Market Structures and the 21st Century Energy Plan

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Protect Michigan

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Executive Summary

Public Act (PA) 141 of 2000 restructured Michigan's electric market in an attempt to bring customer choice and electric supply competition to Michigan. Under PA 141, alternate electric suppliers (AESs) are free to offer electric service[1] at the retail level, but with no obligation to serve customers beyond the length of a contract. Regulated utilities, however, continue to be regulated under PA 141 and, as such, maintain the obligation to serve any choice customers that decide to return to the utility. In other words, Michigan has a hybrid market structure—part regulated and part unregulated. According to a previous study by Public Sector Consultants (PSC), this hybrid structure has created an economically unsustainable system for both producers and consumers of electricity in Michigan.

On April 6, 2006, Governor Jennifer Granholm issued Executive Directive 2006-2, which directed the Chairman of the Michigan Public Service Commission (MPSC) to prepare an electric energy plan for the State of Michigan. This directive came on the heels of the *Capacity Needs Forum Report* of January 3, 2006, which concluded that Michigan requires additional electric supply to meet its needs beginning in the year 2009. The final *Michigan's 21st Century Electric Energy Plan* (the Plan) concludes, as did the earlier *Capacity Needs Forum Report*, that Michigan needs additional electric supply. The Plan proposes to meet this need by establishing an energy efficiency program, creating a mandatory renewable portfolio standard, and ensuring that a new base load coal plant is operational no later than 2015.

Given that a major component of the Plan is the construction of at least one new base load power plant by 2015—and that lack of customer predictability caused by Michigan's hybrid model is the major reason cited by utilities for not proceeding with the construction of new base load generation in Michigan—PSC was retained by the Michigan Municipal Electric Association and Protect Michigan to analyze whether Michigan's current hybrid structure accommodates the goals and initiatives of *Michigan's 21st Century Electric Energy Plan*. If the hybrid structure will not allow Michigan to implement the goals of the Plan as written, PSC was further charged with analyzing whether Michigan would be better served by making the Plan's proposed changes to PA 141 or by returning to a more traditional regulatory model.

Stated more plainly, this study addresses the fundamental energy question facing the state: **If *Michigan's 21st Century Electric Energy Plan* accurately portrays the goals toward which Michigan's electric industry should be moving, what type of market structure would enable the stakeholders to best reach those goals?**

MAJOR FINDINGS

New Base Load Generation

- The Plan's call for a renewable portfolio standard and energy efficiency program reduces, but does not eliminate, the need for new base load generation in Michigan.
- Base load generation is unlikely to be built either by regulated electric utilities or by independent power producers (IPPs) under Michigan's hybrid retail electric market structure. The primary reasons are lack of retail revenue predictability for regulated utilities, and lack of wholesale revenue predictability for IPPs.

[1] AESs sell to retail customers power that the AES purchases wholesale from a utility or an independent power producer (IPP).

- The current energy plan debate has focused almost exclusively on policy changes that are required in order to develop **new** base load power plants. As these policy options are examined, it is equally important to recognize the crucial role that Michigan's **existing** generation base plays in ensuring both reliable and affordable electric supply for all customers. Policy options enacted to encourage new generation, but that would create significant and artificial distinctions between new and existing generation, do not serve Michigan's interests.
- Providing additional retail revenue predictability in Michigan will require major changes to the electric choice program.
- Looking across the nation, other states also are having difficulty constructing new generation plants, and some states are incurring large increases in electricity rates. In response, some other states and regional transmission organizations are adopting new policies to provide additional regulatory and revenue certainty in order to encourage development of new base load generation.

Renewable Portfolio Standards

- Independent estimates of expected rate increases in other states show that while the median increase in consumer electric bills is only $0.38 per month, there is substantial variation above and below this median. Therefore, although renewable portfolio standards (RPSs) differ greatly from state to state, it is not clear from a national review that Michigan's proposed RPS will greatly increase retail electricity rates.
- Since the effect of an RPS on Michigan's rates is unclear and there is an increasing possibility of a federal carbon tax in coming years, creating meaningful comparisons between the cost of base load and renewable sources of energy across multiple future years is extremely difficult. Michigan therefore needs to carefully consider which goal has the highest priority—price stability (which means that the state achieves the 10 percent RPS standard recommended by the Plan, but may not do so by the 2015 timeline) or the stated RPS goal (which means that the state will pay all of the necessary costs, regardless of the price tag, to be certain that Michigan achieves a 10 percent RPS by 2015).
- If Michigan cannot achieve the RPS standard outlined in the Plan—and if electricity demand increases as expected—an additional base load plant may be needed. In this case, Michigan is likely to rely more heavily on a volatile wholesale market until the new base load plant comes online.

Energy Efficiency

- The size of Michigan's proposed energy efficiency (EE) program would place it at the forefront of states across the nation in terms of available program dollars. This will be accomplished with a modest increase of retail rates that averages only $0.50 per month.
- Although EE will cause electric rates to increase, rates are not likely to increase as much for the proposed EE program as they would to construct two additional base load plants offset by the EE gains. The impact of the rate increase affects customers differently, however; those who implement EE will see the total utility cost stay the same or decrease, while customers that do not implement EE will see their total utility costs increase to pay for EE for other customers. To the state, the savings from the proposed EE program are substantial: the equivalent of two base load power plants by 2015.

CONCLUSIONS

- *Michigan's 21st Century Electric Energy Plan* is not an *à la carte* set of options; if the new generation, RPS, and EE programs are not enacted in concert there could be significant consequences. For example, if the state misses its RPS or EE targets, as many as **three** additional base load plants may be needed by 2015. Focusing a policy discussion on any **one** of these three goals of the Plan—at the expense of the other two goals—does not secure Michigan's electric energy future.
- To build new base load generation, Michigan faces a trade-off. On one hand, with either the state's existing hybrid structure or a move to increase choice (i.e., full deregulation), Michigan faces the risk that a new base load plant will not be built prior to 2015—therefore delaying the economic development and electric reliability benefits of the new plant—due to financial decisions of both utilities and IPPs in a market with uncertain multiyear revenue streams. On the other hand, if Michigan modifies PA 141 or moves toward re-regulation, the state increases the possibility that at least one base load plant will be built. Either of these two market structures also increases the possibility that there will be a change to the choice program that could include its elimination.
- While generation is clearly the area that is **most** affected by market structure, the market structure also will affect the state's ability to implement and to achieve the Plan's RPS and EE goals. Broadly stated, both the RPS and EE programs proposed by the Plan can be implemented—albeit with differing degrees of success—in any of the market structures examined by this study. However, a fully deregulated market structure—where all producers are risking customer loads to a choice model—is likely to **increase** the cost of implementation of RPS and EE plans. A fully deregulated market structure would also **decrease** the state's chances to reach the RPS and EE targets since (a) any producer's time horizon will be much shorter than under a fully regulated model, and (b) in markets with more uncertain parameters, the premium demanded by producers increases.
- Given the uncertainty of larger, macro risks in electricity production such as rising fuel prices, rising construction costs for new base load plants (due to both new technologies and increased demand for raw materials used in power plant production), and a possible federal carbon tax, **Michigan should choose the regulatory and market model that best stabilizes Michigan's electric market and diversifies its electric production portfolio**. By reducing risks to both producers and consumers, Michigan stands the best chance of implementing the Plan.
- **The best risk-reduction strategy is to return to a regulated utility model for new and existing generation in order to bring greater predictability to the revenue base of all utilities.** It will be extremely difficult for Michigan to successfully implement *Michigan's 21st Century Electric Energy Plan* without moving to a model where costs of new generation, renewable technologies, and energy efficiency programs are not at risk for recovery for three reasons:
    - Costs to implement elements of each major component are so high that waiting for the market signals to react means that Michigan also will likely wait too long for the market to provide timely solutions.
    - Michigan's existing hybrid structure, let alone a move toward full deregulation, makes decisions to commit to multiyear, capital-intensive projects less likely. While it is possible for an electricity producer to successfully supply new generating power in the hybrid or deregulated model, it is unlikely that an existing provider will want to be the first one to try without seeking long-term purchase contracts (which provide greater predictability to the producer).

- The additional risks (or the same risks but with greater probability or volatility) of the hybrid or deregulated market may cause investors to demand higher risk premiums, leading to higher costs of financing to any company—utility or IPP—that seeks to construct a new base load power plant.

Overview and Project Goals

On April 6, 2006, Governor Jennifer Granholm issued Executive Directive 2006-2, which directed the Chairman of the Michigan Public Service Commission (MPSC) to prepare an electric energy plan for the State of Michigan. This directive came on the heels of the *Capacity Needs Forum Report* of January 3, 2006, which concluded that Michigan requires additional electric supply to meets its needs beginning in the year 2009. *Michigan's 21st Century Electric Energy Plan* (the Plan), as outlined by the governor, was to be a comprehensive report addressing reliability of supply, rate affordability and stability, economic development, environmental protection, and new energy production technologies.

Michigan's 21st Century Electric Energy Plan was released by MPSC Chairman Peter Lark on January 31, 2007. It concludes, as did the earlier *Capacity Needs Forum Report*, that Michigan needs additional electric supply, although the Plan estimates increased demand of 1.2 percent per year compared to the *Capacity Needs Forum Report* estimate of 1.5 percent per year. The Plan proposes to meet this need by establishing an energy efficiency program, creating a mandatory renewable portfolio standard, and ensuring that a new base load coal plant is operational no later than 2015.

Public Act (PA) 141 of 2000 restructured Michigan's electric market in an attempt to bring customer choice and electric supply competition to Michigan. Prior to the enactment of PA 141, electricity providers in Michigan operated under a monopoly market structure in which utilities were provided a nearly exclusive geographical area of service in return for regulated rates and an obligation to serve all customers in the area. Under PA 141, alternate electric suppliers (AESs) are free to offer electric service at the retail level, but with no obligation to serve customers beyond the length of a contract. Regulated utilities, however, maintain the obligation to serve any customers that decide to return to the utility. In other words, Michigan has a hybrid market structure—part regulated and part unregulated. According to a previous study by Public Sector Consultants (PSC), this hybrid structure has created an economically unsustainable system for both producers and consumers of electricity in Michigan.

