Capacity Needs Forum
Status Report
U-14231

July 1, 2005

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Introduction

The Michigan Electric Capacity Need Forum (CNF) was initiated by the Commission through its order in docket U-14231 on October 14, 2004. The Forum represents the first major assessment of Michigan's electric power needs undertaken by the State of Michigan since the Michigan Electric Options Study (MEOS) study in the mid-1980's. Unlike MEOS, which was intended to identify only the State's electric power needs, this Forum takes on the added goal of reviewing the Commission's current resource additions policies and making appropriate recommendations.

The Commission's order included two broad action areas to be undertaken through a participatory process involving Michigan electric industry stakeholders. The first action area is to assess Michigan's electric capacity needs over the short-, intermediate-, and long-term future. If needs are identified, the Forum must identify the best mix of resources to fill them. The Commission has requested analysis of a broad range of resource options, including traditional utility generating plant and transmission expansion along with renewable energy technologies, combined heat and power options, and energy efficiency measures.

The second major action area to be addressed by the CNF is the Commission's policies regarding resource additions. New power sources in Michigan may be built by independent power producers or by regulated utilities. If, in the future, new generating plants are to be built by traditional utilities, the Commission requested guidance on how construction expenditures should be recovered. Since Michigan's most recent major base load units were constructed in the mid 1980's, significant changes have occurred as the result of the advent of competition amongst wholesale and retail suppliers of generation services, raising questions about the continued use of current construction cost recovery mechanisms. The CNF will assess the methods adopted by the Commission for allowing utilities to recover construction expenditures related to electric generating plants and make recommendations for changes, if appropriate.

The Staff has invited numerous participants from throughout the industry to take part in the Forum. In addition, many other parties have learned about the Forum and have requested to participate or be apprised of its progress through electronic notification. A total of over 200 individuals representing 44 groups have participated in the Forum and its work groups. Organizations that have been represented at the Forum or in work group meetings are listed in Appendix A. The Staff also maintains a website devoted to the Forum through which schedules, agendas, draft reports, related planning documents, and other information are publicly available.

This interim report serves to apprise the Commission of the conduct and status of the CNF and to provide the Commission with information and analyses completed to date. The reader should bear in mind that no final conclusions have yet been reached by the CNF. Many issues discussed in this report are rapidly evolving, fluid, and are likely to continue changing in the future. This dynamic nature of energy planning means that updates of the work group reports may be necessary from time to time. The information provided in this report is the most recently available to the CNF and the Staff, but some of the analyses should be viewed as preliminary and subject to change as the CNF work continues.

Study Scope

The electric capacity need assessment is being conducted on a regional basis within Michigan. The State has been split geographically into the southeast portion, the balance of the Lower Peninsula, and the Upper Peninsula. The southeast portion is the area covered by the International Transmission Company (ITC) (roughly the Detroit Edison Company service territory). The balance of the Lower Peninsula is the region covered by Michigan Electric Transmission Company (METC) (roughly the service territory served by Consumers Energy, Wolverine Power, and most of Michigan's large municipal utilities). The Upper Peninsula region is covered by the American Transmission Company (ATC) zone 2. Demand forecasts, generating plant resource inventories, and electric generating need assessments are being developed for each geographical region. In addition, transmissions capacity and reliability assessments have been performed for the ITC and METC regions collectively.

Although we have characterized the CNF's work as "statewide", the electric capacity need assessment does not include the southwest corner of Michigan. Most of this area represents the service territory of Indiana and Michigan Electric Company. The reason is two fold. First, Indiana and Michigan (I&M) is part of the American Electric Power (AEP) system. This system owns and operates the Cook nuclear plant in Bridgman, Michigan, which has a generating capacity of 2,000 MW, while I&M's Michigan peak demand is expected to be approximately 650 MW in 2005.

Second, I&M's service territory is a part of the PJM regional transmission organization (RTO). The remainder of the State is covered by the MISO RTO. PJM establishes reserve requirements for all of its members, including I&M, and requires each member to procure their required reserves in order to assure generation reliability standards are met. PJM also operates capacity markets, in which members must buy their reserves if they do not have sufficient self-scheduled reserves. Currently, the basis for this reserve requirement is 15%, the same reserve standard that we are presently using in the CNF.

Since Michigan's southwest region appears to have ample baseload capacity and must satisfy mandatory PJM reliability standards, the CNF is not including that region within this study. References in this report to the balance of the Lower Peninsula are meant to refer to that portion of the Lower Peninsula lying outside the ITC service territory and excluding the southwest corner of the State.

Summary

The principal effort of the CNF thus far has been to compile information and analyses to support the resource modeling effort now taking place. Much of this work is detailed in the various work group reports that are attached here as appendices. The information in these reports provides both modeling inputs and data necessary for discussing policy options that will be considered by the CNF. The information shows that Michigan's current inventory of generating capability is approximately 27,500 MW while peak demand is forecast to be approximately 26,000 MW in 2009, the plan's base year. Transmission capability, on-peak, is estimated to be approximately 3,000 MW into the Lower Peninsula and 500 MW into the Upper Peninsula for the same time period. Most recent additions to available generating capacity, have been sited in West Michigan, while demand is most concentrated in East Michigan. In the preliminary base reliability run with external support, the combined ITC and METC regions of the Lower Peninsula, also known as the Michigan Electric Coordinated System (MECS), have a combined need of between 400 MW and 500 MW to maintain reliability standards in 2009. The reliability runs, however, do not show the best method of satisfying this need. The capacity could be procured from new native generation, expanded transmission, demand response programs, or any combination of these resources. The best method of securing the needed resources will be identified in the resource expansion modeling that is commencing now.

Two Phase Approach

To address both action areas in U-14231, the CNF is progressing in two phases. The first phase is aimed at assessing Michigan's electric capacity needs. The goal of groups participating in this phase is to determine if Michigan's current resources can adequately meet Michigan's future electric capacity needs. If the resources are insufficient or become insufficient because of load growth, the goal is to determine when new resources will be needed, and what type may be most appropriate to add to the State's current asset portfolio. The second phase is to assess the Commission's current resource addition policy and to recommend changes to that policy, if changes are deemed necessary. To date, most of the CNF's work has been focused on the first phase. The scope and time needed to accurately complete this phase has necessitated a later start of the policy discussion. Although an assessment of policy issues has begun, work in earnest is only now being scheduled.

Phase One

Resource Assessment

Phase one, on which the Forum has focused its efforts to date, has been to assess the adequacy of the State's current generating resource stock. This track represents a major electric energy planning process that has not been undertaken by any agency of the State of Michigan since the MEOS study. The planning process has involved forecasting electric energy demand growth, preparing an inventory of current generation and transmission resources, identifying new resource options, and conducting analysis using multiple, interrelated computer models. This process has been structured and conducted to provide the Commission with a forecast of demand and an appraisal of the ability of existing resources to meet forecast demand. The analysis is focused on three regions within Michigan. These regions coincide with the service territories of the ITC, METC and ATC zone 2.

Determining the ability of current generating and transmission resources to meet growing energy and peak demand along with determining the most appropriate resource mix to add, when needed, requires extensive computer modeling. Three models have been used to assess Michigan's electric generating and transmission adequacy and evaluate future resource options. These include a power flow model to assess the State's electric transmission capability, a reliability model to determine the adequacy of existing generation to satisfy reliability standards, and a resource expansion model to evaluate future resource options, should additions be needed.

In order to provide the data necessary to undertake the three-part modeling effort, the Staff established five work groups from among participants to the CNF. The work group's designations correlate to the principal data input areas that are needed for modeling resource needs and selection. The work groups are:

- Demand
- Central Station
- Alternative Generation
- Transmission
- Integration

A description of each work group is included later in this report. Each work group has responsibility for compiling its designated data and for identifying and explaining related issues. Work group participants, representing numerous organizations, have volunteered their time and energies to acquire, review and analyze the necessary data.

To date, the demand, central station, alternative generation, and transmission work groups have provided the integration work group with the data and analyses required for the resource modeling to commence and, with the exception of the Transmission Work Group, produced written reports. The Transmission Work Group has had extensive, complex modeling of its own to complete and is in the process of preparing a written report. The Transmission Work Group's report will be posted to our website when completed.

The process followed by the CNF and the attached reports satisfy several of the Commission's requests in U-14231. These include forecasts of energy sales growth, an assessment of resource adequacy, a review of PSCR and Annual Reports for sales forecasts, system capabilities, and plant held for future use. We have also collaborated with participants from throughout the electric industry in Michigan to compile and review this information. Finally, the Commission directed Staff to consult with the Midwest

Independent System Operator (MISO), which serves as the reliability coordinator for the electric transmission system in Michigan and surrounding states. Our analysis was undertaken with the assistance of MISO and incorporates information from the MISO planning process.

Demand Work Group

The Demand Work Group was responsible for supplying a twenty-year forecast of energy and demand for each of the three geographical areas designated for modeling. The work group forecast an increase in electric consumption from 113,782 gigawatt hours (GWh) in 2005 to 163,411 GWh in 2025, or an average, statewide annual growth rate of 1.8%. Peak demand is expected to grow from 24,101 megawatts (MW) in 2005 to 36,589 MW in 2025 (an average 2.1% growth rate). The work group also provided the Integration Group an estimate of available energy efficiency as a resource option in the State of Michigan. The work group's energy efficiency estimates are based on the experience of other states with energy efficiency programs and recognize Michigan's past experience. The Demand Work Group's final report is Appendix B to this interim report.

Central Station Work Group

The Central Station Work Group was responsible for identifying future generating plant technologies, estimating the costs to build and operate them, estimating emissions profiles, and identifying other related issues. The plant types included in the work group's report are listed below:

Plant Type	**Fuel**
Pulverized Coal	
Sub-critical	coal
Super-critical	coal
Circulating Fluidized Bed	coal/biomass
Integrated Gasification Combined Cycle	
Bituminous	coal
Powder River Basin	coal
Nuclear	uranium
Combined Cycle	natural gas
Combustion Turbine	natural gas

A potentially important issue identified by the work group that could affect technology options in the future is the possibility of enactment of progressively more stringent emissions requirements. The work group's report is attached as Appendix C.

Alternative Generation Work Group

This work group was charged with identifying and compiling information on non-traditional generating technologies. Members of the work group concentrated on four technologies and estimated the available capacity from each that would be available in the 2009 time period. A summary is shown below:

Technology	Capacity (MW)
Wind Energy	410
Anaerobic Digestion (Dairy Farm)	50
Landfill Gas	105
Combined Heat and Power (Cogeneration)	500

In addition, the work group identified technologies that were currently too expensive to include in the analysis or for which there was insufficient data to include for modeling purposes. Nevertheless, the work group prepared a brief description of these potential technologies for future consideration. These technologies include solar applications and offshore wind and fuel cells. Appendix D is the Alternative Generation Work Group's final report.

The work group conducted its work in close collaboration with the Michigan Wind Energy Program and the Michigan Renewable Energy Program.

Transmission Work Group

The Transmission Work Group was responsible for preparing an assessment of the State's transmission capabilities. The basis for the work group's estimates of available transmission capability is power flow modeling undertaken by ITC and based on planned and proposed projects identified in the Midwest Transmission Expansion Plan 05 (MTEP05). MTEP05 was prepared by the Midwest Independent System Operator (MISO). In addition to providing the transmission transfer capacity, the work group also provided option upgrades to the transmission network as resource options. The goal of these options is to expand transmission into and within Michigan. A final report has not yet been completed by this work group, however, the transmission modeling has been substantially completed.

Most transmission facilities in Michigan are operated by MISO. The estimates of transfer capabilities into and within Michigan have been made in conjunction with proposals in MTEP05, MISO's most recent long-term reliability plan. The base year for MTEP05 is 2009, and we have adopted that base year throughout our study. The Transmission Work Group did estimate transfer capability for a base case of 0 MW power flow to Ontario and an alternate scenario in which 1,500 MW of power flows to Ontario. The rationale for including this scenario is the announced intention of the Province of Ontario to decommission all of its coal-fired generation. There is no certainty of when all coal-fired plants in Ontario will be decommissioned. Depending on the Province's success in replacing that capacity with indigenous sources, the decommissioning may cause power flows out of the U.S. and into Ontario. The base case power flow model produced a 2009 transfer capability of approximately 3,000 MW into MECS from sources throughout this region of the Country. For the Upper Peninsula, the estimated on-peak transfer capability for 2009 was approximately 500 MW.

Integration

The integration work group is responsible for managing the reliability and resource expansion modeling components of the CNF. This includes selecting a resource model and reviewing model documentation and results. It also includes assuring that data is compiled and presented in an accurate and consistent manner and for adopting assumptions for modeling purposes. A model and contractor have been selected for the resource expansion model and work is progressing on this component of the study.

Phase One Models

Power Flow Model

The power flow model is designed to estimate the transmission transfer capability of Michigan's transmission network. The model uses projected information for 2009, which coincides with the MTEP05. This plan projects transmission capability and needs to the year 2009. A part of the plan is the identification of planned and proposed transmission upgrades and investment to improve transmission access and efficiency. The power flow models used for the CNF assumed the adoption of planned and proposed transmission improvements in MTEP05 for the ITC, MTEP, and ATC. The modeling has been performed on behalf of the CNF by ITC.

The transfer capabilities are estimated for the peak demand hour of each system, and indicate during that period how much transmission capability is available into the state and within the state. The power flow presentation follows the regional format used throughout this analysis. In addition, modeling was done to incorporate the METC and ITC regions collectively, or MECS.

The power flow models provide an estimate of on-peak transfer capability of each region's transmission system and is an important input to the reliability model.

Reliability Model

The purpose of reliability modeling is to determine whether existing native generation together with electric transmission transfer capability and available external generation support can meet reliability standards for projected hourly load. Reliability modeling for the CNF was performed by the Midwest Independent System Operator (MISO). The MISO Staff used the Multi Area Reliability Module (MARELI) computer model along with data from the CNF work groups to estimate future generating reliability in each region of the State.

Although reliability standards are not uniformly promulgated throughout the United States, a target of one day in ten years loss of load probability (LOLP) is the most widely acknowledged industry standard. Since electric generating plants are mechanical instruments, they are occasionally prone to failure. The reliability of each plant is based upon its planned and forced outage rates. Of particular concern is each unit's forced, or unforeseen, outage rate. This is important because if a region constructs just enough plant to meet expected load but one of its generating plants is forced off-line, then that there will be insufficient generation to meet the expected load. Therefore, a generating reserve is needed to assure that if one unit is forced-off, other units from a reserve are available to meet the expected load.

The likelihood that a generating unit may be forced off-line is manifest in its forced outage rate. If the rate is high, there is a larger likelihood that the unit might not be available to meet load when needed. On the other hand, a low forced outage rate indicates that the unit is more likely to be available when needed. Because of the probabilities that plants may not be available when needed, large reserves would be necessary to be absolutely certain that all demand will always be met. There is a significant cost associated with building and maintaining necessary reserves that may remain idle most of the time. Therefore, one goal of utility planning is to identify how many reserves are necessary to assure reliability without resulting in excessive fixed costs.

If one were willing to relax the requirement of 100% certainty that demand always be met and, instead, assume a slightly reduced probability that demand could always be met through generation, then reserves, and associated costs, could be reduced significantly. The reduced probability that one is willing to assume is a measure of generation reliability. As indicated previously, the most widely accepted level of reliability is the willingness to tolerate the probability that generation is insufficient in one day out of ten years to meet load. This is the reliability standard that has been adopted by the CNF for generation/transmission planning purposes and the reliability standard used by MISO for the MARELI model runs. It is important to remember that this is a probabilistic outcome which we never expect to occur, not an outage that is actually planned.

