as part of its services to industry and financial clients, reports an additional 4 renewable energy projects – all wind, totaling 390 MW – that are planned to come online by the end of 2015. Finally, the continued implementation of DTE's and Consumers' small-scale solar programs is expected to produce approximately 3.25 MW of additional distributed solar resources by 2015. These projects increase the total amount of renewable energy expected to be online in Michigan by 2015 to 2,798.25 MW. Additional renewable energy development by Michigan's electric providers as a result of P.A. 295 is unlikely due to the availability of inexpensive renewable energy credits (RECs) which will likely be used to meet any additional compliance requirements.

In terms of investment to date, the February 2013 MPSC report estimates that $1.79 billion has been invested to bring 895 MW of new renewable energy projects online in Michigan through 2012. This is based on an assumed cost of $2,000 per kW of installed capacity.[1] This estimate does not include the renewable energy projects that pre-date P.A. 295. Estimating the investments made to develop these projects is difficult due to (1) the long period of time over which these projects were developed (some, like the hydropower resources, date to the early 20th century), and (2) the lack of publicly available data for these projects.

For the 872.5 MW of new renewable energy projects planned through 2015, SNL Financials estimates an investment of $2.39 billion. However, this equates to an average cost of more than $2,700 per installed kW of capacity, which is considerably higher than current project costs reported in the February 2013 MPSC report and by the Lawrence Berkeley National Laboratory. In addition, this renewable energy

[1] The MPSC's estimate of $2,000 per kW of installed capacity appears reasonable when compared to industry data. The Lawrence Berkeley National Laboratory data for installed wind project costs ($/kW) from 2009 to 2012 were $2,192, $2,188, $2,098 and $1,755 respectively.

capacity likely exceeds, by several hundred MW, what will be required to comply with P.A. 295. This additional investment is driven by market forces and the presence of strong wind resources in Michigan.

Using MPSC's estimated cost of $2,000 per installed kW of capacity – an estimate that seems more reasonable in light of recent project costs in Michigan and surrounding areas – the investment will total $1.75 billion. An additional small amount will be invested to continue DTE's and Consumers' small-scale solar programs. In all, current and future renewable energy developments to meet the requirements of P.A. 295 plus the additional investments driven by market forces, (but not including renewable resources developed prior to enactment of P.A. 295) will likely total between $3.5 and 4.2 billion.

Resources:

1) Quackenbush, J.D., O.N. Isiogu, and G.R. White. 2013. *Report on the implementation of the P.A. 295 renewable energy standard and the cost-effectiveness of the energy standards*. Lansing, MI: Michigan Public Service Commission. Online at *http://www.michigan.gov/documents/mpsc/Report_on_the_implementation_of_Wind_energy_resource_zones_2013_413124_7.pdf*, accessed March 26, 2013.

2) Energy Information Administration. 2013. *Michigan state profile and energy estimates.* Online at http://www.eia.gov/state/?sid=MI; Accessed April 8, 2013.

3) DTE Energy. 2012. *Renewable energy projects made in – and for – Michigan.* Online at http://www.dteenergy.com/pdfs/renewableMap.pdf; accessed April 8, 2013.

4) Consumers Energy. 2013. *Renewable energy.* Online at https://www.consumersenergy.com/content.aspx?id=1985; accessed April 8, 2013.

5) SNL Financials. 2013 *Power project details: Detailed projects by state: Michigan*. Online at http://www.snl.com/interactivex/bbsearch.aspx?activeTabIndex=2; accessed April 9, 2013.

6) Wiser, R., and M. Bolinger. 2012. *2011 wind technologies market report.* Washington, DC: U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy. Online at *www1.eere.energy.gov/wind/pdfs/2011_wind_technologies_market_report.pdf,* accessed March 24, 2013.

Question 2:

Renewable Energy Question #2: To date, what has been Michigan's cost of renewables, and how has that impacted rates paid by residential, commercial and industrial customers?

While the MPSC estimates that $1.79 billion has been *invested* in developing Michigan's renewable energy through 2012, this does not reflect Michigan's *cost* of renewables to date for several reasons.

First, while investments made to develop Michigan's renewable energy resources will, for the most part, be recovered from Michigan ratepayers, recovery is amortized over the life of the project – just as it is with any power plant. So Michigan's cost, to date, of renewables is only a small fraction of that initial investment and determining the exact fraction is difficult without access to data (transaction costs, etc.) that is typically kept confidential due to its business sensitivity.

Second, in determining the cost of Michigan's renewable energy and its impact on rates, it is important to recognize the avoided costs of Michigan's renewable energy – that is, what Michigan ratepayers would have otherwise spent on electricity had these renewable resources not been developed. This is primarily in the form of purchasing or generating electricity from non-renewable resources to replace the renewable energy not purchased, but also includes investments in non-renewable resources (such as necessary pollution controls) that are avoided because of the increased reliance on renewable energy. In Michigan's case, properly estimating this avoided cost is difficult, in part because Michigan is still in the early stages of compliance and many of these decisions have yet to be made.

Third, the price impacts of renewable energy on the regional electricity markets must also be taken into account. Lower market prices for electricity mean reduced costs for ratepayers. Because nearly all of Michigan's utilities purchase a portion of their electricity needs from the wholesale markets of the Midwest independent System Operator region (MISO), a true calculation of the cost of Michigan's renewable energy must take into account how increasing amounts of renewable energy in this market impacts the wholesale cost of electricity and how that impacts the costs ultimately paid by ratepayers. Initial studies to quantify the price suppression impacts of renewable energy on wholesale power markets indicate significant cost reductions for ratepayers. For example, a 2012 study by the Illinois Power Agency (and corroborated by similar findings in Massachusetts) found that for 2011, the integration of renewable resources into the power grid has lowered Illinois' average marginal price by $1.30 per MWh, resulting in savings of $176.85 million in total load payments.

Finally, when attempting to determine the cost of Michigan's renewable energy on ratepayers, the future avoided costs of Michigan's over-reliance on fossil fuels must also be considered, but is difficult to quantify. One of the critical benefits of renewable energy is its consistent price over the life of the generating facility. So if the costs of electricity from other resources rise due to increasing environmental costs or increasing fuel costs, renewable energy provides a larger cost benefit. In essence, renewable energy allows Michigan to hedge against the rising costs of electricity from other sources. While it is difficult to quantify this cost exactly, it is widely agreed upon that the cost of coal and natural gas will increase over the next several years.

Because of these factors, it would require extensive analysis involving significant uncertainty to calculate an exact number for the cost of Michigan's renewable energy and the impact it has on ratepayers.

Another way to estimate the cost of Michigan's renewable energy might be to look at the surcharges charged by Michigan utilities to comply with the renewable energy standard of P.A. 295. Under P.A. 295, utilities are allowed to charge a surcharge to their ratepayers to cover the incremental cost of compliance with Michigan's renewable energy standard. The monthly surcharges are limited at $3.00 for residential customers, $16.58 for commercial customers and $187.50 for industrial customers. If compliance with Michigan's renewable energy standard exceeds these statutorily-limited surcharges, a Michigan utility can get relief from its compliance obligations.

However, even utility surcharges do not directly correlate to the cost of Michigan's renewable energy. Surcharges are set based on utility plans approved by the MPSC that attempt to forecast the cost of complying with Michigan's renewable energy standard and do not necessarily reflect real-world experience. Further, there is some allowance of surcharge collection and banking for anticipated future costs, even if that year's cost of compliance would not warrant a surcharge. Therefore, a utility may be charging a surcharge despite the fact that complying with Michigan's renewable energy standard has not been more costly than otherwise and banking these funds for future compliance costs that may or may not materialize.

All this being said, there are several trends and specific data points that strongly indicate that the cost of Michigan's renewable energy and its impact on rates has been, and will continue to be, relatively small:

1. The MPSC calculates in its 2013 report that the weighted average price for RE contracts approved through 2012 is $82.54, which is less than what was forecasted in approved utility renewable energy plans. The MPSC further notes that renewable costs have been "much lower" than expected and continue to show a downward pricing trend.

2. Based on a review of utility renewable energy plans filed with the Commission, all electric providers except one – Detroit Public Lighting Department – are expected to meet the 10% renewable energy standard in 2015 without exceeding the statutory limits on monthly surcharges.

3. Of Michigan's 59 electric providers, 36 have not found it necessary to charge residential customers a monthly surcharge to recover incremental costs of compliance with Michigan's renewable energy standard.

4. Of the 23 electric providers that are charging a residential monthly surcharge, only 10 have shown it necessary to charge a surcharge in excess of $2 per month.

5. The most recent contracts approved by the MPSC for new wind capacity – which makes up the vast majority of Michigan's current renewable energy capacity – have a levelized cost in the $52/MWh range. This is nearly 20% lower than the MPSC's estimated weighted average of overall power supply costs of $64/MWh.

Resources:
1) Quackenbush, J.D., O.N. Isiogu, and G.R. White. 2013. *Report on the implementation of the P.A. 295 renewable energy standard and the cost-effectiveness of the energy standards*. Lansing, MI: Michigan Public Service Commission. Online at *http://www.michigan.gov/documents/mpsc/Report_on_the_implementation_of_Wind_energy_resource_zones_2013_413124_7.pdf*, accessed March 26, 2013.

2) Illinois Power Agency (IPA). 2012. *Annual report: The costs and benefits of renewable resource procurement in Illinois under the Illinois Power Agency and Illinois Public Utilities Acts*. Springfield, IL: IPA. Online at *www2.illinois.gov/ipa/Documents/April-2012-Renewables-Report-3-26-AAJ-Final.pdf*, accessed March 24, 2013.

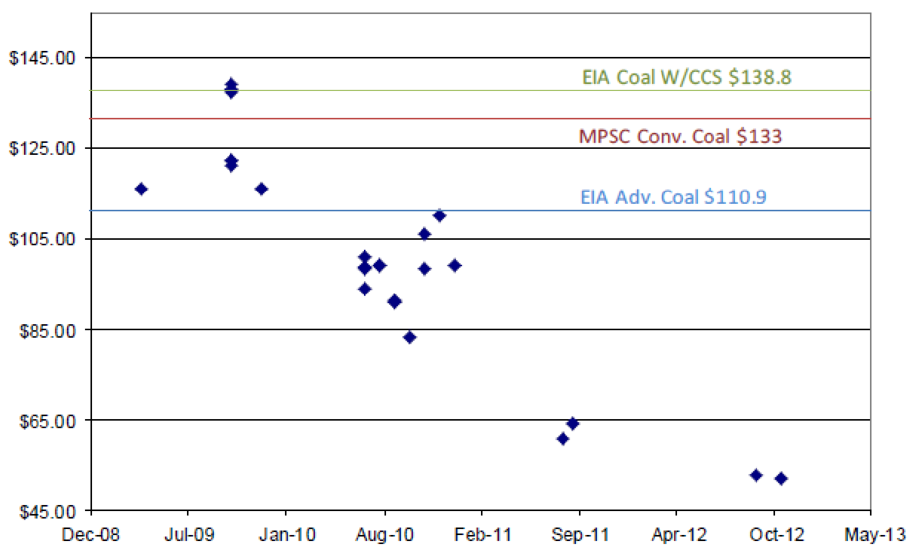
3) Bolinger, M. 2013. *Revisiting the long-term hedge value of wind power in an era of low natural gas prices.* Lawrence Berkeley National Laboratory, U.S. Department of Energy. Washington D.C. Online at http://emp.lbl.gov/sites/all/files/lbnl-6103e.pdf; accessed April 22, 2013.

Question 3:

Renewable Energy Question #3: How do Michigan's costs for RE compare to the cost of existing generation and to the cost of new non-renewable generation today?

Perhaps the best source of data on the recent costs of generating electricity from renewable energy in Michigan comes from the Michigan Public Service Commission's (MPSC) February 2013 renewable energy standard compliance report. The figure below from that report shows that the cost of renewable energy (primarily wind) contracts approved by the MPSC have declined significantly over time, and most of the contracts are well below the cost of building and operating a new coal plant. These contracts are dominated by wind power, which represents 94 percent of the total new renewable energy capacity approved by the MPSC through 2012. In fact, the most recent wind contracts approved by the MSPC (in the $52/MWh range) are below EIA's estimated levelized cost of $65.6/MWh for building and operating a new advanced natural gas combined cycle plant.

Figure 10: Levelized Cost of MPSC Approved Contracts Over Time Compared to the Cost of New Coal Fired Facilities



According to the MPSC report, the weighted average cost of all the renewable energy contracts is $82.45/MWh. The weighted average contract prices for different renewable energy technologies are shown the table below. With the exception of two small anaerobic digesters and one small landfill gas project, all of the other contracts are lower than MPSC's estimated cost of $133/MWh for a new conventional coal plant, which includes a price on CO_2. And most of the contracts are cheaper than EIA's estimated cost of $111/MWh for a new advanced coal plant, which includes a modest CO_2 price of approximately $15/ton. [Note that EIA's most recent estimate of the levelized cost of a new advanced coal plant with an in-service date of 2018 has increased to $123/MWh.]

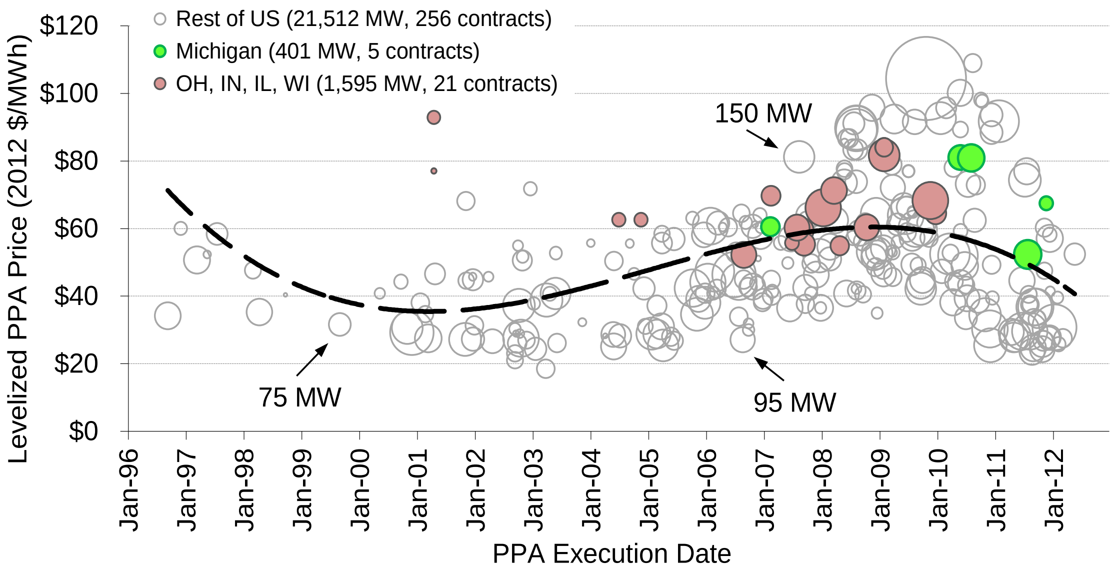
Table 2: Weighted Average Levelized Renewable Energy Contract Prices

Technology	Wind	Digester	Biomass	Landfill	Hydro
Consumers Energy					
Weighted Average	$101.83	$137.02	NA	$105.81	$121.31
Detroit Edison					
Weighted Average	$70.08	NA	$98.94	$98.97	NA
Combined Weighted Average	**$80.32**	**$137.02**	**$98.94**	**$103.84**	**$121.31**

We also agree with this statement from the MPSC report that these declining cost trends for renewable energy are likely to continue:
Based on contract pricing trends and the January 2013 announcement that federal legislation extended the eligibility of the Production Tax Credit for projects that begin construction by December 31, 2013, Commission Staff anticipates that the cost of renewable energy will continue to decline, while the benefits from energy optimization savings and emission reductions from offset generation will continue to increase. The extended tax credit will undoubtedly provide further opportunity for Michigan ratepayers to continue benefiting from reduced renewable energy costs.

The downward trend in the cost of wind projects is evident in Figure 1 below based on data from Lawrence Berkeley National Laboratory (LBNL) for a large sample of wind projects installed in the U.S. between 1996 and 2012. The figure shows that the weighted average power purchase agreement (PPA) prices for wind projects (the black dashed line) have fallen from about $60/MWh to $40/MWh, or one-third, over the past three years. This is due primarily to reductions in capital costs and improvements in capacity factors resulting from technological improvements and taller towers. The figure also shows that the costs of several wind projects installed in Michigan (green circles) and surrounding states (pink circles) are roughly within the same range (~$50-80/MWh), and are generally at or above the national weighted average cost from the sample. This reflects the fact that the wind resource in these states is not as strong as other parts of the country, particularly the plains states, but are similar to projects installed on the east and west coasts.

Figure 1. Levelized Prices for Wind Power Purchase Agreements (PPAs) Installed in the U.S. Between 1996 and 2012.



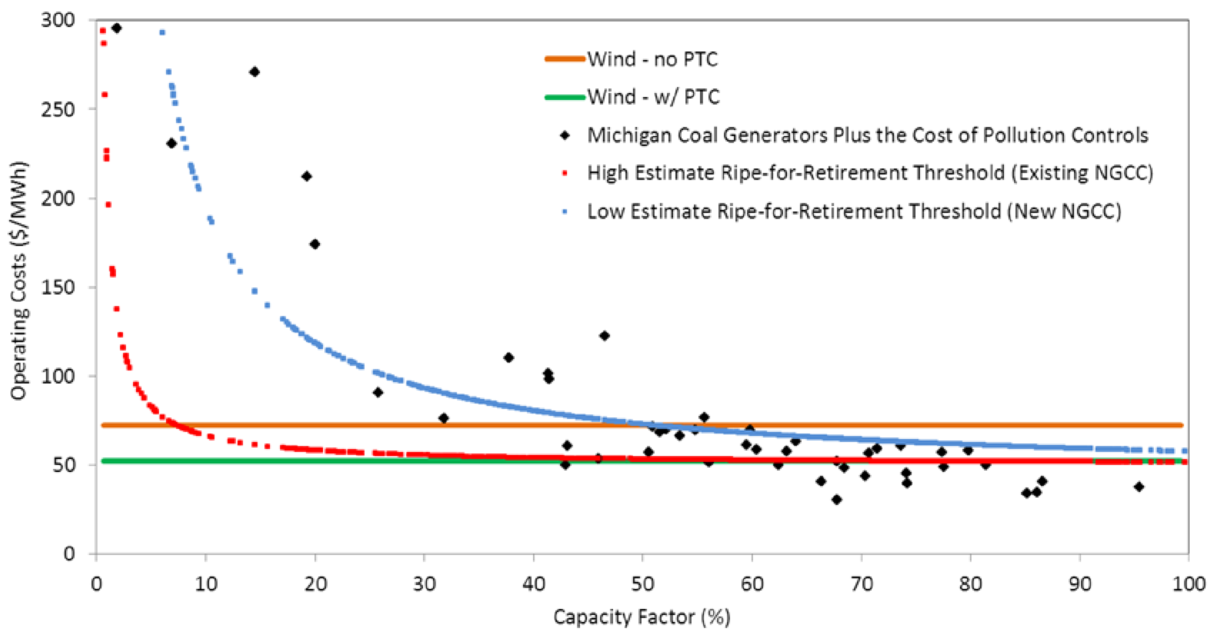
Source: Personal communication with Mark Bolinger, Lawrence Berkeley National Laboratory, April 2013.

A November 2012 study by the Union of Concerned Scientists (UCS), *Ripe for Retirement*, also found that it would be more expensive to retrofit many existing coal plants in Michigan with modern pollution control equipment than retiring and replacing them with new wind projects, new and existing natural gas power plants, and energy efficiency. The study ranked Michigan fifth in the country in terms of total capacity (3,684 MW) that was more expensive to retrofit with pollution controls than purchasing electricity from these cleaner alternatives. Michigan also ranked first for having the greatest number of coal generators on the list, with 39 units. Most of these generators are small, averaging 94 MW, and old, averaging 52 years in age.

When UCS completed this analysis, only two coal generators representing 112 MW of capacity (at the Presque Isle plant) had been announced for retirement. Over the past five months, an additional seven coal generators representing 437 MW of capacity at three plants (Harbor Beach, J.R. Whiting,, James De Young) have been announced for retirement in 2015 and 2016. Six out of seven of these generators were on the list of economically vulnerable generators, which provides some important validation for the credibility of the analysis.

Figure 2 and Table 1 below show the coal generators and coal capacity in Michigan that was identified as economically vulnerable in the analysis under different scenarios. These results were adjusted from the original report to reflect the recently announced retirements. Figure 2 shows that with the costs of new pollution controls included, the operating costs of 33 coal generators (black diamonds) representing 3,140 MW of capacity are more expensive than an average existing NGCC plant (red dotted line), while 11 generators representing 694 MW of capacity are more expensive than a new NGCC plant (blue dotted line). It also shows that 36 coal generators totaling 4,088 MW of capacity are more expensive to retrofit with pollution controls than retiring and replacing the plants with new wind projects (including the PTC—green line) that have similar costs of recently developed wind projects in Michigan. A significant amount of additional existing coal capacity is economically vulnerable in Michigan with a modest cost of $15/ton for CO_2 and low natural gas prices.

Figure 2. Operating Costs of Ripe for Retirement Coal Generators vs. Existing and New Natural Gas Plants and Wind Power Facilities



Source: Cleetus et al 2012.

Table 1. Coal Generators and Capacity Deemed Ripe for Retirement in Michigan under Alternative Scenarios.

Ripe for Retirement Scenario	**Number of Generators**	**Capacity (MW)**
Announced Retirements	9	549
Existing coal without new pollution controls (PC) vs. existing Natural Gas Combined Cycle (NGCC)	6	182
Existing coal with new PC vs. new NGCC	11	694
Existing coal with new PC vs. existing NGCC	33	3,140
Existing coal with new PC vs. wind with PTC	36	4,088
Existing coal with new PC vs. existing NGCC – both with $15/ton CO_2 Price	42	6,128
Existing coal with new PC vs. existing NGCC with 25% lower natural gas prices ($3.66/MMBtu)	45	8,685
Total existing coal fleet in MI included in analysis	59	12,431

Source: Cleetus et al 2012.

References:

1) Michigan Public Service Commission. 2013. *Report on the Implementation of the P.A. 295 Renewable Energy Standard and the Cost-Effectiveness of the Energy Standards*. Online at http://www.michigan.gov/documents/mpsc/implementation_of_PA295_renewable_energy_411615_7.pdf.

2) Energy Information Administration (EIA). 2013. Levelized Cost of New Generation Resources in the Annual Energy Outlook 2013. Online at: http://www.eia.gov/forecasts/aeo/er/electricity_generation.cfm

3) Cleetus, R., S. Clemmer, E. Davis, J. Deyette, J. Downing, and S. Frenkel. 2012. Ripe for Retirement: The Case for Closing America's Costliest Coal Plants. Union of Concerned Scientists: Cambridge, MA. Online at: http://www.ucsusa.org/assets/documents/clean_energy/Ripe-for-Retirement-Full-Report.pdf

Question 4:

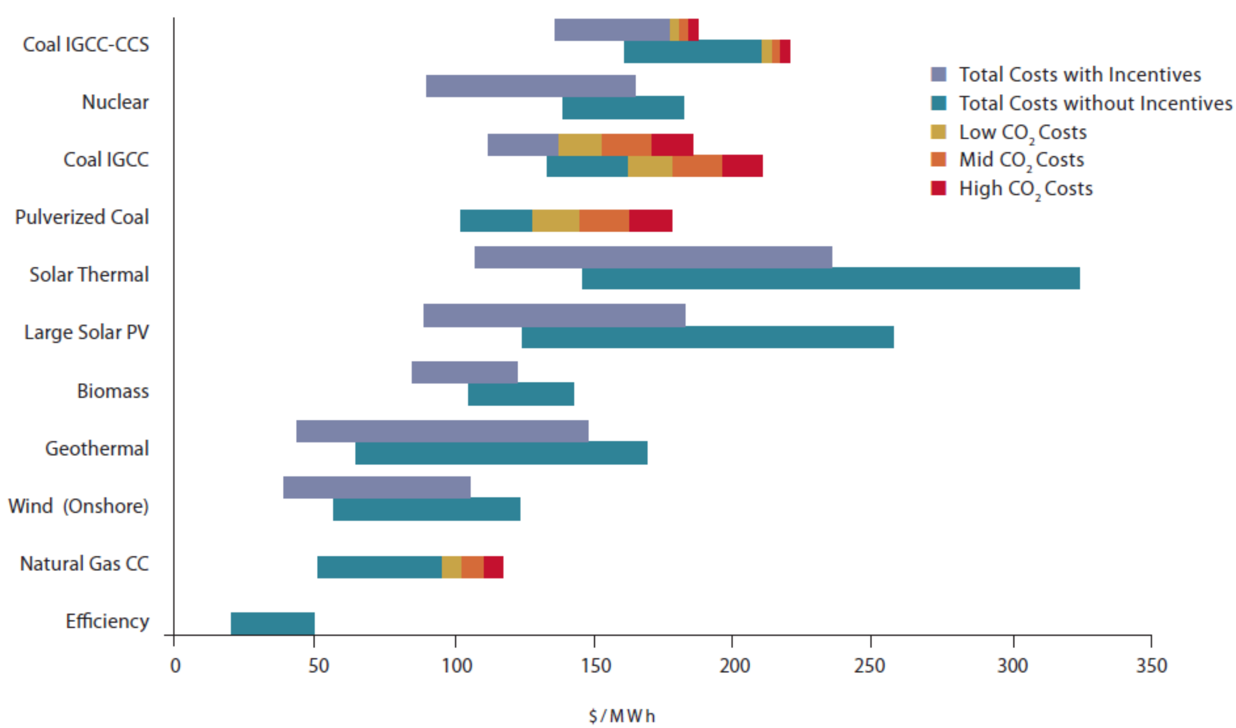
Renewable Energy Question #4: What are the predicted costs of new energy generation by type in the future? How would a carbon tax, increased carbon regulation, and the elimination of specialized tax treatment impact those cost estimates?

NOTE: This response addresses Renewable Energy Questions #4, 10 and 11 which have to do with the costs of various energy resources.

The figure below shows a range of levelized costs of generating electricity from different technologies, assumed to come on-line in 2015, with and without incentives and costs for carbon dioxide (CO_2) emissions. The data comes from a 2011 study by the Union of Concerned Scientists (UCS) called, *A Risky Proposition*: *The Financial Hazards of New Investments in Coal Plants*. It is worth noting that Energy Information Administration's (EIA) most recent levelized cost estimates for different technologies in 2018 fall within this range (EIA 2013). As defined by EIA, "levelized cost represents the present value of the total cost of building and operating a generating plant over an assumed financial life and duty cycle, converted to equal annual payments and expressed in terms of real dollars to remove the impact of inflation."

The range of costs reflects uncertainty in capital and fuel costs, as well as regional variations in costs and resource quality. The assumptions are based on project specific data, where available, and recent estimates from power plant construction and engineering firms, financial institutions, utilities, and state and federal agencies. More details on the cost and performance assumptions for each of these technologies can be found in Appendix A of the study.

Figure 1. Levelized Cost of Electricity for Various Technologies



Source: Freese et al 2011.

Without incentives and CO_2 costs (lower bars), you can see that new natural gas combined cycle (NGCC) plants, onshore wind, and the best biomass and geothermal projects are cheaper than or competitive with a new pulverized coal plant, and energy efficiency is by far the cheapest option. When you include incentives and CO_2 costs, the best large scale solar PV and concentrating solar thermal projects also become competitive. You can also see that coal with carbon capture and storage (CCS) is not competitive with other alternatives, even with incentives. And new nuclear plants are only competitive with a new coal plant when you include generous loan guarantees and other incentives or high CO_2 costs, and are more expensive than new NGCC plants, efficiency and many renewable energy technologies.

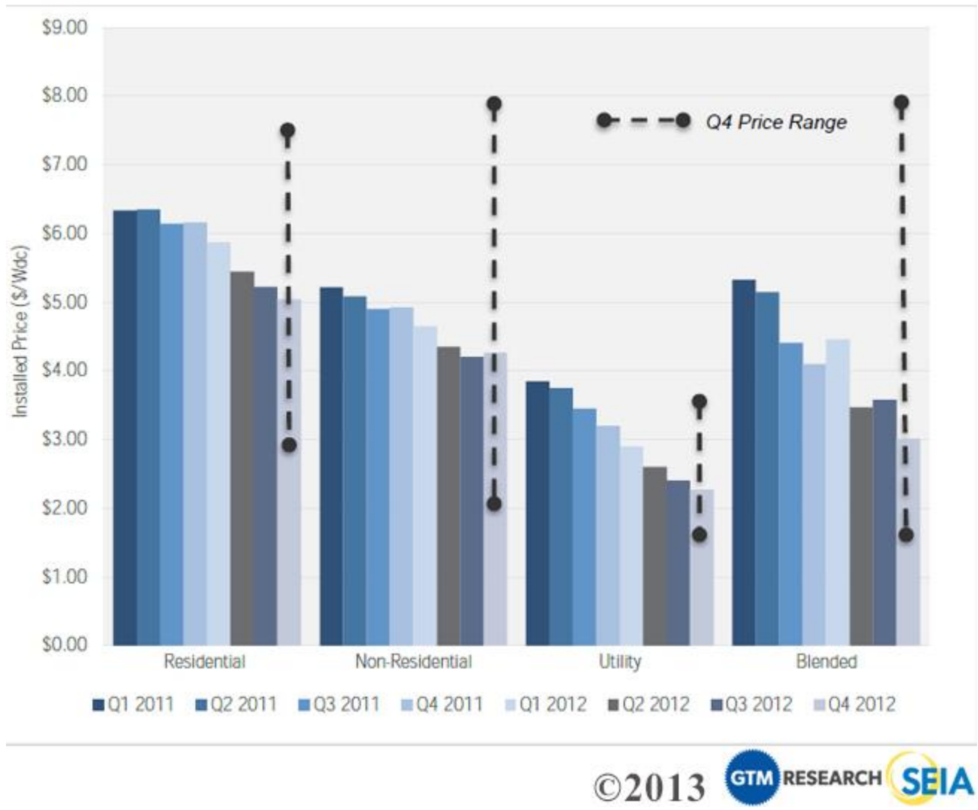
The range of future CO_2 prices assumes $13/ton in the low case, $26/ton in the mid case, and $43/ton in the high case. These estimates are based on a 2011 study reviewing more than 75 different scenarios examined in the recent modeling of various federal climate bills, as well as estimates used by a number of electric utilities in their resource plans (Johnston 2011). These prices should be considered conservative, as the report has since been updated with higher levelized CO_2 prices ranging from $23/ton to $59/ton.

The other significant changes that have occurred since the UCS study was released in 2011 are a decline in natural gas prices and the cost of wind and solar PV projects. The range of natural gas (and coal) prices used in Figure 1 are based on EIA projections from Annual Energy Outlook 2011 (AEO 2011). The recent decline in natural gas prices over the past two years is already captured in the lower end of the range in the figure. This is evident in EIA's most recent levelized cost estimate of $65.6/MWh for a new advanced NGCC plant with a 2018 in-service date (EIA 2013). The ~$20/MWh (33%) decline in average wind costs in the past three years, as shown in the response to question 3, would reduce the low end of the range of levelized wind costs in Figure 1 by approximately $10/MWh.

The cost of solar PV has also fallen dramatically over the past few years. A recent report from the Solar Energy Industries Association (SEIA) that uses a large sample of data from actual projects shows that the average installed cost of a completed PV system dropped by 27 percent over the past year, as shown in Figure 2. The study also found that the average price of a solar panel has declined by 60 percent since the beginning of 2011. These cost reductions are evident in several recent utility scale solar PV projects proposed or approved in the Southwestern U.S. that have PPA prices in the $58-$100/MWh range, including federal tax credits (Marks 2012, Bloomberg 2013). This would reduce the low end of the range for large scale PV in Figure 1 by ~$30/MWh. Significant cost reductions have also occurred for residential and commercial scale PV systems as shown in Figure 2.

While Michigan's solar resources are not as good as the Southwest, recent and projected cost reductions combined with the availability of the 30 percent federal investment tax credits through 2016 will make solar PV systems increasingly competitive with conventional and other renewable energy technologies in the state. With recent wind projects installed in Michigan in the $52-65/MWh range, wind power is already considerably cheaper than new coal plants and competitive with new natural gas power plants. And wind costs are likely to fall even further over the next few years, according to experts from Lawrence Berkeley National Laboratory (Wiser et al 2012).

Figure 2. Average Installed Price of Solar PV by Market Segment, 2011-2012



Source: SEIA 2013.

While these "levelized" costs cost comparisons are a useful screening tool for new power plants, they don't reflect the full value and costs that different technologies provide to the electricity system. For example, it doesn't include transmission and integration costs, reliability needs, the ramping flexibility that natural gas and hydro plants can provide, siting and permitting challenges, and the ability of new technologies to replace existing power plants. Figure 1 also doesn't consider changes in the future costs for different technologies. The cost of some technologies--such as wind, solar and carbon capture and storage (CCS)--are likely to decline over time with increased development, economies of scale in manufacturing, experience, and technological innovation. The cost of other technologies, such as natural gas and coal, are likely to increase as supplies become more limited and fuel prices rise over time.

Modeling recently completed by UCS [and others] that have taken these factors into account have found that it is feasible and affordable for Michigan and the U.S. to significantly increase electricity from renewable energy to much higher levels over time. For example, UCS' 2011 study *A Bright Future for the Heartland* used a modified version of EIA's National Energy Modeling System to analyze the costs and benefits of increasing renewable energy and energy efficiency in the Midwest (Martinez et al 2011). The study found that increasing renewable energy to 30 percent of the electricity mix by 2030 in Michigan and other Midwest states would lower electricity and natural gas bills in Michigan by $9 billion, when combined with investments in energy efficiency. The study also found that investing in renewable

energy and efficiency would create 15,300 more jobs than using coal and natural gas to provide the same amount of electricity.

Resources:

1) Energy Information Administration (EIA). 2013. *Levelized Cost of New Generation Resources in the Annual Energy Outlook 2013*. Online at: http://www.eia.gov/forecasts/aeo/er/electricity_generation.cfm

2) Freese, B, Clemmer S., Martinez C., and Nogee A. 2011. *A Risky Proposition: The Financial Hazards of New Investments in Coal Plants.* Cambridge, MA: Union of Concerned Scientists. http://www.ucsusa.org/assets/documents/clean_energy/a-risky-proposition_report.pdf

3) Johnston, L., E. Hausman, B. Biewald, R. Wilson, and D. White. 2011. *2011 carbon dioxide price forecast.* Cambridge, MA: Synapse Energy Economics. Online at http://www.synapseenergy.com/Downloads/SynapsePaper.2011-02.0.2011-Carbon-Paper.A0029.pdf.

4) Marks, J. A. 2012. Concurrence. Case No. 11-00218-UT. *IN THE MATTER OF THE COMMISSION ESTABLISHING A STANDARD METHOD FOR CALCULATING THE COST OF PROCURING RENEWABLE ENERGY, APPLYING THAT METHOD TO THE REASONABLE COST THRESHOLD, AND CALCULATING THE RATE IMPACT DUE TO RENEWABLE ENERGY PROCUREMENTS*. Santa Fe, NM: New Mexico Public Regulation Commission. (PDF included in Appendix).

5) Solar Energy Industries Association (SEIA) and GTM Research. 2013. U.S. Solar Market Insight Q4 2012 Report. Online at: http://www.seia.org/research-resources/us-solar-market-insight

6) Martinez, C., J. Deyette, S. Sattler, A. McKibben. 2011. *A Bright Future for the Heartland: Powering Michigan's Economy with Clean Energy*. Cambridge MA: Union of Concerned Scientists. http://www.ucsusa.org/assets/documents/clean_energy/A-Bright-Future_Michigan.pdf

7) Goossens E. and C. Martin. 2013. "First Solar May Sell Cheapest Solar Power, Less Than Coal." *Bloomberg*. http://www.bloomberg.com/news/2013-02-01/first-solar-may-sell-cheapest-solar-power-less-than-coal.html

8) Wiser, R., E. Lantz, M. Bolinger, M. Hand. 2012. *Recent Developments in the Levelized Cost of Energy from U.S. Wind Power Projects*. Online at: http://eetd.lbl.gov/ea/ems/reports/wind-energy-costs-2-2012.pdf.

Question 5:

Renewable Energy Question #5: What transmission upgrade costs and back-up capacity/integration costs have Michiganders absorbed as part of the current renewable standard? Are any of those offset by other benefits of those investments?

Michigan ratepayers have not been assigned costs for renewables integration, and the transmission upgrades were approved based on analyses that the benefits would be double the costs.

The Midwest ISO has recently approved spending on a set of Multi-Value Project Transmission upgrades, the costs of which have been spread across all the ratepayers of the Midwest ISO. The benefits from the MVP Transmission are 2 times greater than the costs. The MVP Transmission portfolio provides 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)
https://www.midwestiso.org/Library/Repository/Study/MTEP/MTEP11/MTEP11%20Report.pdf

These benefits accrue in part because Transmission provides Enhanced Market Efficiency. The complete set of Multi-Value projects greatly reduces congestion across the MISO footprint. The MVP portfolio unlocks the value in low cost energy trapped by congestion and enables more efficient usage of generation resources. Michigan has the highest bulk power prices in MISO[2], so adding transmission that reduces congestion has the greatest potential benefit to Michigan.

There are no back-up capacity costs from the RPS. The RPS purchases energy produced, rather than the fixed capacity of the plants. However, there is a capacity benefit from the wind farms that are added to meet RPS energy goals. In determining how much generator capacity is needed each year to meet resource adequacy goals, MISO counts the benefit from the wind generation. MISO tracks the amount of wind produced at the time of the MISO system's peak demand, now using 8 years of data, to find how much capacity is provided from wind. (Landfill gas generation and biomass would be recognized at higher levels of capacity.)

There is also a cost benefit to all consumers from the addition of wind power in the energy market. By adding energy supplies through the renewables standards, the several states of the Midwest have lowered overall electric prices in the wholesale market. This has been confirmed by the independent Market Monitor that watches the Midwest ISO. (2010 State Of The Market Report For The Miso Electricity Markets. June 2011. Potomac Economics)
http://www.potomaceconomics.com/uploads/midwest_reports/2010_State_of_the_Market_Report_Final.pdf

Analysis shows that the continued addition of wind power on the MISO grid will provide increasing savings on the overall price of energy in the market, and this will increase with 1) more transmission, and 2) coal plant retirements. http://www.synapse-energy.com/Downloads/SynapseReport.2012-08.EFC.MISO-T-and-Wind.11-086.pdf

[2] MISO Northern Area Study Technical Review Group (TRG) September 21, 2012 (slide 19) https://www.midwestiso.org/Library/Repository/Meeting%20Material/Stakeholder/Planning%20Materials/Northern%20Area%20Study%20TRG/20120921%20Northern%20Area%20Study%20Presentation.pdf

Question 6:

Renewable Energy Question #6: How can reliability costs and benefits be assessed and incorporated into an analysis of renewables costs? Has any jurisdiction tried to do so, and if so, how?