This lack of predictability in the customer base is the major reason cited by Michigan utilities for not proceeding with the construction of new base load generation in Michigan. Capacity has been added in Michigan since the enactment of PA 141, but it has been in the form of natural gas–fueled cycling and peaking generation plants built by independent power producers (IPPs). Given that a major component of the Plan is the construction of at least one new base load power plant by 2015, can Michigan's current hybrid structure accommodate the goals and initiatives of *Michigan's 21st Century Electric Energy Plan*? Or would Michigan be better served by fully deregulating its electric market, returning to a more traditional regulatory model, or making some changes to PA 141?

That is the fundamental question addressed by this study: **If *Michigan's 21st Century Electric Energy Plan* accurately portrays the goals toward which Michigan's electric industry should be moving, what type of market structure would enable the stakeholders to best reach those goals?** The Plan states that Michigan's current hybrid structure is flawed, but it is not clear what changes are needed to create the right structure for the realization of these goals.

This study will answer the question of what type of market structure is optimal for Michigan to successfully implement the policy initiatives of *Michigan's 21st Century Electric Energy Plan*. To conduct this analysis, this study accepts the initiatives and goals of the Plan **as written**, acknowledging that elements of the Plan will be debated on their own merits.

MICHIGAN'S 21ST CENTURY ELECTRIC ENERGY PLAN: GOALS AND INITIATIVES

Michigan's 21st Century Electric Energy Plan proposes three major initiatives. These major initiatives seek to accomplish six underlying policy goals, which were first established in the Governor's Executive Directive:

1. **Economic development**—job growth related to the construction and operation of in-state generation, renewable energy technologies, and implementation of energy efficiency programs; the new business and entrepreneurial aspects of energy efficiency measures and a mandatory renewable portfolio standard; the opportunity for firms to conduct research and development that leads to technological breakthroughs; and avoiding reliance on energy produced out of state.
2. **Improving environmental quality**—reducing the need for fossil-fuel generation and associated emissions.
3. **Promoting resource diversity—**not relying too heavily on any one source of generation.
4. **Ensuring reliable electric power**—power will be there when it's needed.
5. **Stable prices**—attempting to reduce reliance on the Midwest Independent Transmission System Operator (MISO), because current trends indicate that markets operated by MISO will be costly and volatile.
6. **Sharing corresponding benefits associated with investment and advanced technologies**—requiring new plant construction, energy efficiency efforts, and the use of renewable sources for generation creates incentives for the use of new technology, which has job and economic development effects.

The three initiatives of *Michigan's 21st Century Electric Energy Plan* are based on demand growth in Michigan that would require four base load generating plants to be operational by 2015 if energy efficiency and a renewable energy portfolio are not implemented. The initiatives are:

1. The creation of a **Michigan Energy Efficiency Program (MEEP)** that is financed by a non-bypassable surcharge on all electric retail customers in Michigan. This program would displace the need for two base load plants by 2015.
2. The creation of a mandatory **renewable portfolio standard** (RPS) of 10 percent by 2015. This would displace the need for one base load plant by 2015.
3. The approval of one clean, coal-fueled, **base load plant** so that it is operational by 2015.

Michigan's Current Framework

MICHIGAN'S CURRENT GENERATION MIX

Michigan's existing electric generation capacity is approximately 30,000 megawatts (MWs) and comprises different types of plants (base load or cycling/peaking capacity) with different fuel sources (coal, nuclear, and natural gas).[2] Cycling and peaking generation—defined as plants with flexible operating characteristics such as short start-up times and frequent periods of limited operation—primarily relies on natural gas turbine technology, while base load generation—massive generators that operate continuously at or near full capacity around the clock, and used to supply the majority of the electrical energy used over the course of a year—are characterized by coal and nuclear generation. A combination of base load and cycling/peaking generation is used by utilities to economically meet customers' fluctuating electrical demand.

Modern generation capacity additions in Michigan have occurred in two distinct waves. The first wave occurred in the 1970s and 1980s, when approximately 14,000 MWs of predominately base load coal and nuclear plants were installed by regulated utilities. The second wave occurred after 1990, following the deregulation of the wholesale electric market; at that time, approximately 7,000 MWs of natural gas–fired cycling/peaking capacity was installed, principally as merchant plants by independent power producers (IPPs).[3]

As a result of these more recent additions, Michigan currently relies more heavily on natural gas–fired generation than do Ohio, Illinois, and Indiana.[4] The consequence of the state's greater reliance on natural gas-fired generation is that electric generation fuel costs are higher and more volatile than they would have been if additional base load generation capacity had been installed in Michigan.

PROJECTED FUTURE NEED FOR ELECTRICITY PLANTS

The increased utilization of energy efficiency and renewable energy resources reduces—but does not eliminate—the need for new base load generation in Michigan. The benefit of increased reliance on these alternative energy resources from now until 2015 largely meets the state's additional electric energy resource needs during this time by providing the equivalent of three new base load plants. Beginning in 2015 and beyond, however—even with a renewable portfolio standard (RPS) and energy efficiency (EE) program in place—there is a substantial need for new base load generation due to projected increases in demand. Given that it takes seven to eight years to permit and construct a new base load plant, it is essential for Michigan to implement energy policies now to ensure that necessary new base load generation will be brought on line in time.

Put another way, when reviewing information from *Michigan's 21st Century Electric Energy Plan* and the *Capacity Needs Forum Report,* the following points are clear:

- Michigan could need up to four base load plants between now and 2015. The Plan proposes to provide the equivalent of four base load plants of power by constructing one new plant,

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[2] U.S. Department of Energy (DOE), Energy Information Administration, State Electricity Profiles 2005.
[3] A merchant plant is a plant that is built on a speculative basis to serve the wholesale power market.
[4] In 2005, the base load generation share of Michigan's total generation output was 85 percent, compared to 97 percent, 94 percent, and 96 percent for Ohio, Indiana, and Illinois, respectively. Michigan's percentage of base load generation output includes the power from AEP's 2,160 MW Cook nuclear plant located in southwest Michigan, which primarily serves AEP customers in other Midwest states; therefore, the percentage of base load that serves Michigan customers is lower than 85 percent (DOE, op. cit.).

avoiding one plant through implementation of an RPS, and avoiding two plants through implementation of a statewide energy efficiency program.

- After 2015, electricity demand growth projections show that Michigan may need up to nine additional base load plants—or the equivalent of approximately one new plant per year for the following decade.
- These base load plants are **in addition to** projected growth in peaking plants for periods of intense demand.
- Obviously, any regular, substantial purchase of power from the wholesale market can decrease the need for a new base load plant in Michigan. Such a strategy, however, assumes that new merchant plants will be built in other states to meet the increased demand in Michigan; increases the state's reliance on volatile, deregulated wholesale market power purchases; and brings into the equation all of the complications and considerations of whether the interstate transmission capacity will permit the power to be provided to Michigan when it is needed.

MODELS OF NEW GENERATION DEVELOPMENT IN THE U.S.

By way of background, there are two fundamental paradigms under which new generation can be developed in U.S. markets. The first paradigm is where regulated electric utilities build new generation in response to rules and regulations formulated by state public utility commissions while maintaining the traditional utility obligation to serve all customers in a given region/state. The second paradigm is in a competitive (deregulated) market, where IPPs build new generation in response to market price signals. The former approach exists in states that have retained traditional regulation for retail generation. The latter approach, as a consequence of federal deregulation of wholesale electric markets means that IPPs can build new plants for the wholesale market, even in regulated states.

Regulated electric utilities **must** either build new generation or purchase power generated by others by virtue of their regulated status and legal obligation to serve **all retail customers**; customers, for their part, must purchase all of their power from the utility at a regulated rate. This is the foundation upon which existing capital-intensive coal and nuclear base-load generation was developed nationally and in Michigan. Conversely, IPPs **may** build new generation to serve the **wholesale** market or a large industrial customer. Therefore, an IPP's decision to build is predicated upon analyzing perceived investments risks and potential market financial returns. This is the basis under which recent merchant natural gas–fired cycling/peaking generation was developed nationally and in Michigan.

The critical economic and financial distinction between the two paradigms—and as a result, the different generation plant investment outcomes—is the degree of risk associated with the investment decision. Under a regulated paradigm, stable utility rates tied to long-term recovery of capital-intensive base load plants are determined by a regulatory commission; under a market paradigm, electric prices as determined by the more volatile wholesale market are more likely to yield shorter-term, less capital-intensive investments such as natural gas-fired generation.

WHY MICHIGAN UTILITIES OR IPPs WON'T BUILD BASE LOAD PLANTS TODAY

When companies representing both of these two distinct paradigms are active within Michigan's hybrid structure, major challenges emerge in constructing new base load plants. The greatest challenge is that customer choice—while enabling individual customers to obtain power supply from the deregulated market—does not offer electricity **producers** long-term certainty.

Michigan's regulated electric utilities will not build new base load capacity without **retail** customer predictability (that is, a known and stable number of customers across a multiyear period). To a regulated utility, customer choice allows customers to continually switch back and forth to get the lower of competitive market or regulated generation prices, thereby complicating any decision to justify a major long-term investment.

IPPs will not build base load new capacity without **wholesale** market certainty. This certainty can take two forms: a known and stable price of the generated power across multiyear periods provided by a long-term power purchase agreement (PPA), or an expectation that wholesale prices would consistently be high enough to justify building a plant on a speculative basis (that is, without a long-term contract for the power produced by the new plant). Furthermore, to an IPP, customer choice creates additional barriers to the certainty of its own customer base, and thus to the willingness of investors to fund a new base load plant:

- Since the total cost of electricity from **any** new coal-fired base load plant—regardless of whether the plant is constructed by an IPP or a regulated electric utility—will be higher than the average cost of electricity from Michigan's existing utility-owned plants, it is quite unlikely that any major retail choice customer would decide to enter into a long-term, full-cost contract for power directly from a new base load plant. Instead, these customers would prefer that the higher cost of new generation be "rolled into" a utility's existing generation costs to create a lower blended generation rate and, in doing so, preserve their market choice option as well.
- When IPPs seek long-term PPAs from a utility—which provides the IPP with long-term revenue certainty for the power—the PPA is not matched by any corresponding long-term **purchase** commitment from the utility's retail customers. In other words, while IPPs may demand long-term contracts to provide economic justification to build a new base load plant, there is little economic justification for the purchasing utility to be bound to the same long-term contract.