The MARELI model is a probability based algorithm used to assess whether a geographic region's native generation, together with interruptible load, is sufficient to meet hourly peak loads, within the one day in ten year LOLP tolerance. If the reliability criteria are met, the model gauges the excess import or export capability available. If the criterion is violated, it calculates how much additional imports are required to meet the criteria.

The model uses a probability distribution of available and operational generation in a region based upon each unit's forced outage rate. The distribution takes the form of an aggregate supply-capacity curve, running from a probability of 0 to 100%. The curve depicts the probability that a given level of demand can be met by generators collectively within the region. The LOLP sums the loss of load expectations – when supply is insufficient to meet demand - of daily peak hours over a year. The criterion of one day in ten years translates into 0.1 day in one year in this LOLP calculation.

For the Michigan study, owners of generation reviewed and updated the generation data used by MISO, including capability and availability – incorporating forced outage experience for each plant. Hourly customer demands were supplied by all MISO load serving entities in Michigan, including investor owned electric utilities, cooperative electric utilities, and municipal electric utilities. Transmission capability was provided by ITC from the results of its power flow modeling. Consonant with the power flow model, the MARELI runs used 2009 forecast data as a base year.

Preliminary results are available for the various regions within Michigan. The amount of external support available depends, in part, on which region is the source of the support. Based upon support from external geographical regions, the preliminary LOLP numbers are as follows:

- METC – 0
- ITC – 1.03 days/year
- MECS - 0.2 days/year

Bearing in mind that the target LOLP is 0.1 day per year, the preliminary results seem to indicate that the ITC footprint is forecast to violate the reliability criteria and would require either additional external support, through transmission expansion, additional native generation, implementation of demand response programs, or a combination of these resource options. For an integrated ITC/METC region, or MECS, however the reliability constraint is only marginally violated. This violation would indicate the need for about 400 to 500 MW of additional resources in 2009 in order to satisfy the reliability standards for Michigan's Lower Peninsula. Reliability modeling for Michigan's Upper Peninsula is not yet complete, but the results will be posted to our website in the near future.

Michigan reliability planning can be significantly affected by the Ontario energy markets. Power flows originating from regions to Michigan's south and west and into Ontario are increasing, and this has an impact on Michigan's electric transmission capability. For example, in the preliminary MARELI run, the phase shifters between Michigan and Ontario were set to allow no power flow between the regions. If this is not the case, then flows to Ontario may significantly increase the amount of needed capacity, because transmission available to Michigan decreases as flow to Ontario increases.

It is also important to keep in mind that the MARELI results measure reliability outcomes only. The model is designed to identify whether additional resources are required, but not the type of resources that could most economically meet the need, that is peaking, base load, demand response, external support through expanded transmission, or any combination of these. The type of resource that may most appropriately be added depends on the results of the resource expansion model.

Finally, the CNF has performed its analysis on a regional basis within Michigan as well as a collectively for the Lower Peninsula, represented by MECS. For reliability planning purposes, this recognizes the role of MISO as the regional reliability coordinator with access to network resources throughout the MISO footprint. MISO draws on all available network resources to assure reliability is maintained throughout its footprint.

Resource Expansion Model

The CNF has chosen NewEnergy Associates to assist the Integration group in assessing which resources should be added to the State's existing resource base when additional resources are needed. NewEnergy's Strategist model relies on a dynamic programming algorithm to search for and select an optimum resource solution, when additional resources are needed. Unlike classical constrained optimization models that yield a unique solution, this model format ranks multiple solutions in order by how they satisfy constraints, for example minimizing revenue requirements. This allows a comparison of rankings among solutions as scenarios change, and permits one to manage cost and risk associated with the various scenarios.

The principal objective of the model is to identify the best resource plan that will satisfy the electric generation needs of the State, subject to a reliability-based generation reserve constraint. The model assesses traditional generation technologies, alternate generation technologies, transmission upgrades, and demand-side energy efficiency programs that have been prepared by the various work groups. This modeling effort is just beginning and no results are available at this time.

Modeling Scenarios

The resource modeling plan produces a base case that utilizes the base sales and demand forecasts, resource assumptions, fuel price forecasts, and assumptions regarding economic variables and policy standards. For example, the modeling is based upon existing, known emission compliance standards, even though these standards have become more stringent over the years. Prospective economic and policy developments create uncertainty with respect to the degree of reliance that can be placed on these base case assumptions and forecasts. This creates a significant amount of risk that the plan selected by the model, while least-cost under base assumptions, exposes ratepayers too much higher costs if the assumptions prove to be incorrect. To address this risk, the planning process normally includes scenarios, or the adoption of alternative assumptions, to help assess how the base plan performs if the base assumptions do not materialize.

The CNF has followed this process and included a number of scenarios in its modeling effort in addition to its base model run. The three scenarios proposed for this study measure how the plan changes as emission standards tighten and non-traditional resources are relied upon more heavily. The first is an emissions scenario in which mercury caps are tightened and a carbon mitigation program is adopted in the United States.

The second scenario adopts a utility-based energy efficiency program to help satisfy growing energy sales. It also assumes that some peak oriented combustion turbines may be replaced by load control programs. The third scenario relies more heavily on non-traditional resources. This scenario assumes a mandated renewable energy portfolio of 3% by 2008, 5% by 2010 and 7% by 2015.

The Integration group has also adopted several sensitivities to run with the base case and each scenario. The sensitivities depict the impact on costs if important input values are changed. For example, if demand growth is faster or slower than projected by the base forecast, sensitivity runs will provide data on the resulting cost associated with the additional sales or lower sales. This information demonstrates how sensitive the base resource plan is to certain critical inputs.

Phase Two

The second phase is to review the Commission's resource addition policy and recommend changes to the policy, if needed. The Forum has been meeting monthly since April to learn about key issues in electricity capacity markets in addition to reviewing the progress of the modeling work groups. At this time, discussions concerning the method used by the Commission for rate recovery of utility investments are still in its formative stage.

To date, the entire Capacity Need Forum has met just four times. The first meeting covered the requirements laid out in U-14231, the conduct of the Forum, and an initial schedule. Subsequent meetings highlighted areas around which policy related issues may occur. These include financial requirements to build generation, the effects of clear air requirements, and the experience of PJM with competitive capacity markets. The MISO will be highlighted during the July 18th scheduled meeting of the CNF. Also, the meeting will include a review of the Commission' current policy and a framework for continue policy discussions.

Phase Two Schedule

The initial schedule called for the work groups to complete their data compilation and analysis by the end of April 2005. At that time, the results were scheduled to be turned over to the integration group for modeling purpose. The modeling was scheduled to be complete by mid-August.

Most work groups completed the bulk of their work within the scheduled time, but no work group completed all their tasks within the April time frame. However, extensive power flow and reliability modeling did commence in a timely manner. At this time, the work groups have completed their tasks, compiled the required data and prepared reports. Reports from the work groups, except the Transmission Work Group, are attached as Appendices to this interim report. We remain on schedule for completing the modeling component of the CNF.

With the work group reports available, power flow and reliability modeling substantially complete for this phase, and after a number of important presentations on related topics from outside parties, we are on schedule to examine the Commission's current resource addition policy and assess the need for any recommendations. The schedule for the remainder of the CNF follows:

Recommendations discussed	July 18 – September 15
Modeling complete	August 15, 2005
Draft report	October 15, 2005
Participant Comments	October 30, 2005
Reply to Comment	November 15, 2005
Final Report	January 1, 2006

Appendix A
Participating Organizations

Abate
Attorney General Consumer Protection Division and Special Litigation
American Electric Power
American Transmission Company
Board of Water & Light
Constellation/New Energy
Consumers Energy
Department of Environmental Quality
DTE Energy
Energy Michigan Counsel
Energy Options & Solutions
Ford Motor Land Services
Governmental and Public Affairs
Granger Energy
Holland Board of Public Works
IBEW
International Transmission Company
Lansing Board of Water and Light
Michigan Buildings Trade
Michigan Electric and Gas Association (MEGA)
Michigan Electric Co-Op Association
Michigan Electric Transmission Company, LLC
Michigan Energy Office
Michigan Independent Power Production Association
Michigan Public Power Agency
Michigan Senate Majority Policy Office
Michigan South Central Power Agency
Midwest ISO
Midwest Energy Efficiency Alliance
Mirant
Michigan Municipal Electric Association
Michigan Public Service Commission
National Wildlife Federation Great Lakes Office
NextEnergy Center
Peabody
PJM Interconnection
Premier Energy
Quest Energy/WPS
Shepherd Advisors
Strategic Energy
Upper Peninsula Power Company
We Energies
Wisconsin Public Service Corporation
Wolverine Power Cooperative
WPS Energy Services, Inc.

Appendix B

Demand Work Group

Michigan Electric Sales and Peak Demand Forecast
2005 - 2025

Introduction

This report explains the electric energy forecast methodology and results produced by the Demand Work Group. The Demand Work Group was charged with preparing an electric demand and energy forecast for the period running from 2005 to 2025 for use by the Capacity Need Forum's Integration Group. The projections rely primarily on forecast data provided by members of the work group including: Consumers Energy, Detroit Edison, Wolverine Power Cooperative, Michigan municipal utilities, WE Energies and WPS Energy. Various methods were used by each of these participants to forecast their loads.

The purpose of the forecast is to provide the Capacity Need Forum's Integration Group with demand and energy projections for use in modeling the State of Michigan's electric generating needs in the near to longer-term future. The Midwest Independent System Operator (MISO) has used the forecast prepared by the Demand Work Group in its MARELI model to assess electric reliability needs in Michigan. The Integration group will also use the forecast in order to select the least cost method for meeting future electric supply needs. The sales and peak demand forecast are adjusted upwards to account for transmission and distribution losses to reflect system requirements for input to the modeling effort as shown in Attachment III.

The annual forecast has been prepared for three geographical regions within Michigan: Southeast Michigan, comprising the area served by the International Transmission Company (ITC), the balance of the Lower Peninsula, comprising the area served by the Michigan Electric Transmission Company (METC) and the Upper Peninsula, comprising the ATC Zone 2 region. The breakdown of the estimated 2005 gigawatt-hour[1] (GWh) sales by region is shown below:

Included in the forecast are all electric load-serving entities in the State of Michigan. In addition to the regulated investor-owned utilities, this includes the regulated electric cooperatives and non-regulated municipal utilities. The forecast includes total service territory sales for Consumers Energy and Detroit Edison, consisting of both bundled and competitive choice customers. The forecast numbers are based upon sales to customers with on-site supply net of their internal generation. Specifically not included in this report is the PJM region of Southwestern Michigan.

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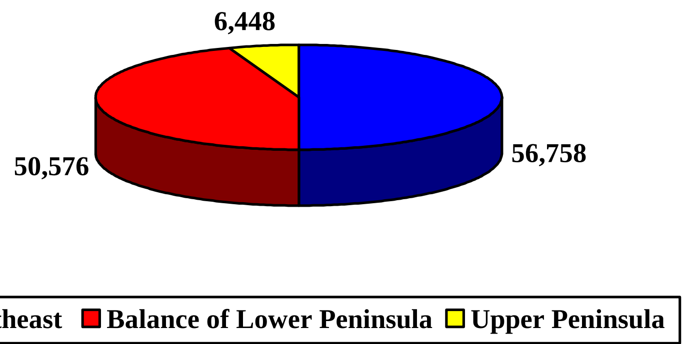
[1] Gigawatthour (GWh): One billion watt-hours.

2005 Forecasted GWh Sales

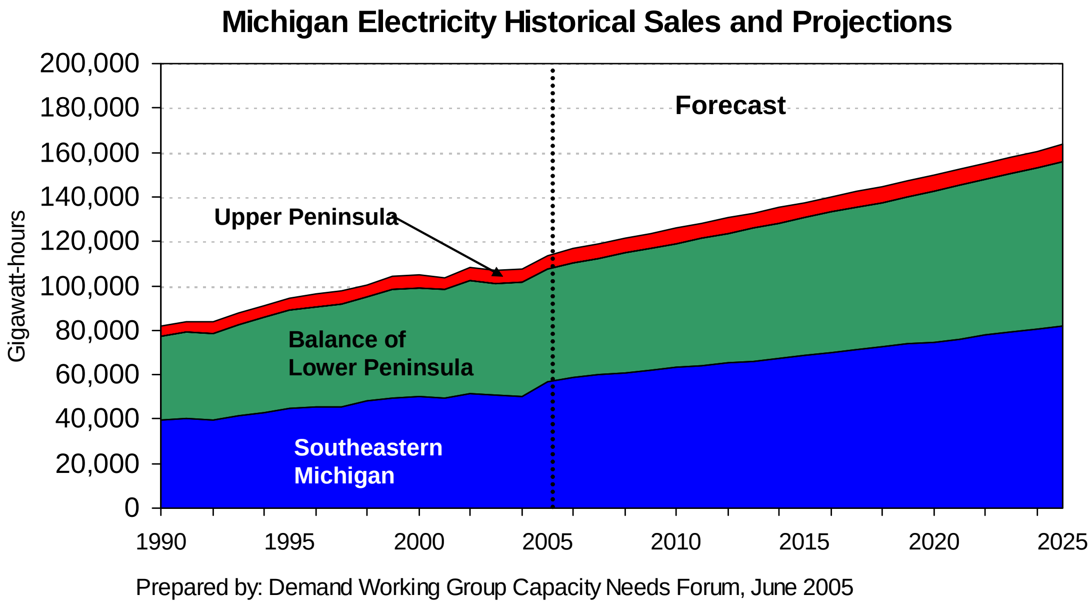


After the enactment of Public Act 141 of 2000, Michigan electric customers were allowed to select electric generation service from non-regulated, competitive, suppliers. According to the Staff's most recent report on electric competition, alternate electric suppliers were serving approximately 4 million megawatt hours of Consumers Energy's commercial and industrial customer's sales for the twelve months ending with November 2004. The competitive suppliers were serving nearly 9 million megawatt hours in Detroit Edison's service territory over the same time period. At the end of 2004, the Staff report showed that alternate electric suppliers were serving 926 and 2,378 megawatts (MW) of load in Consumers Energy and Detroit Edison's service territories respectively. This forecast is intended to project total retail electricity sales and system losses in the future by geographical region within Michigan. No attempt has been made to forecast the future shares of total sales between regulated utilities and competitive suppliers.