While reliability will be defined as maintaining electric service, there are numerous time horizons and components that contribute to keeping the lights on. One measure of reliability, whether generation or delivery, is capacity to serve customer demand for electricity, or "load." Thus, more ways to keep the supply adequate for a given level of demand, or the ability to meet a higher level of load would be recognized as increased reliability. Two of the largest concerns for reliability, and two of the largest fixed costs of the power system, are transmission and generation. Midwest ISO provides analyses of costs and benefits in these two categories. Also, the Union of Concerned Scientists has made a study of the reliability benefits and lowered costs from increasing Michigan use of renewable energy.

1. Transmission

Transmission costs and benefits are assessed by Midwest ISO and discussed with stakeholders. In 2010-2011, Midwest ISO defined and approved a portfolio of transmission upgrades to accommodate generation connections and improve reliability in Michigan and across the MISO footprint. The first package of 17 Multi-Value Projects was described by Midwest ISO 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.
https://www.midwestiso.org/_layouts/MISO/ECM/Redirect.aspx?ID=120701

2. Generation

Part of the utility industry assessment of reliability risks is to identify how a single event or disturbance to the normal operations can cause an outage at more than one power plant. The Union of Concerned Scientists has explored the risks to the power supply from droughts that interfere with the use of water for cooling power plants. In nearby states of Illinois and Minnesota, cooling water disruption from hot dry weather has caused 12 power plants to interrupt electric supply between 2006 and 2012. (For more information, see http://www.ucsusa.org/assets/documents/clean_energy/ew3/Infographic-The-Energy-Water-Collision-Fact-3.pdf.)

The Union of Concerned Scientists has released a study of the risks to reliability, and related economic and environmental benefits from increasing the use of renewable energy generation. The latest UCS report describes the economic disadvantage of continued operation of seven coal plants in Michigan, and the savings of over 5 billion gallons of *consumed* water if these plants are replaced with renewable energy and energy efficiency. Fleishman, L and Schmoker, M. 2013 *Economic and Water Dependence Risks for America's Aging Coal Fleet.* Cambridge, MA: Union of Concerned Scientists. April.

The Midwest ISO has also has an explicit process for establishing the reliability benefits of new generation. This involves calculating the Loss of Load Expectation (LOLE) for a specific set of generators and energy demand patterns. The idea is that adding more energy sources increases the probability that there will be enough generated energy when a shortage threatens reliability. An increase in this measure generally follows when additional generator is included, and that increase for the specific generator is the Effective Load-Carrying Capability (ELCC). The MISO uses ELCC for wind and has done so for 3 years. See this year's report at https://www.midwestiso.org/Library/Repository/Study/LOLE/2013%20Wind%20Capacity%20Report.pdf

Below is description of the steps for finding the reliability benefits from wind from a U.S. Department of Energy-funded research paper. Milligan, M. and Porter, K. 2005. *Determining the Capacity Value of Wind: A Survey of Methods and Implementation*. Golden, CO: National Renewable Energy Laboratory. http://www.nerc.com/docs/pc/ivgtf/milligan_porter_capacity_paper_2005.pdf

ELCC is calculated in several steps. To calculate ELCC, a database is required that contains hourly load requirements and generator characteristics. For conventional generators, rated capacity, forced outage rates, and specific maintenance schedules are primary requirements. For wind, an intermittent resource, at least 1 year of hourly power output is required, but more data is always better. Most commonly, the system is modeled without the generator of interest. For this discussion, we assume that the generator of interest is a renewable generator, but this does not need to be the case. The loads are adjusted to achieve a given level of reliability. This reliability level is often equated to a loss of load expectation (LOLE) of 1 day per 10 years. This LOLE can be calculated by taking the LOLP (a probability is between zero and one and cannot by definition exceed 1) multiplied by the number of days in a year. Thus LOLE indicates an expected value and can be expressed in hours/year, days/year, or other unit of time.

Once the desired LOLE target is achieved, the renewable generator is added to the system and the model is re-run. The new, lower LOLE (higher reliability) is noted, and the generator is removed from the system. Then the benchmark unit is added to the system in small incremental capacities until the LOLE with the benchmark unit matches the LOLE that was achieved with the renewable generator. The capacity of the benchmark unit is then noted, and that becomes the ELCC of the renewable generator. It is important to note that the ELCC documents the capacity that achieves the same risk level as would be achieved without the renewable generator.

A simpler process for finding the reliability benefits for wind generation is used in PJM. The resulting capacity credit can then be by the asset owner in the PJM capacity market. The capacity credit for wind in PJM is based on the wind generator's capacity factor during the hours from 3 p.m. to 7 p.m., from June 1 through August 31. The capacity credit is a rolling 3-year average, with the most recent year's data replacing the oldest year's data. Because of insufficient wind generation data, PJM has applied a capacity credit of 20% for new wind projects, to be replaced by the wind generator's capacity credit once the wind project is in operation for at least a year.

Question 7:

Renewable Energy Question # 7: How does Michigan's renewable requirement compare to other states/provinces/countries? How are other jurisdictions similar/dissimilar? What has been the experience in other jurisdictions in terms of compliance, costs, reliability, and environmental impact?

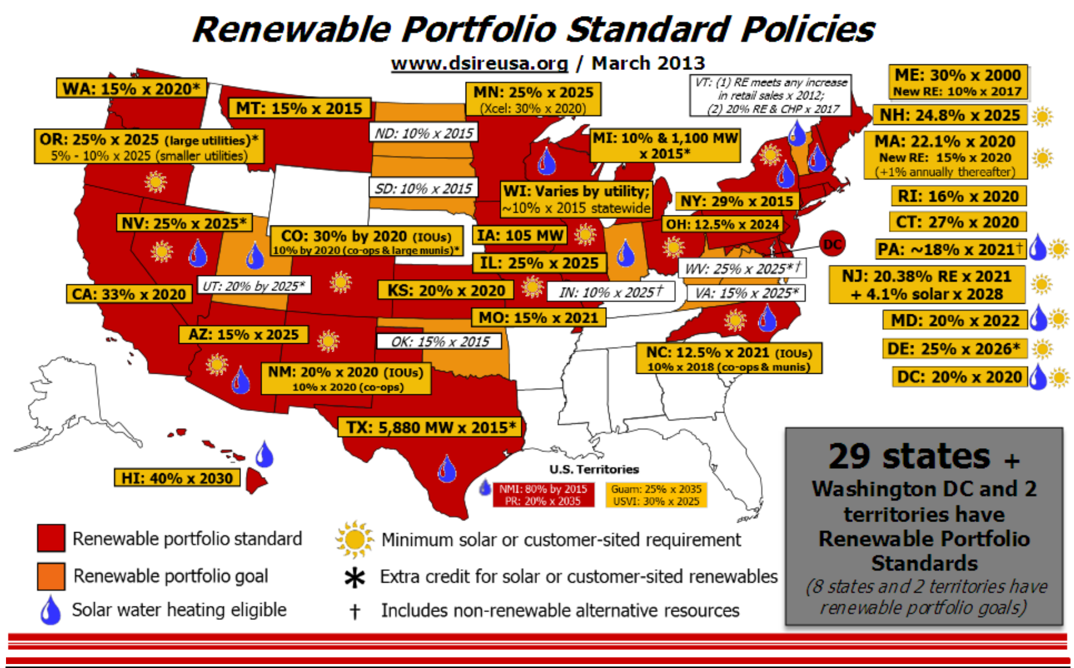
Though simple in their primary goal of supporting the deployment of new renewable energy resources, renewable electricity standards can be complex in design. For example, the Lawrence Berkeley National Laboratory has identified at least 15 different design elements that have been typically considered by states as they develop RES policies:

- 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
- Role of state funding mechanisms

Due to the fact that any of these policy provisions can be designed in different ways in order to meet local economic, environmental, and political considerations, no two states have designed their RES policies exactly the same. The North Carolina Solar Center's Database of State Incentives for Renewables and Efficiency (http://www.dsireusa.org) is an excellent and dependable resource for comparing policy design elements between the states.

In terms of renewable energy targets and timeframes, Michigan ranks either in the middle of, or near the bottom of the list, when compared with other state RES policies. As a percent of total electric consumption, Michigan's 10 percent RES is lower than all but three of the 29 states and the District of Columbia that have an RES. Seventeen states and the District of Columbia have established renewable energy requirements of at least 20 percent. Likewise, Michigan's policy end date of 2015 is shorter than all but four other states. However, in terms of total renewable energy generation supported, Michigan ranks more in the middle of the pack, 16th among the 29 states and the District of Columbia. This is primarily because Michigan has a larger electricity demand than other smaller states that have implemented higher renewable energy targets.

Renewable electricity standards have also been implemented internationally, most with renewable energy targets greater than Michigan's requirement. For example, China has an RES that requires 15 percent renewable energy by 2015. The European Union as a whole also has a 33 percent by 2020 RES.



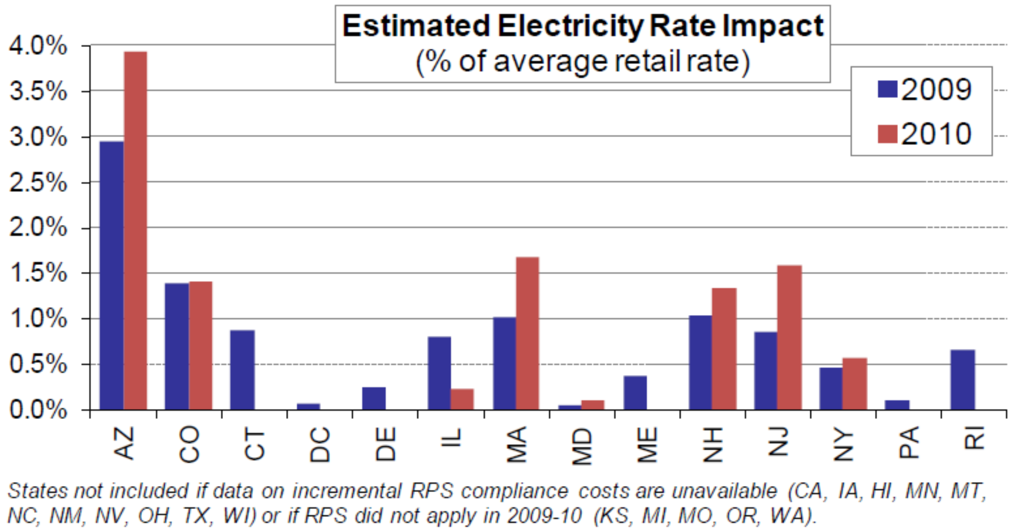
Source: North Carolina Solar Center's Database of State Incentives for Renewables and Efficiency

In terms of cost recovery, Michigan's RES includes a provision for a monthly customer surcharge. Obligated utilities are authorized to include an itemized monthly charge for the costs of compliance with renewable and energy efficiency requirements. This approach is different from most other states, where the typical policy is to allow for recovery of prudently incurred costs after the compliance investments have been made.

Compliance and Cost Experiences: Like most other states, Michigan is on track to meet its 10 percent by 2015 RES. According to data from the Lawrence Berkeley National Laboratory, states monitoring compliance through 2010 reported that utilities had met about 96 percent of their renewable energy requirements. Fifteen of the 29 states with RES policies were in full compliance with their RES requirements, including several states such Colorado, Iowa, Texas, and Minnesota, that are several years ahead of schedule. Twenty of the 29 states had achieved over 90 percent compliance, and most of the remaining states did not have an annual requirement in 2010.

Nearly all state RES policies include cost-containment measures to protect consumers from higher than expected costs. Nevertheless, meeting RES requirements is proving to be an affordable. The Lawrence Berkeley National Laboratory, having recently evaluated 2009 and 2010 RES compliance-cost data that were available for 14 states, estimated that all but one state experienced cost impacts of about 1.6

percent or less (see chart). In some states, like Arizona, the initial rate impact has been higher. However, these rate increases account for the upfront costs associated with building distributed renewable energy systems.



And there is further compelling evidence—found in more recent data reported by utilities and state agencies charged with RES implementation—that demonstrates the inherent cost-effectiveness of RES policies. Consider the following examples:

- In Minnesota, renewable energy investments lowered electricity prices for Xcel Energy customers—the state's largest utility—by 0.7 percent in 2008 to 2009. Xcel also estimated that meeting the RES through 2025 would increase costs by just 1.4 percent.
- In Oregon, renewable energy investments spurred by the RES in 2011 lowered total annual costs for PacifiCorp by $6.6 million, and increased total costs for Portland General Electric by just $630,000 (or 0.04 percent).
- In Illinois, the state's two largest utilities, serving the majority of demand in the state, estimated RES compliance costs at 0.04 to 0.08 percent of average retail rates in 2012.
- In North Carolina, Duke Energy's residential customers paid just 21 cents per month in 2012 to support the state's RES (down from 27 cents in 2010), while Progress Energy's residential customers now pay 41 cents per month (down from 55 cents in 2011).
- In Kansas, RES-driven development by the state's two largest utilities in 2012 and 2013, which will put them more than halfway toward meeting their 20 percent by 2020 target, is resulting in a modest 1.7 percent rate increase for energy consumers.
- In Wisconsin, the PSC estimated that supplying 7.4 percent of the state's total electricity demand from renewable energy resulted in a 1 percent rate increase from 2008 to 2010.

Resources:

1) Barbose, Galen. 2012. RPS Compliance Summary Data. Lawrence Berkeley National Laboratory. Available at: http://dsireusa.org/rpsdata/LBNL_compliance_dataAugust2012.xlsx

Question 8:

Renewable Enegy Question #8: What is Michigan's long-term potential for more wind, solar, hydro, biomass, landfill gas, and other renewable sources?

Michigan has the technical potential to meet all of its electricity needs from renewable sources. Even after adjusting renewable energy potential based on economic and market limitations, it still has the potential to use renewables to generate nearly twice its 2012 electricity demand—led primarily by onshore wind, solar, and bioenergy.[3] And while it is important to note that not all of this technical potential can or should be tapped due to conflicting land use needs, cost considerations, transmission constraints, and other hurdles, Michigan still has strong, diverse and cost-effective resources available to significantly increase its use of renewable energy above the current 10 percent by 2015 requirement.

Solar: According to an analysis conducted by the National Renewable Energy Laboratory (NREL), Michigan has vast solar power potential, both in the development of utility-scale photovoltaic (PV) systems as well as distributed generation systems on residential and commercial buildings. After accounting for cost projections and geographic limitations, NREL estimates the long term market potential for solar in Michigan at approximately 38,260 GWh per year; which is more than one-third of all electricity generation in the state in 2012.

Wind: Onshore wind resources in Michigan have the potential to generate approximately 143,901 GWh of power annually using turbines on towers that are 80 meter tall. This is more than 1.3 times the total state-wide electricity demand in 2012. Significantly more wind resources are also available offshore on Michigan's Great Lakes.

Bioenergy: Bioenergy is the largest source of renewable energy currently deployed in Michigan. There are two types of bioenergy resources that are potential energy sources in Michigan. First, there is a large supply of sustainable cellulosic biomass resources, which includes energy crops, agriculture and forest residues, as well as mill and urban wood wastes. These resources can be used to produce electricity in a dedicated biomass facility or it can be co-fired (up to 10 or 15 percent) at existing coal plants. In addition, there is a potential to generate electricity from methane captured at existing landfills or wastewater treatment facilities. Michigan has already tapped much of its landfill gas potential.

Geothermal: Like most non-western U.S. states, Michigan does not have potential for producing electricity from conventional, hydrothermal forms of geothermal energy. However, with enhanced geothermal system (EGS) technology, Michigan has the potential to tap into significant new energy resources. EGS draws energy from hot rock at greater depths than conventional geothermal systems—approaching the depths of oil and gas wells—to expand the economically recoverable amount of heat and power stored under the Earth's surface.

Hydropower: Hydropower is the second largest source of renewable energy currently deployed in Michigan. While Michigan is unlikely to expand its conventional hydropower resources by further damming waterways, there is potential for increased electricity generation from smaller, more sustainable run-of-the-river hydropower systems.

[3] Note: Technical potential accounts for land-use and topographic constraints. Economic limitations include constraints related to projected technology costs and projected fuel costs. Market limitations include constraints related to policy, regulation, and investment.

(GWh)	Total Estimated Technical Potential in Michigan	Potential after current economic and market limitations	2012 Electricity Generation
Solar	5,290,013	38,261	33
Urban Utility-Scale Photovoltaic	50,845		
Rural Utility-Scale Photovoltaic	5,215,640	38,261	~33
Rooftop Photovoltaic	23,528		
Wind	1,883,709	143,901	1,108
Onshore Wind Power	143,908	143,901	1,108
Offshore Wind Power	1,739,801	NA	0
Bioenergy	15,795	15,795	3,326
Cellulosic biomass feedstocks	14,687	14,687	2,448
Landfill Gas	1,108	1,108	878
Geothermal	457,850	1,289	~0
Hydrothermal Power	0	0	0
Enhanced Geothermal Systems & Co-Produced	457,850	1,289	0
Hydropower	2,486[4]	2,470	1,305
Total	**7,645,955**	**200,608**	**4,894**
2012 State-Wide Electricity Generation			106,609

Resources:

1) NREL - U.S. Renewable Energy Technical Potentials: A GIS-Based Analysis. Online at http://www.nrel.gov/docs/fy12osti/51946.pdf.

2) EIA Electricity Production Monthly. Online at http://www.eia.gov/electricity/.

3) Chaudhari, M., L. Frantzis, T. Hoff. September 2004. Navigant Consulting. *PV Grid Connected Market Potential under a Cost Breakthrough Scenario*. Navigant Consulting, Cambridge, MA. Online at http://www.ef.org/documents/EF-Final-Final2.pdf.

4) U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, Wind Powering America Program. 2010. Wind Maps and Wind Resource Potential Estimates. February. Available online at: http://www.windpoweringamerica.gov/wind_maps.asp#potential

5) Walsh, M. 2008. *U.S. Cellulosic Biomass Feedstock Supplies and Distribution*. June 24. Oak Ridge, TN: M&E Biomass. (Biomass Potential at $90/dry ton). Online at http://ageconsearch.umn.edu/bitstream/7625/2/U.S.%20Biomass%20Supplies.pdf; accessed April 22, 2013.

6) Environmental Protection Agency. Landfill Methane Outreach Program. Available at: http://www.epa.gov/lmop/

7) Petty, S. and G. Porro. 2007. "Updated U.S. Geothermal Supply Characterization, "National Renewable Energy Laboratory Presented at the 32nd Workshop on Geothermal Reservoir Engineering Stanford,

[4] The hydropower numbers reported only include hydropower that has not yet been developed. I added that to the current generation to get total potential

California January 22–24, 2007 NREL/CP-640-41073. March 2007.
http://www.nrel.gov/docs/fy07osti/41073.pdf

8) Table B-1. DOE. EERE. "Feasibility Assessment of the Water Energy Resources of the United States for New Low Power and Small Hydro Classes of Hydroelectric Plants," January 2006 DOE-ID-11263. Online at http://www1.eere.energy.gov/water/pdfs/doewater-11263.pdf; accessed April 22, 2013.

9) Union of Concerned Scientists. 2009. *A Bright Future for the Heartland.* Online at http://www.ucsusa.org/assets/documents/clean_energy/A-Bright-Future-for-the-Heartland.pdf.

Question 9:

Renewable Energy Question #9: What is the long-term potential for more wind, solar, hydro, biomass, landfill gas, and other renewables sources in other locations to which Michigan is tied electrically?

Michigan is tied electrically to regions with substantial potential for renewable energy generation. Michigan is part of both the Midwest Independent System Operator (MISO) and the PJM Interconnection. MISO includes all or parts of Iowa, Illinois, Indiana, Kentucky, Minnesota, Missouri, Montana, North Dakota, South Dakota, Wisconsin, and Wyoming. PJM includes all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, North Carolina, New Jersey, Ohio, Pennsylvania, Virginia, and West Virginia. For the purpose of this assessment, we exclude Montana, South Dakota, Kentucky, and North Carolina; only a small part of these states is part of MISO or PJM territory.

The region to which Michigan is tied electrically has the technical potential to meet all of its electricity needs from renewable sources. Even after adjusting renewable energy potential based on economic and market limitations, the region still has the potential to use renewables to generate eight times total 2012 electricity demand—primarily with onshore wind, solar, and bioenergy.[5] And while not all of this technical potential can or should be tapped due to conflicting land use needs, cost considerations, transmission constraints, and other hurdles, Michigan still has the opportunity to draw on vast and diverse renewable energy resources within the state's surrounding region.

Below are the total technical potential, economic and market potential, and current generation of renewable energy from the 15 states to which Michigan is tied electrically:

(All values are in GWh)	Estimated Technical Potential	Potential after economic and market limitations	2012 Electricity Generation
Bioenergy	340,279	340,279	11,538
Geothermal	6,980,853	67,200	-
Hydropower	61,418[6]	65,558	14,918
Solar	69,665,897	323,014	522
Wind	56,251,192	9,430,339	48,723
Total	**133,299,639**	**10,226,390**	**75,701**
2012 Region Electricity Generation (15 states)			**1,273,313**

A more detailed breakdown of technical potential, economic and market potential, and current generation by technology and state:

[5] Note: Technical potential accounts for land-use and topographic constraints. Economic limitations include constraints related to projected technology costs and projected fuel costs. Market limitations include constraints related to policy, regulation, and investment.

[6] The hydropower numbers reported only include hydropower that has not yet been developed. Potential was added to the current generation to get total potential

	Estimated Technical Potential	Potential after economic and market limitations	2012 Electricity Generation
Delaware			
Bioenergy	1,147	1,147	107
Bioenergy - Landfill Gas		127	59
Geothermal	22,813	-	-
Geothermal - Hydrothermal Power	-	-	
Geothermal - Enhanced Geothermal Systems & Co-Produced	22,813	-	
Hydropower	31	5,074	-
Solar	274,518	3,718	30
Solar - Urban Utility-Scale Photovoltaic	14,856		
Solar - Rural Utility-Scale Photovoltaic	272,333		
Solar - Rooftop Photovoltaic	2,185		
Solar - Concentrating Solar	-	-	
Wind	60,676	22	-
Wind - Onshore Wind Power	22	22	
Wind - Offshore Wind Power	60,654	-	
Illinois			
Bioenergy	62,429	62,429	668
Bioenergy - Landfill Gas		2,041	1,036
Geothermal	676,056	15,053	-
Geothermal - Hydrothermal Power	-	-	
Geothermal - Enhanced Geothermal Systems & Co-Produced	676,056	15,053	
Hydropower	4,981	3,128	98
Solar	8,121,071	42,882	37
Solar - Urban Utility-Scale Photovoltaic	103,552		
Solar - Rural Utility-Scale Photovoltaic	8,090,985		
Solar - Rooftop Photovoltaic	30,086		
Solar - Concentrating Solar	-	-	
Wind	715,538	635,961	7,708
Wind - Onshore Wind Power	649,468	635,961	
Wind - Offshore Wind Power	66,070	-	
Indiana			
Bioenergy	35,047	35,047	347
Bioenergy - Landfill Gas		888	373
Geothermal	434,258	498	-
Geothermal - Hydrothermal Power	-	-	
Geothermal - Enhanced Geothermal Systems & Co-Produced	434,258	498	
Hydropower	2,850	3,703	456
Solar	4,893,337	24,002	-
Solar - Urban Utility-Scale Photovoltaic	98,815		
Solar - Rural Utility-Scale Photovoltaic	4,876,186		

	Estimated Technical Potential	Potential after economic and market limitations	2012 Electricity Generation
Solar - Rooftop Photovoltaic	17,151		
Solar - Concentrating Solar	-	-	
Wind	377,770	370,235	2,231
Wind - Onshore Wind Power	377,604	370,235	
Wind - Offshore Wind Power	166	-	
Iowa			
Bioenergy	70,019	70,019	162
Bioenergy - Landfill Gas		275	78
Geothermal	606,390	-	-
Geothermal - Hydrothermal Power	-	-	
Geothermal - Enhanced Geothermal Systems & Co-Produced	606,390	-	
Hydropower	3,639	2,461	821
Solar	7,002,805	12,855	-
Solar - Urban Utility-Scale Photovoltaic	27,092		
Solar - Rural Utility-Scale Photovoltaic	6,994,159		
Solar - Rooftop Photovoltaic	8,646		
Solar - Concentrating Solar	-	-	
Wind	1,723,588	1,683,397	13,945
Wind - Onshore Wind Power	1,723,588	1,683,397	
Wind - Offshore Wind Power	-	-	
Maryland			
Bioenergy	4,282	4,282	541
Bioenergy - Landfill Gas		393	162
Geothermal	86,649	-	-
Geothermal - Hydrothermal Power	-	-	
Geothermal - Enhanced Geothermal Systems & Co-Produced	86,649	-	
Hydropower	2,478	1,964	1,664
Solar	600,799	21,169	28
Solar - Urban Utility-Scale Photovoltaic	28,551		
Solar - Rural Utility-Scale Photovoltaic	585,949		
Solar - Rooftop Photovoltaic	14,850		
Solar - Concentrating Solar	-	-	
Wind	204,484	3,577	314
Wind - Onshore Wind Power	3,632	3,577	
Wind - Offshore Wind Power	200,852	-	
Minnesota			
Bioenergy	42,606	42,606	1,732
Bioenergy - Landfill Gas		372	183
Geothermal	369,785	-	-
Geothermal - Hydrothermal Power	-	-	
Geothermal - Enhanced Geothermal Systems & Co-Produced	369,785	-	
Hydropower	1,993	7,711	738

	Estimated Technical Potential	Potential after economic and market limitations	2012 Electricity Generation
Solar	10,807,136	19,461	-
Solar - Urban Utility-Scale Photovoltaic	33,370		
Solar - Rural Utility-Scale Photovoltaic	10,792,814		
Solar - Rooftop Photovoltaic	14,322		
Solar - Concentrating Solar	-	-	
Wind	1,528,980	1,392,480	7,529
Wind - Onshore Wind Power	1,428,525	1,392,480	
Wind - Offshore Wind Power	100,455	-	
Missouri			
Bioenergy	33,893	33,893	-
Bioenergy - Landfill Gas		535	196
Geothermal	835,445	112	
Geothermal - Hydrothermal Power	-	-	
Geothermal - Enhanced Geothermal Systems & Co-Produced	835,445	112	
Hydropower	7,919	552	721
Solar	5,351,429	24,695	-
Solar - Urban Utility-Scale Photovoltaic	30,549		
Solar - Rural Utility-Scale Photovoltaic	5,335,269		
Solar - Rooftop Photovoltaic	16,160		
Solar - Concentrating Solar	-	-	
Wind	689,519	679,482	1,245
Wind - Onshore Wind Power	689,519	679,482	
Wind - Offshore Wind Power	-	-	
New Jersey			
Bioenergy	1,364	1,364	922
Bioenergy - Landfill Gas		710	588
Geothermal	35,230	-	-
Geothermal - Hydrothermal Power	-	-	
Geothermal - Enhanced Geothermal Systems & Co-Produced	35,230	-	
Hydropower	549	2,827	-
Solar	455,542	21,891	349
Solar - Urban Utility-Scale Photovoltaic	44,307		
Solar - Rural Utility-Scale Photovoltaic	439,774		
Solar - Rooftop Photovoltaic	15,768		
Solar - Concentrating Solar	-	-	
Wind	430,125	317	13
Wind - Onshore Wind Power	317	317	
Wind - Offshore Wind Power	429,808	-	
North Dakota			
Bioenergy	14,294	14,294	7
Bioenergy - Landfill Gas		17	6
Geothermal	820,226	1,247	-
Geothermal - Hydrothermal Power	-	-	

	Estimated Technical Potential	Potential after economic and market limitations	2012 Electricity Generation
Geothermal - Enhanced Geothermal Systems & Co-Produced	820,226	1,247	
Hydropower	2,824	3,175	2,477
Solar	9,774,415	3,236	-
Solar - Urban Utility-Scale Photovoltaic	4,871		
Solar - Rural Utility-Scale Photovoltaic	9,736,448		
Solar - Rooftop Photovoltaic	1,917		
Solar - Concentrating Solar	36,050	-	
Wind	2,537,825	2,487,758	5,316
Wind - Onshore Wind Power	2,537,825	2,487,758	
Wind - Offshore Wind Power	-	-	
Ohio			
Bioenergy	21,547	21,547	684
Bioenergy - Landfill Gas		1,168	341
Geothermal	495,922	91	-
Geothermal - Hydrothermal Power	-	-	
Geothermal - Enhanced Geothermal Systems & Co-Produced	495,922	91	
Hydropower	3,427	10,661	381
Solar	3,656,246	45,141	38
Solar - Urban Utility-Scale Photovoltaic	86,496		
Solar - Rural Utility-Scale Photovoltaic	3,626,182		
Solar - Rooftop Photovoltaic	30,064		
Solar - Concentrating Solar	-	-	
Wind	299,704	130,199	988
Wind - Onshore Wind Power	129,143	130,199	
Wind - Offshore Wind Power	170,561	-	
Pennsylvania			
Bioenergy	11,592	11,592	2,426
Bioenergy - Landfill Gas		1,623	1,017
Geothermal	327,341	126	-
Geothermal - Hydrothermal Power	-	-	
Geothermal - Enhanced Geothermal Systems & Co-Produced	327,341	126	
Hydropower	10,681	4,669	2,313
Solar	575,571	37,745	40
Solar - Urban Utility-Scale Photovoltaic	56,162		
Solar - Rural Utility-Scale Photovoltaic	553,356		
Solar - Rooftop Photovoltaic	22,215		
Solar - Concentrating Solar	-	-	
Wind	31,802	8,169	2,208
Wind - Onshore Wind Power	8,231	8,169	
Wind - Offshore Wind Power	23,571	-	
Virginia			
Bioenergy	16,518	16,518	2,255

	Estimated Technical Potential	Potential after economic and market limitations	2012 Electricity Generation
Bioenergy - Landfill Gas		708	608
Geothermal	290,737	15	-
Geothermal - Hydrothermal Power	-	-	
Geothermal - Enhanced Geothermal Systems & Co-Produced	290,737	15	
Hydropower	4,664	5,567	1,007
Solar	1,904,734	29,831	-
Solar - Urban Utility-Scale Photovoltaic	27,451		
Solar - Rural Utility-Scale Photovoltaic	1,882,467		
Solar - Rooftop Photovoltaic	22,267		
Solar - Concentrating Solar	-	-	
Wind	365,643	162,770	-
Wind - Onshore Wind Power	4,589	4,534	
Wind - Offshore Wind Power	361,054	158,236	
West Virginia			
Bioenergy	6,426	6,426	-
Bioenergy - Landfill Gas		161	13
Geothermal	261,376	1,724	-
Geothermal - Hydrothermal Power	-	-	
Geothermal - Enhanced Geothermal Systems & Co-Produced	261,376	1,724	
Hydropower	5,735	4,289	1,327
Solar	56,914	9,944	-
Solar - Urban Utility-Scale Photovoltaic	3,024		
Solar - Rural Utility-Scale Photovoltaic	52,694		
Solar - Rooftop Photovoltaic	4,220		
Solar - Concentrating Solar	-	-	
Wind	4,952	4,881	1,286
Wind - Onshore Wind Power	4,952	4,881	
Wind - Offshore Wind Power	-	-	
Wisconsin			
Bioenergy	18,408	18,408	1,687
Bioenergy - Landfill Gas		768	635
Geothermal	647,173	-	-
Geothermal - Hydrothermal Power	-	-	
Geothermal - Enhanced Geothermal Systems & Co-Produced	647,173	-	
Hydropower	4,307	5,336	2,020
Solar	5,056,198	22,466	-
Solar - Urban Utility-Scale Photovoltaic	54,939		
Solar - Rural Utility-Scale Photovoltaic	5,042,259		
Solar - Rooftop Photovoltaic	13,939		
Solar - Concentrating Solar	-	-	
Wind	573,021	252,809	1,546
Wind - Onshore Wind Power	255,266	252,809	

	Estimated Technical Potential	Potential after economic and market limitations	2012 Electricity Generation
Wind - Offshore Wind Power	317,755	-	
Wyoming			
Bioenergy	707	707	-
Bioenergy - Landfill Gas		70	-
Geothermal	1,071,452	48,334	-
Geothermal - Hydrothermal Power	1,373	53	
Geothermal - Enhanced Geothermal Systems & Co-Produced	1,070,079	47,115	
Hydropower	5,340	4,441	895
Solar	11,135,182	3,978	-
Solar - Urban Utility-Scale Photovoltaic	7,232		
Solar - Rural Utility-Scale Photovoltaic	5,727,224		
Solar - Rooftop Photovoltaic	1,551		
Solar - Concentrating Solar	5,406,407	-	
Wind	1,653,857	1,618,282	4,394
Wind - Onshore Wind Power	1,653,857	1,618,282	
Wind - Offshore Wind Power	-	-	

Resources:

1) NREL - U.S. Renewable Energy Technical Potentials: A GIS-Based Analysis. Online at http://www.nrel.gov/docs/fy12osti/51946.pdf.

2) EIA Electricity Production Monthly. Online at http://www.eia.gov/electricity/.

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4) Petty, S. and G. Porro. 2007. "Updated U.S. Geothermal Supply Characterization, "National Renewable Energy Laboratory Presented at the 32nd Workshop on Geothermal Reservoir Engineering Stanford, California January 22–24, 2007 NREL/CP-640-41073. March 2007. http://www.nrel.gov/docs/fy07osti/41073.pdf

5) Table B-1. DOE. EERE. "Feasibility Assessment of the Water Energy Resources of the United States for New Low Power and Small Hydro Classes of Hydroelectric Plants," January 2006 DOE-ID-11263. Online at http://hydropower.inl.gov/resourceassessment/pdfs/main_report_appendix_a_final.pdf.

6) Chaudhari, M., L. Frantzis, T. Hoff. September 2004. Navigant Consulting. *PV Grid Connected Market Potential under a Cost Breakthrough Scenario*. Navigant Consulting, Cambridge, MA. Online at http://www.ef.org/documents/EF-Final-Final2.pdf.

7) U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, Wind Powering America Program. 2010. Wind Maps and Wind Resource Potential Estimates. February. Available online at: http://www.windpoweringamerica.gov/wind_maps.asp#potential

Question 10:

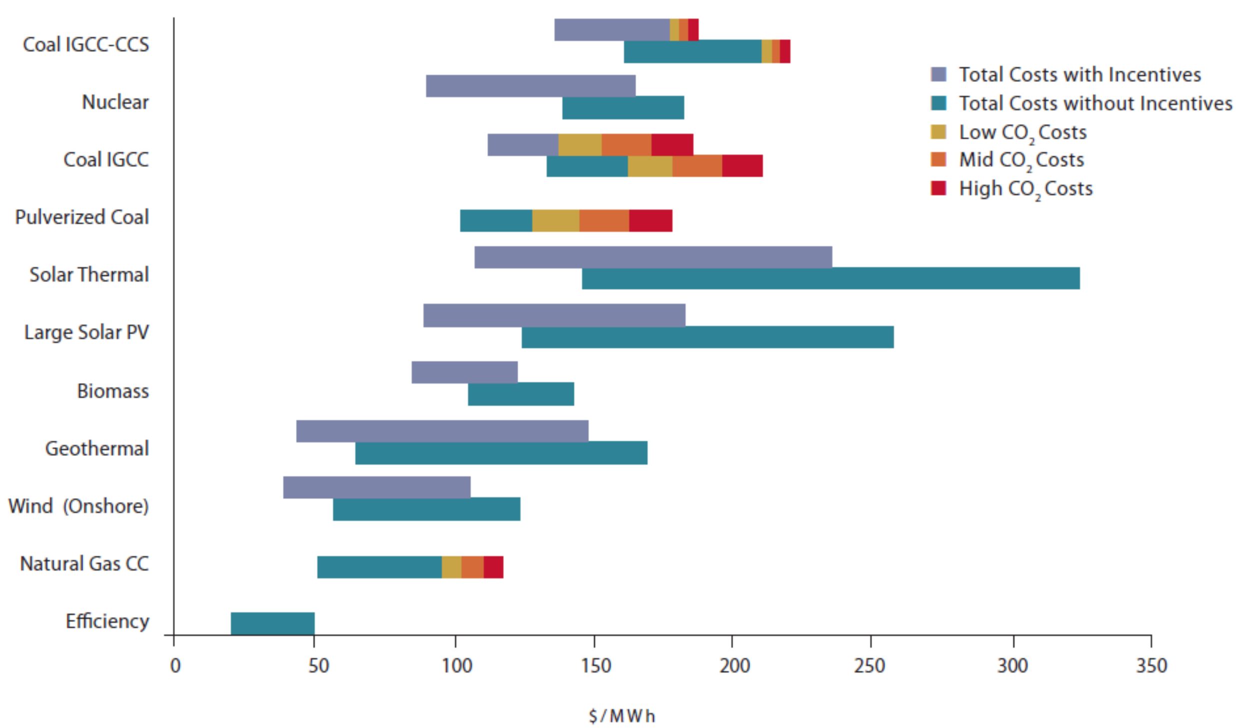
Renewable Energy Question #10: What are the current and projected relative costs of existing and new builds for wind, solar, hydro, biomass, landfill gas, coal, natural gas, nuclear, and other sources? How would those differ if placed in another jurisdiction electrically tied to Michigan?

NOTE: This response addresses Renewable Energy Questions #4, 10 and 11 which have to do with the costs of various energy resources.

The figure below shows a range of levelized costs of generating electricity from different technologies, assumed to come on-line in 2015, with and without incentives and costs for carbon dioxide (CO_2) emissions. The data comes from a 2011 study by the Union of Concerned Scientists (UCS) called, *A Risky Proposition*: *The Financial Hazards of New Investments in Coal Plants*. It is worth noting that Energy Information Administration's (EIA) most recent levelized cost estimates for different technologies in 2018 fall within this range (EIA 2013). As defined by EIA, "levelized cost represents the present value of the total cost of building and operating a generating plant over an assumed financial life and duty cycle, converted to equal annual payments and expressed in terms of real dollars to remove the impact of inflation."

The range of costs reflects uncertainty in capital and fuel costs, as well as regional variations in costs and resource quality. The assumptions are based on project specific data, where available, and recent estimates from power plant construction and engineering firms, financial institutions, utilities, and state and federal agencies. More details on the cost and performance assumptions for each of these technologies can be found in [Appendix A of the study](#).

Figure 1. Levelized Cost of Electricity for Various Technologies



Source: Freese et al 2011.

Without incentives and CO_2 costs (lower bars), you can see that new natural gas combined cycle (NGCC) plants, onshore wind, and the best biomass and geothermal projects are cheaper than or competitive with a new pulverized coal plant, and energy efficiency is by far the cheapest option. When you include incentives and CO_2 costs, the best large scale solar PV and concentrating solar thermal projects also become competitive. You can also see that coal with carbon capture and storage (CCS) is not competitive with other alternatives, even with incentives. And new nuclear plants are only competitive with a new coal plant when you include generous loan guarantees and other incentives or high CO_2 costs, and are more expensive than new NGCC plants, efficiency and many renewable energy technologies.