As a result, the continuation of customer choice is not likely to facilitate the development of new base load generation by either regulated utilities or IPPs.

WHY MICHIGAN BASE LOAD GENERATION IS IMPORTANT

Construction of new base load generation in Michigan is important for several reasons:

- In-state generation capacity is inherently more reliable than out-of-state generation because fewer long distance transmission paths are required to transmit power from out of state to Michigan customers. In addition, ancillary services that are essential to maintaining voltage stability can best be provided by electrical generators located near customer demand.
- Base load generation, by virtue of its lower cost of fuel and ability to operate continuously around the clock, will displace more expensive natural gas–fired generation.
- Without new Michigan generation, a major expansion of the transmission system will be required in order to import additional electric power into the state. Since the transmission expansion—and the related wholesale electric purchase activities—would be interstate in nature, it would be subject to federal oversight through the Federal Energy Regulatory Commission (FERC) as opposed to state oversight through the Michigan Public Service Commission (MPSC). In addition, importing power is by definition a reliance on market- or contract-based rates, as opposed to regulated cost-of-service rates.

New Base Load Generation

INTRODUCTION

Since the last base load plants were placed into service in Michigan more than 20 years ago, significant electric industry restructuring has occurred at both the federal and state levels, new environmental control requirements have been enacted, and new generation technologies have been developed. The *Michigan 21st Century Electric Energy Plan* assessed Michigan's current electric market structure as it affects the development of new base load generation, and found that the current hybrid structure is unsustainable and makes planning and financing expensive, long-lived, base load generating units very difficult.[5] As a result, the Plan recommended a series of policy changes to Michigan's electric market structure in order to encourage the construction of a new base load coal plant.

THE PLAN'S RECOMMENDATIONS

Challenges of Developing Base Load Generation

The Plan identifies a number of significant policy issues, market uncertainties, and regulatory uncertainties that add risks to the development of new base load generation. These can be summarized in three broad categories.

- **Generation plant development risks:** Unknown customer load growth and future penetrations of energy efficiency and renewable resources; emerging, but commercially unproven, new plant technologies; and uncertain future environmental compliance requirements collectively create significant uncertainties about the needed **amount** and appropriate **type** of new base load capacity.
- **Michigan's current hybrid electric regulatory structure:** Lack of a defined and predictable customer base creates uncertain future electricity demand and revenues for new and existing generation.
- **Generation cost management:** It is essential to ensure that expensive new power plants are constructed and operated at the lowest possible costs.

Generation Plant Development

To mitigate the risks that regulated electric utilities face in developing new generation plants, the Plan offers several policy changes similar to those adopted by other Midwest states. These changes, if enacted in Michigan, would provide

- greater stakeholder participation in the integrated resource planning process,
- reduced after-the-fact regulatory decisions that prevent utilities from recovering some or all of the costs of plant construction, and
- greater control and certainty of generation construction costs.

Collectively, these changes would reduce utility generation development risks—and hence the cost—of financing multibillion-dollar base-load generation projects. Specifically, the changes would create a process of pre-approval by the Michigan Public Services Commission (MPSC), and would consist of:

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[5] Michigan Public Service Commission (MPSC), *Michigan's 21st Century Electric Energy Plan* (Lansing, Mich: MPSC, January 2007), 15–17.

Nuclear Power

In discussions of base load power generation, this report follows the lead of Michigan's 21st Century Electric Energy Plan in focusing on coal as the anticipated fuel source. As a result, this report does not discuss the possibility of a nuclear powered base load plant.

This does not mean that nuclear power is an unappealing source of base load power in the state. In many ways, the increased cost stability and certainty associated with base load nuclear power plants may make nuclear power a more appropriate source of base load power than coal in meeting the goals of the Plan.

At a minimum, nuclear power would insulate Michigan's future base load power sources from potential cost increases resulting from new environmental regulations. In particular, any change in the nation's emissions policy or the implementation of a broad-based carbon tax would not affect the cost of generating nuclear power.

Still, the potential benefits of nuclear power come with some non-trivial costs. Currently, there is no effective national long-term storage plan in place for the waste generated by nuclear power generation, thereby requiring each nuclear facility to have its own plan to store and control waste. Nuclear power plants also tend to be more difficult to site than coal plants due to safety and environmental concerns, and the more complex nature of the generating plant lengthens both engineering and construction timelines.

- **Integrated Resource Planning (IRP) process:** The IRP process provides the opportunity for public analysis and comment regarding a utility's assessment of its need for new generation, including the utility's use of energy efficiency and renewable energy resources.
- **Certificate of Need (CON):** If, as a result of the IRP process, the MPSC determines that additional generation is needed, it would issue an irrevocable certificate of need to the utility.
- **Recovery of construction financing during the construction period:** A utility would have the ability to recover some, or all, of the construction **financing** costs during the construction period at the sole discretion of the MPSC.

Michigan's Current Market Structure

The second category of risk—Michigan's hybrid regulatory structure—is unique to Michigan and exists because the state has not embraced either a fully regulated or a fully deregulated structure relative to retail electric generation. The ability of retail customers to move freely between regulated and competitive markets creates permanent uncertainty about the size of the customer base for both utilities and alternate energy suppliers (AESs), which then complicates utility and independent power producer (IPP) decisions about building new base load plants.[6] As a consequence, the Plan offers policy changes to provide increased revenue predictability for Michigan's electric utilities that choose to develop new power plants. The Plan also recommends rate de-skewing[7] and changes to the operation of the choice program in attempt to reduce the uncertainty stemming from customer switching.

[6] This issue is also discussed in the previous section, Why Michigan Utilities or IPPs Won't Build Base Load Plants Today.

[7] Skewing refers to the fact that regulated rates for rate classes (residential, commercial, and industrial) are not set at actual cost; rather, some rates are intentionally set above cost (in Michigan, commercial and industrial rates) to allow others to be set below cost (residential rates).

Role of New Versus Existing Base Load Plants

The current energy plan debate has focused almost exclusively on policy changes that are required in order to develop new base load power plants. As these policy options are examined, it is equally important to recognize the crucial role Michigan's existing generation base plays in ensuring both reliable and affordable electric supply for all customers. Any policy adopted to encourage new generation that creates significant and artificial distinctions between new and existing generation will not serve Michigan's best interests.

When reliable power is needed, there is no distinction between existing and new generating plants. On a hot summer afternoon, all generators within a geographic area contribute equally to ensuring that the grid is reliable. Unfortunately, the total cost of electricity from a new base load generating plant, regardless of who builds the plant, will be higher than the total cost of electricity from Michigan's existing plants. Consequently, adding new base load plants into the state's generation mix will drive overall generation costs upward as the higher costs of new plants are blended with lower cost, existing plants.

Conversely, preserving existing utility generating plants—when existing plants have a useful "life span" and are economically effective—produces significant positive public benefits.

- Since a greater percentage of Michigan's generation output would be from lower cost, existing plants, fewer expensive new plants would be required.
- As existing plants age and new environmental compliance regulations are enacted, utilities will be required to make significant capital investments in these plants in order to continue their operation. These investments could represent comparatively lower cost capacity opportunities since existing plants are partially or fully depreciated. Additional investments are cost effective as long as the existing plant's infrastructure can support the expansion or environmental control.

To the extent that investments in existing plants are at risk for recovery due to customer switching, but similar dollar investments in new plants would be provided revenue certainty, perverse financial incentives would be created which could lead to unintended economic consequences: If incentives that provide greater customer predictability or recovery of costs are only made available to new plant construction, utilities would have little incentive to keep in operation existing low-cost base load plants, and a comparatively larger incentive to construct new plants.

To provide at least a degree of certainty to electric utilities, the Plan recommends that once a utility is granted a CON for a new power plant—effectively signaling to the utility that the plant's construction cost is more likely to be recovered—customers must choose whether they want to remain with the incumbent utility or move into the choice program. If incumbent utility customers later elect service from an AES, these customers would be required to take their share of the plant's fixed cost with them to the AES as a non-bypassable distribution charge. Consequently, the utility would have retail revenue certainty for construction of **new** generation, and the effect of this policy change is the full regulation of **new** retail generation in Michigan.

Generation Cost Management

In order to ensure that power plant construction costs are reasonable, the Plan recommends that Michigan's regulated utilities be required to solicit bids for the engineering, procurement, and construction (EPC) of a new plant. The utility would own and operate the power plant, and the plant would be subject to regular MPSC review and oversight.

OTHER STATES

By definition, states that have deregulated retail electricity generation no longer have the option to develop new regulated, cost-based generation; therefore, these states are entirely dependent upon IPPs and market forces to develop their new generation. Wholesale market fundamentals—rising wholesale electric market prices and declining generation reserve margins—are signaling a need for new base load capacity, yet this generation is not being developed because of wholesale market price volatility and hence wholesale revenue uncertainty. [8]

This situation has led some states and regional transmission organizations (RTOs) to examine regulated, cost-based pricing alternatives for providing wholesale certainty for both new and existing generation, such as forward capacity market (FCM) subsidies and "reliability must run" (RMR) contracts. For example, the major RTOs that operate the New England, New York, Middle Atlantic, and portions of the Midwest wholesale electric markets have created FCMs approved by the Federal Energy Regulatory Commission (FERC) in an attempt to provide increased certainty for IPPs to build power plants. The FCMs are administratively determined amounts that are added onto spot energy market prices for a period of three to five years; the amount of the FCM is equivalent to the annual capital cost of a natural gas–fired cycling/peaking plant. FCMs also are paid to **existing** generators in recognition of the fact that preserving existing generation is critical from a reliability perspective.