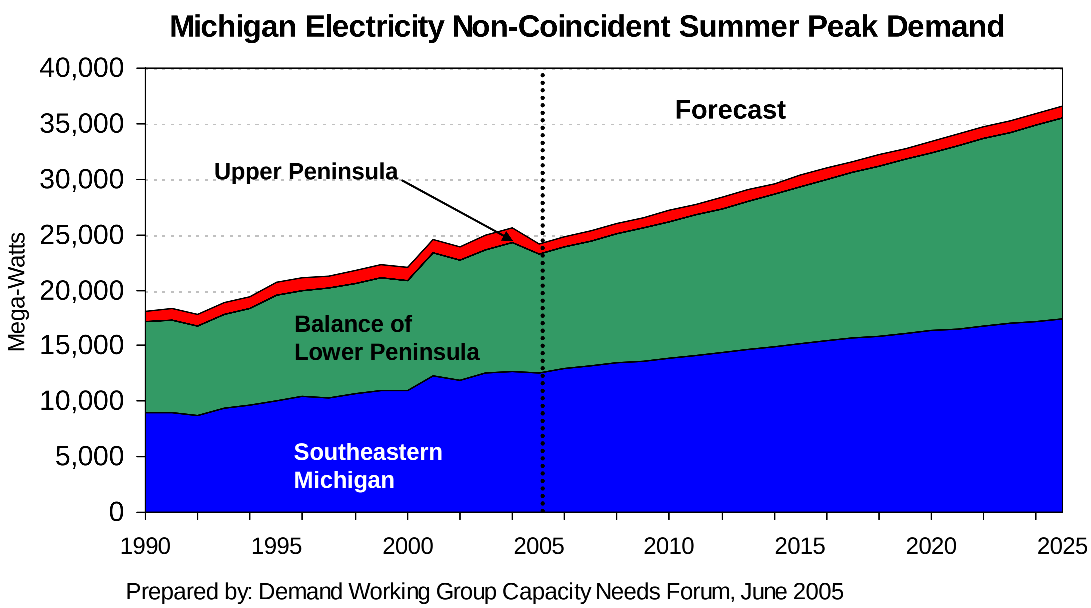
Forecast Results

In the base case, Michigan's total electricity needs are expected to grow by 1.8% from 2005 to 2025, from 113,782 GWh to 163,411 GWh. Southeast Michigan is expected to experience a growth rate of 1.8%, the balance of the Lower Peninsula is expected to grow at 1.9% and the Upper Peninsula is expected to grow at 0.9% over this time period. Historical and forecast sales are shown in the graph below and more detailed tables of forecast sales by region of the State and by scenario are included in the Appendices to this report.

Peak demand is expected to grow from 24,101 MW to 36,589 MW, or at a rate of 2.1%



from 2005 to 2025. The expected peak load growth for southeast Michigan is 1.7%, for the balance of the Lower Peninsula it is 2.7%, and for the Upper Peninsula it is 0.9%. The graph below depicts forecast demand growth:



Annual demand forecast tables for each geographic region by forecast scenario are included in the Appendices.

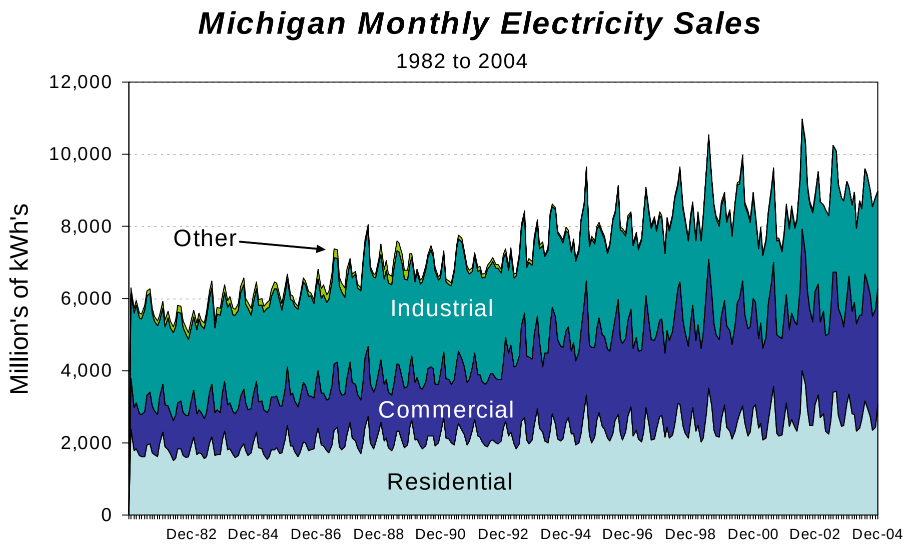
Discussion

Southeast Michigan's near-term forecast reflects a resumption of economic growth in 2005, but at a relatively slow rate. This growth is not projected to increase employment, however. Manufacturing, especially related to the auto and truck industry, drives much of southeast Michigan's demand for electricity. The longer-term future growth of this sector is clouded. The forecast is based upon slow growth in auto and truck production, with a significant downturn beginning in 2007 and, eventually, a resumption of transportation related growth. The forecast is also based upon no growth in the rate of housing starts over the next several years and short-term growth in Detroit area steel production, with flat production after 2007.

The balance of the Lower Peninsula's forecast is based upon slow growth in housing starts and mixed, but generally positive, growth in industrial manufacturing. Slow to negative growth is expected in out state transportation related employment over the near future, even with growth in output. More robust growth is expected in electrical equipment and appliance manufacturing and chemical production. More modest growth is projected for rubber and plastics manufacturing, along with furniture.

The Upper Peninsula's forecast is affected by the operation of two mines in the Upper Peninsula that are served by We Energies. These two mines currently represent 280 MW of total load (20 MW firm, the balance interruptible), which is approximately one-third of the entire Upper Peninsula's forecasted load. Ongoing speculation that the mines could close for various reasons has existed for a number of years. Similarly, discussion of potential increases in mine production and electric load has also taken place. The current forecast provided by We Energies assumes no change in the electrical loads of the mines. Another factor possibly impacting the electric loads in the Upper Peninsula is changing environmental regulations that would cause electric generation units that are operated by paper companies in the Upper Peninsula to be closed. The closing of these paper companies might result in over 100 MW of additional generation being supplied by the existing investor-owned or municipal electric utilities.

It is helpful t keep in mind that the forecast reflects annual totals that do not display the variability of demand seen over the year. This variability while best seen in daily data can also be seen in historical monthly sales as shown in the following graph. The summer peak sales can be seen more clearly in this graph and it should be remembered that for the purpose of capacity planning the need is to assure sufficient capacity to meet peak demand. Therefore, when looking at the summer peak demand forecast it is not unlike drawing a line across all the highest points shown in this historical data. The variability of loads from hour to hour and day to day are important factors in understanding the complexity of evaluating the best way of meeting this demand curve.



Source: Energy Information Administration, Electric Power Monthly, prepared by MPSC Staff
http://www.eia.doe.gov/cneaf/electricity/epm/epm_sum.html

Forecasting Methods

The regional forecasts represent composite projections made by individual participants. Southeast Michigan's forecast is based almost exclusively on Detroit Edison's projections. Detroit Edison's forecast was updated in March of 2005 and is for the period 2005 through 2019. Growth rates (1.76% for energy and 1.30% for demand) were applied to the 2019 forecast data to trend the demand and energy forecasts from 2019 through 2025. The economic parameter forecast has been created by DTE Energy's corporate economist and is based upon data and forecasts from Global Insight and Blue Chip Economic Indicators. The economic parameters of Detroit Edison's forecast include: U.S. and Detroit car and truck production Detroit steel production, Detroit and Ann Arbor non-manufacturing employment, Detroit index of coincident indicators, U.S. FRB industrial production index and Detroit and Ann Arbor Housing permits. The Detroit and Ann Arbor non-manufacturing employment and the U.S. FRB industrial production index parameters are based on the North American Industrial Classification System (NAICS) rather than on the Standard Industrial Classification (SIC).

The forecast of the balance of the Lower Peninsula includes Consumers Energy, Wolverine Power Cooperative, municipal utilities and several other utilities, with Consumers Energy's forecast contributing the majority of the forecasted load.

Consumers Energy's forecast was updated in April of 2004 and is for the period 2005 through 2019 with all years after 2009 based on forecast trends. Annual adjustments to energy (848 GWh) and demand (330 MW) were applied to the 2019 forecast data to trend the demand and energy forecasts from 2020 through 2025. The economic parameter forecast has been created by Consumers Energy and is based upon data and forecasts from Global Insight and include: the U.S. industrial production eight sector average, the Michigan industrial production six sector average, the composite Michigan transportation index and Michigan housing starts. Consumers' key forecast inputs also include cooling-degree and heating-degree days based on a fifteen-year average, an adjustment for leap days as appropriate and adjustments have been made for expected major industrial plant closings. Consumers' forecasts are based on the following:

- Residential class forecasts were developed from projections of customer growth and average use per customer and were based on regression modeling.
- Commercial forecasts were developed using regression analysis that quantifies the influence of time-series trends, weather conditions and seasonal factors on monthly commercial class usage.
- Industrial forecasts (GM/Delphi and Industrial Other usage) were developed using regression analysis.
    - The GM/Delphi forecast quantifies the influence of Michigan Transportation Equipment sector economic activity, seasonal factors and historical plant closings and efficiency improvements on quarterly usage of General Motors and Delphi accounts.
    - The Industrial Other forecast quantifies the influence of U.S. and Michigan industrial production activity and seasonal factors on the quarterly usage of industrial customers other than General Motors, Delphi and one Dow Chemical account.
- Other class forecasts include street lighting and interdepartmental usage and were developed using regression analysis.
- Summer peak forecast was developed using regression analysis that quantifies the influence of customer growth, average usage of the industrial class and other class customers during the months of July and August, average temperatures on the day of the system peak, the peak day average dew point temperature variance and estimated impacts of extreme weather conditions.

Wolverine Power Cooperative's forecast was updated in 2004 and is for the period 2005 through 2018. Growth rates (3.0% for energy and 3.3% for demand) were applied to the 2018 forecast data to trend the demand and energy forecasts from 2019 through 2025. Wolverine's forecast is developed at the member-distribution cooperative level and rolled up to create a single Wolverine system forecast, which includes transmission system losses and own use. This fifteen-year forecast is updated annually. County level demographic projections are taken from Woods & Poole Complete Economic and Demographic Data Source and from the National Planning Association Regional Economic Projections Series. Wolverine's various forecasts are based on the following:

- Residential sales, which comprise the majority of sales in all four of the member cooperatives, is forecast by combining independent projections of consumers and use per consumer using a combined time series, cross sectional econometric model and includes variables for real electric price, heating-degree and cooling-degree days adjusted by the trend in equivalent air-conditioning
- Seasonal sales are forecast using separate econometric equations

- Commercial and industrial forecasts are based on both facility-specific individual forecasts for short-term forecasting and aggregate econometric models for long-term expansion projects
- Street and highway lighting accounts, public authorities and irrigators, which represent less than 2% of total Wolverine sales, is based on simple trending

The Lower Peninsula municipal forecast is based upon past individual trends of each individual municipality taking into account specific customer information that is available to the municipality at the time of the forecast and is for the period 2005 through 2025. Growth rates (3.25% for both energy and demand) were applied to the 2014 forecast data to trend the demand and energy forecasts from 2014 through 2025. The City of Lansing was reported separately and the growth rates applied for the period 2014 through 2025 was 2.0% for both energy and demand.

The Upper Peninsula's forecast reflects the aggregation of several investor-owned utilities and municipal utilities. Three of the five investor-owned utilities in the Upper Peninsula are multi-state utilities and generally forecast loads on a system-wide basis. These system-wide load forecasts utilize econometric forecasting methods. The investor-owned load forecast for the Upper Peninsula was derived by various allocation methods. The load forecasts for the remaining two Michigan-only investor-owned utilities and two municipal electric utilities reflect the use of general historical load growth trends. Due to the economic situation in the Upper Peninsula, these load growth trends have been minimal. These Upper Peninsula forecasts cover the period 2005 through 2013, 2014 or 2015 depending upon the utility, with average combined growth rates (0.89% for energy and 0.89% for demand) applied to the 2014, 2015 or 2016 forecast data to trend the demand and energy forecasts through 2025.

Impact of Energy Efficiency

The electric forecast prepared by the Demand Work Group includes some consideration of "business as usual" energy efficiency. For example, appliance efficiencies mandated by the federal government are considered. Other states have demonstrated that energy efficiency programs and more aggressive energy policies can achieve energy savings that go beyond current federal standards and the "business as usual" policy. These programs include utility sponsored energy efficiency investments and regulatory standards adopted by the states, such as new building standards. Michigan has had experience with utility programming during the first half of the 1990s. During that period, both Consumers Energy and Detroit Edison undertook sizable energy efficiency and load management programs that produced energy and demand savings in Michigan. Although Detroit Edison retains two load management programs, no new energy efficiency programming has been undertaken by the utilities since the mid 1990s.

There are two methods to estimate the energy efficiency potential in Michigan. The first represents a bottom-up approach. This approach involves identifying specific programs, for example accelerating the retirement of old, inefficient refrigerators through financial incentives. The method would involve arriving at an estimate of the number of such refrigerators and the likely number of owners who would retire their old refrigerator for the incentive payment. It would also involve estimating the savings that each retirement might provide and summing these savings over all the participants. Through this method, one could estimate the potential energy savings of the program. There are numerous other types of programs for residential, commercial and industrial customers. By summing up the impact of all such programs, it is possible to estimate the potential savings through energy efficiency programming. It is also possible to estimate the cost of these savings by summing the incentive payments, administrative costs and any indirect or participant costs that might be included in an economic assessment of the programs.

This bottom-up approach was the method relied upon in the Michigan Electric Options Study (MEOS) undertaken over the period of 1985-1987. The study estimated potential energy and demand savings for Michigan through 2005, over a 20-year period. Based upon this approach, the MEOS report estimated the following savings – along with estimated cost to achieve (or cost of conserved energy) – for Michigan's customer classes as a percent of total estimated class sales:

Description	**Residential**	**Commercial**	**Industrial**	**Total**
Percent of Sales	17.2%	7.2%	1.6%	7.9%
Cost of Conserved Energy Cents/kWh	1.0-2.0	1.0-2.5	.05-1.0	

This bottom-up approach to estimating both demand and energy programming has been used in a number of jurisdictions throughout the United States.

Although discontinued by Michigan's major electric utilities, traditional utility energy efficiency and load management programming has continued in a number of other states. Based upon program evaluation results being reported for those states and based upon estimated impacts from regulatory changes like building standards, information is available to estimate the energy savings potential in Michigan. Recently, the American Council for an Energy-Efficient Economy (ACEEE) prepared and issued a report entitled "Examining the Potential for Energy Efficiency to Help Address the Natural Gas Crisis in the Midwest" in January 2005. Although the report was primarily aimed at natural gas, substantial space was devoted to electric energy savings as well. The report included estimated electric savings for Illinois, Indiana, Iowa, Michigan, Minnesota, Missouri, Ohio and Wisconsin. The report estimated electric savings for each state in the region from both traditional utility programs and regulatory changes. The state data, including Michigan-specific electric saving estimates, covered the time frame being addressed by the Capacity Need Forum. We believe that this report provides useful information for developing an energy efficiency, or conservation, scenario for use by the Integration Work Group of the Capacity Need Forum.

