MICHIGAN'S

21ST CENTURY ELECTRIC ENERGY PLAN

Appendix – Volume I

Policy Proposals

SUBMITTED TO

HONORABLE JENNIFER M. GRANHOLM

GOVERNOR OF MICHIGAN

BY

J. PETER LARK

CHAIRMAN, MICHIGAN PUBLIC SERVICE COMMISSION

JANUARY 2007

Table of Contents

Copies of the 21st Century Electric Energy Plan, and Appendices I and II are available on the Michigan Public Service Commission's website at: http://www.dleg.state.mi.us/mpsc/electric/capacity/energyplan/index.htm.

EXECUTIVE SUMMARY

ES-1 Introduction and Goals of the 21st Century Energy Plan Study

On April 6, 2006, Governor Granholm issued Executive Directive 2006-2 initiating the 21st Century Energy Plan (Plan). The Directive requests the Chairman of the Michigan Public Service Commission (MPSC or Commission) to provide a proposed electric energy plan for the State of Michigan that addresses the following eight goals:

1. The state's short-term and long term electric needs for residential, industrial, commercial, and governmental customers shall be met in an optimum manner that assures a reliable, safe, clean, and affordable supply.
2. The future development of Michigan's electric infrastructure shall further the state's competitive business climate, grow jobs, and provide affordable rates for all customers.
3. The appropriate use and application of energy efficiency, alternative energy technology, and renewable energy technologies shall be consistent with the goal of assuring reliable, safe, clean and affordable energy.
4. This state's natural resources and the environment shall be protected from pollution, physical or visual impairment, or destruction, and future risks associated with fossil fuels shall be mitigated.
5. A renewable portfolio standard shall be created that establishes targets for the share of this state's energy consumption derived from renewable energy sources.
6. New technology options to generate, transmit, or distribute energy more cleanly or more efficiently shall be identified.
7. The state's economic interest in ensuring development of the intellectual capital, financing, infrastructure, and other resources necessary for continued growth of alternative and renewable energy technologies within the state shall be fostered.
8. The plan shall identify any legislative or regulatory changes necessary to its implementation, together with any financial, funding, or incentive mechanisms needed to best position the state to meet the energy challenges of the future.

To assist the Chairman in preparing his Plan, the Commission Staff conducted a collaborative planning process using the same format as the recently completed Capacity Need Forum (CNF). Two courses of action were pursued to address the two major topical areas of the Plan. The first was a major modeling initiative to affirm and update the resource modeling results from the CNF. The second was development of policy options for meeting the Governor's goals.

The Plan's first meeting was held on April 24, 2006 and attended by over 160 industry stakeholders. Nearly 200 additional participants were added over the course of the following six-month planning process, ultimately representing over 150 organizations including: customer groups, business groups, jurisdictional and non-jurisdictional utilities, independent transmission companies, environmental groups, energy efficiency advocates, independent power developers, and alternative and renewable energy providers, government agencies, electric transmission companies and regional transmission organizations.

Four Workgroups were created to provide information, data, and comments on various aspects of the modeling initiative and the policy review. The four Workgroups were the Capacity Need Forum (CNF) Update Workgroup, the Energy Efficiency Workgroup, the Renewable Energy Workgroup, and the Alternative Technologies Workgroup. Workgroups began meeting in earnest in early May and continued throughout the summer.

Throughout the planning process, Staff sought input and feedback from industry experts and participants. During June and July, strawman policy proposals from each workgroup were drafted and several opportunities for comment were provided. The first comment period was limited to the participants in the specific workgroup, but in early August, the strawman policy proposals were packaged together and comments sought from all Plan participants. In addition to several public meetings, Staff also conducted one-on-one colloquies with participants to discuss policy issues. Staff met with over 35 different individuals or groups during September, October, and November.

The final documents prepared by MPSC Staff and transmitted to J. Peter Lark, Chairman of the Michigan Public Service Commission are bound in Appendices I and II.

Appendix Volume I contains an overview of resource modeling conducted for the Plan, policy reports that identify the barriers to developing and securing electric resource and generating assets necessary for Michigan's future and recommended policy changes, some of which require legislation and others require Commission action.

Appendix Volume II, details the results of the quantitative analysis (modeling), assesses Michigan's future electric capacity needs, identifies resource options available to the state and its ratepayers, and proposes a general plan to meet the future electric capacity and energy needs. Appendix Volume II, Chapter 1, contains a discussion of the scenarios and sensitivities that were analyzed, the model results, and the assumptions and model inputs, including emission allowance cost and fuel price forecasts. Appendix Volume II, Chapters 2 through 5, are resource assessment reports prepared for each of the four Plan Workgroups and drafted by the respective Workgroup chairs. They report on the data used in the modeling program and also analyze operational issues, planning principles, scenario development, and policy development.

On some issues workgroup consensus could be reached. On a number of important issues, however, parties provided conflicting positions, especially on policy issues. This report represents Staff's conclusions from conducting the Plan, and includes both a discussion of participants' key positions regarding resource assessments and policy issues and Staff's summary recommendations. The complete text of comments and policy positions submitted to Staff by plan participants can be found at http://www.dleg.state.mi.us/mpsc/electric/capacity/energyplan/strawmanpolicycomments_sept12_2006.pdf.

ES-2 21st Century Modeling Methodology and Findings

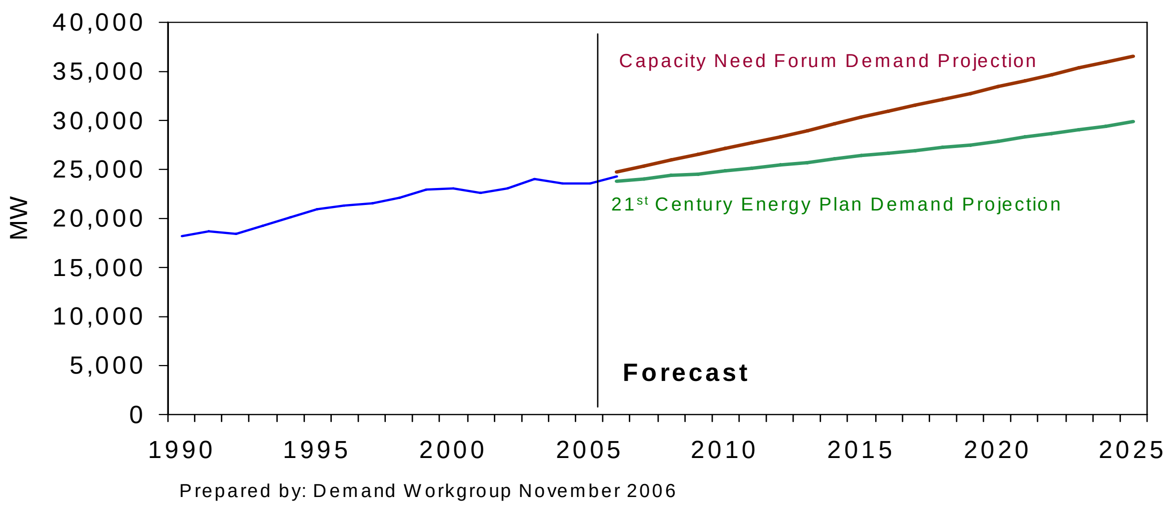
The resource assessment had four objectives:

1. Determine whether Michigan's electric generating resources can reliably meet Michigan's future electric requirements;
2. Evaluate options for meeting those future requirements;
3. Assess future risks to Michigan's ratepayers, and
4. Recommend resources and strategies for managing future risks to assure adequate supplies of electric energy will be available at affordable prices for all Michigan ratepayers.

The process used to meet these objectives was to update the recently completed CNF assessment. One major difference between the CNF and the Plan was the decline in the demand forecast annual growth rate from approximately 2 percent to 1.2 percent. This substantial change alone required updates to the system reliability analysis and the capacity expansion plan. Figure ES-1 shows the comparison between the CNF and Plan forecasts.

Second, a more rigorous and thorough review of the renewable energy and energy efficiency components was necessary to provide a reliable basis for making specific policy recommendations for these resources. The current study reflects a step-up in both detail and confidence in the estimates for these resources. It should be noted that the assumptions used for resource modeling are likely to change as existing generating technologies and energy efficiency options are improved and new technologies are developed. Also, costs used in this modeling initiative are likely to change in the future as price changes occur in the industry. Therefore, further updates to the modeling initiative are recommended on a regular basis.

Figure ES-1: Comparison of CNF and Plan Base Case Peak Demand Projections



Reliability modeling was performed for this study by the Midwest Independent System Operator (MISO) using the industry standard one day in 10 years loss of load probability – meaning that on a probability basis the system will have adequate generating resources to serve forecast loads in all but one day in 10 years. Multiple reliability scenarios were included in the MISO study, and these scenarios show that additional generating resources will be needed by about 2009 to maintain reliability. This capacity need grows as demand continues to increase and older units are retired. However, the reliability model does not provide information on the best type of generating resources to meet future need or address risk factors, or the amount of necessary resources that will be required over the planning horizon. These questions were examined using a capacity expansion model.

For the Plan's resource expansion modeling, the CNF's inventory of generating plant and simultaneous, on-peak transmission capability were adopted. One new option evaluated in this study was a major transmission project involving the International Transmission Company (ITC), a project first proposed in the CNF. The initial proposal was a 2,500 megawatt (MW) direct current (DC) line and the alternative an extension of the 765 kilovolt (kV) system from Southwest Michigan to Northwest Detroit. Recently ITC signed a study agreement with the American Electric Power Company (AEP) to study a 765 kV loop through Michigan. The DC option serves as the basis for one of our sensitivities, the expanded transmission sensitivity in the Central Station Scenario.

Two levels of energy efficiency programming were incorporated. The base scenario was developed for the Plan by the Energy Center of Wisconsin and represents a relatively aggressive program. A low case sensitivity was also modeled. The low case energy savings are approximately the same as the demand and energy savings used in the CNF, or about one-half the savings of the Plan base Energy Efficiency Scenario.

Renewable energy resources also received more focus in this update. Between 1,100 MW and 2,700 MW of new renewable generation could be available by 2015, mostly in the form of wind power installations. Because wind is variable or variable output resource, the Plan used the same on-peak capacity credit of 12.5 percent for wind that was used in the CNF. In total, renewable energy is credited with between 664 and 810 MW of on-peak capacity by about 2015. For modeling purposes, a conservative strategy of using the lower renewable energy total for the 7 percent standard, was adopted.

The principle objectives of the capacity expansion model are maintaining a 15 percent planning reserve margin and minimizing the present value of the incremental generation related costs for electricity over the 20 year planning period. Importantly, the geographically separate Lower and Upper Peninsula results can be and are separated in the modeling results.

ES-3 Modeling Results

The Plan modeling results, together with results from the CNF, represent a comprehensive assessment of Michigan's electric utility industry involving numerous Scenarios and sensitivities. The quantitative results provide a basis for policy recommendations to assure that

Michigan will have a reliable, safe, clean, and affordable electricity supply in the near and long term that manages future fuel, environmental, and reliability risk.

The extensive reliability and expansion modeling underscores the importance of a near term focus on system reliability, and a long term focus on affordable energy and risk management. Major risk factors are the potential for new environmental restrictions, energy and demand growth, and fuel price risk. Multiple Scenarios and sensitivities indicate that the best way to manage these risks is to use a broad resource mix.

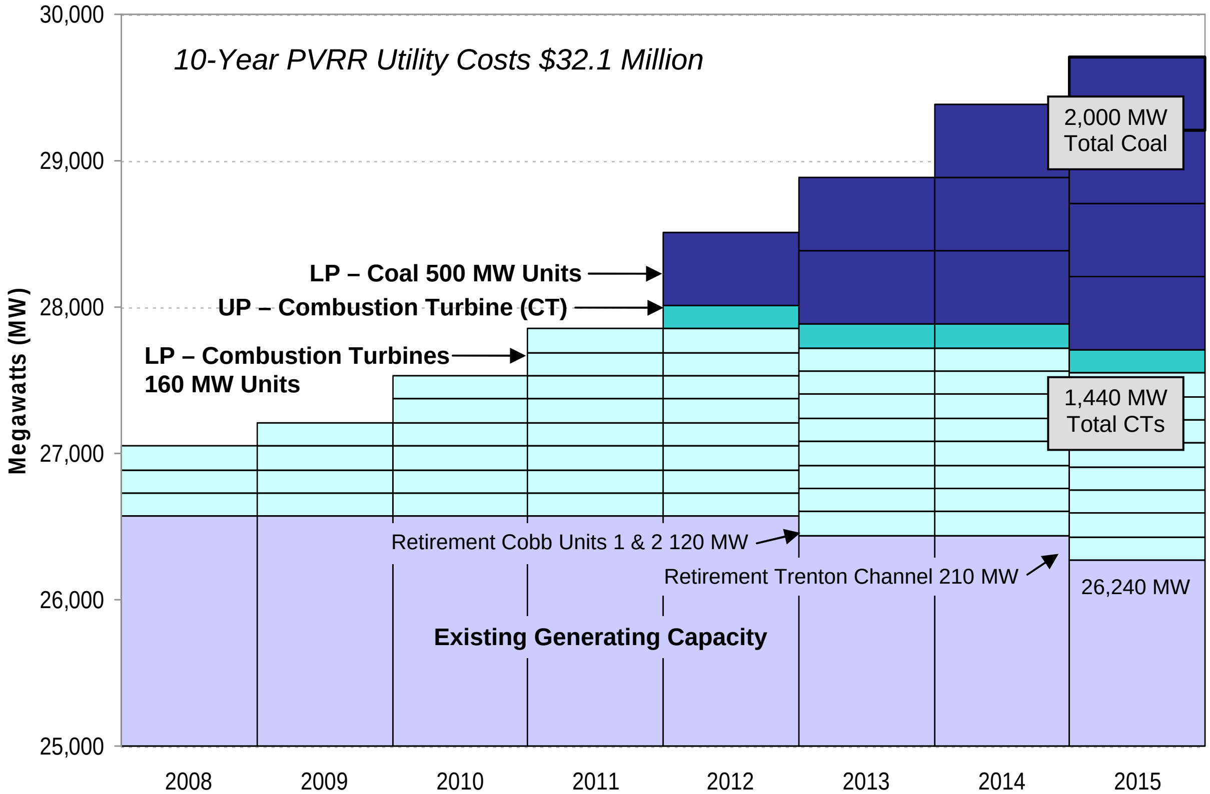
Twenty four Scenarios and sensitivities were analyzed in the modeling program. Conclusions from these Scenarios, especially for fuel price and environmental risk factors, are also pertinent to the Upper Peninsula. Scenarios include combinations listed in Table ES-1, along with sensitivities run for selected Scenarios.

Table ES-1: Modeling Scenarios and Sensitivities

Scenarios:
Central Station Generation
Emissions (carbon dioxide controls)
Energy Efficiency
Renewable Energy
Energy Efficiency with Renewable Energy
Combustion Turbines Only
Sensitivities Run for Selected Scenarios:
High Demand Growth
Low Demand Growth
Expanded Transmission Capability
Low Transmission Capability
Low Energy Efficiency Penetration

Over the first ten years of the planning horizon and assuming base forecast conditions, the model projects that Michigan will need more than an additional 3,000 MW of generating capacity and approximately 20,000 gigawatt hours (GWh) of electricity generation resources assuming base forecast conditions. Under most growth Scenarios and sensitivities used in the CNF and the Plan, combustion turbines (CTs) are added by 2008 to the state's generating portfolio to maintain the 15 percent reserve margin. However, under low growth and the more aggressive energy efficiency cases, the addition of combustion turbines is delayed until 2011- 2012. Figure ES-2 shows the schedule of generation additions for the Central Station Scenario.

Figure ES-2: Schedule of Cumulative Generation Additions for Central Station Scenario



Note: LP Lower Peninsula, UP Upper Peninsula
PVRR - Present Value of Revenue Requirements

Importantly, all the Scenarios show that Michigan should add baseload generating capacity in the 2012-2015 time frame. The long lead-time for planning, permitting, and constructing any baseload facility requires that construction planning would need to commence as soon as practical in order to add a baseload facility within this time frame.

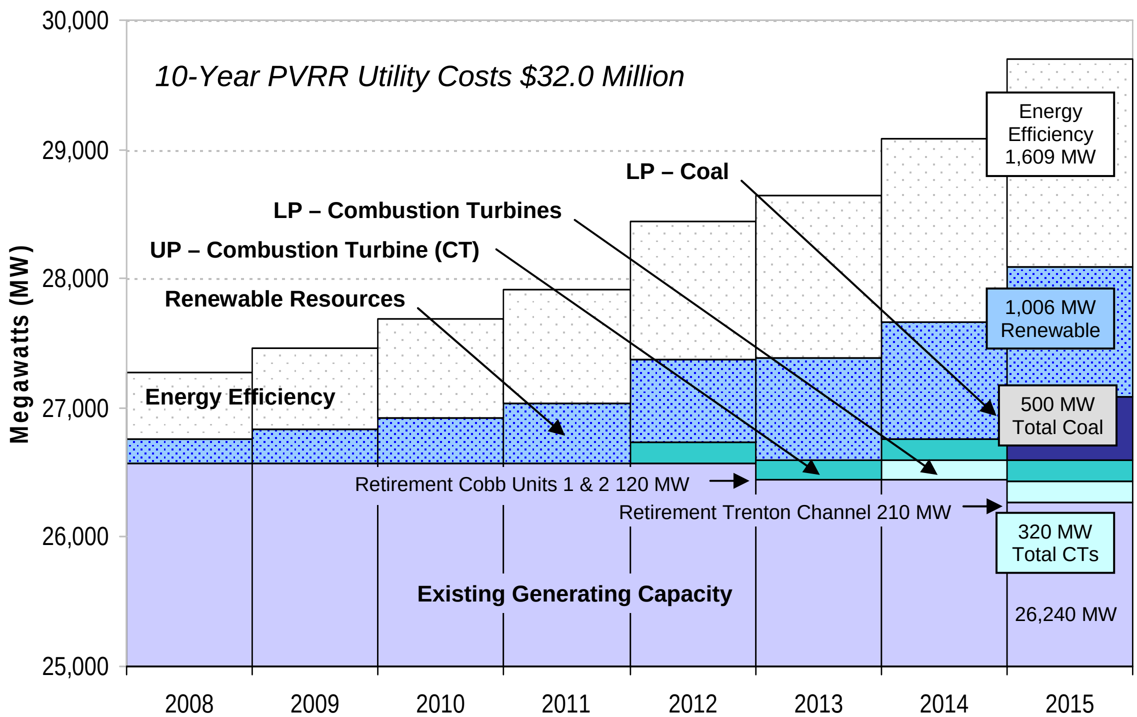
The high penetration energy efficiency case includes an additional 550 MW of interruptible load management, so many of the CTs, along with some coal units, are eliminated from these model runs. In both the CNF modeling and the Plan modeling results, energy efficiency programming provided long-run favorable outcomes on a total cost basis compared to reliance on central station generating options alone.

Renewable energy options in this study result in slightly higher total costs than central station generating resources under standard assumptions. However, renewable resources do result in lower total cost under the emissions scenario. Further, the energy efficiency programs combined with renewable resources options served to significantly reduce the total cost of resource additions over the 20 year planning horizon in most scenarios.

Changes in projected fuel costs within the ranges modeled in the CNF and in this Plan do not appear to have a major impact on the type of central station generating plant chosen by the model. However, potential exposure to costs associated with greenhouse gas controls emerged as a major contingency. Approximately 60 percent of Michigan's electric generation is fueled by coal, which is a major contributor of atmospheric carbon dioxide (CO_2). Carbon dioxide controls or related allowance costs could have a significant impact on generation costs throughout the Great Lakes region.

Figure ES-3 shows the contributions of the more aggressive energy efficiency programs together with a 7 percent renewable portfolio standard, reached by the end of 2016, and the base forecast. Note the PVRR Utility Costs of $32 million is nearly equivalent to the $32.1 million for the Central Station Base Case. And while the combined Energy Efficiency and Renewable Expansion case does not entirely eliminate the need for baseload plant additions, the need is delayed from 2012 in the Central Station Base Case to 2015 for the Energy Efficiency and Renewable Expansion Case.

Figure ES-3: Schedule of Cumulative Generation Additions for Energy Efficiency with Renewable Energy Scenario



Note: LP Lower Peninsula, UP Upper Peninsula
PVRR - Present Value of Revenue Requirements

Finally, even though expanded electric transmission capability to and from Michigan by 2,500 MW resulted in a reserve margin reduction from 15 percent to 12 percent, this option resulted in a slightly higher present value cost. The market price forecast indicated that it was less expensive to build baseload power in Michigan than to build transmission and import market priced power from outside the state. Expanding electric transmission capability into Michigan would serve a long term goal of more fully integrating Michigan with other Midwest markets and should continue to be explored as an option for meeting future electric generating capacity needs.

Modeling results for the Upper Peninsula – Upper Peninsula electric reliability is highly dependent on timely completion of ATC's Northern Umbrella Project.[1] A major difference between this study and the CNF is our assumption now that the first four units at Presque Isle will be retired in 2012. These units total approximately 175 MW of capacity. This schedule has recently been accelerated for the first two units, which were taken out of service in January 2007.

For Upper Peninsula modeling purposes, a baseload coal-fueled circulating fluidized bed (CFB) plant of 150 MW capacity was included as an available resource. This is smaller than the other baseload units analyzed in the CNF study, and the purpose for the smaller unit was to match the UP's smaller load. The model, however, did not select the smaller CFB unit. Instead, it selected two peaking units to provide capacity support to meet the minimum reserve margin constraint, but then purchased wholesale energy to meet UP energy consumption as the least-cost energy solution.

ES-4 MPSC Staff Policy Recommendations

There is a broad consensus that the State's electric energy policy and the Commission's current authority do not assure that Michigan can rely on a diversified resource strategy for meeting its future electric energy needs. Policy proposals to address the State's needs were discussed extensively by the workgroup participants. Based on comments, information, and analysis provided through the course of these discussions, Staff prepared a set of policy recommendations requiring both legislative and Commission action. These recommendations cover energy efficiency, renewable energy, and other distributed energy technologies and utility based generation construction.

Michigan 2000 PA 141 restructured Michigan's retail electric generation market. The Act provided for a hybrid, two market system, where customers can opt for full service under traditional ratebase-priced generation from incumbent utilities or market priced generation from alternative electricity suppliers. A second change in electricity markets occurred in 2005 when regional wholesale markets operated by the Midwest Independent System Operator moved to market-based pricing. These two changes have profoundly altered industry dynamics by increasing uncertainty and risk while at the same time facilitating market transactions.

Since ratepayers can move freely between the two markets, most Plan participants including Commission Staff, conclude that Michigan's current market structure does not provide sufficient certainty to finance a major generating plant on reasonable terms. This leaves Michigan vulnerable to either declining reserve margins and reliability, or reliance on cheap to build but expensive to operate combustion turbines. The likely result is a market that is unsustainable, with electricity prices becoming more volatile and rising to levels significantly higher than would be experienced with a more robust state electricity policy. Model results indicate that the

[1] The Northern Umbrella Project refers to several upgrades in the Upper Peninsula and northern Wisconsin that are designed to improve reliability. See http://www.atc10yearplan.com/documents/zone2_06.pdf.

uncertainties created by the current hybrid market may result in over $4 billion of additional costs over the next 20 years, on a present value basis, than would be incurred if the state adopted a more robust energy policy. Staff recommends that legislative and other affirmative action is needed to address these issues.

Policy Recommendation 1 - Optional Utility Power Plant Construction Program

Legislation

- Legislation would permit the Commission to issue a Certificate of Need for new generating plant being proposed by an incumbent utility, so that the issue of need is not contestable after the plant is completed.
- The incumbent utility would be required to file an integrated resource plan (IRP) demonstrating the need for additional generating capacity. The Commission would be authorized to establish standards for the IRP.
- The Certificate of Need process must include competitive bidding for new plant engineering, procurement and construction (EPC), and must be accompanied by a financing plan.
- Customers who contribute to the need for a new generating plant will be responsible for contributing to the plant's cost recovery.
- The Commission should require customers who elect to be supplied by an alternative electric supplier to provide a two year notice before returning to regulated rates. Until the two years have passed, the utility would need to serve the returning customer at market based rates.

Commission Action

- The Commission should, at its sole discretion, consider extending its current policy of allowing construction work in progress (CWIP)[2] without an allowance for funds used during construction (AFUDC)[3] offset for environmental investment to additional CWIP investment, if the request for the extension is made as part of a utility financing plan.
- The Commission should promote accurate and efficient price signals by moving to cost based rates.

[2] Construction work in progress (CWIP): The balance shown on a utility's balance sheet for construction work not yet completed but in process. This balance line item may or may not be included in the rate base. Source: U.S. Dept. of Energy, Energy Information Administration *Glossary*; http://www.eia.doe.gov/glossary.

[3] Allowance for Funds Used During Construction (AFUDC; sometimes also referred to as Interest During Construction): The accounting mechanism used to reflect either the financing or carrying charges on monies invested in an ongoing construction project. AFUDC treatment may be applied to long term construction projects which have a total estimated cost, as prescribed by the Commission. AFUDC may be charged on a construction project until it is placed into operation or is otherwise determined to be ready for service.

Policy Recommendation 2 – A Renewable Portfolio Standard

Legislation

- Establish a mandatory renewable energy standard of seven to 10 percent for all load serving entities (LSEs) in Michigan by the end of 2015, and with a target of 20 percent by 2025; including a requirement for a Commission hearing in 2014 to determine the appropriate renewable energy portfolio standards to apply 2016 through 2025.
- Eligible facilities should include those defined in the Customer Choice and Reliability Act (2000 PA 141; MCL 460.10 *et seq*) and include existing renewable energy resources.
- Provide for alternate compliance payments (ACP) that can be made by all utilities until 2012, and by LSEs with less than 100,000 customers thereafter. ACP payments would go to the energy efficiency fund to be used exclusively for funding renewable energy projects like a community based renewable energy program.
- Adopt a renewable energy certificate (REC) trading program. Out-of-state RECs should be permitted if they originate from facilities that assist Michigan in meeting air quality standards and provide economic development benefits to Michigan.
- Clarify the Commission's authority to set terms and conditions of net metering tariffs for projects up to 150 kW and authorize the Commission to adopt distribution use tariffs for transmitting power over a utility's distribution system.
- Exempt residential property owners from some portion of their property tax for solar photovoltaic (pv), wind energy, and fuel cell installations.
- Legislation should be adopted that authorizes the Commission to direct a solar energy pilot program involving one or more utilities.