RTOs are also utilizing FERC-approved RMR contracts for specific existing power plants to ensure the recovery of plant operation costs when market prices are insufficient to provide for this. Without an RMR in place, in unfavorable market conditions the owner may choose not to operate the plant, which would decrease the overall reliability or reserve capacity of the region's electricity grid.

In other states, new coal-fired generation currently under construction is being developed by investor-owned utilities in states that have retained the traditional regulatory structure or by cooperative, municipal, or other quasi-governmental entities elsewhere. For example, Connecticut is considering creating a state power authority to build new plants. Pennsylvania is reexamining the regulated distribution utility's role as Provider of Last Resort (POLR) to determine whether the utility should be responsible for ensuring that necessary new generation is developed. Ohio is contemplating a non-bypassable wires charge mechanism to enable utilities to recover the cost of new generation.[9] Some states, including Wisconsin and Iowa, have enacted policy changes that enable a utility to obtain a binding CON for new generating plants. Even though these states did not implement customer choice, and therefore do not have future customer base uncertainty, a binding commission pre-approval process was implemented in order to reduce power plant financing risks and hence lower the costs of new plants. In addition, 35 states have historically required utilities to obtain siting approval or certificate of public need prior to construction of new power plants, and an increasing number of states are allowing utilities to request ratemaking decisions before beginning construction of a new plant.[10]

In summary, the common approach in states with deregulated generation markets, and elsewhere with some regional wholesale market operators, is to avoid reliance on volatile spot market prices and provide increased wholesale and/or retail revenue certainty through a variety of regulatory mechanisms or procedures. In states with a traditional, regulated generation structure, the common theme is to eliminate the after-the-fact prudency risks—thereby reducing financing costs

[8] North American Electric Reliability Corporation (NERC) *2006 Long-Term Electric Supply Assessment*, dated October 2006. The assessment takes into account customer demand projections and planned generation additions and retirements. Electric reserve margins will decline over the 2006–2015 period in most regions, including the Midwest, and reflects a short-term resource acquisition strategy that has been the norm for most of the past ten years.

[9] In addition, Ohio continues to delay the expiration of utility rate caps and the transition to deregulated existing utility generation to prevent retail customers from being exposed to high wholesale electric market prices.

[10] *Michigan's 21st Century Electric Energy Plan, Appendix - Volume I*, 49.

associated with development of base load generation—through processes such as binding commission pre-approval of the decision to build a new plant.

EVALUATING POLICY FRAMEWORKS

Status Quo

The status quo is the default policy if Michigan fails to adopt new policies with regard to electric generation. It is highly unlikely that any company[11]—regulated utility or IPP—will build generation under this scenario, given the continued lack of retail customer revenue or wholesale market price certainty, respectively. If the status quo fails to encourage the construction of a new base load coal plant by 2015, then a major goal of the Plan cannot be achieved.

In the absence of a new base load plant, the status quo would violate other principles or desired outcomes of the Plan.

- Michigan's power supply practice would shift from in-state generation additions to reliance upon a deregulated wholesale market, out-of-state generation, and imported power. While additional transmission investments would be required to import additional power into Michigan; some of these expenditures would have to be made outside of the state to relieve regional grid constraints that adversely affect Michigan. Furthermore, under the status quo Michigan is very likely to miss out on the economic development associated with the construction and operation of a new base load plant—both in direct and indirect jobs and related economic activity.
- Since (as long as the transmission capacity is available) generating plants serving Michigan can be located anywhere in the region, electric supply reliability would be diminished under a status quo option. There would be greater day-to-day reliance on imported power to replace generating plants not developed in Michigan. In-state, local generation is inherently a more reliable source of electric supply than the importation of remote, out-of-state generation across the interstate transmission grid.[12]
- Michigan by necessity would have to increase its purchases from the Midwest Independent Transmission System Operator (MISO) regional wholesale electric market, thereby violating the Plan's goal of stable prices. Ultimately, Michigan would effectively deregulate its generation over time as existing regulated power plants are retired and customer demand grows—to be met with IPP-based merchant plants (which operate in a volatile market) and purchase of power through the MISO (which also operates in a volatile market).
- Wholesale market prices would increase over time in response to the increased utilization of natural gas–fired generation in Michigan, and wholesale prices would likely be higher than the average regulated utility generation rate in Michigan, thereby violating the Plan's goal of stable and affordable electric prices. In addition, if wholesale prices increase relative to regulated utility rates, the ability of Michigan's retail customers to continue to realize price savings by procuring power from alternative electric suppliers would be limited at best.
- In addition to greater reliance on out-of-state, market-based purchases to meet customer needs, utilities could use the market to help meet environmental regulations by purchasing

[11] The Wolverine Power Supply Cooperative, which is the wholesale power supplier for four retail distribution cooperatives in northern Michigan, has announced plans to build a coal-fired plant at Rogers City to meet its own projected load. Wolverine's distribution cooperatives, however, have non-bypassable charges on their distribution tariffs to fund the plant's development (*Michigan's 21st Century Electric Energy Plan*, 16).
[12] This issue is also discussed in the previous section, Why Michigan Base Load Generation is Important.

environmental allowances to minimize potential creation of additional stranded costs. This would also provide operational and financial flexibility to quickly adjusted market purchases in response to customer switching levels.

- Promoting resource diversity would not be achieved because Michigan's dependence upon natural gas–fired generation would continue to increase. There would also be no shared corresponding benefits associated with investments and advanced technologies since current gas-fired turbine technology would be installed as the capacity of last resort.

Modify PA 141

By implementing the modifications to PA 141 recommended in the Plan, this policy option would enable the continuation of Michigan's traditional power supply practice of building in-state generating plants to serve additional customers' load requirements. These policy changes would re-establish the traditional utility "obligation to serve" compact in Michigan for new—but not for existing—utility generation.

- With new in-state generation plants, Michigan could begin to reduce power purchases from the MISO regional wholesale market, which should bring more stability to electricity prices. Additional transmission investments would be required, not to increase power import capacity, but rather to connect new base load generators to the Michigan grid.
- If modifying PA 141 as the Plan outlines allows new base load plants to be built in Michigan, wholesale market prices should decrease over time as Michigan's dependence upon natural gas–fired generation is reduced when new coal-fired generating plants are built, restoring the state's generation fuel mix closer to the regional average.
- Michigan's regulated utilities would be confronted with a major generation investment quandary with respect to **existing** generation. Utility capital investments to expand or preserve existing generating plants would be at risk for cost recovery due to potential customer switching, yet capital investments in **new** Michigan generation would not be at risk under this policy option. As with the status quo option, there would be increased reliance on market-based purchases to meet environmental regulations (i.e., emission allowances) to minimize potential creation of additional stranded costs and provide operational and financial flexibility to quickly adjusted market purchases in response to customer switching levels.
- Michigan's economic development climate would be improved if PA 141 were modified. New base load generating plants would be built in Michigan, creating temporary construction jobs, permanent plant operations and maintenance jobs, and additional tax base. Fewer Michigan dollars would be sent out of state to MISO to purchase power and import it into Michigan, and, if the new plant has capacity, Michigan may be able to export power to others states by selling excess capacity into the MISO market. Michigan electric rates could be higher if less existing, low-cost generation is preserved, and they could be volatile if customer switching continues to occur because lost utility generation revenues would be recovered from fewer remaining customers.
- Promoting resource diversity would be achieved because Michigan's dependence upon natural gas–fired generation would be reduced as new in-state coal-fired generating plants are built.
- Electric supply reliability would gradually be improved by modifying PA 141. There would be less day-to-day reliance on imported power because in-state, local generation, which is inherently a more reliable source of electric supply, would replace existing out-of-state power purchases. In-state generation reserve margins would likely be within the range considered acceptable.

Investment Profile of a New Base Load Plant

While the primary purpose of Michigan's 21st Century Electric Energy Plan is to provide energy security for Michigan, there can be significant job benefits from the construction and operation of base load power plants in the state. Estimates from utility companies suggest that the construction of a 750 megawatt coal-powered plant could involve a total investment of $1.5 billion and—at peak construction—approximately 1,200 jobs in the construction and building trades sectors. Following the plant's construction, operations and maintenance activities are likely to involve 100–150 permanent jobs. In comparison, the total investment for a 1,200 MW base load nuclear facility would be $3 billion, with approximately 1,800 construction jobs and 500 permanent jobs.

These skilled construction and plant operations jobs in the electricity generation and transmission sector will be essential to the long-term development of Michigan's economy.

- Stable and affordable electricity prices would not be achieved if this policy is adopted. It would result in a gradual but eventually full re-regulation of generation in Michigan, because over time, new plants that enjoy the non-bypassable surcharge would replace aging, existing plants that do not have the same revenue stability. In fact, the disparate regulatory treatment of new and existing utility generation could accelerate the transition from existing to new plants in Michigan. Preserving aging but low-cost plants, installing environmental retrofits, and seeking innovative, low-cost capacity expansion opportunities at existing Michigan power plants, all of which are in the public interest, would unfortunately be discouraged under this energy policy option. Regulated electric prices could rise at a more rapid rate as lower cost, existing generation is replaced by higher cost, new generation at an accelerated pace. Additional base load generation output would reduce reliance on wholesale market purchases and natural gas–fired generation, which would drive down wholesale electric prices. As a consequence, customer choice switching could accelerate, with adverse rate increase consequences for regulated utility customers.

Repeal PA 141

Repeal of PA 141 would enable regulated utilities to build new base load generation and in addition, would encourage the continued utilization of Michigan's existing low-cost generation capacity. Assuming that re-regulation would also include the binding commission pre-approval recommended in the Plan as a modification of PA 141, a regulated utility would construct new generation or make major capital investments in existing generation after the MPSC issued a CON authorizing the investment, and all retail customers would have a corresponding obligation to pay for the reasonable cost of the plant investments. These policy changes would reestablish the traditional utility "obligation to serve" compact in Michigan as it existed prior to the enactment of PA 141 (which created a disparity between a utility's obligation to serve and the lack of the same obligation on the part of an AES).