ACEEE's overall estimated of achievable energy savings for Michigan are based upon a concerted, statewide program to implement energy efficiency through multiple venues as a mater of public policy. For example, it would include legislation to tighten Michigan's building code to promote energy efficiency as well as requiring extensive replacement of inefficient lighting or appliances through traditional utility or non-utility programming. In total, ACEEE estimated the following savings (as a percentage of statewide sales) available to Michigan:

Year	Percentage of Total Sales
2006	1.90
2007	2.55
2008	3.20
2009	3.85
2010	4.50
2011	5.05
2012	5.60
2013	6.15
2014	6.70
2015	7.25
2016	7.80
2017	8.60
2018	9.40
2019	10.20
2020	11.00

The ACEEE report is based upon a review of both utility and non-utility programs from other states. Among the important assumptions made in the report are that 50% of the savings would come from utility programs and 50% from non-utility programs and that the overall cost of conserved energy upon which an investment cost should be based is three cents per kWh. The cost to achieve the savings that ACEEE estimated are available in Michigan through utility programming is heavily dependent upon a cost of conserved energy number of three cents per kWh. The ACEEE authors state that this figure represents a typical number that one would expect from a well-run program. This three-cent figure is very similar to the experience here in Michigan with utility sponsored programs. The largest energy efficiency program undertaken in the 1990s was Consumers Energy's reduce the use program. Results from the program are shown below:

Residential Programs:

Program	Energy Savings (GWh)	Demand Savings (MW)	CCE (¢/kWh)
Appliance Recycling	15.33	1.75	
Free Install	13.01	1.97	
Rebate Coupon/Catalog	8.24	0.74	
Water Heater Conversion	3.74	0.52	
Total Residential	27.32	3.02	5.75
Non-Residential Programs:			
Free Install	9.61	3.03	
Direct Rebate	128.29	27.42	
Custom Rebate	90.95	15.71	
Total Non-Residential	228.85	46.16	2.33
Total Program Savings	269.17	51.15	2.82

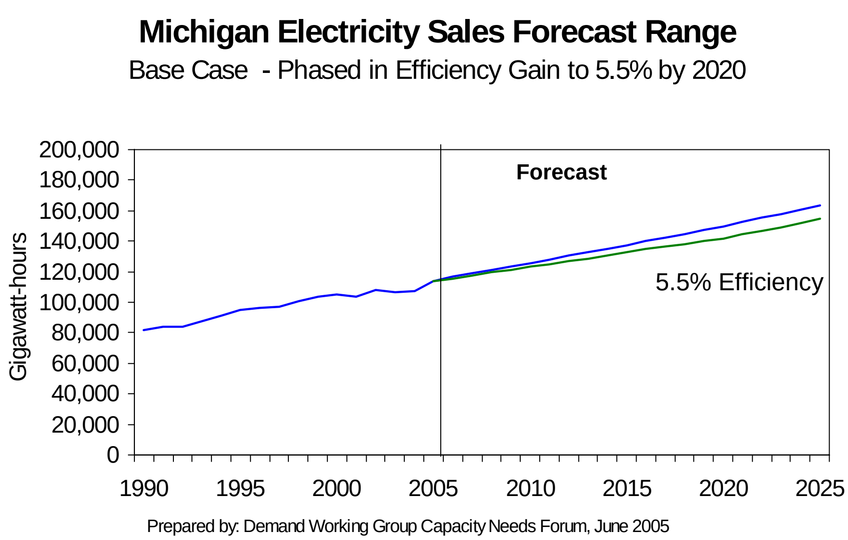
This would seem to indicate that the three cents per kWh for conserved energy would serve as a reasonable estimate of the cost of achieving similar savings today. It should be noted that these figures do not include transmission and distribution losses, which would lower the net cost of conserved energy. Further, evaluation of data from Detroit Edison's contemporaneous programs produced a cost of conserved energy figure of 1.5 cents per kWh.

Both Michigan historical data and data from other states indicate that use of three cents per kWh for conserved energy would be reasonable. However, it should be noted that not everyone reporting the cost of conserved energy from their programs uses the same discount rate or measure lifetime in their calculations. This data is not calculated and reported uniformly. It should also be noted that many of the program results are based upon experience from the West Coast and East Coast. Although ongoing energy efficiency programming is taking place in Wisconsin and Minnesota, the bulk of traditional utility programming is taking place on the west Coast and east Coast. On the other hand, Michigan has not undertaken a large-scale energy efficiency program for a decade and this would seem to indicate that the potential for savings is relatively greater in Michigan than some other states. As a result, we recommend using 50% of the ACEEE savings as an estimate of energy efficiency savings available in Michigan through traditional utility programming.

The results are as follows:

Year	Percentage of Achievable Savings
2006	0.95
2007	1.28
2008	1.60
2009	1.93
2010	2.25
2011	2.53
2012	2.80
2013	3.08
2014	3.35
2015	3.63
2016	3.90
2017	4.30
2018	4.70
2019	5.10
2020	5.50

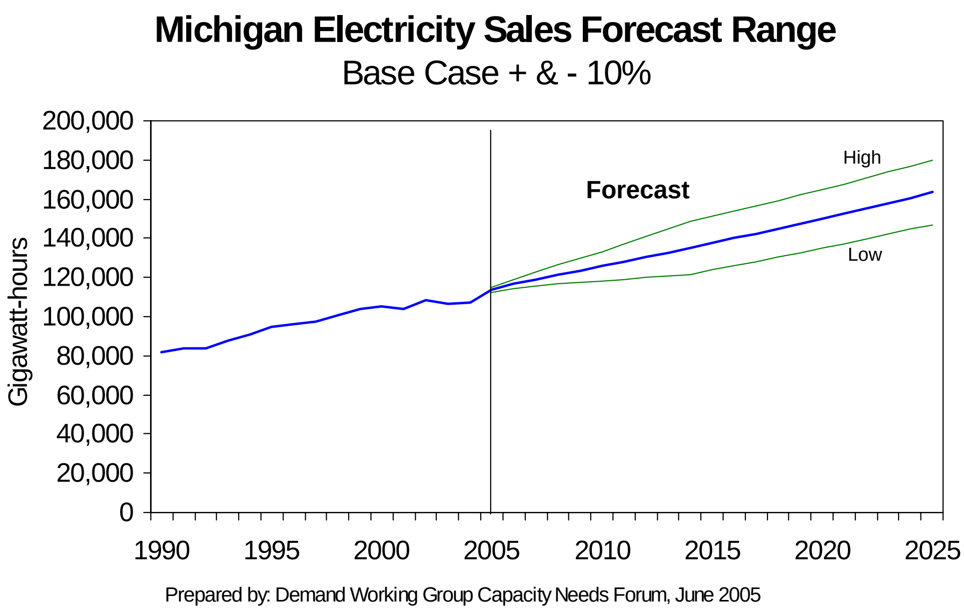
Based upon ACEEE's estimate of an achievable three cents per kWh cost and an average twelve-year measure life, the cost to achieve these savings would be approximately $110 million annually, in 2005 dollars. It is assumed that these policies and programs begin in the year prior to the first year of savings shown and continue over time.



The ACEEE study estimates provide the basis for developing an "energy efficiency scenario." We also recommend that the estimates be used in an "environmental scenario," since the electric efficiency savings may be the least cost option available.

Risk and Uncertainties

In order to assess how robust the selected resource plan is to changes in the growth rate of electric demand, we have provided a base forecast along with a more rapid growth and a slower growth forecast. It is a common feature of energy plans to create scenarios and sensitivities to account for the uncertainty of electric demand forecasts, and therefore a high and low growth case have been developed to gauge the effects that these difference outcomes might have on future planning decisions.



The actual future electricity demand will be higher or lower than our base forecast. The actual course of future demand will be dependent upon numerous factors, like weather patterns, population growth and economic growth to mention a few important factors. If one anticipates normal weather, economic and customer growth will likely drive the eventual growth rate of electricity sales and resulting system requirements in Michigan. A number of participants have indicated that growth is likely to be affected by manufacturing output and employment in Michigan. The past several years have witnessed a steady erosion of manufacturing employment, and it is unclear what the future of employment in this traditionally important employment sector may be over the twenty-year timeframe included in the study. Manufacturing employment is heavily related to the auto and truck industry, which besides experiencing business cycles is facing stiff international competition. The drive to compete will have a continuing impact on Michigan manufacturing employment. This is offset to some degree by the continuing weakness in the U.S. dollar, which makes U.S. manufactured goods cheaper in international markets. Due to the complexity of the factors influencing manufacturing output and employment, the Demand Work Group has not attempted to quantitatively measure forecast contingencies, but recognizes that there are significant uncertainties related to Michigan's manufacturing sector that may have a significant impact on future electricity demand.

The low-growth and high-growth forecasts include the following adjustments to the base forecast:

	2005	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
Low-Growth	+1%	+2%	+3%	+4%	+5%	+6%	+7%	+8%	+9%	+10%
High-Growth	-1%	-2%	-3%	-4%	-5%	-6%	-7%	-8%	-9%	-10%

Attachment I

Base Demand Forecast and Sensitivities

Michigan Electric Peak Demand Forecast

Annual Non-coincident Peak in Megawatts

Base Case

	Southeast Michigan	Balance of Lower Peninsula	Upper Peninsula	Total Demand	Percent Change
Year	Summer	Summer	Summer	Summer	Summer
1990	9,032	8,071	950	18,053	
1991	8,980	8,317	997	18,294	1.3%
1992	8,704	8,121	1,002	17,827	-2.6%
1993	9,362	8,512	950	18,824	5.6%
1994	9,684	8,723	1,040	19,447	3.3%
1995	10,049	9,553	1,098	20,700	6.4%
1996	10,377	9,593	1,118	21,088	1.9%
1997	10,305	9,875	1,055	21,235	0.7%
1998	10,704	9,920	1,115	21,739	2.4%
1999	11,018	10,144	1,152	22,314	2.6%
2000	10,958	9,946	1,169	22,073	-1.1%
2001	12,240	11,102	1,205	24,547	11.2%
2002	11,308	11,907	1,171	24,386	-0.7%
2003	10,470	12,115	1,220	23,805	-2.4%
2004	12,714	11,575	1,258	25,547	7.3%
Forecast					
2005	12,551	10,652	898	24,101	-5.7%
2006	12,896	10,965	903	24,765	2.8%
2007	13,174	11,285	910	25,368	2.4%
2008	13,415	11,626	918	25,959	2.3%
2009	13,648	11,970	926	26,544	2.2%
2010	13,888	12,313	938	27,138	2.2%
2011	14,125	12,663	946	27,734	2.2%
2012	14,377	13,014	953	28,344	2.2%
2013	14,650	13,367	962	28,979	2.2%
2014	14,939	13,724	971	29,634	2.3%
2015	15,218	14,101	979	30,299	2.2%
2016	15,505	14,484	988	30,977	2.2%
2017	15,697	14,871	997	31,565	1.9%
2018	15,898	15,265	1,008	32,171	1.9%
2019	16,108	15,671	1,016	32,794	1.9%
2020	16,318	16,071	1,025	33,414	1.9%
2021	16,532	16,472	1,036	34,040	1.9%
2022	16,748	16,877	1,044	34,668	1.9%
2023	16,967	17,283	1,054	35,303	1.8%
2024	17,189	17,692	1,063	35,943	1.8%
2025	17,413	18,103	1,073	36,589	1.8%

Michigan Electric Peak Demand Forecast

Annual Non-coincident Peak in Megawatts

Low Growth Case

	Southeast Michigan	Balance of Lower Peninsula	Upper Peninsula	Total Demand	Percent Change
Year	Summer	Summer	Summer	Summer	Summer
1990	9,032	8,071	950	18,053	
1991	8,980	8,317	997	18,294	1.3%
1992	8,704	8,121	1,002	17,827	-2.6%
1993	9,362	8,512	950	18,824	5.6%
1994	9,684	8,723	1,040	19,447	3.3%
1995	10,049	9,553	1,098	20,700	6.4%
1996	10,377	9,593	1,118	21,088	1.9%
1997	10,305	9,875	1,055	21,235	0.7%
1998	10,704	9,920	1,115	21,739	2.4%
1999	11,018	10,144	1,152	22,314	2.6%
2000	10,958	9,946	1,169	22,073	-1.1%
2001	12,240	11,102	1,205	24,547	11.2%
2002	11,308	11,907	1,171	24,386	-0.7%
2003	10,470	12,115	1,220	23,805	-2.4%
2004	12,714	11,575	1,258	25,547	7.3%
Forecast					
2005	12,426	10,545	889	23,860	-6.6%
2006	12,638	10,746	885	24,269	1.7%
2007	12,779	10,946	882	24,607	1.4%
2008	12,878	11,161	881	24,920	1.3%
2009	12,966	11,371	879	25,217	1.2%
2010	13,055	11,574	881	25,510	1.2%
2011	13,136	11,777	880	25,793	1.1%
2012	13,227	11,973	877	26,076	1.1%
2013	13,332	12,164	875	26.371	1.1%
2014	13,445	12,352	874	26.671	1.1%
2015	13,696	12,691	881	27,269	2.2%
2016	13,955	13,035	889	27,879	2.2%
2017	14,128	13,384	897	28,409	1.9%
2018	14,308	13,738	907	28,953	1.9%
2019	14,497	14,104	914	29,515	1.9%
2020	14,687	14,463	923	30,073	1.9%
2021	14,878	14,825	932	30,636	1.9%
2022	15,073	15,189	939	31,201	1.8%
2023	15,270	15,555	948	31,773	1.8%
2024	15,470	15,922	957	32,349	1.8%
2025	15,672	16,292	965	32,930	1.8%

Michigan Electric Peak Demand Forecast

Annual Non-coincident Peak in Megawatts

High Growth Case

	Southeast Michigan	Balance of Lower Peninsula	Upper Peninsula	Total Demand	Percent Change
Year	Summer	Summer	Summer	Summer	Summer
1990	9,032	8,071	950	18,053	
1991	8,980	8,317	997	18,294	1.3%
1992	8,704	8,121	1,002	17,827	-2.6%
1993	9,362	8,512	950	18,824	5.6%
1994	9,684	8,723	1,040	19,447	3.3%
1995	10,049	9,553	1,098	20,700	6.4%
1996	10,377	9,593	1,118	21,088	1.9%
1997	10,305	9,875	1,055	21,235	0.7%
1998	10,704	9,920	1,115	21,739	2.4%
1999	11,018	10,144	1,152	22,314	2.6%
2000	10,958	9,946	1,169	22,073	-1.1%
2001	12,240	11,102	1,205	24,547	11.2%
2002	11,308	11,907	1,171	24,386	-0.7%
2003	10,470	12,115	1,220	23,805	-2.4%
2004	12,714	11,575	1,258	25,547	7.3%
Forecast					
2005	12,677	10,759	907	24,342	-4.7%
2006	13,154	11,185	921	25,260	3.8%
2007	13,569	11,624	937	26,130	3.4%
2008	13,951	12,091	954	26,997	3.3%
2009	14,331	12,568	972	27,871	3.2%
2010	14,721	13,051	994	28,767	3.2%
2011	15,114	13,550	1,013	29,676	3.2%
2012	15,527	14,055	1,029	30,612	3.2%
2013	15,969	14,570	1,048	31,587	3.2%
2014	16,433	15,097	1,068	32,598	3.2%
2015	16,740	15,512	1,077	33,328	2.2%
2016	17,056	15,932	1,086	34,074	2.2%
2017	17,267	16.358	1,096	34,722	1.9%
2018	17,488	16,791	1,108	35,388	1.9%
2019	17,719	17,238	1,118	36,074	1.9%
2020	17,950	17,678	1,128	36,756	1.9%
2021	18,185	18,120	1,139	37,444	1.9%
2022	18,423	18,564	1,148	38,135	1.8%
2023	18,663	19,011	1,159	38,834	1.8%
2024	18,907	19,461	1,169	39,537	1.8%
2025	19,155	19,913	1,180	40,248	1.8%