Commission Action

- Commission Staff should conduct a collaborative on smart power grid technologies, especially for application to the Michigan grid.
- Siting and zoning guidelines for wind energy and other distributed generation resources should be communicated to local authorities through the Michigan Renewable Energy Program (MREP).
- The option of using revenue as the basis for valuing renewable energy installations for property tax purposes should be communicated to local taxing authorities through the MREP.
- Commission Staff should commence an investigation of the costs of extending its underground line policy.

Policy Recommendation 3 – Statewide Energy Efficiency and Load Management

Legislation

- The Commission shall be authorized to administer a Michigan Energy Efficiency Program.
- The Commission will select an independent third party administrator to operate a statewide program.
- All retail electric load serving entities must participate, including investor owned utilities, cooperative utilities, alternate electric suppliers, and municipal utilities.
- The program will be funded by a non-bypassable charge on all retail sales.
- The first year budget will be $68 million and the Commission will conduct a public hearing to determine the second and third year budget, with a goal of $110 million in the third year.
- Large manufacturing customers with billing demands of one megawatt or more may opt-out by demonstrating equivalent investment.
- Triennial public hearings will be conducted to set funding charges, establish priorities, and evaluate program performance.
- Independent evaluation will be conducted annually.
- The Commission shall be authorized to require load management programming by regulated utilities and to authorize demand response pilot programs.

State Action

- DLEG should begin a collaborative process to review residential and commercial building codes and make recommendations on improving energy efficiency in new Michigan construction.
- The Michigan Energy Office should analyze the benefits of state mandated appliance efficiency standards not currently included in federal standards.
- The Commission should initiate a demand response pilot program.

1. Introduction and Process Description

The 21st Century Energy Plan (Plan) was initiated in April 2006 by Governor Jennifer M. Granholm through Executive Directive 2006-2 (included here as Section 5). The Governor's directive called for a comprehensive assessment of Michigan's electric industry needs and a broad review of electric energy policy by adopting eight goals:

1. The state's short-term and long term electric needs for residential, industrial, commercial, and governmental customers shall be met in a manner that assures a reliable, safe, clean, and affordable supply.
2. The future development of Michigan's electric infrastructure shall further the state's competitive business climate, grow jobs, and provide affordable rates for all customers.
3. The appropriate use and application of energy efficiency, alternative energy technology, and renewable energy technologies shall be consistent with the goal of assuring reliable, safe, clean and affordable energy.
4. The state's natural resources and the environment shall be protected from pollution, physical or visual impairment, or destruction, and future risks associated with fossil fuels shall be mitigated.
5. A renewable portfolio standard shall be created that establishes targets for the share of this state's energy consumption derived from renewable energy sources.
6. New technology options to generate, transmit, or distribute energy more cleanly or more efficiently shall be identified.
7. The state's economic interests in ensuring development of the intellectual capital, financing, infrastructure, and other resources necessary for continued growth of alternative and renewable energy technologies shall be fostered.
8. The plan shall identify any legislative or regulatory changes necessary to its implementation, together with any financial, funding, or incentive mechanisms needed to best position the state to meet the energy challenges of the future.

The Plan follows work completed for the Capacity Need Forum (report issued in January 2006. The Plan's first meeting was held on April 24, 2006, and attended by over 160 industry stakeholders. Nearly 200 additional participants were added over the course of the following six-month planning process, ultimately representing over 150[4] organizations including: customer groups, business groups, jurisdictional and non-jurisdictional utilities,[5] independent transmission companies, environmental groups, energy efficiency advocates, independent power developers, and alternative and renewable energy providers, government agencies, electric transmission companies, regional transmission organizations and interested individuals. Participants were divided into four Workgroups – the Capacity Need Forum Update Workgroup (chaired by Paul Proudfoot), the Energy Efficiency Workgroup (chaired by Robert Ozar), the

[4] The participant list is contained in Section 1 of this report.

[5] The Commission's jurisdiction extends to investor-owned electric utilities and cooperatively-owned electric distribution companies in Michigan.

Renewable Energy Workgroup (chaired by Tom Stanton), and the Alternative Technologies Workgroup (chaired by Steve Kulesia).

Workgroups began meeting in earnest in early May and continued throughout the summer. In all, over 35 Workgroup meetings and five large group meetings were held. The Plan website was used to post relevant information.[6]

Throughout the planning process, Staff sought input and feedback from industry experts and participants. During June and July, strawman policy proposals from each Workgroup were drafted and several opportunities for comment were provided. The first comment period was limited to the participants in specific Workgroup, but in early August, the strawman policy proposals were packaged together and comments sought from all Plan participants. In addition to several public meetings, Staff also conducted one-on-one colloquies with participants to discuss policy issues. Staff met with over 35 different individuals or groups during September, October, and November.

1.1 Appendix Volume I and II Organization

The following two Appendix volumes serve as the foundation for the Plan. Appendix Volume I contains an overview of resource modeling conducted for the Plan, policy sections that identify the barriers to developing and securing electric resource and generating assets necessary for Michigan's future, and recommended policy changes. Sections 1 through 6 are included in Appendix Volume I. Appendix Volume II details the results of the quantitative analysis (modeling), assesses Michigan's future electric capacity needs, identifies resource options available to the state and its ratepayers, and proposes a general plan to meet future electric capacity and energy needs. Appendix Volume II is comprised of five chapters. Chapter 1 is the expansion modeling report and contains a discussion of the Scenarios and sensitivities that were analyzed, the model results, and the assumptions and model inputs, including emission allowance costs and fuel forecasts. The remaining four chapters (2 through 5) of Appendix Volume II contain the resource assessments from the Workgroups: CNF Update, Energy Efficiency, Renewable Energy, and Alternative Technologies. In addition, Chapter 5 contains three supplemental documents referred to as Chapter 5A, Estimate of CHP Potential; Chapter 5B Distributed Generation and Technology Matrix; and Chapter 5C, Smart Power Grid. These resource assessments provided data used in the modeling program and also analyzed operational issues, planning principles, scenario development, and policy development. The workgroup assessment reports and other relevant documents are also posted on each Workgroup's webpage.

[6] Workgroup reports, membership lists, presentation handouts, participants' comments, and other draft documents can be found on the website at http://www.dleg.state.mi.us/mpsc/electric/capacity/energyplan/index.htm.

1.2 Resource Assessment Modeling Summary

The resource assessment course had four objectives:

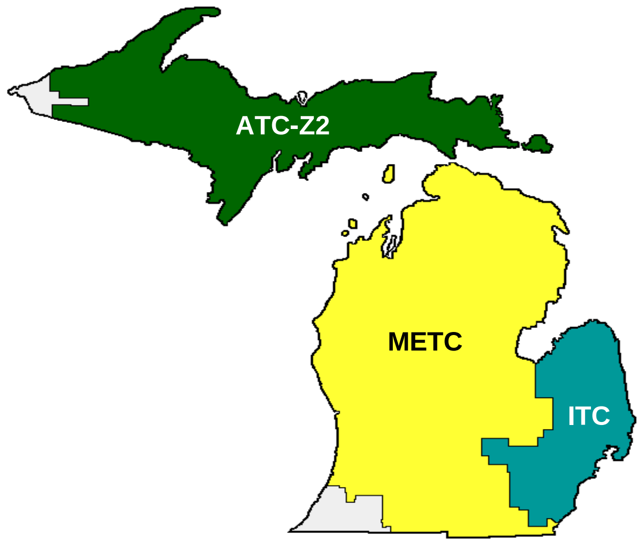
1. determine whether Michigan's electric generating resources can reliably meet Michigan's future electric requirements;
2. evaluate options for meeting those future requirements;
3. assess future risks to Michigan's ratepayers; and
4. recommend resources and strategies for managing future risks to assure adequate supplies of electric energy will be available at affordable prices for all Michigan ratepayers.

The process used to meet these objectives was to update the recently completed CNF assessment. First, Staff and Plan participants reviewed the recently completed CNF to determine whether its data, information, analysis, and modeling results remained reasonable and acceptable for assessing Michigan's future electric energy needs. Significantly lower demand and energy forecasts provided by utility participants – a drop from 2.1 percent to 1.2 percent in the statewide average annual demand growth rate – resulted in the decision to undertake new reliability and expansion modeling efforts following the same six-step process as the CNF:

1. forecasting electricity demand and energy consumption over the next 20 years;
2. compiling an inventory of existing electric power generation assets, central station and non-central station;
3. determining current and planned electric transmission capacity available for power interchanges with markets outside of Michigan;
4. determining whether existing generation resources will satisfy future demand;
5. determining what additional resources are available, if needed, to meet future demand for electric generation or transmission capacity; and
6. providing information on the economic costs and characterizing other effects associated with the use of various additional resources.

The new study, like the CNF, partitioned Michigan into three geographical regions: southeast Michigan, the balance of the Lower Peninsula, and the Upper Peninsula (see Figure 1). The southeast Michigan portion, served by the International Transmission Company, generally corresponds to the Detroit Edison Company (DTE) service territory. The balance of the Lower Peninsula, served by Michigan Electric Transmission Company (METC), generally corresponds to the service territories served by Consumers Energy Company (Consumers), Wolverine Power Supply Cooperative (Wolverine), and most of Michigan's largest municipal electric utilities. The Upper Peninsula is served by the American Transmission Company (ATC) Zone 2. Although ITC and METC have recently merged, the use of these three regions continues to reflect historic electric power transfer limits between the regions.

Figure 1: Study Regions for the Plan[7]



The resource assessment process is comprised of two components. First is an electric reliability analysis for the year 2009. Second, capacity expansion modeling was used to determine the timing, amount, and type of new generating resources needed to meet Michigan's electric capacity needs for the planning period 2007 through 2025.

Information provided by the resource assessment process was necessary to aid development of policy recommendations. Combined with data and modeling results from the CNF, the Plan results provide a comprehensive assessment of Michigan's electric utility industry under numerous Scenarios and sensitivities. The resource assessment provides quantitative results that are necessary to assist with policy-making related to managing emerging and chronic risks and uncertainties facing Michigan ratepayers and to assure affordable and reliable electric supplies over the next two decades.

1.2.1 Reliability Modeling

Reliability modeling undertaken for this study projects a violation of reliability standards for the ITC region by 2009, when examined on a stand-alone basis. This analysis was performed for the Plan by the Midwest Independent System Operator (MISO).

The target reliability level is one day in 10 years loss of load probability (LOLP). The ITC region is forecast to experience 14.58 LOLP on a stand-alone basis in 2009. This is less than the

[7] This study excluded the southwest corner of Michigan, which is mostly served by Indiana Michigan Power Company (I&M), because electric generating capacity requirements for this area are addressed by the PJM Regional Transmission Organization's (RTOs) resource adequacy requirement. For a further explanation of this region's exclusion, please consult Staff's July 1, 2005 Status Report in the Capacity Need Forum, page 4. Also excluded is the western portion of the ATC-Z2 area, which is served by Xcel Energy and therefore addressed by the resource adequacy requirements for the MAPP regional transmission authority.

28 days identified in the CNF, which was based on the higher CNF base demand forecast. ITC and METC (usually called the Michigan Electric Coordinated System, or MECS) collectively also fail the reliability standard on a stand-alone basis (0.92 days LOLP) under base demand forecast conditions. However, MECS satisfies the reliability standard for 2009 if all transmission not currently reserved by non-Michigan transmission customers and sufficient generation in adjacent states would be available to support the Michigan system.

CNF participants identified two major contingencies impacting system reliability. First is the amount of transmission capability available for reliability support in Michigan, and second is any deviation of actual from the forecast electricity demand. Transmission capability may be unavailable for reliability support because firm contract reservations on Michigan's electric transmission system may be utilized for out-of-state transactions, and because of parallel flows or loop flows, that are a part of firm transmission transactions over transmission routes located south of Michigan, and are unrelated to Michigan-specific purchases or sales transactions. In other words, these parallel or loop flows are important when assessing electric reliability because they may be unrelated to Michigan-specific purchases or sales transactions, but still limit the use of the transmission system to support electric reliability within Michigan.

To assess the impact of loop flows as a reliability contingency, MISO also calculated the LOLP assuming 1,500 MW of transmission as unavailable for reliability support to Michigan. This contingency causes ITC and MECS to fail to meet LOLP reliability standards in base and high forecast Scenarios for the year 2009. The lower demand and sales forecast in the current study compared to the CNF resulted in LOLP estimates more favorable than those made by the CNF, but reliability concerns remain for southeast Michigan beginning in 2009. Under the most favorable conditions, southeast Michigan will experience reliability violations on a stand–alone basis and with capacity support provided through transmission. Without additional generation and transmission investment, reliability standards erode over the planning horizon for the entire MECS region, as demand grows in the Lower Peninsula.[8] Reliability modeling does not provide information about which generating resources would best meet the future need, nor the amount of necessary resources required over the 2007-2025 planning horizon. In order to determine the type and amount of resources that will be needed, a dynamic expansion model was used.[9]

Upper Peninsula reliability is highly dependent on the timely completion of ATC's Northern Umbrella Project. Presque Isle is the Upper Peninsula's only major, multi-unit power plant. For modeling purposes, the first four units of the plant were projected to be removed from service by 2012. This will reduce the amount of generating capacity within the Upper Peninsula zone. The first two units, however, were removed from service in January, 2007. Electric reliability will be highly dependent on access to capacity from outside the Upper Peninsula through the ATC transmission upgrades.

---

[8] For a description of the electric reliability analysis undertaken for the Plan, please refer to Chapter 1 of Appendix Volume II.

[9] For a description of the expansion modeling analysis undertaken for the Plan, please refer to Chapter 1 of Appendix Volume II.

1.2.2 Expansion Modeling Format

Expansion modeling was used to analyze a comprehensive set of resources to meet Michigan's future needs. These include energy efficiency and load management; central station generating plants; renewable energy alternatives; combined heat and power (CHP); and expanded transmission capability. Several Scenarios and sensitivities were used to assess the impact of different types of resource choices. The scenario approach helps identify exposure to risks and uncertainties and allows comparison of resources that have widely or broadly divergent costs and operating characteristics. The base Scenarios and sensitivities are shown below:

Table 1 Modeling Scenarios and Sensitivities

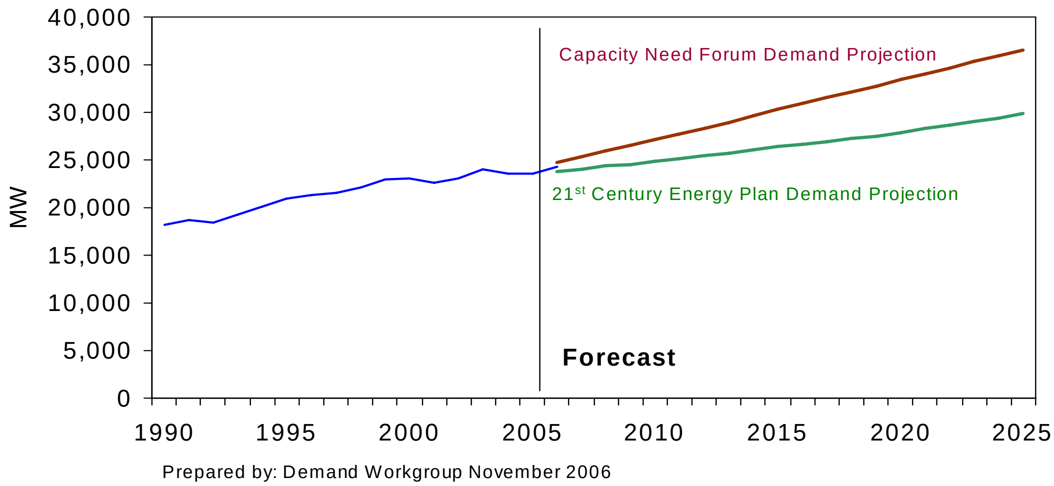
Scenarios:
Central Station Generation
Emissions (carbon dioxide controls)
Energy Efficiency
Renewable Energy
Energy Efficiency with Renewable Energy
Combustion Turbines Only
Sensitivities Run for Selected Scenarios:
High Demand Growth
Low Demand Growth
Expanded Transmission Capability
Low Transmission Capability
Low Energy Efficiency Penetration

Details of each scenario and sensitivity are discussed in Chapter 1 of Appendix Volume II. The expansion model results, driven by the demand and energy growth projections, forecast generation retirements, the need to maintain electric reliability, and available resource options.

Electricity Demand and Energy Forecast: A full discussion of the energy forecasts, including the high and low forecast sensitivities, is included in Chapter 2 of Appendix Volume II. The demand and energy projections are a compilation of Michigan utility forecasts. Updated utility forecasts for the Lower Peninsula are significantly lower than the CNF forecasts. Michigan's peak demand is forecast to grow at 1.2 percent annually between 2006 and 2025 in this study, compared to 2.1 percent annually in the 2005 CNF study. Growth in energy requirements is similarly lower. Energy requirements for 2006 through 2025 are now forecast to grow at 1.3 percent annually, compared to 1.8 percent in the CNF study.[10]

[10] This comparison uses the year 2006 as the base year for both CNF and Plan forecasts. CNF growth rates given here vary slightly from those published in the CNF study, which had a different base year.

Figure 2: Comparison of CNF and Plan Base Case Peak Demand Projections



Lower demand growth results from a revised forecast of Michigan's economic growth, which is now lower than the economic outlook used in the CNF forecast. Manufacturing sales weakness is expected to continue due to restructuring of Michigan's auto industry, assumed by both Detroit Edison and Consumers Energy in their updated outlooks. It is also lower because of lower projected growth in the residential air conditioning market. Consumers Energy and DTE now estimate higher current levels for air conditioning market saturation than previously thought. The higher current market saturation for air-conditioning leaves little room for future increases, resulting in lower electric demand growth.

Resource Options: The expansion plan modeling program uses the same generating plant inventory and simultaneous, on-peak transmission capability as for the CNF study. Generating plant capacities and operational capabilities are also the same as used for the CNF projections, as are the unit retirement schedules.[11]

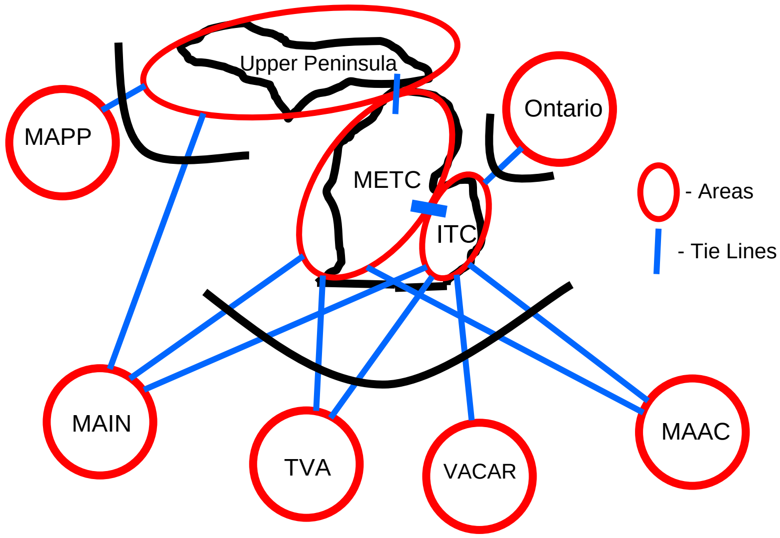
A major transmission project, first proposed in the CNF was studied by MISO as part of the Midwest ISO Transmission Expansion Plan 2006 (MTEP06). During the formative period of this study, there were two alternatives proposed for the Michigan transmission expansion. The initial proposal was either for a 2,500 MW direct current line or an alternative extension of the 765 kV system from southwest Michigan to northwest Detroit. This DC option is included as one of our sensitivities; the expanded transmission sensitivity of the Central Station Scenario. The model assumption is that the DC line would be operational in 2009 at a cost of $800 million. However, in early November 2006, ITC and AEP announced plans to jointly study a 765 kV loop through Michigan's Lower Peninsula that would link to AEP's existing 765 kV transmission infrastructure. The draft MTEP06 report includes this 765 kV loop as a proposed project with an estimated cost of $2.5 billion and an in-service date of 2016.

[11] For a more detailed discussion of Michigan's generation inventory please refer to Chapter 1 of the Appendix Volume II.

Transmission allows the state to purchase from and sell energy to markets outside Michigan. For power sales or purchases, the Strategist model used in this study includes estimated economy energy market prices for the entire 20-year planning horizon.

Given the demand and sales projections, the model has the option to select additional generation resources within Michigan or purchase economical energy from the external markets. The model operates under a reserve margin constraint, in this instance 15 percent, which forces the selection of resources to maintain the minimum reserve margin. Figure 3 shows the external markets that were included in the modeling study.

Figure 3: Michigan System Representation



Two levels of energy efficiency programming were developed for the model runs. The first was developed by the Energy Center of Wisconsin and represents the base case energy efficiency program (the more aggressive program). The base case efficiency scenario represents a successful statewide efficiency program delivering energy savings at a comparatively low cost of conserved energy of approximately 2.5 cents/kWh.

A less aggressive, lower penetration, program showed demand and energy savings at approximately the same level as the CNF. This study also doubled the cost of conserved energy for this program.[12]

Renewable resource options currently operational are included in the generation inventory presented in Chapter 4 of the Appendix Volume II. Between 1,100 MW and 2,700 MW of new renewable generation could be available by 2015, mostly in the form of wind power installations. Because wind is a variable output, the Plan used the same on-peak capacity credit of 12.5 percent for wind that was used in the CNF. In total, renewable energy is credited with between 664 and

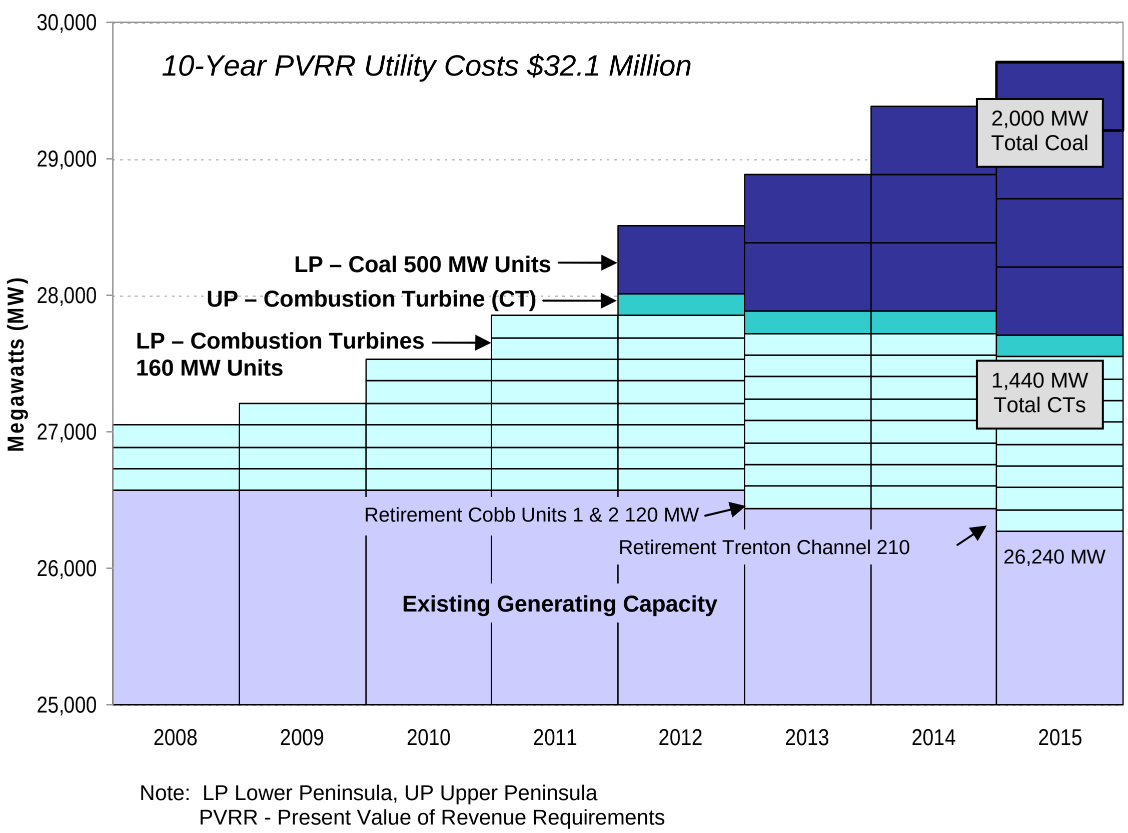
[12] For a more detailed discussion of the development of energy efficiency programming levels, please refer to Chapter 3 in the Appendix Volume II.

810 MW of on-peak capacity by about 2015. For modeling purposes, a conservative strategy of using the lower renewable energy total was adopted.[13]

The Plan also reviewed the CNF assumptions regarding combined heat and power applications (CHP). The CNF estimated approximately 500 MW of capacity could be available from CHP installations in Michigan over the first half of the planning period, 2006-2015. In this study, the Alternative Technology Workgroup reviewed additional information about potential sites and surveyed possible CHP adopters. Based on its review and survey, the Workgroup recommended 180 MW of CHP would be available instead of 500 MW. Consistent with this Workgroup's recommendation, 180 MW of CHP capacity is included in our planning model.

Expansion Modeling Results: For illustration, the generating resources selected in the base demand Central Station Scenario are shown in Figure 4. The Central Station Scenario selects several combustion turbines beginning in 2008, to preserve electric reliability by maintaining the minimum reserve margin constraints. Baseload coal generation is selected as soon as the construction schedule permits, which is 2012.

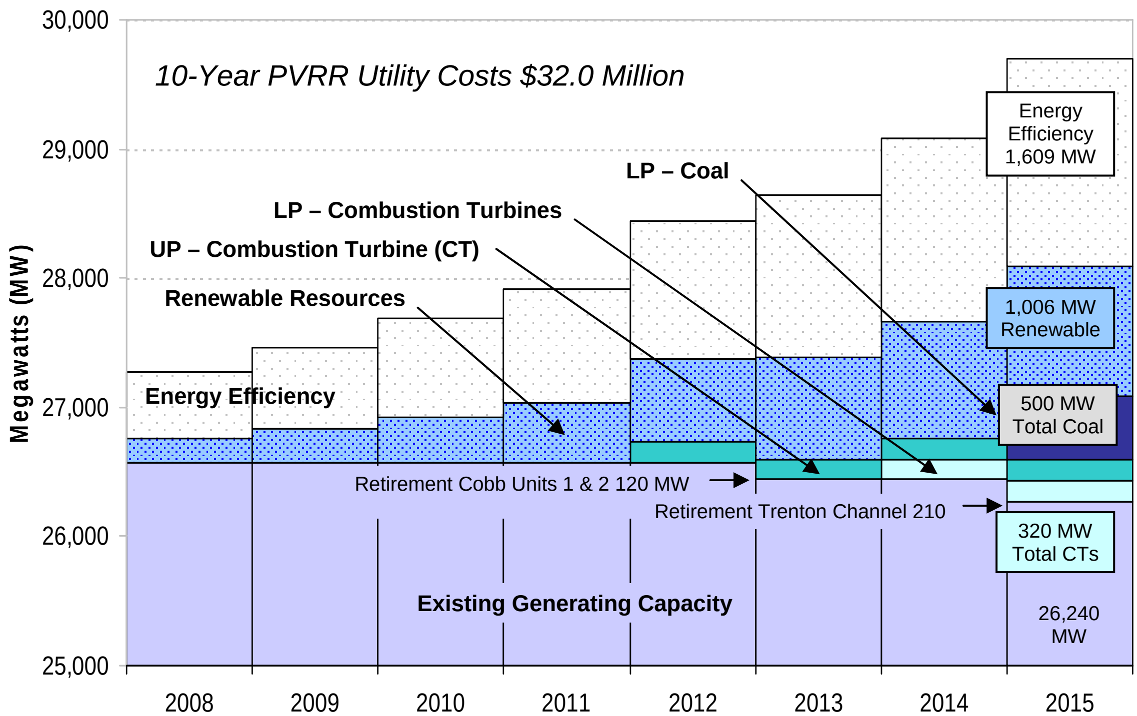
Figure 4: Schedule of Cumulative Generation Additions for the Central Station Scenario



[13] Please refer to Chapter 4 in the Appendix Volume II, for more information on new renewable resource options.