- This policy option would enable the continuation of Michigan's traditional power supply practice of building in-state generating plants to serve additional load requirements. New base load generation would be built in conjunction with increased utilization of energy efficiency and renewable resources to meet customer demand. Over the long term, fewer new plants would be required, since utilities would make significant investments in existing power plants to preserve and clean up the emissions from lower cost existing plants to the greatest extent possible. Moreover, innovative, low-cost capacity expansion options would potentially be available at existing generating plants.
- With new in-state generation plants, Michigan would begin to reduce power purchases from the MISO regional wholesale market. Additional transmission investments would be

required, not to increase power import capacity, but rather to connect new base load generators to the Michigan grid and remove intra-state capacity bottlenecks. Michigan would not be at risk if new merchant base load generation were not built in the region. New natural gas–fired peaking capacity would not be the generation option of last resort. Existing and new base load generators would provide reliability as well as lower fuel cost generation benefits.

- In a re-regulated environment, electric rates for remaining utility customers would not have to increase to provide for recovery of generation fixed costs from a smaller utility customer and sales base (e.g., choice customers). Michigan's regulated utilities would not face the quandary of making major investments in existing generation because these investments would not be at risk for cost recovery; therefore, utilities would be encouraged to make major capital investments in their existing base load generating plants to reduce environmental emissions, expand plant output, or simply preserve aging generating units based on a longer time horizon with a more stable customer base.
- Michigan's economic development climate would be maximized under a repeal of PA 141. New base load generating plants would be built in Michigan, creating temporary construction jobs, permanent plant operations and maintenance jobs, and additional tax base. Fewer Michigan dollars would be sent out of state to MISO to purchase power and import it into Michigan. In fact, if the new plant has sufficient capacity, Michigan may be able to export power to others states by selling excess capacity into the MISO market. Michigan electric rates would be the lowest possible and most competitive with surrounding states because existing, low-cost generation would be preserved as long as investments in existing plants are cheaper than constructing new plants. Further, rates would be stable since utility generation revenue losses due to choice would not have to be recovered from fewer remaining customers. The MPSC could be given authority to implement special economic development tariffs to retain and attract businesses to Michigan, similar to the policies in other states that have retained a traditional utility regulatory structure.
- Repealing PA 141 would provide the greatest potential for reducing power generation emissions in Michigan. Although state-of-the-art environmental control technologies would be installed on new coal-fired plants some additional residual emissions would occur. However, major capital investments in advanced environmental control technologies would also be made at existing power plants since the customer switching risk would be eliminated.
- Promoting resource diversity would be achieved because Michigan's increasing dependence upon natural gas–fired generation would be reduced as new in-state coal-fired generating plants are built, bringing Michigan closer to the regional average for base load generation. Elimination of customer choice revenue uncertainty would enable utilities to consider all technology and resource options and adopt those that minimize long-term costs and environmental compliance risks.
- Electric supply reliability would gradually be improved under a repeal of PA 141. There would be less day-to-day reliance on imported power because reliable, in-state, local generation would replace some of the existing out-of-state power purchases. In-state generation reserve margins are likely to be within the range considered to be acceptable.
- This option would afford the greatest likelihood of stable and affordable electricity prices. Elimination of the disparate regulatory treatment of new and existing utility generation would allow the optimal long-term transition from low-cost, existing plants to higher cost, new plants in Michigan in order to minimize the impact of rate increases. Elimination of customer choice switching would prevent adverse rate increases for utility customers caused by the loss of choice customer revenues.

The repeal of PA 141 would appear to be the best policy option to foster development of Michigan base load plants. Evidence from across the country suggests that increased regulatory revenue stability of some type will be required in order to build new base load generation. Consequently, it is simply a matter of time before the current complete reliance on *existing* generation would transition to a significant reliance on *new* generation to meet customer demand. Given that an eventual *de facto* re-regulation of existing generation is inherent in any policy that re-regulates only new generation, there would be no public policy benefit from waiting until this inevitability occurs. On the contrary, there are substantial public benefits from moving toward a re-regulated equilibrium more quickly. Stated differently, if the state's regulatory model does not create a disparity between existing and new generation, then all generation capital investments are placed on the same footing with respect to cost recovery risks—and Michigan utilities can choose the best long-term mix of new plant construction versus investments in existing base load plants.

Renewable Portfolio Standard

INTRODUCTION

Renewable portfolio standards are a method of diversifying the fuel sources for power generation, and are now active in 24 states covering roughly 40 percent of the nation's electricity generating power.[13] Similar regulatory structures are in place in other nations, including the Belgium, Italy, Poland, Sweden, and the United Kingdom.

Renewable portfolio standards are generally judged on two interrelated factors: (1) the ability to generate new forms of renewable energy supplies, and in turn sustain a viable renewable sector, and (2) the ability to meet this goal without drastically increasing retail electricity rates. It is the combination of these two factors that mark a successful renewable portfolio standard (RPS). Furthermore, studies suggest that renewable portfolio standards have promoted the development of new sources of renewable energy and are not simply codifying choices that utilities would have made anyway. The Lawrence Berkeley National Laboratory estimates that between 2001 and 2006 "over 50 percent of the total wind additions in the United States were motivated, at least in part, by … state RPS policies."[14]

The justifications for an RPS range from the environmental to the economic. At its heart, an RPS is an environmental standard designed to move a state's energy supply toward cleaner and more sustainable fuels. Beyond these environmental reasons, however, are economic arguments related to both local economic development and energy price stability. Clearly, the construction of renewable electricity plants involves a number of short-term construction jobs. States hope, however, that requiring the construction of these plants will spur the development of a broad-based renewable energy sector in the state. Such a sector would likely involve highly skilled jobs that are seen as critical to successful long-term economic development. As will be discussed below, some states have tried to mandate this outcome through local source requirements for renewable power. Such policies, however, could have questionable long-term effects on economic development.

In addition to economic development resulting from the location of renewable fuel sources, an RPS can introduce needed stability to some electricity markets—particularly during times of peak demand in the market or disruptions in supply of traditional fuels. Prices for electricity from the natural gas–based generators that serve Michigan's peak energy demands are susceptible to the volatile natural gas commodity market. As has been seen over the last several years, the prices in this market can be greatly affected by external factors such as inclement weather in the Gulf of Mexico and cold winters across the nation. In contrast, renewable fuel sources, while potentially having a slightly higher average price than other sources, offer a **cost** stability that is necessary for long-term planning.[15] In this way they are a valuable part of a sustainable and stable fuel mix.

While the cost stability and environmental benefits of an RPS are described above, the overall cost impact on consumer electricity rates are less clear. Independent estimates of expected price increases in other states predict a wide range of potential impacts when comparing renewable energy to natural gas-based production. An analysis of these existing studies found potential rate

[13] Ryan Wiser et al., *Renewable Portfolio Standards: A Factual Introduction to Experience from the United States* (Berkeley: Lawrence Berkeley National Laboratory, April 2007), 2.
[14] Ibid., 13.
[15] Depending on the renewable technology, renewable sources also can offer generation stability. Biomass has generation stability since it can be run "on demand," while wind-based generation (at least in Michigan) does not have generation stability since it depends on the presence of wind.

changes ranging from an **increase** of 8.8 percent to a **decrease** of 5.2 percent. Therefore, while the median estimate of these studies is only 0.7 percent, this statistic obscures the high variance in predicted effects.[16]

The lack of certainty regarding costs is an important consideration in the ability of Michigan to meet the goals of the RPS. If Michigan is committed to meeting the 10 percent target regardless of the cost to Michigan providers to implement the standard, then the effect of Michigan's RPS on electricity rates could be at or above the high range of previous estimates. If, however, Michigan is sensitive to the potential impact on consumer electricity rates and decides to slow down the implementation to stabilize the effects on rates, then it is less certain that Michigan's electricity producers will meet the RPS requirement by 2015.

The potential of Michigan failing to meet the 10 percent RPS requirement has far-reaching implications for the adequate supply of power in the state. While renewable power is not intended to be a source of base load generation, the Plan's projected need for only one new base load plant by 2015 is based partly on meeting the RPS requirements. If Michigan fails to meet the RPS standard, the state may require additional base load plant construction.

THE PLAN'S RECOMMENDATIONS

Michigan's 21st Century Electric Energy Plan proposes, for the first time, a formal commitment by Michigan to a renewable portfolio standard. The proposed RPS would require that all load serving entities (LSEs)—essentially, anyone selling electricity on a retail basis—in Michigan certify that 10 percent of their power be generated from renewable resources by 2015.

The RPS proposed by the Plan has a number of features that need to be understood:

1. It is a mandatory standard.
2. LSEs could meet the standard by owning and operating RPS projects, they could contract with independent RPS developers located within Michigan, they could make payments (alternate compliance payments—ACPs) in lieu of meeting the RPS,[17] or they could purchase qualifying renewable energy credits (RECs).
3. "Eligible" renewable energy projects would include those currently defined in PA 141—solar, wind, geothermal, hydroelectric, and biomass.[18] While the Plan would not require specific renewable types from this mix, the Plan assumes the 10 percent standard for 2015 will be attained from biomass and wind resources.[19]
4. The Plan proposes **in-state** renewable energy projects. The only exception appears to be with the REC program; however, the Plan states that "…RECs may be purchased from

[16] Chen et al., *Weighing the Costs and Benefits of State Renewables Portfolio Standards: A Comparative Analysis of State-Level Policy Impact Projections* (Berkeley: Lawrence Berkeley National Laboratory, March 2007).

[17] LSEs with fewer than 100,000 customers can make ACPs throughout the entire program. Those with more than 100,000 customers can only meet their RPS requirement through ACPs until 2012. These payments are placed into the energy efficiency fund described in the next section.

[18] Biomass includes (1) cellulose-containing biomass, such as wood and cornstalks; (2) waste-water treatment plant waste, as well as cattle, swine, and poultry waste; (3) landfill gas; and (4) waste-to-energy.