Attachment II

Base Sales Forecast and Sensitivities

Michigan Statewide Electric Sales Forecast
Annual Sales (GWh) Base Case

Year	Southeast Michigan	Balance of Lower Peninsula	Upper Peninsula	Total Sales	Percent Change
1990	39,674	37,716	4,183	81,573	
1991	40,135	38,851	4,838	83,824	2.8%
1992	39,377	39,411	5,052	83,840	0.0%
1993	41,716	40,992	4,880	87,588	4.5%
1994	43,211	42,667	5,281	91,159	4.1%
1995	44,926	44,385	5,390	94,701	3.9%
1996	45,328	45,407	5,567	96,302	1.7%
1997	45,822	45,990	5,578	97,390	1.1%
1998	47,905	46,899	5,702	100,506	3.2%
1999	49,822	48,582	5,577	103,981	3.5%
2000	50,211	48,836	5,839	104,886	0.9%
2001	49,370	49,033	5,415	103,818	-1.0%
2002	51,650	50,695	5,873	108,218	4.2%
2003	50,953	49,898	5,940	106,791	-1.3%
2004	50,268	51,113	6,040	107,421	0.6%
Forecast					
2005	56,758	50,576	6,448	113,782	5.9%
2006	58,552	51,570	6,526	116,648	2.5%
2007	59,857	52,621	6,565	119,043	2.1%
2008	60,982	53,877	6,624	121,483	2.0%
2009	61,979	54,977	6,684	123,640	1.8%
2010	63,037	56,058	6,754	125,850	1.8%
2011	64,098	57,180	6,821	128,099	1.8%
2012	65,186	58,424	6,875	130,486	1.9%
2013	66,315	59,444	6,929	132,688	1.7%
2014	67,509	60,598	6,991	135,097	1.8%
2015	68,729	61,747	7,053	137,529	1.8%
2016	69,996	63,029	7,116	140,141	1.9%
2017	71,138	64,077	7,180	142,394	1.6%
2018	72,341	65,259	7,243	144,843	1.7%
2019	73,612	66,474	7,306	147,392	1.8%
2020	74,910	67,693	7,370	149,973	1.8%
2021	76,231	68,923	7,434	152,588	1.8%
2022	77,575	70,164	7,499	155,238	1.8%
2023	78,942	71,417	7,564	157,924	1.7%
2024	80,334	72,682	7,632	160,649	1.7%
2025	81,751	73,959	7,701	163,411	1.7%

Michigan Statewide Electric Sales Forecast
Annual Sales (GWh) Low Growth Case

Year	Southeast Michigan	Balance of Lower Peninsula	Upper Peninsula	Total Sales	Percent Change
1990	39,674	37,716	4,183	81,573	
1991	40,135	38,851	4,838	83,824	2.8%
1992	39,377	39,411	5,052	83,840	0.0%
1993	41,716	40,992	4,880	87,588	4.5%
1994	43,211	42,667	5,281	91,159	4.1%
1995	44,926	44,385	5,390	94,701	3.9%
1996	45,328	45,407	5,567	96,302	1.7%
1997	45,822	45,990	5,578	97,390	1.1%
1998	47,905	46,899	5,702	100,506	3.2%
1999	49,822	48,582	5,577	103,981	3.5%
2000	50,211	48,836	5,839	104,886	0.9%
2001	49,370	49,033	5,415	103,818	-1.0%
2002	51,650	50,695	5,873	108,218	4.2%
2003	50,953	49,898	5,940	106,791	-1.3%
2004	50,268	51,113	6,040	107,421	0.6%
Forecast					
2005	56,190	50,071	6,384	112,645	4.9%
2006	57,381	50,538	6,396	114,315	1.5%
2007	58,061	51,043	6,368	115,472	1.0%
2008	58,543	51,722	6,359	116,624	1.0%
2009	58,880	52,228	6,350	117,458	0.7%
2010	59,255	52,694	6,349	118,299	0.7%
2011	59,611	53,178	6,344	119,132	0.7%
2012	59,971	53,750	6,325	120,047	0.8%
2013	60,346	54,094	6,305	120,746	0.6%
2014	60,758	54,538	6,292	121,587	0.7%
2015	61,856	55,572	6,348	123,776	1.8%
2016	62,996	56,726	6,405	126,127	1.9%
2017	64,024	57,669	6,462	128,155	1.6%
2018	65,107	58,733	6,519	130,358	1.7%
2019	66,251	59,826	6,575	132,653	1.8%
2020	67,419	60,923	6,633	134,975	1.8%
2021	68,608	62,031	6,691	137,329	1.7%
2022	69,817	63,148	6,749	139,714	1.7%
2023	71,048	64,275	6,808	142,132	1.7%
2024	72,301	65,414	6,869	144,584	1.7%
2025	73,576	66,563	6,931	147,070	1.7%

Michigan Statewide Electric Sales Forecast
Annual Sales (GWh) High Growth Case

Year	Southeast Michigan	Balance of Lower Peninsula	Upper Peninsula	Total Sales	Percent Change
1990	39,674	37,716	4,183	81,573	
1991	40,135	38,851	4,838	83,824	2.8%
1992	39,377	39,411	5,052	83,840	0.0%
1993	41,716	40,992	4,880	87,588	4.5%
1994	43,211	42,667	5,281	91,159	4.1%
1995	44,926	44,385	5,390	94,701	3.9%
1996	45,328	45,407	5,567	96,302	1.7%
1997	45,822	45,990	5,578	97,390	1.1%
1998	47,905	46,899	5,702	100,506	3.2%
1999	49,822	48,582	5,577	103,981	3.5%
2000	50,211	48,836	5,839	104,886	0.9%
2001	49,370	49,033	5,415	103,818	-1.0%
2002	51,650	50,695	5,873	108,218	4.2%
2003	50,953	49,898	5,940	106,791	-1.3%
2004	50,268	51,113	6,040	107,421	0.6%
Forecast					
2005	57,325	51,082	6,513	114,920	7.0%
2006	59,723	52,601	6,657	118,981	3.5%
2007	61,652	54,200	6,762	122,614	3.1%
2008	63,421	56,032	6,889	126,343	3.0%
2009	65,078	57,726	7,018	129,822	2.8%
2010	66,820	59,421	7,160	133,401	2.8%
2011	68,584	61,183	7,299	137,066	2.7%
2012	70,401	63,098	7,425	140,924	2.8%
2013	72,283	64,794	7,552	144,629	2.6%
2014	74,260	66,657	7,690	148,607	2.7%
2015	75,601	67,922	7,759	151,282	1.8%
2016	76,995	69,332	7,828	154,155	1.9%
2017	78,251	70,485	7,897	156,634	1.6%
2018	79,575	71,785	7,967	159,327	1.7%
2019	80,973	73,121	8,037	162,131	1.8%
2020	82,401	74,462	8,107	164,970	1.8%
2021	83,854	75,815	8,178	167,846	1.7%
2022	85,332	77,181	8,249	170,761	1.7%
2023	86,837	78,559	8,321	173,716	1.7%
2024	88,368	79,950	8,395	176,714	1.7%
2025	89,926	81,355	8,471	179,752	1.7%

Attachment III

Loss Factor Table
(Applied to Base Forecast 2005 – 2025 to Obtain Net Sales/Demand)

Detroit Edison	6.5%
Southeast Michigan	6.5%
Consumers Energy	7.0%
Balance of Lower Peninsula	7.0%
Upper Peninsula	9.2%

The summer peak demands of Northern States Power, Wisconsin Electric and Wisconsin Public Power Total Company have been prorated based upon Michigan sales.

Appendix C

Central Station Work Group

Introduction

The Capacity Need Forum (CNF) established by the Michigan Public Service Commission (MPSC) in Case No. U-14231 has been charged with the task of developing forecasts of Michigan electric power supply and demand and analyzing different scenarios for resource options that best meet future demands. As a subset of the CNF a Central Station Work Group has been established and charged with three key tasks. These tasks include 1) performing an inventory of current generation assets within the State, 2) forecasting costs associated with construction and operation of most likely new large central generation station technologies, and 3) evaluating siting issues for large central generation stations related to transmission and environmental impacts.

Generation Inventory

The work group decided to evaluate issues within the State in three distinct geographical areas. These areas include the Southeastern Lower Peninsula, "out-state" Lower Peninsula and the Upper Peninsula. Southeastern Lower Peninsula and the out-state Lower Peninsula have important differences because of the heavier concentration of demand vs. generation in the eastern Lower Peninsula compared to heavier concentration of generation vs. demand in the remaining out-state Lower Peninsula area. This distinction is important because of the transmission constraints related to west-to-east energy flow limitations. The Upper Peninsula has issues caused by the lack of transmission interconnections with the Lower Peninsula, its low concentration of load and its heavier ties to Wisconsin compared to the Michigan Lower Peninsula.

One of the tasks assigned to this work group was to provide an inventory of existing generation within Michigan. The purpose was to provide a descriptive summary of the generation and to provide likely service lives, capacities, and fuel requirements for modeling purposes. The MPSC Staff obtained details on generating units collected by the Midwest Independent System Operator (MISO) from generation owners in support of the startup of MISO operations and were reviewed by the generation owners through the CNF work group. This data has been corrected as needed and is presented in summary on the following form:

Michigan Electrical Generating Unit Inventory

Operating Units in Michigan

Eastern Michigan	Summer Capacity (MW)	Winter Capacity (MW)	Maximum Unit (MW)	Minimum Unit (MW)	Ave/Unit Size (MW)	Number of Units	Total Summer Capacity for Units in Age Range: <20 yrs (MW)	20-40yrs (MW)	>40yrs (MW)	Unk Age (MW)
IOU										
Nuclear	1,110.0	1,125.0	1,110.0	1,110.0	1,110.0	1.0	1,110.0	X	X	X
Steam Gas	236.0	236.0	120.0	116.0	118.0	2.0	X	X	236.0	X
Steam Oil	775.0	785.0	775.0	775.0	775.0	1.0	X	775.0	X	X
Steam Coal	7,236.5	7,253.5	750.0	83.0	314.6	23.0	1,025.5	4,053.0	2,158.0	X
Combine Cycle/GT	969.0	1,188.0	82.0	11.0	31.3	31.0	578.0	391.0	X	X
Internal Comb	151.7	151.8	2.8	0.8	2.5	61.0	2.3	146.0	X	3.4
Muni/Coop/Public Auth										
Steam Gas	154.0	154.0	60.0	44.0	51.3	3.0	X	60.0	94.0	X
Steam Coal	286.5	288.5	118.2	20.0	71.6	4.0	266.5	X	20.0	X
Steam Other	30.0	30.0	30.0	30.0	30.0	1.0	X	X	X	30.0
Combine Cycle/GT	25.0	30.0	25.0	25.0	25.0	1.0	X	25.0	X	X
Internal Comb	39.0	40.1	2.5	0.4	1.1	36.0	20.9	7.5	10.6	X
Non-Utility										
Steam Unknown	61.3	61.3	22.0	1.3	15.3	4.0	X	X	X	61.3
Steam Gas	199.0	206.0	199.0	199.0	199.0	1.0	X	X	199.0	X
Steam Coal	1.9	2.0	1.9	1.9	1.9	1.0	X	1.9	X	X
Steam Other	63.6	68.4	63.6	63.6	63.6	1.0	63.6	X	X	X
Combine Cycle/GT	1,502.2	1,515.4	570.0	1.6	65.3	23.0	1,441.5	35.2	X	25.5
Hydro	4.9	6.1	1.9	0.0	0.8	6.0	1.6	X	X	3.3
Internal Comb	76.4	77.2	5.4	0.1	1.0	76.0	21.1	X	X	55.3
TOTAL	12,921.9	13,218.2				276.0				

Western Michigan	Summer Capacity (MW)	Winter Capacity (MW)	Maximum Unit (MW)	Minimum Unit (MW)	Ave/Unit Size (MW)	Number of Units	<20 yrs (MW)	20-40yrs (MW)	>40yrs (MW)	Unk Age (MW)
IOU										
Nuclear	2,820.0	2,898.0	1,060.0	760.0	940.0	3.0	X	2,820.0	X	X
Steam Gas	1,441.0	1,441.0	638.0	52.0	280.9	5.0	X	1,276.0	165.0	X
Steam Coal	2,491.3	2,496.3	737.3	155.0	276.8	9.0	X	1,092.3	1,399.0	X
Combine Cycle/GT	357.8	437.5	30.0	2.0	17.0	21.0	X	355.8	X	2.0
Hydro	94.5	113.4	10.1	0.2	1.4	69.0	5.6	89.0	X	X
Pump Storage	1,871.7	1,871.7	159.1	152.9	156.0	12.0	X	1,871.7	X	X
Muni/Coop/Public Auth										
Steam Coal	782.8	810.2	153.4	10.5	43.5	18.0	X	608.5	154.8	19.5
Combine Cycle/GT	407.3	433.6	73.0	18.0	31.3	13.0	297.3	60.0	X	50.0
Hydro	8.3	8.6	1.0	0.1	0.4	23.0	0.4	1.5	1.3	5.1
Internal Comb	159.1	159.1	7.8	0.1	2.3	70.0	22.4	71.4	42.0	23.3
Wind	0.6	0.6	0.6	0.6	0.6	1.0	X	X	X	0.6
Non-Utility										
Steam Gas	11.3	11.8	9.6	1.7	5.6	2.0	1.7	X	9.6	X
Steam Coal	148.9	158.8	30.0	5.8	16.5	9.0	105.0	X	43.9	X
Steam Other	194.9	203.8	18.4	3.5	13.0	15.0	176.9	X	X	18.0
Combine Cycle/GT	4,895.7	4,909.2	671.3	0.8	119.4	41.0	4,245.3	X	X	650.4
Hydro	21.6	22.2	2.7	0.1	0.6	38.0	8.2	0.1	5.5	7.8
Internal Comb	92.6	167.8	29.0	0.1	1.7	96.0	51.4	X	X	41.2
Wind	1.8	1.8	0.9	0.9	0.9	2.0	1.8	X	X	X
TOTAL	15,801.1	16,145.3				447.0				

UP Michigan	Summer Capacity (MW)	Winter Capacity (MW)	Maximum Unit (MW)	Minimum Unit (MW)	Ave/Unit Size (MW)	Number of Units	<20 yrs (MW)	20-40yrs (MW)	>40yrs (MW)	Unk Age (MW)
IOU										
Steam Coal	613.0	613.0	90.0	25.0	68.1	9.0	X	551.0	62.0	X
Combine Cycle/GT	23.8	27.5	23.8	23.8	23.8	1.0	X	23.8	X	X
Hydro	138.9	142.1	7.5	0.1	1.1	121.0	14.4	0.6	116.0	7.9
Internal Comb	4.8	4.8	2.8	2.0	2.4	2.0	X	2.8	2.0	X
Muni/Coop/Public Auth										
Steam Coal	82.5	82.5	43.7	12.5	20.6	4.0	X	56.2	26.3	X
Combine Cycle/GT	23.0	24.0	23.0	23.0	23.0	1.0	X	X	23.0	X
Hydro	9.6	9.6	1.6	0.3	1.0	10.0	X	2.0	6.9	0.7
Internal Comb	17.2	17.2	2.5	0.5	1.7	10.0	X	9.0	8.2	X
Non-Utility										
Steam Gas	26.1	27.2	26.1	26.1	26.1	1.0	X	26.1	X	X
Steam Coal	73.1	77.6	50.2	2.4	18.3	4.0	X	64.5	8.7	X
Steam Other - Black Liquor	47.2	50.1	26.0	21.2	23.6	2.0	26.0	21.2	X	X
Hydro	21.8	21.8	5.3	0.4	2.4	9.0	X	1.1	20.7	X
TOTAL	1,081.1	1,097.3				174.0				
Michigan Total	29,804.0	30,460.8				897.0				

Central Station Cost Analysis

The work group first dealt with the issue of selecting the base technologies for which detailed construction and operating cost data would be developed. The options selected were: 1) Pulverized coal (supercritical or subcritical), 2) Circulating Fluidized Bed Boilers (CFB), 3) Nuclear, 4) Integrated Gasification Combined Cycle (IGCC), 5) Traditional combined cycle combustion turbines, and 6) Simple cycle combustion turbines. For pulverized coal it was assumed that new source environmental compliance would require selective catalytic reduction (SCR) for NOx removal, a scrubber for SO_2 removal, a fabric filter or precipitator for particulate control, and some type of sorbent injection for removal of mercury.