Under almost all Scenarios and sensitivities used in the CNF and the Plan, combustion turbines are added to the state's generating portfolio until baseload generation, or its equivalent, can be constructed. Assumed construction schedules lead to the selection of combustion turbines initially, since they can be built and brought on-line in one to two years. These units are chosen because the model attempts to meet reserve margin requirements (preserve reliability) until baseload units are added. The high penetration energy efficiency scenario represents the only exception. Since an additional 570 MW of load management is added immediately in the high penetration Energy Efficiency Scenario, many of the CTs, along with some coal units, are eliminated. Even in this scenario, however, the model adds a baseload unit as soon as the construction schedule allows. The combined Energy Efficiency with Renewable Energy Scenario eliminates the need for most CTs in the first half of the planning horizon and delays selection of a baseload unit until 2015 (see Figure 5).

Figure 5: Schedule of Cumulative Generation Additions for the Energy Efficiency with Renewable Energy Scenario



Note: LP Lower Peninsula, UP Upper Peninsula
PVRR - Present Value of Revenue Requirements

The modeling results from the high and low growth sensitivities, and the major change in the base demand forecast from the CNF to the Plan, demonstrate that additional resources will be needed to meet Michigan's electric needs under almost any plausible growth scenario. To meet continuing growth in electricity use and to replace aging generators, all Scenarios and sensitivities add additional generating resources. Even in the low growth sensitivities, the model selects a baseload unit, but not until 2015. Under the CNF energy efficiency scenario and the

Plan's reduced penetration sensitivity of the Energy Efficiency Scenario, baseload generation is also added as soon as construction permits.

Selection of a new baseload unit is delayed until the second half of the planning horizon only in the low growth sensitivity in the Energy Efficiency Scenario and the Renewable Energy Scenario. Based on multiple Scenarios and sensitivities, it is highly likely that Michigan will need additional baseload resources coming online in the 2012 through 2015 time period.
Fuel cost changes do not appear to have a major impact on the type of central station generating plant chosen by the model. CNF results indicated high natural gas prices do not have an impact on resource selection because even the lower, base case natural gas price forecast rendered natural gas fueled generating units uneconomic. As noted above, natural gas CTs were chosen in the initial years of the analysis simply to meet reliability needs until a baseload unit could be built.

The coal price forecast in this Plan is initially 22 percent higher than the CNF coal price forecast, and the difference increases over the planning horizon. The natural gas price forecast is 16 percent higher initially but converges to the CNF forecast within 10 years. The relative increase in coal prices compared to natural gas prices between the two major studies does not lead to gas plants being adopted other than for reliability purposes. The higher coal prices, however, favored renewable energy options and energy efficiency. The revenue requirement impact of adopting these options improved relative to central station options when the CNF results are compared to the Plan results.

A major exposure to risk was identified in the Emissions Scenario. The emissions scenario assumed a major U.S. policy change to control greenhouse gases, with a carbon dioxide tax starting at $10 per ton in 2010 and increasing to $30 per ton in 2018. Consequently, utility generating costs for fossil fuel units rise substantially. On a levelized lifecycle cost basis, the CO_2 emissions cost assumption used in this study could raise the cost of electricity produced by new sub-critical coal units by 1.5 to 2.0 cents per kilowatt hour (kWh). The carbon tax scenario shows that higher electricity prices are likely to be the result of a carbon tax, since coal units remain more economic than natural gas fueled units for baseload purposes.

An expanded transmission sensitivity was assumed to reduce the planning reserve margin from 15 to 12 percent. Assuming base demand forecast conditions, this eliminated or deferred the need for eight CTs over the first 10 years of the planning horizon but did not defer or eliminate the need for baseload units.[14] It also lowered production costs until 2012, when the first baseload unit could be built. After 2012, in-state baseload electricity production increased and imports of energy were substantially reduced, similar to the CNF modeling results. Price forecasts produced by the external market module for wholesale markets indicate external electricity market prices will be high enough to make building and operating in-state generation the more economic resource choice.

[14] The expanded transmission option included the addition of one combined cycle plant, which was not needed in the Central Station Scenario.

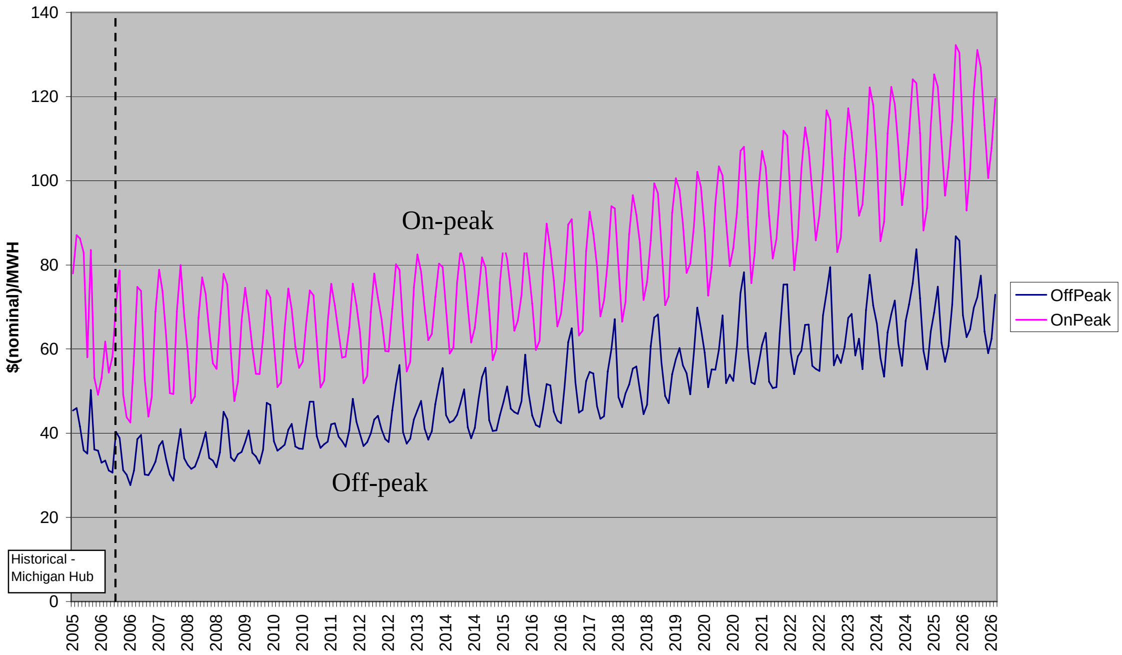
The 10 and 20 year net present value of revenue requirements (PVRR) of new resources for meeting electricity needs under the various Scenarios and sensitivities, are shown in Table 2.

Table 2: Net Present Value of Revenue Requirements for Comparisons for Scenarios and Sensitivities Modeled in the Plan

Scenario		10-Year PVRR ($ millions)	20-Year PVRR ($ millions)	10-Year Total Capacity Additions MW	20-Year Total Capacity Additions MW
Central Station		**$32,073.0**	**$56,716.9**	**3,440**	**11,260**
Sensitivity Analyses	High Load	$35,512.2	$64,116.8	6,740	15,040
	Low Load	$28,873.2	$49,811.6	660	7,640
	Reduced Imports	$32,169.2	$57,004.8	3,440	11,220
	Expanded Transmission	$32,329.1	$57,085.5	2,660	10,300
Emissions		**$36,956.6**	**$70,752.2**	**3,440**	**10,760**
Sensitivity Analyses	High Load	$40,832.7	$79,492.7	6,760	14,240
	Low Load	$33,321.8	$62,254.7	320	7,480
	Renewable & EE	$36,098.0	$65,594.5	3,026	10,079
	EE Only	$36,189.0	$66,707.5	3,249	11,261
Renewable Energy		**$32,506.9**	**$57,496.7**	**3,370**	**11,218**
Sensitivity Analyses	High Load	$35,929.4	$64,758.6	6,699	14,698
	Low load	$29,436.3	$50,797.8	599	7,238
Energy Efficiency		**$31,510.1**	**$53,794.5**	**3,249**	**10,581**
Sensitivity Analyses	High Load	$34,918.3	$61,040.0	6,569	14,241
	Low load	$28,638.7	$47,384.1	1,609	6,781
	Reduced EE Penetration	$32,208.7	$55,765.2	3,267	10,700
Energy Efficiency with Renewable Energy		**$31,998.1**	**$54,623.2**	**3,028**	**10,359**
Sensitivity Analyses	High Load	$35,354.4	$61780.4	6,188	13,899
	Low load	$29,246.5	$48,407.9	2,208	6,579
	Reduced EE Penetration	$32,692.1	$56,546.1	3,386	10,518
Combustion Turbine Only		**$32,126.9**	**$58,987.6**	**3,520**	**11,200**
Sensitivity Analyses	High Load	$35,630.2	$68,096.6	6,720	14,880
	Low Load	$28,856.0	$50,737.5	320	7,680

Figure 6 depicts the model's forecast of Lower Peninsula wholesale market prices. The figure shows nominal prices through the 20 year planning horizon. Seasonal variation like that seen the last few years is projected to continue. Higher summer electricity demand drives higher summer prices, and it is higher summer electricity demand that also drives the model to select combustion turbines in the near term to maintain reserve margin requirements.

Figure 6: Wholesale Market Prices for the Lower Peninsula



In the CNF and the Plan modeling, energy efficiency programming provided long-run favorable outcomes relative to central station generating plant alone. The average cost of conserved energy (levelized cost incurred to save a kWh) in the CNF was three cents/kWh and was 2.5 cents/kWh for the Plan's larger scale program. To test the limit of energy efficiency benefits, the cost of achieving energy savings in the reduced penetration scenario was doubled. Even at the higher cost, the reduced penetration case showed lower long term total costs relative to other resource choices.

The lowest present value cost of all Scenarios is associated with the Energy Efficiency Scenario. Since the estimated cost of energy conserved by these energy efficiency programs is an average 2.5 cents/kWh, these programs reduced the cost of providing electricity services compared to central station options alone. The combination of energy efficiency with renewable energy significantly reduced the cost of providing generation services in the Emissions Scenario.

It should be noted here that the optimization criteria for this model was the minimum net present value of revenue requirements. To be consistent, the energy efficiency programming scale was based on utility costs alone (utility cost test). Program participants, however, also incur costs not included in this test. An alternative test including participant costs would change the cost-effective scope of energy efficiency programming. Most cost-benefit tests,[15] however, would result in an energy efficiency program of significant scale, and the program would lower total revenue requirements relative to central station options alone.

Although energy efficiency programs may lower total costs, they may also tend to raise rates at the same time. Some participants recommended using the ratepayer impact test along with other tests. Evaluating the costs and benefits of energy efficiency programming requires more than one test. To judge the full impact and value of energy efficiency, the utility cost, total cost, and ratepayer impact tests should all be used when determining program scope and design. The process recommended by Staff for determining specific energy efficiency program characteristics and program scope is discussed in Section 4.

Expansion Modeling Upper Peninsula Results: The model framework allows for each of the state's three regions to be studied individually. This is particularly important for studying the Upper Peninsula since its interconnection with the Lower Peninsula has limited capability. Expansion modeling shows Upper Peninsula electric reliability is dependent on the timely completion of ATC's Northern Umbrella Project, a CNF conclusion that is confirmed in this Plan. The current study differs from the CNF, however, in its assumption that the first four Presque Isle units will be retired in 2012. These units total approximately 175 MW of capacity and were not assumed to be retired in the CNF. A review of We Energy's consent agreement with the Environmental Protection Agency, however, suggests completion of the Northern Umbrella Project will result in their retirement.[16] As a result, the model selects combustion turbines in 2012 and 2016 to maintain reliability standards under the minimum reserve margin constraint included as a modeling parameter.

The resources modeled for the Upper Peninsula included a coal-fueled baseload circulating fluidized bed (CFB) plant of 150 MW of capacity. For the remainder of the state, the available baseload units ranged from 300 MW to 1,000 MW in size. Because these units are too large for the electric system in the Upper Peninsula, the smaller CFB unit was exclusively considered for the UP.

---

[15] Several benefit/cost tests are available to evaluate energy efficiency programming, including a utility cost test (UCT), a total resource cost test (TRC), a societal cost test (SCT) and a ratepayer impact measure (RIM) test. A recent update of the California Standard Practices Manual, an important source of information on benefit cost tests, identified three of the four tests mentioned above (the Societal test is a variant of the TRC test). The manual helps to understand the cost effectiveness of energy efficiency programs and describes the strengths and weaknesses of each.

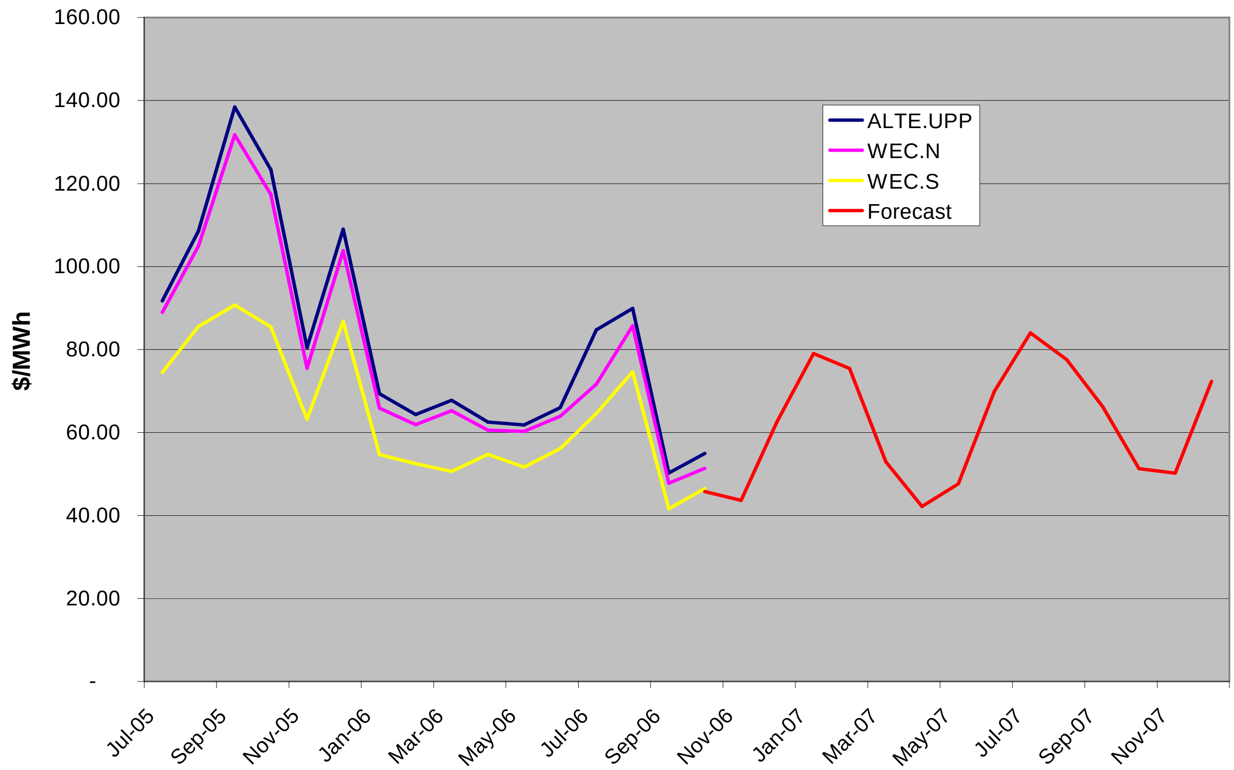
Ratepayer Impact Measure (RIM) test – measures the impact on customer bills or rates due to changes in utility revenues and operating costs caused by the program.
Total Resource Cost (TRC) test – measures the net costs of energy efficiency programs based on the total cost of the program, including both the participants' and the utility's costs.

Utility Cost Test (UCT) – measures the net costs of a demand side management program as a resource option based on the costs incurred by the program administrator (including incentive costs) and excluding any net costs incurred by the participant. The benefits are similar to the TRC benefits but costs are defined more narrowly.

[16] The first two units, however, were retired in January, 2007.

Instead of selecting the smaller CFB baseload unit, however, the model chose two peaking units to provide capacity support and purchased economy energy to meet UP energy consumption needs. This may have occurred because of the projected convergence of UP and Wisconsin economy energy prices. In 2005, UP locational marginal prices (LMP) were significantly higher and more volatile than prices in Wisconsin and Michigan's Lower Peninsula. However, as electric transmission to and from Wisconsin expands with the Northern Umbrella Project, prices in the UP are forecast to converge to and mirror those in Wisconsin. Much of this convergence has already occurred as seen in Figure 7, where "ALTE.UPP" represents UP on-peak locational marginal prices. The figure shows the relatively high price in the UP compared to WEC.S (southern Wisconsin) in 2005 and through the end of 2006, when the prices began to converge.

Figure 7: Comparison of Energy Prices for Northern MI and WI



The forecasted moderation of LMP in both the UP and Wisconsin causes the model to purchase economy energy at LMP and build combustion turbines for reliability, instead of building baseload generation to serve both purposes.

This is the opposite effect that occurs in the Lower Peninsula, and the difference may be due to the lower cost of generating with larger baseload plants in the Lower Peninsula. These large units used in the Lower Peninsula add too much capacity for the Upper Peninsula, but the smaller CFB units intended for the Upper Peninsula do not have benefits from the economies of assumed for the larger units.

Finally, although the model selects 160 MW of CTs to meet reserve margins within the Upper Peninsula, this need could or might also be met by reserves in Wisconsin that could provide power over the ATC system. It is possible that the smaller unit could still prove to be economical if built at an existing site, without the need for substantial investments in transmission, site preparations, or fuel delivery infrastructure.

1.3 Conclusions of Modeling Results

1.3.1 Near Term Resource Options

Reliability analysis forecasts near term reliability issues for the southeast Michigan region in the 2009 time period. As this period approaches, Michigan's composite reserve margin is projected to fall below the 15 percent planning reserve margin used to assure electric reliability. After 2009, in-state reserves, even with the external capacity support expected through the interconnected transmission system, will no longer provide acceptable reliability when likely contingencies are modeled. While this does not mean rolling blackouts are likely, it does mean increased potential for voltage disturbances and a higher potential to lose some load due to insufficient generation at periods of peak demand.

Combustion Turbines/Combined Cycle Units: The expansion model adds gas combustion turbines to provide reliability as early as 2008. Approximately 1,280 MW of combustion turbines are added in the Central Station Scenario base demand forecast by 2012, when the first coal plant is brought on-line by the model.

Combustion turbines represent a relatively quick method of boosting reliability without incurring onerous capital costs. Fuel costs for these plants are prohibitive, however, so they are intended to run for very brief periods and only to meet peak demands. Siting, financing, and constructing combustion turbines can be done relatively quickly. Staff assumed a one to two-year schedule to bring combustion turbines online.

The model selects the CT units to meet reliability needs but not to provide more energy. CT units are the only units available to be selected in the near- term, due the short lead time required for planning and installing these units. Therefore, CT units are selected to maintain the 15 percent reserve margin constraint. Although the high natural gas fuel expense to run these units generally eliminates their being used to generate electricity. Instead, the model obtains energy from the cheaper wholesale market.

Normally, the model selects combined cycle (CC) units to meet both reliability and energy generation. Since CC units are much more efficient that CTs, during the near term reliability period, the model selects the CC when a plant is needed for more than a few hours during the year. Despite the greater fuel efficiencies of CC in contrast to CT plants, the current and forecast costs of natural gas result in CC plants not playing a major role in energy production, either. In the Central Station Scenario base demand forecast, CC units were not selected by the model for inclusion in the resource mix.

Transmission: External capacity support using expanded transmission resources could provide an alternative option for meeting the anticipated reliability need in southeast Michigan. When selecting nearly 1,200 MW of capacity over the immediate five-year future, the model did not use transmission for capacity support. As noted above, the Lower Peninsula is forecast to have 3,000 MW of transfer capability available in 2009. Approximately 800 MW have been reserved for firm transmission service by parties outside of Michigan and is unavailable for use as firm capacity for Michigan. The remaining 2,200 MW capacity was included in the reliability study, which identified the 2009 reliability problem in southeast Michigan

If a proposed TIER II transmission option is available to increase transmission capability into Michigan by 2009, this option could relieve the forecast reliability violation. TIER II upgrades are estimated to increase transfer capability into southeast Michigan by 2,500 MW or more. The TIER II upgrades offer a major increase in transfer capability that can be used to purchase external capacity to satisfy reliability needs. Based upon early representations by ITC, this study's expanded transmission sensitivity assumes that a TIER II upgrade would be operational by 2009, would be a DC line, would cost $800 million, and would allow the planning reserve margin to be lowered from 15 to 12 percent. Lowering the reserve margin results in only one combustion turbine (160 MW) and one combined cycle (500 MW) unit being added to the resource mix by 2012. However, it does not defer or eliminate the need for any baseload units. For a more detailed discussion of the TIER I and TIER II options, please refer to the Transmission and Distribution Workgroup report from the CNF study.[17]

Using expanded transmission to lower in-state reserves requires one to assume there is sufficient generating capacity outside of Michigan to support a major in-state contingency. Reserve sharing among utilities has been a common practice for many years. However, with the development of regional wholesale markets, it is unclear how planning reserves and reserve sharing will evolve. MISO intends to implement an ancillary services market for operating reserves, but has not indicated an intention to become involved with requiring planning reserve requirements.[18] MISO evaluates whether adjacent states are forecast to have sufficient reserves to support Michigan during peak periods and does indicate that nearby states are forecast to have sufficient reserves within its footprint in the 2009 period. This study's assessment of transmission as a method to provide access to capacity outside Michigan and to satisfy reliability needs relies on MISO's MTEP process and its determination that sufficient reserves exist to provide needed support.

There is no certainty, however, when transmission expansion may be available to meet reliability needs. The original assumption was that a 2,500 MW expansion would be available in 2009, based on the construction of a DC line on an existing right of way. Recently, however, ITC and AEP have announced plans to study a 765 kV AC loop through lower Michigan. Transmission expansion on this scale would require a new right-of-way, and the time and cost of securing it is uncertain. It is unclear now what transmission expansion option is most likely to be proposed, so a transmission option will need to be reevaluated when more details become available.

---

[17] Transmission and Distribution Workgroup report of the CNF, available online at http://www.dleg.state.mi.us/mpsc/electric/capacity/cnf/transdist/finalreportjan_2006.pdf.

[18] MISO has agreed to act as Group Administrator for a regional planning reserve sharing group by performing services as a contractor.

Electric transmission expansion can be expensive: a 2,500 MW DC line across southern Michigan was estimated at $800 million, using existing right-of-way. The transmission expansion cost allocated to Michigan ratepayers for the proposed transmission upgrade does not include the cost of the capacity or energy at the other end of the line. The cost of capacity and/or energy at the other end of the line plus the cost of the line allocated to Michigan ratepayers must be less than the cost of building and operating generating plants in Michigan for the line to be economical. The Federal Energy Regulatory Commission (FERC) provided liberal rate treatment for transmission investment, allowing ITC the nation's highest rate of return on investment that Staff is aware of for FERC jurisdictional utilities. ITC's charges amplify transmission costs and, because customers must also pay for the power at the end of the line, the charges contribute to putting the transmission option at a cost disadvantage to in-state generation. The Plan's analysis indicates the transmission expansion option is more expensive than building generation in Michigan, even though the planning reserve margin is lowered to 12 percent and six combustion turbines are dropped from the generation mix in the expanded transmission sensitivity. Further, it is possible that some, or even most of the transmission upgrades will be reserved by out-of-state market participants and not be available for Michigan market participants. For example, although the CNF study estimated that 3,000 MW of on-peak transmission will be available into Michigan, approximately 800 MW has already been reserved by other market participants and, therefore, unavailable for Michigan reliability planning. Nevertheless, the value of expanding transmission capability to reduce reliability costs and further integrate Michigan into the Midwest market should continue to be studied as a long term goal of the Plan

In addition, recent price volatility in energy markets is a major planning concern, and poses a significant risk for any strategy that relies on purchases of short-term capacity to meet system reserves. The Midwest wholesale imbalance market prices all power at the marginal cost of the last unit brought online. For several reasons, this can cause customer costs to swing quickly and wildly. As load in this region grows, proportionally more of Michigan's energy consumption could be exposed to volatile prices. Baseload units provide stable power sources that can provide more predictable and, generally, lower life-cycle electric energy prices, if they are ratebased or their power is secured through a long term contract.

Load Management/Energy Efficiency: Load management offers a third option for meeting near term reliability needs. Staff included approximately 570 MW of active load management programs in the Energy Efficiency Scenario. Used intermittently in summer, load management programs can offset the need for additional capacity and help meet peak loads. Including load management with the base energy efficiency program reduces the need for combustion turbines to just 320 MW (2 units) by 2012.

Energy efficiency measures are also available to meet demand and energy needs. Due to the phase-in nature of energy efficiency programming, efficiency results are more pronounced in the 20 year data. Total demand is projected to be reduced 1,065 MW by 2015 through a combination of load management and energy efficiency programming.

Renewable Energy: Most of the renewable options identified by the Resource and Technology Team could be sited and constructed within a comparatively short timeframe. Landfill gas, anaerobic digesters, and combined heat and power installations can be relied on for on-peak energy production. The Workgroup projected approximately 1,100 to 2,700 MW of renewable energy could be available by the end of 2015; not including 180 MW of combined heat and power. Wind energy represents 525 to 2,100 MW of total renewable capacity. Because wind is a variable output resource, total renewable energy on-peak capacity is credited between 664 and 810 MW by about 2015. For modeling purposes though, the more conservative value of 664 MW associated with the 7 percent renewable portfolio standard (RPS) was used. Renewable energy with CHP can eliminate the need for five combustion turbine units by 2012.