[19] The Plan cites the high capital costs and low-capacity features of solar, the small scale of hydro power projects in Michigan, and the fact that Michigan does not have access to geothermal sources of power in discounting the contribution to the target from those sources.

out-of-state resources as long as the REC produced an air quality or economic benefit to Michigan."[20]

5. The cost of an RPS would be recovered from customers as part of overall cost-recovery mechanisms and rates for regulated utilities and through rates or a non-bypassable charge for alternative energy suppliers (AESs).
6. The 10 percent requirement for 2015 is phased in—3 percent by 2009, and a gradual increase until the 10 percent figure is reached at the end of 2015.
7. Existing resources can only be used to meet the initial 3 percent target. The remaining 7 percent must come from new resources.
8. Once enacting legislation is passed establishing an RPS in Michigan and granting authority to the Michigan Public Service Commission (MPSC) to implement it, the MPSC would have the authority to **defer** RPS targets for one year for a specific LSE if the rate impact is deemed "unreasonable" by the commission or if the LSE demonstrates "hardship" in meeting the target. The Plan also proposes granting the MPSC the authority to establish the annual ACP charge, as well as the authority to increase the RPS to 20 percent by 2025 after appropriate studies and hearings.

OTHER STATES

The 24 states that currently have an RPS in place, with targets ranging from 1.1 to 30 percent and target years ranging from 2009 to 2022, encompass a variety of market and regulatory structures ranging from traditional cost-of-service to a variety of hybrid models.[21]

When discussing renewable portfolio standards, it must be noted that there are a variety of requirements that differ greatly across the states. These differences extend far beyond the mandated target level for renewable fuel sources, and include:

- Targeted level of the standard
- Type of fuel considered renewable
- Requirements for specific types of renewable power sources
- Location of eligible renewable suppliers
- Cost recovery mechanisms
- Renewable energy credits (RECs), and whether to allow only in-state RECs or also accept RECs from other states

Renewable Target

Michigan's target of power from renewable resources is below that of the neighboring states of Minnesota (25–30 percent), New York (25 percent), Pennsylvania (18 percent), and Wisconsin (15 percent). It is above the 8 percent called for in Illinois, but the Illinois target is voluntary and thus not fully comparable to Michigan's. Iowa has a requirement that its utilities generate 105 MW of power from renewable fuels.

[20] *Michigan's 21st Century Electric Energy Plan*, 43.
[21] For a summary of RPS programs in other states, see Table 5 in *Michigan's 21st Century Electric Energy Plan, Appendix - Volume 1*, 58.

Mandated Renewable Fuel Sources

While all renewable portfolio standards require a certain percentage of power from renewable resources, there is a great deal of variety concerning both the definition of a renewable power source and the required distribution of power sources within the mandated percentage.

The Plan defined a renewable power source as "energy generated by solar, wind, geothermal, biomass (including waste-to-energy and landfill gas) or hydroelectric sources."[22] Other states have other definitions of what constitutes a renewable power source. While all states recognize wind and solar power as an acceptable means of fulfilling an RPS, some allow for other, less traditional sources. For example, Pennsylvania allows waste coal as a fuel source under its RPS.

In addition to variety in the definition of a renewable power source, several states also have subcategories within their RPS that require the utilization of certain technologies. States establish "tiers" or "bands" of fuel sources and then allocate percentages of the RPS requirement among these categories. For example, the Illinois RPS mandates that 75 percent of the renewable energy in the portfolio come from wind. Similarly, approximately 83 percent of the renewable power required by Minnesota's RPS must come from wind technology. Other nearby states such as Iowa, New York, and Wisconsin do not require any specific breakdown of fuels within the renewable standard. Michigan's Plan, too, does not specify a breakdown of particular fuel types.

Renewable Energy Credits

A common component of nearly all existing state renewable portfolio standards is the allowance for renewable energy credits. An REC is granted to companies that produce energy from renewable resources. By purchasing these RECs, utilities can offset a portion of their required renewable portfolio. Several surrounding Great Lakes states, including Illinois, Minnesota, and Wisconsin, have an REC program. Minnesota's program explicitly states that all credits must be counted equally regardless of geographic source.

Cost Recovery and Rate Impacts

Part of the concern over increased consumer electricity rates is the possibility of unmanageable increases in production costs resulting from the requirements for renewable energy sources. The ability to recover theses costs differs greatly across existing renewable portfolio standards and also varies by regulatory structure. Clearly, in the case of typical cost-of-service regulatory structures, the cost of the RPS is easily recoverable through higher rates. When consumer choice exists, however, there is less certainty about this cost recovery. As a result, an increasing number of state policies have included cost caps that limit the risk to utilities. Cost caps freeze the implementation of the RPS when costs exceed a pre-established ceiling. Other states include provisions to defer targets within the RPS; in Minnesota the utility commission is allowed to modify the RPS if it deems that it is in the public interest to do so. In Pennsylvania, electricity distribution (but not generation) companies have been granted the right to recover all costs caused by the standard.

While cost recovery can obviously be accomplished through surcharges on consumer rates, one of the goals of the RPS is to accomplish fuel source diversity with limited impact on retail rates. Furthermore, there is a concern that under a consumer choice framework, surcharges that are not broadly applied could give an unfair advantage to certain suppliers. As a result of these concerns, some states have also included rate caps in their cost recovery mechanisms. The Illinois program, for example, specifies that expenditures required to meet the renewable goal can not increase consumer electrical rates by more than 0.5 percent in any year, or 2.0 overall.

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[22] *Michigan's 21st Century Electric Energy Plan*, 25.

EVALUATING POLICY FRAMEWORKS

As a general statement, the RPS program proposed by the Plan can potentially work in any of the market structures examined by this study. This said, a number of issues need to be raised that have implications for market structure in the discussion of an RPS:

1. Approximately 3 percent of the total electricity currently sold to Michigan utility customers is generated by renewable energy sources. Even if the goals of *Michigan's 21st Century Electric Energy Plan* **are met**—i.e., 10 percent renewables by 2015—one base load plant will still required by 2015, and additional ones as early as 2016. In that sense, while the renewable power generated to fulfill the RPS is not intended to be a source of base load power, the proposed RPS is inextricably linked to the issue of new base load capacity.
2. *Michigan's 21st Century Electric Energy Plan* relies heavily upon wind for meeting an RPS in the near term, yet acknowledges that the "uncertainty about markets, interconnection, and production costs have slowed new wind development in Michigan." Land use issues such as local zoning might also slow wind development. In addition, the cost of wind power equipment and engineering could increase significantly because a number of states are mandating the use of wind in their respective RPS. As other states mandate a wind standard, it is likely that—at least in the short term—purchases by Michigan generators would result in higher purchase prices and longer construction timelines than a few years earlier. [23] If the Plan looks to wind to provide a substantial portion of Michigan's RPS, then the state must look to the regulatory framework that provides the optimal balance between such factors as cost, investment risk, construction timelines, and ability to deliver sustained generating power.
3. *Michigan's 21st Century Electric Energy Plan* implicitly recognizes the possibility of not reaching the target of 10 percent—given that one of the recommendations is to give the MPSC authority to defer the goal for specific LSEs on an annual basis. However, the Plan does not discuss any contingency plans if Michigan misses its RPS target. If the target of 10 percent renewable energy by 2015 is not achieved, Michigan would face two significant capacity implications: (1) additional base load capacity would be required (which means that planning for these new plants must begin immediately, given construction duration), and/or (2) the state would be forced to rely more on a volatile wholesale market in the near term until the new base load plant comes online.
4. Implementing an RPS without addressing market structure means that the initiative could be launched in an electric market that is costly and volatile. Since an RPS initiative might be costly in the short run, a question exists about the political sustainability of an RPS if the underlying market situation is not addressed.

The Plan clearly envisions that the renewable energy generation will occur in Michigan, although it apparently would allow some limited non-Michigan purchases of RECs. Much of the immediate economic development value from the construction sector of an RPS would be lost without a requirement for in-state production. If renewable power is imported, the environmental benefits of an RPS would still occur—i.e., fewer emissions, less greenhouse gas produced, less

[23] It must be noted that these potentially higher short-term costs may not continue into the long term as suppliers of wind generating technology increase production to match increased demand. Furthermore, as more states implement RPS, the potential profits earned by firms may increase research and development activities, leading to significantly more efficient means of generating power from renewable resources. Taken together, all of these effects could have dramatic implications on the *relative* costs of various sources of electricity generation in different years.

reliance on fossil fuels—but Michigan consumers would be exporting dollars as they do now for electrical power, and would not benefit from job creation and the experience in developing renewable energy sources. To the extent that these exported dollars might be the result of lower power costs from other states, it is unclear what the net effect would be on employment in the power-consuming sectors of the economy. These buyers of electricity could be paying less for electricity and as a result have resources available for economic development.

It is clear that Michigan's RPS can be implemented under any regulatory structure. There could, however, be great differences in the cost of the mandate based on level of regulation. In a deregulated or modified PA 141 environment, the lack of customer predictability could make utilities and AESs unwilling to sign long-term contracts for renewable power. Without long-term contracts, the costs of implementing renewable electricity sources could dramatically increase the cost of meeting the RPS. As a result, the lack of customer predictability in a deregulated market could lead to a price for renewable power that is higher than the state is willing to bear. Under a fully re-regulated market structure, where electric producers have a greater degree of customer predictability, utilities and AESs alike will be more willing to sign long-term renewable energy contracts. As a result, these companies are more likely to meet their RPS requirements in a cost-effective manner and less likely to seek or receive exemptions from the 10 percent RPS standard.

Energy Efficiency

INTRODUCTION

Energy efficiency (EE) is often referred to as an invisible fuel source because every kilowatt of power saved by efficiency programs represents power that does not need to be generated by new or existing power plants. Unlike a renewable portfolio standard (RPS)—which simply has targets and definitions of renewable fuel—EE programs have a variety of components and means of achieving their goals.

Energy efficiency programs in the United States vary from funds that distribute loans and grants to EE initiatives, to new building codes, to load management programs designed to decrease peak demand. Overall, EE initiatives have two distinct yet often overlapping goals: to reduce overall electricity use and to limit demand during peak periods. While these goals can often be jointly met by similar initiatives, there are particular programs that are explicitly designed to address peak demand.