Pulverized Coal

Pulverized coal generating units rely on the conversion of coal to a fine dust, which is injected into a boiler and burned as a fuel to produce steam. The steam is used to rotate a turbine, which turns a generator and produces electricity. This process, known as the Rankine cycle, is the basis for steam-based generation throughout the world. A majority of U.S. coal plants operate at subcritical pressures, 2,400 pounds per square inch (psi) or less, with superheat and reheat steam temperatures normally limited to 1050 degrees Fahrenheit. New sub-critical plants can operate at design net plant efficiencies of approximately 9,500 BTU/kWh. Design efficiencies are the heat rates expected at full load and do not include losses to efficiency due to bringing the unit online, ramping up, ramping down, or operating at partial loads. In the mid 1950's supercritical pressure steam plants were introduced which operate at main steam pressures of approximately of 3,600 psi and provide net plant design efficiencies of about 8,900 BTU/kWh.

In order to operate at the higher pressure, supercritical plants require greater capital costs when compared to sub-critical plants. With comparatively low and stable coal prices, this capital cost vs. fuel cost tradeoff resulted in no clear winner between sub-critical and supercritical plants in the U.S. As a result, a mix of both types of plants was built and although both continue to be planned for the future there appears to be a preference to build large supercritical units. Both technologies have performed well throughout the world.

One advantage of supercritical plants is their efficiencies. Since supercritical plants operate more efficiently than sub-critical plants, they require less fuel input for each megawatt hour of electrical production. This means that there are fewer emissions associated with each megawatt hour produced with a supercritical plant. Nevertheless, either plant built new would require a scrubber for sulfur dioxide (SO_2) control, a SCR system for NOx removal, and a fabric filter or electrostatic precipitator for particulate control. The implications of new mercury rules have not yet been determined and therefore the cost to install this control technology has not been included in the cost analysis summary table. A further discussion of the new mercury rule issues can be found later in this report.

Nuclear

Nuclear units also operate on the Rankine cycle, similar to coal fired electric steam generation. The source of fuel, however, is uranium and the heat is produced by fission in a controlled environment. Nuclear power plants in the U.S. have operated with high reliability and excellent safety records. The last generation of nuclear plants built around the time of the Three-Mile Island incident (1979), generally saw significant costs increases as plants were delayed and new regulations forced significant safety design changes. Spent nuclear fuel waste disposal is still an issue that needs resolution. The U.S. government has constructed a waste fuel repository site at Yucca Mountain, Nevada. This site, however, has yet to accept material due to environmental and political issues. Moreover, the decommissioning cost of a nuclear plant is significant and must be considered along with the spent nuclear fuel disposal issue in any decision to build a new nuclear plant.

These older nuclear design units would not be built as a new plant today. Instead there are a number of new reactor designs being proposed by the nuclear industry. If one or more of these proposals result in a standardized design(s), the cost competitive position of nuclear plants could be greatly improved. At this point in time, it is not clear which design(s) and set of costs are likely to be incurred with a new generation of nuclear plants. Further, the long lead times and uncertainties around technology, construction cost and regulatory treatment make it very difficult for any investor to make such a major commitment at this time. The nuclear industry, however, continues to make significant strides in foreign countries, most notably France and Japan. These gains could be captured in the U.S, market if the many issues can be resolved.

There are two factors that have brought nuclear production technology back into considerations. First, nuclear units do not emit SO_2, NOx, Hg, particulate or carbon dioxide, and, therefore, do not contribute significantly to acid rain, ground level ozone, or global warming. From an environmental air emissions viewpoint, nuclear plants offer both low emissions and virtually no risk to new air emission regulations and the associated technology retrofit costs. Second, the fuel needs of nuclear plants can be satisfied from domestic sources providing both low dispatch cost and assured supply.

Circulating Fluidized Bed

Circulating Fluidized Bed Boilers (CFB) has been built throughout the world with hundreds of units currently operating. The size of CFB's continues to evolve with single boilers in the 300 MW size now being offered with dual unit 600 MW systems being planned. These systems are now available with operating conditions equivalent to sub-critical and supercritical PC boilers. The advantage of CFB's is that they offer extreme flexibility in fuel type and coal quality, operate at low combustion temperatures that reduce NOx formation and "fire" a limestone / coal mixture that reduces SO_2 without the need for a wet scrubber system.

The CFB design feeds crushed coal and limestone into a burning bed of solids. This solids mixture utilizes air introduced into the bottom of the bed to constantly re-circulate the coal and limestone mixture while introducing combustion air. Cyclones are utilized to separate entrained particles from the flue gas leaving the combustor and return the hot solids to the combustor. Modern CFB's incorporate superheater, reheater and economizer tube surfaces much like those utilized in PC boilers. A CFB operates at lower fuel combustion temperatures than PC boilers which improves its ability to reduce air emissions and to utilize lower cost steel alloys for the high temperature – high pressure components. SCR's can be added for additional NOx removal and flash dryers can be added for enhanced SO_2 removal.

Integrated Gasification Combined Cycle

Integrated gasification combined cycle (IGCC) is an emerging technology with four coal-fired IGCC facilities in operation today. IGCC technology makes use of two power cycles; these facilities use the Brayton cycle in the combustion turbine and the Rankine cycle in the HRSG cycle. Two of these are demonstration facilities located in the U.S. and two are located in Europe. The two U.S. plants include one in Florida, Tampa Electric IGCC plant employing the GE/ChevronTexaco gasification method and the other in Indiana, the Wabash River Coal Gasification Repowering Project utilizing the E-Gas/ConocoPhillips gasification method. Two additional gasification technologies are in use in Europe, the Shell technology is being used at one plant in the Netherlands and the Prenflo technology is being used at a plant in Spain.

IGCC plants require that coal be gasified by reacting coal with steam and controlled amounts of oxygen under high pressures and temperatures. The heat and pressure result in a synthesis gas (syngas) being formed that is made up primarily of carbon monoxide and hydrogen. The syngas is then combusted in a gas turbine. From this point in the electrical generation cycle the IGCC plant operates like conventional natural gas fired combined cycle units. The IGCC cycle includes an air separation unit to produce oxygen required in the gasification process. Air separation units add significant capital cost to the overall process, require large amounts of station power and add additional availability risk to the electrical generation process cycle.

Although gasifying coal is a commercially proven process and is used throughout the world in the chemical industry, its integration with a combined cycle combustion turbine cycle results in operational complexity beyond that of a PC plant. Generally, the demonstration plants have encountered technical and operational difficulties that have reduced the plants' availabilities. To achieve cycle availability comparable to base load coal or nuclear generation an IGCC plant would need to be built with a spare gasifier. The additional gasification unit would increase the fixed cost of an IGCC unit relative to other generating technologies. The need to maintain high availability and capacity factors comes with an increased cost that needs to be considered in the planning process.

The U.S. demonstration IGCC plants were designed to operate with a bituminous coal source. The use of low cost, low quality high ash content coals will result in a reduction in plant performance results compared to current gasification plants. Current gasifier technology has not been proven to be cost effective with other than bituminous coals. Although IGCC costs utilizing PRB coals are shown in the summary cost table, this data is based on pilot plant comparative data since no commercial size gasifiers are operating on PRB coals.

To date IGCC technology has not been commercially deployed because of its higher capital cost and its technology risk. American Electric Power (AEP) is in the process of performing an engineering scoping study in concert with GE and Bechtel on the design of a 600 MW IGCC plant for 2010 operation in Ohio, West Virginia, or Kentucky with potential plans for a second 600 MW unit for operation at a later date. This would represent the first commercial U.S. application of this technology beyond the demonstration plants currently operating. To offsets the 15-20 percent higher cost of this technology, when compared to traditional pulverized coal systems, AEP is requesting ratepayers contribute to the development costs. At this time it is uncertain if AEP will receive this regulatory subsidy for implementation of IGCC technology.

IGCC technical literature reports that this technology offers significantly lower emission levels for SO_2, NOx and Hg. Due to the high cost of IGCC technology, AEP is proposing to build its first IGCC plants without adding the additional equipment required to achieve these lower emission levels. The costs shown in the following table for IGCC technology do not include the additional capital or operating costs required to achieve emission levels lower than conventional PC plants. One major advantage of IGCC technology that has drawn adherents is the potential of IGCC plants to allow more economic sequestration of carbon dioxide than might be achievable with PC boilers. This would be important should carbon dioxide become a future controlled emission in the U.S., and if sequestration becomes a proven technology. Again, capital or operating costs to achieve carbon sequestration are not known at this time and, therefore, are not included in the technology cost table.

Combined Cycle Combustion Turbines

Combined cycle combustion turbines (CCCT) rely on a two-stage process of electricity production. Although these plants can also utilize #2 fuel oil, the vast majority of CCCT's operate with natural gas as their only fuel option. Natural gas is first combusted and used to turn a gas turbine. The hot exhaust air from the gas turbine is routed though a heat recovery steam generator, which produces steam. The steam is then used to turn a conventional steam turbine, which turns an electric generator for additional electrical energy. By capturing the exhaust gas from the gas turbine in order to produce a steam cycle, the combined cycle plants can reach design net plant efficiencies of 7,200 BTU/kWh. A number of combined cycle plants have been built in Michigan since 2000. These include the CMS DIG (760 MW), Kinder Morgan Jackson (550 MW), Renaissance (Carson city) (546 MW), Mirant Zealand (830 MW), and Covert Township (1,170 MW).

Combined cycle units are relatively efficient, with comparatively favorable emissions characteristics and have been reasonably easy to site and build. The schedule to build a gas plant is estimated to be from one to three years depending on whether the plant built is a simple or combined cycle unit. A coal unit on the other hand is estimated to take approximately seven years from the start until the plant becomes operational. Natural gas plants have one big drawback, however, they are dependent on natural gas prices, which recently have been very volatile. At current natural gas prices combined cycle plants cannot economically serve the role of baseload plant. Instead, these are run only during peak demand or near peak demand conditions. The high current natural gas prices, compared to the electricity market prices and the high reserve margins in the region have resulted in many combined cycles plant projects being delayed or abandoned in the State of Michigan and in neighboring states.

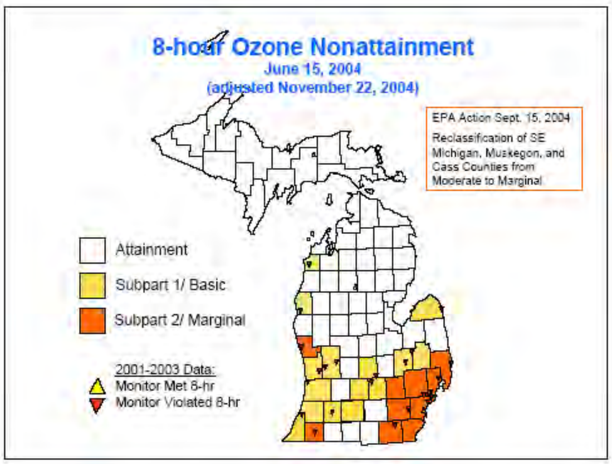
Combustion Turbines

Combustion turbines (CT) are simple cycle plants use the Brayton cycle for power production and are used strictly for peaking or emergency purposes. Many of these plants are dual fuel, capable of operating with both natural gas and fuel oil. The plants use fuel to create a hot gas that spins a turbine, which turns a generator to produce electricity. There is no heat recovery system associated with these plants, and new unit designs can be expected to have heat rates of approximately 10,450 BTU/kWh. These plants can move quickly from investment decision to operation, have low capital costs and low fixed operating but very high variable operating costs due to their low cycle efficiencies and the high cost of fuel.

General

The Technology Price Estimate table on the following page summarizes the Central Station Work Group's estimate of costs and typical emissions profiles associated with construction and operation for each type of plant described above. Plant construction costs include land, boiler, turbine and electrical switchyard components. Plant cooling water, coal transportation and transmission connection costs are unknown until specific plant locations are selected, but have been included as generic costs. Transmission system upgrades necessary to move the power from a new plant to the electrical load centers is not included in any estimates provided and could vary widely dependent on plant location and current transmission design and loadings.

Construction costs are provided as "overnight costs" meaning that any interest costs to finance the plant during its construction period are not included, nor is the effect of inflation included in these overnight costs. Plant costs are assumed for a "green field site" meaning that these units are not being constructed at the site of an existing power plant and can therefore not take any advantage of existing infrastructure. There will be limited opportunities in Michigan to add units at existing plant sites, the exact number of and cost advantage of these are unknown at this time. The fact that many counties in southeastern Michigan have been designated as non-attainment for various environmental pollutants, as reflected in the pictorials below, means that extra measures or costs could be incurred to construct coal-fired power plants near the Southeast Michigan load centers. Depending on siting, it is likely that any new coal plant, regardless of the level of environmental control technology employed, would face resistance. The following maps show the current ozone non-attainment counties in Michigan and the southeastern counties that are also currently designated as non-attainment for PM 2.5 (particulate matter less than 2.5 micron in size). Offsets must be acquired for any new plants constructed in these counties.

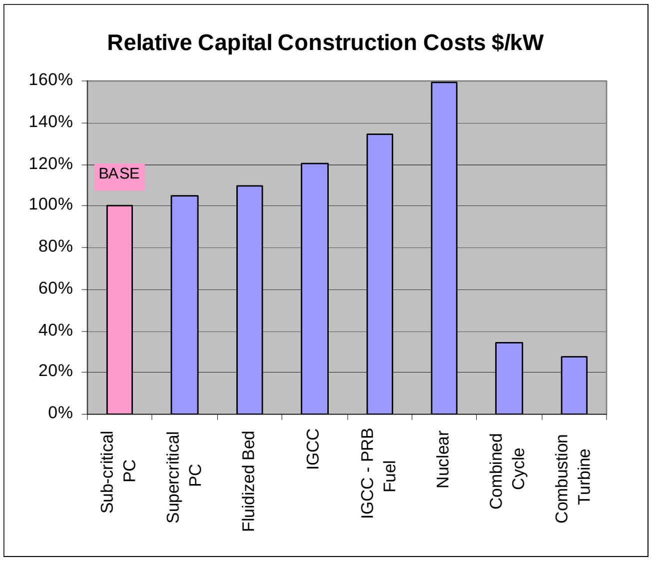


Technology Price Estimates (2005 Dollars)

Technology	Size	$/kW Construction	$/kW Fixed O&M	$/MWh Var. O&M	Design Net Plant Heat Rate BTU/kWh
Pulverized Coal					
Sub-critical	500	1,370	42.97	1.80	9,496
Supercritical	500	1,437	43.60	1.70	8,864
Fluidized Bed	300	1,505	44.77	4.24	9,996
IGCC	550	1,647	59.52	0.95	9,000
IGCC - PRB Fuel	550	1,845	59.52	0.95	10,080
Nuclear	1000	2,180	67.90	0.53	10,400
Combined Cycle	500	467	5.41	2.12	7,200
Combustion Turbine	160	375	2.12	3.71	10,450
	Fuel Cost $/MMBTU	Capacity Factor	Dispatch Cost $/MWh	Fixed Costs (Cap + O&M)	Bus Bar Costs $/MWh
Pulverized Coal					
Sub-critical	1.25	85%	13.67	27.85	41.53
Supercritical	1.25	85%	12.78	29.01	41.79
Fluidized Bed	1.25	85%	16.74	30.27	47.01
IGCC	2.75	80%	25.70	36.70	62.40
IGCC - PRB Fuel	1.25	80%	13.55	40.08	53.63
Nuclear	0.50	90%	6.23	41.79	48.02
Combined Cycle	6.00	45%	45.32	15.58	60.90
Combustion Turbine	6.00	5%	66.41	107.58	174.00

The construction cost estimates shown in this table were completed in 2004 and are based on the EIA/DOE Annual Energy Outlook 2005, a U.S. Department of Energy and National Coal Council report entitled "Opportunities to Expedite the Construction of New Coal-Based Power Plants"[2] and CNF work group member inputs. It should be noted that the construction forecasts do not reflect the current major cost run ups in steel and concrete commodity price that have been the result of China's major building program. Mercury control equipment construction costs and operating costs are similarly not included in the above estimates. Both of these could impact price forecasts by 15 percent or more. As previously stated the above costs do also not include any transmission system upgrade costs that would be required to move the generation to the load demand center.