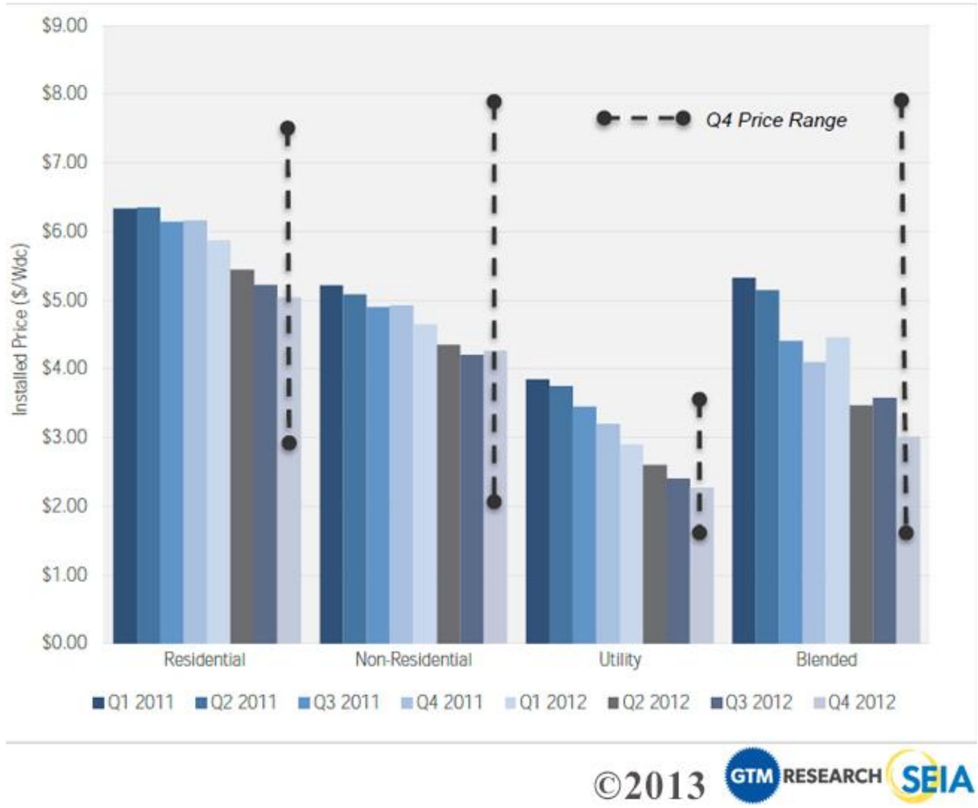
The range of future CO_2 prices assumes $13/ton in the low case, $26/ton in the mid case, and $43/ton in the high case. These estimates are based on a 2011 study reviewing more than 75 different scenarios examined in the recent modeling of various federal climate bills, as well as estimates used by a number of electric utilities in their resource plans (Johnston 2011). These prices should be considered conservative, as the report has since been updated with higher levelized CO_2 prices ranging from $23/ton to $59/ton.

The other significant changes that have occurred since the UCS study was released in 2011 are a decline in natural gas prices and the cost of wind and solar PV projects. The range of natural gas (and coal) prices used in Figure 1 are based on EIA projections from Annual Energy Outlook 2011 (AEO 2011). The recent decline in natural gas prices over the past two years is already captured in the lower end of the range in the figure. This is evident in EIA's most recent levelized cost estimate of $65.6/MWh for a new advanced NGCC plant with a 2018 in-service date (EIA 2013). The ~$20/MWh (33%) decline in average wind costs in the past three years, as shown in the response to question 3, would reduce the low end of the range of levelized wind costs in Figure 1 by approximately $10/MWh.

The cost of solar PV has also fallen dramatically over the past few years. A recent report from the Solar Energy Industries Association (SEIA) that uses a large sample of data from actual projects shows that the average installed cost of a completed PV system dropped by 27 percent over the past year, as shown in Figure 2. The study also found that the average price of a solar panel has declined by 60 percent since the beginning of 2011. These cost reductions are evident in several recent utility scale solar PV projects proposed or approved in the Southwestern U.S. that have PPA prices in the $58-$100/MWh range, including federal tax credits (Marks 2012, Bloomberg 2013). This would reduce the low end of the range for large scale PV in Figure 1 by ~$30/MWh. Significant cost reductions have also occurred for residential and commercial scale PV systems as shown in Figure 2.

While Michigan's solar resources are not as good as the Southwest, recent and projected cost reductions combined with the availability of the 30 percent federal investment tax credits through 2016 will make solar PV systems increasingly competitive with conventional and other renewable energy technologies in the state. With recent wind projects installed in Michigan in the $52-65/MWh range, wind power is already considerably cheaper than new coal plants and competitive with new natural gas power plants. And wind costs are likely to fall even further over the next few years, according to experts from Lawrence Berkeley National Laboratory (Wiser et al 2012).

Figure 2. Average Installed Price of Solar PV by Market Segment, 2011-2012



Source: SEIA 2013.

While these "levelized" costs cost comparisons are a useful screening tool for new power plants, they don't reflect the full value and costs that different technologies provide to the electricity system. For example, it doesn't include transmission and integration costs, reliability needs, the ramping flexibility that natural gas and hydro plants can provide, siting and permitting challenges, and the ability of new technologies to replace existing power plants. Figure 1 also doesn't consider changes in the future costs for different technologies. The cost of some technologies--such as wind, solar and carbon capture and storage (CCS)--are likely to decline over time with increased development, economies of scale in manufacturing, experience, and technological innovation. The cost of other technologies, such as natural gas and coal, are likely to increase as supplies become more limited and fuel prices rise over time.

Modeling recently completed by UCS [and others] that have taken these factors into account have found that it is feasible and affordable for Michigan and the U.S. to significantly increase electricity from renewable energy to much higher levels over time. For example, UCS' 2011 study *A Bright Future for the Heartland* used a modified version of EIA's National Energy Modeling System to analyze the costs and benefits of increasing renewable energy and energy efficiency in the Midwest (Martinez et al 2011). The study found that increasing renewable energy to 30 percent of the electricity mix by 2030 in Michigan and other Midwest states would lower electricity and natural gas bills in Michigan by $9 billion, when combined with investments in energy efficiency. The study also found that investing in renewable

energy and efficiency would create 15,300 more jobs than using coal and natural gas to provide the same amount of electricity.

References:

1) Energy Information Admininistration (EIA). 2013. *Levelized Cost of New Generation Resources in the Annual Energy Outlook 2013*. Online at: http://www.eia.gov/forecasts/aeo/er/electricity_generation.cfm

2) Freese, B, Clemmer S., Martinez C., and Nogee A. 2011. *A Risky Proposition: The Financial Hazards of New Investments in Coal Plants.* Cambridge, MA: Union of Concerned Scientists. http://www.ucsusa.org/assets/documents/clean_energy/a-risky-proposition_report.pdf

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4) Marks, J. A. 2012. Concurrence. Case No. 11-00218-UT. *IN THE MATTER OF THE COMMISSION ESTABLISHING A STANDARD METHOD FOR CALCULATING THE COST OF PROCURING RENEWABLE ENERGY, APPLYING THAT METHOD TO THE REASONABLE COST THRESHOLD, AND CALCULATING THE RATE IMPACT DUE TO RENEWABLE ENERGY PROCUREMENTS*. Santa Fe, NM: New Mexico Public Regulation Commission. (PDF included in Appendix.)

5) Solar Energy Industries Association (SEIA) and GTM Research. 2013. U.S. Solar Market Insight Q4 2012 Report. Online at: http://www.seia.org/research-resources/us-solar-market-insight

6) Martinez, C., J. Deyette, S. Sattler, A. McKibben. 2011. *A Bright Future for the Heartland: Powering Michigan's Economy with Clean Energy*. Cambridge MA: Union of Concerned Scientists. http://www.ucsusa.org/assets/documents/clean_energy/A-Bright-Future_Michigan.pdf

7) Goossens E. and C. Martin. 2013. "First Solar May Sell Cheapest Solar Power, Less Than Coal." *Bloomberg*. http://www.bloomberg.com/news/2013-02-01/first-solar-may-sell-cheapest-solar-power-less-than-coal.html

8) Wiser, R., E. Lantz, M. Bolinger, M. Hand. 2012. *Recent Developments in the Levelized Cost of Energy from U.S. Wind Power Projects*. Online at: http://eetd.lbl.gov/ea/ems/reports/wind-energy-costs-2-2012.pdf

Question 11:

Renewable Energy Question #11: What are the current and projected relative costs per kilowatt hour for existing and new builds for wind, solar, landfill gas, coal, natural gas, nuclear, and other sources? How would those differ if placed in another jurisdiction electrically tied to Michigan?

NOTE: This response addresses Renewable Energy Questions #4, 10 and 11 which have to do with the costs of various energy resources.

The figure below shows a range of levelized costs of generating electricity from different technologies, assumed to come on-line in 2015, with and without incentives and costs for carbon dioxide (CO_2) emissions. The data comes from a 2011 study by the Union of Concerned Scientists (UCS) called, *A Risky Proposition*: *The Financial Hazards of New Investments in Coal Plants*. It is worth noting that Energy Information Administration's (EIA) most recent levelized cost estimates for different technologies in 2018 fall within this range (EIA 2013). As defined by EIA, "levelized cost represents the present value of the total cost of building and operating a generating plant over an assumed financial life and duty cycle, converted to equal annual payments and expressed in terms of real dollars to remove the impact of inflation."

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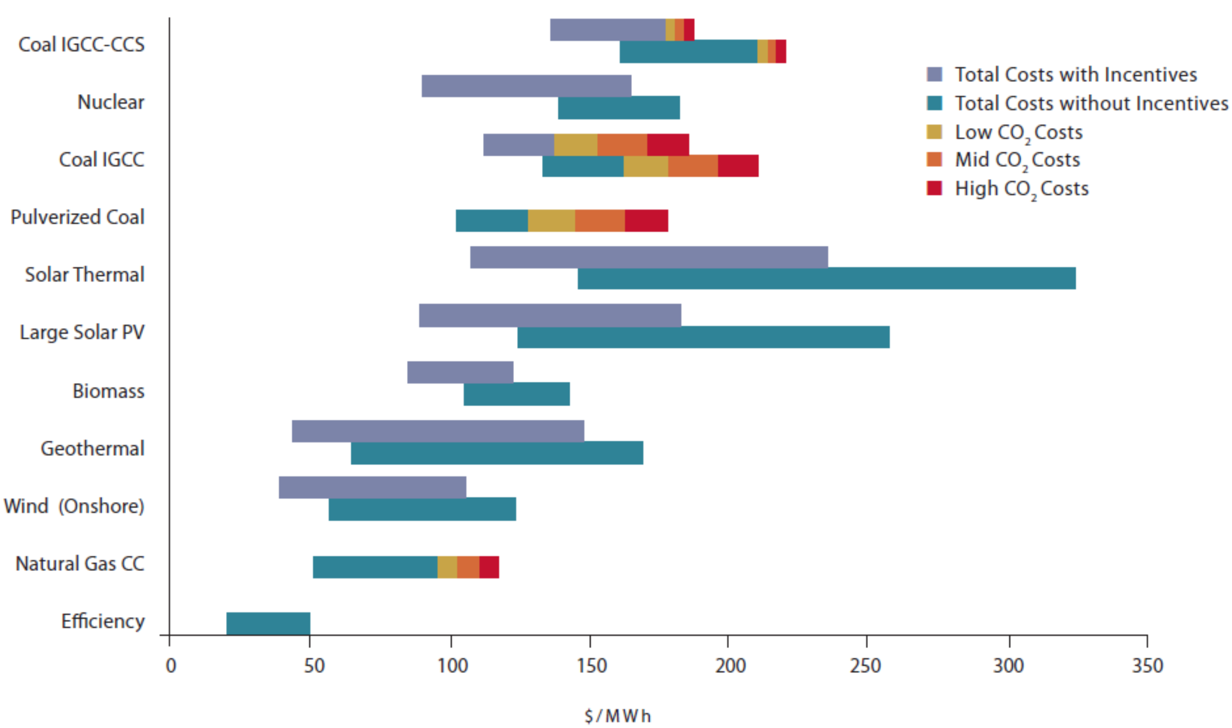

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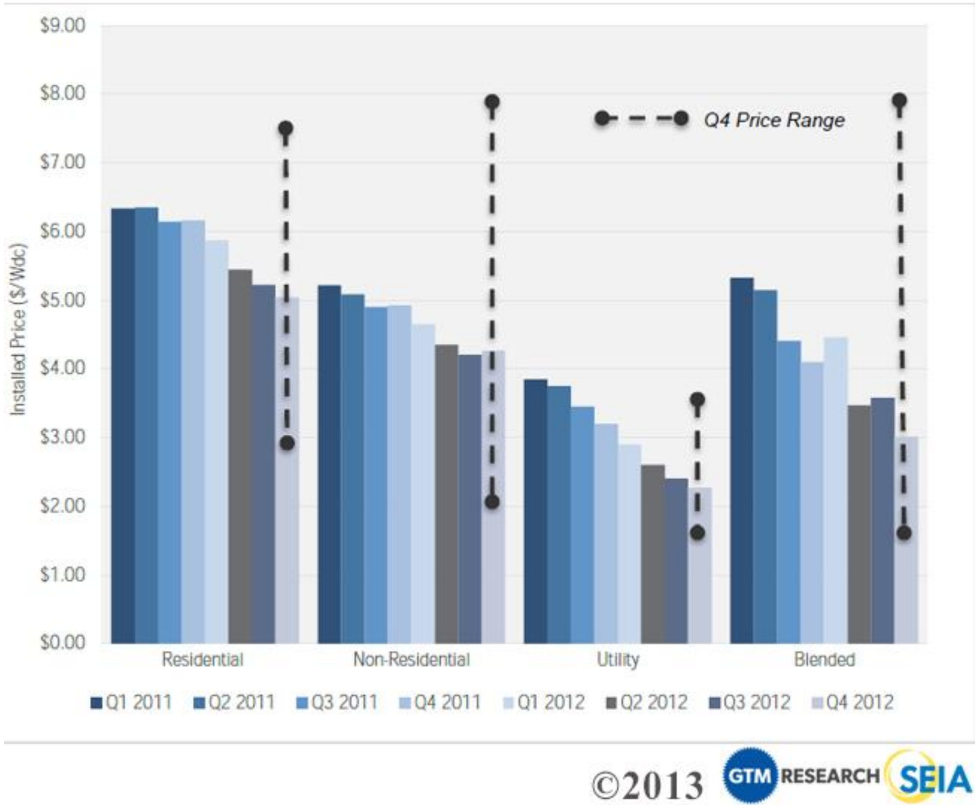
While Michigan's solar resources are not as good as the Southwest, recent and projected cost reductions combined with the availability of the 30 percent federal investment tax credits through 2016 will make solar PV systems increasingly competitive with conventional and other renewable energy technologies in the state. With recent wind projects installed in Michigan in the \$52-65/MWh range, wind power is already considerably cheaper than new coal plants and competitive with new natural gas power plants. And wind costs are likely to fall even further over the next few years, according to experts from Lawrence Berkeley National Laboratory (Wiser et al 2012).

Figure 2. Average Installed Price of Solar PV by Market Segment, 2011-2012



Source: SEIA 2013.

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References:

1) Energy Information Administration (EIA). 2013. *Levelized Cost of New Generation Resources in the Annual Energy Outlook 2013*. Online at: http://www.eia.gov/forecasts/aeo/er/electricity_generation.cfm

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4) Marks, J. A. 2012. Concurrence. Case No. 11-00218-UT. *IN THE MATTER OF THE COMMISSION ESTABLISHING A STANDARD METHOD FOR CALCULATING THE COST OF PROCURING RENEWABLE ENERGY, APPLYING THAT METHOD TO THE REASONABLE COST THRESHOLD, AND CALCULATING THE RATE IMPACT DUE TO RENEWABLE ENERGY PROCUREMENTS***.** Santa Fe, NM: New Mexico Public Regulation Commission. (PDF included in Appendix.)

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6) Martinez, C., J. Deyette, S. Sattler, A. McKibben. 2011. *A Bright Future for the Heartland: Powering Michigan's Economy with Clean Energy*. Cambridge MA: Union of Concerned Scientists. http://www.ucsusa.org/assets/documents/clean_energy/A-Bright-Future_Michigan.pdf

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8) Wiser, R., E. Lantz, M. Bolinger, M. Hand. 2012. *Recent Developments in the Levelized Cost of Energy from U.S. Wind Power Projects*. Online at: http://eetd.lbl.gov/ea/ems/reports/wind-energy-costs-2-2012.pdf

Question 12:

Renewable Energy Question #12: What methods have been used by other states or countries to set renewable targets?

There is no precise formula for determining the 'right" renewable energy requirement for a state to establish. Rather, best practices indicate that renewable energy target should be directly related to the primary goals that policy designers are trying to achieve, which can be different for each jurisdiction. Therefore, as a first step, policy designers should consider and develop clear goals and priorities for issues like resource diversity, environmental and public health benefits, jobs and local economic development, and technology advancement. This step can then be followed by an evaluation of available renewable energy resources, the state of existing energy infrastructure, access to transmission, and other market and policy conditions such as supply-and-demand balances, consumption growth rate, or forthcoming environmental regulations. The outcome of these priorities and evaluations must be balanced against best estimates of policy cost, and what levels of cost are ultimately acceptable to consumers and policy makers.

The result should therefore be an ambitious, but achievable renewable energy target that matches policy goals and ensures consistent, predictable renewable energy investment from the outset and continues over a sufficient period of time. It is also important to note that many state RES policies started out with a modest renewable energy target, which was later increased once the policy proved successful. Since 1999, at least 18 states have gone back and increased their renewable energy targets, and several states have done so more than once. For example, Colorado's initial RES—passed via ballot initiative—was set at 10 percent by 2015. Since that time, the Colorado legislature has increased the target first to 20 percent and then later to 30 percent by 2020. Seventeen states and the District of Columbia now have renewable energy targets of 20 percent or higher.

<u>Resources</u>

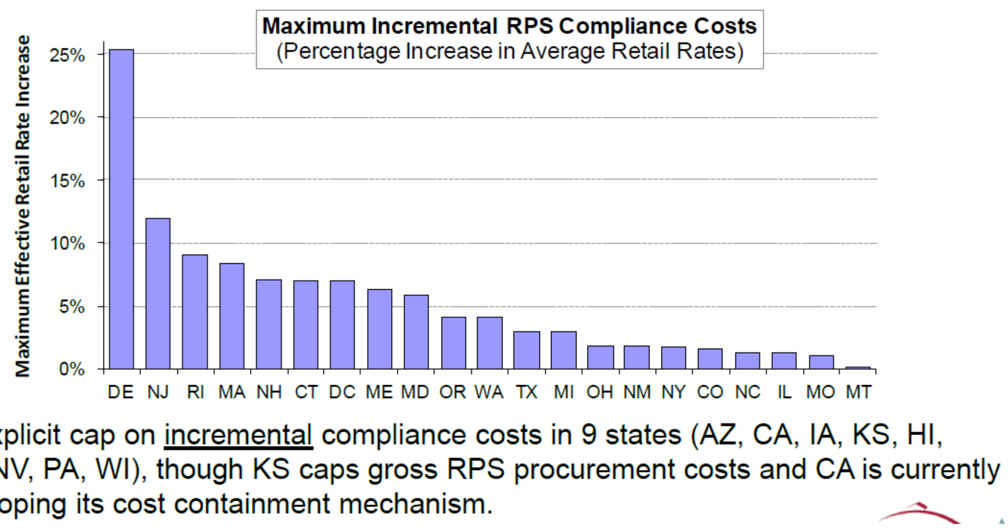
1) Rader N. and S. Hempling. 2001. *The Renewables Portfolio Standard: A Practical Guide*. Prepared for the National Association of Regulatory Utility Commissioners. Online at: http://www.naruc.org/grants/Documents/rps.pdf.

2) Leon, W. 2012. *Designing the Right RPS: A Guide to Selecting Goals and Program Options for a Renewables Portfolio Standard*. Prepared for the State-Federal RPS Collaborative and the National Association of Regulatory Utility Commissioners. Online at: http://www.cleanenergystates.org/assets/2012-Files/RPS/CESA-RPS-Goals-and-Program-Design-Report-March-2012.pdf.

Question 16:

Renewable Energy Question #16: How has Michigan, and how have other jurisdictions limited the rate impact of RE mandates on the residential, commercial and industrial sector, if at all? What effect have such rate limitations had on other areas?

Most state renewable electricity standard policies, including in Michigan, have cost-containment measures to protect consumers from higher than expected costs. According to the Lawrence Berkeley National Laboratory, Michigan's cost cap ranks in the middle of those state RES policies that include them, with a maximum effective retail rate increase of less than 3 percent (see chart).



Source: Lawrence Berkeley National Laboratory.

Michigan limits the rate impact of its renewable energy requirements by (1) allowing utilities to charge a surcharge per meter to recover the cost of complying with Michigan's renewable energy standard; (2) by statutorily limiting the amount of the surcharge for residential, commercial and industrial ratepayers; and (3) by forgiving compliance obligations if a utility can show that the incremental cost of compliance would exceed these statutorily-limited surcharges. This per-customer cost cap is one of several methods that states use to limit the cost of complying with renewable energy standards. North Carolina and Arizona also have this type of surcharge-based cost control.

Two methods to calculate the surcharge are (1) a flat-rate basis that Michigan employs; and (2) a usage-based, per kWh basis that Arizona uses. Both states base surcharges on utility estimates of compliance costs submitted to and approved by the state's utility commission. The benefit of a surcharge-based cost cap is that it is a relatively administratively efficient and straight-forward way for utilities to recover compliance costs. Specifically, it avoids the need for rate cases before the commission, allows customers to see how much they are paying for compliance, and provides certainty for utilities making investment decisions.

The downside to using a set surcharge to recover compliance costs is the lower level of scrutiny that this process receives as compared to a rate case proceeding. For customers, the reduced level of scrutiny provides no guarantee that the surcharge is funding least-cost resources or that the surcharge represents the real-world experience of compliance because surcharges are based on forward-looking projections. When costs are lower than expected, utilities are often allowed to keep over-charges in expectation of future compliance costs that, again, may be lower than expected. Set surcharges also offer little flexibility for state commissions that must balance consumer protection with the intent of the renewable energy standard.

Other methods of controlling compliance cost for renewable energy standards include: Alternative compliance payments; rate impact caps; utility annual revenue expenditure caps, contract price caps; and funding limits. Each of these methods involves a trade-off between administrative efficiency, transparency and the level of scrutiny provided. Some of the key issues that must be considered are:

1. Cost limits must reflect an objective expectation of what compliance with the renewable energy standard will actually cost. Arbitrary cost caps or those set based on what lawmakers are willing to accept will make the policy more complicated and potentially less effective.

2. Cost limits must be well-defined. Vague or general cost caps typically lead to confusion and uncertainty as regulators struggle to interpret the law and implement proper rules for its enforcement.

3. Cost caps can have unintended consequences that can increase the cost of compliance. Cost caps based on a percentage of utility annual revenue or rates can increase the administrative burden for utilities seeking to recover costs of compliance. On the other hand, surcharges and contract price caps can end up becoming “price targets” for renewable energy developers who know utilities are required to buy renewable energy. Clarity in how cost caps are to be determined and a consistent focus on procuring the least-cost renewable resources are necessary to avoid these pitfalls.

Michigan’s surcharge-based cost cap appears to be working relatively well. Only 23 of Michigan’s 59 electric providers have found it necessary to impose a surcharge on residential customers to recover incremental cost of compliance with Michigan’s renewable energy standard. Of those 23, thirteen are $2 or less per month. In addition, the MPSC reports that all but one of Michigan’s electric providers are expected to achieve compliance with Michigan’s 10 percent by 2015 renewable energy standard. This indicates that Michigan’s cost cap is not overly burdensome on compliance while protecting consumers from unacceptably high compliance costs.

Resources:
1) Peirpont, B. 2012. *Limiting the cost of Renewables: Lessons for California.* Washington DC: Climate Policy Initiative. Online at http://www.mirecs.org/resources/MIRECS-2011-Annual-filing-PUBLIC_Version2.pdf, accessed April 4, 2013.

2) Stockmayer G., V. Finch, P. Komor, and R. Mignogna. 2011. *Limiting the costs of renewable portfolio standards: A review and critique of current methods.* Energy Policy 42 (2012) 155 – 163. (PDF included in Appendix)

3) Pierpont, B. 2012. *Renewable Portfolio Standards – the high cost of insuring against high costs.* December 2012. Online at http://climatepolicyinitiative.org/2012/12/17/renewable-portfolio-standards-the-high-cost-of-insuring-against-high-costs/, accessed April 4, 2013.

4) Union of Concerned Scientists. Renewable Electricity standards Toolkit – Escape Clauses. Online at: http://go.ucsusa.org/cgi-bin/RES/state_standards_search.pl?states=All&category3=&category7=&category8=&category32=&category39=&category43=49&category51=&submit43.x=11&submit43.y=8.

5) Barbose, Galen. 2012. Renewable Portfolio Standards in the United States: A Status Update. Lawrence Berkeley National Laboratory. Available at: http://www.cleanenergystates.org/assets/2012-Files/RPS/RPS-SummitDec2012Barbose.pdf.

6) Leon, Warren. *Designing the Right RPS: A Guide to Selecting Goals and Program Options for a Renewable Portfolio Standard*. Clean Energy States Alliance and National Association of Regulatory Utility Commissioners. March 2012. Online at http://www.cleanenergystates.org/assets/2012-Files/RPS/CESA-RPS-Goals-and-Program-Design-Report-March-2012.pdf.

Question 19:

Renewable Energy Question #19: How has MI, and how have other jurisdictions, applied energy mandates in situations where an existing provider has excess capacity prior to the mandate?

Of the 29 states that currently have renewable electricity standards (RES) in place, Oregon and Washington State are the only two that deal explicitly with the issue of excess capacity. In both cases, the possibility of securing temporary compliance waivers were put in place primarily to account for utilities in the region that rely heavily on hydropower from federally owned and operated dams. Strict criteria also must be met in order to gain the waivers.

For example, Oregon's obligated electric utilities are not required to comply with the RES if both of the following conditions are met: "(1) Compliance would require the utility to acquire electricity in excess of the utility's projected load requirements in any calendar year; and (2) Acquiring the additional electricity would require the utility to substitute qualifying electricity for electricity derived from an energy source other than coal, natural gas or petroleum." In addition, Oregon's electric utilities are also not required to comply with the RES to the extent that compliance would require the utility to substitute qualifying electricity for electricity available to the utility under existing contracts (entered into before June 2007) for electricity from dams that are owned by Washington public utility districts and are located between the Grand Coulee Dam and the Columbia River's junction with the Snake River.

Similarly in Washington State, obligated utilities that have not experienced any retail load growth in three consecutive years are allowed to meet a lesser requirement. However, three conditions must be met to trigger this temporary reprieve: "(1) the utility's weather adjusted load for the previous three years on average did not increase over that time period; (2) after 2006, the utility did not commence or renew ownership or incremental purchases of electricity from resources other than renewable resources other than on a daily spot price basis and the electricity is not offset by equivalent renewable energy credits; and (3) the utility invested at least one percent of its total annual retail revenue requirement that year on eligible renewable resources, renewable energy credits, or a combination of both."

While no other state RES legislation addresses excess capacity, several compliance flexibility mechanisms have been implemented under numerous state RES policies that can potentially help alleviate the issue for affected utilities. For example, most state RES policies track compliance by issuing and retiring tradable renewable energy credits (RECs), and many states permit the use of unbundled RECs (that is, a REC which is separate from the electricity generation that created it) for compliance. Obligated utilities therefore have the option to acquire RECs from other developers rather than investing directly in new renewable energy capacity themselves. In addition, many states allow for the short-term banking and/or borrowing of RECs as a further means of compliance flexibility.

<u>Resources:</u>

1) North Carolina Solar Center. Database of State Incentives for Renewables and Efficiency. Online at: http://www.dsireusa.org.

Question 20:

Renewable Energy Question #20: How has MI, and how have other jurisdictions, treated EE or optimization and renewables as related or separate? For instance, have credits generated from one or the other been interchangeable or separate? What have been the cost, reliability, and environmental impacts of different regimes?

Most states treat energy efficiency and renewable energy separately. While both energy efficiency and renewable energy are critical to the swift transition to a clean energy economy and deserve policy support, having an energy efficiency portfolio standard that is separate from the renewable electricity standard helps ensure that these energy resources complement rather than compete with one other.

A study by the National Renewable Energy Laboratory concluded that when energy efficiency is eligible for RES compliance, it is important that it be included in a separate tier or capped. In addition, there needs to be “rigorous measurement and verification protocols to ensure achievement of energy and environmental goals.”

Seven of the 29 states with a renewable electricity standard allow energy efficiency to comingle with renewable energy in meeting compliance obligations:

- In Michigan, utilities may use energy efficiency (energy optimization credits) with approval of the Public Service Commission. They may be substituted at a 1:1 ratio to RECs, but can only account for 10 percent of a utility’s total obligation.

- In Pennsylvania, a variety of energy efficiency technologies are eligible to meet the Tier II requirements of the states Alternative Energy Portfolio Standard. The standard calls for utilities to generate 8 percent of their electricity by using "Tier I" energy sources and 10 percent using "Tier II" sources by 2021.

- In North Carolina, up to 25 percent of the annual RES requirements can be met through energy efficiency technologies, including combined heat and power systems powered by non-renewable fuels. After 2021, up to 40 percent of the standard may be met through energy efficiency. The state also distinguishes between energy efficiency and energy demand reduction, which can be used to meet 100 percent of the standard. Energy demand reduction is defined as: "a measurable reduction in the electricity demand of a retail electric customer that is voluntary, under the real-time control of both the electric power supplier and the retail electric customer, and measured in real time, using two-way communications devices that communicate on the basis of standards.

- In Nevada, energy efficiency measures can be used to meet the portfolio standard, but their contribution to the total is capped at 25 percent for each year.

- In Hawaii, energy efficiency technologies can be used to meet the state's RES. However, beginning in 2015, energy efficiency technologies will no longer be eligible to fulfill Hawaii's RES; as these technologies will be part of a separate energy efficiency portfolio standard.

- In Connecticut, there is a separate tier for energy efficiency under the state's RES. It represents approximately 29 percent of the total RES requirement in 2010 and approximately 15 percent in 2020.

- In Ohio, demand side management or energy efficiency improvements count towards the state RES, but can only be used to meet half of the annual RES requirement.

In the remainder of states with renewable electricity standards, energy efficiency is either treated as a separate standard or through other policies/regulatory means.

Regarding costs, the allowance of energy efficiency to meet RES compliance tends to reduce the overall cost of compliance because energy efficiency remains the cheapest resource available -- whether compared to renewable energy, fossil fuels or nuclear. In states that allow energy efficiency to count towards compliance with an RES, utilities are taking advantage. However, this also reduces the overall amount of renewable energy developed to meet standards in those states. That is why most states cap the amount of energy efficiency that can be used to meet a renewable energy standard, typically at 25% or less. This cap limits the competition between energy efficiency and new renewable energy resources.

Studies of the effects on reliability of allowing energy efficiency to count towards meeting renewable energy standards (or not) have not been done. However, it is unlikely that either allowing energy efficiency to count or not would have an impact on reliability. Any time you add a resource to the grid – whether in the form of new generation or reduced generation through energy efficiency – you increase reliability. You either have more resources to meet the same demand (if adding new generation), or the same resources to meet less demand (if adding energy efficiency). Both increase the likelihood that there will be enough electricity available to meet demand at any given time. Thus, allowing energy efficiency to count towards meeting renewable energy standards likely has little, if any negative impact on reliability.

Allowing energy efficiency to count towards compliance with renewable energy standards probably has a small positive impact on the environment. While studies on this specific topic have not been conducted, energy efficiency is widely regarded as the most environmentally benign resource available. Even renewable energy, while significantly better to the environment and climate than fossil fuels or nuclear, has some cradle-to-grave impacts on the environment – whether it is from the manufacture and distribution of renewable energy components or the land use impacts associated with the development of renewable energy facilities. However, it is important to note that (1) while our energy efficiency resources is large and relatively untapped, new generation resources will be required to meet future energy demand, and (2) that renewable energy resources are, by far, our cleanest and most environmentally benign generation resources available.

Because of this, both energy efficiency and renewable energy warrant strong policy support.

Resources:

1) Heeter, Jenni and Lori Bird. 2012. *Including Alternative Resources in State Renewable Portfolio Standards: Current Design and Implementation Experience*. National Renewable Energy Laboratory: Golden, CO. Available at: http://www.nrel.gov/docs/fy13osti/55979.pdf

2) Database of State Incentives for Renewables and Efficiency. Available at: http://www.dsireusa.org/

Question 21:

Renewable Energy Question # 21: How has MI, and how have other jurisdictions, chosen to incentivize or penalize exceeding or falling short of renewable targets?

States have implemented a variety of enforcement mechanisms to penalize utilities for falling short of their annual renewable energy requirements. According to research by the Lawrence Berkeley National Laboratory (LBNL), enforcement mechanisms fall into five general categories:

- **Alternative Compliance Payments (ACPs) with automatic cost recovery**: If a utility is not able to generate renewable energy or purchase Renewable Energy Credits (RECs) to meet its obligations, it must pay for ACPs. Each state sets the price of ACPs at a different level. Automatic cost recovery allows the utility to pass along the costs of the ACP to its customers.
- **ACPs with possible cost recovery**: ACPs are paid as above, but the utility is not necessarily allowed to pass these costs along to its customers.
    - In 2009, states collected $50 million in ACPs, and they collected $66 million in 2010.
- **Explicit Financial Penalties with no automatic cost recovery**.
- **Discretionary Financial Penalties with no cost recovery**.
- **Enforcement at PUC discretion**.

The table below lists the type of enforcement mechanism and the penalty or alternative compliance payment level for each state RES policy. However, it is important to note that a utility's failure to comply with an annual renewable energy requirement will not necessarily result in an enforcement action. That is because implementing agencies grant waivers, temporary reprieves, or other excusals from compliance by utilities typically on a case by case basis. Still, penalties have been levied in several states, including California, Connecticut, Montana, Ohio, Pennsylvania, and Texas.

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 recovery	Failure to comply with the renewable energy requirements results in a minimum penalty equal to 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	
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	
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	

To date, no state has officially incentivized over-compliance with a state renewable energy standard. However, utilities in several states, including Texas, Minnesota and Colorado are ahead of schedule in complying with state requirements. This is due to an abundance of renewable energy resources and rapidly declining costs of renewable energy.

Resources

1) Barbose, G. 2012. *Renewable portfolio standards in the United States: A status update*. Presented at the 2012 National Summit on RPS, Washington, DC, December 3. Online at *www.cleanenergystates.org/assets/2012-Files/RPS/RPS-SummitDec2012Barbose.pdf*, accessed Arpil 15, 2013.

2) Database of State Incentives for Renewables and Efficiency. Available at: http://www.dsireusa.org/

3) Presentations: 2011 National Summit on RPS. State-Federal RPS Collaborative. October 26 – 27, 2011. Online at http://www.cleanenergystates.org/assets/Uploads/2011-RPS-Summit-Combined-Presentations-File.pdf; accessed April 22, 2013.

Question 22:

Renewable Energy Question #22: Michigan law currently contains provisions for incentive renewable energy credits, and advanced cleaner energy credits. What impact has the provisions for incentive renewable energy credits and advanced cleaner energy credits had on renewable energy in Michigan? What has been the impact of similar provisions in other jurisdictions?

The use of credit multipliers can be an effective strategy for states to accomplish specific economic, resource diversity, or environmental goals under their renewable electricity standards. When designed properly, they can recognize and value unique benefits such as local economic development or grid reliability. They can also incentivize certain technologies or investments at a lower risk of cost impact to consumers. However, establishing multiplier values at levels that will stimulate the intended investment without overvaluing it can be challenging and requires ongoing management. Furthermore, by their very nature credit multipliers reduce the overall RES requirements, and can erode the support for new renewable energy development. This underscores the importance of proper policy design and evaluation.

P.A. 295 contains several provisions for both incentive renewable energy credits and advanced cleaner energy credits that can be used to help utilities meet Michigan's 10 percent by 2015 renewable energy standard. Incentive renewable energy credits provide multipliers for renewable energy credits (RECs) from renewable energy systems that are (1) solar generated electricity; (2) on-peak production or successfully stored to be used during peak demand times; and (3) constructed using Michigan labor or Michigan-made equipment.

As the Michigan Public Service Commission (MPSC) found in its 2012 and 2013 reports on the implementation of P.A. 295, a significant number of renewable energy projects are receiving incentive credits (IRECs) for using Michigan-made products and utilizing Michigan-based labor. Between 2009 and 2012, IRECs made up 10% of the total credits created – about 190,000 RECs total. Since one IREC equals 0.1 REC, this represents 1.9 million MWh of renewable energy generation that qualifies for the IREC multiplier. As the MPSC 2013 report discusses, renewable energy manufacturing is responding to demand for IRECs by continuing to invest in Michigan.

Several states include credit multipliers for in-state development of renewable energy resources or for distributed generation, typically not to exceed a certain size. Incentive credits are also given for community-scale projects, and Delaware and Arizona offer incentive credits for facilities using in-state manufacturing. Similar to Michigan, these incentive credits are a contributing factor to the amount of renewable energy developed in those states, and the impact of the incentive credits is largely dependent on the exact multiplier used. Michigan's incentive credits for in-state manufactured products and Michigan labor are within the range offered by other states, typically 0.1 to 0.5 credits per MWh.

The solar IREC that provides an additional 2 RECs for every MWh of solar generated electricity is also providing some incentive for Michigan utilities to develop solar PV resources. Both DTE and Consumers have successful distributed solar programs. Between DTE and Consumer Energy's distributed solar programs, more than 25 MW of solar capacity is projected to be installed in Michigan by 2015. The multiplier credit, combined with falling prices for solar systems, appears to be helping to drive this investment.

Several additional states, including Arizona, Delaware, Nevada and Oregon, also offer incentive credits specifically for solar generated electricity, ranging from an additional 0.5 to 3 additional credits for each MWh of generated electricity. There is some question, however, as to whether credit multipliers are the best policy strategy for stimulating solar energy development. In its 2010 report, "Supporting Solar Power in Renewables Portfolio Standards: Experience from the United States," the Lawrence Berkeley National Lab found that while both approaches have their advantages and disadvantages, issuing multiple credits to solar technologies is not as effective as solar carve-outs at promoting solar technology development. LBNL concluded that multipliers provide less certainty for solar developers than do solar carve-outs, and "to the extent that they do stimulate solar development, they do so at the expense of reducing the effective RPS percentage."

The 1/5 incentive credit available in Michigan for renewable energy capable of being distributed during peak-demand times (either generated on peak or able to be stored until peak) may be a factor in decisions about where to site renewable energy facilities, but is probably not driving additional renewable energy development in Michigan. Solar systems (and wind to a lesser degree) will generate electricity during peak times (as defined by the Michigan legislature), and renewable energy facilities may be able to coordinate with Michigan's Ludington pump-storage facility to take advantage of this IREC opportunity, but given the current availability of inexpensive RECs to meet compliance obligations, a 1/5 incentive credit per MWh of generation is likely not large enough to drive additional renewable energy development in Michigan.