1.3.2 Long Term Resource Options

Long term planning contingencies center on wholesale energy market price concerns and potential emissions costs or restrictions. Demand growth forecasts are a source of chronic uncertainty, and the CNF report along with this study included a number of demand growth sensitivities. Nearly all of the modeled cases resulted in additional baseload generation being added to the Michigan portfolio as soon as the construction schedule allows. Even the Central Station low growth sensitivity, which assumed a 0.21 percent growth in demand over the first 10 years, and a 0.76 percent growth over the 20 year planning horizon, added a baseload unit in 2015. Only the Energy Efficiency with Renewable Energy Scenario, with the low demand growth sensitivity, pushes the need for a baseload unit farther into the future. However, these Scenarios result in an unlikely prospect; a net negative demand growth over the next 10 years. Therefore, the CNF conclusions remain valid:

> Since the last baseload unit was added in 1989, twenty two years will have passed before another baseload unit could be added to the State's generation mix assuming a new baseload plant is added in 2011. Between 1990 and 2004, energy consumption in the State has grown over 30 percent, without additional baseload generation. Considering these facts, it is not a surprise that the model selects a baseload plant as soon as the schedule permits. Barring a catastrophic collapse in electricity demand, we do not consider the CNF demand forecast as the critical planning contingency at this time.[19]

Although CNF modeling identified the need for eight new baseload units in the first 10 years, the Staff report recommended constructing only one or two new plants on a staged basis. Staging allows the planners to continue investigating the need for a second plant, a conservative recommendation. The model results in this study, although based on a lower forecast of 1.2 percent demand growth, do not change this conclusion.

Like the CNF, this study predicts a turnaround in Michigan's traditional role as a net power importer. Modeling suggests that Michigan will continue to import power from out-of-state markets until new baseload units can be brought on-line in Michigan. Normally, as new more efficient units are brought on-line, older, less efficient units would reduce their capacity factors. These older units could continue to produce power for the wholesale market, however. The model's spot market energy price forecast shows an upward nominal price trend, consistent with

[19] Michigan Capacity Need Forum Staff Report to the Michigan Public Service Commission, January 2006, page 46.

recent experiences in the region. This makes owning generation in the future more advantageous than relying on purchased power.

Although the Strategist model selects pulverized coal technology for its baseload additions, other baseload generating technologies should also be considered. Circulating fluidized bed (CFB) and integrated gasification combined cycle (IGCC) coal based technologies are available and might or could offer additional benefits. Which technology might be the most appropriate will depend on cost, air quality permit requirements, site location, and its ability to mitigate future risks. CFB technology permits a broad set of fuel options, including carbon-neutral biomass fuels. It offers these additional benefits coupled with adoption of super-critical pressures and temperatures. Likewise, IGCC technology allows more efficient removal of a variety of air pollutants compared to other coal based generation. If additional pollutants, including greenhouse gas emissions, are controlled in the future, this technology could play an important role in a greenhouse gas compliance strategy. Even a decision to use pulverized coal would need to consider recent developments with ultra super-critical units, which are much more efficient than existing pulverized coal units.

Baseload need can also be met with nuclear generating plants. The expansion model did select a nuclear unit in the emissions scenario in the post-2015 phase of the planning period. A major advantage of nuclear technology is that it does not emit CO_2 or other greenhouse gases. Although nuclear generating technology advanced in recent years, no new plants have been commenced in the United States since the late 1970s. Although the Nuclear Regulatory Commission (NRC) implemented a design certification process, the process has not yet been tested. Further, unresolved issues related to spent nuclear fuel storage create uncertainty related to nuclear production technology. Given the long lead time involved for siting, permitting and constructing nuclear units, and the need to resolve spent fuel storage issues, it seems that this option will be available to supply state needs only after 2015.

Finally, longer term energy needs can also be met through energy efficiency programs and renewable energy options. Efficiency programs can be tailored to satisfy both annual energy needs and on-peak requirements.

1.4 Staff Resource Recommendations

Resource integration modeling reveals three important findings pertaining to Michigan's electric generation and related resource requirements.

1. Additional electric generation or related resources are needed in the near term to continue to meet electric reliability standards.
2. Because of long planning and construction lead-time requirements, Michigan must act soon to provide new baseload electric generating plant to meet resource requirements in the 2012 through 2015 period.
3. A broad resource mix is necessary to mitigate major risk variables such as future fuel price volatility and environmental costs.

Additional generating resources will be needed in Michigan, and resources selected to satisfy the near term reliability needs should complement a long term strategy to provide affordable prices and manage likely risks. To meet near term reliability needs, Staff recommends initiating or, where currently operational, expanding active load management programs like air conditioning cycling programs. Staff also recommends commencing a broad based, statewide energy efficiency and renewable energy program. Collectively, these resource options should eliminate or defer the need for multiple CTs. Smaller renewable energy options, along with energy efficiency programs, can be added or deferred quickly to meet unanticipated changes in demand growth. When needed, CTs can be added to meet reliability needs.

Over the longer term, the Plan's modeling results are consistent with the results of the recent National Electric Reliability Council (NERC) report warning that U.S. transmission and generation resources need to be substantially augmented to ensure reliability.[20] Declining reserve margins not only impact reliability, but also cause wholesale market prices to become more volatile. Adding to this volatility has been the growth of natural gas fueled electric generating capacity. Natural gas fueled units have increased from about 10 percent of Michigan's generating capacity in 1992 to about 29 percent today. Growth in natural gas generation in Michigan and throughout the nation contributed to high and volatile wholesale electricity prices. Natural gas prices have risen so dramatically that new, efficient natural gas fired generation plants, intended as baseload additions, have become uneconomic.

Over the longer term, additional baseload generation will be needed to protect ratepayers from volatile wholesale market prices and increased reliance on natural gas fired generation. Therefore, a long term strategy should combine baseload construction with an expansion of the energy efficiency, load management, and renewable energy options that are relied upon to meet near term reliability needs. These resources will also offer protection from any greenhouse gas controls that could potentially be adopted by the federal government in the future. Baseload generation construction should anticipate the possibility of tighter air emission standards, including greenhouse gas controls, and be designed as a "clean" generation option.

Finally, we recommend that options involving expanded transmission investment continue to be studied. Integrating Michigan more closely into the Midwest markets should be a long term goal of the Plan.

1.5 Policy Background

Implementing a sound long term resource strategy for Michigan is hampered by current state policy. Michigan P.A. 141 of 2000 restructured Michigan's retail electric generation market. The Act provided for a hybrid, two market system, where customers can opt for full service under traditional ratebase-priced generation from incumbent utilities or market priced generation from alternative electricity suppliers. A second change in electricity markets occurred in 2005 when regional wholesale markets operated by MISO moved to market-based pricing. These two

[20] See NERC website at http://www.nerc.com/. Document, *2006- Long-Term Reliability Assessment: The Reliability of the Bulk Power Systems in North America, October 2006,* available online at ftp://www.nerc.com/pub/sys/all_updl/docs/pubs/LTRA2006.pdf.

changes have profoundly altered market dynamics by increasing uncertainty and risk while at the same time facilitating market transactions.

Because ratepayers can move relatively freely between the regulated and customer choice markets, most Plan participants, including Commission Staff, conclude that Michigan's current market structure provides insufficient certainty to finance a major generating plant on reasonable terms. This leaves Michigan vulnerable to either declining reserve margins with eroding reliability or reliance on cheap to build but expensive to operate combustion turbines. The likely result is that electricity prices in Michigan will become more volatile and will rise to levels higher than would be experienced with a more robust state electricity policy. Model results estimate that the current policy will result in costs that are over $4 billion more over the next 20 years than would be experienced with the broader set of resources and policies envisioned in the Plan.

Resource modeling also shows that energy efficiency and renewable energy options are needed to manage electricity demand, reduce total electricity costs, and mitigate risk. However, Plan participants have suggested the Commission needs additional authority to require adoption of these resources. Experience has demonstrated that neither energy efficiency programming nor renewable energy options will be adopted voluntarily on a significant level on a voluntary basis by Michigan load serving entities. Staff recommends that legislative and other affirmative action is needed to address these issues and offers the following three policy recommendations:

Policy Recommendation 1 - Optional Utility Power Plant Construction Program

Legislation

- Legislation would permit the Commission to issue a Certificate of Need for new generating plant being proposed by an incumbent utility, so that the issue of need is not contestable after the plant is completed.
- The incumbent utility would be required to file an integrated resource plan (IRP) demonstrating the need for additional generating capacity. The Commission would be authorized to establish standards for the IRP.
- The Certificate of Need process must include competitive bidding for new plant engineering, procurement and construction (EPC), and must be accompanied by a financing plan.
- Customers who contribute to the need for a new generating plant will be responsible for contributing to the plant's cost recovery.
- The Commission should require customers who elect to be supplied by an alternative electric supplier to provide a two year notice before returning to regulated rates. Until the two years have passed, the utility would need to serve the returning customer at market based rates.

Commission Action

- The Commission should, at its sole discretion, consider extending its current policy of allowing construction work in progress (CWIP) (see footnote 2)without an allowance for funds used during construction (AFUDC) (see footnote 3)offset for environmental investment to additional CWIP investment, if the request for the extension is made as part of a utility financing plan.

- The Commission should promote accurate and efficient price signals by moving to cost based rates.

Policy Recommendation 2 – A Renewable Energy Standard

Legislation

- Establish a mandatory renewable energy standard of seven to 10 percent for all load serving entities (LSEs) in Michigan by the end of 2015, and with a target of 20 percent by 2025; including a requirement for a Commission hearing in 2014 to determine the appropriate renewable energy portfolio standards to apply 2016 through 2025.
- Eligible facilities should include those defined in the Customer Choice and Reliability Act (2000 PA 141; MCL 460.10 *et seq*) and include existing renewable energy resources.
- Provide for alternate compliance payments (ACP) that can be made by all utilities until 2012, and by LSEs with less than 100,000 customers thereafter. ACP payments would go to the energy efficiency fund to be used exclusively for funding renewable energy projects like a community based renewable energy program.
- Adopt a renewable energy certificate (REC) trading program. Out-of-state RECs should be permitted if they originate from facilities that assist Michigan in meeting air quality standards and provide economic development benefits to Michigan.
- Clarify the Commission's authority to set terms and conditions of net metering tariffs for projects up to 150 kW and authorize the Commission to adopt distribution use tariffs for transmitting power over a utility's distribution system.
- Exempt residential property owners from some portion of their property tax for solar photovoltaic (pv), wind energy, and fuel cell installations.
- Legislation should be adopted that authorizes the Commission to direct a solar energy pilot program involving one or more utilities.

Commission Action

- Commission Staff should conduct a collaborative on smart power grid technologies, especially for application to the Michigan grid.
- Siting and zoning guidelines for wind energy and other distributed generation resources should be communicated to local authorities through the Michigan Renewable Energy Program (MREP).
- The option of using revenue as the basis for valuing renewable energy installations for property tax purposes should be communicated to local taxing authorities through the MREP.
- Commission Staff should commence an investigation of the costs of extending its underground line policy.

Policy Recommendation 3 – Statewide Energy Efficiency and Load Management

Legislation

- The Commission shall be authorized to administer a Michigan Energy Efficiency Program.
- The Commission will select an independent third party administrator to operate a statewide program.
- All retail electric load serving entities must participate, including investor owned utilities, cooperative utilities, alternate electric suppliers, and municipal utilities.
- The program will be funded by a non-bypassable charge on all retail sales.
- The first year budget will be $68 million and the Commission will conduct a public hearing to determine the second and third year budget, with a goal of $110 million in the third year.
- Large manufacturing customers with billing demands of one megawatt or more may opt-out by demonstrating equivalent investment.
- Triennial public hearings will be conducted to set funding charges, establish priorities, and evaluate program performance.
- Independent evaluation will be conducted annually.
- The Commission shall be authorized to require load management programming by regulated utilities and to authorize demand response pilot programs.

State Action

- DLEG should begin a collaborative process to review residential and commercial building codes and make recommendations on improving energy efficiency in new Michigan construction.
- The Michigan Energy Office should analyze the benefits of state mandated appliance efficiency standards not currently included in federal standards.
- The Commission should initiate a demand response pilot program.

.

1.6 Summary of Introduction

Collectively, these recommendations are designed to overcome barriers to the adoption of a broad set of conventional and unconventional resources consisting of generating plant, energy efficiency, load management and renewable energy options, and to enable the development and adoption of new, distributed generation resources. The following sections present Staff's policy recommendations for three major resource categories: Central Station; Renewable Energy and Distributed Generation; and Energy Efficiency. The sections also summarize opinions held by various participants regarding resource assessments and policy issues. Additional discussion of participants' comments on major issues can be found on the Plan's website, which contains the full text of all comments submitted regarding the Plan.

2. Central Station Policy

2.1 Summary of Recommendations

The following Staff recommendations pertain to central station resource acquisition and related Michigan retail electric customer choice market issues:

1. Modify Commission policy to assure cost based rates for efficient functioning of the Michigan market.
2. Modify Commission policy to set a mandatory planning reserve standard for all load serving entities.
3. Provide Commission with authority to establish integrated resource plan standards, issue a certificate of need for new utility generating plant, and require incumbent utilities to competitively bid the EPC costs of a new generating unit.
4. Require a utility proposing to build a new generating unit to file a financing plan for the unit's construction costs. Modify Commission policy so the Commission, at its discretion, could extend its policy of permitting CWIP in ratebase for pollution control investment to some or all of the remaining plant investment.
5. Provide authority to assure that customers who cause plant construction to be undertaken will contribute to the recovery of the plant's cost. Customers who take service from an alternative electric supplier would be required to notify their incumbent utility two years prior to returning to regulated rates.

2.2 Introduction

Central Station resources are conventional electric generation plants, including baseload, intermediate, and peaking units. Conventional hydropower, including dams and the Ludington pumped storage plant owned by Consumers Energy and DTE, are also included in this category. Strong consensus exists among Plan participants that the current market and regulatory structure does not provide sufficient certainty to promote supply-side investments in major, new electric generating facilities, especially baseload facilities. Michigan's retail choice program and the market-based regional wholesale markets have contributed to this risk. Michigan needs to address this dilemma soon, because Plan modeling shows that to maintain system reliability and assure future electricity affordability, Michigan needs to add generation or alternative resources in the near term. Most participants support some form of legislation providing the Commission with authority to establish procedures to ensure that new electric generating plants will be added to the state's generation mix when needed.

Subsection 2.3 presents the central station policy proposals offered by Plan participants, and Subsection 2.4 discusses major issues related to the acquisition of central station resources. Staff conclusions and recommendations are then presented in Subsection 2.5.

2.3 Central Station Policy Proposals, 21st Century Energy Plan Participants

The Central Station policy discussion began with various participants submitting strawman policy proposals intended to address shortcomings in Michigan's hybrid market. Originally, four

Central Station strawman policy proposals were developed. Subsequently, three of the strawman proposals, which had similar approaches, were combined by participants, into one strawman proposal.

The two resulting proposals began with similar approaches. Both recommend each utility prepare and file an integrated resource plan (IRP) to determine its generation needs. They also recommend the IRP analyze a broad set of resources to address additional generation need. The resource mix includes central station generating units, energy efficiency, renewable energy, load management, wholesale market opportunities, and transmission expansion. The proposals disagree on whether the filing should be mandatory and on a regular basis, or only when a utility seeks to add generation.

Each proposal advocates a two-step Commission process: one proceeding to review resource need and the proposed capacity bidding process, which may result in Commission certification for the need of baseload generation and guidelines for subsequent capacity bidding, and a second phase for the bidding process to acquire the needed capacity. The bidding process would incorporate all the Commission requirements from the first administrative step. All proposals recommended a contested case process. Elements of the proposals' first phase are summarized in Table 3.

There are numerous differences in detail between the two strawman proposals, but two differences are critical. These two differences are (1) capacity ownership options under the capacity bidding process and (2) the framework for "obligation to serve" in the state's customer choice program.

2.3.1 Capacity Ownership Options under the Capacity Bidding Process

Strawman 1 requires competitive bidding for any capacity – If the Commission deemed a baseload plant necessary to meet a utility's future energy demand, Strawman 1 would require the utility to issue an request for proposal (RFP) to give independent power developers the opportunity to bid on building, owning, and operating the plant, or supplying equivalent power to the utility under a power purchase agreement (PPA). Based on the bids, the Commission would determine whether the utility would be allowed to build the plant that would serve its customers, or whether an independent power producer could provide the power through a PPA. In this Commission review, the utility would be treated in the same manner as all other interested or potential project developers.

Bidding standards would be established by the Commission, which would have 180 days to adopt a bidding format for the draft RFP, including evaluation criteria and standard contract terms. Bidding standards would govern utility participation and provide for independent evaluation of the bids, binding price caps on bids, rules for contesting the bids, confidential bids, and rules for allocating risks between ratepayers and project developers. The standards would also provide for all source bidding with a preference for cost effective energy efficiency and renewable energy options.

Table 3: Central Station Strawman Proposals

Criteria	Strawman #1	Strawman #2
Schedule	• Mandatory – every two years	• When needed
Long Term Forecast	• Entire service territory and wholesale customers identify choice sales	• Full service customers
Resources	• Central station generation	• Central station generation
	• Energy efficiency	• Energy efficiency
	• Renewable energy	• Renewable energy
	• Load management	• Load management
	• Transmission expansion	• Transmission expansion
	• Regional generation sources including MISO markets	• Existing generation from within region
Bidding	• Required to bid need to include all market participants	• Bid engineering, procurement construction (EPC)
Resource Selection	• All source bid, with first allocation to all cost effective energy efficiency and renewables	• Energy supply plan
Cost Allocation	• Overruns borne by developers and utilities	• Option: would allocate cost overruns to utility for higher rate of return
	• No cost recovery prior to in-service date	• Option: prudently incurred costs recovered
Customer Choice	• Maintain current return to service provisions	• Return to utility service at negotiated rates, no obligation to serve returning customers
		• Choice suppliers must meet reliability standards
Other	• Analyze alternative reliability targets	• Deskew rates
	• Determination of capacity for reliability or economic reasons	• Preapproval through Certificate
	• Preapproval granted	

Strawman 2 also recommends competitive bidding, but only for engineering, procurement, and construction (EPC) of a utility owned power plant – EPC represents an estimated 85 percent of a new plant's construction costs. In this case, the utility would submit a resource plan to the Commission, detailing its plans to use energy efficiency, renewable energy, transmission, existing regional resources, and new generation to meet its customers' needs. If the plan includes a new generating unit, the utility could request a Certificate of Need. The Commission would have 180 days to issue or deny the request.

After the issuance of a certificate, the utility would be required to develop preliminary engineering specifications, a site analysis, and a detailed cost basis for the plant. The Commission would review the utility's preliminary proposal, determine whether costs were prudent, and issue an irrevocable order authorizing need for the plant. Following a Commission order, the proposal would allow rate relief related to financing cost prior to commercial operation. Excess costs would be subject to Commission prudence review.

2.3.2 Framework for Obligation to Serve

Incumbent utilities' "obligation to serve" in Michigan's hybrid market was the second significant difference between the strawman proposals. Utilities presently have an obligation to serve all customers, but the customer choice program allows customers to take generation service from an alternative provider. The obligation to serve means customers can take service from an alternate electric supplier but return to a regulated utility's generation service at a later date, at which time the utility must provide service to the returning customer.

Strawman 1 asserts that the Commission's current policy regarding return to full service does not need to be altered – The policy, which proponents say should be codified, requires returning customers to inform the utility of plans to return by December 1 for the subsequent year. Otherwise, returning customers are charged market based costs through the summer. Returning customers must also remain with the utility for 12 months.

It initially appeared that Strawman 1 proponents anticipated that continuing stranded cost cases would be sufficient to protect utility plant investment. Discussions with some of these participants, however, indicated that they do not advocate continuing the Commission stranded cost process. Instead, some strawman proponents suggest that current ratemaking along with DTE's impending choice incentive mechanism (CIM) protects the utility from the effects and risks of customer migration. As a result, they see no need to change current return to service provisions.

Strawman 2 proponents argue retail choice gives alternative electric suppliers freedom to choose customers without an obligation to serve – Alternative electric suppliers can avoid serving any customer or customer group, such as residential customers, who are small and expensive to serve, or customers with less desirable load shapes that are, therefore, more expensive to serve. In contrast, Strawman 2 proponents argue, utilities are obligated to serve all customers large or small, and customers with good or difficult load shapes. They also argue rates are not set at cost of service. As a result, the utility obligation to provide universal service, has added costs and burdens, and Strawman 2 proponents believe this current situation is inequitable.

Strawman 2 proponents assert utilities should not be obliged to serve at regulated rates those customers who leave for choice but later choose to return. These participants argue customers have no obligation to stay with the utility after resources have been purchased to serve them, creating an unfair obligation for the utility, which ultimately disadvantages its remaining customers. Therefore, under Strawman 2, once a customer leaves for choice, they should be able to return to the utility's service but only at market prices or negotiated rates.

Strawman 2 proponents also argue choice suppliers should be required to meet the same reserve margin standards of regulated utilities, acquire ancillary services, and participate in energy efficiency and renewable energy programs. In addition, regulated rates for full service utility customers should be set according to cost of service calculations, according to this proposal. Without cost of service based rates, proponents say that incorrect signals are sent to market participants and alternative suppliers have the opportunity to selectively market to high margin customers. The proposal also calls for a circuit breaker to limit customer choice participation. The circuit breaker would be triggered if customer choice participation levels increased above a certain level.

Regulated utility rates would also be automatically adjusted to account for changes in electric choice participation by the LDC customers, under the Strawman 2 proposal. Finally, Strawman 2 advocates urge use of a wires charge to supply revenue certainty for new plant construction.

2.4 Major Issues impacting Central Station Resources

As noted previously, Michigan's hybrid electric choice market is a major factor contributing to financial risk of any major investments in generating capacity. Each Strawman proposal seeks a solution to the current market situation by creating a capacity bidding framework and addressing return to full service issues. The following sections discuss issues related to the choice market, capacity bidding, and return to full service.

2.4.1 Michigan's Retail Choice Market

Three market alternatives have been identified to address Michigan's electric generation capacity needs. First, the market could be re-regulated by repealing retail choice under Michigan 2000 PA 141 (PA 141; MCL 460.10 *et seq* the statutory revision that created the electric customer choice program. Second, the market could be fully deregulated and regulated utilities required to spin-off generation resources. And third, existing law could be modified to make Michigan's electric market sustainable while balancing the interests of Michigan ratepayers.

With regard to these three alternatives, Staff: (1) believes re-regulating retail generation service is plausible, but takes no position on whether this action is appropriate; (2) strongly rejects complete deregulation; and (3) recommends modifying the current regulatory framework, to both maintain and refine Michigan's split-market retail model. The third recommendation emerged as the central theme expressed by Plan participants. It was the focus of the CNF Update Workgroup proposals and Staff's response proposal.

<u>Policy Options</u>

Re-regulation – The Governor and the Legislature could reverse 2000 PA 141 and eliminate the uncertainty that it has created. Staff initially considered re-regulation as impractical. However, it has been pointed out that California, which led the nation in the deregulation movement, has already has suspended indefinitely, its retail choice option. Delaware, which likewise deregulated its electric generation market, has recently announced plans to study re-regulation after experiencing price increases in a volatile market.[21] Ohio repeatedly extended price freezes on its ratepayers and deferred the implementation of competitive market prices for fear of rapidly escalating costs associated with its deregulated markets. In Illinois, the state rejected implementation of market based prices for its commercial and industrial customers served by

[21] "Delaware Considers Regulating Electricity," *Platts Megawatt Daily,* November 30, 2006, p. 1; http://www.platts.com.

distribution companies as providers of last resort, after a supply auction resulted in bids of 8.5 - 9.0 cents/kWh. This price was deemed too high by the Illinois Commerce Commission.

Perhaps the most surprising turnaround on this issue is the position of the Electricity Consumers Resource Council (ELCON),[22] a national association of large industrial electricity users. ELCON is in the forefront of advocating for competitive electricity markets. However, in a recent article, ELCON indicated that it continues to advocate for "real" competition, but then advises that today's market structures cannot provide that competition. While ELCON indicates it would prefer modifying the current market structures, it seems doubtful that ELCON's proposed changes would or could induce significantly different circumstances than those that exist today. ELCON recommends, among other things:

> States that have not yet restructured should not do so: Roughly two-thirds of the states have not yet restructured or have begun the process but are not past the point of no return. They have the opportunity to wait until a wholesale market structure develops that can support retail competition and actually bring demonstrated benefits to consumers. . . . If today's organized markets cannot be fixed, explore all options including a return to traditional regulation: If today's organized markets – which are not a step toward competition but in truth a new form of regulation – are the best we can ever expect, large industrial electricity consumers are prepared to explore all options, including a return to regulation based on cost of service. We recognize that in states where local distribution companies have sold their generation this may be especially difficult and will take considerable time and effort. Our preference would be that the existing markets be fixed.[23]

A recent study conducted by Public Sector Consultants for the Michigan Municipal Power Association concluded that Michigan's current industry structure is a flawed attempt at market restructuring and is unsustainable. The report states:

> What is clear, however, is that the currently partially deregulated status of 2000 PA 141 is not sustainable, does have an impact on reliability, and causes regulated utilities to operate in a less than efficient manner.

The report stresses that incumbent utilities have an obligation to serve all customers, but that alternative electric suppliers can pick and choose the most profitable customers to serve. According to the report:

> If policymakers truly wish to have a competitive electric market in the state, they must be willing to allow the introduction of risk through the removal of the

---

[22] For more information on Electricity Consumers Resource Council, visit http://www.elcon.org/.

[23] ELCON, December 2006, *Today's Organized Markets – A Step Toward Competition or an Exercise in Re–regulation*, p. 4, 5; http://www.elcon.org/Documents/Publications/12-4piom.pdf.

> obligation to serve at least for customers that leave regulated providers. This will, most likely, result in a less reliable but also more competitive and fairer electric market. If, however, policymakers are not willing to accept these risks then they should take steps that move the state toward a more traditional regulatory framework.[24]

The Staff's position on reversing the effects of 2000 PA 141 is neutral; however, from a regulatory perspective, reversing 2000 PA 141 would have two effects: it should provide a remedy for the seeming inability to site and build new baseload plant in Michigan; and it would foreclose retail choice for customers who find it desirable or economic to buy electricity from alternative electric suppliers.