[2] Opportunities to expedite the construction of new coal-based power plants / Michael J. Mudd, American Electric Power Company, Thomas G. Kraemer, Burlington Northern Santa Fe Railway, Georgia Nelson, Midwest Generation, EMC, LLC. Washington, DC: National Coal Council, 2005



The above chart shows the relative construction costs of the various technologies analyzed. This data is consistent with multiple forecasts reviewed by the work group. For modeling purposes it was deemed more important for cost information on competing technologies to have the correct relative position and magnitude than it was to have precise construction cost estimates developed with a very high level of engineering, which would lower the forecast accuracy risk. In part this was a necessity since more accurate cost estimates are dependent on unit size, permit standards, the specific site location, etc. There are no proposed units currently at a stage that would allow this more specific information to be compiled. As the planning process moves forward and more detailed information becomes available, more specific cost estimates may be possible.

Technology Emission Characteristics

Emission rates are shown for a typical plant assuming PRB coal for the PC, CFB and IGCC units. Data source is the National Coal Council Report (Reference 1) and "Financial Incentives for Deployment of IGCC: A Coal Fleet Working Paper", Senate Committee on Energy & Natural Resources Bipartisan Coal Conference March 20, 2005 Washington DC.

Plant Typical Emissions (#/MMBTU)					
	SO_2	NOx	Particulate	Hg	CO_2
Pulverized Coal					
Sub-critical	0.05	0.08	0.015	1.22E-06	201
Supercritical	0.05	0.08	0.015	1.22E-06	201
Fluidized Bed	0.02	0.10	0.015	1.22E-06	200
IGCC	0.03	0.06	0.006	8.05E-07	195
Nuclear	0.00	0.00	0.00	0.00	0.00
Combined Cycle	0.001	0.03	0.00	0.00	120
Combustion Turbines	0.001	0.03	0.00	0.00	120

Major Assumptions and Issues

Plant Retirements

To perform a long-term analysis integrating generation, transmission and demand, the retirement of existing generation assets must be addressed. Without this considering prospective retirements, the future need for new generation resources will likely be understated. This is particularly true in Michigan due to the age distribution of existing generation assets.

A general review of service lives of Michigan base load generating units showed that 50-55 years was typical for coal based generation constructed before 1950. These retired units can generally be described as small in size, less than 75 MW per boiler, and lower efficiency with heat rates of greater than 11,000 BTU/kWh. The low efficiency was the result of the technology of the time for which boiler-operating pressures were 1,500 psi or less, superheater steam temperature limits were 950 F and systems did not include reheaters or intermediate pressure (IP) turbines.

Since the late-1950’s, the basic thermodynamic design of steam electric generating units has changed little due to metallurgical limits of high temperature steel alloys. In the late 1950’s main steam pressures of 2400 psi with 1000/1000F main steam/reheat temperatures became typical. Modern sub-critical electric central generating units are being built today to these same basic parameters. The most notable change of the last 50 years in sub-critical boiler design has been increased unit output capacity (unit size). A typical late 1950’s unit would have been capable of producing 250-300 MW; new units are now built in the 600-1,000 MW size. The advantage of the increased size is less operating and maintenance costs per megawatt hour of electricity produced.

This work group discussed these issues and agreed that units built since 1950 should expect to realize longer economic life than older units. The group recommends a 60-year retirement age be used for modeling of coal fired generating units. While it is likely that some will retire sooner than 60 years old and some will retire later, 60-years is a good modeling assumption.

Although boiler and turbine components can be economically replaced almost indefinitely there are other issues that will move existing coal fired units towards retirement. Major environmental investment required to meet evolving and ever tightening air emission limits on coal fired electric generating units will create additional economic pressure on smaller and older units. The issues of size, age, component replacements and environmental investment will all work against maintaining these units in service. Support for continued operation of these units comes from high natural gas prices, demand growth and the long lead-time required to permit, design and construct large new central generating units. Support also comes from their costs to ratepayers, which is comparatively low because of their lower construction costs and accumulated depreciation.

Nuclear unit retirement dates were also reviewed by the group. Original plant licenses were granted for 40 years and it now seems that extensions of another 20 years will likely be granted. This 60-year life is in concert with those of coal plants discussed above.

Combined and simple cycle peaking units have both a low capital cost structure and a short construction lead-time requirement. These factors combine to preclude the need to consider retirement dates for these types of units.

Environmental Issues

Environmental issues are prevalent on two major fronts. Permitting for a new coal fired central generating unit will require addressing a number of critical requirements, many of which are currently uncertain or speculative. The uncertainty arises because no new coal units have been placed in service in Michigan since 1985. Therefore, air quality permitting remains uncertain, lengthy and difficult. The other major issue is the uncertainty of future air emission regulations both with regard to tightening of existing limits and the potential regulation of additional combustion byproducts such as carbon dioxide.

To obtain the necessary environmental permits to install a new electric utility generating unit today, the air emission control equipment must meet; 1) the Federal Standards of Performance for New Stationary Sources, commonly referred to as New Source Performance Standards or NSPS, 2) requirements of the New Source Review (either Prevention of Significant Deterioration or Non-attainment Area permitting regulations) program and 3) any applicable Maximum Achievable Control Technology (MACT) requirements for hazardous air pollutants. In addition, any new generating unit must meet all other federal and state emission limitations (i.e., new federal mercury and clean air interstate rules). The most stringent requirement will ultimately drive the emission control equipment specification for each regulated pollutant. NSPS requirements are found in 40 CFR Part 60. The Environmental Protection Agency (EPA) updates these requirements periodically.

The New Source Review (NSR) process requires adoption of either Best Available Control Technology (BACT) or Lowest Achievable Emission Rate (LAER) regulations for major emission sources depending on whether or not the new generation will be located in an attainment area for National Ambient Air Quality Standards (NAAQS). For non-attainment areas, in addition to LAER emission controls, the new source owner must also provide (obtain or purchase) a greater than 1 for 1 offset of any significant increase in emissions of a non-attainment pollutant. Generally LAER requirements are more stringent than BACT; however, that is not always the case. LAER, once specified, can become a default BACT. The major difference in the BACT/LAER determination is that cost is a factor in establishing BACT that is not present with LAER. The EPA maintains a database, in their BACT/LAER Clearinghouse, on BACT and LAER determinations (emission limitations) that have been made across the country. Generally, BACT and LAER are more restrictive than NSPS requirements but it has not been recently updated.

EPA revised its December 2000 regulatory finding issued pursuant to Section 112, removing coal and oil-fired electric steam generating units from the CAA Section 112c source category list. Section 112 addresses hazardous air pollutants (HAPs) like mercury, arsenic, etc., and major sources of HAPs are subject to MACT standards. This means coal-fired electric utility steam generating units are a “delisted source category” from Section 112c and are no longer subject to a MACT regulation. However, in March 2005, the EPA signed two new rules that materially alter future air emissions from power plants. On March 10, 2005 the final Clean Air Interstate Rule (CAIR) was published that will permanently decrease emission caps for sulfur dioxide (SO_2) and nitrogen oxides (NOx) in 28 eastern states. On March 15, 2005 EPA signed the Clean Air Mercury Rule (CAMR). Both new and existing coal fired power plants are affected by CAMR, which proposes a cap-and-trade program in two distinct phases. The first phase creates a nation wide cap of 38 tons beginning in 2010, with a final cap of 15 tons implemented in 2018. Individual states have the opportunity to participate in the nation wide cap-and-trade program or to require their power plants to comply on a more regional or even an individual statewide basis. CAMR also provides mercury NSPS for new electric utility generating units.

Finally, all State air permitting regulations must also be satisfied (i.e, air quality impact analysis, alternate site review, etc.). In Michigan, the federal NSPS, BACT and LAER requirements will be the most stringent emission control requirements for new power plant installations. It should be pointed out that the Michigan Department of Environmental Quality (MDEQ) Air Quality Division is in the process of preparing a revision of the Michigan SIP (State Implementation Plan), for EPA approval. This is intended to establish a Michigan-specific NSR program. The State of Michigan must also prepare a SIP-like plan (rules) for CAMR. If the State implements requirements in excess of those required under CAMR the costs to construct and operate new coal fired electric generation could materially increase and shift the economics of new central generation station towards nuclear or gas combustion turbines. To understand the impact of differing mercury regulations on electrical generation station needs in Michigan the work group has recommended modeling both a Federal and a State only mercury cap-and-trade program.

Michigan has not permitted a new coal-fired power plant since the 1980's. Historically, permitting agencies have evaluated permit applications based upon the level of control placed on the process, and have not mandated that applicants evaluate other alternate processes which may allow the unit to be able to achieve better levels of environmental performance. Recent appeal actions have challenged this review process and are asking that permit reviewing authorities consider alternate processes in the permit review process.

In recent months there have been appeal actions that have challenged the type of coal burning technology chosen by a permit applicant. IGCC has been receiving support and from some groups because of the purported favorable environmental performance, as compared to conventional pulverized coal furnaces of the same generating capacity. An unresolved issue is whether or not IGCC needs to be considered as an alternate technology to conventional coal-fired power plants. Recent permitting activities in EPA's Region V have asked applicants to consider IGCC, but have not forced an applicant to use the technology since some would consider IGCC not to be "commercially available" technology. There has been much debate over the reliability and cost of IGCC technology. If a permitting agency advances an air use permit without a comprehensive and convincing review of IGCC technology, there is a very high likelihood that the permitted use of the conventional pulverized coal-burning technology (Pulverized Coal-Fired Combustion, Circulating Fluidized Bed Combustion, Critical and Super-critical coal-fired boilers) could be contested or appealed. While there appears to be a move towards IGCC technology with several utilities announcing plans to build new generating capacity based upon this new technology in other states, we believe that this technology must be assessed like all other resources by considering its costs, emissions profiles, and operating availability along with those of other generating technologies.

Natural gas and oil-fired boilers would likely be less challenging to permit than coal-fired boilers. All boilers, if of sufficient size, could face additional challenges depending on where they choose to locate. Generally, in "non-attainment" areas (those areas of the state not meeting National Ambient Air Quality Standards for one or more criteria pollutants), there are more stringent environmental standards. Of particular concern to the permit applicant is the requirement to have "emission offsets" previous to constructing the boiler. In effect, the emission-offset requirement obligates the permit applicant to offset the "new" emissions from the boiler by reductions of that pollutant from other sources in the area. Emission offsets could be generated from equipment, which is shut down, or by additional levels of control placed on existing emissions sources. A permit applicant must acquire a greater reduction in the pollutant than they are estimated to emit from the proposed installation. Typically, this requirement is problematic for a permit applicant.

Finally, our review of central station generating options does not include explicit consideration of any future controls related to carbon dioxide. It should be noted that the EPA is not now authorized to develop or promulgated, any rules relating to carbon dioxide abatement. However emissions that may contribute to global warming represent a continuing issue for energy planners. In order to assess the impact that a carbon abatement policy may have on generation options in Michigan, the modeling group will perform one or more environmental scenarios, including carbon mitigation.

Summary

The CNF has identified base load generating unit technologies, cost structures and environmental issues that will form the basis for a State wide integrated resource plan (IRP). While IRP modeling will provide a view of the best economic alternative and mix of generation equipment to meet the future needs of the State, historical lessons indicate that fuel diversity is critical to any future planning effort. The oil embargo of the 1970's, the Three Mile Island incident of 1979 and the current natural gas price spike all show that over reliance on one fuel source can create significant future risk. The work group also notes that a number of technological and policy developments are unfolding that could have an impact on the generating technology selected for Michigan. The work group will continue to stay abreast of these developments and, if needed, will provide updates to this report.

Appendix D

Alternative Generation Working Group

Introduction

In case U-14231 the Michigan Public Service Commission (MPSC) established the Capacity Needs Forum. The goal of this forum is to develop forecasts of optimum power supply and demand for Michigan. As part of the forum, the Alternate Generation Working Group was formed to evaluate nontraditional power supply options that would be feasible within Michigan. Specific tasks include: 1) Define the most promising alternates to traditional generation 2) Quantify the cost structure of these alternatives, and 3) Determine the capacity that could be online within 2009 timeframe and detail the capacity location by three geographic areas in Michigan. (Upper Peninsula, Southeast Michigan, and the balance of Lower Peninsula).

Promising Alternates

The working group decided to evaluate four technologies based on cost, suitability within Michigan, commercial viability, and the availability of data for modeling purposes. The technologies included combined heating and power (CHP), onshore wind energy, landfill gas, and farm based anaerobic digestion. Other technologies that have potential were classified as emerging technologies. They might include, for example, solar electric and solar thermal, small-scale biomass and wind, and small scale CHP. However, production from emerging technologies was not incorporated into the data submitted for modeling purposes to the Integration Work Group. At least to some extent, such technologies will be more easily modeled as reductions to demand, rather than as additions to supply. Thus, it can be assumed that at least some contribution from emerging technologies will be captured in historical demand trends. In the future, it may be possible to more accurately predict market penetration from some of these emerging technologies, in which case they might be explicitly incorporated into one or more demand scenarios. In the meantime, such technologies for renewable energy are being explored through the Michigan Renewable Energy Program's various committees and future MREP reports will provide market penetration estimates.

Unlike central station power, there is relatively little cost and operating history available in the public domain for alternate generation including those identified as promising above. While the work group compiled sufficient data to develop estimated fixed and operating costs and quantities of alternate generation, it should be noted that the results are current estimates and that many of these alternatives are experiencing technological improvements. As more information becomes available, the work group may update findings included in this report.

Combined Heating and Power (CHP)

CHP technology takes process steam generated by industrial or large commercial boilers and passes the steam through a turbine before it is used for its ultimate purpose. In some applications natural gas fires a combustion turbine or reciprocating engine and the waste heat in the exhaust or cooling water is used to make steam, hot water, or direct heat for process use at the site. This technology provides improved fuel efficiency over generation only combustion by utilizing the fuel source twice, once for generation and then for process heat. Such fuel efficiency savings can be up to 60% of a traditional power generation unit. The scale of these installations can range from a fraction of a megawatt per unit to over 1,000 megawatts per unit.