Regarding the use of advanced cleaner energy credits (ACECs) to comply with P.A. 295, the availability of ACECs and the various restrictions on their use does not appear to be having a significant impact on renewable energy in Michigan. According to the Michigan Renewable Energy Certification System Annual Report for 2011-2012, ACECs made up only 8% of total credits issued from 2009 to 2012, and that percentage dropped significantly in 2012 over 2011. The MPSC, in its 2013 report on the implementation of P.A. 295, states that no electric provider indicated that the percentage limits on the use of advanced cleaner energy resources has affected development of these resource, that advanced cleaner energy continues to be a small percentage of the Michigan renewable energy portfolio, and that the percentage limits on these resources for compliance are far from being met, indicating that renewable energy resources continue to be the preferred method for compliance with P.A. 295.

Across the country, a number of states allow non-renewable energy resources to count towards meeting alternative energy resource standards. Four states allow for non-renewable resources: Michigan, Ohio, Pennsylvania and West Virginia. All of these states plus four others (Connecticut, Hawaii, Nevada and North Carolina) allow energy efficiency to contribute to renewable energy standards. The level of impact that these provisions have on renewable energy development depends largely on the type of resources allowed and the cost-effectiveness of those resources compared with renewable energy. Generally, non-renewables and energy efficiency are being heavily utilized where allowed, particularly energy efficiency which is very cost effective compared to just about any other available resource. Nearly all of these states provide a separate tier or cap on the amount that these resources can contribute. Energy efficiency levels are often capped at 25% or less of total RPS compliance, and non-renewable energy levels are typically capped at lower percentages, such as 10%.

When states seek to drive investments in efficiency or non-renewable resources through inclusion in a renewable energy standard, it is critical that (1) there be thoughtful caps in place to ensure that the goal of driving investment in renewable energy is not compromised, and (2) that there be rigorous protocols in place, particularly regarding energy efficiency, to verify the amount of energy generated or saved by these alternative resources.

Resources:

1) DSIRE database. Online at http://www.dsireusa.org/; accessed April 8, 2013.

2) Heeter, J. and L. Bird. 2012. *Including Alternative Resources in State Renewable Portfolio Standards: Current Design and Implementation Experience.* Golden, CO: National Renewable Energy Laboratory. Online at: http://www.nrel.gov/docs/fy13osti/55979.pdf, accessed April 4, 2013.

3) Quackenbush, J.D., O.N. Isiogu, and G.R. White. 2013. *Report on the implementation of the P.A. 295 renewable energy standard and the cost-effectiveness of the energy standards*. Lansing, MI: Michigan Public Service Commission. Online at *http://www.michigan.gov/documents/mpsc/Report_on_the_implementation_of_Wind_energy_resource_zones_2013_413124_7.pdf*, accessed April 5, 2013.

4) Quackenbush, J.D., O.N. Isiogu, and G.R. White. 2012. *Report on the implementation of the P.A. 295 renewable energy standard and the cost-effectiveness of the energy standards*. Lansing, MI: Michigan Public Service Commission. Online at *www.michigan.gov/documents/mpsc/implementation_PA295_renewable_energy2-15-2012_376924_7.pdf*, accessed March 24, 2013.

5) APX. 2013. Michigan Renewable Energy Certification System annual report for 2011 – 2012. Online at http://www.mirecs.org/resources/MIRECS-2011-Annual-filing-PUBLIC_Version2.pdf; accessed April 3, 2013.

6) Wiser, Ryan, and Galen Barbose. 2012. *Supporting Solar Power in Renewable Portfolio Standards: Experience from the United States*. Lawrence Berkeley National Laboratory. Available at: http://eetd.lbl.gov/ea/emp/reports/lbnl-3984e.pdf

Question 23:

Renewable Energy Question #23: How have eligible "renewable"/ "clean"/ "sustainable" energy resources been defined in other jurisdictions? How has the possibility of new forms of energy been accommodated, if at all?

Renewable, clean, and sustainable energy resources have been defined in various ways under the 29 states that have established renewable electricity standards. See the table below for a detailed listing of eligible energy technologies under each state RES.

Solar: Nearly all states, including Michigan, consider both Solar Photovoltaic and Solar Thermal Electric to be eligible to meet their RPS. Other states include solar technologies that do not produce electricity, such as solar water heat, solar space heat, and solar thermal process heat.

Wind: All states include wind energy in their renewable electricity standards.

Geothermal: Most states, including Michigan, count geothermal electric as a renewable energy resource in their RPS. Some states also give credit for other forms of geothermal energy that do not produce electricity, including the geothermal heat pumps in buildings and the direct use of hot water produced in geothermal reservoirs.

Hydroelectric: All states include hydroelectric resources in some way. Because large-scale hydro is a mature technology that typically does not need the policy support as other renewable energy technologies, states have chosen to deal with hydroelectric in different ways. Some states include provisions for small hydroelectric facilities, and some include hydroelectric in a separate tier so that it does not compete with other renewable technologies. Several states require hydroelectric facilities to be certified by the Low Impact Hydropower Institute (LIHI certification) or meet other generic environmental criteria. For example, California's RPS only includes new hydroelectric that facilities have a capacity of 30 MW or less and does not "cause an adverse impact on instream beneficial uses or cause a change in the volume or timing of streamflow."

Ocean: Coastal states and states located on the Great Lakes also include various forms of Ocean Energy renewable technologies, including wave, tidal, and ocean thermal.

Biomass: Michigan, along with most other states, includes four categories of biomass: generic biomass, landfill gas, municipal solid waste, and anaerobic digestion. However, not all biomass resources have the same environmental benefits. As a result, several states have adopted sustainability criteria when determining biomass energy eligibility for a renewable electricity standard. For example, New York has extensive sustainability and emissions criteria for biomass.

New Technologies: Most states do not include explicit provisions for new technologies in their renewable electricity standards. For the states that do include such provisions, the public service commission in the state typically has discretion to allow new technologies, and best practice requires that these decisions are made in an open stakeholder process. New Mexico has an open category for "zero emission technology with substantial long-term production potential". Arizona includes “additional technologies upon approval”. Michigan includes advanced cleaner energy facilities using a technology that is not in commercial operation as of the date of the act's effective date. It specifically identifies gasification, industrial cogeneration, and coal-fired facilities that capture and sequester (CCS) 85 percent of carbon dioxide emissions as eligible technologies.

Alternative Resources: In general, renewable electricity standards should not include support for non-renewable resources. However, some states, including Michigan, Ohio, and Pennsylvania, have included provisions for non-renewable resources, generally using a separate tier or cap on the amount of generation that is eligible from these resources.

Resources:
1) Database of State Incentives for Renewables and Efficiency. Available at: http://www.dsireusa.org/

2) New York State Renewable Portfolio Standard Biomass Guidebook. Available at: http://www.dps.ny.gov/NYS_Biomass_Guidebook_April_2006.pdf

3) Heeter, Jenni and Lori Bird. 2012. *Including Alternative Resources in State Renewable Portfolio Standards: Current Design and Implementation Experience*. National Renewable Energy Laboratory: Golden, CO. Available at: http://www.nrel.gov/docs/fy13osti/55979.pdf

Question 24:

Renewable Energy Question #24: What has MI done in the past regarding carve-outs for certain renewable sources? What have other jurisdictions done? What are the impacts of such carve-outs on adaptability, affordability, reliability, and environmental protection?

Establishing a carve-out or set-aside requirement for certain technologies under a renewable electricity standard (RES)—either by size, type of renewable energy resource, or ownership structure—has emerged an effective tool for states to accomplish specific economic, resource diversity, or environmental goals. Solar and/or distributed generation carve-outs are the most popular form of carve-outs, with 16 states having established them as part their RES policy (see Table below). Four states (Arizona, Colorado, Illinois, and New Mexico) have set minimum requirements for distributed generation by limiting the size of the renewable energy project. Two states (Colorado and New York) have minimum requirements for customer-sited renewable generation. Six states (Delaware, Illinois, Massachusetts, Oregon, and Pennsylvania) have requirements for solar photovoltaic. And, eight states (Maryland, Missouri, Nevada, New Hampshire, New Jersey, New Mexico, North Carolina and Ohio) have minimum targets for all forms of solar.

In addition to solar, several other renewable energy technologies have been included among some states' carve-out provisions. For example, Illinois, Maine, Minnesota, New Jersey, and New Mexico have established set-aside requirements for wind power (offshore wind in the case of New Jersey). Other technologies that have carve-outs in at least one state include existing hydropower, existing biomass, geothermal, swine waste and poultry litter. The Michigan RES does not have a carve-out for any renewable energy sources.

Carve-outs are proving to be a particularly effective means for stimulating the development of solar PV technologies. According to the U.S. Department of Energy's Lawrence Berkeley National Laboratory (LBNL), from 2005 to 2009, 65 to 81 percent of the annual grid-connected PV capacity additions in the United States outside of California occurred in states with active or impending solar/DG set-aside obligations. Through 2011, solar requirements in RES policies have supported 1,500 MW of solar PV development. And today, 18 of the 20 states with the most total installed solar PV capacity have RES policies in place.

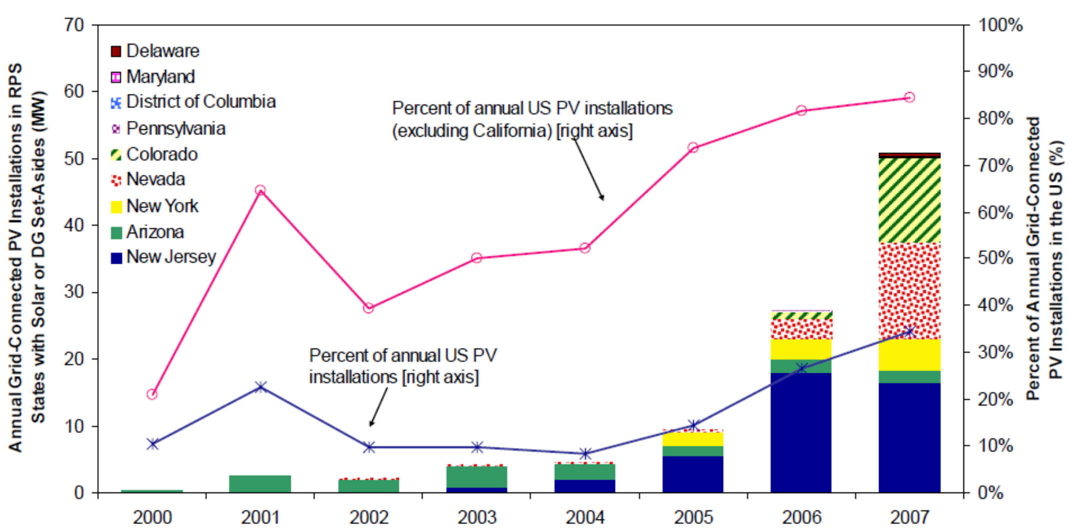


Figure 9. Annual Grid-Connected PV Installations in RPS States with Solar or DG Set-Asides[20]

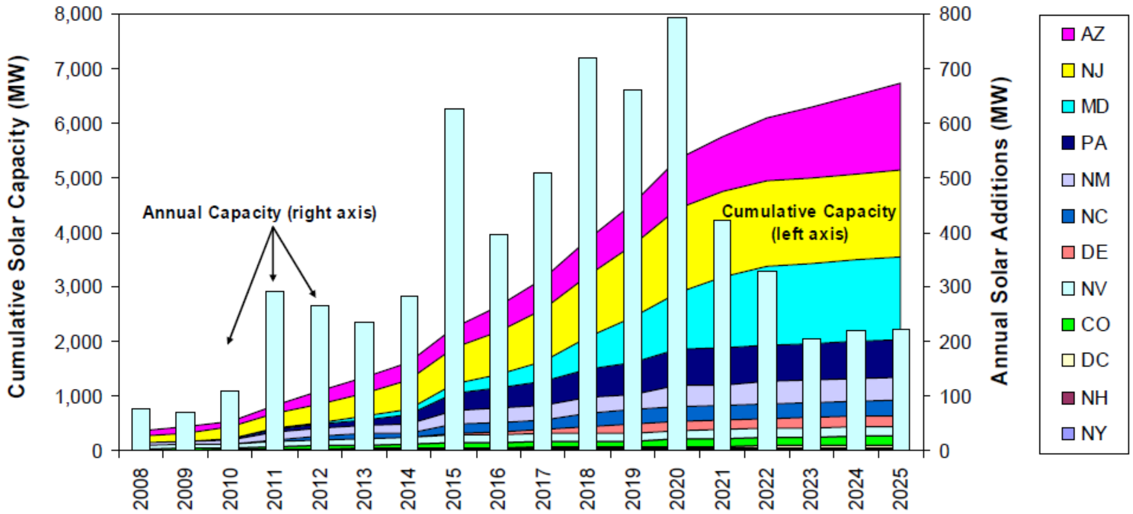
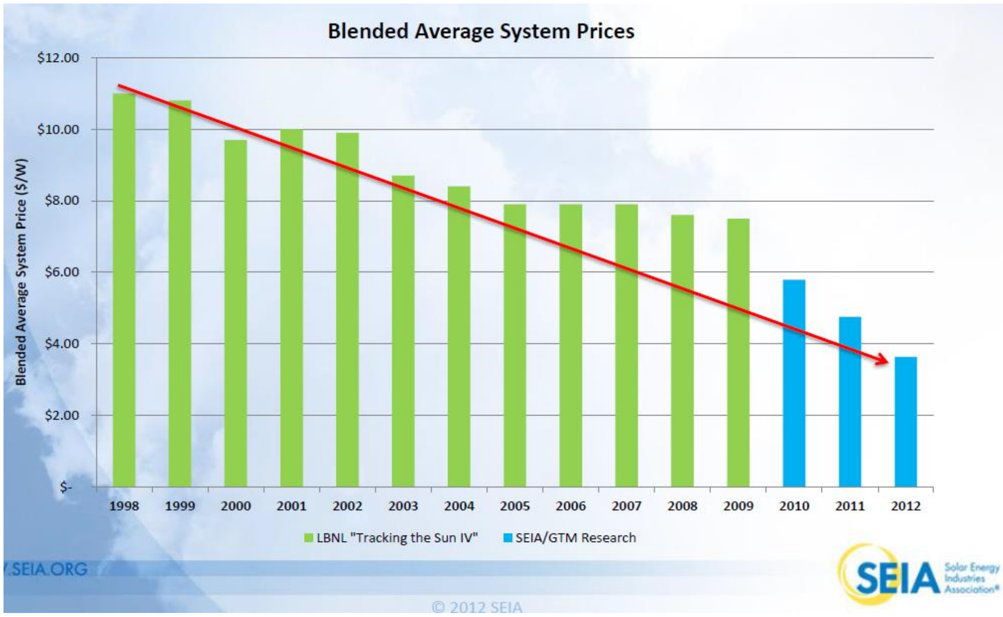


Figure 10. Solar Capacity Required to Meet Existing State RPS Solar and DG Set-Asides[22]

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

Adaptability: There has not been much research on the impacts of set-aside requirements writ large, but LBNL did release a study in 2010 examining the experiences and impacts of solar carve-outs. LBNL found that solar and/or distributed generation set-asides have played a significant role in the recent growth of the U.S. solar market. And while compliance with solar set-asides has been challenging in some states during the initial years, their achievement has steadily increased over time, and these set-aside provisions are poised to drive significant growth in the U.S. solar market. Furthermore, the presence of carve-outs encourages a more diverse mix of renewable energy technologies. A more diverse power mix is also more adaptable and resilient to sudden changes in market conditions.

Affordability: Solar prices have declined substantially in recent years. According to the Lawrence Berkeley National Lab and the Solar Energy Industry Association, prices have been more that cut in half over the last decade, and declined 27% between 2011 and 2012. Due to these declining costs and the consumer protection price caps that have been implemented in most states, solar carve-outs have not been overly burdensome for consumers.



Nine states use Solar Renewable Energy Certificates (SRECs) as a market mechanism to meet their solar energy carve-outs, which helps to minimize the cost of these carve-out provisions. Some SREC markets allow a portion of solar projects to be from out of state, while others restrict trading to in-state solar projects. Most states with SRECs have also made provisions for alternative compliance payments, which entities must pay if they are not able to purchase enough SRECs on the market. These essentially set a cap on the prices of SRECs. The price cap for the solar carve-out is higher than the price cap of the broader RES, which incentivizes the development of solar projects. Also, in most states, the price cap for SRECs falls over time to reflect the anticipated fall in the prices of solar.

Reliability: Existing carve-outs for certain renewable energy sources have not had any negative effect on the overall reliability of the power supply. In fact, there is strong evidence to suggest that diversifying the power supply with renewable energy technologies can enhance the reliability of the U.S. electric grid. In addition, grid operators have the tools necessary to integrate both utility-scale and distributed generation technologies reliably onto the power grid today, in much greater quantities than existing carve-outs require. For example, they can integrate solar project over large geographical areas to help smooth out uneven power supply from individual projects. They can also share energy reserves to balance electricity supply and demand over larger areas. Improvements in weather forecasts, including the use of computer models and statistical analysis help to accurately project solar output.

Environmental Protection: Solar energy is a zero emissions resource. It does not emit global warming emissions or other harmful air and water pollutants. In addition, in Michigan and elsewhere, solar systems can be built on existing buildings or on brownfields or other degraded land, which minimizes the land use impact of solar energy.

Resources:

1) Wiser, Ryan, and Galen Barbose. 2012*. Supporting Solar Power in Renewable Portfolio Standards: Experience from the United States*. Lawrence Berkeley National Laboratory. Available at: http://eetd.lbl.gov/ea/emp/reports/lbnl-3984e.pdf

2) Database of State Incentives for Renewables and Efficiency. http://www.dsireusa.org/

3) Solar energy Industry Association. 2013. *U.S. Solar Market Insight 2012 Year-In-Review*. Available at: http://www.seia.org/research-resources/us-solar-market-insight-2012-year-review

4) Bird, Lori, Jenny Heeter, and Claire Kreycik. 2011. Solar Renewable Energy Certificate (SREC) Markets: Status and Trends. National Renewable Energy Laboratory: Golden, CO. Available at: http://apps3.eere.energy.gov/greenpower/pdfs/52868.pdf

5)Union of Concerned Scientists. 2013. *Ramping Up Renewables*. Cambridge, Mass: Union of Concerned Scientists. Online at: http://www.ucsusa.org/rampinguprenewables.

Question 25:

Renewable Energy Question #25: Has MI, or have other jurisdictions, incentivized dispatchable renewable sources such as biomass compared to intermittent renewable generation? Why or why not?

There has been no state that has set renewable energy policy incentives to differentiate between dispatchable and intermittent variable renewable generation. The reasons for this can be found in the in the goals for state renewables policy, energy markets generally, and in the research on variable energy integration.

State goals: States have set renewable energy goals and procured supplies that meet these goals without including the distinction of "dispatchable" in the definitions or targets for the renewable energy procurement. States instead have sought to include the characteristics that bring benefits to the state. As the discussions below of energy markets and research on the subject show, there is little or no distinction between renewable energy that is dispatchable and renewable energy that is intermittent.

Markets: All energy has some variability. The costs of variability of generators are generally not investigated and assigned different values. The definition of "Dispatchable" in the Midwest ISO includes wind generation that responds to instructions to turn down when conditions on the grid merit such instructions. This lowers the costs to operate the grid, and, importantly, does not include an incentive.

Grid operators maintain reliability while providing consumers with high levels of variable renewable energy by using operational adjustments and wind forecasts. For an excellent summary of the widespread use of these tools amongst Independent System Operators, see the August 2011 ISO/RTO Council Briefing Paper "Variable Energy Resources, System Operations and Wholesale Markets" http://www.isorto.org/atf/cf/%7B5B4E85C6-7EAC-40A0-8DC3-003829518EBD%7D/IRC_VER-BRIEFING_PAPER-AUGUST_2011.PDF

UCS has collected experiences of utilities in the Midwest and the West that demonstrate the ability of power systems to operate with high levels of variable renewable energy. In 2012, wind power provided 24 percent of South Dakota's annual electricity needs, 24 percent in Iowa, 15 percent in North Dakota, 14 percent in Minnesota, and more than 10 percent in five more states (EIA 2013).

Xcel Energy—the largest retail provider of wind power in the U.S. in 2011—set a new U.S. record on April 15, 2012 by generating more than 57 percent of the electricity needed to supply its customers in Colorado on a night when the winds were strong and electricity demand was low (Xcel 2012). "We are very proud of this accomplishment," said Steve Mudd, product manager for Xcel Energy's Windsource program. "Achieving 57 percent is amazing, and it has taken a lot of hard work to reach such a record. But this is just one more milestone, and we are continually working to improve."

According to Mudd, these world records also help dismiss the long-held criticism of wind's unreliability. "What each of our world records shows is that while wind is intermittent, it can be relied upon. And as we continue to bring more wind onto our system, we hope to become smarter and more efficient."

Renewable energy supplied about 25 percent of Germany's electricity in 2012, with more than half coming from wind and solar (Federal Ministry for the Environment 2012). On May 8, 2012, wind and solar reached a record 60 percent of total electricity use in Germany during a sunny afternoon with low

demand (NREL 2012). (Germany is the world leader in installed solar capacity, with 24 GW as of 2011, and is among the world leaders in wind capacity, with 29 GW as of 2011.)
In 2012, wind supplied 30 percent of Denmark's annual electricity use, 17 percent of Portugal's, and 16 percent of Spain's. (See full set of data in Clemmer, S. 2013. *Ramping Up Renewables*. Cambridge, MA: Union of Concerned Scientists. April.)

Research on the subject: over many studies of many regions with a wide range of renewable energy scenarios, the impact of the variability appears to be approximately half a cent per kilowatthour of wind energy. As is the case in the actual markets, there is little consensus on what the costs are for the variability and behaviors of conventional generation. The research finds that there is a greater stress in the scheduling practice of many generators to commit and sell energy for 18 hours per day, a practice known as "block schedule." The research and real-world observation suggests the combined impact of all these generators shutting down at the end of the 18-hour day imposes a greater challenge for grid operators than the uncorrelated variation in wind generation across the Midwest. See link to 2-page fact sheet from National Renewable Energy Lab: http://www.nrel.gov/docs/fy12osti/56235.pdf

Detailed simulations by grid operators, utilities and other experts in the United States have found that the grids in the Eastern and Western halves of the country can accommodate up to 30 percent of total electricity from wind, and another 5 percent from solar energy in the West (EnerNex 2010, GE Energy 2010). Using energy storage to balance out fluctuations in these resources was found to be helpful but not necessary, and not always economic. These simulations showed that significant new transmission investment would be required, along with changes to how the grid is operated today. One of these studies found that the 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.

Question 26:

Renewable Energy Question #26: Has MI, or have other jurisdictions, incentivized energy storage technologies or included energy storage in a renewable or clean energy standard? Why or why not?

Energy storage technologies have not been included in any renewable energy standards because there has been no need for storage procurement for renewable energy or any other grid services. Massachusetts includes a specific type of energy storage in its clean energy standard (as a non-renewable resource) and Michigan includes incentive credits for renewable electricity that is stored to be used on-peak. But the actual inclusion of energy storage as a renewable energy resource is not done in any state.

As the amount of variable renewable energy increases on the grid, the need for new procedures that bring flexibility to the grid becomes more important. The creation of the Midwest ISO, with the pooling of resources and the reduction of internal boundaries, provides a great deal of added flexibility. Several papers discussing renewables integration describe the tools that can be used that are less expensive than storage for managing increasing levels of renewable energy. Also noted in these reports, the greater use of natural gas generation and reduced use of coal, both of which tend to increase system flexibility and allow greater economic use of variable renewable energy.
(Clemmer, S. 2013. *Ramping Up Renewables*. Cambridge, MA: Union of Concerned Scientists. April.)
Denholm, P. Ela, E. Kirby, B. and Milligan, M. 2010. *The Role of Energy Storage with Renewable Electricity Generation* NREL/TP-6A2-47187 http://www.nrel.gov/docs/fy10osti/47187.pdf

The experience and the research with integration of renewable energy in the Midwest emphasize the management of uncertainty with the use of forecasts of wind production, scheduling practices that allow greater flexibility, transfers between neighboring areas to improve balancing, and active management of wind (i.e. curtailment) due to local constraints. Modern wind turbines can reliably curtail output, but this is largely undesirable because curtailment spills energy that has no marginal costs or emissions. Nonetheless, the tactics, used individually or in tandem with each other, provide enough flexibility and reliability to the system at lower cost than the use of storage technologies.

A recent report for PJM addresses the topic of storage, noting that "Storage can provide several valuable grid services, including instantaneous and short-term balancing, regulation and load-shifting. Nevertheless, variable generation integration studies have generally found that while higher levels of variable generation may increase the use of existing storage (mainly pumped hydro), additional storage is not necessary or economically justified."
Hinkle, G. and Porter, K. 2012. *Review of Industry Practice and Experience in the Integration of Wind and Solar Generation. Schenectady, NY:* GE Energy (PDF included with this response). When the Midwest ISO took up a study of Storage in 2011, it generally found that there was no compelling need.
http://www.uwig.org/MISO_Energy_Storage_Study_Phase_1_Report.pdf

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.

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. This result is part of the National Renewable Energy Laboratory's Renewable Electricity Futures Study, (http://www.nrel.gov/analysis/re_futures/)

the most comprehensive study so far of a very high proportion of energy from renewable generation for the U.S.

Beyond the present lack of need for energy storage as part of a renewable energy standard, there is a challenge to match the functioning of storage with the mechanics of a clean energy standard. All existing standards are designed to reward the energy produced. With storage, the technology does not produce energy. Storage stores energy. Further, an energy production incentive is more valuable to an asset if that asset runs as often as possible. The run time for storage assets can be divided into three functions: absorbing energy (charging); discharging energy; and waiting. That is, a storage asset is designed to hold energy and wait for the circumstances when the absorbing or discharging is particularly valuable. Storage assets are described, and valued, for their instantaneous capacity, not the total energy that will be cycled through. These characteristics of storage would make it difficult and complex for it to be included in a renewable energy standard as they are currently thought of.

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

Question 27:

Renewable Energy Question #27: Has Michigan, or have other jurisdictions, incentivized flexible, fast-ramping non-renewable generation as a part of or a complement to the renewable standard? Why or why not?

While states have not incentivized flexible or fast-ramping non-renewable generation as part of or a compliment to renewable energy standards, incentives for flexible, ramping generation have been and continue to be a complement to the power grid because of power supply and demand fluctuations, regardless of the presence of renewable generation. The grid has always required and provided real time increments and decrements of supply from assets that are capable of ramping. The Midwest ISO offers an enormous pool of ramping resources, and the creation of power pools has been motivated over the years in part by the benefits of pooling reserves and the flexibility they offer.

The most relevant flexible, ramping service is known as Frequency Regulation, which is also the most expensive and most difficult of the ancillary services to supply. Frequency Regulation requires the generator or load providing ramping to continuously respond to power system operator signals to move up and down. The ISOs and FERC have recently addressed the advantages of procuring Frequency Regulation from resources that respond quickly and accurately. FERC recently reviewed and reformed the incentives for all ISOs' procurement of flexible, fast ramping resources of any kind. FERC Order 755 found that pre-reform, the Frequency Regulation market paid for the capacity set aside to respond to requests for ramping, but ignored the performance. FERC found that slow response times forced ISOs to make larger procurements and to not meet performance targets. FERC issued Order 755 in October 2011 to align market incentives for fast-ramping resource so as to make rates fair and reasonable.

Amongst the fast-ramping resources providing flexible ramping services are industrial loads. For example, manufacturer ALCOA's Warrick Operations (located in Southern Indiana) is a direct participant in the Midwest ISO Energy Market for this purpose. The ability of a process company such as ALCOA to support the grid has been discussed for years, prior to any renewable energy standards. See for example this paper by Oak Ridge National Lab, here noted by Midwest ISO:
https://www.midwestiso.org/Library/Repository/Meeting%20Material/Stakeholder/DRWG/2009/20090202/20090202%20DRWG%20ALCOA%20Public%20Final.pdf

A July 2011 review by MISO staff provides a summary of the market's ability to provide the ramping capability associated with growing wind energy on the system. See "Ramp Capability for Load Following in the MISO Markets."
https://www.midwestiso.org/Library/Repository/Communication%20Material/Key%20Presentations%20and%20Whitepapers/Ramp%20Capability%20for%20Load%20Following%20in%20MISO%20Markets%20White%20Paper.pdf

The actions by FERC and the ISOs to align incentives, and the integration of industrial and smaller loads to respond to the need for flexibility are new innovations to meeting the need for flexibility on the grid. The trend in most regions in recent years has been to decrease the quantity of flexibility purchased because of such reforms, while at the same time adding renewable energy generation through renewables standards. These trends indicate that (1) there is a surplus of flexible, fast–ramping resources from which to draw on, and (2) that the system has yet to approach a penetration level of wind energy that would raise concern about the availability of flexible resources.

There are scenarios where power pool arrangements are unavailable and renewable generation with a regional power system is tightly clustered, raising the issue of the need for additional ramping capability. However, the real-world experience of the Midwest ISO has not included a link between renewable energy standards and a need for additional ramping resources and there remains (now and in the foreseeable future) a large pool of flexible resources on which to rely.

Question 28:

Renewable Energy question #28: Has Michigan, or have other jurisdictions, used a statewide net metering program? How have such systems handled small scale and larger projects? What policies have been proposed or tried regarding community renewables, meter aggregation and neighborhood net metering?

Response prepared by Vote Solar.

Net metering is a policy that has been implemented by some 43 states to reduce the barriers to end-use retail electricity consumers for adoption of on-site electricity generation, primarily renewable and mainly solar. It's a fundamental building block policy for distributed generation, and can deliver many benefits to renewable energy owners, the grid as a whole, and all other ratepayers. The Solar Electric Power Association (SEPA - an educational non-profit organization dedicated to helping utilities integrate solar energy into their portfolio, comprised largely of utilities) assembled a group of experts to address net metering related issues. The current SEPA working definition for net metering is as follows:

Net metering is a billing mechanism that credits solar system owners for the electricity exported onto the electricity grid. Under the simplest implementation of net metering, a utility customer's billing meter runs backward as solar electricity is generated and exported to the electricity grid and forward as electricity is consumed from the grid.

It is equally important to remember what net metering is not. It is not a policy to address technical safety and reliability issues. Such issues are addressed in the utility's interconnection standards. Net metering is designed to allow the host customer to offset some or all of their on-site electricity consumption by self-generation. In fully regulated states, this is the only form of customer choice that consumers may have.

The net metering policy is generally applicable to all customer types, although clearly some customers groups are more likely to take advantage of this alternative. For example, residential, small business, and large commercial and industrial customers are the most frequent hosts for such on-site generation.

There have been a number of studies performed that compare the values and benefits derived by the utility and the grid from net metered solar energy projects, that offset any utility costs incurred. In isolation, a host utility receives less revenue (as with any sales reduction for any reason) from the net metered customer due to reduced sales to customers with on-site generation, however such revenue reductions are offset by additional values including but not limited to avoided marginal fuel costs, reduced need for new generation and transmission facilities, deferred or avoided distribution system upgrades, and reduced electricity losses across the grid. It should be noted that the full list of benefits usually considered is far more extensive.

The specific benefits and values delivered depend on locational-specific factors. Some recent analyses include one in California done by the consulting firm Crossborder Energy which found that, at 5% of non-coincident peak load under current rate structures, the benefits net of the costs of net metering totaled about $90 million annually. (http://votesolar.org/wp-content/uploads/2013/01/Crossborder-Energy-CA-

Net-Metering-Cost-Benefit-Jan-2013-final.pdf) The costs avoided were found to be approximately 19.3¢ per kWh. Studies in other states have found values that range from 12.8¢ (Austin Energy, Texas) to 25-32¢ (New Jersey and Pennsylvania). These figures can be compared to retail rates to determine net benefits.

It is important to note that net-metering in itself does not necessarily make a successful distributed generation market. It's impact as a policy depends largely on local rate structures. It may be useful to use an analogy: think of net metering as the road, and the combination of rate structures, cost of renewable generation, and any available incentives are the engine.

Community Solar

This is a growing trend across the country. The term is rather broad, and encompasses many different business models. At its most basic, these programs simply provide more ways for people to participate in the benefits of renewables. Some utilities have developed programs where centralized solar projects are built that allow retail customers to participate as owners or subscribers in the project, pay a small delivery charge or in some cases receive free delivery, and reduce monthly consumption by their pro rata share of the generation. This model can utilize other types of renewable resources as well.

Meter Aggregation

This is a twist to net metering policy that allows multiple meters –usually co-located on a single property – to be aggregated for purposes of offsetting net-metered generation. The benefit of this program is that it allows for the maximization of siting potential. Imagine, for example, an instance where a farmer has multiple meters serving irrigation pumps on a single property. With meter aggregation, the farmer could choose the site with the best wind or solar generating potential, and not worry about laying a lot of conduit to each meter or installing several smaller, less efficient systems at each meter. It makes the program more efficient, and lower cost.

Another great application is virtual net metering for multi-tenant buildings. With this application, the owner of a building could install solar on the roof, and then credit the meters of the tenants – without having to hard-wire to each meter (a costly process). California has recently developed this program, and its being used to great effect particularly with low-income housing.

In sum, net metering is a foundational policy for customer choice and opening access to retail consumer self generation, at no cost to the incumbent utilities. Further, it has largely been responsible for the growth of small, local solar installation companies and the jobs and indirect economic gains made at the local level.

Further references:

- IREC best practices model can be found at http://freeingthegrid.org/#education-center/best-practices/
- Michigan currently has a "B" ranking for its net metering policies, according to Freeing the Grid, a rankings website managed by four non-profit agencies with high levels of experience with distributed solar. By reducing or eliminating certain sizing limitations, Michigan could regain its "A" Ranking. (http://freeingthegrid.org/#state-grades/michigan)

Question 29:

Renewable Energy Question #29: How has MI or other jurisdictions proposed addressing possible impacts from the adoption of a federal RPS?

States have long been leaders when it comes to advancing the development of renewable energy using the renewable electricity standard (RES) as a policy tool. However, the RES has also been considered at the national level, with proposals passing the Senate three times from 2002 to 2005, and in the House in 2007 and 2009. Though passage of a federal RES in the current Congress seems unlikely, RES legislation remains under consideration, and President Obama has publically supported a national clean energy standard. While no federal RES law currently exists, the question of how a federal RES would interact with the existing RES policies in 29 states and the District of Columbia is important to consider. If designed well, a federal RES can work effectively together with state-level standards, leading to increased renewable energy deployment and economic and environmental benefits for the entire nation.

While it is no guarantee of how a possible future federal RES would be designed, examining past legislative proposals can provide some insight into how a national standard may be designed to interact with state standards, and likewise how a state may address possible impacts from that standard. Historically, it has been clear that Congress does not seek to undermine the ability of states to establish their own RE policies, and rather has sought to develop a federal program that sets a national floor for renewable energy use on which states can expand. For example, previous federal RES bills have explicitly prevented any preemption or diminishing of existing or new state-level RES or other renewable energy policies, and allowed for states to administer different RES policies, including higher targets and alternative eligibility criteria in order to achieve state and local goals. In addition, states have been given expressed authority to administer their own RES policies, regulate the acquisition and disposition of national renewable energy credits (RECs), and decide on how to treat additional renewable energy generation (above the national targets) that results from their own state standards. Furthermore, the U.S. Department of Energy (DOE), which has typically been authorized to administer the federal RES program under earlier proposals, was instructed to facilitate the coordination between state and federal programs. And though some federal RES proposals have differed in the specifics, many bills have allowed for the states to administer the disposition of funds collected by the DOE in the form of alternative compliance payments.

Michigan is one a just a few states that have proactively included a provision in its RES legislation that addresses possible interactions with a future federal RES. Michigan's law states: "The same renewable energy credit may be used by an electric provider to comply with both a federal standard for renewable energy and the renewable energy standard under this subpart."[7] While this provision addresses one aspect of potential state-federal RES interaction (the counting of state compliance toward federal obligations), other important issues may emerge, including, but not limited to REC ownership, REC tradability, treatment of federal RECs in excess of the national requirement, and the treatment of state

[7] http://www.legislature.mi.gov/%28S%28laudxj45k0c02r55zyuuch45%29%29/mileg.aspx?page=getobject&objectname=mcl-460-1041&query=on&highlight=federal

or federal alternative compliance payments. As a result, further state legislative discussions and clarifying legislation may be required to address the possible impacts of a federal RES, should Congress move forward with one in the future.

Question 32:

Renewable Energy Question #32: How has Michigan or other jurisdictions designed their renewable standards to adapt to unforeseen circumstances, or proposed to do so? What methods beyond legislative changes have been considered or implemented?

While legislative changes are always available as a means of adapting RES policies to unforeseen circumstances, most states incorporate relatively broad provisions in their existing RES policies that will relieve electric providers of RES requirements under various conditions, including the catch all “force majeure” clause. Please refer to the Union of Concerned Scientists’ Renewable Electricity Standards Toolkit for a comprehensive discussion of these various “escape clauses.” (See references list below)

In the case of Michigan, an electric provider may petition the MPSC for up to two extensions of the 2015 10% renewable electricity standard. The extensions will be granted if the MPSC determines there is good cause for such. If two extensions of the 2015 RES deadline have been granted to an electric provider, upon subsequent petition by the electric provider at least three months before the expiration of the second extended deadline, the PSC shall, after consideration of prior extension requests and for good cause, establish a revised RES attainable by the electric provider. In addition, an electric provider that makes a good faith effort to spend the full amount of incremental costs of compliance as outlined in its approved renewable energy plan and that complies with its approved plan, subject to any approved extensions or revisions, shall be considered to be in compliance.

“Good cause” includes, but is not limited to, the electric provider’s inability, as determined by the PSC, to meet the RES because of a renewable energy system feasibility limitation including, but not limited to, any of the following: (a) renewable energy system site requirements, zoning, siting, land use issues, permits, or any other necessary governmental approvals that effectively limit availability of renewable energy systems, if the electric provider exercised reasonable diligence in attempting to secure the necessary governmental approvals; (b) equipment cost or availability issues including electrical equipment or renewable energy system component shortages or high costs that effectively limit availability of renewable energy systems; (c) cost, availability, or time requirements for electric transmission and interconnection; (d) projected or actual unfavorable electric system reliability or operational impacts; (e) labor shortages that effectively limit availability of renewable energy systems; (f) an order of a court of competent jurisdiction that effectively limits the availability of renewable energy systems.

Twenty-six of the 29 states with RES requirements include some forbearance clause in the policy language. Some become applicable only when the costs of compliance exceed a certain threshold. However, most contain additional discretion for the state PUC to delay compliance requirements if they cannot reasonably be met or failure to comply by an electric provider was due to events beyond its reasonable control. These “force majeure” clauses often leave significant discretion for state PUCs to delay compliance or forgive noncompliance in the event of unforeseen circumstances.

In addition, several states include specific authority for a state PUC to delay or forgive compliance if (1) reliability will be impacted in a negative way; (2) if siting and permitting of renewable energy systems cannot be reasonably secured; (3) if an electric provider is facing financial hardship regardless of its renewable energy requirements; (4) if transmission constraints hinder delivery of service; or (5) if complying with the renewable energy requirement would force an electricity provider to acquire electricity in excess of its projected load in a compliance year.