Complete Deregulation – The turmoil created by fully deregulated markets – most recently in Maryland where rates increased by 72 percent, in Illinois where residential rates have increased up to 55 percent, and in Delaware where rates increased by 59 percent – make a strong case for rejecting complete deregulation of retail generation services and/or divesture of generation plants to market-based rates. Those states are the most recent examples of rapid cost increases following full deregulation.

Fully deregulating Michigan's electricity market may lead to an unprecedented transfer of real economic wealth from ratepayers to the owners of the deregulated generation assets. A generating plant now priced at its actual, depreciated historical value would be allowed to price at market rates, significantly raising rates on all customers and undermining Michigan's economy.

Modify Current Framework – Most of the Plan's policy discussion centered on modifying Michigan's current industry framework to address issues related to 2000 PA 141. Staff spent considerable time and effort last year in the Capacity Need Forum to develop a framework that could resolve the conflicts and difficulties associated with 2000 PA 141. That work was continued by participants and Staff in this Plan, as witnessed by the strawman proposals discussed previously. The remainder of Section 2 will discuss those attributes of 2000 PA 141 that Staff finds most problematic and in need of change and present Staff's recommendations for modifying Michigan's regulatory structure.

2.4.2 Michigan Market Flaws

The goal of 2000 PA 141 was to shift public policy and the regulated electric utility industry toward competition. The act encouraged vertically integrated utilities to join independent regional transmission organizations (RTOs) or to divest their transmission assets. One outcome of 2000 PA 141 was independent electric transmission companies that allow competitors of incumbent electric utilities access to wholesale power markets. By encouraging development of independent third party transmission to all parties and retail choice of generation suppliers,

[24] Public Sector Consultants, November 2006, *Electric Restructuring in Michigan: The Effects to Date of Public Act 141 and Potential Future Challenges*, pp. 5, 19. See http://www.publicsectorconsultants.com/Documents/electricityrestructuring/index.htm

2000 PA 141 encouraged the development and reliance on competitive electric markets and a movement away from traditional regulated electric utilities.

Michigan policymakers, however, did not adopt utility divestiture of generating assets nor the concept of universal competition at market based rates when they restructured Michigan's electric industry. Consequently, the Michigan market under 2000 PA 141 offers customers the option of electric generation services by alternative electric suppliers at market-based prices or full generation service from their local utility under the traditional regulated rate model. Advocates of full deregulation criticized the policy, but it has kept Michigan prices affordable compared to states that required generation to be spun off and prices fully deregulated. The importance of maintaining regulated generation is evident from the recent experiences in Maryland and Illinois, which required utilities to divest their generation. Since generating plant costs have typically increased, unregulated prices have drifted upward over the past several years. Market prices have also increased because most new generating plants constructed over the past decade have been natural gas fueled units and excess baseload capacity in the region has been declining.

The ability of Michigan customers to move between regulated and competitive markets, however, creates an uncertain customer base for both electric utilities and alternative electric suppliers (AESs). This makes planning for expensive, long lived baseload generating units difficult and adds considerable financial risk to plant investment decisions. Market prices have soared over the past two years and, in response, more than 2,000 MW of customer load returned to utility service from alternative suppliers in Michigan. A major issue that arose is the responsibility of incumbent utilities to plan and construct generating plant for this load, when it may migrate again to the competitive sector.

Some new plant construction is in the early development phase, but only involving suppliers protected from the risks of deregulation. Wolverine Power, a generation and transmission cooperative, is considering plans to build a baseload facility in Rogers City. Wolverine differs from the investor owned utilities, however, because its members have retail tariff provisions providing for non-bypassable charges for the plant's development costs. And, Wolverine Cooperative's members, unlike the major investor owned utilities, have not lost customers to AESs.

Without regulatory changes to promote more certainty, most Plan participants agree that financing baseload generating plants on favorable terms is unlikely. It is also clear that an independent power producer is unlikely to build base or intermediate load plants without a long term power purchase contract with load serving entities in Michigan. Contracts could potentially be secured with a combination of Michigan's municipal and/or cooperative utilities, which have not yet experienced customers migrating to AES competitors. Major utilities, however, are unwilling to sign contracts with independent power producers due to uncertainty of customer need, regulatory risk, and wholesale market price risk. Without a regulatory-out clause, power purchase agreements (PPAs) expose regulated utilities to the same uncertainty and risk as building a new generating plant. The combination of fixed PPA costs and customers who are free to migrate to AESs could lead to serious difficulties for a utility and its remaining customer base. As fixed costs need to be recovered from smaller numbers of customers, and thus lower total sales, then the inevitable result would be higher rates, utility under-recovery, or a combination of the two. This conclusion remains unchanged from the CNF report.

Based on public comments and discussion with CNF and Plan participants, utilities are unlikely to add major baseload generating units in the current hybrid market. It is also clear independent power producers are unlikely to build new baseload facilities without long term PPAs with credit worthy parties, such as distribution utilities. Utilities, however, are unwilling to sign long term PPAs, which makes independent power projects unlikely. Moreover, because state policy encourages competition in the industry, it is conceivable, although undesirable, that utilities may simply forego new investment and rely on wholesale markets for a growing portion of their generation needs.

The relatively easy movement of customers between Michigan's two markets also undermines the ability to finance new generating plant because it undercuts the long held regulatory principle of cost causation. This occurs because customers can move freely between the two markets without consequences, even when they cause costs to be incurred for their benefit. This relatively cost free migration creates a rate burden on customers who have no choice of suppliers.

Regulated utilities must provide power to all ratepayers, but AES suppliers are permitted to select customers that are profitable to serve and avoid those that are difficult or expensive to serve. For example, residential customers are thought to be relatively more expensive to serve when compared to commercial or industrial customers. To date, AES suppliers have not marketed to residential customers, and virtually no residential customers have had a choice of generation service providers. AES commercial and industrial customers, however, have a major benefit provided by the customers of the local utilities – the option of returning to regulated rates if market prices increase.

Since enactment of 2000 PA 141, Michigan's experience has demonstrated that customers can migrate to an AESs to take advantage of temporarily lower market prices, causing the rates of customers who remain with the utility to increase. This occurred between 2001 and 2004, when market prices were at comparatively low levels. During this period, electric market prices were being set by excess baseload power in the Midwest region and by electric generation fueled by inexpensive natural gas. In 2004, Detroit Edison's rates increased by $385 million, of which approximately $300 million was necessary to replace revenue lost for the 9,200 GWh of electric sales that migrated to the customer choice program. This $300 million represented fixed costs of maintaining the Edison system and was shifted to customers remaining with Edison from customers migrating to choice suppliers.

When wholesale market prices began a sustained increase through 2004, 2005, and 2006, customers who had previously migrated to the competitive choice market began to return to the utility's regulated rates. To help serve these returning customers, the regulated utilities were required to purchase more expensive power in the volatile wholesale markets. This more expensive market power caused the incumbent utilities power supply costs to increase. The resulting rate increases were passed on to all customers, including those who had never left the utility for the choice program and even those who were never afforded an opportunity to leave.

Detroit Edison's power supply costs have been estimated to have increased by $60 million to accommodate these returning customers in 2005.

The 2001 through 2006 period is a graphic example of the cost burden borne by full service customers, particularly residential customers, who have thus far had no opportunity to migrate to choice, caused by other customers seeking to take advantage of temporarily lower market prices. Departing customers have enjoyed the lower prices without incurring the risks and costs created by their decisions. Their decisions are made risk free by the option of returning to regulated rates and a generation system being maintained by other customers. This very option, however, creates the uncertainty that makes the Michigan system unsustainable.

Some participants suggested an automatic revenue recovery mechanism like DTE's CIM would eliminate the risks of revenue loss due to customer choice. Automatic recovery programs that raise rates for customer migration however, can be counterproductive. They actually accentuate the risk of major plant construction or PPAs. With an automatic recovery mechanism, as customers leave, remaining customers' rates automatically increase, as the higher fixed costs are spread over a smaller sales base, thereby providing a greater incentive for other customers to leave. Over the longer term, it is not clear that this type of mechanism would improve revenue certainty.

Finally, even as customers who move to an alternate electric supplier can avoid the cost of maintaining the regulated system, they benefit from additions made to that system. If a new baseload unit is constructed by a regulated utility, it serves to lower the locational marginal price to which all ratepayers are exposed, whether they contribute to the new plant or not. A new plant will also improve electric reliability for the benefit of all ratepayers. This is known as the "public good" effect and was discussed at length in the CNF. Even though choice customers are not required to pay for new generating units, they do benefit from the capacity that is added by regulated utilities. The Michigan market is not designed to recover the indirect benefit from construction of new plants, even though the benefits may accrue to both regulated utility customers and choice customers.

2.5 Staff Conclusions and Recommendations

2.5.1 Integrated Resource Plan and Certificate of Need

Staff agrees with the recommendation in both strawman proposals that a regulated utility seeking to build a new generating unit should first file an integrated resource plan (IRP). Staff recommends the IRP process, as described here, as one of two options available to a utility seeking to build a new generating plant. The other option would be the Commission's traditional method of incorporating new generating plant into a utility's ratebase, which occurs after a hearing which reviews a utility's application for rate recovery after the new plant is completed and has become operational. The operative expression is that a plant has to be "used and useful" before its costs should be eligible for rate recovery.

In the IRP process option, the utility's IRP should conform to standards adopted by the Commission. The IRP process would be conducted as a contested case, offering participants the opportunity to review the utility's assessment of its need for new generation, fully examine the utility's proposal, and provide recommendations to the Commission.

The utility would be required to assess all reasonable options for meeting its capacity needs. This would include energy efficiency and renewable energy in its plan, with the appropriate level of investment in energy efficiency determined in a public hearing conducted exclusively for that purpose, and renewable capacity determined by the state's RPS targets. The utility would also be required to assess load management options, and the availability and cost of external market purchase options including required transmission expenses. The IRP would also identify and examine major contingencies and explain why the utility's preferred plan is the best plan for its customers.

After modeling the availability of all these resources and examining planning contingencies, the utility would need to demonstrate that a central station generating plant is needed and is an integral part of the best plan to meet its customers' needs. For any new utility-owned generating plant, the utility would need to specify its cost, with as much accuracy as practical, including any required investments related to grid interconnection and transmission.

If the Commission agreed that additional generation was needed, this process would result in the Commission issuing a certificate of need. This certificate would be irrevocable, subject to the Commission's normal appeals process. The certificate of need process would provide assurance to the utility and its investors that a plant would not be deemed imprudent afterwards, because of customer choice migration after the plant is constructed. The Commission could, however, scrutinize the prudence of costs incurred.

At its discretion, the Commission could extend its current policy regarding recovery of some or all of the construction financing costs during the construction. The Commission's current ratemaking policy is to allow earnings on CWIP (no AFUDC offset) for pollution control equipment. A proposed extension of this policy would be at the Commission's sole discretion. The extension would have to be requested by the utility as part of its financing plan. The Commission would not allow recovery of plant construction costs, until after the plant became operational.

Staff recommends this IRP process as one of two alternatives available to a utility seeking to build a new generating unit. The other alternative is the Commission's traditional method of incorporating new generating plant into a utility's rates.

2.5.2 Capacity Bidding Issues

Capacity Bidding for New Utility Central Station Resources Requires Careful Consideration – Strawman 1 suggests the Commission adopt rules to allocate risks among the developers, the utility, and the ratepayers. For example, any PPA resulting from a competitive bidding procedure may include provisions for future greenhouse gas emissions controls. Or, the bidding process might apportion risk by allowing for the pass-through to ratepayers of future costs. Alternatively, the PPA might place risks on the developer and, in response, developers would presumably raise bid prices.

Fuel cost is another significant risk factor. A PPA signed under a competitive bid process and sufficient to support construction is likely to be a long term contract. Bid prices related to the operating cost component might need to be tied to future fuel costs. These costs, however, cannot be known ahead of time, so changes in fuel costs might simply be passed through to customers, including regulated utilities, or a risk premium would have to be paid to the bidder for accepting the risk associated with future fuel costs.

These risks, along with other unforeseen risks, require that much care must be exercised in a competitive bidding process. It is not clear that all these risks and uncertainties can be identified in an RFP process. Some independent power producers (IPP) participants propose that the preferred way to handle these risks is to treat the IPP like a regulated utility. They reason that if the regulatory process allows a pass through of costs incurred by a utility, it should also allow a pass through of those same costs incurred by an IPP.

Regulated utilities, however, are subject to prudence review, and any attempt to pass through costs can be closely scrutinized and costs can be disallowed, if that is appropriate. IPPs, on the other hand, do not come under the Commission's jurisdiction. The Commission cannot scrutinize costs incurred by these entities, nor can it penalize IPPs for engaging in imprudent practices by reducing their rates of return.

For some PPA generating plant options, like combustion turbines, bidding could be a straight forward process. These units are easy to site and have standard features. However, for major solid fuel baseload units, bidding is not as straightforward. Tradeoffs would need to be considered, in terms of cost, availability, unit efficiencies, fuel diversity, future fuel security, and future emissions requirements. Acquiring air permits and siting a unit can be problematic.[25] The risk of delays must be apportioned between bidder and ratepayer, which is certain to lead to disagreements – whether it is apportioned up front in the RFP and contract, or in a subsequent prudency review.

Transmission interconnection requirements present another bidding dilemma. Strawman 1 participants noted cost and scheduling of new generating plant construction is now more uncertain due to MISO's evolving interconnection policy and administrative procedures.[26] Participants suggested an allowance be made for this uncertainty, but did not specify a method for allocating the associated risks.

A disadvantage of IPP construction of a new generating plant under a bidding framework is that the principal advantage – leveraged financing typically used by IPPs – could prove

[25] Wolverine's experience with the proposed Prairie States coal generating unit is illustrative: it has taken five years to secure the necessary air quality permit from the U.S. EPA Environmental Review Board. In the meantime, the plant's estimated cost has escalated.

[26] The cost and difficulties have recently been highlighted by Noble Energy's experience in Michigan's thumb area. Noble won an RFP bid with Consumers Energy before making arrangements for interconnections on its proposed facilities. The difficulty and cost of arranging the interconnections has set back the project's completion date, and energy that Consumers had anticipated being supplied by the project is not yet available. Further, it is still not clear when the power may be available.

counterproductive. Highly leveraged financing can lower capital costs of a new generating plant by making extensive use of debt financing. However, according to a September 2005 presentation made by the Electric Power Supply Association (EPSA)[27] to the CNF, rating agencies may view utility PPAs as a utility debt obligation. This would cause the required rate of return on all of a utility's investments to increase due to the negative impact of additional debt. According to the EPSA presentation, states across the country have recognized the tendency of PPAs to be treated as a utility debt and have adjusted PPA bids accordingly. The treatment of a PPA as debt is likely for Michigan utilities because of the state's customer choice program. Thus, the cost advantage for an IPP to build using highly leveraged construction secured by a PPA would be offset by transferring the risk and resulting financial burden onto the utility and its customers.

Many participants agree that comparing bids for major units is a complex and difficult exercise if properly done. It might require the Commission to assume risks for ratepayers up front, prior to the bidding process. This could include the assumption of risks that are not now apparent, and perhaps even risks that cannot be known or understood in advance. Ultimately, using competitive bidding to correct past utility plant construction errors, cost-overruns, and unforeseen fuel and environmental costs may be a remedy that cannot avoid a pass through of much the same risks, in one way or another, because financial markets and developers may not construct plants if they have to assume those risks.

Wolverine Power's experience with the Prairie States project has caused it to conclude that the administrative and contracting complications and difficulties associated with bidding outweigh any benefits that might be derived from the process. Unlike an IPP, an investor owned utility, or project developers, Wolverine has no financial incentive to add a generating plant to its ratebase since it does not earn a profit on plant investments. From a financial perspective Wolverine should be indifferent to whether it builds or bids. But, Wolverine concludes that bidding may not lower its costs or reduce risks that need to be assigned to customers.

Capacity Bidding Supporters – Support for bidding stems from two sources of opposition to utility construction. First, some participants indicate utilities should focus on distribution service only and that 2000 PA 141 should have served as a transition to a fully competitive industry structure, including generation divesture by incumbent utilities. As mentioned previously, the concern for affordable power and observations of rapid cost increases in states that have adopted this approach cause Commission Staff to consider this the least desirable policy change for Michigan and a threat to the state's economic future.

Second, many participants are concerned with cost overruns or paying too much for a utility-constructed plant. Excessive costs associated with the Fermi II and Midland nuclear projects have not been forgotten. Some oppose utilities building any new generating plants. Others are indifferent as to who builds the next baseload generating unit, but lack confidence that incumbent utilities can do it at the lowest cost.

[27] Electric Power Supply Association (EPSA), is an independent power producers' advocacy group. See website at, http://www.epsa.org/forms/documents/DocumentFormPublic/. To view EPSA's September 2005 presentation to the CNF, see link at http://www.dleg.state.mi.us/mpsc/electric/capacity/cnf/jhawkssep29_2005.pdf.

Competitive solicitation of power through a PPA is touted as a measure to assure reasonable costs. This option is alluring for a regulatory agency hoping to avoid unnecessary and unreasonable rate costs.

Staff surveyed other states to determine how prevalent competitive bidding has become as a method for acquiring resources. The results indicate that 12 of the 48 states surveyed require competitive bidding. The large majority – 35 states – requires regulated utilities and, in some cases IPPs, to obtain siting approval or certification of need from a siting board or regulatory commission prior to the construction of a new power plant. State laws and policies governing rate recovery for new generating plants vary considerably, from traditional, after-the-fact prudence reviews in rate cases to pre-approval of construction costs (13 states). An increasing number of states are allowing utilities to request prudence determinations or advanced ratemaking treatment prior to construction. In states where generation is deregulated (e.g., the Northeast, Texas, Illinois) cost recovery is left to market forces alone.

Staff concludes that capacity bidding for utility generation conforming to the Strawman 2 proposal better balances risks for Michigan customers – This proposal requires bidding for the EPC phase of new facilities and under this proposal the utility would own the plant, which would be eligible for ratebase treatment using conventional accounting.

While some participants strongly advocate the merits of competition in bidding for generation ownership, they seem to distrust its merits as a means of disciplining utility construction costs. Competitive markets allow customers to buy service from the low cost provider. If a utility invests too much money in a new generating facility, or fails to complete a project within schedule, it risks losing customers to competitive suppliers. Ironically, parties who support competitive bidding for capacity through PPAs and the need for competitive choice markets also distrust the ability of competition to discipline utility construction costs. Michigan's hybrid market should help prevent excessive costs if a Michigan utility builds a baseload generating plant for its customers. If construction causes a utility's costs to rise relative to wholesale market prices, unhappy customers can exercise their choice to leave the utility's generation service.

Utilities indicate that approximately 85 percent of a new plant's cost can be accounted for by the EPC contract, which Staff would require be competitively bid. Since most of a new plant's cost would be subject to a competitive bid process, and customers have the option to leave the utility for a choice supplier, there seems little likelihood that competitive PPA solicitation could produce additional gain, especially given the difficulties with specifying all of the important attributes associated with a baseload plant RFP and allocating the associated risks among participants.

Under the Staff proposal, the risks of future uncertainty, such as fuel price and air emissions concerns, will be dealt with under the current regulatory framework. The Commission can also review a utility's decisions and costs, and disallow any deemed imprudent.

Staff is wary of undertaking a contentious, complex appraisal of multiple bids that may result in litigation. Even without lawsuits, Staff is not aware that IPPs can or will finance projects where major risk factors are borne by the IPP and its financiers without increasing prices in the bid process to deal with these contingencies. Consequently, utility ownership represents no more risk to ratepayers than alternative strategies. Staff recommends that a competitive bidding option must be offered, but also recommends it should be limited to the engineering, procurement and construction work for a new plant.

Finally, Staff notes that utilities are free to make use of competitive bidding for PPAs. These contracts have already been used to secure long term and short term capacity needs. Staff does not recommend that competitive bidding PPAs be mandatory, however, for the reasons cited above.

2.5.3 Customer Choice Option

While the certificate of need process may reduce risks related to a new generating plant's need, it would not remedy the rate burden on a utility's full service customers caused by other customers migrating to the choice program. Instead, full service customers would be paying to maintain the regulated system that choice customers rely on if market prices increase or power becomes scarce. To more fairly balance the interests of various ratepayers, the opportunity of customers to choose an AES, and the need to provide more revenue certainty in order for a utility to be able to finance a new plant, Staff has developed a proposal based on the cost causation principle and centered on changes to the current return to service provisions that apply to electric choice customers.

If a utility seeks a certificate of need for a new generating plant and the certificate is granted, customers must choose whether they want to remain with the incumbent utility or take advantage of the customer choice program. Customers electing full service from the utility, therefore, are responsible, in part, for construction of the new plant. If those customers later elect service from an AES, they should take their pro-rata share of the plant's fixed cost with them as a non-bypassable distribution charge.

If customers choose instead to take service from an AES when a utility applies for a certificate, they will not be responsible for the costs of the new plant, as long as they remain in the customer choice program.

Based upon recent cost increases caused by customers first departing for the customer choice program and then returning, Staff further recommends changes to the return to service provisions for those customers electing AESs. Those customers returning to a utility's full service from the customer choice program should provide a two year notification of their return to regulated rates. Customers will be allowed to return to the utility's generation service 60 days after notification of return is given, but the return will be at a "best efforts," that is a market basis, until the two year notification is satisfied. The two year period will permit the utility adequate time to arrange the power supply necessary to serve the returning customer, rather than being required to jump into potentially volatile wholesale markets to secure the power in a manner that causes non-choice customer rates to increase. Once the two year notification is given, the customer must return to the utility's full service.

This combination of assigning cost recovery to those customers who cause the costs to be incurred, and a return to service provision that does not unfairly burden customers who remain on regulated rates will contribute significantly to making the Michigan system more sustainable.

2.5.4 Cost Based Rates

Staff recommends modifying Commission policy to assure mandatory cost based rates for efficient functioning of the market – Maintaining both regulated utilities with an obligation to serve all customers and a competitive choice program requires ongoing program modifications that will continue to create uncertainty for regulated utilities and AESs. Minimizing the disruption caused by simultaneous operation of both markets over the longer-term requires providing market participants with information and regulatory certainty. Cost of service based rates are an important component of a longer-term, stable program.

Unless regulated utilities' rates are set equal to their cost of service, customers will have an incentive to choose an AES supplier even when the supplier's cost is greater than the utility's cost to serve the customer. This incentive can cause the migration of significant numbers of high margin customers from the utility to AES suppliers, raising costs to residential customers who have no supplier choice, and creating uncertainty in forecasting capacity needs associated with the incumbent utilities' obligation to serve. If utility rates are not cost based, migration of high margin customers will occur for reasons other than each parties' competitive advantage in providing service. Future Commissioners will have to protect ratepayers who do not have an AES alternative to manage this migration, or raise rates for non-choice customers.

Rates for non-choice customers likely will be affected either by the migration of high-margin customers away from the utilities or by adjusting rates on a cost of service basis. In the absence of cost of service based rates, the Commission faces an ongoing need to review the financial impact of customer choice participation on customers who have no choice of suppliers. It may also be required to implement a stranded cost proceeding for the regulated utilities or raise the rates of customers who remain with the incumbent utility. Price signals based on cost of service are important to assure that migration to choice decisions are made on a rational economic basis. This should provide a more stable customer choice program because economic considerations would govern the decision to move from the utility to an AES supplier.

2.5.5 Mandatory Planning Reserve

Staff recommends modifying Commission policy to set a mandatory planning reserve standard for all load serving entities – In the CNF report, Staff asserted electric reliability has the characteristics of a public good. As a public good, it is not possible to prohibit someone from taking advantage of the reliability, even if they do not pay for it.

This has been the case in Michigan since electric restructuring has occurred. Electric reliability is secured through the provision of operating reserves and planning reserves. Although AES suppliers are required by MISO to maintain operating reserves, they are not required to carry planning reserves. The experience over the past two years has confirmed that AESs might meet the MISO operating reserves, but they have not demonstrated they carry planning reserves.

Their electricity supply does not appear to satisfy generally accepted reliability standards; rather, the implicit conclusion is that they are simply relying on total system reliability for backup.

Generation planning reserves provide a critical backup supply, to address major unit or transmission line outages for extremely hot weather, or unanticipated economic growth. As noted earlier, peak demand was forecast to grow at 1.2 percent for this year, but due to abnormally hot weather, actual peak demand grew about 3.3 percent based on Consumers Energy data, and 4.1 percent before interruptions based on Detroit Edison data.

Until the regional electric reliability organization establishes and enforces reliability standards equivalent to the standards adopted in this report, Michigan's restructuring program should be modified to allow the Commission to require planning reserves or their equivalent for all utilities and AESs operating within the state.

2.5.6 Maintain Securitization Charge

Staff recommends that the current securitization charge placed on all customers should be maintained for market stability and to comply with 2000 PA 141 – Strawman 1 proponents assert that choice customers do not receive a benefit for securitization charges. They do not support changes to the return to service provisions currently operative in the Michigan market. There appears to be widespread recognition by Plan participants, however, that securitization was a non-conditional component of Michigan's restructured electricity market. No one has suggested that any benefit was intended to follow this payment, other than creation of the choice market. This issue has become prominent among some participants because market prices have risen, adding to the cost of AES service. Staff does not recommend revisiting this issue.

2.6 Summary of Central Station Power Plant Policies

Staff's proposal for remedying the risks and uncertainty created by Michigan's hybrid market structure includes a transparent, public process for evaluating a utility's resource plan when a new generating unit is needed. Financial risk related to customer choice is ameliorated by recognition of the need for the unit even if future customer migration occurs. The utility must demonstrate that it has a viable plan for financing the plant. Staff also proposes a requirement that customers who cause the plant to be needed must contribute to the plant's cost recovery, and altered return to full service provisions that allow sufficient time for a utility to arrange reasonable power supply. Cost of service based rates will promote more rational customer decisions regarding service choices, electric reliability will be preserved through new Commission authority to require adequate reserves and securitization should not be revisited.

3. Renewable Energy and Distributed Resources Policy

3.1 Summary of Recommendations

Staff developed four policy recommendations based on the efforts of the Renewable Energy and Alternative Technologies Workgroups.

1. Promote the adoption of cost-effective renewable and alternative energy technologies in Michigan through a mandatory renewable energy portfolio standard (RPS) of seven to 10 percent by 2015. The RPS should be applicable to all Michigan load serving entities (LSEs) with deferral of RPS targets for one year at a time, for hardship or rate impacts that are burdensome.
2. Support distributed resources through a review and appropriate changes in MPSC rates and tariffs including net metering and distribution system use tariffs; and interconnection procedures.
3. Create an on-going collaborative process to monitor national smart power grid infrastructure initiatives. When options appear cost-effective and practical to implement, establish evaluation criteria and standards and trigger pilot programs or broader deployment in Michigan.
4. Support legislation to create a residential property tax exemption for solar, wind and fuel cell installations.
5. Create a solar energy pilot program.