Load management programs are expressly designed to lower power demand during peak hours. These programs take two basic forms. Active load management programs allow **utilities** to switch off power to air conditioners, hot water heaters, and other large appliances during times of high demand. In exchange for agreeing to these potential power reductions or cutbacks, customers get an overall lower electricity rate.

In contrast to active load management systems, passive load management requires **customers** themselves to limit their electricity usage in response to price information. Part of the difficulty in limiting peak demand is the current lack of a connection between the choice to use power at any particular time and the customer's knowledge of the cost of power at that same time. While utilities are often forced to buy electricity at high prices during times of peak demand, consumers are simply charged a weighted average price regardless of the time or amount of usage; in addition, customer bills can be presented many days after the peak has passed, providing no real-time pricing signal to the customer. Passive load management systems attempt to bridge this information gap and provide price-based incentives to customers willing to limit usage during peak demand. Traditionally these programs offer rebates to customers willing to voluntarily curtail power use during times of peak demand. These rebates are often related to the marginal price of electricity during that time period.

Unlike an RPS, where the potential rate impacts are unknown, the potential rate impacts of EE programs are limited to the amount of the surcharge; therefore, there is little danger of missing the EE target due to high electricity rates. This does not, however, mean that it is certain Michigan will meet its targeted energy reductions under this program. Accomplishing the Plan's EE program requires the participation of business and residential customer in a variety of programs. If the EE targets cannot be met, Michigan will be required to build up to two additional base load plants by 2015. Combined with the already-proposed base load construction in the Plan, and the plant that would be required if RPS goals are not met, Michigan could be required to construct four base load plants before 2015.

THE PLAN'S RECOMMENDATIONS

Michigan's 21st Century Electric Energy Plan proposes an EE program that would reduce peak demand by 1,330 megawatts (MW) over the next ten years and eliminate the need for two base load plants by 2015 if it is successful. This proposal is based upon several assumptions, including

- High energy prices are not temporary.
- Michigan is almost totally dependent on fuels from other states and countries to produce electricity.
- Other states are far ahead of Michigan in EE programs and have demonstrated their viability over the past two decades.
- The costs of EE efforts are lower than the cost associated with new generation.
- EE is the only viable near- to mid-term policy response to increasing demand.
- EE produces a number of other significant economic and environmental benefits that are consistent with the goals of *Michigan's 21st Century Electric Energy Plan*.

For the purposes of this study, three of the plan's five recommendations are key: (1) the creation of a comprehensive, statewide, third party–administered energy efficiency program financed with a "public benefits fund"; (2) the implementation of utility programs for managing load; and (3) pilot programs for investigating new ways for customers to shave peak demand using advanced metering technologies.

The Michigan Energy Efficiency Program (MEEP) is the centerpiece of the Plan's EE proposals. The Plan calls for creating a new government body that is separate from but ultimately accountable to the Michigan Public Service Commission (MPSC), with financing for this new venture coming come from a non-bypassable surcharge on all retail electricity companies. The funds would be deposited in the Michigan Energy Efficiency Fund (MEEF), which would have an initial annual budget of $68 million/year, and a ten-year average of $146 million/year. As will be discussed below, this program would place Michigan's energy efficiency program budget near the forefront of all states in terms of available dollars. Despite this high budget, it is projected that the average residential customer would only see a rate increase of approximately $0.50 per month. Large industrial customers (1 megawatt or more) would be allowed to opt out of the program provided they can demonstrate sufficient independent energy efficiency.

The MEEP would fund a variety of activities designed to promote and implement energy efficiency efforts, including education, marketing, research and development grants, evaluation studies and other activities defined by the contract with the MPSC. The commission would use a competitive solicitation process to select the program administrator; the work of MEEP would be independently evaluated every year; and an advisory committee would be established.

Unlike previous EE efforts, the Plan calls for the program to be administered by an independent third party.[24] This is a key point in the program's potential success. By their very nature, EE programs are not aligned with the underlying goals and motivations of electricity companies—ostensibly to sell more power. For this reason, without adjusting the utility's economic incentives, programs that are administered and evaluated by utilities are likely to have little success.[25] Even though the administrator is intended to be an independent actor, it is clear that any successful EE program will require the full and complete cooperation of all utilities in the state.

[24] It should be noted that Michigan had a successful set of demand-side management programs operating throughout the state during the 1990s. Following the creation of an active choice market, Michigan ceased operation of these programs.

[25] Since the purpose of this study is to evaluate the Plan as it is written, it is not appropriate to debate the relative benefits of a third-party administrator versus a utility-run program with economic incentives tied to increased energy efficiency. It is not clear, at this point, which of these methods is a superior means of achieving the goal of energy efficiency. What is clear, however, is that a utility-run program without explicit economic incentives for reduced power demand is inferior to both of these options.

In addition to the MEEP, *Michigan's 21st Century Electric Energy Plan* proposes an update of the state's commercial building codes in order to increase energy efficiency. According to the plan, these building code changes could lower total demand by 6 percent and lighting demand by 25 percent.[26]

In order to address the issue of lower peak demand, Michigan's plan calls for enabling legislation for the MPSC to mandate the offering of load management programs. The recommendations regarding load management and advanced metering technologies basically authorize the MPSC to expand utility load management programs and require pilot projects on advanced metering technologies. It is estimated that over ten years, enacting these programs statewide could save 570 MW.

Rising fuel costs, unstable electric markets, environmental issues, and the cost competitiveness of EE have given significant impetus to energy efficiency efforts across the country. If the recommendations of the Plan are successful in displacing traditional fossil fuel energy, Michigan energy users will certainly benefit—the Plan estimates a savings of $3 billion over the next 20 years by avoiding otherwise necessary base load plants.

OTHER STATES

EE standards are not as widely adopted as renewable portfolio standards. According to *Michigan's 21st Century Plan*, 15 states have implemented energy efficiency programs similar to the MEEP. Two of these (Illinois and Pennsylvania) are nearby states. In neither of these states, however, is the EE program both mandated and stand-alone, as proposed in Michigan. Since Michigan's neighboring states provide little information regarding the potential effect of Michigan's proposed energy efficiency standard, it is necessary to look to the experiences of other states with similar EE programs. These states include California, New Jersey, Texas, and Vermont.

Fund Size, Revenue Source, and Administration

There are generally two types of energy efficiency funds—those that provide grants and those that provide loans. In addition, some funds are focused primarily on helping low-income families pay bills and increase their energy efficiency, in contrast to funds that are available to all customers. This analysis will focus on funds available to all residential customers.

While Michigan's proposal to fund the MEEP with a non-bypassable surcharge is also seen in other states, there are alternative means of financing energy efficiency programs.

- Pennsylvania, for example, operates four sustainable energy funds that provide loans to individuals and organizations to increase energy efficiency. The funding mechanism for Pennsylvania's initiative grew out of the state's electricity restructuring. The state came to four separate negotiated settlements with the major utilities for an initial endowment for these funds of $55 million. At least a portion of these funds must go toward energy efficiency programs. These funds are administered by independent boards.
- Illinois has a relatively small EE trust fund that is supported by payments from all electricity utilities and alternate electric suppliers (AESs) in the state. This fund has a total budget of $3 million and is intended to assist residential customers. The Illinois Department of Commerce and Economic Opportunity administers this program.
- Beginning in 2001, New Jersey has used a system benefits charge to collect funds to support a Clean Energy Program. This fund had a budget of $115 million in 2001 and $124 million in

[26] *Michigan's 21st Century Electric Energy Plan*, 40.

2003. Seventy-five percent of this revenue was dedicated to EE programs and initiatives. After first allowing the utilities to administer the EE programs, in 2003 the state switched administration to the newly created New Jersey Energy Council.

- California is considered by many to have one of the most successful EE programs in the nation. Beginning in 1996, the California legislature required that the state's three largest utilities collect a surcharge to promote sustainable energy options. Among the targets for this money was $872 million for energy efficiency efforts. Initially this fund was designed to operate for four years, but was extended until 2011 with an annual budget of $228 million for EE programs. The management of these funds and distribution to investor-owned utilities is handled by the California Public Utility Commission, which annually approves each utility's energy efficiency plans.
- Since 1989, Texas has operated the LOANStar revolving loan fund to provide loans to government agencies in order to implement EE initiatives. This fund has an endowment of $98 million that resulted from oil overcharge fees from 1976.
- Vermont's successful EE program served as the primary model for the Plan's proposed EE program in Michigan. Vermont's EE fund—which is managed by a third part administrator—has distributed $31 million.[27] These funds are earmarked by a separately identified surcharge on consumer electricity bills.

Energy Efficiency Targets and Goals

While Michigan hopes to achieve its EE goals through a third party–administered energy fund, along with other initiatives, some states have left the means of achieving targeted savings to utilities. Illinois has an energy efficiency component as part of its voluntary sustainable energy plan. This program "requires" that utilities meet at least 25 percent of projected demand growth between now and 2017 through energy efficiency savings. It is not clear how effective this program can be given that it is voluntary.

During the electricity restructuring effort in Texas, transmission and distribution utilities were required to use EE initiatives to reduce annual growth in demand by 10 percent. This target can be met through load management programs that reduce peak demand.

Energy Efficiency as a Renewable Fuel

In addition to, or in place of, dedicated energy efficiency funds, some states have simply folded energy efficiency into their RPS. In this system, energy efficiency is counted as a renewable fuel or an "invisible" renewable power plant. Savings from energy efficiency can be used to meet the standard for renewable fuels. For example, Pennsylvania, in addition to its four sustainable energy funds, includes energy efficiency in its RPS. Pennsylvania requires specific percentage of its RPS be met by fuels that are broken up into two categories or "tiers." Included in the second tier are "demand-side management" and energy efficiency savings. Similarly, Nevada allows utilities to offset one-fourth of their 20 percent RPS requirement with energy efficiency savings. North Carolina recently enacted an RPS that allows energy efficiency savings to be counted as a fuel source—but demand-side management programs are not counted in this category.