Nearly all of these attempts to provide relief in the face of unforeseen circumstances provide some level of discretion to the state PUC to determine that (1) the electric provider seeking relief is acting in good faith to meet RES requirements; and (2) that circumstances beyond the reasonable control of the electric provider are the driving cause of noncompliance. None of them require legislative action to implement. However, in the rare case that these provisions do not provide adequate protections from unforeseen circumstances, legislative action would still be available if necessary.

Resources:

1) Union of Concerned Scientists. 2013. *Renewable Electricity Standards Tookit.* Online at: http://go.ucsusa.org/cgi-bin/RES/state_standards_search.pl?states=All&category3=&category7=&category8=&category32=&category39=&category43=49&category51=&submit43.x=6&submit43.y=3, accessed April 5, 2013

Question 33:

Renewable Energy Question #33: How does Michigan's renewable capacity compare with other states as a percentage of total electric load?

Michigan ranks in the bottom 1/3 of U.S. states in terms of renewable capacity as a percentage of total capacity in the state. Likewise, Michigan is in the bottom third in terms of renewable electricity generation as a percent of total generation in the state.

There are several ways to make these comparisons. Capacity is the maximum electric output a generator can produce, which is a direct measure of renewable electricity infrastructure. In 2012, Michigan had approximately 2,000 MW of hydroelectric electricity capacity, and approximately 1,500 MW of other renewable capacity, mostly wind and biomass. This adds up to 11% of total available capacity in the state.

An RPS is measuring and tracking the energy produced from the capacity that is installed. Most of the time, both customers and generators operate at well below peak capacity.[8] Hence, it is instructive to consider renewable generation as a percent of total state generation, which is the actual amount of electricity that is produced over a certain time period. Renewable energy comparisons measure how renewable energy contributes to meeting total electric load and how well renewables have been incorporated into the grid.

Capacity (2012) (Source: SNL database):

State	Hydroelectric (MW)	Other Renewables (MW)	Total Renewables (MW)	Total State Capacity (MW)	Renewables as Percent of Total Capacity
WA	23,323	2,906	26,229	33,284	79%
HI	25	1,982	2,007	2,691	75%
OR	6,626	3,173	9,798	14,074	70%
ID	2,769	629	3,398	5,172	66%
SD	1,598	1,022	2,620	4,316	61%
MT	2,741	651	3,392	6,357	53%
ME	758	1,368	2,126	4,802	44%
AK	436	606	1,042	2,402	43%
VT	335	152	487	1,315	37%
IA	139	5,806	5,946	16,570	36%
ND	508	1,799	2,307	6,508	35%

[8] The electric energy consumed in Michigan in 2012 was nearly the same as the electric energy produced for the year. (Consumption in 2012 was 104,079 GWH in Michigan, and production was 108,726 GWH.)

CA	14,119	7,553	21,672	71,044	31%
CT	160	2,622	2,782	9,656	29%
NY	5,769	5,597	11,366	41,743	27%
VA	4,160	2,657	6,817	25,877	26%
CO	1,229	2,843	4,072	15,614	26%
NH	509	682	1,192	4,570	26%
MN	219	3,495	3,714	16,517	22%
WY	308	1,543	1,851	8,490	22%
KS	8	3,023	3,030	14,286	21%
MA	1,993	918	2,911	14,873	20%
TN	4,188	79	4,267	22,354	19%
OK	1,114	3,343	4,457	23,546	19%
SC	4,055	509	4,564	24,477	19%
NV	1,052	493	1,546	11,117	14%
AZ	2,937	1,023	3,960	28,578	14%
PA	2,247	4,101	6,348	46,744	14%
MD	590	1,081	1,671	12,737	13%
GA	3,822	1,370	5,192	40,330	13%
MO	1,170	1,648	2,819	22,607	12%
NE	278	722	1,000	8,042	12%
TX	582	12,860	13,442	109,697	12%
NM	85	944	1,029	8,522	12%
MI	2,152	1,485	3,637	32,484	11%
FL	55	6,466	6,521	61,766	11%
AL	3,244	100	3,343	33,678	10%
UT	281	480	761	7,690	10%
NC	2,236	523	2,760	31,244	9%
IL	34	4,093	4,127	47,594	9%

IN	61	2,329	2,390	28,089	9%
AR	1,365	17	1,382	16,797	8%
NJ	406	1,055	1,460	19,921	7%
WI	497	790	1,287	19,877	6%
WV	346	598	944	16,969	6%
KY	820	79	899	22,224	4%
LA	273	788	1,061	27,704	4%
OH	108	1,252	1,360	35,938	4%
DE		73	73	2,992	2%
RI	3	12	15	2,028	1%
MS		49	49	16,135	0%

Generation (2012) (Source: Energy Information Administration):

State	Hydroelectric (GWh)	Other Renewables (GWh)	Total Renewables (GWh)	Total State Generation (GWh)	Renewables as Percent of Total Generation
Idaho	11,750	2,408	14,158	16,176	88%
Washington	88,533	8,212	96,745	115,974	83%
Oregon	39,257	6,801	46,058	60,372	76%
South Dakota	5,964	2,914	8,878	12,168	73%
Maine	3,527	4,795	8,322	15,049	55%
Montana	11,304	1,281	12,585	27,726	45%
California	25,960	31,009	56,969	201,341	28%
Iowa	821	14,107	14,928	56,919	26%
Vermont	1,195	516	1,711	6,708	26%
New York	25,058	5,181	30,239	136,966	22%
North Dakota	2,477	5,323	7,800	36,179	22%
Alaska	1,434	17	1,451	6,979	21%

Minnesota	738	9,261	9,999	52,560	19%
Nevada	2,439	3,321	5,760	35,566	16%
Colorado	2,004	6,278	8,282	53,594	15%
New Hampshire	1,294	1,383	2,677	19,270	14%
Kansas	0	5,179	5,179	44,782	12%
Oklahoma	1,136	8,531	9,667	78,267	12%
Tennessee	8,012	1,058	9,070	77,449	12%
United States	276,535	218,787	495,322	4,054,485	12%
Wyoming	895	4,394	5,289	49,811	11%
Hawaii	90	920	1,010	10,075	10%
Nebraska	1,507	1,342	2,849	34,645	8%
New Mexico	201	2,575	2,776	36,574	8%
Texas	512	33,695	34,207	431,017	8%
Wisconsin	2,020	3,233	5,253	64,484	8%
Alabama	7,157	3,258	10,415	152,664	7%
Arizona	6,729	1,358	8,087	110,694	7%
Maryland	1,664	882	2,546	37,815	7%
Arkansas	2,168	1,684	3,852	65,382	6%
Massachusetts	969	1,322	2,291	35,397	6%
Utah	1,138	1,113	2,251	39,649	6%
Georgia	2,331	3,357	5,688	122,704	5%
North Carolina	3,517	2,393	5,910	116,024	5%
Virginia	1,007	2,255	3,262	70,895	5%
Illinois	98	8,413	8,511	197,738	4%
Michigan	1,305	3,556	4,861	108,726	4%
South Carolina	1,396	2,049	3,445	96,510	4%

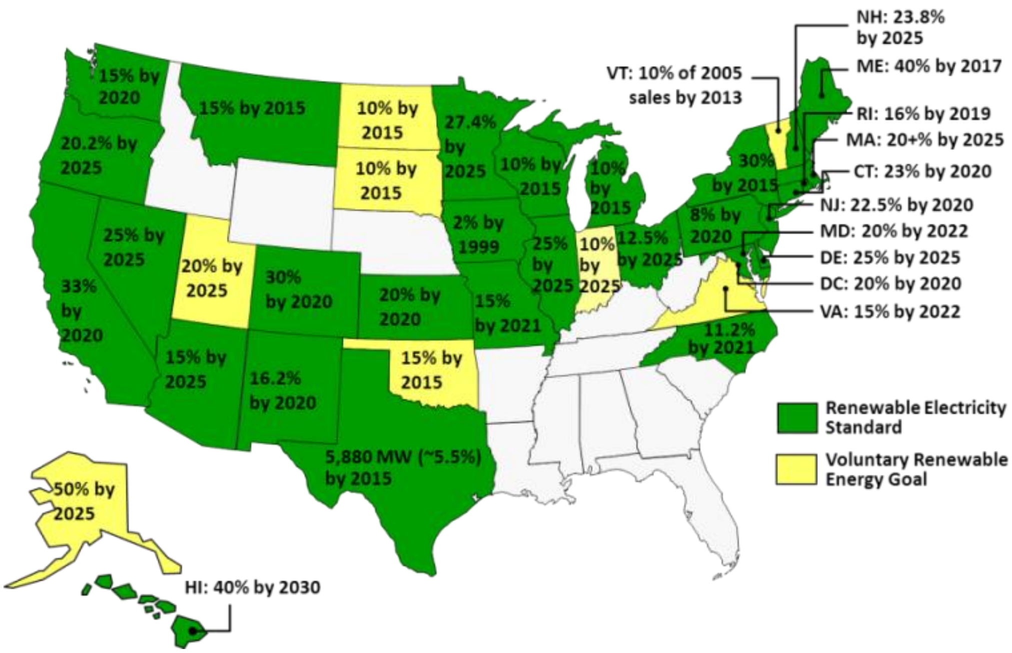
West Virginia	1,327	1,286	2,613	73,326	4%
Connecticut	472	688	1,160	35,733	3%
Indiana	456	3,511	3,967	114,680	3%
Kentucky	2,376	330	2,706	89,819	3%
Louisiana	680	2,240	2,920	103,770	3%
Mississippi	0	1,414	1,414	54,193	3%
Pennsylvania	2,313	4,674	6,987	224,714	3%
Delaware	0	142	142	8,808	2%
Florida	154	4,699	4,853	220,751	2%
Missouri	721	1,307	2,028	91,985	2%
New Jersey	0	1,284	1,284	64,092	2%
Ohio	381	1,710	2,091	129,307	2%
Rhode Island	0	129	129	8,370	2%

Resources:
1) U.S. Energy Information Administration. 2013. *Electric Power Monthly: Net Generation for All Sectors*. Available at: http://www.eia.gov/electricity/data/browser/#/topic/0?agg=2,0,1&fuel=vvvo&geo=g0fvvvvvvvvvo&sec=g&linechart=ELEC.GEN.ALL-US-99.A&columnchart=ELEC.GEN.ALL-US-99.A&map=ELEC.GEN.ALL-US-99.A&freq=A&ctype=linechart&ltype=pin&pin=&rse=0&maptype=0

Question 34:

Renewable Energy Question # 34: How many state with RPS standards have a) achieved the standard, b) modified the standard, or c) frozen compliance due to cost or other factors?

States are achieving annual benchmarks of their RPS policies, but because the vast majority of RPS policies do not require full compliance until at least 2015, only Iowa (with a requirement of 2 percent by 1999) and Texas (5,880 MW by 2015), have officially achieved their total RPS requirement.

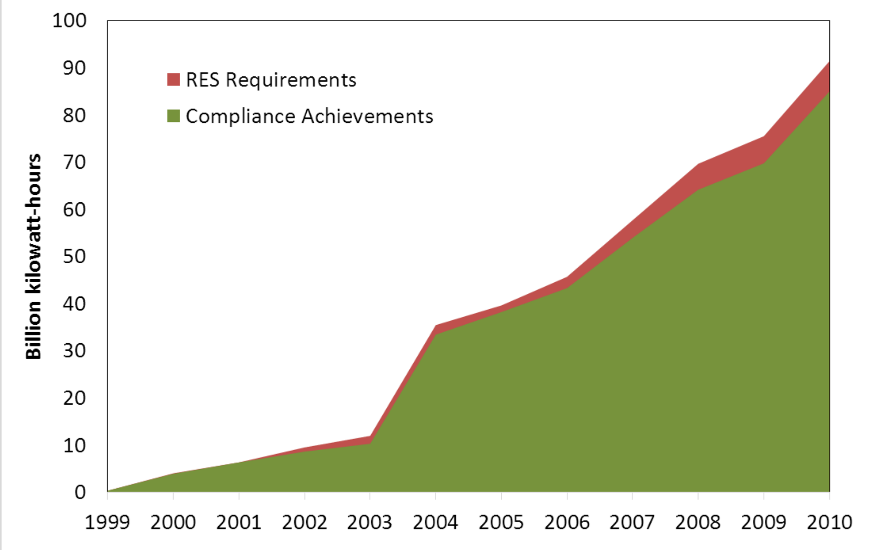


That being said, annual compliance obligations are largely being met and utilities are on track to meet full compliance within the time allotted in the majority of states with RPS policies. Twenty-three states and the District of Columbia have now logged at least three years of operation and compliance with their RES policies, and eleven of these states have seven or more years of experience. In 2012, for the first time, every state with an RPS requirement had a compliance target to meet.

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 all but three of the states that had an annual compliance requirement achieved greater than 90 percent compliance, with most states reporting full compliance.[9] Many states—including Colorado, Texas, and Minnesota—appear to be several years ahead of schedule in meeting annual renewable energy targets.

[9] Connecticut did not report on their RES compliance in 2009 or 2010, despite having an annual renewable energy obligation in those years.

Compliance with Annual Renewable Energy Targets

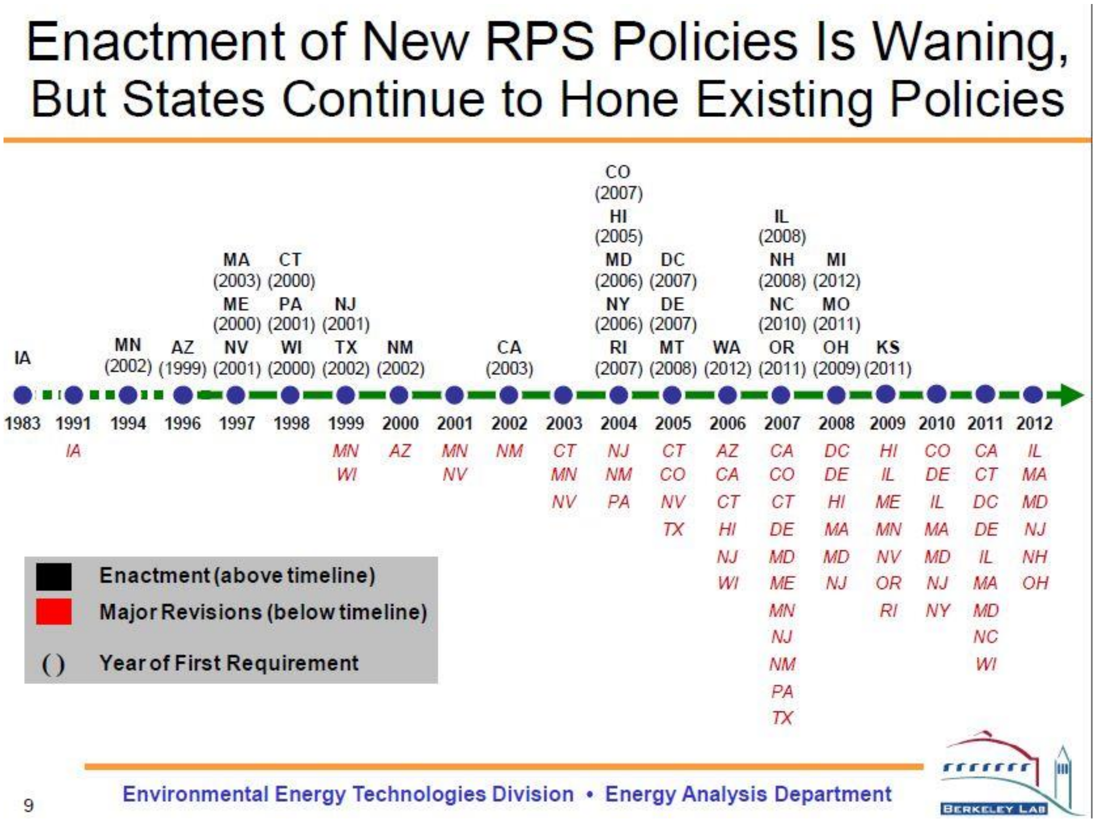


Source: Lawrence Berkeley National Laboratory, 2013

Despite the overall strong track record for RES compliance, there have been a few examples of states struggling to meet their annual requirements – not due to a lack of renewable energy resources, but because of market or regulatory barriers that need to be addressed before development can continue. For example, renewable energy developers in Massachusetts have experienced difficulties in obtaining contracts and financing, as well as delays in siting projects. Recent legislation requiring utilities to enter into long-term contracts for renewable power should ease concerns of financing institutions and help alleviate this problem. In New York, where a state agency (as opposed to utilities) is responsible for renewable energy development to meet RES requirements, long lags between agency actions to develop renewable energy have slowed development. A major new call for renewable energy project proposals issued in December 2012 should put the state back on track.

Looking ahead, as RES requirements continue to increase, the renewable energy industry appears to be well-positioned to keep pace with growing demand. The amount of renewable energy capacity brought online in each of the past five years has ranged from 6,000 MW to more than 16,000 MW. These levels well exceed the 4,000 MW to 5,000 MW of renewable energy capacity additions projected to be needed annually to meet existing RES requirements through 2020.

Since the first wave of RES policies was adopted in the late 1990s, states have refined their policies to expand them or make them more effective in achieving state-specific goals. For example, 18 states have increased or accelerated their renewable energy targets, in some cases more than once. In addition, many states amended their RES policies to include a variety of provisions specifically designed to further state-specific goals, such as supporting solar and/or small- and community-scale renewable energy systems, requiring long-term contracts for purchasing renewable power, or to expand the list of renewable energy resources that can qualify to meet the standard. The Database of State Incentives for Renewables and Efficiency, online at http://www.dsireusa.org/, provides a good summary of each state's policies to support renewable energy development.



Source: Barbose, G. 2012. *Renewable portfolio standards in the United States: A status update*.

To date, no state has frozen overall compliance with the standard due to cost or other constraints. Most states track compliance on a utility-by-utility basis and freezing compliance obligations would likely also happen on a utility-by-utility basis. In several states with RPS policies, certain utilities have been granted extensions or been forgiven compliance obligations because of cost concerns or other constraints. In Michigan, for example, the MPSC currently projects that one utility, the Detroit Public Lighting Department, will not be able to meet the state's 10 percent by 2015 standard within the cost limitations provided for in the statute. Typically, utilities that are having difficulty meeting RPS requirements are utilities serving small service territories representing a small fraction of the state's overall load. These utilities may be unable to meet RPS requirements for a variety of location-specific issues, including transmission constraints or localized shortages of cost-effective renewable energy resources. As indicated above, however, the vast majority of utilities are achieving compliance with RPS obligations.

Resources:

1) Database of State Incentives for Renewables and Efficiency. Online at http://www.dsireusa.org/.

2) Union of Concerned Scientists. *Renewable Electricity Standards Toolkit.* Online at http://go.ucsusa.org/cgi-bin/RES/state_standards_search.pl?states=All&category3=&category7=7&category8=&category32=&category39=&category43=&category51=&submit7.x=25&submit7.y=4.

3) Barbose, G. 2012. *Renewable portfolio standards in the United States: A status update*. Presented at the 2012 National Summit on RPS, Washington, DC, December 3. Online at *www.cleanenergystates.org/assets/2012-Files/RPS/RPS-SummitDec2012Barbose.pdf*, accessed April 22, 2013.

4) Governors' Wind Energy Coalition (GWEC). 2013. *Renewable electricity standards: State success stories.* Washington, DC: GWEC. Online at http://www.governorswindenergycoalition.org/wp-content/uploads/2013/03/RES-White-Paper-March-2013.pdf; accessed April 5, 2013.

5) Lawrence Berkeley National Laboratory (LBNL). 2013. *LBNL RPS compliance data spreadsheet.* Berkeley, CA. Online at *http://www.dsireusa.org/rpsdata/*, accessed April 1, 2013.

Question 35:

Renewable Energy Question # 35: How has the dispatch of renewable generation changed since the implementation of MISO's Dispatchable Intermittent Resource (DIR) tariff? How has dispatching of renewable energy impacted rates in Michigan?

The introduction of MISO's DIR tariff makes the integration of renewable energy less expensive and more efficient. It also has resulted in more renewable generation being utilized to meet demand across the MISO system. The DIR tariff provides MISO and the wind farm operators more tools with finer control for managing the output of wind farms. It also provides more certainty and less curtailment for wind energy providers. According to the MISO DIR Factsheet (available at https://www.midwestiso.org/Library/Repository/Communication%20Material/Strategic%20Initiatives/DIR%20FAQ.pdf), DIR's are beneficial in several ways:

- The entire market benefits when more resources are fully integrated into the Energy Market. Specifically, operational efficiency and market transparency will be improved since fewer manual wind curtailments will be necessary and locational marginal prices (LMPs) will reflect each resource that impacts a constraint.
- The automated dispatch for DIRs will be more efficient than the manual curtailment process previously in place for Intermittent Resources. This will lead to more optimal economic solutions that utilize wind more completely than a manual process.
- The make-whole provisions of the tariff apply to DIRs, whereas they do not apply to Intermittent Resources. If a DIR is unprofitably dispatched above its Day-Ahead position, it is eligible for the real-time Offer Revenue Sufficiency Guarantee Payment provisions of the tariff. If a DIR is dispatched below its Day-Ahead position, and does not maintain its Day-Ahead margin, it is eligible for the Day Ahead Margin Assurance Payment provisions of the tariff. This provides DIRs with assurance that the dispatches, both upward and downward, will be economical.

According to MISO's Reliability Subcommittee, manual curtailments of wind power have dropped significantly since the implementation of MISO DIR tariff – from 2.7 percent in 2011 to 0.9 percent in 2012. Overall curtailments (including manual and DIR dispatch) dropped from about 3.3 percent in 2011 to about 2.7 percent in 2012 even as increasing amounts of wind energy are deployed onto the grid. This reduction in curtailments means more economic certainty for wind power providers as they are paid for more of the total energy they are able to generate. The share of wind generation in MISO that is participating under the tariff has increased from 17 percent in December 2011 to 53 percent in December 2012, to 78 percent in March 2013. The remaining 22 percent is exempt because it was operational before April 1, 2005 or is an intermittent resource with certain network designations and firm transmission rights.

The DIR tariff also provides benefits to MISO grid operators. Before implementation of the DIR tariff, wind resources were manually curtailed – i.e. the grid operator had to call the wind power provider and tell them to curtail in real-time. Under the DIR tariff, wind resources are now dispatchable automatically using MISO's Unit Dispatch System that identifies the most cost-effective dispatchable resources. In this way, the DIR tariff provides more precise management of the fleet of generation and thus reduces the costs and risk of providing the bulk electricity supply.

The impact of the DIR tariff on rates in Michigan is difficult to quantify, particularly due to the fact that the DIR tariff is still in the early stages of implementation. However, because the DIR tariff allows for higher levels of wind energy onto the grid and more efficient dispatch of those resources, the DIR tariff is likely decreasing wholesale electricity rates across the system, including the portions of Michigan that it serves. Because there are no fuel costs associated with renewable energy resources like wind and solar, these resources are "price-takers"; that is they will accept whatever the market is offering at the time generation occurs. In contrast, fossil fuel and nuclear resources are "price-makers" in that they must receive a certain minimum price for generated electricity to make operating the power plant economical. When additional renewable energy resources are available, this tends to push higher-priced resources out of the market, reducing the overall price paid for electricity. This effect has been documented in other parts of the Midwest. See, for example, *Annual report: The costs and benefits of renewable resource procurement in Illinois under the Illinois Power Agency and Illinois Public Utilities Acts* that found that wind and other renewable energy sources reduced wholesale electricity prices across the entire eastern United States, resulting in $177 million is savings for Illinois in 2011 alone.

Resources:
1) MISO Reliability Subcommittee Monthly Informational Forum presentations, available at https://www.midwestiso.org/STAKEHOLDERCENTER/COMMITTEESWORKGROUPSTASKFORCES/RSC/Pages/home.aspx.

2) Illinois Power Agency (IPA). 2012. *Annual report: The costs and benefits of renewable resource procurement in Illinois under the Illinois Power Agency and Illinois Public Utilities Acts*. Springfield, IL: IPA. Online at www2.illinois.gov/ipa/Documents/April-2012-Renewables-Report-3-26-AAJ-Final.pdf, accessed March 24, 2013.

3) MISO Market Subcommittee. 2012. *Dispatchable Intermittent Resource Registration Deadline.* Presentation on October 2, 2012. Online at https://www.midwestiso.org/Library/Repository/Meeting%20Material/Stakeholder/MSC/2012/20121002/20121002%20MSC%20Item%2004i%20DIR%20Registration%20Deadline.pdf; accessed April 23, 2012.

4) MISO Wind Integration website: https://www.midwestiso.org/WhatWeDo/StrategicInitiatives/Pages/WindIntegration.aspx.

5) MISO February 2013 Monthly Markets Assessment Report. Online at https://www.midwestiso.org/Library/Repository/Report/Monthly%20Market%20Reports/2013%20Monthly%20Market%20Reports/201302%20Monthly%20Market%20Report.pdf.

Question 37:

Renewable Energy Question #37: How are renewable energy sources and distributed generation impacting grid operation and reliability?

Renewable energy and distributed generation (DG) resources are far from reaching the levels of penetration that might negatively impact grid operation or reliability. As penetration levels have increased in recent years, and as they continue to increase in the future, grid operators have several tools at hand to effectively manage the influx of these new resources while maintaining grid stability and reliability.

Renewable energy and distributed generation present different challenges to grid operators. In the case of renewable energy, challenges to grid stability and reliability typically stem from the intermittent or variable nature of certain renewable energy resources, namely wind and solar photovoltaic (PV). Renewable energy resources such as biomass, hydropower and certain types of solar power are dispatchable just like more traditional fossil fuel fired resources and therefore present no new issues.

While wind and solar PV are intermittent resources, it is first important to remember that *every* resource is variable to some degree. Grid operators are accustomed to dealing with both expected and unexpected outages of generation resources, whether weather-related or for scheduled or unscheduled maintenance. Today, grid operation is done regionally by regional transmission operators, such as MISO that serves the majority of Michigan as well as 12 other states. The MISO Market and Operations Update, (available at https://www.midwestiso.org/MarketsOperations/Pages/MarketsOperations.aspx), shows that the MISO reliability is not affected by the amounts of renewable energy currently serving the grid. From month to month, as the amount of wind varies, MISO does not require additional reserves as the amount of renewable energy increases. This indicates that MISO is comfortably integrating increasing amounts of variable renewable energy without issue.

Grid operators maintain reliability while providing consumers with high levels of variable renewable energy by using operational adjustments and wind forecasts. For an excellent summary of the widespread use of these tools amongst Independent System Operators, see the August 2011 ISO/RTO Council Briefing Paper "Variable Energy Resources, System Operations and Wholesale Markets" http://www.isorto.org/atf/cf/%7B5B4E85C6-7EAC-40A0-8DC3-003829518EBD%7D/IRC_VER-BRIEFING_PAPER-AUGUST_2011.PDF

The experience and research with integration of renewable energy in the Midwest emphasize the management of uncertainty with the use of forecasts of wind production, scheduling practices that allow greater flexibility, transfers between neighboring areas to improve balancing, and active management of wind (i.e. curtailment). These tactics, used individually or in tandem with each other, provide enough flexibility and reliability to the system to accommodate high levels of renewable energy penetration.

Distributed generation poses both benefits and challenges to utility distribution grid operators that operate on a more localized scale than MISO. The benefits of distributed generation include:

1. Reduced line loss: Electricity lost as it is transmitted to consumers can reach 10% or more during times of heavy demand. Distance transmitted is a factor of line loss and having distributed generation resources at the point of consumption can reduce line loss, making the system as a whole more efficient.

2. Demand Reduction: Demand reduction during peak times is a valuable benefit that DG systems can provide, particularly solar PV systems that tend to generate electricity during high- demand periods.

3. Reduced transmission and generation costs: DG systems reduce the need for transmission build out because they generation electricity where it is used. With wide scale deployment, they will also avoid the need for new centralized generation resources.

The being said, there are challenges to connecting significant amounts of distributed generation to the grid. Voltage fluctuation and imbalance, power output fluctuations and islanding (when DG delivers power to the network even after circuit breakers have disconnected that part of the network from the main grid) all pose challenges. However, all of these challenges can be overcome with current technologies and sound interconnection policies. And it is important to note that Michigan and the power grids that connect to it are a long way from levels of DG penetration that would necessitate any significant change in grid operation. As utilities and installers of DG systems become more experienced with installing systems and connecting them to the grid with proper controls, many of the potential issues with a wide scale deployment of distributed generation will become easier and easier to manage.

Resources:
1) Passey, R. 2011. *The potential impacts of grid-connected distributed generation and how to address them: A review of technical and non-technical fixes.* Energy Policy 39 (2011) 6280 – 6290. (PDF included with this response.)

2) Union of Concerned Scientists. 2013. *Ramping up renewables.* Online at http://www.ucsusa.org/assets/documents/clean_energy/Ramping-Up-Renewables-Energy-You-Can-Count-On.pdf; accessed April 16 2013.

3)U.S. Department of Energy. 2007. *The potential benefits of distributed generation and the rate-related issues that may impeded its expansion.* Online at http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/1817_Report_-final.pdf; accessed 4/17,2013.

4) Vitolo, T., G. Keith, B. Biewald, T. Comings, E. Hausman and P. Knight. 2013. *Meeting load with a resource mix beyond business as usual.* Synapse Energy Economics, Inc. Cambridge MA. Online at http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/1817_Report_-final.pdf; accessed April 18, 2013.

5) Vittal, V. 2010. *The impact of renewable resources on the performance and reliability of the electricity grid.* The Bridge, Spring 2010. National Academy of Engineering. Online at http://www.nae.edu/File.aspx?id=18585; accessed April 17, 2013.

Additional Areas Question 1:

What are possible definitions of "reliability" that have been used or proposed for use by policy makers? What studies exist regarding the economic and environmental benefits of baseline or "additional" reliability?

For most discussions of "reliability", the definitions used by power system engineers to describe bulk power and longer time frames would also be used by policy makers. These look at distinct time horizons and large-scale components of the power system. The usual measure of reliability for both generation and delivery is capacity to serve customer demand for electricity, or "load." Thus, more ways to keep the supply adequate for a given level of load, or the ability to meet a higher level of load would be recognized as increased reliability. Common examples are the reliability or adequacy of the power supply for the forecasted needs for the coming year, or the reliability of the transmission system to deliver enough power to the Upper Peninsula. In these terms, the economic benefits of adding reliability would generally be found in a comparison to the cost of an incremental expansion of capacity using an identified avoided generating plant or transmission solution.

Additional policy-oriented definitions of reliability are those that consider future scenarios of concern to the public, such as systemic disruption or stress from a macro-scale external event, such as drought or fuel supply disruption. This type of reliability study has become more relevant in recent years as power system interdependencies and vulnerabilities to extreme weather have been recognized as threats to reliability.

The Union of Concerned Scientists has released a study of the risks to reliability, and related economic and environmental benefits from increasing the use of renewable energy generation. The latest UCS report describes the economic disadvantage of continued operation of seven coal plants in Michigan, and the savings of over 5 billion gallons of *consumed* water if these plants are replaced with renewable energy and energy efficiency.

More generally, the Midwest ISO uses two approaches to defining the benefits of additional transmission, and the reliability benefits of additional wind generation.

1. Transmission

Transmission costs and benefits are assessed by Midwest ISO and discussed with stakeholders. In 2010-2011, Midwest ISO defined and approved a portfolio of transmission upgrades to accommodate generation connections and improve reliability in Michigan and across the MISO footprint. The first package of 17 Multi-Value Projects was described by Midwest ISO 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." MTEP 11, page 1.
https://www.midwestiso.org/_layouts/MISO/ECM/Redirect.aspx?ID=120701

2. Generation

The Midwest ISO also has an explicit process for establishing the reliability benefits of new generation. This involves calculating the Loss of Load Expectation (LOLE) for a specific set of generators and energy demand patterns. The idea is that adding more energy sources increases the probability that there will be enough generated energy when a shortage threatens reliability. An increase in this measure generally follows when additional generation is included, and that increase for the specific generator is the Effective Load-Carrying Capability (ELCC). The MISO uses ELCC for wind and has done so for 3 years.

See this year's report at
https://www.midwestiso.org/Library/Repository/Study/LOLE/2013%20Wind%20Capacity%20Report.pdf
Below is description of the steps for finding the reliability benefits from wind from a U.S. Department of Energy-funded research paper: Milligan, M. and Porter, K. 2005. *Determining the Capacity Value of Wind: A Survey of Methods and Implementation*. Golden, CO: National Renewable Energy Laboratory. http://www.nerc.com/docs/pc/ivgtf/milligan_porter_capacity_paper_2005.pdf

ELCC is calculated in several steps. To calculate ELCC, a database is required that contains hourly load requirements and generator characteristics. For conventional generators, rated capacity, forced outage rates, and specific maintenance schedules are primary requirements. For wind, an intermittent resource, at least 1 year of hourly power output is required, but more data is always better. Most commonly, the system is modeled without the generator of interest. For this discussion, we assume that the generator of interest is a renewable generator, but this does not need to be the case. The loads are adjusted to achieve a given level of reliability. This reliability level is often equated to a loss of load expectation (LOLE) of 1 day per 10 years. This LOLE can be calculated by taking the LOLP (a probability is between zero and one and cannot by definition exceed 1) multiplied by the number of days in a year. Thus LOLE indicates an expected value and can be expressed in hours/year, days/year, or other unit of time.

Once the desired LOLE target is achieved, the renewable generator is added to the system and the model is re-run. The new, lower LOLE (higher reliability) is noted, and the generator is removed from the system. Then the benchmark unit is added to the system in small incremental capacities until the LOLE with the benchmark unit matches the LOLE that was achieved with the renewable generator. The capacity of the benchmark unit is then noted, and that becomes the ELCC of the renewable generator. It is important to note that the ELCC documents the capacity that achieves the same risk level as would be achieved without the renewable generator.

Resources:

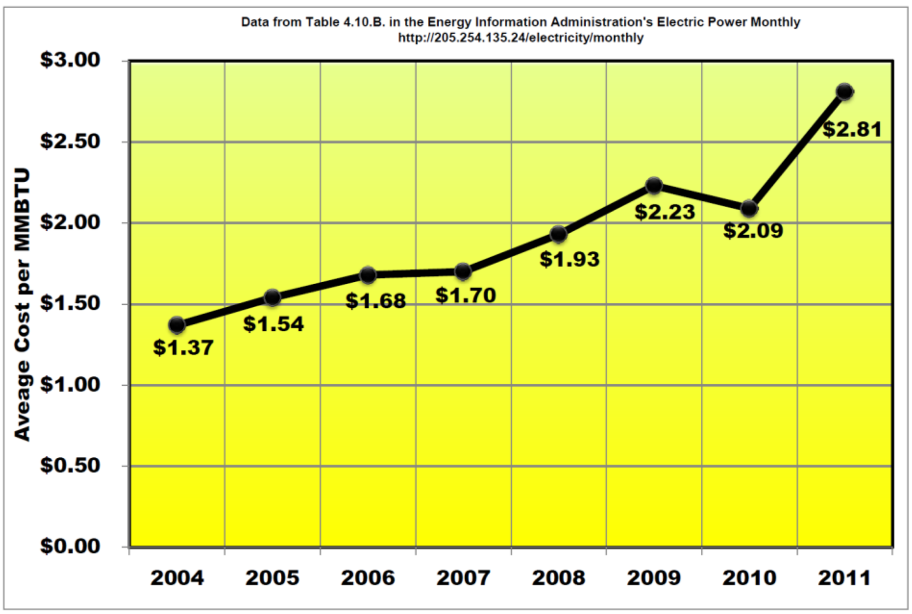
1) Fleishman, L and Schmoker, M. 2013 *Economic and Water Dependence Risks for America's Aging Coal Fleet.* Cambridge, MA: Union of Concerned Scientists. April. Online at http://www.ucsusa.org/assets/documents/clean_energy/Water-Dependence-Risks-for-America-s-Aging-Coal-Fleet.pdf; accessed April 8, 2013.

Additional Areas Question 15:

Additional Areas Question #15: What are the major reasons for the cost increases seen over the past several years for delivered coal to Michigan?

Over the past decade, the cost of coal delivered to coal-fired power plants across the nation and in Michigan has increased by more than 50%. Michigan has been particularly susceptible to this trend because the state, despite having no in-state coal supplies, relies on coal for approximately 58 percent of its in-state electricity generation. To supply that power, all Michigan power producers collectively paid nearly $1.3 billion to import coal in 2010. From 2002 to 2010, their cumulative purchases of imported coal reached nearly $10.4 billion. More than half of this total—$5.4 billion—was spent by Detroit Edison, while during those years the price the utility paid for coal increased by 81 percent, a much larger increase than the national average. As the chart below indicates, the average cost of Michigan coal has risen steadily from 2004-2011:

MICHIGAN AVERAGE COAL COSTS 2004-2011



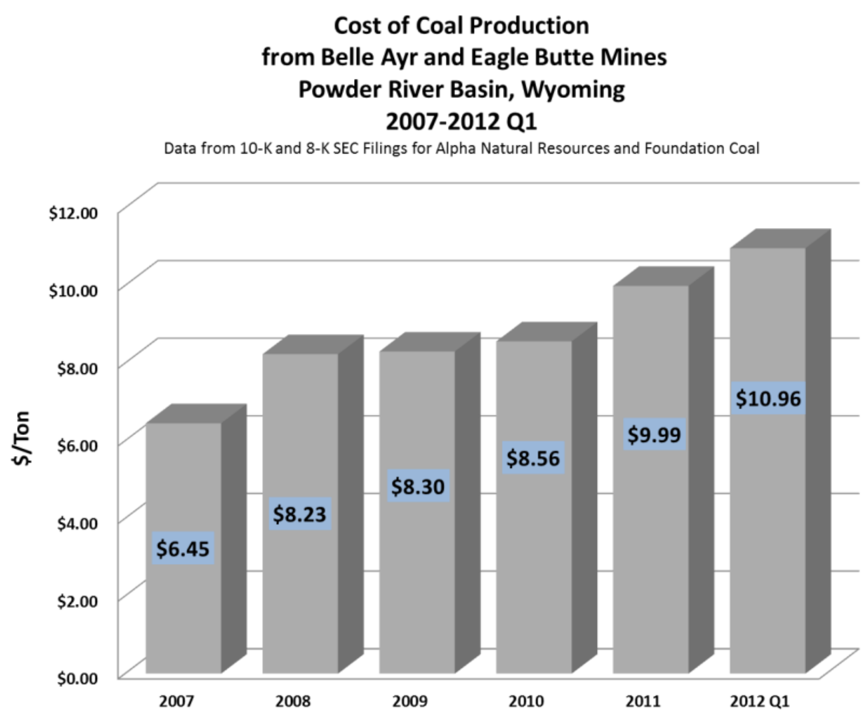
Source: Mufson, S. *Cost of mining coal continues to climb.* Washington Post. October 24, 2012.

When compared to other Midwestern states and the entire U.S., Michigan's coal costs are the highest in the Midwest (although Indiana's coal prices rose at a slightly greater rate) and higher than the national average in 2011.