3.2 Introduction and Workgroup Process

Because Renewable Energy and Alternative Technologies Workgroup participants identified many similar policy issues, it was agreed to form a single policy team comprised of participants from both workgroups. The combined policy team met twice, in July and August, in addition to full Workgroup meetings held in June, July, August, and September.

The general procedure used for developing policy concepts for consideration by the combined Policy Team was for Workgroup leaders to produce strawman proposals on which interested participants could comment. Two major proposals were provided; one for a renewable portfolio standard (RPS), and a second on policies to promote distributed resources which might employ either renewable or alternative energy technologies. These distributed resources policies might be implemented independent of or in concert with an RPS.

The various renewable and alternative energy policies investigated are discussed here in four groups: (1) an RPS; (2) distributed resources, including both MPSC rates and tariffs and other regulations; (3) smart power grid technologies; and (4) financing, funding, and incentives.

Benefits of Renewable and Alternative Energy – Three principle reasons for supporting renewable and alternative technologies are fuel and technology diversity, economic and employment benefits, and environmental protection.

Fuel and technology diversity can reduce a variety of risks associated with electric generation. Primary benefits of fuel and technology diversity include reduced risks due to the effects of fuel price volatility and demand forecasting error. The shorter lead times associated with bringing smaller facilities on line greatly enhances this flexibility and risk reduction, including the ability to more efficiently coincide with demand growth. In an uncertain world and economic climate, fuel diversity and the use of indigenous resources – especially those not subject to price volatility and shortages – represent valuable safeguards to utility ratepayers.

Environmental benefits are often associated with renewable and alternative energy technologies. Each new power source must be evaluated individually in order to determine its impacts on the environment, but generally speaking, renewable and alternative energy technologies produce less air pollution compared to many central station power plant options analyzed for this study. Some available renewable resources produce no emissions during normal operations (e.g., wind and solar energy). The environmental benefits associated with renewable and alternative energy technologies are especially important given present air quality regulations, Michigan’s central location within the Great Lakes basin, and global climate change concerns.

Barriers to Renewable and Alternative Technology Adoption – Economic concerns, including fear of higher costs, valuation, risk aversion and uncertainty, are barriers to renewable and alternative technologies.

Utilities and some customer groups are reluctant to have utility rates rise as a result of incorporating renewable and alternative energy technologies which can cost more relative to existing options. Often, this attitude is held regardless of substantial long term economic and environmental benefits associated with renewable and alternative energy options.

Energy planners face difficulty in valuing resources with variable output, and this serves as a barrier to adoption. The value of wind and solar energy, for instance, varies greatly depending on the local wind regimes or solar exposure.

Risk aversion associated with technologies considered unproven or undergoing rapid improvement in efficiency and performance acts as a barrier as well. Many renewable and alternative energy options are novel and utility managers question how they will affect the utility grid and its operations.

Finally, uncertainty regarding interconnection costs and timing undermines interest in these options. Though the Commission has established rules governing utility interconnection standards and procedures, the first applications demonstrate uncertainty remains and can be a major concern for project developers.

In its review of existing policy barriers, workgroup participants identified the major areas of concern and the agencies best able to address them, including the Commission and other state regulatory agencies. Under the directive regarding development of the Plan, our focus is almost exclusively on State of Michigan policies, though some barriers might also be addressed through federal or local government actions, as well.

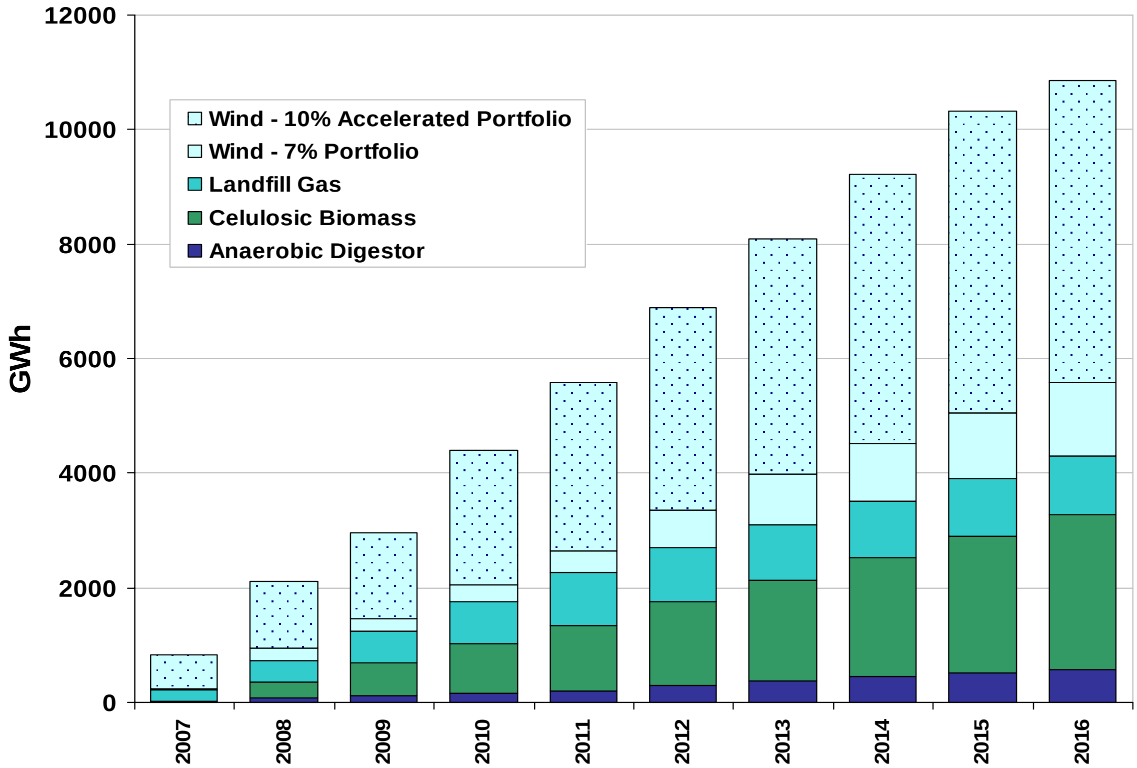
3.3 Proposal for Renewable Portfolio Standard

The Executive Directive explicitly requests a proposal for "a renewable portfolio standard with established targets for the share of the state's energy consumption to be derived from renewable energy sources." In response, MPSC Staff proposes a mandatory RPS with the following basic characteristics:

- All load serving entities (LSEs) in Michigan shall gradually increase the percentage of new renewable energy in their portfolios. All LSEs not yet meeting the statewide average of approximately 3 percent renewable energy shall have until the end of 2009 to reach at least the statewide average. After 2009, all LSEs shall increase their renewable energy portfolio from new facilities until they reach seven to 10 percent by the end of 2015. The Commission shall hold a public hearing in 2014 to determine whether it is in the public interest to pursue an RPS goal of 20 percent by 2025.
- An LSE with less than 100,000 customers shall comply through any combination of: (a) producing or purchasing renewable energy; (b) procuring independently certified and verified renewable energy certificates (RECs); or (c) making a Commission-established alternative compliance payment (ACP) per kilowatt-hour. LSEs with more than 100,000 customers shall comply through any combination of (a), (b), and (c) through 2012 and (a) and (b) thereafter. ACP payments shall be credited to the Michigan Energy Efficiency Program fund and will be used exclusively to help finance renewable energy projects.
- The Commission may defer RPS targets for one year at a time, for hardship to an LSE or its customers, or if it determines that rate impacts are burdensome.
- Eligible facilities will be those producing electricity delivered in Michigan for consumption by end-use customers and meeting the definition of renewable resources found in the Michigan Customer Choice and Electricity Reliability Act. Only new resources will be eligible for meeting the expanding RPS, beginning in year four.
- RECs associated with out-of-state facilities will be eligible if they improve air quality or provide economic development benefits to Michigan as a result of the energy generated.
- The Commission shall: (1) establish and oversee a program to provide for REC verification and trading; (2) establish and update every two years a just and reasonable per-kWh alternative compliance payment (ACP) amount; (3) establish LSE reporting requirements; and (4) file with the Governor and Legislature annual reports on the RPS and in-state renewable energy resources.
- Legislation shall grant the Commission authority to impose remedies and penalties if it is determined that an LSE is in non-compliance with the RPS requirement.

Figure 8 shows the estimated growth of electricity from renewable resources that would result from the proposed RPS for Michigan.

Figure 8: Proposed RPS (Estimated Statewide New GWh per Year, by System Type, 2007–2016)



There are several important reasons to include renewable resources in Michigan's portfolio of generating resources. One additional reason that guided Staff in the development of its RPS proposal is the finding of many of the Scenarios and sensitivities analyzed for the Plan, that a significant level of renewable resources can be achieved at a modest, incremental cost above that incurred through reliance on central station generation options alone. Modeling suggests a combination of renewable energy and energy efficiency resources as important components of a broad portfolio of resources that can help meet much of the state's short term electric resource needs at no incremental cost above the cost of reliance on central station generating options alone. At the same time, however, these resources will protect Michigan ratepayers from some major planning contingencies.

Staff prefers an RPS that is as simple to understand and administer as possible, but no simpler than needed to make it effective. Therefore, Staff prefers a mandatory RPS combined with appropriate policies to reduce, and where possible, remove barriers to renewable energy market growth. If a mandatory RPS is not adopted though, various additional incentives and specialized financing and funding will be required, to overcome existing obstacles.

Table 5 (p. 58) summarizes many important features associated with RPSs in other states. It is worth noting that since 2003, 11 states upgraded existing RPSs (AZ, CA, CT, HA, IL, ME, MN, NV, NJ, TX, and WI). And, since 2004, 10 states and the District of Columbia initiated RPSs (DC, CO, DE, MD, MT, NM, NY, PA, RI, VT, and WA), with Colorado and Washington added by voter referendum.[28] In addition, a few more states, like Michigan, are presently considering RPSs. These include North Carolina, where a 5 percent RPS is under consideration and Oregon, where RPS legislation will reportedly be proposed in 2007.[29] RPS legislation has already been introduced in Ohio, proposing a formal advisory council to consider an RPS, and Virginia, calling for a 20 percent RPS within 10 years.[30]

The issues and concerns expressed about the strawman proposal by commenting parties are reviewed and summarized in a separate report, will be posted on the 21st Century Energy Plan's Renewable Energy Workgroup webpage. The MPSC Staff RPS proposal is summarized in Table 6. The following narrative explains the Staff proposal and the major concerns raised by commenting parties.

Staff proposes a portfolio standard of at least seven to 10 percent, to be reached by the end of 2015, and a goal to reach 20 percent by 2025 – Resource modeling confirms meeting this goal will be challenging yet achievable. Staff believes the estimates of renewable resources and costs indicate that a mandatory RPS in this range can be achieved with only a moderate incremental cost compared to an alternative scenario based on the construction of new central station power plants. The modeling also suggests the benefits of the additional renewable resources, in terms of fuel and technology diversity and reduced environmental risks, are expected to offset any short-term increased costs that might result.

A voluntary RPS alternative is preferred by utility company representatives and ABATE, and several parties believe extending the RPS to municipal utilities on anything other than a voluntary basis could be problematic. Other parties recommend percentages, on the order of 10 percent by 2015, 20 percent by 2020, and 25 percent by 2025. Staff proposes the Commission hold a public hearing in 2014 to determine whether it is in the public interest to pursue an RPS target of 20% by 2025.

One option is for legislation to initiate a voluntary program with provisions to switch to mandatory status if pre-established target percentages are not achieved. Another approach is for RPS targets to be based only on LSE sales growth or new capacity need, rather than total sales. For example, the RPS target could be to employ renewable resources to meet a minimum of 50 percent of all sales growth or 50 percent of all new capacity need. Staff favors a statewide mandatory approach. Experience with voluntary programs does not instill confidence that a voluntary program would achieve the goals recommended here.

---

[28] http://www.dsireusa.org; viewed December 22, 2006.

[29] http://www.ncuc.commerce.state.nc.us/rps/rps.htm, for North Carolina and http://www.oregon.gov/ENERGY/RENEW/RenewPlan.shtml, for Oregon, viewed January 5 2007.

[30] See: http://pickocc.org/publications/renewable_energy/Need_for_Alternative_Energy_Portfolio_Standard.pdf for Ohio summary report; http://leg1.state.va.us/cgi-bin/legp504.exe?071+sum+SB278 for Virginia proposed Senate Bill 278; both viewed January 5, 2007.

Table 5: Other States RPS Programs

State	Start Year	Target Year	Start %	Target %	ACP[1]	Rate Impact Limit	New / Existing Facilities?	Technology Set-Asides?	Uses RECs ?	Electric Customer Choice?
Arizona	2006	2025	1.25	15		Y	New	Distributed Generation	Y	Y
California	2003	2017	6	20	SEP[2]	Y	Both			N [3]
Colorado	2007	2015	3	10		Y	Both	Solar	Y	
Connecticut[4]	2004	2010	4	14	Y	Y[5]	Both		Y	Y
D.C.	2007	2022	4	11	Y	Y[5]	Both	Solar	Y	Y
Delaware	2007	2019	1	10	Y	Y[5]	Both[6]	Y[7]	Y	Y
Hawaii	2003	2020	7	20		Y	Both			
Illinois[8]	2007	2013	2	8			Both	Wind		Y
Iowa[4]						Y				
Maine	2000	2000		30			Both		Y	Y
Maryland	2006	2019	3.5	7.5	Y	Y[5]	Both	Y[9]	Y	Y
Massachusetts	2003	2009	1	4[10]	Y	Y[5]	New		Y	Y
Michigan Proposal	**2007**	**2025**	**~3.0**	**10%**	**Y**	**Y**	**Both**		**Y**	**Y**
Minnesota[8]	2005	2015	1	10			Both	Biomass		
Montana	2008	2015	5	15	Y	Y	Both[11]		Y	Y [12]
Nevada	2005	2015	6	20	Y	Y	Both	Solar	Y	Y [12]
New Jersey	2004	2020	3.25	22.5	Y	Y[5]	Both[11]	Solar	Y	Y
New Mexico	2006	2011	5	10		Y	Both	Y[13]	Y	N[3]
New York		2013	19	24		Y	New	Y[14]		Y
Pennsylvania	2007	2020	5.7	18	Y	Y	Both	Solar	Y	Y
Rhode Island	2007	2019	3	16	Y	Y[5]	Both[6]		Y	Y
Texas	2007	2015			Y	Y	New	Y[15]	Y	Y
Vermont[8]	2005	2012[16]			Y		New		Y	
Washington	2012	2020	3	15		Y	New		Y	
Wisconsin		2015		10		Y	Both		Y	

Source: Data gathered from http://www.dsireusa.org/index.cfm?EE=1&RE=1.

1 ACP stands for Alternative Compliance Payment.
2 SEP stands for Supplemental Energy Payments.
3 CA and NM have formally reversed, suspended, or delayed restructuring.
4 States with rows shaded gray do not have utility green pricing programs. States with rows shaded black mandate their utilities to offer green pricing programs. States with rows not shaded have both an RPS and utility green rate programs. No states with both an RPS and green rate programs allow sales to the green rate programs to count towards RPS requirements. (Source for Green Pricing data is National Renewable Energy Laboratory, July 2006; http://www.eere.energy.gov/greenpower/markets/pricing.shtml?page=0.)
5 Price ceiling for RPS compliance is determined by the alternative compliance payment (ACP) amount.
6 RPS limits the amount of existing renewables that can be used to meet annual requirements.
7 DE provides extra RPS compliance credit for solar PV, fuel cells, and wind turbines.
8 IL, MN, and VT have voluntary RPS goals, rather than mandatory RPSs.
9 MD provides extra RPS compliance credit for solar PV, wind, and methane.
10 Ending percentage increases 1% per year until the Massachusetts Division of Energy Resources ends the program.
11 Out-of-state renewables must be new.
12 MT and NV have limited restructuring.
13 NM provides extra RPS compliance credit for biomass, solar, geothermal, landfill gas or fuel cells.
14 NY has a set-aside for customer-sited generation.
15 TX requires at least 500 MW from renewable sources other than wind.
16 VT total incremental energy growth between 2005 and 2012 is to be met with new renewables (as long as the state does not exceed a cap of 10% renewable resources).

Table 6: Summary of MPSC Staff Renewable Portfolio Standard Proposal

Topic/Feature of RPS	MPSC Staff Proposal
Applies to which LSEs?	• RPS applies to all load serving entities (LSEs). • LSEs can comply by producing or purchasing renewable energy, or procuring renewable energy certificates (RECs). • LSEs with less than 100,000 customers can also comply by making a Commission-established alternative compliance payment (ACP), per kWh.
RPS Targets	• Target is for all LSEs to meet statewide average by end of 2009. Then, all LSEs increase by approximately 1% of total sales per year until the statewide average reaches 7–10% by end of 2015. The Commission shall hold a hearing in 2014 to determine whether it is in the public interest to pursue an RPS target of 20 percent by 2025. • Targets will be mandatory, but MPSC can defer targets one year at a time for hardship to an LSE or its customers.
Eligible Resources	• Use definition from Michigan Customer Choice and Electricity Reliability Act; (MCL 460.10g(1)(f)). • Do not include pumped storage, except when pumping using renewables. • Non-electric-producing technologies are not eligible. They are supported only through non-RPS policies. • Out-of-state renewables must be "new" (>1/1/1999)
Eligible Facilities	• Producing electricity delivered in Michigan for consumption by end-use customers and meeting the MCL 460.10g (1)(f) definition. • Existing in-state renewables will be eligible to count towards reaching and meeting the statewide average. • Only new resources will be eligible for meeting RPS expansions, beginning in year four. • MPSC will certify facilities for utility PPAs.
RECs	• RECs can be used to meet 100% of RPS obligation. • Out-of-state RECs can count, but only if air quality and economic development benefits accrue to Michigan. • Two year maximum REC banking. • MPSC will establish requirements for independent REC certification, verification, and tracking.
Rate-Impact Limit	• RPS targets may be deferred for one year at a time, for hardship to an LSE or its customers or if the Commission determines that rate impacts are burdensome. • ACP amount set by MPSC will act as a second rate impact limit, and ACP will be recoverable in rates.
Cost Recovery	• Utility costs recoverable through PSCR process. • AES costs recoverable through rates, or via non-bypassable charge.
Compliance Reporting	• All LSEs report annually to MPSC. • MPSC will set report content requirements.
RPS Program Review	• MPSC will report annually to Legislature and Governor.
Other Associated Policies	• Siting/zoning guidelines/standards. • Property tax guidelines/standards, and exemptions for residential systems. • ACP payments will be placed into a fund which is only used for in-state renewable energy development, especially community-based systems.

The RPS should apply to all LSEs, including investor owned utilities, cooperative utilities, alternative electric suppliers, and municipal utilities – Staff believes broad applicability is necessary to ensure all competitors remain on an equal footing in Michigan's competitive electricity supply market. Staff anticipates that long term benefits from adopting a renewable portfolio standard will accrue to all Michigan's ratepayers. Therefore, it is appropriate for all ratepayers to participate in the program.

In line with comments regarding possible hardship exemptions or variances for some LSEs in meeting the RPS standard, Staff believes its proposed alternative compliance payments and rate impact limits, described below, will both constrain compliance costs to reasonable levels and provide a hearing process for an LSE that might need to defer, for a reasonable time period, its obligation to meet specific RPS annual targets.

Qualifying renewable resources should be based on the definition provided in the Michigan Customer Choice and Electricity Reliability Act (P.A. 141 of 2000) as – electric energy generated from solar, wind, geothermal, hydroelectric or biomass, including waste-to-energy and landfill gas.

Facilities should be eligible only if they meet all applicable regulations and generate electricity that would otherwise be produced using fossil fuels. Co-firing biomass fuels in existing fossil-fueled utility boilers would qualify under this definition.

Some participants have proposed that pumped storage hydroelectricity qualify as a renewable resource. The Ludington facility, jointly owned by Consumers Energy and DTE, is a valuable Michigan electric generating resource but it is a storage facility rather than a power source. The Ludington storage facility could be a valuable compliment to a renewable program but generation from the facility should not count towards the RPS.

Some parties recommended allowing thermal energy from renewable resources to receive an appropriate credit (for example solar thermal, geothermal, and thermal energy generated in conjunction with biomass-fired CHP). Staff believes it is best not to complicate the RPS by trying to accommodate non-electricity producing technologies; incentives for those technologies can better be provided through energy efficiency programming.

Establishing a broader clean energy portfolio standard, as some other states have recently done, has been proposed. A few state standards include targets and provide energy portfolio credits for energy efficiency; some include CHP because of its greater efficiency compared to central station power plants; and others allow credit for selected alternative technologies, such as fuel cells, regardless whether they are powered by renewable fuels. Broadening eligible technologies is assumed to provide LSEs with more portfolio options at lower costs, especially if energy efficiency is included. On the other hand, Staff believes the relative simplicity of a more limited RPS outweighs the potential benefits that might be associated with development of a broader energy portfolio standard. Also, a portfolio standard which includes energy efficiency is impractical if energy efficiency programs will be administered by one independent entity, rather than LSEs. Likewise, Staff believes the benefits associated with statewide energy efficiency program administration outweigh the potential benefits of a broader energy portfolio standard.

Similar to the question of what technologies might count towards meeting RPS targets is the more specific question of which facilities should qualify. Several states' standards include provisions to restrict qualification to in-state facilities or grant them favorable treatment. Treatment of pre-existing versus new renewable resource facilities has also been raised as an issue. Several parties commented that existing facilities should be eligible for inclusion in a Michigan RPS, and no party proposed existing facilities should be ineligible. An RPS should not disadvantage pre-existing, in-state renewable resource facilities, nor should it create windfall profits for pre-existing facilities. Staff recommends RPS eligibility for pre-existing in-state resources for the initial 3 percent requirement.

Roughly equal numbers of parties recommended allowing RECs only from in-state facilities versus RECs from anywhere. Those advocating in-state RECs only cite environmental and economic development benefits from new in-state renewable facilities, which directly accrue to the ratepayers. Advocates for eligibility from out-of-state are concerned single-state restrictions could be challenged under the commerce clause of the U.S. Constitution, and some believe restricting a special market to in-state production could restrict competition, driving prices to unreasonable levels. Staff believes its proposal strikes a reasonable balance between these positions, allowing out-of-state RECs to qualify, but only when it can be shown that Michigan utility customers will obtain at least some of the associated air quality or economic development benefits.

In addition to these technical concerns, LSEs will seek regulatory assurance regarding the eligibility of specific facilities proposed for inclusion in renewable resource portfolios. Several parties note a need for pre-certification of facilities and perhaps other assurances that costs associated with RPS compliance will be recoverable through utility rates. Staff agrees there should be no doubt about what technologies and facilities will qualify. Adequate rules can be developed so generators should be able to initially self-certify their eligibility to participate, and Staff recommends that LSEs be pre-authorized to meet RPS obligations through power purchase agreements (PPAs), purchase of RECs, ACP payments, or ownership of qualifying renewable facilities. Staff believes all these options should be eligible for cost recovery. Reasonable and prudently incurred compliance costs on the part of regulated utilities should be recoverable through power supply cost recovery (PSCR) rates, subject to the rate impact limits discussed below. Staff proposes that LSEs serving less than 100,000 customers be allowed to opt for their customers to pay a non-bypassable ACP surcharge, either in lieu of compliance with the RPS or to meet any portion of their RPS target. And, Staff proposes this ACP option should also apply through 2012 to utilities serving more than 100,000 customers.

The Legislature should provide the Commission with authority to resolve any remaining questions raised by parties, such as how to apply RPS targets to regulated distribution cooperatives that have full-requirements contracts with power supply cooperatives, that are not MPSC regulated; and how to apply RPS cost recovery for utilities operating without PSCR clauses or annual PSCR hearings.

The ACP, set in a biennial, contested-case MPSC hearing, should accurately reflect market conditions. It should be low enough not to be punitive, nor to influence artificially high REC prices. At the same time, however, the ACP should not be set so low as to discourage LSEs from building or purchasing capacity and energy or RECs to meet their RPS requirements. ACP amounts should be recoverable in rates through a non-bypassable surcharge.

Staff proposes ACP funds be placed in the statewide energy efficiency fund and used to support Michigan renewable energy projects, especially community based projects, where renewable energy production helps to reduce costs for facilities where utility bills are ultimately paid by taxpayers.

The impact of the RPS on utility rates should be limited – Some participants prefer renewable energy policies designed to completely avoid rate increases. MPSC Staff recognizes the longstanding tension between utility plans that minimize short-term versus long term costs and rate impacts, and believes this proposal strikes a reasonable balance.

Flexibility and stability are two competing goals for RPS policies. A good RPS should allow enough flexibility to avoid significant rate impacts and hardships for LSEs and their customers. At the same time, however, it should produce sufficient long term stability to enable new facilities to obtain financing at attractive interest rates. In comments, several parties recognized the desirability of long term stability and others recommend at least a limited ability for the Commission to be able to react quickly to prevent hardships or unreasonable rate impacts.

This proposal includes three mechanisms that will limit the RPS's rate impact. One is setting the ACP as described above. A second is through MPSC authority to defer RPS targets for one year at a time, if it were shown that meeting the annual target would result in a hardship for an LSE or its customers or if an LSE is unable to satisfy the standard for reasons beyond its control; for example, if a renewable energy developer fails to complete a project on schedule. Third, the Commission could defer targets for one year if the cumulative rate impact of meeting the RPS target were deemed to be burdensome.

The RPS should incorporate provisions for the use and trading of RECs – As shown in Table 5, about three-quarters of all states with an RPS have incorporated provisions for REC trading. Staff recommends that REC trading be approved for Michigan's RPS program. A REC is a unique, independently certified and verifiable record of the production of one megawatt hour of renewable energy. When employed in an RPS program, RECs can be purchased by an LSE as one mechanism for meeting part of its RPS target commitment, and then one REC is retired to represent each MWh of qualifying renewable energy sales to the LSE's customers. LSEs typically can assemble a portfolio of qualifying resources through any combination of building their own renewable resource production facilities, purchasing renewable energy through long term contracts, and purchasing RECs, either through contracts or spot-market sales. REC trading provides a mechanism by which renewable resource generators can separately market their electricity production and its green-power attributes. Typically, a renewable resource generator will sell its electricity production bundled with RECs in one contract, or they might sell their electricity production into an energy-only market while separately selling their RECs to a purchaser who will use them to meet some part of a renewable portfolio commitment.