There is an estimated 4,580 MW of CHP currently installed in Michigan. Of this, 2419 MW (52%) of CHP is at the Midland Cogeneration Venture (MCV) and the Dearborn Industrial Generation sites, serving DOW and Ford Motor Company respectively. An additional 990 MW (22%) of installed CHP capacity is at eight different utility-owned sites. The installed base of remaining 26% of Michigan's CHP capacity can be broken down into sectors as follows:

Sector	**CHP MW**
Pulp and Paper	209 MW
Educational	132 MW
Other Automotive	63 MW
Other Industrial	67 MW
Municipalities	17 MW
Hospitals	5 MW
Total	493 MW

Data from the Michigan Boiler Permit database, E-Grid database, and Midwest CHP Applications Center's database, suggests that there is up to 1,471 MW of additional base load capacity for CHP available, the workgroup believes that 37 companies that have large (100,000+ lbs/steam/hr) boilers have the best potential to provide an estimated 1,085 MW of CHP capacity. Capacity by sector is as follows:

Sector	%	Potential
Automotive/Transportation	43%	466 MW
Mining/Metal Forming	18%	193 MW
Pulp/Paper	15%	159 MW
Chemical/Pharmaceutical	10%	108 MW
Food Processing	9%	99 MW
Other	5%	59 MW
Total	100%	1,084 MW

A break down of potential industrial CHP by region follows:

Source of Potential CHP	**ITC**	**METC**	**ATC**
Industrial/Institutional w/ Large Boilers	543	504	37
Industrial/Institutional w/ Mid-sized Boilers	70	209	41
Totals:	613	713	78

A break down of installed and potential CHP by fuel type and by Service Territory is as follows:

	Coal			**Gas**			**Oil**		
	ITC	**METC**	**ATC**	**ITC**	**METC**	**ATC**	**ITC**	**METC**	**ATC**
Installed CHP (Excl. MCV)	2	67	5	1,113	39	50	0	0	67
Potential CHP W/Large Boilers	140	166	0	315	316	17	0	0	0
Potential CHP W/ Mid-sized Boilers	0	18	14	60	175	17	10	12	6
Total Potential	140	184	14	375	491	34	10	12	6

Thus, more than 300 MW of potential CHP could be fired by current coal-fired boiler systems, and more than twice that could be available with current gas-fired boiler systems.

The estimated cost structure for large-scale CHP systems is as follows:

		CHP Coal Fired	CHP Gas Turbine	CHP Gas Engine
Assumptions				
Capital Installed Costs ($/kW)		$1,800	$900	$1,200
Capital Recovery Rate (%)	a.)	14%	14%	14%
Annual Operating Hours		8760	8760	8760
Capacity Factor (%)		85%	90%	95%
Gross Heat Rate (MMBtu/MWh)		10,000	9,200	10,400
Recoverable Heat (MMBtu/MWh)		6,000	3,200	3,300
Efficiency for 150 PSI Steam (MMBtu/MWh)		4,000	6,000	7,100
Fuel Costs $/MMBtu		$3.20	$7.00	$7.00
Resulting Costs per kWh				
Capital Recovery		$0.03	$0.02	$0.02
Fuel		$0.01	$0.04	$0.04
O&M (incremental over process heat)		$0.01	$0.00	$0.01
Average Cost of CHP Power:		$0.05	$0.06	$0.07

a.) For illustrative purposes

Finally, there is concern that much of the current CHP potential is related to the automotive industry, which is currently running at 75% of capacity and trending downward. Given these dynamics, it is probably prudent to reduce the amount of potential capacity from industrial/institutional facilities with large boiler to 1,000 MW, down from 1,084 MW. Further, the difficulty of providing adequate incentive to a large number of major industrials to make major investments in their capital stock for energy purposes when so many other factors affect the viability of their core business must be recognized. Not all those facilities will choose to go forward regardless of the economics. A reasonable level of ultimate development would likely be closer to 50% of the original potential or 547 MW phased in over several years.

The work Group believes it is also important to note that there is a huge untapped potential market for CHP at smaller industrial facilities. Changes in the economics either through a change in fuel costs or technology improvements could lead to rapid deployment. For now they are treated as an emerging technology.

Wind Energy

Wind generation technology is comprised of a generator placed atop a 70-90 meter tower and driven by three 30-meter wind turbine blades. Output of each generator is between one and three megawatts. Groups of turbine generators are located in favorable locations (wind farms) that provide consistent winds with substantial velocity to drive the wind turbines.

Based on NREL data approximately 830 MW of Class 4 (high quality) or higher wind capacity exists on-shore in Michigan. Taking into account siting issues, transmission constraints, the need for large tracts of land to achieve economies of scale, and lack of specific wind data at the potential sites, the workgroup decided to take a conservative approach and estimate approximately 50% or 415 MW of capacity is feasible within the timeframe of the study. Of this amount 95 MW exists in the Upper Peninsula, 50 MW in Southeast Michigan and the balance of 270 MW is available in the remainder of the Lower Peninsula.

The estimated cost structure for Class 4 and higher wind systems is as follows:

Assumptions			
Capital Installed Costs ($/kW)		$	1,200
Capital Recovery Rate (%)	a.)		14%
Annual Operating Hours			8,760
Capacity Factor (%)			25%
Efficiency (MMBtu/MW)			-
Fuel Costs $/MMBtu		$	0.00
Resulting Costs per kWh			
Capital Recovery		$	0.077
Fuel		$	0.000
O&M		$	0.010
PTC (10 Years Only)	b.)	($	0.018)
Average Cost of Wind Power:		$	0.069

a.) For illustrative purposes.

b.) The federal Production Tax Credit (PTC) for wind power was originally enacted as part of the Energy Policy Act of 1992 and was first scheduled to sunset on June 30, 1999. Congress has extended the PTC three times. The last extension is until December 31, 2005. The recently passed Senate energy bill extends the PTC until December 31, 2008. It is very likely that Congress will approve a PTC extension since it has bipartisan support. The PTC will provide a 1.9-cent per kWh incentive for the first ten years of a facility's operation

Capital cost was based on five 1.5 MW wind turbines at an elevation of 80 meters. These costs are based on an estimated 25% annual capacity factor and monthly on and off peak average wind speeds to calculate capacity factors that would equate to the 25% annual number. Capacity factor calculations are difficult for wind generation because wind speed varies due to climatic conditions. The following capacity factors used by the workgroup are based on average wind speed at the Muskegon Airport:

Month	Weighted Average Wind speed	On-peak Wind speed	Off-peak Wind speed	On-peak Cap. Factor	Off-peak Cap. Factor	Weighted Capacity Factor
January	8.52	8.68	8.19	45.66	37.44	41.55
February	8.21	8.47	7.70	42.42	31.11	36.77
March	7.61	8.06	6.72	36.56	20.68	28.62
April	7.60	8.00	6.81	35.75	21.52	28.63
May	7.34	7.99	6.05	35.61	15.09	25.35
June	6.42	7.18	4.92	25.84	8.12	13.98
July	5.94	6.73	4.37	21.28	5.69	13.48
August	5.59	6.35	4.05	17.88	4.53	11.20
September	6.63	7.17	5.55	25.73	11.65	18.69
October	6.57	6.84	6.03	22.34	14.94	18.64
November	7.67	8.01	6.98	35.88	23.18	29.53
December	7.69	7.86	7.36	33.90	27.17	30.54
Total	**7.15**	**7.61**	**6.23**	**31.57**	**18.43**	**25.00**

Landfill Gas

Landfill gas technology involves extraction of methane gas produced from buried waste in landfills and using the gas to fuel micro turbines to produce electricity. In the past the methane would be typically flared and if the gas was not flared, a greenhouse gas would be emitted. Since the methane gas production is anaerobic (absent the presence of oxygen), the rate at which methane is extracted is somewhat limited. If it is extracted too rapidly, oxygen will be pulled into the buried landfill and the anaerobic process will be disrupted. However, technology and operating experience have developed sufficiently so that landfill generators can now produce electricity to follow load.

Currently there are 79 MW of landfill gas generators in Michigan. Expansion potential at these sites is estimated to be 54 MW to provide 123 MW of capacity. New sites are also expected to be developed and provide another 104 MW of capacity over the next ten years. The geographic locations of these sites and existing and potential capacity are:

	Existing	Expansion	New	Total
Upper Peninsula	0	0	2	2
SE Michigan	53	29	62	144
Balance of Lower Peninsula	26	15	40	81
Total	79	44	104	227

Since new landfill gas sites will be smaller in size, require transmission, and will not likely be able to utilize the existing interconnect, the capital costs are approximately 30% higher than expansions at existing sites. The typical unit size is 800 KW and all expansion would be in 800 KW increments. Capacity factors were based on sufficient landfill gas being available for all on-peak periods to provide full generator output.

The estimated cost structure for landfill gas generation follows:

Assumptions		New	Expansion
Capital Installed Costs ($/kW)		$ 1,200	$ 1,000
Capital Recovery Rate (%)	a.)	14%	14%
Annual Operating Hours		8,760	8,760
Capacity Factor (%)		90%	90%
Efficiency (MMBtu/MW)		10,000	10,000
Fuel Costs $/MMBtu		$ 1.80	$ 1.80
Resulting Costs per kWh			
Capital Recovery		$ 0.021	$ 0.018
Fuel		$ 0.018	$ 0.018
O&M		$ 0.030	$ 0.030
Average Cost of Power:		$ 0.069	$ 0.066

a.) For illustrative purposes

Based on operating experience of existing facilities, both new units and expansions will be capable of achieving 95% annual availability rates. Incremental emissions are considered to be zero because of the need to otherwise flare the methane generated by the landfill.

Anaerobic Digester

Like landfill gas, anaerobic digesters produce methane from farm waste (typically cattle waste) and use it to fuel reciprocating engines for power generation as well as for farm heat. Farm digesters require that a digester dome be constructed to capture the methane as it is produced. This process becomes economically feasible for herds of over 500 head of cattle. Due to the manure management practices of different types of farms, this usually means that large dairy farms are the most likely candidates for anaerobic digesters. We estimate that there are farms in Michigan that could use anaerobic digesters to produce approximately 51 MW. The geographic locations of these farms are:

Upper Peninsula	2
SE Michigan	5
Balance of Lower Peninsula	44
Total	51

It should be noted that very limited cost and operational data is available. The group's best estimate of cost is as follows:

Assumptions			
Capital Installed Costs ($/kW)		$	2,500
Capital Recovery Rate (%)	a.)		14%
Annual Operating Hours			8,760
Capacity Factor (%)			90%
Efficiency (MMBtu/MW)			10,000
Fuel Costs $/MMBtu (fertilizer replacement)		($	0.00)
Resulting Costs per kWh			
Capital Recovery		$	0.044
Fuel		$	0.000
O&M		$	0.025
Average Cost of Power:		$	0.069

a.) For illustrative purposes

Summary:

The four technologies studied have the potential to provide nearly 1,200 MW of capacity in the near to mid term. The capacity and cost by technology is:

Technology MW $/kWh

CHP - Coal	182	$.052
CHP - Gas	365	.061
Landfill – Expansion	44	.066
Landfill – New	104	.069
Anaerobic Digester	51	.069
Wind	415	.069
Total	**1,161**	**$.064**

This analysis did not include any incentives for emission reductions or any subsidies for green/renewable energy programs. It does assume that the current wind energy production tax credit. Program will be extended. Such programs can drastically improve the cost structure of the four technologies that were evaluated.

Alternate generation resources can play a significant role in capacity growth within the State of Michigan. Due to smaller size and lower environmental impacts alternate units could be brought on line within a shorter timeframe than central station power plants. This generation could provide a stopgap solution to projected capacity needs.

Extensive data analyses have been performed to support the conclusions in this report. Information detailing the data compiled and analyses undertaken is described in the following reports:

CHP Summary Data
Hourly Wind Capacity Factors
Michigan Wind Energy Potential
Landfill Gas Cost Data
Anaerobic Digester Cost Data

These reports are available on the CNF website at the following address:
http://www.cis.state.mi.us/mpsc/electric/capacity/cnf/othergen/other.htm

To learn more about these topics, the reader is encouraged to visit the CNF website and consult the Alternate Generation Work Group's products.

Emerging Energy Technologies

As noted in the beginning of this report, there are a number of emerging energy technologies that could play a significant role in satisfying Michigan's future electric needs. Unfortunately, at this time, there are too many unknowns associated with these technologies to make any reasonable projections of the contributions they might make to Michigan's energy future.

Solar Photovoltaic Systems

Photovoltaic (PV) technology, including some commercial applications, has been in existence for decades. It was born in the U.S. in 1954 when Bell Labs researchers developed the first silicon photovoltaic cell. However, for purposes of the Electric Capacity Forum and utility scale electric generation, PV systems are still fairly expensive. This is due in part to the high cost of semi-conductor materials. For purposes of the CNF, this technology is still considered an emerging technology. It should be noted, however, that PV systems are already cost effective in many niche applications (e.g. calculators, watches and other small consumer products, mobile highway signs, solar attic fans, battery charging on boats and recreational vehicles, etc.).

PV costs continue to drop and PV technology has many attractive attributes including no air pollution and peak production in the summer when electric demand is high. Distributed PV systems, like other distributed energy resources, can help to minimize line losses and improve system reliability. PV systems are popular with the general public and progress with building-integrated systems is helping to minimize aesthetic concerns. PV systems could be considered a demand-side measure that could help reduce peak electric power demands, assuming that customers were provided a sufficient incentive.

Urban Wind Generators

The wind generators we are most familiar with have horizontal axis blades. McKenzie Bay International is developing vertical axis rooftop wind turbines. Wind resource evaluations are being performed for a number of buildings including a 22-story condominium complex in downtown Toronto and five Michigan sites. Vertical axis wind generators are also being considered for the Freedom Tower that will be built on the former site of the World Trade Towers in New York City. The Freedom Tower is to rise 70 floors and be topped by wind turbines that designers predict will provide 20 percent of the building's electricity. If plans to commercialize the technology are successful, these systems are likely to be cost competitive in many installations.

New types of small wind generators are being developed for use by homeowners. For example, Aerotecture, a small company in Illinois, is developing a 1500-watt wind generator for urban use. The generator could be installed on the roofline of a house and would have very low startup speeds. According to the manufacturer, the low speed operation and rigid structure eliminates maintenance and noise concerns and improves performance throughout the year. Unless combined with battery storage, however, it is not likely that these systems would significantly reduce peak loads. In Michigan, wind speeds tend to be low during the same weather patterns that lead to the highest demands for air conditioning, and therefore the highest summer peak loads.

Off Shore Wind Generators

New wind energy resource maps for Michigan indicate a significant energy resource off shore in the Great Lakes. Wind speeds in the offshore areas are considered excellent for wind energy development. Although the costs associated with off shore development are presently higher than on land, it is expected that the superior off shore wind production capability will more than make up for the cost differential. The National Renewable Energy Laboratory has estimated that Michigan has over 44,000 MW of wind energy potential in the area 5-20 kilometers offshore (exclusions include all areas less than 5 km from shore and 2/3 of the area between 5-20 km). In Europe, installed wind generation capacity in off shore areas grew from zero in the early 1990’s to 613 MW in October 2004. An additional 20,000 MW of off shore capacity is now being explored or already under development in Europe. A large number of issues – environmental, economic, regulatory, and technical – would need to be addressed before any development could take place in the Great Lakes. However, it is expected that significant development could occur during the 15-year time horizon being addressed by the CNF.

Fuel Cells

Fuel cells use hydrogen or hydrogen-derived from other fuels, such as methanol, ethanol, natural gas, gasoline, or diesel fuel, to produce electricity. Waste heat from a fuel cell can be used to provide hot water or space heating. More than 2,500 fuel cell systems have been installed as stationary power sources all over the world – in hospitals, nursing homes, hotels, office buildings, schools, utility power plants, and an airport terminal, providing primary power or backup.

According to Allied Business Intelligence, Inc., the current $40 million stationary fuel cell market will grow to more than $10 billion by 2010, and the overall fuel cell energy capacity will increase by a factor of 250, with global stationary fuel cell capacity jumping to over 15,000 MW by 2011 from just 75 MW in 2001. ("Fuel Cell Vehicles to Number 800,000 by 2012, According to ABI," Oyster Ball, New York www.alliedworld.com