	2004 Coal Cost $/MMBTU	2011 Coal Cost $/MMBTU	2004-2011 Average Increase / Yr
Illinois	$1.16	$2.01	10.5
Indiana	$1.21	$2.47	14.9
Iowa	$0.90	$1.44	8.60
Michigan	**$1.37**	**$2.81**	**14.7**
Minnesota	$1.06	$1.94	11.8
Ohio	$1.32	$2.29	10.5
Midwest Average	**$1.17**	**$2.16**	**11.83%**
U.S. Total	**$1.34**	**$2.41**	**11.40 %**

Several key factors driving this trend both in Michigan and nationally: rising production costs, rising transportation costs and an increase in coal exports.

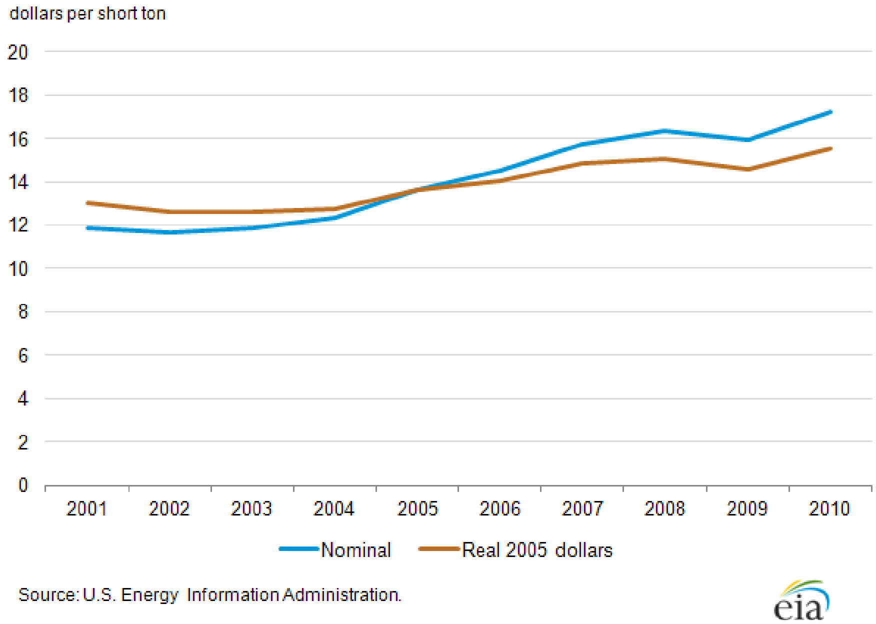
For both eastern and western coal production, costs are rising as the most easily-accessed coal resources are depleted and coal that is more difficult, and therefore more expensive, to mine represents an increasing proportion of delivered coal. These increasing production costs are one factor driving U.S. coal costs upward. The Washington Post cited an observation from the U.S. Energy Information Administration that projected an “upward trend of coal prices [that] primarily reflects an expectation that cost savings from technological improvements in coal mining will be outweighed by increases in production costs associated with moving into reserves that are more costly to mine.” As the chart below indicates, the cost of mining some Wyoming coal has risen by nearly 70% since 2007:



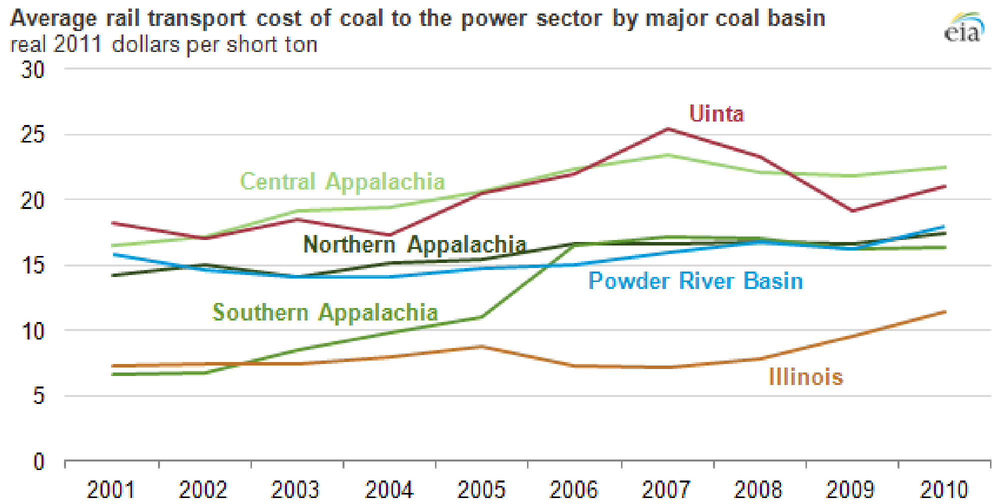
Source: Foster, T., W. Briggs and L. Glustrom. 2012. *Trends in U.S. Delivered Coal Costs: 2004 – 2011.* Clean Energy Action.

Another factor pushing coal prices higher is the cost of transporting coal by rail. Transportation costs for coal are increasing because of rising diesel fuel prices. According to the Energy Information Administration, "The average cost of shipping coal by railroad to power plants increased almost 50% in the United States from 2001 to 2010." EIA reported that, in 2010, transportation costs represent 40% of the total cost of delivered coal, which means that rising transportation costs directly impact coal costs. During this period, average rail transportation costs per short ton rose from $11.83 to $17.25 from 2001 to 2010.

Figure 5. U.S. average rail transport cost of coal to electric generating plants

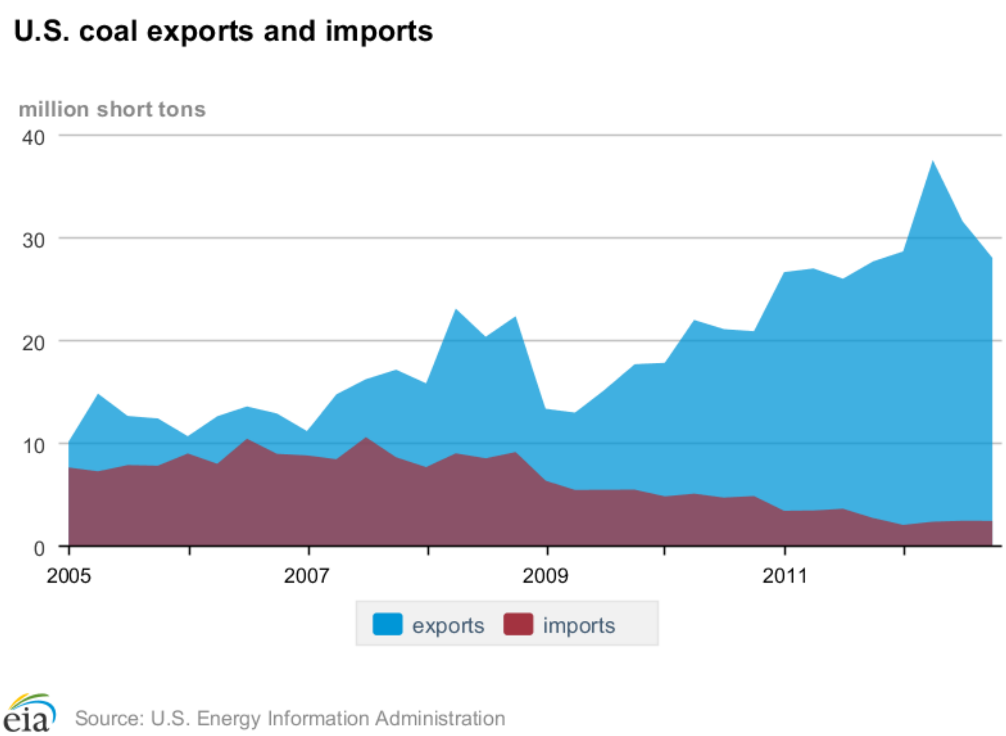


However, the rise in transportation cost varied significantly by geography, with Southern Appalachian costs rising more than Powder River Basin (PRB) costs. Transportation costs for PRB coal can account for more than half the total cost of delivered coal. Michigan is particularly impacted by rising PRB transportation costs since DTE and Consumers Energy collectively spent more than $500 million in 2010 to import PRB coal from Wyoming. Compounding this risk exposure was the recent expiration of DTE's long-term rail contracts and the imposition of diesel fuel surcharges.



Source: U.S. Energy Information Administration Power Plant Operations Report (EIA-923) and U.S. Surface Transportation Board's Confidential Waybill Sample.

Finally, greater coal exports are another important source of upward pressure on coal prices as international coal markets provide new opportunities for U.S. coal mining companies. The upward trend in coal exports combined with declining coal imports are reducing domestic coal supplies, contributing to higher U.S. coal prices.



Resources:

1) Union of Concerned Scientists. *Burning Coal, Burning Cash: Detroit Edison's Dependence on Imported Coal.* Fall 2012. Online at http://www.ucsusa.org/assets/documents/clean_energy/Michigan-Coal-Use-Detroit-Edison-Dependence-on-Imported-Coal.pdf.

2) Mufson, S. 2012. *Cost of mining coal continues to climb*. Washington Post. Published: October 24, 2012. Online at http://www.washingtonpost.com/business/economy/cost-of-mining-coal-continues-to-climb/2012/10/24/d15666ca-1931-11e2-bd10-5ff056538b7c_print.html.

3) Foster, T., W. Briggs and L. Glustrom. 2012. *Trends in U.S. Delivered Coal Costs: 2004 – 2011.* Clean Energy Action. Online at http://cleanenergyaction.org/2012/07/11/cea-research-report-trends-in-u-s-delivered-coal-costs-2004-2011/.

4) Energy Information Administration. 2012. *Cost of transporting coal to power plants rose almost 50% in decade.* November 19, 2012. Online at http://www.eia.gov/todayinenergy/detail.cfm?id=8830.

5) Zaski, F. 2011. *Michigan Coal Trends*. West Michigan Environmental Action Counci Blog. June 2011. Online at http://thewmeacblog.org/2011/07/19/michigan-coal-trends-june-2011/

6) Energy Information Administration. 2012. *Coal Transportation Rates to the Electric Power Sector*. November 16, 2012. Online at http://www.eia.gov/coal/transportationrates/index.cfm.

7) Energy Information Administration. 2012. *Cost of transporting coal to power plants rose almost 50% in decade.* November 19, 2012. Online at http://www.eia.gov/todayinenergy/detail.cfm?id=8830.

Appendix:

The following resources are referenced in various responses included in this document, but are not available online. They are included here for your convenience.

1) Marks, J. A. 2012. Concurrence. Santa Fe, NM: New Mexico Public Regulation Commission. Referenced in responses to Questions #4, 10 and 11.

2) Stockmayer G., V. Finch, P. Komor, and R. Mignogna. 2011. *Limiting the costs of renewable portfolio standards: A review and critique of current methods.* Energy Policy 42 (2012) 155 – 163. Referenced in response to Question #16.

3) Passey, R. 2011. *The potential impacts of grid-connected distributed generation and how to address them: A review of technical and non-technical fixes.* Energy Policy 39 (2011) 6280 – 6290. Referenced in response to Question #37.

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF THE COMMISSION	)	
ESTABLISHING A STANDARD METHOD	)	
FOR CALCULATING THE COST OF	)	
PROCURING RENEWABLE ENERGY,	)	
APPLYING THAT METHOD TO THE	)	**Case No. 11-00218-UT**
REASONABLE COST THRESHOLD, AND	)	
CALCULATING THE RATE IMPACT DUE	)	
TO RENEWABLE ENERGY	)	
PROCUREMENTS	)	
	)	

CONCURRENCE

New Mexico's commitment to including renewable energy in the resource portfolios of electric utilities dates back to the Commission's original specification of Renewable Portfolio Standards in 2002 via an administrative rulemaking. The evolution of this policy has been guided by the statutory adoption of the RPS in 2004, subsequent statutory amendments, intermittent rulemakings on various aspects of the RPS, and the ongoing cycle of annual renewable procurement plan cases.

The RPS has been successful. Today, all three of our investor-owned utilities have reached the second major milestone of having 10% of all retail electric sales arising from renewable energy sources (or in the case of PNM, having an approved plan that will result in full compliance soon). Additional renewable energy is supplied to customers through voluntary renewable energy tariffs, where PNM's voluntary program has been recognized nationally for its participation rates and will soon include a solar component. Four large-scale wind farms serve New Mexico utility customers through long-term purchased power agreements, with three more supplying other markets. Thanks largely to the diversity targets established by the Commission by rule in Case No. 07-00157-UT, New Mexico's utility-scale solar electric generation quotient went from nil to 153 MW, with another 20 MW approved for deployment next year. A separate category, distributed solar generation, climbed from less than 100 kw to more than 20 MW. In 2011, New Mexico was ranked number one nationally in solar electric watts per capita.

Despite the fears of skeptics, we have accomplished our goals without causing unmanageable problems for grid operators and without subjecting utility customers to unreasonable and excessive costs. Technological and manufacturing progress has continued to drive down costs for new wind and solar energy resources, driven by commercial demand created by RPS policies of U.S. states and similar initiatives around the globe. The decline in cost for solar energy to the customer has been especially dramatic – the Commission just approved a solar procurement at a levelized cost of $77 per MWh. Our current year reasonable cost threshold (RCT) is 2.25%, and while the application of the RCT has heretofore been subject to differing interpretations, it is clear that net bill impacts considering avoided costs, are modest. But for (welcome) decreases in natural gas prices, added costs for RPS compliance would be even less of an issue; in fact, during past periods when natural gas prices were high, ratepayers experienced savings due to low-cost wind energy contracts made for RPS compliance purposes.

Policies that encourage renewable energy substitution for conventional resources have overwhelming support among the general public. A 2012 Colorado College survey of New Mexico voters found that "71% would tell their State Legislator to maintain the current standard knowing it was put in place to help create clean energy jobs, promote energy independence and provide locally created energy, while 24% would opt to reduce the standard in order to help bring down electricity rates."[1] In that survey, two-thirds of New Mexicans picked solar as one of their top two preferred energy sources, followed by wind energy. In a recent national poll, 92% of all voters said that it was important for America to develop and use more solar power.[2] In the present case, my office received emailed comments from around two hundred members of the general public, both individually and as part of petitions and campaigns, *all but one* in favor of keeping or increasing diversity targets and taking a pro-renewable energy to the RCT.

Numerous entities representing environmental and renewable energy industry interests actively participated in the proceedings with well-taken comment, testimony, and briefs.[3] PRC Staff brought an objective perspective to the case, supporting the effectiveness of diversity targets and the rationale for encouraging solar energy in New Mexico, and providing a usable framework for RCT calculations. Even New Mexico investor-owned utilities, as evinced by comment and testimony in this case. have for the most part accepted and adapted to the Commission's renewable energy policies, including the diversity targets. Among stakeholders, opposition to policy-driven renewable energy development was largely limited to the Attorney General and NMIEC, who nevertheless represent important constituencies.

Given these factors, along with the continued relevance of legislative findings that the generation of electricity through the use of renewable energy presents opportunities to promote energy

[1] Colorado College, State of the Rockies Report 2012, retrieved from http://www.coloradocollege.edu/other/stateoftherockies/conservationinthewest/

[2] SEIA National Solar Survey 2012 (September 2012), retrieved from http://www.seia.org/research-resources/america-votes-solar-national-solar-survey-2012

[3] Commendations are in order for NM REIA for particularly strong written pleadings, CCAE/WRA for continued dedication to developing creative solutions, Vote Solar Initiative for a long-term commitment to share national expertise and experience with our state, and the New Mexico Green Chamber of Commerce for effective advocacy.

self-sufficiency; preserve the state's natural resources and pursue an improved environment in New Mexico; that utilities should be required to have minimum amounts of diverse sources of renewable energy in their portfolios, and should be encouraged to exceed those minimums (NMSA § 62-16-2); it is disheartening that a dominant theme in the current proceeding was skepticism towards policies that seek to go beyond paper compliance with the REA and actually reach for its aspirational goals.

The Commission's Final Order dodges the worst of the attacks, and holds the center. The Final Order accomplishes the important objective of ratifying the successful, *a priori* target-based approach to achieving statutorily-mandated diversity, and explaining why opposing arguments are not well-taken. It establishes a standardized approach to the calculation RCTs that results in a test that truly reflects incremental bill impacts, including all material avoided costs. It extends an invitation to neighboring states to join New Mexico in a non-discriminatory interstate market for renewable energy (a market that New Mexico, with its abundant high-quality resources, would be poised to benefit from). It promulgates language to implement 2011 REA amendments enabling self-directed public entity renewable energy programs. I commend Commissioners Becenti-Aguilar, Howe and Hall for joining me in supporting the Commission Final Order and a compromise resolution that benefits New Mexico. The Final Order is arguably the best possible order that could garner majority support in the foreseeable future; the alternative would have chilled the development of a diverse portfolio of renewable energy.

Based on the comment and evidence in the case record, I would have retained the 10% "other" diversity target. As the Final Order points out, biomass, biogas, geothermal, and hydro projects can provide important dispatchability benefits to resource portfolios. FO ¶ 38. Successful development of biogas holds the promise of leveraging existing high-efficiency generating plants with a "green" fuel, as well as offering a needed solution to waste disposal problems challenging commercial dairies in Southern New Mexico. A 10% diversity targets would have kept the pressure on utilities to develop successful projects in that area. And, since unreasonable expensive or uncertain projects are already rejected, cutting the target to 5% provides no actual benefits in cost savings. All it does is make it less likely that our state will even try to succeed in this area.

I also would have changed the language in Section 13 (C) of the rule to read "A utility shall select resources based on net present value analysis, long and short term rate impacts, and operating characteristics such as availability, reliability, and dispatch flexibility." The language adopted in the Final Order makes "cost-effectiveness" the only criterion for procurements not needed to meet diversity targets, contra to the statutory principles in the REA whereby resources' technical characteristics, as well as cost, are to be considered in constructing portfolios. I am concerned that the adopted language could prevent pursuit of portfolios that otherwise make sense; e.g., a solar-heavy portfolio for El Paso Electric, which has excellent solar but no wind resources within its footprint. It was the Commission's position during debate that no changes to the adopted language were needed in to permit utilities the flexibility to use something other than the least-cost resource (as defined in the rule) when a different resource was more advantageous, all factors considered, because utilities could obtain variances in such a situations. I hope this proves correct.

Finally, while the RCT percentage is a policy determination in which the Commission balances competing goals, there are facts such as public preferences, as determined through survey research, and cost estimates under various scenarios, that can inform the decision. It is critical that we not undercut public support for sustainable energy source by wasteful spending; however, information we have suggests that public opinion would likely support slightly higher RCTs, as recommended by Staff, if needed in future years. This could be looked at with more rigor in any future proceedings.

This Concurrence should be served on all parties to the service list. Filed this 26 day of December 2012 at Santa Fe, New Mexico.

/s/

Jason Marks
Commissioner

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF THE COMMISSION ESTABLISHING A STANDARD METHOD FOR CALCULATING THE COST OF PROCURING RENEWABLE ENERGY, APPLYING THAT METHOD TO THE REASONABLE COST THRESHOLD, AND CALCULATING THE RATE IMPACT DUE TO RENEWABLE ENERGY PROCUREMENTS.	)	**Case No. 11-00218-UT**

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing Jason A. Marks's Concurrence was sent by electronic mail on December 27, 2012, to the individuals listed below.

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DATED this 27th day of December, 2012.

NEW MEXICO PUBLIC REGULATION COMMISSION

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Energy Policy 42 (2012) 155–163

Contents lists available at SciVerse ScienceDirect

Energy Policy

journal homepage: www.elsevier.com/locate/enpol

Limiting the costs of renewable portfolio standards: A review and critique of current methods

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ARTICLE INFO

Article history:
Received 13 May 2011
Accepted 21 November 2011
Available online 16 December 2011

Keywords:
Renewable portfolio standards
Costs
Rate impact

ABSTRACT

Over half of U.S. states have renewable portfolio standards (RPSs) mandating that a minimum percentage of electricity sold derives from renewable sources. State RPSs vary widely in how they attempt to control or limit the costs of these RPSs. Approaches utilized include alternative compliance payments, direct rate caps, and cost caps on resource acquisitions, while some states employ no specific limitation at all. This paper describes how states attempt to control RPS costs and discusses the strengths and weaknesses of these various cost controls. There is no one best method; however the experience to date suggests that the most important factors in implementing an effective mechanism to curtail costs are clarity of the rule, consistency in application, and transparency for customers.

1. Introduction

Currently twenty-nine states plus the District of Columbia and Puerto Rico[1] have enacted Renewable Portfolio Standards ("RPSs") mandating that a specified percentage of the electricity sector's energy derives from renewable sources. (www.dsireusa.org). These RPSs generally (although not always) increase the wholesale costs of electricity to utilities with the attendant costs being passed on to consumers. One estimate found that state RPSs, on average, have thus far increased electricity rates by about one percent (Wiser and Barbose, 2008). However, the mechanisms for calculating these impacts vary considerably from state to state. Future cost impacts are of course more difficult to calculate (Chen et al., 2007). As state RPSs ramp up their renewable targets and solar and distributed generation set-asides in coming years, RPS cost impacts will be an increasing concern for industry and customers alike.

State legislators, public utility commissions, and other regulatory agencies have struggled to manage the costs of implementing their RPSs in the face of political pressure and statutory mandates to protect ratepayers from excessive costs of RPS compliance. For example, according to one staff member of the New Mexico Public Service Commission, electricity rates have increased four to five percent over the past six years due to the RPS requirements. Many states thus utilize mechanisms to curtail what electricity providers spend, and consequently what ratepayers must pay, to implement their RPSs.

This paper explains the primary cost limitation mechanisms being used today, discusses differences in design across states, and draws conclusions about how such mechanisms should be designed and implemented. A summary of states' cost impact limitation mechanisms is shown in Table 1.

2. Review of utility regulation and restructuring

The U.S. electricity market is an eclectic mix of traditionally regulated (or "cost-of-service") utilities—whose prices are regulated by a government body—and restructured (also known as "competitive") markets, in which multiple retail providers compete for customers. While most states operate as either regulated or competitive markets, a few employ a hybrid of both approaches. For example, in Oregon and Nevada, respectively, only commercial and industrial customers and very large customers have the freedom to choose their electric suppliers. Restructured power markets with retail choice operate in the Northeast, the Mid-Atlantic, Texas, Oregon, and parts of the Midwest. In Table 1 traditionally regulated states are shown in standard font, restructured states in *italics*, and hybrid states in *underlined italics*.

It is useful to briefly review how utilities operating under a cost-of-service model recover costs as compared to those operating in a restructured market because RPS cost limitation mechanisms often derive from cost recovery calculations. For example, utilities held to a cap on retail revenue requirements must make calculations and projections that generally arise in rate-making procedures. Additionally, although regulatory structure is not the

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[1] This paper focuses on the approaches of the twenty-nine states.

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doi:10.1016/j.enpol.2011.11.060

Table 1
Summary of states' cost limitation mechanisms. States with restructured electricity markets are shown in italics, hybrid states in underlined italics, and traditionally regulated states in standard font. States in parentheses utilize a mechanism analogous to the listed cost limitation.

Approach	Description	States
Annual cost caps on utilities' annual revenue requirement	Limits additional costs as % of expected annual net retail revenue requirement.	Kansas, *Ohio*, *Oregon*, Washington, (*Maryland, Delaware, Maine*)[a]
Retail rate impact limitation	Limits additional costs as % of expected total of customers' bills.	Colorado, *Illinois*, Missouri, New Mexico
Set surcharge on customers' bills	Caps monthly surcharge on customers' bills at a set amount.	Arizona[b], *Michigan*, North Carolina
Cap on total expenditures	Above-market price contracts limited by total fund of $770+ million allocated among IOUs.	*California*
Alternative compliance payment	Sets an amount utilities pay to a central fund instead of procuring renewable energy; serves as de facto cap.	*Connecticut, D.C., Delaware, Illinois, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, Ohio, Oregon, Pennsylvania, Rhode Island*, (*Texas*)[c]
Public benefits funds	Funds renewable energy in the state, thus indirectly mitigating cost impacts to consumers of RPS requirements. Often Alternative Compliance Payments fund PBFs.	*Connecticut, D.C., Delaware, Illinois, Maine, Massachusetts, , New Hampshire, New Jersey, New York*[d], *Ohio*, *Oregon*, *Pennsylvania, Rhode Island*, (*California*, Minnesota, *Michigan*, *Montana*, Wisconsin)[e]
Cap on individual contracts	Limits procurement of contracts priced above set % above market-price.	*Montana*, Hawaii
Ad hoc agency discretion:		
No cost cap, "just and reasonable" review	No set limitations on costs. PUCs use traditional reasonableness review. May include waivers.	Iowa, Minnesota, Wisconsin
Rider review	PUC reviews utilities' riders under just and reasonable standard	Arizona, Eastern Wisconsin
Contract review	PUC reviews procurement contracts under modified just and reasonable standard.	*Nevada*
Other off-ramps (waivers, freezes)[f]		Arizona, *California*, Colorado, *Connecticut, Delaware*, Hawaii, *Illinois*, *Maryland, Maine, Michigan*, Minnesota, Missouri, *Montana*, *Nevada*, *New Hampshire, New Jersey*, New Mexico, North Carolina, *Ohio*, *Oregon*, *Pennsylvania, Rhode Island, Texas*, Washington, Wisconsin

[a] These states use alternative compliance mechanisms, but also have an "off-ramp" provision which allows a utility to request delays or waivers of its compliance if it can prove compliance costs exceed a set % of its annual sales revenues.
[b] Utilities may adopt the sample tariff, or one "substantially similar." This provides more flexible surcharge pricing than N.C. or Michigan.
[c] Texas's penalty provision may constitute a de facto price ceiling, analogous to an alternative compliance mechanism. PUCT Substantive Rule 25.173(p).
[d] New York's PBF, centrally administered, is funded by a non-bypassable volumetric "System benefits/RPS charge" applied to all major utilities' customers' bills.
[e] These states have PBFs that are not funded by ACPs.
[f] For a comprehensive list of waivers, see Union of Concerned Scientists' RPS Toolkit on Escape Clauses, at http://go.ucsusa.org/cgi-bin/RES/state_standards.

determining factor, the absence of regulatory rate-making oversight in restructured states appears to favor the use of alternative compliance mechanisms and public benefits funds which are more readily implemented in those markets.

In a cost of service jurisdiction, utilities are entitled to a monopoly in their service area and a fair rate of return on capital investments in return for their commitment to serve the public with reliable and non-discriminatory service. The rate of return is calculated based on the interest rates of utilities' liabilities (in debt and equity). When a retail utility is faced with an earnings shortfall, due for example to the projected costs of a new power plant or new regulatory requirements, it undergoes a rate proceeding conducted by the state's public utility commission. In a "rate case," the utility must demonstrate its projected net revenue requirement for a test year including its variable operating costs, annual fixed costs, expected depreciation, and tax gross-up. Traditionally, the test year has been a historic year. Increasingly, regulatory commissions are allowing utilities to establish rates on the basis of anticipated costs of a future test year. Annual fixed costs are calculated as the utility's fixed capital or rate base multiplied by its commission approved rate of return which is typically based on its weighted average cost of capital. Thus derives the classic formula in the cost of service regime:

$$R = O + B(r)$$

where R is the net revenue requirement, O the operating costs, B the capital costs, or "rate base," and r the rate of return.

In a separate proceeding for rate design, rates are determined, among other things, by allocating big R among various ratepayer classes. One major critique of the cost of service model is that, because recovery is prospectively based on the utility's estimates of operating costs, rate base, and rate of return of a historic or future test year, a utility is likely to over- or under-recover its actual costs in the coming years. Another concern is that utilities are motivated to maximize their retail revenue requirements to increase profits. These criticisms may be applicable to the budgeting approaches described herein for cost-of-service utilities.

In restructured states such as Texas, Maryland, and New York, retail electricity providers recover their costs of capital investment through direct sales in the market. There are no rate proceedings, although regulators may retain discretion to freeze rates or otherwise protect consumers if competition fails to do so. Several vertically integrated investor-owned utilities remain in partially restructured states, such as Illinois, where traditional cost-of-service models apply. Cost recovery in restructured states is not assured and providers must look to market forces to allocate their budgets, even in the face of mandates to acquire expensive new renewable resources.

3. Annual cost caps

An appealingly simple approach to limiting RPS costs is to cap the annual costs of implementation. In practice, however, cost caps can be quite complex and suffer from a lack of transparency.

3.1. Cap on utilities' annual revenue expenditure

Several states cap utilities' expenditures on renewable resources for RPS compliance at a set percentage of the utilities' annual retail revenue requirements (the R in the rate case formula $R=O+B(r)$). In these states, utilities that spend a specified percentage of their annual revenue requirement on renewables may be deemed in compliance with the RPS even if they have not met the annual RPS targets. The general formula for this cost cap is

$$C_{RetailRevenue} = \frac{I_{renewables}+I_{alternatives}}{R} \times 100$$

where $C_{Retail\ Revenue}$ is the retail revenue percentage, $I_{renewables}$ the incremental cost of renewable resources, $I_{alternatives}$ the annual costs of alternative compliance mechanisms (renewable energy credits, alternative compliance payments), R the net retail revenue requirement.

It should be noted, however, that only Oregon and Washington strictly set the denominator above to R. Although the Kansas cost cap excuses utilities from penalties for noncompliance if the "incremental rate impact of renewables" exceeds one percent, the impact is based on the revenue requirement from the last rate case.[2] In the restructured state of Ohio, the incremental costs of compliance are compared against "reasonable expected costs of generation" which may not necessarily include the traditional elements of R, depreciation, tax gross-up, and a rate of return.[3] These states are nonetheless discussed herein as their approaches are procedurally similar to, and raise similar concerns as, a strict revenue requirement cap. Overall, the most contentious aspect of this approach is typically how to determine the incremental cost of the renewable resources. With many state RPSs just underway, many states are still working through such determinations.

Ohio, Oregon, Kansas, and Washington utilities all count the levelized annual "incremental costs" of obtaining eligible renewable resources against the cap. The Washington legislature requires utilities to calculate this levelized incremental cost as the difference between the levelized delivered cost of the eligible renewable resource, compared to the levelized delivered cost of an equivalent amount of reasonably available substitute resources that do not qualify as eligible renewable resources, where the resources being compared have the same contract length or facility life (Wa. Admin. Code §§ 194-37-170 et seq, 2011). Oregon's mandate further clarifies that the calculation of levelized annual incremental costs should capture the costs of capital, operating costs, financing, transmission and distribution costs, load following and ancillary services, additional assets, and R&D (Or. Rev. Stat. §§ 469A.100 et seq, 2011). Ohio utilities, on the other hand, may not count against its three percent cap those "construction or environmental expenditures of generation resources" that are commission-approved and passed on to consumers through a surcharge (Ohio Admin. Code § 4901:1-40-07). The substitute non-qualifying resources against which the costs of renewables are compared may vary, although most states currently use a natural gas-fired resource as the proxy resource to represent the cost of non-qualifying electricity (OPUC, 2009).

In addition to the costs of any built renewable resources, the actual annual costs of meeting a state's RPS also often include the costs of renewable energy credits ("RECs"), of acquiring renewable resources via power purchase agreements ("PPAs") or on the spot market, and alternative compliance payments ("ACPs") if the RPS permits. States differ on whether these costs count in the cap. Oregon's cap of four percent of a utility's annual net retail requirement includes the incremental levelized costs of building renewables, as discussed above, as well as the cost of unbundled RECs, and the cost of ACPs (Or. Rev. Stat. §§ 469A.100 et seq, 2011). In Ohio, utilities may not count ACPs toward the cap nor may they recover ACP payments from ratepayers (Rev. Code Ohio § 4928.64, 2011). This limitation reduces the likelihood that utilities will rely on ACPs to meet the RPS unless faced with harsher penalties for noncompliance. For the integrity of the cap, the incremental costs of compliance should be least-cost measures. For this purpose, Washington and Oregon provide that only "prudently incurred costs" are recoverable, a point that will likely be argued in ratemaking or RPS compliance proceedings (Wa. Stat. § 19.285.050, 2011; Or. Rev. Stat. §§ 469A.100 et seq, 2011).

With respect to the denominator of the above equation, states appear generally to allow utilities to base the annual revenue requirement or its analog on a future test year. Washington is one such example (Rev. Code Wa. 19.285.050, 2011; Wa. Admin. Code, §§ 194-37-170 et seq, 2011). In Ohio, too, utilities may compare incremental costs against the "reasonable expected costs of generation" (Ohio Admin. Code § 4901:1-40 et seq, 2011; Ohio Rev. Code Ann. § 4928.64, 2011). An alternative to basing R on the projections of a coming year would be to set the cap off a prior year or of some specified average. Kansas bases its impact calculus on the R used in a utility's previous rate case. Such an approach likely results in a cap that is more certain, less administratively burdensome, and more evenly administered amongst utilities. Another important consideration is whether utilities exclude the incremental compliance costs (the numerator of the cap) from the total net revenue requirement. Oregon excludes these costs so as not to inflate the revenue requirement above that which is required using only conventional resources. Without this modification, the revenue requirement assumes the presence of eligible renewable resources and thereby increases the funds available for renewables under the cap.

Apart from how the cap is calculated, states may choose to implement the cap as either mandatory or voluntary. The Washington legislature made clear, for example, that its cap is voluntary: "a utility may elect to invest more than [the] amount" set forth in the four percent rate cap, and will still be entitled to recover its prudently incurred costs of complying with the RPS (Rev. Code Wa. 19.285.050, 2011). Oregon, Ohio, and Kansas are also voluntary, leaving spending ultimately to the utilities' discretion though presumably subject to approval by their respective commissions.

Finally, states may use a variation of this retail revenue impact as an optional "off-ramp" (or waiver) provision where prices for the RPS are getting too high. In Maryland, in addition to alternative compliance payments, utilities may request that the Maryland Public Service Commission delay the incremental increases in renewable targets if the actual or anticipated cost of compliance is for solar, greater than or equal to 1% of the electric supplier's total annual electricity sales revenues; or for non-solar resources, the greater of 10% of electricity supplier's total annual retail sales or the Tier 1 percentage requirement for that year (Md. Pub. Util. Co. Code §§ 7-701 et seq, 2011).

3.2. Rate cap

Related but not equivalent to a cap on annual net retail revenue requirements is an annual rate impact limitation or "rate cap." A utility's annual retail revenue requirement or the equivalent in deregulated states is apportioned among various ratepayer classes to derive unit rates. The rate cap limits RPS compliance expenditures to an amount that raises the rates of different

[2] Kansas Corporation Commission Staff has expressed concern with the rules and how they should be applied going forward.

[3] No utility has yet triggered Ohio's cost cap and so there is no formal guidance on how the state agency will interpret the provisions of the statute and the implementing rules.

customer classes by a set percentage over a specified period of time. Thus, the formula for this approach generally follows:

$$C_{ratecap} = (l)(B_{net})$$

where $C_{rate\ cap}$ is the rate cap, l the % rate impact limitation, and B_{net} the customers' bills.

Applications of this formula vary, however. The rate impact limitation may be calculated incrementally, or averaged cumulatively over a longer period of time. Customers' bills, B_{net}, may be based on customers' actual costs, or more similarly to the retail revenue requirement cap, on their projected costs.

An incremental rate cap specifies the allowable rate increase for a given year. Colorado's cap authorizes its investor-owned utilities to collect up to two percent of customers' bills annually for the purpose of meeting the RPS (Colo. Code Reg., 4 CCR 723-3-3661(a), 2011). New Mexico's cap ramps up to three percent of customers' aggregated annual electric bills by 2015 (N.M. Admin. Code § 17.9.572.11(C), 2011). Illinois's investor-owned utilities, by 2012, are limited to spending the greater of either an additional 2.015% of the amount paid per kilowatt-hour by eligible customers during the 2007 baseline year or an additional 0.5% of the amount paid per kilowatt-hour by those customers during the previous year on renewable energy resources procured pursuant to the RPS (Ill. Comp. Stat. 20 ILCS 3855/1-75(c), 2011).

In contrast, a cumulative or average rate cap limits the rate increase over a longer period of time. Missouri uses a hybrid cumulative annual rate cap that poses some interesting issues in design and efficacy. Based on the mandate of Missouri's legislature, as of January 2011, utilities in Missouri may spend up to the "maximum average retail rate" increase of one percent to implement the RPS (Rev. Stat. Mo. § 393.1030.2(1), 2010). The Missouri Public Service Commission ("PSC") decided that, in light of the "average" language and the goal of smoothing out "spikes in compliance costs and recovery caused by new technology coming on-line in the beginning of implementation" (Missouri Register, 2010)) the rate cap would be both cumulative over a ten-year period and calculated annually. The planned approach requires utilities to estimate their incremental costs of compliance for each year, based on the difference in levelized costs of a portfolio under the RPS and one without, over a ten-year period. The average annual increase over this succeeding ten year period should not surpass one percent (Mo. Code State Reg., 4 CSR 240-20.100(5)(A), 2011). On its face, this approach appears to limit the annual incremental cost of compliance to approximately one percent of customers' bills for that year while allowing some years to cost more, others less. Yet regulators in the state admit they are worried about how this will work administratively.

Otherwise, the rate cap approach creates many of the same issues inherent to the net retail revenue impact discussed above: what costs of compliance count toward the incremental costs of compliance; what avoided costs establish the base against which the impact is measured; and is the cap mandatory or voluntary? The rate caps in Colorado, Illinois, and Missouri are statutory and mandatory. In Colorado, because utilities have been allowed to loan money into the renewable fund (and earn interest thereon), the cap has not actually served to limit utility expenditures on renewables and this has become an important point of contention. In New Mexico, utilities may petition the New Mexico Public Regulation Commission for a waiver of any above-cap cost requirements, but may not exceed the cap for large customers (>10 million kWh per year) (N.M. Admin. Code § 17.9.572.11(C), 2011). Even when mandatory, however, a rate cap does not necessarily provide transparent customer protection. For example, in Colorado, the PUC has granted utilities waivers from the cost impact calculation for selected resources that are applied toward their RPS compliance obligation.

3.3. Critique of cost caps

Depending on how they are administered, cost caps may be administratively burdensome, non-transparent, and insufficiently protective of consumers. The annual process of determining the cap is time intensive. Moreover, as illustrated by New Mexico, without clear rules, the case-by-case process of determining caps may result in extremely skewed results for different entities. Whether the measures chosen are least-cost is also of grave concern to critics of cost caps. State PUCs likely vary with respect to how stringently they review the renewable measures set forth in utilities' annual compliance plans against a least-cost standard.

Most worrisome about the current approach to implementing caps is that the cap may be looking like no cap at all. Basing the cap on rates or even on revenue requirements allows costs already sunk on compliance to be imbedded in the denominator from which the cost cap derives. As the denominator increases, so does the cost to consumers. While such costs are often necessary to actually fund the aggressive goals of some states, administrators have expressed concern with the lack of transparency to consumers. While statutes may promise a rate increase no greater than a certain percent, the actual cumulative rate increases over many years may be much greater. For example, according to the Colorado PUC staff, after accounting for resources excluded from Colorado's rate impact calculation under a special waiver provision, renewable expenditures since its first compliance year in 2007 have actually far exceeded the two-percent rate cap. (Dalton, W.J., 2009, 2010). According to one estimate by New Mexico Public Regulation Commission Staff, New Mexico's rate increase may be closer to twenty percent over 2006 by 2020.