Load Management Programs

Illinois, New Jersey, Ohio, and Pennsylvania have passive load management programs through their participation in the PJM RTO (regional transmission organization). Customers in these states have access to information about the marginal and wholesale costs of power during peak

[27] The budget was increased from approximately $19 million to $31 million for 2008.

times and are offered rate reductions equal to these amounts for power curtailment. Participation in these programs is completely voluntary and customers are not penalized for failing to participate in them. All four large utilities in Pennsylvania offer some additional active and passive load management programs. In Illinois, there are no current active load management programs. In none of these states is offering such programs mandated by law.

California has several passive and at least one active load management program available to electricity customers in the state. For example, the Critical Peak Pricing pilot program provides lower electricity rates throughout the year in exchange for higher rates (3 to 5 times the average price) on 12 peak summer days. Two utilities also offer active load management for commercial customers in the form of air-conditioning cycling—allowing the utility to turn down the customer's air conditioning as needed during the months of May through September.

Building Codes

As discussed above, changes to building codes can have significant effects on overall and peak energy demand. Such changes are generally implemented in one of two ways. States either require that government office buildings meet a certain elevated standard, or they include all businesses in their requirement. Ohio requires ASHRAE 90-1.2004[28] for all commercial buildings and the 1998 International Energy Conservation Code (IECC) for residential buildings. Pennsylvania requires commercial and residential building to meet the 2003 IECC. Illinois has no residential standards but has adopted a slightly modified version of ASHRAE 90.1-2001 for commercial customers. California has a state-crafted building code that exceeds the 2000 IECC for residential facilities and meets or exceeds ASHRAE/IESNA[29] 90.1-2001 for commercial buildings. In Texas, ASHRAE/IESNA 901-1999 is mandated statewide commercially and the 2001 IECC is the minimum standard for residential buildings.

Tax Incentives

While Michigan's proposed energy plan does offer property tax relief for homeowners who install wind, solar, or other renewable energy production, it does not offer explicit tax incentives related to energy efficiency. Several states, however, offer some form of tax relief related to energy efficiency. New Jersey provides a sales tax exemption for the retail sale of gas and electricity generated through the use of cogeneration. California allows individuals to deduct interest paid on loans used for EE projects from their state income tax. In Nevada, there is a property tax abatement of up to 50 percent for buildings that improve energy efficiency following the Leadership in Energy and Environmental Design (LEED) guidelines.

EVALUATING POLICY FRAMEWORKS

When analyzing which market structure creates the best environment for realizing the EE goals and initiatives of *Michigan's 21st Century Electric Energy Plan*, the following points are relevant:

1. Can effective EE programs be implemented in restructured electric markets that include customer choice? The general answer is yes. As is true with RPS, there does not appear to be any direct correlation between market structure and energy efficiency programs. While choice markets are deregulated with respect to the utility from which customers must purchase electricity, regulations that concern other issues still exist. In this way, EE

[28] One of the standards developed by the American Society of Heating, Refrigerating, and Air-Conditioning Engineers.
[29] Illuminating Engineering Society of North America.

standards become simply another non-price-based regulation in the marketplace. The American Council on an Energy Efficient Economy (ACEEE) recently published its ranking of the 50 states on energy efficiency efforts.[30] The top states have a variety of market structures, leading to the conclusion that market structure per se is not an issue. Michigan, incidentally, is ranked 30 among the 50 states, spending $0.79 per capita on utility and public benefits energy and efficiency programs; the top state, Vermont, spends $22.54 per capita. Iowa and Wisconsin are the top spending states in Michigan's region, each spending $9.76 per capita.

2. During the first wave of electric restructuring beginning in the mid-1990s, the dollars devoted to electric energy efficiency programs across the country plummeted—in fact, they dropped by 50 percent, from $1.8 billion in 1993 to $900 million in 1998.[31] One reason for this was essentially philosophical, in that markets were to take care of everything and anything appearing like regulation or command and control was incompatible with this notion. Another reason was more practical—the general attempt was to drive down prices, and surcharges such as those represented by energy efficiency programs were considered counterproductive.

   The trend has been reversed, with many states now refocusing on energy efficiency programs (some, of course, never did abandon them) as it has become clear that restructuring did little to promote energy efficiency. What has changed is the approach to energy efficiency and the structure of EE programs: a non-bypassable surcharge on all customers levied at the retail level can conceptually work in any market structure, but may be more philosophically consistent with a regulated environment.

3. The major recommendations of *Michigan's 21st Century Plan* are inextricably linked. Even if the energy efficiency goals are met, one new base load plant will still be needed by 2015 and more soon thereafter. If the energy efficiency goals are not met, additional base load capacity will be needed by 2015. In other words, market structure and whether base load plants can be built remain crucial issues.

   Many factors will help determine whether the Plan's goals are met. One of the most significant will be the involvement of the two major regulated utilities in the energy efficiency program. The Plan recommends the use of a third-party program administrator, after considering the option of charging the utilities themselves with the task. Because the utilities have the customer base and an existing relationship with customers, the probability of reaching the goal increases as their involvement increases.

4. The costs of the RPS apparently become part of the general rates that customers pay. Unlike the RPS, however, the MEEP is funded by a clearly identified surcharge on all retail customers. If market structure is not addressed, and volatility and price increases characterize the future electric markets in Michigan, is the MEEP sustainable politically? Will electric customers be willing to continue paying this surcharge if rates are rising dramatically in either a fully deregulated market or the hybrid market where a substantial amount of new power is purchased based on Midwest Independent Transmission System Operator (MISO) rates?

One must also not lose sight of the load management and advanced metering recommendations of the Plan. Are these to be required of **all** load serving entities (LSEs) in Michigan, or only of the

[30] Maggie Eldridge, Bill Prindle, Dan York, and Steve Nadel (primary authors), *The State Energy Efficiency Scorecard for 2006* (Washington, D.C.: American Council for an Energy-Efficient Economy, June 2007).
[31] Ibid., 4.

investor-owned utilities? In other words, under the current hybrid market structure, some providers operate in the regulated market and some in the unregulated market. Will any new load management requirements and advanced metering requirements apply to all? The potential clearly exists to drive any cost differentials higher for one type of energy provider over another.

EE programs, like an RPS, can operate under any regulatory structure. Similar to an RPS, however, EE programs can be more efficiently implemented in a regulated setting. Even though the third party administrator will be an independent body, it will require the active participation and assistance of utilities in order to meet Michigan's EE goals. As the number of electricity suppliers grows in a deregulated environment, the ability to effectively coordinate these EE activities will shrink, making it less likely that Michigan can effectively implement the Plan's proposed EE programs.

Conclusions

This study answers the question of what type of market structure is optimal for Michigan to successfully implement the policy initiatives of *Michigan's 21st Century Electric Energy Plan*. To conduct this analysis, this study accepts the initiatives and goals of the Plan **as written**, acknowledging that elements of the Plan will be debated on their own merits. The study's basic conclusion is that a regulated market structure provides the best environment for the risk reduction strategy necessary for Michigan's energy future. Specifically:

- *Michigan's 21st Century Electric Energy Plan* is not an *à la carte* set of options; if the new generation, renewable portfolio standard (RPS), and energy efficiency (EE) programs are not enacted in concert there could be significant consequences. For example, if the state misses its RPS or EE targets, as many as **three** additional base load plants may be needed by 2015. Focusing a policy discussion on any **one** of these three goals of the Plan—at the expense of the other two goals—does not secure Michigan's electric energy future.
- To build new base load generation, Michigan faces a trade-off. On one hand, with either the state's existing hybrid structure or a move to increase choice (i.e., full deregulation), Michigan faces the risk that a new base load plant will not be built prior to 2015—therefore delaying the economic development and electric reliability benefits of the new plant—due to financial decisions of both utilities and independent power producers (IPPs) in a market with uncertain multiyear revenue streams. On the other hand, if Michigan modifies PA 141 or moves toward re-regulation, the state increases the possibility that at least one base load plant will be built. Either of these two market structures also increases the possibility that there will be a change to the choice program that could include its elimination.
- While generation is clearly the area that is **most** affected by market structure, the market structure also will affect the state's ability to implement and to achieve the Plan's RPS and EE goals. Broadly stated, both the RPS and EE programs proposed by the Plan can be implemented—albeit with differing degrees of success—in any of the market structures examined by this study. However, a fully deregulated market structure—where all producers are risking customer loads to a choice model—is likely to **increase** the cost of implementation of RPS and EE plans. A fully deregulated market structure would also **decrease** the state's chances to reach the RPS and EE targets since (a) any producer's time horizon will be much shorter than under a fully regulated model, and (b) in markets with more uncertain parameters, the premium demanded by producers increases.
- Given the uncertainty of larger, macro risks in electricity production such as rising fuel prices, rising construction costs for new base load plants (due to both new technologies and increased demand for raw materials used in power plant production), and a possible federal carbon tax, **Michigan should choose the regulatory and market model that best stabilizes Michigan's electric market and diversifies its electric production portfolio**. By reducing risks to both producers and consumers, Michigan stands the best chance of implementing the Plan.
- **The best risk-reduction strategy is to return to a regulated utility model for new and existing generation in order to bring greater predictability to the revenue base of all utilities.** It will be extremely difficult for Michigan to successfully implement *Michigan's 21st Century Electric Energy Plan* without moving to a model where costs of new generation, renewable technologies, and energy efficiency programs are not at risk for recovery for three reasons:

- Costs to implement elements of each major component are so high that waiting for the market signals to react means that Michigan also will likely wait too long for the market to provide timely solutions.
- Michigan's existing hybrid structure, let alone a move toward full deregulation, makes decisions to commit to multiyear, capital-intensive projects less likely. While it is possible for an electricity producer to successfully supply new generating power in the hybrid or deregulated model, it is unlikely that an existing provider will want to be the first one to try without seeking long-term purchase contracts (which provide greater predictability to the producer).
- The additional risks (or the same risks but with greater probability or volatility) of the hybrid or deregulated market may cause investors to demand higher risk premiums, leading to higher costs of financing to any company—utility or IPP—that seeks to construct a new base load power plant.