Within this general context, there are many specific characteristics of the applicability of RECs and REC trading programs operations that must be determined. For example, MPSC Staff is recommending that RECs used for compliance with the Michigan RPS: (a) should be bankable for a maximum of 24 months, after which they should expire, whether or not they are used; (b) must be retired upon use, and systems must be employed to account for the transfer and retirement of RECs thus avoiding double-counting; and (c) beginning with the fourth year, should come only from new facilities. Though pre-existing in-state facilities would be counted as renewable resources for the purpose of meeting the statewide average, beginning with the fourth year, MPSC Staff recommends REC certification and trading only for renewable resources from facilities independently certified as being new.

Parties expressed three general concerns about the operation of a Michigan REC trading program: (1) the extent to which out-of-state RECs might be used to meet Michigan's RPS; (2) fair treatment for renewable resource facilities developed prior to the establishment of a REC market; and (3) whether the benefits of a REC trading program would outweigh the costs associated with REC certification and tracking. The MPSC Staff proposal addresses pre-existing in-state renewable resource facilities by acknowledging them in the baseline determination for each LSE to reach the statewide average of approximately 3 percent renewable resources, and allowing until the end of 2009 for those LSEs presently below the statewide average to catch up, as it were. MPSC Staff believes its proposal for a REC trading program strikes a reasonable balance between the interests of all parties.

Staff also recommends that RECs come from in-state resources – Staff would allow RECs to be included from out-of-state sources, under certain conditions. RECs and renewable resources serve to manage fuel price increases and volatility and protect against potential air quality compliance costs, including risks associated with the growing concern regarding global climate change. Furthermore, in-state facilities create jobs within Michigan, pay taxes in Michigan, and support Michigan's economy. Such benefits can more than offset any incremental costs associated with renewable energy generators compared to central station generation. These are direct benefits to Michigan, and for facilities located in Michigan. It is less clear whether and how these benefits accrue to Michigan ratepayers if the facility is located out-of-state. To capture these benefits, MPSC Staff recommends that RECs originate with Michigan generation. However, RECs would be allowed from out-of-state generators, if they can be shown to help protect Michigan air quality and produce benefits for Michigan's economic development. A REC trading program could be efficiently administered through development of an in-state program or in cooperation with an existing regional program.

Annual Commission reports to the Legislature and Governor will provide accountability – The reports would include monitoring data on each LSE's performance with respect to its RPS target, lists of all in-state renewable energy facilities being used to meet RPS requirements, data on the amount of power generated from renewable sources within Michigan, and the percentage of power purchased by Michigan customers obtained from renewable energy sources. Data on the number and aggregate capacity of renewable energy generators receiving third-party certification, and on Michigan sales and purchases of renewable energy certificates (RECs) would also be provided. Lastly, the percentage and absolute change indicators of renewable energy penetration in Michigan will help policy makers track growth of the renewable electricity sector.

Each LSE covered by the RPS will file an annual compliance report for the previous year explaining in detail its renewable resource plans for the next year and providing a renewable resource forecast for the next five years. The report shall be due to the Commission each September 30, with regulated utility reporting incorporated into the Commission's annual PSCR process. A reporting schedule and requirements will be developed for AESs. The Commission should establish the filing requirements and can utilize, to some extent, the same data already required to be submitted to FERC and the Energy Information Administration (EIA).

Additional policies could be important or even necessary to implement in conjunction with an RPS – RPS strawman comments indicate three policies are most important to consider in conjunction with an RPS: statewide zoning guidelines or standards for renewable energy system siting; changes in property taxation; and financial incentives for some renewable and distributed energy systems, which presently have limited market potential, such as solar photovoltaic systems and fuel cells. These three subjects are discussed in the following section, along with other policies that might be implemented in conjunction with and support of a Michigan RPS.

3.4 Distributed Resources Policies

This section of the report addresses important renewable and distributed energy technology policy issues identified by participants in the Plan project. These policy issues are in addition to the RPS and RECs policies already discussed,

The Distributed Resources strawman proposal identified and recommended for potential consideration by the Commission certain approaches to address several issues. These include treatment of renewable and distributed energy options in LSE planning, utility power purchase agreements, and utility rate design. In addition to issues explicitly identified in the Distributed Resources proposals, both the RPS and Distributed Resources strawman proposals elicited comments regarding incentive regulation.

Reducing costs associated with renewable and alternative energy applications is an important goal so that the smaller the generator, the lower the transaction costs. A second major goal is to review rate treatment and tariff terms and conditions of service to identify and, wherever practical, remove barriers to renewable and alternative energy applications. Staff supports removing barriers to the full extent practical, but recommends stopping short of introducing new ratepayer-funded subsidies for renewable and alternative energy technology.

Two fundamental concerns addressed by many of the specific proposals for distributed resources policies in the Plan are: (1) no practical market options exist, at present, to allow distributed generators, particularly small ones, to effectively participate in electricity markets as merchant plants; and (2) changes in rates, tariffs, and interconnection procedures may be warranted in order to enable adoption of self-service power options, when appropriate. The several proposals discussed in the following pages are all recommendations for MPSC actions intended to address these two major concerns. The proposals cover utility purchase power agreements; rate design, including net metering and distribution system use tariffs; and interconnection procedures.

Following the discussion of proposals amenable to MPSC action, is a section regarding proposals for action by other state agencies.

3.4.1 Policy Recommendations for MPSC Action for Distributed Resources

Utility Power Purchase Agreements – Non-utility generators should be able to enter into contractual agreements to sell power to utilities under varying terms that reflect the specific characteristics of various resources, including benefits from avoided transmission and distribution system charges and line losses, considerations for the value of the power, and enhanced reliability.

Some participants indicate provisions for such contractual agreements already exist in the open, wholesale marketplace, with many of the detailed requirements already specified in MISO tariffs. They are also skeptical that distributed resources will prove capable of producing quantifiable distribution system benefits. Other participants recommend evaluating such benefits on a case-by-case basis and propose these issues be addressed through bilateral contracts, by mutual agreement, for sales to LSEs. Some participants also assert that obligations mandated for regulated utilities should apply to all market participants.

Although the Commission has limited authority to oversee specific PPA terms and conditions, a mandatory RPS will provide renewable energy producers much better opportunities to negotiate contracts which recognize specific system benefits. Staff recommends legislation authorizing the Commission to review the terms of PPA contracts in the event of a dispute between a utility and a renewable or CHP energy provider.

Rate Design – Changes in Commission policies and tariffs are necessary to remove barriers to the adoption of renewable and alternative energy technologies. These include proposals for specific modifications to Michigan's net metering program. A distribution system use rate should be adopted that varies by interconnection voltage level for distributed generators who wish to convey power from a generator to a wholesale customer, utilizing the local distribution company grid.

A general proposal for application to all distributed generation is that each LSE should be required to offer to its customers with on-site generation equipment standby, backup, maintenance, and supplemental power, under terms and conditions that reflect the cost of serving a class of such customers on an aggregate, service territory wide basis. Staff supports this general concept and recommends that it be investigated in upcoming Commission proceedings. Staff recommends development of pilot load management and demand response programs, incorporating smart metering and real time pricing as recommended in the energy efficiency section, Subsection 4.6.2, as a preliminary step to begin investigating how this general proposal might be implemented.

Net Metering – The Distributed Resources strawman included a proposal to make available net metering tariffs for all qualifying renewable and CHP facilities less than 150 kW in size. Under this proposal, a fixed monthly service charge would be applied to ensure net metering customers continue to pay their fair share of distribution system and utility administrative expenses.

Little opposition to this proposal was expressed in comments from any parties. Some utilities report a general willingness to consider such changes, as long as (a) net metered customers continue to pay their fair share of distribution system and administrative expenses; (b) the current maximum system limit for net metering (0.1% of each utility's peak load) remains in place; and (c) credits for net excess generation (NEG) are limited only to power supply charges, and do not reflect a subsidy. Even then, however, some utilities recommend no changes to the current net metering program until more experience has been gained, and it can be thoroughly evaluated.

Some participants requested an even larger capacity limit be considered for net metering treatment. This concern is important to consider because renewable resource technology system costs decline rapidly as system size increases. These proposals would allow much larger net metered systems for wind and solar equipment to be sized, up to 2 MW, based on the customer's total annual energy needs. Others' comments recommend no changes to the existing voluntary net metering agreement, but a few propose increasing the value of credits for net-metered power flowing back to the utility.

Staff generally supports modifying tariffs for self-service power provided from renewable resources and high-efficiency CHP systems to include larger units, but believes the public interest may be best served by making targeted changes to the Commission's existing net metering program for the smallest generators and utilizing PPAs for larger generators. The Legislature should explicitly recognize the Commission's authority to establish net metering and resolve PPA issues for all regulated utility companies in Michigan.

Distribution System Use Tariffs – Local distribution companies should offer tariffs for eligible renewable resources and high-efficiency CHP. With new tariffs available for this purpose, distributed generators will be able to pay for and use the distribution system to transmit energy for sales under a bilateral contract to any wholesale provider. Comparable tariffs already exist in unbundled utility rates for distribution service, but they are based on energy delivered by the utility or an AES to an end-use customer. This proposal requests a similar utility service be provided to accommodate the distribution of energy from a generator. Staff believes it could be helpful and feasible to establish such tariffs so that rates would reflect costs associated with the specific equipment utilized to provide the service (the voltage of the distribution equipment used), and, perhaps, the distance covered by the transaction. Staff believes this type of service may be essential for small generators to obtain the benefits of self-service power or exercise the rights provided merchant plants in the Customer Choice and Electricity Reliability Act. Staff recommends legislation to explicitly authorize the Commission to establish rates, terms, and conditions of service for these tariffs.

Interconnection Procedures – The distributed resources proposal also included some ideas about streamlining utility interconnection procedures. The Commission has already adopted interconnection standards rules. Workgroup participants did not suggest revising the Commission's currently established interconnection standards rules, but some parties have proposed changes in the way that utilities are implementing those rules. For example, the distributed resources strawman proposal recommends, "Net metering interconnections, metering, and billing options shall be the lowest total cost to customers while still maintaining system safety and integrity, and meeting all MPSC approved interconnection rules."

Staff notes the Commission has already initiated a proceeding, Case No. U-15113, to: "(1) investigate the interconnection of independent power producers with a utility's system, (2) identify any problems or deficiencies in the existing interconnection procedures, and (3) develop and implement remedies." The Commission has directed utilities to file reports on all interconnections and pending applications completed pursuant to the approved procedures, including "whether any problems arose in the process." The Commission also invited interested parties to file, by December 19, 2006, "information detailing interconnection problems they have experienced and any suggestions for changes to the interconnection procedures." And, the Commission directed MPSC Staff to convene a public meeting on this subject on January 9, 2007, and file a report by January 31, 2007, "summarizing the issues identified and making recommendations for future action." MPSC Staff believes this hearing process provides the appropriate venue for determining changes to the current utility interconnection procedures.

3.4.2 Other State Agency Policy Proposals for Distributed Resources

Additional policy proposals were recommended for consideration by Workgroup participants. These would not be under MPSC jurisdiction, but involve other state and local government agencies. They include proposals for statewide guidelines or standards for siting and zoning; smart power grid technology policy proposals; distribution reliability planning; financing, funding and incentives, including property tax treatment; plus concerns regarding the implementation of existing environmental regulations.

Siting and Zoning for Renewable Resource Facilities – The distributed resources strawman proposal included a call for the establishment of statewide siting and zoning guidelines, which would take effect for any townships and municipalities that had not otherwise passed their own ordinances.

Staff believes that these are matters for legislative consideration, and recognizes that wind energy siting and zoning bills have already been drafted. In 2004-2005, the MREP Wind Working Group developed guidelines for siting and zoning of wind generators. Those advisory guidelines were published by the State Energy Office. Staff recommends the appropriate MREP committees undertake a similar process for biomass, solar, and hydroelectric facilities, as practical, to try to achieve the broadest possible consensus on practical siting and zoning guidelines for renewable resource facilities.

Smart Power Grid Technologies Policy Proposals – Staff recommends the Commission establish an ongoing collaborative process amongst utilities and other LSEs, customers, other interested parties, and Staff, for the purpose of monitoring the various national initiatives reviewed in Chapter 5C of Appendix Volume II. Once it is clear specific technologies can be used in a way that will reduce utility system costs, deployment should begin promptly at least on a pilot or experimental program basis. At the appropriate time, the collaborative process can be used to establish evaluation criteria and standards, to be applied to pilot or experimental program proposals. This will likely include the load management, smart metering, and real time pricing pilot programs, as proposed in the energy efficiency (Section 4) of this volume.

Distribution Reliability – A recurring concern expressed by plan participants has been the quality and reliability of power delivered to the end-user. Although much of the modeling performed for the plan has been to evaluate prospective generation reliability, distribution reliability likewise play a critical role in assuring an uninterrupted flow of power to end-users. Distribution lines are essential to the delivery of generated power, and these lines are particularly vulnerable to disruptions caused by weather or growing trees. Sometimes recurring problems are confined to specific circuits or local distribution areas because of faults on existing lines. At other times they may be due to an inability of the particular circuit to handle growing loads. Recently, Commission Staff has received complaints from industrial customers and local governmental entities regarding distribution reliability. Some customers indicate that even brief distribution failures cost them thousands of dollars. When major storms occur, distribution outages can be widespread and service restoration often takes several days. The transformation of Michigan's economy from traditional manufacturing to computer-assisted, high precision, flexible manufacturing processes, along with the growing role of sophisticated communications, requires better distribution reliability. Improving distribution reliability is a multi-dimensional undertaking and will require monitoring and adopting smart grid advancements and advanced metering infrastructure, accommodating distributed resources efficiently, and minimizing interruptions.

Underground placement of distribution lines will harden our infrastructure and reduce distribution vulnerability. Reliability and power quality will also be enhanced by the development and application of smart grid technology, including deployment of smart metering technologies that can sense distribution faults or other disturbances. Currently, underground distribution facilities are required for new residential subdivisions and new commercial developments. Presently, when right-of-way construction or reconstruction is undertaken for any reason, opportunities are being missed to bury lines at a reduced price. Underground wires do a better job of keeping electricity flowing to homes, businesses, and neighborhoods. The Plan proposes that the Commission undertake rulemaking to extend the requirement of underground placement to poorly performing existing circuits, especially those that experience repeated faults; all new secondary distribution line extensions and primary lines[31] that are presently on the same pole; and to primary lines where facilities are being relocated due to road improvements.

[31] A primary electrical distribution system is that part of an electric utility's system delivering electricity from a substation to the neighborhood. It is operated at a voltage level that is too high for most customers to use. This higher voltage is used for efficiency in delivering electricity over long distances. Some large commercial and industrial customers take service at such voltages and then provide their own voltage reducing transformers. A primary system, depending on utility and circuit, is usually operated at 4,800 to 14,400 volts. A primary distribution system might also be described as the system immediately on the utility's side of the service transformer. A secondary electric distribution system is that part of a utility's system that actually connects to customers. A transformer separates a primary from a secondary system. The transformer (either a box on the ground or a canister on a pole near a customer) is used to reduce the primary voltage to levels that customers can use. The particular voltage depends on the customer's need, which could include 480, 277, 240, 208, or 120 volts for a commercial or small industrial customer. Most, if not all, residences are served with a secondary voltage of 240 and 120 volts. Central air conditioners, electric hot water heaters and electric dryers usually run on 240 volts. Plug outlets and lights throughout a residence are typically 120 volts. The secondary system might also be described as the system immediately on the customer side of a service transformer.

Financing, Funding, and Incentives – The strawman included a proposal for a “Michigan 21st Century Energy Endowment Fund” to be established by the Legislature, to facilitate project financing.

Staff believes few if any new financial incentives will be required to adequately support robust renewable and alternative energy development in Michigan if a mandatory RPS and the other policy recommendations presented here are implemented. If mandatory RPS targets are not adopted, however, then Staff supports establishing a non-bypassable systems benefit charge as a source of funds to be used explicitly to support renewable and alternative energy technology projects.

Staff recommends that the MREP Financing Committee complete in 2007 its effort to review existing state programs in order to identify all available sources of state and federal financial support and incentives for renewable and alternative energy technologies. Several programs already have been identified that might be viable sources funding and financial support. At the state level, these include: the Michigan Department of Environmental Quality’s Pollution Prevention Small Business Loan Program and special state bond funds for wastewater treatment plant upgrades; NextEnergy program financial incentives; and advanced energy technology grants possible through the 21st Century Jobs Fund. From the federal government, the list includes sources such as the U.S. DOE, Environmental Protection Agency (EPA), Department of Agriculture, and the Small Business Innovations Research initiatives of many federal departments.

Staff notes other states have successfully leveraged federal funding by establishing programs to assist in-state projects with the development of high quality proposals. Staff recommends that the state identify a single point of contact for such assistance and adequately staff it (through DLEG, Michigan Economic Development Corporation, the Michigan Department of Agriculture, etc.).

Michigan’s NextEnergy legislation provides extensive taxpayer funded incentives for renewable resource and alternative energy technology research and development and in-state manufacturing. Staff prefers to minimize the use of taxpayer or ratepayer funded financial incentives intended to support consumer purchases of renewable resources. However, some technologies that could become important contributors for Michigan’s electricity supply in the future have experienced limited market penetration in Michigan and may require additional financial incentives in the near term, to establish themselves. These technologies will benefit from larger scale production and continued technological innovation. For example, solar photovoltaic installations typically cost more than conventional power generation sources. Another example is fuel cells, which can provide both uninterrupted electricity and domestic hot water.

Staff recommends that carefully targeted financial incentives for renewable resources be implemented under the auspices of the statewide energy efficiency program using ACP revenues. ACP revenues should be deposited into a fund to be used exclusively for the support of renewable resource projects, as directed by the board overseeing the statewide energy efficiency programs. The program administration should place special consideration on community-based renewable energy projects, including self service power for facilities such as schools, government buildings, and subsidized housing, where utility bills are paid by taxpayers. Individual property tax exemptions might also be adopted to offset some of the costs associated with renewable energy options, and Staff supports this proposal as described in the following section.

Property Taxes – Property taxes should not disadvantage renewable energy production. To provide more financial certainty for renewable energy facilities, local tax assessors should apply consistent property valuations, based on the value of energy produced. The other commonly used method is to assess facilities based on their capital cost, which greatly disadvantages renewable energy facilities, especially the smallest ones, in comparison to central station power plants. It may be sufficient for the state to recommend this approach to local assessors, and provide the basic education and guidelines necessary to apply this method. This issue will be pursued by the Michigan Renewable Energy Program as one of it goals.

A second distributed resources strawman recommendation was, “Property tax increases should be capped at no more than the percent increase in power and energy sales revenue received in the most recent three year period, relative to the first three years of operation.” Staff believes this policy might prove unnecessary if its first recommendation is implemented, and recommends postponing this action until ample experience can be gained with the property valuation proposal..

A third strawman recommendation was, “The Legislature should promulgate property tax exemptions for residential and small-commercial-scale renewable and CHP applications. Staff recommends legislation to exempt residential solar and wind renewable energy and residential fuel cell equipment from property taxes. Staff notes 26 states have enacted special property tax policies for renewable energy facilities and 23 offer exemptions for at least some types of equipment.

3.5 Summary of Renewable Energy and Distributed Resources Policies

In summary, Staff proposes a mandatory RPS combined with distributed resources policies to remove market barriers to renewable and alternative energy technologies. Once an RPS is in place, the consideration is to complete regulatory changes necessary to enable renewable and distributed generators to enter into wholesale and retail markets as merchant plants and facilitate the provision of self-service power. Some of the required changes can be implemented by the Commission without new legislation. However, Staff believes the Legislature should explicitly acknowledge Commission authority to engage in some of the proposed activities.

4. Energy Efficiency Policy

4.1 Summary of Recommendations

Staff developed four policy recommendations based on the efforts of the Energy Efficiency Workgroup.

1. Create by statute a comprehensive statewide energy efficiency program overseen by the Commission, administered by an independent organization, and funded through surcharges on ratepayers.
2. Establish statutory support for the Commission to investigate and authorize comprehensive electric demand response initiatives.
3. An Executive Directive should be issued to commence a collaborative process to assure that energy efficiency improvements will be incorporated into new Michigan residential and commercial construction. Upon completion of the collaborative process, the Department of Labor & Economic Growth should file a report with recommendations to the Legislature.
4. Establish appliance efficiency standards following an Executive Directive to the State Energy Office to analyze, develop criteria, and to file a report and recommendation to the Legislature.

4.2 Introduction and Workgroup Process

Michigan currently has an ad hoc arrangement of utility load response programs, low-income energy efficiency funding, and state energy services, but no statewide coordinated energy efficiency programming. Michigan ratepayers presently spend a small amount of money on energy efficiency programs, but it is targeted to low-income customers as a result of the Commission's implementation of a Low Income and Energy Efficiency Fund (LIEEF). The fund, originally authorized by Act 141, is primarily used to provide payment assistance for low-income customers rather than energy efficiency services.

Other states, however, have enacted comprehensive energy efficiency legislation and implemented energy efficiency programs. Successful state programs, like Vermont's and Wisconsin's, were discussed by the Workgroup. In addition, participants developed, shared, and commented on strawman proposals. Participants provided essential information and were instrumental in helping to refine Staff's recommendations.

Staff believes the potential economic and employment benefits associated with increased energy efficiency should be recognized and given serious consideration by policy makers. In formal energy efficiency programs, all proposed energy saving measures and packages are scrutinized to make sure cost savings will exceed investment cost, and most measures pay for themselves through reduced utility bills in the matter of just a few years or less. Many studies have explored the relationships between energy efficiency programs and state and local economic and employment impacts, and identified positive and significant results. One general finding is that businesses associated with energy efficiency measures tend to be more labor intensive compared to the traditional energy and utility industries. Another is that positive impacts accrue when utility bills decrease and, in turn, consumer discretionary spending increases. And a third important finding, especially for energy importing states like Michigan, is that local and state economic multipliers associated with efficiency measures are typically higher than for fuel purchases and utility bill payments. Therefore, studies typically find that economic and employment gains go hand in hand with energy efficiency programs.[32] Staff recognizes our proposal calls for tens of millions of dollars of new expenditures on energy efficiency programs, each year for several years to come. But, there is every reason to believe these will prove to be investments with multiple positive returns for all Michigan electricity customers.

Table 4 (p. 74) presents the complete outline for a proposed Michigan Energy Efficiency Program.

4.3 Proposal for Michigan Energy Efficiency Program

4.3.1 Program Creation

Staff recommends legislation creating a statewide electric energy efficiency program under the oversight and guidance of the Michigan Public Service Commission. The Plan's centerpiece program, the Michigan Energy Efficiency Program (MEEP), would require all utilities to participate in a program administered by a third-party and would allow the Commission to disburse money from a public trust fund, the Michigan Energy Efficiency Fund.

The proposal draws heavily from successful energy efficiency program models implemented in other states. Replicating other states' successes avoids the time, risk, and expense of developing a program structure from scratch. Creating a single statewide program will provide economies of scale by spreading program administrative costs over a large customer base. This will benefit smaller utilities, cooperatives and municipal utilities that lack sufficient revenue to support the base infrastructure needed for a comprehensive and diverse energy efficiency program.

4.3.2 Program Administration

Participants are split over the program's structure, some advocate utility administration of efficiency programs, while some utilities support a third-party framework. Staff recommends third-party administration, with the MEEP program administrator operating independently, not as an officer, employee, or agent of the state. The program administrator would contract with the Commission through a competitive solicitation process. The solicitation process and resulting contract would define the scope of services.

A single statewide program administrator provides several significant benefits. Continuity from a single entity is an efficient mechanism for a statewide program to bring about "market transformation" in end-use energy efficiency markets. With respect to energy efficiency, market transformation relates to a change in the culture of energy use and the availability of efficient end

[32] See, for example, Howard Geller, John DeCicco, and Skip Laitner; 1992; *ED922, Energy Efficiency and Job Creation*; and Skip Laitner, *et al*., 1995, *ED951, Energy Efficiency and Economic Development in the Midwest*; Washington, DC, American Council for an Energy-Efficient Economy; http://www.aceee.org.

use devices. The goal of market transformation would be reduction of program incentives as energy customers and service providers become more aware of energy efficiency options and as implementation of efficient end-use devices become commonly accepted. Retrofitting, new technology purchases, or new construction or new process technologies contribute to market transformation as efficiency measures become more available and accepted. Retail appliance vendors, businesses providing energy efficiency services and customers will benefit from consistent and comprehensive statewide programming.

Using an unaffiliated third party administrator to oversee a statewide energy efficiency program corrects a fundamental conflict; utility revenues and profits depend on higher sales levels, while energy efficiency programming reduces sales. The process of selecting the third party administrator and program parameters would be established in a contested case process, which allows for extensive public input. The Commission, with the advice of a solicitation screening committee, would select the administrator. The screening committee would be chaired by the Commission chairman, and include the director of the Department of Management and Budget, the director of the Department of Treasury, and two outside experts in energy efficiency programming.

Performance-based competitive bidding ensures efficient provider contracts. Legislation should allow the Commission to evaluate the MEEP administrator, under a performance-based contract which includes concrete energy savings targets. In addition to pay-for-performance, the contract should be of sufficient length to allow administrative efficiency and long term program stability. The contract should be at least three years long and include an opportunity for a three year renewal if the program administrator meets the program's goals.

The MEEP administrator would be reimbursed from the MEEF for actual costs, including the cost of financing expenses and eligible program costs, administration costs, and performance based incentive awards. Incentives would be based on annual program evaluations conducted by an independent evaluation contractor. The MEEP administrator should be allowed to deliver energy-efficiency programs itself or through subcontractors. To avoid conflicts of interest, the program administrator and sub-contractors should not be affiliated with retail electric providers or related entities in Michigan. While the Commission would exercise primary authority over the program, legislation would establish the structure, oversight and review responsibilities.

Table 4: Staff Outline of Legislative Initiative for a Proposed Michigan Energy Efficiency Program (MEEP)

Program Creation	• Commission authority granted, after notice and hearing, to provide for the development, implementation, monitoring and evaluation of a statewide energy efficiency program. • All retail load serving entities in the state required to participate. • All retail electric customers eligible to receive efficiency services.
Program Administration	• Delivery through an independent program administrator. • Program administrator not affiliated with retail energy providers in the state. • Commission selects the program administrator through a transparent solicitation. • Solicitation process includes an opportunity for public input. • Screening committee assists with selection of the program administrator. • Program administrator operates under a direct contract with the Commission.
Oversight	• Public hearings underlie Commission determinations. • Program evaluation will be provided by independent contractors. • MEEP Advisory Committee facilitates public input process. • Committee consists of 2 representatives of IOU's, one representative of retail electric cooperatives, one representative of municipal utilities, two representatives of customer groups, and two representatives of consumer advocates. • Mandatory reports to Legislature. • Annual performance evaluation.