Another point of contention in determining the retail revenue requirement for purposes of calculating the rate impact of renewables is the inclusion of hypothetical costs in the "no-renewable" base case. For example, the Colorado PUC has required that utilities include both a carbon adder and a capacity credit in their system modeling to determine the rate impact. The carbon adder artificially inflates the apparent cost of the no-renewable revenue requirement while the capacity credit benefits the renewable resource. But neither the carbon cost nor the renewable capacity credit really exists at the present time. The impact of these hypothetical costs and benefits is to artificially diminish the apparent incremental cost of renewable compliance. This approach has been widely criticized in Colorado PUC proceedings by the parties most concerned with the cost impacts of renewable energy acquisitions while being supported by renewable energy advocates.

4. Surcharge on customers' bills

A relatively straight-forward way for utilities to recover RPS compliance costs is through a surcharge, also called a "rate rider" or adjuster, on consumers' bills. Riders allow utilities to directly incorporate into rates the fluctuating prices of traditional operating costs, such as fuel and labor costs, without undergoing multiple rate cases. Some commissions have allowed utilities to treat RPS compliance costs similarly and add cost recovery to customers' bill. States use various methods of calculating riders; for example, a flat system benefits charge or a usage-based adder. Overall, identifying the incremental costs of renewable resources via a bill surcharge—whether calculated on a flat-rate basis or per kWh—allows customers to see how much they are paying for RPS compliance.

A usage-based rider is generally set at a per kWh price. To cover the incremental cost of compliance with Arizona's Renewable Energy Standard, Arizona utilities may assess a monthly surcharge "substantially similar" to the one set forth in the sample tariff upon approval by the Arizona Corporation Commission ("ACC") (Ariz. Admin. Code R 14-2-1808, 2011). The Sample Tariff provides for a monthly surcharge assessed as $.004988 per kWh,[4] and utilities must substantiate their claims for this recovery in a proceeding based on the estimates of their annual implementation plans and the costs likely incurred. In order to protect customers, the rule appears to cap the overall surcharge at a flat rate of $1.05 for residential, $39.00 for small non-residential, and $117.00 for large non-residential. In 2008, most cooperative utilities did adopt the sample tariff's caps. Arizona's cap is not a ceiling, however. The state's largest utility proposed, and the ACC approved, a surcharge well-above the sample rate based on its calculated financing needs. Moreover, the state allows utilities to adjust the surcharge in their tariffs as needed. Additionally, the surcharge does not capture all costs of compliance as utilities may also drop large renewable construction projects into rate base.[5]

A variation of a usage (kWh)-based rider is one in which the rider is calculated as a percentage of a customer's total bill in dollars. Colorado has interpreted its two percent rate cap to allow its utilities to collect an additional two percent from each customer's monthly bill, itemized as the "Renewable Energy Standard Adjustment" or "RESA", to fund RPS compliance. In Colorado, utilities may bank unused portions of annual recovery toward future costs. However, this has led to criticism that the utilities are also incentivized to overspend the funds available under the RESA and earn their commission-authorized rate of return on funds advanced to the RESA, even if, as in the case of one major Colorado utility, the RPS compliance targets have been met or exceeded.[6]

4.1. Critique of surcharges

Overall, riders are more administratively efficient because they minimize the need for rate cases. North Carolina's rider was passed, in part, due to the lobbying efforts of utilities to avoid rate cases. And, in Michigan, which requires a rate case to establish a rider, few utilities have yet done so. With the exception of the banking allowed by Colorado, most states still require the utilities to go through some administrative process of truing up their incremental cost of compliance. The processes are much less cumbersome than rate cap true-ups, however. Another advantage of a surcharge as a cost limitation and recovery mechanism is that utilities have more certainty in their investment decisions. The surcharge caps set a clear benchmark. Utilities feel more assured that they can recover at least as much as they need, so long as they do not spend more than the statutory caps. One regulator has commented that this approach avoids imposing a "moving target" on utilities, as opposed to some of the cost caps for example.

The approach presents potential trade-offs for both customers, electricity providers, and the environment, as well. For customers, when costs are passed through with less scrutiny than in a ratemaking case, there is no guarantee that the surcharge is funding least-cost resources. Colorado's two-percent surcharge, passed directly through to customers, raises these concerns as well as whether the cap is actually protective. As described above, the RESA rider allows utilities to automatically recover the *maximum* allowable rate and bank recovery toward future costs, or even earn a return on advancing future funds. In Colorado as in many other RPS states, proponents have often argued that the RPS targets represent a floor, not a ceiling, and so utilities should be able to acquire renewables up to the limit of the cost cap. In contrast, RPS critics argue that the cap should represent an unambiguous limitation on the cost of meeting RPS targets, not a de facto minimum level of expenditures. Finally, whereas North Carolina and Michigan's surcharges are fixed and cannot be amended except by legislation, those states' RPSs may be compromised if the costs of renewables surpass what has been forecasted. North Carolina may reach its overall projected expenditures in just 5–6 years (N.C. Gen. Stat. § 62-133.8(i), 2011).

Arizona's hybrid approach attempts to remedy some of these issues by permitting utilities to apply capital expenditures to rate base and adjustable surcharges upon petition. However, the trade-off is less administrative efficiency and more of a moving target on actual costs. With so many off-ramps from the fixed tariff, customers' protection ultimately rests with the Commissioners' decisions to approve implementation plans.

5. Cap on utilities' total expenditures

One state that currently limits compliance costs to a specified dollar amount for its investor-owned utilities is California. California's approach is the so-called AMF Program (above-market price referent funds program) (Cal. Pub Util. Code § 399.15, 2011; Cal Pub. Res. Code §25740.5, 2011).The total AMFs available for the implementing period is equivalent to the amount of funds that would have been available if utilities were still required to charge a Public Goods Charge to its customers through 2012: over $770 million. Public Utilities Code § 399.15 provides that each of the state's major investor-owned utilities is allocated a specific amount of this total from which it will be eligible for cost recovery of above-market contracts in its rates subject to certain criteria.[7] Contracts must meet specific eligibility criteria related, in part, to cost-competitiveness and longevity (Cal. SB 1036, 2007; Cal. Resolution E-4199, 16, 2009). The cap is voluntary in that a utility is relieved of procuring any other above-market cost contracts in compliance with the RPS once it reaches the cap, but may petition the California Public Utility Commission ("CPUC") to approve above-cap cost recovery. The CPUC may also require a utility to procure additional renewables after the utility has reached the cap. In this regime, all contracts eligible for AMF-funds, and the entire contract price, must be counted against the cap.

The CPUC must determine whether a contract is eligible for AMF-funds by considering the difference between a project's levelized contract price (per MWh) and a specific market price referent ("MPR"). Annually, the CPUC adopts by resolution MPRs based on the presumptive cost of electricity from a non-renewable energy source, including the long-term market price of electricity for fixed contracts, the long-term fuel and operating costs for comparable new generating facilities, and the value of the electricity's characteristics such as peaking or baseload. Thus, the positive difference between a contract price and the MPR counts toward the electrical corporations' cost limitation. The CPUC does not review unbundled RECs purchases—permitted for compliance since 2010—under the AMF program and so their costs do not count against the utilities' cap (Cal. Pub Util. Code §

[4] This is 5.7 times the amount initially allowed.

[5] For example, Arizona Public Service Company is seeking to put its $500 million new 100-MW PV system into rate base. Interview with Staff at Arizona Corporation Commission (Dec. 3, 2010); Docket E-0 1345A- 10-0262, APS Application (July 2010).

[6] In recently issued decisions C11-1079 and C11-1080, the Colorado PUC has also expressed concern with the "deviations between budgeted RESA expenditures and actual charges against the RESA account (Colorado Public Utilities Commission, 2011a,b)."

[7] BVES $ 328,376; PG&E $ 381,969,452; SDG&E $ 69,028,864; SCE $ 322,107,744; Total $ 773,434,436. Resolution E-4199, 16.

399.15, 2011). For price protection, the CPUC has set a de facto REC price cap of $50 and limits utilities to meeting 25% of their compliance obligations with tradable RECs.

5.1. Critique of California's cap

The AMF program constitutes a significant change from the state's former cost curtailment program. The California legislature amended the former cost curtailment process of using Supplemental Energy Payments (SEPs) to cover above-market costs in 2007 in order to streamline the process. Formerly, utilities collected a Public Good Charge ("PCG") via customers' bills, part of which was transferred to the New Renewables Resource Account (NRRA) in the Renewable Resource Trust Fund to fund SEPs. The California Energy Commission administered these funds for the above-market costs of electric corporations. There was no individual utility cap. Once the funds were fully allocated, utilities were required to procure in fulfillment of the RPS only those renewable resources that were at or below market price. In contrast, the new method utilizes rate increases, not the PCG, and requires the CPUC's approval of both the above-market costs and the procurement contracts in order for cost recovery of AMFs that fall within each utility's overall cap. The CPUC has identified several added benefits of the new methodology: (1) to further promote the goals of RPS program (in-state, long-term, stable), (2) to support viable least-cost best-fit renewable energy projects, (3) to allocate AMFs transparently, and (4) to result in simpler administration of AMFs (Resolution E-4199, 10, 2009).

On the other hand, California's current approach presents two disadvantages for utilities. First, the process is administratively burdensome. A utility must seek agency approval for every contract. Second, it is unclear whether the specified caps will allow utilities to meet California's aggressive RPS targets. Once a utility reaches its cap, the utility would be required under this approach to seek cost recovery to procure additional resources. Utilities therefore may not be inclined to petition to exceed the cap in order to meet the RPS. It is worth noting that the CPUC may have alleviated this concern when it permitted unbundled RECs for compliance.

6. Alternative compliance payments

6.1. Alternative compliance payment as de facto cap

Many restructured states utilize an alternative compliance payment ("ACP"), either alone or in conjunction with other cost curtailment mechanisms. The ACP enables electric distributors and retail providers to pay a specified amount into a central fund in lieu of procuring renewable energy or buying RECs. For those states in which the ACP is recoverable,[8] the ACP serves as a de facto cap in that it sets the price ceiling for the cost of compliance. Where ACPs are required, the ACP price constitutes the cost of RPS compliance. The alternative electricity suppliers in Illinois (distinct from the vertically-integrated utilities discussed above) must fulfill half of their RPS requirements through ACPs, for example (Ill. Comp. Stat. 220 ILCS 5/16-115D, 2011). In states where the ACP is optional, rational entities will tend to opt for other means of compliance (RECs, PPAs, etc.) up to point at which those costs are equivalent to or higher than the ACP. Where prices of procurement surpass the ACP price, without additional incentives or obligations, utilities will opt for the ACP which sets the ceiling price. Whether ACPs are recoverable, how they are priced, and other nuances contribute to the efficacy of this mechanism as a cost cap. This section discusses some of the states that rely on ACPs for RPS cost control and their overarching issues.

States differ with respect to the burden utilities bear for obtaining approval of ACP costs from the state agencies. In Maine, Massachusetts, New Hampshire, New Jersey, and Rhode Island, utilities may recover any cost of ACPs deemed reasonable and prudent by the state commissions (35-A Maine Rev. Stat. § 3210, 2011 ; Mass. Gen. Law ch. 25A, § 11F, 2011; N.H. Rev. Stat. § 362-F, 2011; N.J. Stat. § 48:3-87, 2011; R.I. Gen. Laws § 39-26-1 et seq., 2011). In contrast, the ACP costs incurred by providers in Delaware, Oregon, Maryland, Pennsylvania, and D.C. may only be passed on to consumers if they demonstrate in addition to general reasonableness (1) the ACP is the least cost measure to ratepayers compared to the purchase of renewable energy credits to comply with the RPS; or (2) there are insufficient renewable energy credits available for the electric supplier to comply with the RPS causing the Commission to find a force majeure (26 Del. Code § 358, 2011; Md. Pub. Util. Co. Code §§ 7-701 et seq, 2011; Penn. Stat., 73 P.S. § 1648.3, 2011; Penn. Admin. Code, 52 PA ADC § 75.67, 2011; D.C. Code § 34-1431 et seq, 2011; Or. Rev. Stat. §§ 469A.100 et seq, 2011). Maryland also allows cost recovery if (3) a wholesale electricity supplier defaults or otherwise fails to deliver RECs under a commission-approved supply contract (Md Public Util Comp § 7-706, 2011). Additionally, whereas cost recovery of ACPs generally occurs as a specific surcharge on customers' bills, at least one state allows utilities to petition the state agency for inclusion of ACPs in rate base. Prudence review by a state commission subjects a utility's ACPs to the commission's further scrutiny. Oregon has expressly prohibited ACPs from being recovered in rate base (Or. Rev. Stat. §§ 469A.100 et seq, 2011).

ACP prices also vary. The total ACP is calculated by multiplying the alternative compliance payment rate by the number of deficient kilowatt-hours. The ACP rate may be established by statute or by state regulators. For example in New Jersey, the ACP is $50 per MWh, while the solar ACP drops from over $700 per MWh to about $600 per MWh by 2016 (N.J. Admin. Code § § 14:8-1.1 et seq, 2011). State legislatures may also establish guidelines for ACPs via statute. Although Texas does not currently have an ACP, the state legislature has expressly authorized its commission to establish an ACP which, for compliance that could otherwise be satisfied with a REC from wind, may not be less than $2.50 per credit or greater than $20 per credit (Texas Util Code § 39.904(o)). Presently Texas has only a penalty provision that itself serves as a de facto cap by penalizing entities $50 for each MWh a utility falls short of compliance with the RPS targets. Finally, Illinois's AC payments are derived from the state's statutory rate cap. The state Power Agency sets the ACP price for each service area equal to "the maximum allowable annual estimated average net increase" calculated in the annual procurement planning of the state's large utilities for that service area (PUCT Substantive Rule 25.173(p) (2011).

Some states may "freeze" increasing RPS targets if costs of compliance exceed a specific indicator. Maine uses its ACP as such an indicator. The Maine PUC may suspend annual increases in the RPS standard if ACPs are used to achieve more than 50% of the compliance obligation of utilities. Alternatively, the Maine PUC may also suspend the RPS if it determines that meeting the target is overly burdensome to customers.

6.2. ACPs generally fund public benefits funds with several exceptions

ACPs are extremely important in reducing the overall cost impacts to consumers of increasing renewable generation

[8] Where not recoverable, as in Ohio (discussed above), the ACP merely serves as a penalty for non-compliance.

because they often help fund a central public benefits fund that supports renewable development in the state. States with PBFs include: California, Connecticut, D.C., Delaware, Illinois, Maine, Massachusetts, Minnesota, Michigan, Montana, New Hampshire, New Jersey, New York, Ohio, Oregon, Pennsylvania, Rhode Island, and Wisconsin.

PBFs are viewed as a complement to, not an integral part of, most state RPSs with the exception of New York. In New York, the New York State Energy Research and Development Authority ("NYSERDA") administers the state's 30x15 RPS with funds collected from a non-bypassable volumetric "System Benefits/ RPS Charge" on major utilities' customers' bills (NY PSC Order Case 03-E-0188, 2004; http://www.nyserda.org/rps/index.asp). The RPS portion of this charge was approximately $2.87 in 2007 for a typical residential customer and $30.24 for a typical non-residential customer. NYSERDA solicits renewable projects with these funds, which have culminated to date in 38 facilities under contract to provide a combined 4,276,140 MWh of renewable energy per year, from approximately 1,532 MW of new renewable capacity.

PBFs in most other states are managed by a neutral entity that solicits projects based on specific criteria. Many state PBFs are managed by a governmental office. Others are managed by corporations or non-profit organizations created specifically to manage the fund (e.g. Oregon, Rhode Island, and Connecticut). At least one state, Arizona, allows utilities to manage renewable energy funds (Az. Corp. Comm. Dec. No. 69663, 86 2007). With respect to funding, a few states fund their PBFs for renewables from something altogether separate from ACPs, such as a public purpose charge (Oregon, New Jersey) or leftover savings from other projects (Michigan). Some states also keep separate funds collected for specific set-asides. For example, Maryland and Massachusetts require that ACPs for the solar obligation only be used to support new solar resources in the state (Md. Code § 9-20B-05, 2011 ; Code Mass. Reg., 225 CMR 14.07, 2011).

6.3. Critique of ACPs and public benefits funds

Where they exist, ACPs become the ultimate price ceiling on compliance for utilities and their consumers. In this way, they are extremely important for consumer protection, particularly where the costs of RECs or renewables are unknown or prohibitively high. At the same time, because ACPs set the ceiling, the price must be properly set or else risk the integrity of the RPS. If the ACP price is too low, electricity providers as rational business entities may be encouraged to choose the alternative and not procure renewables. If too high, on the other hand, or if not-recoverable, the ACP merely becomes a penalty and not a safety valve. In states where cost recovery of compliance is a near foregone conclusion, however, the ACP price may do nothing to affect utilities' procurement decisions even if it means higher prices for consumers. In addition to price, the efficacy of the ACP as a cost limitation mechanism also rests on how effectively ACP funds are used to procure renewable resources. If ACPs are not used, or not used efficiently, to fund renewable projects, they cannot be considered a cost curtailment mechanism. By not efficiently funding renewable projects today, faulty ACPs either inhibit the ultimate goals of the RPS or raise the costs of eventually meeting those goals by drawing out the process of compliance.

Different issues arise with PBFs that are not funded by ACPs. A hard-line surcharge such as that of New York funds renewables with more certainty than other approaches, but does not necessarily ensure that the state reaches its targets and at the lowest price. The government administrator likely does a better job on average than a utility considering least-cost alternatives, however.

7. Cap on contract price

Two states, Montana and Hawaii, utilize a cost limitation on a per-contract basis. In both states, utilities may petition the state agencies in the event that they are unable to meet their RPS obligations and request for a waiver if contracts for procuring generation or renewable energy credits were above-market price for other available resources. In Montana, a competitive retail provider is not obligated to take electricity from an eligible renewable resource unless the total cost of electricity from that eligible resource, including the associated cost of ancillary services necessary to manage the transmission grid and firm the resource, is less than or equal to bids in the competitive bidding process from other electricity suppliers for the equivalent quantity of power over the equivalent contract term (Mt. Code Admin. 69-3-2007, 2011; Mt. Admin. Rules 38.5.8301(4)). In contrast, a regulated public utility in Montana is not obligated to take electricity from an eligible renewable resource unless the cost per kilowatt-hour of the generation does not exceed by more than 15% the cost of power from other alternate available generating resources. In Hawaii, utilities may petition the Public Utilities Commission for a waiver of a penalty for failure to meet the RPS (Haw. Rev. Stat. Ann. § § 269-92, 2011). The Commission may grant such a waiver if it determines a utility is unable to meet the RPS "due to reasons beyond the reasonable control of an electric utility" including, in part, inability to acquire sufficient cost effective renewable electrical energy (Haw. Rev. Stat. Ann. § § 269-92, 2011). "Cost-effective" means the ability to produce or purchase electric energy or firm capacity, or both, from renewable energy resources at or below avoided costs consistent with the methodology set by the PUC.

7.1. Critique of cap on individual contracts

This mechanism is likely cost-protective of consumers, holding the cost of compliance close to the cost of alternate sources (i.e. gas). Because the cap is generally enforced by state regulatory bodies, however, this approach may create an administrative hurdle that could prevent utilities from acquiring the most cost effective resource. Moreover, the ultimate discretion lies with the agency to determine whether the resources are really least-cost. As discussed more below, such discretion leads to uncertainty for utilities, investors, project developers, customers, and the state. On the other hand, if utilities utilize this limitation to its potential, the mechanism could severely reduce the integrity of the RPS as the price of renewables may often be higher than alternative resources.

8. Ad hoc agency discretion to curtail costs

Some states have not relied on specific cost curtailment mechanisms but instead look to the state commissions to limit excessive costs to consumers by exercising their traditional duty to ensure just and reasonable rates. Depending on whether the state is restructured or not, and on its legislative mandates, states without a cap often rely on their statutory obligation to ensure just and reasonable rates in rate cases, the review of rate riders, and the approval of individual contracts. The states without a defined cap include Minnesota, Wisconsin, Iowa, and Nevada. Additionally, almost all states embody state regulatory agencies with sufficient discretion to waive certain compliance provisions where concerns of cost and fairness are raised.

8.1. Just and reasonable review in ratemaking

In Minnesota, pursuant to the cost-of-service model, utilities may recover any prudently and reasonably incurred costs if approved by the Minnesota Public Utilities Commission. There are no specified caps on rate increases or utilities' budgets for implementing the RPS. The legislature granted the PUC the authority, however, to grant modifications or waivers of utilities' compliance obligations upon request if the commission find it is "in the public interest" to do so (Minn. Stat. § 216B.1691, Subd. 2b, 2011). The enacting legislation clarifies that the PUC must consider, among other factors, "the impact of implementing the standard on its customers' utility costs, including the economic and competitive pressure on the utility's customer." With regard to a request for a waiver based on costs to customers, the PUC may only grant a waiver "if it finds implementation would cause significant rate impact." There are no additional rules or regulations that clarify exactly what constitutes a "significant rate impact." To date, all 118 electric providers in the state have complied with the law every year since it was revised in 2005, and not one has requested a compliance deadline extension. Therefore, because no utilities have yet come forward with a petition for a waiver, Staff at the PUC was unable to discuss the process further. Decisions would likely be made on a case by case basis unless the legislature amends the statute in the coming years.

Iowa's Alternative Energy Law ("AEL"), which requires the state's two vertically-integrated utilities either to own a certain amount of renewable energy in the state or to procure long-term contracts for such sources in the utilities' service area, applies only the traditional just and reasonable cost standard to renewable procurement (Iowa Code § 476.43, 2009). For new facilities, the state's Utility Board may adopt individual utility or uniform statewide facility rates "sufficient to stimulate the development of alternative energy production" that are deemed reasonable in light of economic and other factors. Power purchased by contracts must be competitively priced, "based on the electric utility's current purchased power costs." The AEL targets are sufficiently conservation that they likely do not require significant cost curtailment.

8.2. Contract review

Pursuant to the legislation enacting Nevada's Energy Portfolio Standard, the Public Utility Commission of Nevada ("PUCN") must review and approve every new contract for renewable energy procurement or energy efficiency under a *modified* just and reasonable standard (Nev. Admin. Code § 704.8885, 2011). The modified standard requires the PUCN to consider factors such as price reasonableness, characteristics of the resource, fitness and viability of the project, and the terms and conditions of the contract. With respect to price reasonableness, the PUCN must explicitly consider: (1) consistency with long-term planning, (2) reasonableness of price indexing; (3) environmental costs and reductions; (4) net economic impact and environmental costs and benefits; (5) economic benefits to the state; (6) diversity of energy resources; (7) transmission costs and benefits; and (8) the utility's long-term avoided costs. The review of whether specific contracts are just and reasonable may impact whether the utility may be exempted from meeting all of its compliance obligations. A utility may petition the PUCN for exemption from an administrative fine or other action resulting from its failure to meet the RPS and must show that there was not a sufficient supply of contracts with just and reasonable terms available to the utility. This review is likely similar to that in Hawaii and Montana but less constrained as the PUCN appears to have greater discretion to consider factors besides the costs of alternative sources.

8.3. Freeze provisions

Some states have statutory or regulatory freeze provisions that allow agencies to freeze incremental increases of RPS targets when compliance costs reach specific cost caps. Some states also give state agencies more discretion to freeze the RPS if costs become excessive. For example, New Hampshire's statute states that the PUC, after notice and hearing, may accelerate or delay by up to one year, any given year's incremental increase in class I or II renewable requirements for "good cause". PUC rules state that the term "good cause" means that the acceleration or delay would reasonably be expected to: (1) increase investment in renewable energy generation in New Hampshire; or (2) mitigate cost increases to retail electric rates for New Hampshire customers without materially hindering the development of renewable resources.

8.4. Waivers

In addition to cost limitations, most states also expressly provide state agencies the discretion to grant entities waivers. Some provisions appear broad enough to allow for waivers due to cost impacts to consumers. In Ohio, in addition to the net revenue requirement rate cap and an alternative compliance payment, the Commission may identify the existence of force majeure conditions and grant waivers (Ohio Admin. Code § 4901:1-40 et seq, 2011). The North Carolina PUC may modify or delay the RPS provisions if the PUC determines that it is "in the public interest" (N.C. Gen. Stat. § 62-133.8(i), 2011). In New Mexico, utilities may seek a waiver for "good cause" (N.M. Rule 14-2-1816, 2011). Waivers may be from the RPS compliance targets or, as in Colorado, from the rate impact provisions themselves (Colorado PUC, 2007).

8.5. Critique of agency discretion

Utilizing traditional commission review to set the cost of RPS compliance on one hand makes a lot of sense. Utilities and commissions follow traditional administrative processes to work through issues that are at the same time novel and familiar. In doing so, they also hew to the regulatory compact. Utilities likely can recover costs they can reasonably justify. Moreover, there is no seemingly arbitrary point (a cap) at which compliance obligations stop short of the RPS targets. Further, customers are not lured into a false sense of security from a non-transparent cap.

On the other hand, traditional agency review creates its own risks and an enormous amount of uncertainty. In addition to a significant administrative burden, there is a risk that case-by-case decisions to approve utilities' costs of compliance may be arbitrary, politically motivated, or unfair, may favor one stakeholder group over another, and may prioritize utilities' return on investment over the costs to consumers. The more discretion that is left to a state commission, a body that is subject to political influence or other motivations, the greater the level of uncertainty to electricity providers and consumers alike.

9. Conclusion

In the face of the uncertain and likely increasing costs of implementing state RPSs, lawmakers, regulators, and interested parties must walk a fine line between consumer protection and maintaining the integrity of the policies. The range of mechanisms designed to mitigate the costs of RPS compliance embodies these competing concerns. At first glance, a hard-line cost cap would appear to protect consumers from excessive price increases due to increasing renewable energy penetration. A closer look suggests that many states with a cap actually utilize a hybrid incremental cost cap that may compromise consumer protection and transparency in order to satisfy aspirational renewable targets and utilities' needs. Alternatively, traditional agency discretion in rate regulation leaves state commissioners with the job of balancing dueling considerations of consumer protection and RPS integrity. Although an ample reserve of discretion must be left to state commissions to allow for flexibility in this extremely complicated area of renewable energy policy, there must be safeguards to ensure waivers are limited and granted in an even-handed fashion. Additionally, implementation of the various mechanisms described above also raises issues of utilities' ability to recover, transparency, and administrative burdens.

Although the costs of implementing state RPSs are uncertain, it is clear that the transition to cleaner energy will not come free. While utilities and regulators must work to mitigate cost increases shouldered by consumers, they should not hide cost increases through sunk costs, complex administrative proceedings, convoluted opaque rate cap methodologies, or misnomers. Given how intricately different state electricity markets are structured, we do not presume to prescribe only one preferred cost limitation approach that will work in all cases. Rather, this preliminary survey suggests that the most important factors in implementing any effective and credible mechanism to curtail costs are clarity of the rule, consistency in application, and, above all, transparency for customers.

Acknowledgments

The authors would like to thank the staffs at state regulatory agencies across the U.S. that provided their valuable insight and time. Many of the concerns raised with respect to RPS cost control mechanisms were identified in discussions with state regulatory agency staff who could only speak without attribution. The opinions expressed herein are solely those of the authors and do not necessarily reflect the views of any state regulatory body or governmental authority.

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Energy Policy 39 (2011) 6280–6290

Contents lists available at ScienceDirect

Energy Policy

journal homepage: www.elsevier.com/locate/enpol

The potential impacts of grid-connected distributed generation and how to address them: A review of technical and non-technical factors

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ARTICLE INFO

Article history:
Received 12 May 2011
Accepted 11 July 2011
Available online 27 July 2011

Keywords:
Distributed generation
Grid-connected
Non-technical factors

ABSTRACT

Distributed generation is being deployed at increasing levels of penetration on electricity grids worldwide. It can have positive impacts on the network, but also negative impacts if integration is not properly managed. This is especially true of photovoltaics, in part because it's output fluctuates significantly and in part because it is being rapidly deployed in many countries. Potential positive impacts on grid operation can include reduced network flows and hence reduced losses and voltage drops. Potential negative impacts at high penetrations include voltage fluctuations, voltage rise and reverse power flow, power fluctuations, power factor changes, frequency regulation and harmonics, unintentional islanding, fault currents and grounding issues. This paper firstly reviews each of these impacts in detail, along with the current technical approaches available to address them. The second section of this paper discusses key non-technical factors, such as appropriate policies and institutional frameworks, which are essential to effectively coordinate the development and deployment of the different technical solutions most appropriate for particular jurisdictions. These frameworks will be different for different jurisdictions, and so no single approach will be appropriate worldwide.

1. Introduction

Distributed generation technologies are typically defined as small-scale generation options that connect to the electrical distribution network. Here our focus is on the low voltage end of the distribution network, around 10–15 kV. As the range of such technologies increases, and a number have begun to achieve significant penetrations, there has been growing attention to their potential impacts, both positive and negative, on the network. The technologies themselves vary significantly in their operation and potential impacts. Cogeneration, micro-hydro and bioenergy generally have limited weather-related dependencies and hence offer relatively constant and predictable energy output by comparison with wind and solar technologies. Small-scale grid-connected wind is relatively rare at present, and therefore currently having very little impact on distribution networks in most countries. Where small-scale wind is used at higher penetrations, such as on remote mini-grids, well developed technologies such as battery storage and diesel generator backup are currently used. Photovoltaics (PV) on the other hand, is being rapidly deployed in many countries at present, is based on a source of energy that can fluctuate significantly over timescales from seconds through hours to days and seasonally, and is only partially predictable. PV technology itself has almost no inherent energy storage. As such it can have significant negative power quality impacts at high penetrations if appropriate measures are not implemented. Such penetrations are now being seen in some countries due to the extraordinary take-up of small-scale (often residential-scale) PV systems over recent years. As a result, solar power and its associated inverter connection to the grid is the predominant focus of this paper. Nonetheless, the discussed grid impacts capture all those that other DG technologies are likely to present.

Potential positive impacts on grid operation can include reduced network flows and hence reduced losses and voltage drops. Potential negative impacts include voltage fluctuations, voltage rise and reverse power flow, power fluctuations, power factor changes, frequency regulation and harmonics, unintentional islanding, fault currents and grounding issues.

This paper first describes each of these impacts along with the current technical approaches to address them. It is clear there is no 'one size fits all' solution for any of these impacts, and even where technical solutions exist, they may not be implemented because of lack of appropriate policies and institutional frameworks. Thus, the second section of this paper discusses the non-technical factors that influence which types of technological solutions are most likely to be appropriate, and provides suggestions for increasing the likelihood of best practise.

2. Addressing grid integration issues

Electricity grids must have standard conditions of supply to ensure that end-use equipment and infrastructure can operate

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0301-4215/$ - see front matter
doi:10.1016/j.enpol.2011.07.027

safely and effectively. These conditions are commonly referred to as power quality requirements and are defined in standards or by supply authorities. As discussed below, they most commonly relate to voltage and frequency regulation, power factor correction and harmonics. In all distribution networks, challenges to maintaining these power quality requirements arise from the technical characteristics and end-user operation of electrical loads, and the network equipment and lines. Some loads have significant power demands that increase network current flows pulling down line voltage (such as electric hot water heaters and large air-conditioners). Some have very short-lived but major power draws on start-up (such as standard induction motors) driving voltage fluctuations. Some have significant reactive power needs (again including motors) or create significant harmonics (such as computer power supplies and fluorescent lighting). Power quality at different points of the distribution network at any time is impacted by the aggregate impacts of loads and network equipment in highly complex ways.

DG connected to the distribution network can significantly influence these aggregated impacts. Some impacts can be positive – for example where PV generation is closely correlated to air-conditioning loads and hence reduces the peak network currents seen in the network. At other times DG can have adverse impacts – for example where maximum PV generation occurs at times of minimum load hence reducing current flows below what they would otherwise be, and causing voltage rise in the network. Other issues related to the connection of DG to a network that are not generally also seen with loads include possible unintentional islanding,[1] fault currents, grounding and highly correlated power output fluctuations, all issues that can have significant impacts on power quality yet also system safety, security and control. The following discusses these issues as they relate to DG, as well as options for addressing them. We consider options ranging from those currently being used through to those undergoing trials or still in the R&D stage.

2.1. *Voltage fluctuation and regulation*

Voltage fluctuation is a change or swing in voltage, and can be problematic if it moves outside specified values. It affects the performance of many household appliances and can consist of variations in the peak and RMS (root mean square) voltage on the line. Supply authorities or government regulators generally stipulate the maximum acceptable deviation from the nominal voltage as seen by the customers. Effects on loads are usually noticed when the voltage fluctuates more than 10% above or below the nominal voltage, and the severity of the effects depend upon the duration of the change. Extended undervoltage causes "brownouts"—characterised by dimming of lights and inability to power some equipment such as fridge compressors. Extended overvoltage decreases the life of most equipment (end-user and networks) and can damage sensitive electronic equipment.

DG systems are relevant to voltage regulation because they are not only affected by voltage fluctuations that occur on the grid, but can cause voltage fluctuations themselves—where the latter effects can be divided into voltage imbalance, voltage rise leading to reverse power flow, and power output fluctuations. These are discussed below.

2.1.1. *Grid-derived voltage fluctuations*

Inverters are generally designed to operate in what is known as grid 'voltage-following' mode and to disconnect DG when the grid voltage moves outside set parameters. This is both to help ensure they contribute suitable power quality as well as help to protect against unintentional islanding and protect the inverter (discussed below) (Hudson, 2010). Where there are large numbers of DG systems or large DG systems on a particular feeder, their automatic disconnection due to out of range voltage can be problematic because the network will then have to provide additional power (SEGIS, 2007). For example, where there is voltage sag on the grid due to a sudden increase in demand, inverters may disconnect while the loads do not, exacerbating the problem and potentially overloading the network causing a brownout or blackout (Miller and Ye, 2003).

To avoid this happening, voltage sag tolerances could be broadened and where possible, Low Voltage Ride-through Techniques (LVRT) could be incorporated into inverter design. LVRT allows inverters to continue to operate for a defined period if the grid voltage is moderately low but they will still disconnect rapidly if the grid voltage drops too low. In Germany, LVRT standards are now incorporated into grid-connection standards (Tröster, 2009); this is also true in some parts of the USA. Many inverters do not come standard with these capabilities but simple software updates generally could incorporate this feature if required by standards.

Some inverter designs can also be configured to operate in 'voltage-regulating' mode, where they actively attempt to influence the network voltage at the point of connection. Inverters operating in voltage-regulating mode help boost network voltage by injecting reactive power during voltage sags,[2] as well as reduce network voltage by drawing reactive power during voltage rise. However, this capability is not allowed under some national standards—for example, Australian Standard AS4777.2 requires that inverters operate at close to unity power factor (i.e. inject only real power into the grid) unless they have been specifically approved by electricity utilities to control power factor or voltage at the point of connection. In addition, all inverters have limits on their operation and even in voltage regulation mode external factors on the grid may force the voltage outside normal limits—in which case the inverter disconnects (McGranaghan et al., 2008).

Thus, connection standards need to be developed to incorporate and allow inverters to provide reactive power where appropriate. Such standards would need to ensure that this capability did not interfere with any islanding detection systems (discussed below). Utility staff may also need to be trained regarding integration of such inverters with other options used to provide voltage regulation—such as SVCs (Static VAr Compensator) or STATCOMS (static synchronous compensators).

2.1.2. *Voltage imbalance*

Voltage imbalance is when the amplitude of each phase voltage is different in a three-phase system or the phase difference is not exactly 120° (PVPS-T10, 2009). Single phase DG (or loads for that matter) installed disproportionately on a single phase may cause severely unbalanced networks leading to damage to controls or transformers (SEGIS, 2007). Voltage imbalance will have a negative impact on small distributed three-phase generators, such as temperature rise of rotors, noise, and vibration. It can also have an impact on some loads such as motors and power electronic devices (PVPS-T10, 2009).

Thus, at high PV penetrations, the cumulative size of all systems connected to each phase should be as equal as possible. All systems above a minimum power output level of between 5 and 10 kW typically should have a balanced three-phase

[1] Unintentional islanding is when a section of the electricity network remains 'live', despite being disconnected from the main network, because of distributed generation that continues to operate.

[2] For example due to disturbances in the grid or sudden changes in the renewable energy resource (e.g. cloud cover).

output. The maximum single phase power rating will depend on local conditions and the network to which they are connected.

2.1.3. Voltage rise and reverse power flow

Traditional centralised power networks involve power flow in one direction only: from power plant to transmission network, to distribution network, to load. These flows are managed through the dispatch of generation yet also network equipment such as tap-change transformers that can adjust network voltages. Other voltage regulation technologies include those that adjust reactive power demand such as Static VAr Compensators (Mizuho, 2008). Voltage settings at the last controllable transformer before the loads are often set at 5–10% higher than the nominal end-use voltage in order to accommodate line losses. These losses and associated voltage drops depend, of course on the actual current flows that are being demanded by the load.

The introduction of distributed generation changes the dynamic of the network because power flows may change significantly and potentially in both directions. In other words, the network becomes an active system with power flows and voltages determined by the mix of centralised and distributed generators as well as the load. With significant levels of DG, localised overvoltage can occur, and the voltage at the load end may be greater than the voltage on the normal supply side of the line—this is known as the voltage rise and can result in reverse power flow (Demirok et al., 2009). Voltage rise is exacerbated when customer demand is at its lowest and distributed generation at its highest, and is especially likely to be a significant issue on long feeders in rural areas (SEGIS, 2007).As discussed below, repeated switching of DG systems on and off in response to overvoltage can impose consequent cycling of network voltage control equipment with associated asset life and maintenance impacts.

In addition to having negative impacts on end-use equipment, voltage rise can have negative customer equity impacts. As discussed below, one of the ways to minimise voltage rise is to restrict DG output when the line voltage exceeds set limits. This is achieved in Japan using inverters called Power Conditioners or Power Conditioning Subsystems that are designed with additional power quality enhancing features that can gradually reduce active power injection. This results in PV output being lost and this might be viewed as unfair to system owners towards the end of the line as the voltage rise will be greater at that point (Mizuho, 2008).[3]

In a small number of locations reverse power protection relays may be installed. These devices are sometimes installed on the low-voltage side of a network transformer to detect and stop current flow 'upstream' towards the transformer. Their normal function is to stop reverse current flow that has occurred because of a fault on the high voltage side of the line, but they can also limit the degree to which DG can contribute to a power system (NREL, 2009). Other negative impacts of reverse power flow include destabilisation of the control systems in voltage regulators where they are not designed for both forward and reverse power flow conditions (McGranaghan et al., 2008).

In many locations and networks, installation of relatively large PV systems does not result in significant voltage rise or reverse power flow issues, but where voltage rise is an issue, four common approaches currently used to minimise voltage rise and applied to the PV systems themselves (NREL, 2009) are:

1. Ensure the PV systems are smaller than the minimum daytime load at the customer metre, so the site should never export power to the grid.
2. A minimum import relay (MIR) can be used to disconnect the PV system if the load drops below a preset value.
3. A dynamically controlled inverter (DCI) can be used to gradually reduce PV output if the load drops below a preset value.
4. A reverse power relay (RPR) can be used to disconnect the PV system if the load drops to zero or reverses direction.

Of these, a DCI set to maximise PV output while avoiding export would allow greatest use of the PV system. However, all these measures not only limit voltage rise but also restrict the potential penetration of PV systems, limiting their contribution to sustainable energy production. Alternatives to these revolve around changes to the network or customer loads, and while they are not currently used, they could be implemented with appropriate policy settings (Whitaker et al., 2008). For example:

1. Decrease the network's series impedance[4] so that it has low voltage drop along its length. While this would come at increased capital cost, it reduces the need for high upstream voltage, leaving more 'headroom' for the PV.
2. Require customer loads to operate at improved power factor, again reducing the need for high upstream voltage.
3. Require customers with large loads (who create the need for the high upstream voltage), to incorporate some form of load-shedding scheme. Shedding of non-critical loads could be triggered when network voltage goes below a specified threshold (which occurs at times of high load), again reducing the need for high upstream voltage.
4. Discretionary loads can be used at times of high network voltage (which occurs at times of low load), to soak up the extra power provided by PV.
5. Storage can also be used to soak up the extra power provided by PV.

All these may cause inconvenience and incur costs for stakeholders who do not necessarily benefit directly from the PV systems. In addition, large loads suitable for load shedding and discretionary loads may not be readily identified.

Thus, optimising PV output, operation of loads and the structure of the network is likely to require appropriate coordination/management of the different stakeholders and options available to them. It essentially requires some mix of investment in lower impedance infrastructure as well as in complex monitoring and control functionality in order to achieve voltage regulation throughout the distribution network. This is not a trivial task and indicates an important role for government and appropriate regulation.

2.1.4. Power output fluctuation

Fluctuations in power output are an inherent problem for DG reliant on renewable energy resources such as sunlight and wind. Short-term fluctuations (seconds) can cause problems with power quality (both voltage and power factor, that can manifest as light flicker or variable motor speed for example), while longer-term fluctuations require back-up generation to maintain power supply. Short-term fluctuations can also result in tap-changers and capacitor switches continually 'hunting' as they attempt to maintain power quality, which results in increased wear of these devices, as well as an increased number of switching surges (McGranaghan et al., 2008).

Three approaches to minimise the impact of such fluctuations are geographical dispersion, forecasting and storage, and these are discussed below. Other options to manage such fluctuations involve

[3] Inverters in European countries such as Germany and Spain do not have features that control voltage by reducing output because the Feed-in-Tariff policies used to drive uptake promote maximum output (PVPS-T10, 2009).

[4] Impedance is essentially a measure of the resistance to an alternating current (AC). It is the equivalent of resistance to direct current (DC).

the use of voltage control and are discussed below in the section on *Power factor correction*. It is likely that coordinated use of all these approaches, which will include the development of novel grid control schemes, will be required to minimise issues caused by power output fluctuation from renewable energy generation.

2.1.4.1. Geographical dispersal. Short-term intermittency of PV can be reduced through geographical dispersal. Very little or no correlation in output over 1 min time intervals has been found for sites as little as 2 km apart (Murata et al., 2009) and even within a single 13.2 MW PV plant (Mills et al., 2009). However, as the assessed time intervals increase, the level of correlation increases. Mills and Wiser (2009) found that while sites 20.5 km apart had close to zero correlation for 1 and 5 min intervals, for 30 min intervals there was almost a 30% correlation, which increased to 50% for 60 min and 80% for 180 min intervals. As expected, the greater the distance between sites, the lower the correlation, with sites 400 km apart displaying only about 15% correlation for 180 min intervals. However for solar technologies at least, dispersal is not as feasible in relatively small areas that are subject to the same weather conditions (for example, on distribution network feeders) and of course is only effective during daylight hours (Eltawil and Zhao, 2010; Mills et al., 2009; Mills and Wiser, 2009).

2.1.4.2. Solar forecasting. The effect of weather can vary on timescales from minutes to seasons and can be quite location-specific, and hence can effect where installations can be sited. Once installations are operational, the impact of inevitable supply fluctuations must be predicted and managed. Solar forecasting techniques are currently being developed through international efforts to provide better forecasting and management tools to manage the variability of intermittent solar energy (both PV and solar thermal). Forewarning that output is likely to diminish could be used to prepare alternative sources of power, and output by solar plants could even be gradually preemptively curtailed in order to reduce the ramp rate required by backup generation (Whitaker et al., 2008).

However, solar forecasting is still in its infancy and there is much work to be done before it can make a significant and effective contribution to management of solar power plant. For example, current prediction systems are generally lacking the small-scale resolution that is required for location-specific forecasts, as well as an understanding of the relationship between the weather conditions and the specific technology for which forecasts are required (Archer and Jacobson, 2005). In addition, all forecasting can do is inform the use of different management options, which still need to be available and then used as appropriate.

2.1.4.3. Storage. Various types of storage including batteries (e.g. lithium-ion batteries, lead-acid batteries, flow batteries), electric double-layer capacitors, Superconducting Magnetic Energy Storage (SMES), flywheels, compressed air and pumped hydro can be used to regulate power output. In addition to reducing the amount of voltage rise on feeders, storage can be used to provide services such as peak shaving, load shifting, demand side management and outage protection. Storage can help defer upgrades of transmission and distribution systems, and can help with ‘black starts’ after a system failure (Denholm et al., 2010). It can also help provide several ancillary services, including contingency reserves (spinning reserve, supplemental reserve, replacement reserve), and voltage and frequency regulation (Kirby, 2004; Whitaker et al., 2008; Inage, 2009).

As a result of these various benefits, there has been increasing interest in the use of storage at the distribution level, however the costs, benefits, maintenance, reliability and life cycle of storage systems are still being researched (Ueda et al., 2008, 2007; Nakama, 2009; Whitaker et al., 2008; Nishikawa, 2008; Shimada et al., 2009; Manz et al., 2008). Systems having separate batteries associated with each DG system, separate batteries associated with each DG system but under coordinated operation, and a single battery at the community level have been investigated (Kurokawa et al., 2009).

For recent reviews of the technology options for storage see (Bradbury, 2010), and for the use of large-scale storage to regulate power output as well as power quality see Inage (2009) and Denholm et al. (2010), while Perez et al. (2010) present costings of the storage requirements of large-scale PV penetration. For small-scale RE systems, lead-acid batteries remain the lowest cost and most reliable option, with flywheels, supercapacitors and flow batteries now being demonstrated on medium sized systems and nickel-cadmium batteries used for smaller applications. These benefits may make storage more cost-effective for a DG system, and similarly, installation of a battery specifically to provide one or more of these functions may provide an opportunity for a DG system to be installed and receive a degree of backup (SEGIS-ES, 2008).

In summary, while batteries and other forms of storage have significant potential to enable higher penetration of many types of DG, realising that potential will not only require careful consideration of how best to develop storage options, but also how to integrate them into electricity networks along with DG.

2.2. Power factor correction

Poor power factor on the grid increases line losses and makes voltage regulation more difficult. Inverters configured to be voltage-following are generally set to have unity power factor,[5] while inverters in voltage-regulating mode provide current that is out of phase with the grid voltage and so provide power factor correction. This can be either a simple fixed power factor or one that is automatically controlled by, for example, the power system voltage (Passey et al., 2007).

A number of factors need to be taken into consideration when using inverters to provide power factor correction. The first is that to provide reactive power injection while supplying maximum active power, the inverter size must be increased. For example, increasing the inverter size by 10% means the reactive power capability can be increased from zero to nearly 46% in the maximum PV power generation condition (Liu and Bebic, 2008).

The second factor to be taken into consideration is that the provision of reactive power support comes at an energy cost.[6] For example a 10 kVA inverter, which is 94% efficient at full power output, will be dissipating 600 W. When that same inverter is delivering 10 kVAr and no real power the inverter is 0% efficient and will still be consuming 600 W. The owner of the inverter may not directly benefit from the VAr compensation it provides but they will bear the cost of the energy loss incurred by the inverter in providing the compensation.

The third factor is that simple reactive power support can probably be provided more cost-effectively by SVCs or STATCOMS—unless of course the inverter is to be installed regardless as part of a DG system. Their energy loss is also considerably less than for the equivalent inverter VAr compensation. The main advantage of inverter VAr compensation is that it is infinitely variable and very fast in response to changes in the power system. In areas where rapid changes in voltage are experienced due to large load transients (e.g. motor starts) or

[5] Note that current-source inverters can be specially configured to operate outside unity power factor, however the vast majority of commercially available inverters used for PV are not.

[6] Inverters can provide reactive power in the absence of DG output. The energy cost would then be drawn from the grid.

where only a small range of VAr control is required, then an inverter VAr compensator may be justified.

The fourth factor is that while this sort of reactive power compensation is effective for voltage control on most networks, in fringe of grid locations system impedances seen at the point of connection are considerably more resistive, and so VAr compensation is less effective for voltage control. In these situations, real power injection is more effective for voltage regulation. Thus, PV inverters connected to fringe of grid lines can provide voltage regulation at the point of connection provided the real power input of the inverter (which can only occur when there is sufficient solar insolation or some form of storage backup) correlates in time with the load on the system (Passey et al., 2007; Demirok et al., 2009).

Studies into the use of inverters to regulate network voltage at high PV penetrations have found that in order to achieve optimal operation of the network as a whole, some form of centralised control was also required (PVPS-T10, 2009; Uemura, 2008; Morozumi et al., 2008; Sulc et al., 2010; Turitsyn et al., 2010). It has also been found that reactive power injection by inverters may be limited by the feeder voltage limits, and so coordinated control of utility equipment and inverters, as well as additional utility equipment, may be required (Liu and Bebic, 2008).

In summary, PV inverters are capable of VAr compensation to assist with voltage control on the grid, although this requires larger inverters and comes at an energy cost. How the VAr compensation is valued and who pays for the energy has generally not been addressed. Although large load transients may justify an inverter, SVCs or STATCOMS may be a more cost-effective source of VAr compensation. Of course, where an inverter is already paid for as part of a separate DG system, it is likely to be the more cost-effective option. The effectiveness of reactive power injection for voltage control is also influenced by location, and it is likely that coordinated control of inverters and the existing utility equipment may be required.

2.3. Frequency variation and regulation

Frequency is one of the more important factors in power quality. The frequency is controlled by maintaining a balance between the connected loads and generation. It is controlled within a small deviation: for example, in Japan the standard is 0.2–0.3 Hz; in the U.S. it is 0.018–0.0228 Hz; and in the European UCTE it is 0.04–0.06 Hz (Inage, 2009).

Disruptions in the balance between supply and demand lead to frequency fluctuation—it falls when demand exceeds supply and rises when supply exceeds demand (Inage, 2009). Power systems contain a number of sources of inertia (e.g. large rotating generators and motors), which result in considerable time constants involved in frequency movements when there is a mismatch between load and generation. The time constants depend of course on the size of the system and how well it is interconnected.

Frequency regulation is maintained by control loops built into the power generating sources on the network. In conventional grids, generators and turbines use an actuator to control the flow of fuel, gas or steam to maintain the required frequency. It is the performance of these actuators, turbo devices and inertia of the generators that give the frequency sturdiness (Asano et al., 1996; Kirby, 2004).

With the increasing penetration of intermittent energy sources such as wind and solar, frequency control becomes more difficult. Although the contribution to power fluctuation from PV systems is currently much smaller than that from wind generators, as the number of grid-connected PV systems increases, the issue of frequency fluctuation may become more noticeable (PVPS-T10, 2009). One study found that 10% penetration of PV required a 2.5% increase in conventional frequency control, while a 30% PV penetration required a 10% increase (Asano et al., 1996).

DG inverters may be able to help with frequency control. Inverters can provide frequency control in milliseconds, which is significantly faster than conventional generation (Inage, 2009). Of course, grid-connected inverters would only be able to control frequency to the extent that changes in their real power output actually influences the overall (grid wide) supply–demand balance. Generally they will not be able to change the frequency unless they represent a significant amount of generation—such as in relatively small grids. In addition, special control algorithms would need to be developed to take advantage of the fast response times, and at present DG is unproven in this application.

In a number of circumstances DG may be unable to provide frequency support. Inverters can only provide frequency control when they can inject power into the network (e.g. during daylight hours for PV) (Whitaker et al., 2008), and DG linked to combined heat and power plant are restricted in their ability to provide frequency regulation because of their thermal loads (Kirby, 2004). Most importantly, where inverters are configured to disconnect from the grid when the frequency moves outside set limits (as a form of islanding detection), their ability to provide frequency support may be compromised. If the power system has lost generation for some other reason (e.g. a lost transmission line) and the system load is greater than the connected generation, then the frequency will start to fall. If it falls outside the trip limits then all the DG will also disconnect, exacerbating the power imbalance and leading to a need to shed more load to avert a complete system shutdown (Whitaker et al., 2008). New frequency ride through systems that do not interfere with the anti-islanding protection systems will need to be developed to cope with this situation as penetration levels increase.

2.4. Harmonics

Harmonics are currents or voltages with frequencies that are integer multiples of the fundamental power frequency. The standard frequency is 50 or 60 Hz depending on the country, and so a harmonic in a 50 Hz country could be 100, 150, 200 Hz, etc. Electrical appliances and generators all produce harmonics and are regulated under the International Electrotechnical Commission (IEC) Electromagnetic Interference (EMI) standards.[7] However in large volumes (e.g. computers and compact fluorescent lamps), these harmonics can add up to cause interference that can result in vibration of elevators, flickering of TV monitors and fluorescent lamps, degradation of sound quality, malfunctioning of control devices and even fires (PVPS-T10, 2009).

The existing inverter standards in Australia (AS4777.2) and in the US (UL1741) for small PV systems require that the inverter must produce less than 5% total harmonic distortion (THD) on injected current with tight limits on specific harmonics. This is much more stringent than for loads of equivalent rating (as specified in the IEC61000 series of documents). For PV, Europe and the UK rely on similar standards to those for loads, i.e. the IEC61000 series of standards. Most grid-connected inverters for DG applications put out very low levels of harmonic current, and because of their distribution on the network are unlikely to cause harmonic issues, even at high penetration levels (Infield et al., 2004; Latheef et al., 2006; Nishikawa, 2008).

Inverters may be able to help with correcting harmonics, however as discussed below, they must be configured to provide

[7] This is because they need direct current (DC) power or AC at a different frequency to that supplied, and use power electronics technologies to change the grid AC to the desired current waveform, and in doing so generate harmonics in the grid.

out of phase current, and the equity impacts of harmonic correction need to be taken into account.

There are generally two types of control schemes used in PV inverters: as a sinusoidal voltage source or a sinusoidal current source. Most PV inverters at present are the current-source type because this makes it easier to meet grid-connection standards and provide rapid overcurrent protection. However, many loads expect the power system to be a sinusoidal voltage source and many of them demand non-sinusoidal currents and currents out of phase with the supply voltage. The net effect of a large number of loads of this type is that the supply system has to provide a considerable amount of out of phase and harmonic currents, and the flow of these currents on the network creates harmonic voltages that then can affect other loads. Adding PV inverters which provide sinusoidal currents at unity power factor means that the inverters supply the in-phase sinusoidal component of the loads and the grid is left to still supply out of phase current and harmonics. Thus, while current-source PV inverters generally do not make the situation worse, they do not contribute to the supply of the out of phase and harmonic currents required by loads. Note that current-source inverters can be specially configured to provide reactive power, however for the vast majority of commercially available inverters used for PV, this facility is not used i.e. they are locked at unity power factor. The voltage source type of inverter could assist by contributing the harmonic currents required by loads but this type of inverter is at present not common in the market place, and may be illegal in some jurisdictions. Currently, inverters are not required to be characterised as being voltage source or current source and hence it is very difficult for purchasers of equipment to select a particular type.

Even when a voltage source inverter is used to help correct poor harmonic voltage, and so the inverter produces harmonic currents to assist in correcting the grid voltage, its energy output is reduced. This is equitable provided the owner of the inverter is also the cause of the harmonics on the grid and so they are assisting with correction of their own problem. However the owner of the inverter may be experiencing high harmonic flows, and so reduced energy output, because of the poor harmonic performance of other customers on the power system. This is another reason why current source inverters are common—their output is not generally affected by the grid's voltage harmonics.

Harmonics can also be eliminated using passive and active filters, which are generally cheaper than inverters. Passive filters are composed of passive elements such as capacitors or reactors, and absorb harmonic current by providing a low-impedance shunt for specific frequency domains. They come in two forms: tuned filters (which are targeted to eliminate specific lower-order harmonics) and higher-order filters (that can absorb entire ranges of higher-order harmonics). Active filters detect harmonic current and generate harmonics with the opposite polarity for compensation. They are better than passive filters because they can eliminate several harmonic currents at the same time, they are smaller and quieter, and they do not require a system setting change even when a change occurs in the grid (PVPS-T10, 2009).

In summary, while the most common type of inverters (current-source) do not create harmonic distortion, they also do not provide the harmonic support required from the grid. Voltage-source inverters can provide harmonic support but do so at an energy cost and there are a variety of harmonic compensators that are likely to be cheaper. Labelling that identified the type of inverter (voltage or current source) would help purchase of voltage source or current source inverters as required, as would financial compensation for reducing energy losses if voltage source inverters are installed. Note that, unless specially configured, PV inverters disconnect from the grid when there is insufficient sunlight to cover the switching losses, meaning that no harmonic support would be provided outside daylight hours. Of course, requiring loads to not create excessive harmonics or THD in the first place could have a significant and beneficial effect.

2.5. Unintentional islanding

Unintentional islanding occurs when distributed generation delivers power to the network even after circuit breakers have disconnected that part of the network from the main grid and associated generators. This can cause a number of different problems (SEGIS, 2007; McGranaghan et al., 2008; Coddington et al., 2009):

(i) Safety issues for technicians who work on the lines, as well as for the general public who may be exposed to energised conductors.
(ii) It may maintain the fault conditions that originally tripped the circuit breaker, extending the time that customers are disconnected.
(iii) Possible damage to equipment connected to the island because of poor power quality (e.g. where inverters are in voltage-following mode).
(iv) Transient overvoltages caused by ferroresonance and ground fault conditions are more likely when an unintentional island forms.
(v) Inverters could be damaged if the network is reconnected while an island of DG exists.
(vi) It is possible for a network that does not have synchronising capabilities to reclose in an out of phase condition, which can damage switchgear, power generation equipment and customer load.

Since islanding is a well-known problem, grid inverter technology has developed to include anti-islanding features as are required by local regulations and standards. Islanding detection methods can be divided into five categories: passive inverter-resident methods, active inverter-resident methods, passive methods not resident in the inverter, active methods not resident in the inverter, and the use of communications between the utility and DG inverter (Eltawil and Zhao, 2010).

(i) Passive inverter-resident methods involve the detection of the voltage or frequency at the point of grid connection being over or under specified limits.[8] These methods also protect end-users' equipment.
(ii) Active inverter-resident methods involve active attempts to move the voltage or frequency outside specified limits—which should only be possible if the grid is not live.[9]
(iii) Passive methods not resident in the inverter involve the use of utility-grade protection hardware for over/under frequency and over/under voltage protection.
(iv) Active methods not resident in the inverter also actively attempt to create an abnormal voltage or frequency or perturb the active or reactive power, but the action is taken on the utility side of the inverter connection point.
(v) Communications between the utility and DG inverter methods involve a transmission of data between the inverter or

[8] They may also detect the rate of change of power and voltage, and trip the inverter offline if these exceed a preset value. Harmonic detection methods (that detect either the change of total harmonic distortion or the third harmonic of the PV output voltage) and phase jump detection methods (that monitor the phase difference between PV output voltage and the output current) can also be used (Yu et al., 2010).

[9] Active methods can also include monitoring changes in grid impedance after the injection of a particular harmonic or a sub-harmonic (Trujillo et al. 2010).

system and utility systems, and the data is used by the DG system to determine when to cease or continue operation.

As briefly outlined below, each of these approaches has strengths and weaknesses.

Passive methods:

- Can malfunction due to interference from a cluster of inverters (NEDO, 2006; SEGIS, 2007).
- May fail to detect islanding when the reactive power of the DG system and the load on the customer side of the inverter are the same (this is known as the non-detection zone), especially where inverters can vary their power factor because this allows them to best match load and supply to maximise efficiency (Trujillo et al., 2010; Eltawil and Zhao, 2010).
- As the resonant frequency of the local load approaches the local grid nominal frequency, the inverter may not detect that the line voltage has been cut and the automatic cut-off feature will not function (Yu et al., 2010).

Active methods:

- Can in theory have a minor but negative impact on grid power quality when there are a number of inverters on the same line and interference from the signals occurs. Pulses associated with impedance detection for anti-islanding can accumulate in high penetration scenarios and may cause out-of-specification utility voltage profiles. Such power quality impacts could then interfere with islanding detection capabilities. However, most inverters incorporate internal controls to minimise these problems and no practical impacts have been reported so far (Whitaker et al., 2008; PVPS-T10, 2009).
- Are considered to be incompatible with microgrids because (i) they cannot readily be implemented at the point of connection of the microgrid to the main grid and (ii) the active attempts to move the voltage or frequency outside specified limits work against a seamless transition between grid-connected and stand-alone modes (Whitaker et al., 2008).
- Have no uniform standards and so there is a diverse mixture of control algorithms on networks. Some algorithms attempt to drift the frequency up, some down, some depend on the load generation match and some do not drift but use impedance measuring current pulses. The problem with this situation is that there is an increased risk of forming a stable island because a stable frequency operating point may be reached. It appears that this may have happened in Spain on a 20 kV feeder for a brief period of time several years ago (Pazos, 2009).

Active and passive methods:

- Can conflict with inverters injecting reactive power during sags to help boost network voltage, and adds complexity to the control algorithms (Whitaker et al., 2008; PVPS-T10, 2009).
- Can fail when the DG uses voltage regulation and governor control characteristics, because the DG output may adapt to the islanded system load demand without reaching the voltage or frequency trip points. However, such control characteristics are not generally used for DG, except when they are used as backup power sources independent of the grid (Walling and Miller, 2003).

In addition, on a weak grid, an inverter may cut out prematurely or, more likely, may not reclose (i.e. reconnect to the grid). For example, Australian Standard AS4777 specifies that the autoreclose function needs the grid to be stable for 60 s, which on a weak grid may not occur for some time. Networks are generally designed to reclose after 10 s and so for the next 50 s the DG will not be providing network support. To increase DG's ability to provide line support, the network operator could specify more reasonable tolerance limits and shorten the reclose time. Some form of short-term storage could also be used to bridge the gap between the network and the PV inverter reclosing (Passey et al., 2007).

According to Whitaker et al. (2008) and McGranaghan et al. (2008), the best options to improve islanding detection are based on improved communications between the utility and the inverter. These could help overcome the problems associated with failure to detect an island condition, with false detection of island conditions, and failure to reclose and so provide grid support. For example, power line carrier communications (PLCC) could be used as a continuity test of the line for loss-of-mains, fault, and islanding detection—but only once technical challenges such as having a continuous carrier are solved. However, because such a system is unlikely to be perfect, it should include some redundancy in the form of autonomous active island detection options. Communications-based systems are also likely to be higher cost (Ropp, 2010).

In summary, passive, active and communications-based islanding detection methods have a number of issues that need to be resolved. It is likely that different mixes of these methods will be required in different locations, and that phasing out or replacing less effective methods will not be a simple task, and will likely involve a coordinated approach by government, utilities and installers and owners of DG systems.

2.6. Other issues

Other issues, that are likely to be of less importance and for space reasons have not been included here, include fault currents and effective grounding (McGranaghan et al., 2008), DC injection and high frequency waves (PVPS-T10, 2009) and of course the impacts of aggregated DG on subtransmission and transmission networks (McGranaghan et al., 2008).

3. Factors that influence how these issues are addressed

As discussed in the previous section, there are many potential technical issues associated with connection of DG to electricity networks, especially at high penetrations. While some of these impacts may be beneficial in some circumstances such as reduced losses and peak current flows, some adverse impacts are likely at significant penetrations whilst others may also be possible in low penetration contexts. The challenge is to facilitate the deployment of DG in ways that maximises their positive grid impacts whilst minimising adverse impacts, within the context of wider societal objectives associated with DG uptake. The types of technical solutions likely to be required to achieve this may sometimes be different in different countries, simply because they have different types of electricity networks, renewable energy resources, mixtures of conventional and renewable energy generators, correlations between renewable generation and load, government priorities and, ultimately, technical capacities within utilities, government and the private sector.

DG of course does not represent the first disruptive set of technologies for electricity industry arrangements. For example, wind energy represents the first major highly variable and somewhat unpredictable generation to achieve high penetrations in some electricity industries. As such, it has tested, and in some cases driven changes to, current technical and wider industry arrangements. These include low voltage ride through requirements, technical connection standards and more formal participation in electricity markets (MacGill, 2009). As such, the transition, with growing penetrations, from wind energy being treated by the electricity industry as negative load, through to its current formal and active participation in many electricity industries, provides an interesting analogy to the transition that DG must now also make. However, DG adds a whole new set of distribution network issues that we are still coming to terms with.

Recent high financial support for PV, such as Feed-in-Tariffs in Europe and grant-based support in Australia have led to very rapid increases in installed PV capacity, with institutional and electricity sector capacity falling behind in some cases. Problems have been exacerbated when such financial support has been linked to time or capacity-based caps, which have encouraged a rush to install. Poor quality components and installations have often resulted, which will cause problems for the DG sector in future.

Thus, addressing these technical problems requires more than just the technical solutions described above. It will require policy and regulatory frameworks to coordinate the development and deployment of the different technologies in ways most appropriate for particular jurisdictions. These frameworks will be different for different countries, and so no single approach will be appropriate worldwide. Thus, this section discusses the non-technical factors that influence which types of technological solutions are most likely to be appropriate, and provides suggestions for increasing the likelihood of best practise.

3.1. Role of government, regulator and electricity utilities

Irrespective of the jurisdiction in question, if governments choose to put in place appropriate regulation, standards and agreements, as well as the related mechanisms for enforcement, then appropriate technological solutions for adverse DG network impacts are more likely to be implemented. Of course for this to occur, the government needs to know what is required, based on industry research and expert advice.

Government and educational institutions may need to assist with information dissemination (regarding new rules and regulations), promotion of the use of technologies and facilitation of training for the appropriate public entities and private companies. Training could be a very important factor in some countries, because inadequate technical capability will restrict the uptake of best practices, even if the willingness is there. For example, the Government of Fiji and the Fiji Electricity Authority (FEA) have published ambitious targets for renewable energy generation (Department of Energy, 2006; FEA, 2010), however, technical capacity on the ground to implement appropriate technologies and solutions, both within the Government itself and within the private sector to which the Government and FEA are increasingly looking, is still lacking (Singh, 2009; Hook, 2009). In 2010, the newly formed and largely PV-industry led Sustainable Energy Industry Association of the Pacific Islands (SEIAPI), noted the urgent need for compilation and dissemination of guidelines for installation, operation and maintenance of grid-connect PV systems (SEIAPI, 2010). Members working in the industry were willing to apply standards and be regulated but needed this information to be standardised and disseminated, with training opportunities set-up with appropriate educational service providers.

This all assumes a certain level of capacity within government and utilities, and if this is not immediately available then delays in developing and establishing standards and enforcement may affect the timeline of technology take up, or lead to what were avoidable adverse impacts. Poor delivery early on may then impact longer-term confidence in the measures proposed.

Whether electricity utilities are privately or government owned should not in itself be an issue, assuming that all utilities are subject to and held to equivalent standards and regulations. An independent energy regulatory framework is also almost certainly required for such standards and regulations to be enforced. If utilities still retain a regulatory role, conflicts of interest may arise. This has been the case in Fiji and Palau, where the state-owned and self-regulating utilities have been hesitant to allow the widespread (e.g. household) take-up of solar PV DG until grid-connection standards and agreements are developed. However, with limited resources available to them and low incentive to act, the utilities do not prioritise the development of these documents themselves and so progress stagnates.

Where electricity retailers and/or network operators – whether publicly or privately owned – have their income directly linked to kWh sales, DG can be seen as a threat to revenue (as can energy efficiency) and hence the electricity sector may hinder DG proposals via active obstruction, or passive resistance via long delays and high costs for interconnection. If a utility is self-regulating, they may set the feed-in-tariff too low for DG to be attractive, thus deterring DG development and protecting their own interests. This is the case in Fiji, where hydropower investors have argued for some time that the FEA tariff is too low to encourage investment (Hydro Developments Limited, 2011).

3.2. Institutional and regulatory barriers

The main barrier of this type appears to be existing standards that were originally developed for DG when it was at relatively low penetrations. The standard most commented on is IEEE 1547, which is currently being expanded in light of higher penetration in order for DG to provide ancillary services such as local voltage regulation, as well as to improve the speed at which unintentional islands are cleared (McGranaghan et al., 2008). Requirements such as low voltage ride through could also be included into standards, as they are in Germany. Frequency limits can also be broadened, helping to avoid large amounts of DG prematurely disconnecting from the grid and so causing more significant disruptions, as has recently happened in Alice Springs, Australia (Hancock, 2011). Standard processes need to be very responsive to rapid changes as penetration levels and potential solutions develop.

Similarly, as research in DG is published and international standards change over time, it is important to prevent national regulations which may be out of date from obstructing the application of new best practices developments in DG. A possible solution is national committees which follow developments of international standards and research and update relevant national standards when required.

Otherwise, either a lack of appropriate standardised grid-connection agreements and requirements, or the presence of inappropriate agreements and requirements, can inhibit the uptake of best practise DG. Indeed, the absence of PV-specific standards for grid connection has in the past been a significant barrier to uptake in many IEA countries (Panhuber, 2001).

Utilities may place limitations on the amount of DG that can be connected to their networks (e.g. limiting the amount of DG to being less than the minimum expected load) if they feel that their network is inadequately protected from low quality renewable technologies and installations or if they are unaware of the latest best practise technological advances which make grid-integration safer and easier. Existence and dissemination of installation and product standards can engender more “trust” in renewables and DG more generally from the utility side.

It is possible to achieve a virtuous cycle, where application of the most appropriate technologies can help to overcome institutional and regulatory barriers, since the use of such technologies should gradually allow much higher penetrations. As more technologies are demonstrated, there will be increased confidence in grid-connected renewables and even utilities that might generally oppose DG would have the opportunity to visit existing best practise installations before deciding on their future DG policy.

3.3. Existing electricity infrastructure

Where growth in demand requires new infrastructure to be built, there is an opportunity for that infrastructure to be constructed from the ground up with the most appropriate technologies and grid architecture, and so best practices can be applied—ideally up to the standard of a smart grid. Where demand growth requires existing infrastructure to be augmented, this may also provide an opportunity for best practices to be applied. It is worth noting that there may be conflicts of interest between the need for energy efficiency to limit growth and then reduce demand in absolute terms, and the ease of applying best practices. Where best practices can be retrofitted to existing infrastructure or incorporated into asset replacement programs, demand growth is not required and the nature of the existing infrastructure is less relevant.

For example, all the approaches that can be integrated into newly connected DG, such as ancillary service capabilities in inverters, storage and geographical distribution of DG, can be applied independently of the existing infrastructure—as can avoiding voltage imbalance by connecting the same amount of new DG to each phase of a network.

Applying best practices to existing DG would not so much be limited by the existing network infrastructure as by the existing systems, especially inverters, as these would need to be either reconfigured or replaced. The addition of storage to existing DG should not be affected by existing infrastructure, as long as there is space for it to be installed—although charge regulators would need to be added to most inverters currently used for grid applications. Again, ensuring that the same amount of existing DG is connected to each phase of a network can be retroactively applied at modest expense and effort.

Addressing unintentional islanding by using improved active detection methods can be included into new DG but would require inverter replacement for existing DG. Integrated communications-based control systems are most likely to be readily applied to new-build or significantly upgraded networks, such as smart grids, but might still be applied to existing networks. Fully integrating a communications-based control system with redundant autonomous passive or active methods, would again be easier (and cheaper) in new-build networks, but could still be done for existing infrastructure.

Technological approaches that would be most restricted by the existing infrastructure are those that require changes to the infrastructure itself, such as reducing its series impedance.

Of course, a fully integrated smart grid, that included best practices in system architecture, including possible mesh/loop network structures and the technologies required to operate them, could only be purpose-built from the ground up. In this case the nature of the existing infrastructure is also irrelevant, as such a smart grid could only be built to meet increased demand or supply new green-field developments.

3.4. Relative availability of conventional and renewable resources

The relative availability of conventional and renewable resources has the most impact on the *need* for particular technological solutions to be applied, rather than on the *likelihood* of their introduction. Generally, the greater the uptake of renewables, the greater the need for technological solutions to deal with grid integration. Where no formal regulation and standards are in place, utilities may restrict uptake of renewables to the grid. This could create a bottle-neck for renewable energy applications until regulations and standards are put in place, which comply with best practices.

To the extent that the use of conventional resources is restricted, the rate of uptake of renewable energy will be increased. The use of conventional resources may be restricted for a variety of reasons including: access to the resources themselves (e.g. through lack of indigenous resources or restrictions on imports); the impact that importing them has on the national balance of payments; the relatively high cost, especially if a price is placed on carbon; any pollution impacts; and conventional power stations being too large-scale for the purpose required.

The need for particular technological solutions to then be used to address any grid impacts will depend on the type and particularly the scale of renewable energy resource to be used. Resources such as bioenergy, geothermal and hydro, that are more likely to be dispatchable and able to provide constant power output, will often be of transmission network scale and even at smaller scale will often be direct AC generation and so not use inverters. Other smaller scale DG should have little requirement for anything beyond standard inverter technology and grid architectures. Solar thermal electricity technologies are unlikely to be of the scale to be connected to distribution networks, but would have a greater requirement for new technology especially if they do not include some form of storage. Similarly, small-scale wind is deployed at relatively low levels, but where it is deployed, is more likely to result in the need for best practices to be applied, as is PV, as both these resource are intermittent in nature and can affect, for example, local voltage and, in smaller grids, frequency.

The nature of the load profile will also influence the need for particular technologies. Where it is well matched to renewable energy supply there will be less need for storage or demand management, and voltage rise may be less of a problem. In these circumstances, DG will also be better placed to provide ancillary services and so implementation of appropriate technologies will provide more value to the electricity network.

3.5. Stages of economic and technical development

Different countries are in different stages of economic and technical development, which means that different issues may need to be addressed, and so different types of technologies are likely to be appropriate. Even within countries, different regions, with different renewable energy resources, socio-economic conditions and technical capacities may need different treatment.

For example, many Asia-Pacific countries may have one large main island with high rainfall and mountainous landscape making grid-connected hydro resources a promising technology for development, while also having a large number of isolated, small low-lying islands where there would be no hydro but a very good solar resource for solar PV mini-grid development.

It is also possible that grids will not be so robust in less developed areas and economies, and so will be less able to withstand rapid fluctuations in power output. Of course, it is also possible that end-users may already have significantly lower expectations of power quality, and more robust electrical loads. To the extent that such networks are more likely to be in need of technologies that can deal with such fluctuations (e.g. inverters with wide voltage fluctuation thresholds), they may also have lower economic and technical capacity to apply best practices, and so should be targeted for technical capacity building. Thus, service providers on small islands and isolated rural areas should receive priority training in technical operation and maintenance of renewable energy technologies and how to select appropriate technologies for the areas where they are trying to provide new or maintain existing electricity supply.

3.6. Local expertise in renewable and associated technologies

Of most relevance here is the local expertise in DG technologies and the impacts of different types of DG technologies on the networks. In large part this can be driven by requirements laid down by governments (provided they are enforced), as such requirements will drive the development of the expertise required to meet them. Adequate training should also be made available for energy professionals by appropriate government, industry, and educational bodies.

Industry associations, if they exist, can help lobby for application of best practices. These are often renewable energy resource-specific (e.g. hydropower associations, solar PV associations) but sometimes are not. These associations can provide services such as information dissemination, training and promotion of best practices for the technologies they represent.

To a certain extent, the installation of DG in developing countries is undertaken by external expertise. Such expertise can bring in the knowledge from developed countries, but it is important that knowledge transfer occurs to drive capacity building in local expertise and to allow the gradual scaling down of reliance on external expertise in the medium to long-term. The REP-5 Programme (Federated States of Micronesia, Nauru, Niue, Palau and the Republic of the Marshall Islands, 2006–2010) installed over 250 kWp of grid-connected PV and was largely implemented by external expertise in the Programme Management Unit and short-term international consultants and companies. However, the European Union funded-programme also conducted more than 15 renewable energy training sessions for in-country utility, government and private sector staff, hired local staff to work alongside overseas contractors and assisted the governments of the target countries to develop appropriate policies for renewable energy technologies (Syngellakis et al., 2010).

What has been found to be critical, in both developed and developing countries, is ongoing maintenance of DG. This means that appropriate mechanisms need to be in place to ensure that inverters and any other enabling technologies (e.g. batteries) are maintained on an ongoing basis. This can be a difficult issue if project finance is based on up-front capital cost only, with separate provision needed for ongoing maintenance. This has been typical of aid-based finance, but is also an issue for up-front grant-based support in developed countries.

Regardless of the amount of training given to local operators, a post-installation assistance programme should be put in place to monitor the performance of any installed system. Capacity to monitor renewable energy installations or to deal with manufacturers to replace broken down components, takes time to build, despite the local operators having been trained in the operation and maintenance of the installations during the project. Many past and present aid-based projects have not taken this into account, resulting in failure of the installed energy generation system or even worse, damage to equipment connected to the DG energy supply.

Ultimately, the ability to apply best practise design, installation and maintenance of grid-connected renewables in the long-term will depend on the local expertise available. This means that energy professionals in the public and private sector need to be trained on an on-going basis, so that as technologies, products, installation methods, standards, regulations and best practices evolve, knowledge in the national industry also evolves.

4. Conclusion

When considering increasing levels of penetration of DG in electricity networks, it must be remembered that the original design of networks did not envisage DG in the distribution system. The design of networks was based on more centralised generation sources feeding into the transmission system, then subtransmission and distribution systems. The security, control, protection, power flows, and earthing of the network was predicated on a centralised generation model with a small number of source nodes, with communication and control linking major generators and nodes. When installing DG, very low penetration on a distribution system can generally be tolerated without significant problems as described in this paper. The threshold where problems occur depends heavily on the configuration of the network, length of lines involved (and hence impedances) and the concentration and time dependence of the load and generation in the area.

When penetration of DG rises above the network's minimum threshold, more significant issues can arise in the some networks. More DG may be accommodated by making changes to the network such as minimising VAR flows, power factor correction, increased voltage regulation in the network and careful consideration of protections issues such as fault current levels and ground fault overvoltage issues. In many countries which have actively encouraged DG in recent years, the level of penetration is already at this middle stage and significant network modification is under consideration to allow expansion of DG without taking the next significant step of major design and infrastructure change.

At high levels of penetration, a point is reached (which again is very network dependent) where significant changes have to be made to accommodate these higher levels of DG. This will probably require significant overall design and communications infrastructure changes to accommodate coordinated protection and power flow control. This third stage is very much in the research area and, although there are a number of communications protocols developed for distributed generation, the use, coordination and the design philosophy behind this are very much under research and development, the microgrid concept being one example. The full use of microgrids within the wider electricity network is again still very much in the research and development stage.

There is increasing pressure to quickly implement DG on electricity networks, but to do this at medium to high penetration levels will require careful preparation and development of safe and carefully integrated protection and control coordination.

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