Funding Levels	• First year funding level \$68 million. Commission will conduct a public hearing to determine the second and third year budget, with a goal of \$110 million in the third year.
	• Commission may set higher or lower funding levels, after triennial notice and hearing that coincides with three year term of contract with program administrator.
	• Factors to be considered by the Commission in its order changing funding levels include:
	1. updated potential studies of demand and energy savings,
	2. benefit/cost studies,
	3. evaluations of program effectiveness, and
	4. studies of economic costs and benefits of reducing or delaying construction of electric generating plants or transmission lines.
	• Triennial proceeding provides a forum for Commission to:
	  • define specific programs;
	  • set goals, priorities and performance targets and other factors it determines appropriate;
	  • and allocate funding requirements by utility.
	• Non-bypassable Michigan Energy Efficiency Surcharge applied to all retail electricity sales on a per kWh basis.

Public Benefits Fund	• Public trust fund created, called the Michigan Energy Efficiency Fund. • Fund created in the State Treasury and administered by the Commission. • Fund may receive personal or corporate donations. • Commission approves disbursements from the fund. • Commission draws direct oversight expenses from the fund.
Program Design	• Spending in customer classes generally in line with revenues from these classes. • Specific programs tailored to needs of each customer class, and differentiating between non-manufacturing and manufacturing sectors. • Broadly defined performance targets and considerable freedom in setting program parameters provided to program administrator by performance based contract. • Manufacturing efficiency programs focus on total process efficiency.
Large Customer Opt-Out	• Manufacturing customers with a peak demand of 1 MW or more, that demonstrate self-delivery of efficiency measures.

4.3.3 Oversight

Michigan has a long history of strong public input in its regulation and oversight of public utility energy efficiency programs. A strong public input process is a necessary component of the energy efficiency program. Public input would be received at all stages of the implementation and review process using the Commission's notice and hearing process. Stakeholders could submit comments and expert testimony. Customers of all load serving entities would be required to participate.

Legislation would grant the Commission authority to hold contested cases to determine program elements. Moreover, the Commission could change funding levels through triennial contested cases. Legislation could establish specific criteria as a prerequisite to adjusting funding levels.

Public input would be incorporated by way of the creation of a Michigan Energy Efficiency Program Advisory Committee. The advisory committee would be an independent body, with appointments made by the Commission. It would include representatives of regulated utilities, electric cooperatives, municipal utilities, customer groups, and consumer advocates. The advisory committee would provide advice and recommendations to the program administrator, but would have no authority over it. Nevertheless, the advisory committee would serve as a key feedback link from stakeholders to the program administrator.

Multiple types of benefit/cost tests should be used in studies and evaluations, including potential demand and energy savings studies and tests, to provide evaluation data. Results should be conveyed to the Legislature and Governor every three years, with the first report due one year after the end of the initial three year implementation. The Commission should be allowed to contract for evaluation studies using a dedicated portion of the Michigan Energy Efficiency Fund or undertake the evaluation through its Staff. The Commission would fund up to three Staff positions from the fund for program oversight.

Program spending should include all of a utility's service area. The MEEP administrator's report to the Commission, and the Commission's report to the Legislature, should include the geographic distribution of spending and descriptions of program mechanisms to ensure equal funding distribution.

4.3.4 Large Customer Opt Out

A large customer opt-out option is a matter specifically addressed in the Plan strawman proposals. Many participants agree a statewide energy efficiency program might include large customer opt-out, although some participants prefer no exclusion.

Exclusion advocates argue that large users have sufficient expertise to identify and undertake cost-effective energy efficiency measures and investments. Exclusion opponents argue all customers face market barriers to full implementation of energy efficiency, and customers who do not participate may obtain indirect benefits such as lower marginal costs of power. A compromise would allow a large customer opt-out on the condition it is implementing its own proposal for energy efficiency projects in its facility. The Association of Businesses Advocating

Tariff Equity (ABATE) offered a specific qualifying demand level for a simple opt-out of 500 kW.

Staff recommends a conditional opt-out, restricted to large manufacturing electric users with a billing demand of at least 1 MW, after submitting to the MEEP administrator and the Commission a qualifying energy efficiency proposal. The Commission would have exclusive authority to permit a customer to opt-out of the program. Michigan has a large commercial and industrial base. Almost 70 percent of Michigan's current electrical consumption is related to the commercial and industrial sectors. MEEP should place a high priority on meeting the business community's needs. For the manufacturing sector, MEEP would work with businesses to design, implement, and finance industrial energy efficiency initiatives tailored to specific firms or industries. This is a more focused approach than a broad rebate for efficient industrial motors or another generic electric end-use efficiency technology. Technical assistance, rebates, low-interest loans, or loan guarantees could all be included. A loan, loan guarantee, or Pay As You Save™ (PAYS®)[33] program might be directed to a specific electric energy end-use application or as a component of a customer's overall energy or process efficiency project or strategy.

4.3.5 Funding Levels

Similar to Michigan's LIEEF, MEEF would be held in a restricted Department of Treasury account. Funded primarily through electric utility surcharges, MEEF would be dedicated to achieving energy savings for the state. Funds would not lapse into the state's general fund but would be used only for MEEP related costs. Accrued interest should remain in the fund.

4.3.6 Public Benefits Fund

Money disbursed from the fund would be used for MEEP administration, program education and marketing, research and development grants, and evaluation studies. A portion should be available to the Commission for oversight expenses and special studies. To minimize ratepayer impact, the fund should be permitted to obtain financing from non-utility capital sources such as private foundations, personal or corporate donations, and seek state or federal funding opportunities. The Commission and program administrator should develop independent efficiency funding sources that leverage non-ratepayer funds. Surcharge contributions might be exempt from state sales tax and local or municipal utility taxes.

Energy Efficiency modeling performed for Staff in the Plan estimated a budget up to $114 million/year would be cost effective. However, Staff recommends starting with an initial annual level of $68 million in the first year, with funding for the second and third year determined by the Commission after conducting a public hearing to affirm a goal of $110 million in the third year. Funding levels and resulting changes would be set every three years thereafter following a public hearing that considered program evaluations, benefit-cost studies, and energy efficiency potential. Fund revenue would be raised through a surcharge on electricity bills, through one of two methods of revenue collection. Under the first option, the MEEF charge would be set on a uniform basis for all customers in the state, including electric choice

[33] See http://www.paysamerica.org.

customers. The same charge, in mils per kWh (1 mil is one-tenth of one cent) would be paid by all customers receiving retail electric distribution services, including customers of municipal utilities.

Under the second option, MEEP program costs would be allocated by rate-class, potentially resulting in different mil/kWh charges. The rate-class allocation method has an advantage because it can provide the Commission with additional flexibility compared to a uniform charge. The additional flexibility of the rate class allocation method allows energy efficiency spending targets to be optimized for each rate class. The Commission should be allowed to set the charge using the method that it deems most appropriate.

Energy efficiency program spending in a utility's service territory should align with funding provided by that utility's customers. Spending by customer class or type should align with MEEF revenues.

4.3.7 Revenue Decoupling

Revenue decoupling refers to the separation of utility revenues, or profits, from the impacts of energy efficiency programs. Plan participants agree electricity sales and demand reductions stemming from efficiency programs should be incorporated into rates, but disagree whether decoupling is needed. Consensus on a specific approach for decoupling that is fair and cannot be gamed remains elusive. Staff believes the current rate-making process allows the Commission to consider and authorize rates in future periods that can accommodate actual and expected impacts of efficiency programs.

Decoupling for efficiency programs may be desired in the instance of utility administered energy efficiency programs. The disincentive to reduce sales for a utility, and the incentive to increase sales and profits, is large. Staff's recommendation shifts the responsibility to promote energy efficiency programs from the utility to the third party administrator, and thus obviates the need to decouple for that reason. However, adverse effects on utility earnings may result from program induced sales and demand reductions, particularly from the largest, most effective energy efficiency programs, if the rate setting process fails to recognize the resulting sales and demand impacts.

4.4 Michigan Appliance Efficiency Standards

Staff recommends Michigan should implement state-specific appliance standards based on resource assessments and analysis developed by the ACEEE/ASAP – The Workgroup considered the opportunity for Michigan to set state-specific appliance efficiency standards. Various participants provided input, with considerable input from the American Council for an Energy Efficient Economy (ACEEE) and the Appliance Standards Awareness Project (ASAP). State mandated standards may result in a significantly higher market penetration level of energy efficient products at a reduced cost of implementation compared to an incentive-based energy efficiency effort.

As noted in the resource assessment section of this report, the participants were able to identify specific appliance categories not subject to the Energy Policy Act of 2005 (EPACT05) that might be included in Michigan efficiency standards. However, due to time constraints, the participants were unable to review the feasibility of technical improvements associated with each appliance type. They were also unable to coordinate efforts with other states considering the implementation of appliance efficiency standards or investigate the formal, detailed language that is required to establish a particular product's legal standard for efficiency.

Staff recommends the State Energy Office in the Department of Labor and Economic Growth be directed by the Governor to provide further analysis and recommendations for the development of Michigan-specific appliance efficiency – Upon completion of its review, the State Energy Office should file with the Legislature a report and recommendations pertaining to appropriate legislation. The report should identify specific products that should be targeted, the need for any federal pre-emption petitions, appropriate benefit/cost analysis, and projected energy and demand savings. Technical feasibility of the proposed product standards should also be addressed.

The Energy Office should coordinate its efforts with other states in the process of developing recommendations pertaining to state appliance efficiency standards to avoid setting conflicting standards. Also, the Energy Office should coordinate its work with the Commission to ensure MEEP efforts appropriately complement any proposed state appliance efficiency standards initiative.

Finally, although the Plan was restricted to electric issues, the State Energy Office effort should include both electric and natural gas appliances.

4.5 Building Code Update

Several participants suggest that building codes should be updated as part of a comprehensive energy strategy for Michigan. Staff agrees.

On the basis of studies outlined in the resource assessment section of this report, Staff determined that updating Michigan's commercial building code represents a regulatory option that would provide substantial energy efficiency improvement at a modest cost. Lighting represents the dominant end-use in commercial sector electricity consumption, and lighting efficiency improvements typically show the largest savings impact. Lighting uses approximately 25 percent of the electricity in commercial buildings. Updating the residential code has the potential to provide cost-effective energy savings as well.

Staff recommends that the Governor direct the Department of Labor and Economic Growth (DLEG) to commence a broad-based collaborative of stakeholders as a platform to undertake a critical review and analysis of energy efficiency in building design and construction, culminating in recommendations and methods to – (1) incorporate the latest technologies to improve energy efficiency in all buildings in Michigan; (2) develop procedures for increasing the accuracy of economic analysis of updated energy code amendments, including development of appropriate measures for benefit/cost analysis, and to base the analysis on actual/projected energy costs as well as general inflation factors; and (3) recommend changes that could facilitate the rapid adoption of the latest codes and standards so as to increase the energy efficiency of building design and construction in Michigan for both commercial and residential buildings.

Upon completion of its review, DLEG should file with the Legislature its report and recommendations. The collaborative should include participation by the Bureau of Construction Codes, the State Energy Office, the Michigan Public Service Commission, building industry stakeholders and trade associations, and consumer representatives.

4.6 Demand Response Programs

The Plan's process of identifying demand response policy issues began with the Workgroup's creation of a demand response team to investigate technologies, techniques, and rate-making methods needed to implement a demand response program.

Demand response refers to customer efforts to reduce consumption (demand) in response to price signals, incentives, or directions from grid operators. Grid operators may use demand response to reduce demand during periods of high wholesale price, to provide a system resource alternative to generating capacity in response to short-term system reliability constraint.

Michigan utilities provide a diverse range of demand-response programs, but they have experienced low participation rates. Detroit Edison's residential air-conditioning cycling program, a direct load control program which currently has over one quarter of a million customers, is an exception.

The resource modeling phase of the Plan demonstrates that even a limited statewide effort can result in large electricity capacity reductions. Demand response programs fall into two general categories, active (direct) load-control programs (also called load management), and passive (price-response) programs. Both categories can be implemented using established technology. Nonetheless, participant consensus suggests a statewide effort to expand customer participation in demand response programs will depend on advanced technology infrastructure. Some could be implemented in conjunction with time-of-day, critical peak, or real-time rate structures.

4.6.1 Barriers to Adoption of Demand Response

Four primary barriers are preventing greater customer demand-response participation in Michigan. They impede efforts to expand implementation of demand response programs to realize the maximum potential impact on electric demand. These are:

1. ineffective customer incentives resulting from sub-optimal or inaccurate electricity price signals;
2. absence of demand response and ancillary services markets that could assist in funding effective customer incentives;
3. lack of wide-scale deployment of advanced metering and communications technologies; and

4. lack of actual experience combining advanced technologies with effective time-based electric rate structures.

Each of these barriers is discussed in the following sections. A detailed discussion of available new technologies, including smart metering, is contained in the Chapter 5 of Appendix Volume II.

Barrier 1: Incentives derived from accurate electricity price signals – A key barrier to increasing the level of demand-response resources in Michigan relates to rate and tariff structures. Appropriate price incentives are a foundation of both active demand response programs (interruptible and direct load control) and passive demand response programs (time-based rate structures). For both, price-response induces a change in demand.

In the new Midwest wholesale markets prices are market-driven and can vary significantly by time-of-day, day-to-day, and season-to-season, whereas retail rates are historically set on an annual, weighted average cost basis. While retail rates produce price stability by smoothing out the dynamic movements in utility power costs at the wholesale level, they effectively break the connection between retail demand for electricity and wholesale prices.

In line with the recent statements of federal policy in EPACT05, Staff recommends that the Commission explore rate structures that follow appropriate electricity price signals and signal customers to eliminate this barrier to demand response measures and thereby promote economic efficiency.

Barrier 2: Absence of demand response and ancillary services markets – There is currently no available market mechanism for selling or trading benefits from demand response initiatives. In such a market, Michigan's load serving entities could sell demand resources into the wholesale energy market. Revenues received might be used to cover or complement program incentive payments.

Demand response could also be used to provide "ancillary services" such as operating reserves, or bid into Midwest energy markets, with additional revenues to be gained for Michigan. Staff notes that these markets for demand response are currently not available through MISO, although MISO is working to implement them.

Barrier 3: Lack of wide-scale deployment of advanced metering technologies – A major barrier to greater deployment of advanced metering technologies and the opportunity to offer customer level demand response programs is the current lack of a clearly articulated policy direction in Michigan. Commission demand response program policy would also encourage electric-utilities to expand their corporate growth strategies to embrace a strong commitment toward capital investment in advanced technologies necessary to support demand response programs.

Barrier 4: Uncertainty due to lack of experience combining advanced technologies with effective time-based rate structures – All the above barriers combine to yield a current situation in which Michigan utilities have little incentive to lead initiatives for demand response programs unless they can show clear benefits for the utility, therefore, Michigan utilities and their customers have little experience in this area.

For some active load management programs like interruptible air conditioning, there is a long history of experience. Utilities have generally not expanded these programs for the past several years, however, even though they can be effective at managing load and lowering power costs. We recommend legislation be enacted to authorize the Commission to require these programs, where they can be shown to be cost-effective and in the public interest.

In response to the impact of these barriers on price responsive demand programs, Staff believes the best approach is to implement a pilot program, as an essential prerequisite for developing needed real world data and experience with various advanced technologies. The Energy Efficiency Workgroup asked participants for proposals that would define a pilot program action plan to commence such a program. DTE responded with a workable and well thought-out proposal to address specific issues. Staff used this proposal as a basis for its recommendation.

Staff is recommending that the Demand Response Action Plan include three workgroups comprised of a Demand Response Rate Options Workgroup; an Advanced Metering Infrastructure Workgroup; and a Demand-Response Pilots and Advanced Appliances Workgroup. Each workgroup would be charged with developing statewide proposals with multiple policy options. The efforts of all three workgroups would be coordinated by a Demand Response Steering Committee chaired by the Staff, and including representatives from all stakeholders.

To implement the collaborative process and workgroup structure, Staff recommends the Commission commence a Notice of Inquiry of Demand Response Pilot Programs. The directive should include all demand response stakeholders and specify a deadline for final reports. After the demand response workgroup documents are submitted to the Commission and the programs are demonstrated to be cost-effective and in the public interest, an order would be issued and further docketed proceedings implementing demand response pilots or programs would begin.

To assure that demand response programming is fully and completely evaluated, Staff recommends that legislation authorize the Commission to require demand response programs upon a finding of that these programs are cost effective and in the public interest.

4.6.2 Policy Recommendations for Demand Response Programs

Staff makes the following recommendations:

1. Commence a Commission "Notice of Inquiry for Demand Response Programs" in order to affect a statewide collaborative process, culminating in demand-response pilot programs.
2. Provide legislative authority for the Commission to require regulated electric utilities to investigate demand response programs, and implement programs if they are found to be in the public interest. Utilities could be required to offer demand response programs, for example through special time-of-use-rates, but customer participation would be optional.

4.7 Summary of Energy Efficiency Policies

In summary, Staff proposes the creation, by statute, of a comprehensive statewide energy efficiency program funded through surcharges on all Michigan electricity customers, with oversight and guidance provided by the Commission. The program shall be administered by an independent organization. In addition, Staff proposes legislation for the Commission to investigate and authorize comprehensive electric demand response initiatives. By Executive Directives to the appropriate offices in the Department of Labor and Economic Growth, Staff proposes updating Michigan's commercial and residential building codes, and analyzing and developing criteria for the establishment of stronger electric appliance efficiency standards.

5. Governor's Executive Directive 2006-2

EXECUTIVE DIRECTIVE No. 2006-2
21st Century Energy Plan

WHEREAS, Section 1 of Article V of the Michigan Constitution of 1963 vests the executive power of the State of Michigan in the Governor;

WHEREAS, under Section 8 of Article V of the Michigan Constitution of 1963 each principal department of state government is under the supervision of the Governor unless otherwise provided by the Constitution;

WHEREAS, it is critical to the public health, safety, and economic welfare of the State of Michigan to have reliable, safe, clean, and affordable supplies of energy;

WHEREAS, recent price shocks in the international and domestic energy markets have resulted in rising energy costs that have placed increased strain on Michigan businesses and citizens, especially low-income residents struggling to pay utility bills;

WHEREAS, Michigan has the intellectual, agricultural, and industrial capabilities to become America's alternative energy development epicenter, which offers a tremendous opportunity to diversify our economy and provide high-tech, high-wage, 21st century jobs to our residents;

WHEREAS, the Michigan Public Service Commission prepared and issued the Capacity Need Forum Report on January 3, 2006, after consultation with stakeholders representing all segments interested in the electric energy market including representatives from customer groups, business groups, utilities, independent transmission companies, environmental groups, energy efficiency advocates, independent power developers, and alternative and renewable energy providers, and this report makes clear that Michigan will need additional electric supply to meet its needs beginning in the year 2009;

WHEREAS, the Capacity Need Forum Report reflects a concern that institutional factors, including existing state laws and regulatory constraints, may impede the development of reliable, safe, clean and affordable electric energy supplies to meet the needs of our citizens and businesses;

WHEREAS, knowledge of the nature, location, and reliability of energy supplies, including the availability of alternative energy supplies, is critical to effective long term planning for this state and local units of government, including law enforcement, infrastructure development, transportation and land use planning, as well as for businesses seeking to locate or expand in Michigan;

WHEREAS, Michigan's unique geography increases the challenges for transporting energy and increases the need for a focus on the unique needs of both the Lower and Upper Peninsulas;

WHEREAS, a comprehensive energy plan can provide a framework for the state's future energy needs and stimulate economic growth by planning for a reliable, safe, clean, and affordable supply of energy for Michigan's future;

NOW, THEREFORE, I, JENNIFER M. GRANHOLM, Governor of the State of Michigan, by virtue of the power and authority vested in the Governor by the Michigan Constitution of 1963 and Michigan law, direct the following:

A. Not later than December 31, 2006, the Chairman of the Michigan Public Service Commission shall prepare a proposed Energy Plan for the State of Michigan. The plan shall address the following:

1. The state's short-term and long term electric needs for residential, industrial, commercial, and governmental customers shall be met in an optimum manner that assures a reliable, safe, clean, and affordable supply.

2. The future development of Michigan's electric infrastructure shall further the state's competitive business climate, grow jobs, and provide affordable rates for all customers.

3. The appropriate use and application of energy efficiency, alternative energy technology, and renewable energy technologies shall be consistent with the goal of assuring reliable, safe, clean and affordable energy.

4. This state's natural resources and the environment shall be protected from pollution, physical or visual impairment, or destruction, and future risks associated with fossil fuels shall be mitigated.

5. A renewable portfolio standard shall be created that establishes targets for the share of this state's energy consumption derived from renewable energy sources.

6. New technology options to generate, transmit, or distribute energy more cleanly or more efficiently shall be identified.

7. The state's economic interest in ensuring development of the intellectual capital, financing, infrastructure, and other resources necessary for continued growth of alternative and renewable energy technologies within the state shall be fostered.

8. The plan shall identify any legislative or regulatory changes necessary to its implementation, together with any financial, funding, or incentive mechanisms needed to best position the state to meet the energy challenges of the future.

B. The Chairman of the Public Service Commission shall consult with the directors of state departments and agencies as he or she deems necessary or advisable, and shall consult with appropriate stakeholder representatives. All departments, agencies, committees, commissioners, or officers of this state shall give to the Chairman of the Public Service Commission any necessary assistance to fulfill this Directive. Free access also shall be given to any books, records, or documents in its, his, or her custody, relating to matters within the scope of inquiry, study, or investigation of the Chairman of the Public Service Commission under this Directive.

This Directive is effective upon filing.

Given under my hand this sixth day of April in the year of our Lord, two thousand and six.

JENNIFER M. GRANHOLM

6. Community Participant List

AARP	1
Amcab	1
American Association of Blacks in Energy	1
American Council for an Energy-Efficient Economy (ACEEE)	1
American Electric Power	8
American Transmission Company (ATC)	3
Ameritech	1
Apollo Alliance	1
Bauer Power	1
Bay Energy Services	1
Bob Kildea	1
Boulanger Energy	1
Butzel Long	2
Capitol Group, Government and Public Affairs Consultants	1
Capitol Services Inc.	1
Citizens for Alternatives to Chemical Contamination	1
City of Ann Arbor	2
Clark Hill PLC	3
Clear Choice Development LLC	1
COBASYS	1
Coffman Electrical Equipment	1
Commonwealth Associates	1
Community Action Agency	1
Community Action Bureau	1
Competitive Power Ventures, Inc.	4
Constellation NewEnergy, Inc.	11
Consumers Energy Company	29
CSES International	1
Daimler Chrysler	1
Delta College	1
Dickinson Wright PLLC., Counselors at Law	1
Direct Energy	1
DTE Energy	24
Dykema, Gossett PLLC	1
El Paso	1
Energy Activi	1
Energy Advantage Consulting, Inc.	1
Energy Conversions, LLC.	1
Energy Michigan Council	1
Energy Options & Solutions	1
Energy Resources	1
EnVinta	1
Environment Michigan	1
Environmental Resources Trust	1
Erb Institute for Global Sustainable Enterprise (Univ. of Michigan)	2
Ferris State University	2
First Power, LLC	1
FordLand	1
Fraser, Trebilcock, Davis & Dunlap, P.C. Law Firm	3
General Motors Corporation	1

Grand Valley State University	2
Granger Energy	1
Great Lakes Renewable Energy Association	1
Holland Board of Public Works	1
House Democratic Policy Staff	1
Howard & Howard	1
IESO	1
Infineon Technologies	1
International Brotherhood of Electrical Workers (IBEW)	1
International Transmission Company	5
Julian Vail, LLC	2
Karoub Associates	1
Lansing Board of Water & Light	6
Lawrence Technological University	1
Legal Counsel, PC	1
Legislative Services Bureau	1
LS Power Development, LLC	4
Mackinaw Power	2
McKenzie Bay/Windsor Power	1
Michigan Alternative and Renewable Energy Center (MAREC, GVSU))	1
Michigan Attorney General	4
Michigan Building Trades	1
Michigan Chamber of Commerce	1
Michigan Consumer Federation	1
Michigan Department of Agriculture	1
Michigan Department of Environmental Quality	9
Michigan Department of Human Services	4
Michigan Department of Labor & Economic Growth	3
Michigan Department of Transportation	1
Michigan Department of Treasury	2
Michigan Economic Development Corporation	2
Michigan Electric and Gas Association (MEGA)	2
Michigan Electric Cooperative Association (MECA)	3
Michigan Electric Transmission Company LLC (METC)	3
Michigan Environmental Council	1
Michigan Extension Office	1
Michigan Farm Bureau	1
Michigan Floriculture Growers Council	1
Michigan Forest Products Council	1
Michigan House of Representatives	5
Michigan House of Representatives, Office of Chris Kolb	1
Michigan House of Representatives, Office of Mike Nofs	1
Michigan Independent Power Producers Association	1
Michigan Interfaith Power and Light	2
Michigan Legislative Consultants	1
Michigan Manufacturing Association	1
Michigan Public Power Agency (MPPA)	2
Michigan Public Service Commission	35
Michigan Senate, Office of Bruce Patterson	2
Michigan State University	3
Michigan Water Environment Association	1
Midland Energy	1

Mid-Michigan Community Action Agency Inc	1
Midwest Energy Efficiency Alliance	2
Midwest ISO (MISO)	5
Mirant Corporation	2
Michigan Municipal Electric Association (MMEA)	1
Michigan Sustainable Energy Coalition (MSEC)	1
National Wildlife Federation	3
NewEnergy Associates	7
Noble Environmental Power, LLC	1
Northern Options Energy Center	2
Northwest Michigan Human Services	1
Oakland Livingston Human Service Agency	1
Orion Energy, LLC.	1
Peabody	3
Peake Marketing & Advertising	1
Phase 3 Developments and Investments, LLC	1
Pinnacle Advisors, LLC	1
PJM Interconnection	1
Premier Energy	1
Preston Lighting	1
Public Interest Research Group in Michigan	1
Quest Energy/WPS	1
Sauber & Sons, LLC., Carpentry and Renovations	1
SEMCO Energy	2
Shepherd Advisors	1
Small Business Association of Michigan (SBAM)	3
Smigel, Anderson & Sacks	1
Society of Manufacturing Engineers	1
Southwest Michigan Community Action Agency	1
State Representative Mike Nofs' Office	1
Strategic Energy	1
Svanda Consulting	1
Technology, Energy, and Marketing Strategies	1
The Regulatory Assistance Project	1
U.S. Partnership for the Decade of Education for Sustainable Development	1
University of Michigan	9
Upper Peninsula Power Company	1
Urban Options	1
Washtenaw County	2
We Energies	4
Weston Solutions, Inc.	1
Whirlpool Corporation	1
White Pine Electric Power LLC	1
Whitecase	1
William J. Celio Consulting LLC	1
Wisconsin Public Service Corporation	5
Wolverine Power Supply Cooperative, Inc.	5
WPS Energy Services, Inc.	1
Total Participants	351