



State of Michigan
Jennifer M. Granholm, Governor

Michigan Public Service Commission
J. Peter Lark, Chairman
Laura Chappelle, Commissioner
Monica Martinez, Commissioner

MEMORANDUM

Date: January 3, 2006

To: Chairman J. Peter Lark
Commissioner Laura Chappelle
Commissioner Monica Martinez

From: George Stojic, Director
Operations & Wholesale Markets Division

Subject: Final Staff Report of the Capacity Need Forum

Attached is a two-volume set of the Final Staff Report on the Capacity Need Forum prepared in response to your Order of October 14, 2004, in Case No. U-14231. The Capacity Need Forum included representatives from all stakeholder groups involved in the electric power market in Michigan, including: investor-owned, cooperative, and municipal utilities; customer groups; environmental organizations; alternative electric suppliers; independent power producers; financial organizations; government agencies; electric transmission companies; and regional transmission organizations. The Forum participants estimated the anticipated future power needs of the State, analyzed the appropriate resources for meeting those needs, and discussed the regulatory actions needed to develop those resources. The specific recommendations contained in the Report are the work product of the Staff, and they were discussed and debated by the Forum participants. Some participants have taken exception to some of the recommendations, especially policy recommendations. I believe, however, that Staff's recommendations will be generally supported by most of the participants.

The conclusions and recommendations in the Report are as follows:

- Electric power demand in Michigan is projected to increase at approximately 2.1% annually over the 20-year study period.
- The development of additional resources, in both the short-term and the long-term, would be reasonable and prudent in light of this anticipated increase in demand.
- In the short-term, we recommend a portfolio of low-cost options that can be implemented within the next five years, including: (1) enhanced energy efficiency, (2) additional renewable resources, (3) additional transmission

capacity, (4) combustion turbines for peaking, and (5) load management. These options (particularly energy efficiency, renewable resources, and transmission enhancements) will have beneficial effects for the Michigan economy in both the short- and long-term.

- In the long-term, we recommend commencing a program to build one or two additional baseload coal generating plants in Michigan on a staggered basis, with the first becoming operational about 2011 or shortly thereafter. The further need for additional base load plants (if any) should be assessed on a regular basis in the future.
- From discussions among the Forum participants, it is clear that, due to the risk involved, a new baseload generating plant is unlikely to be financed or built without ratemaking changes to support construction. Accordingly, Staff recommends adoption of a Reliability Option ratemaking model, which emphasizes the need to preserve system reliability and recognizes the public benefit that all customers receive from a new baseload plant.
- Under the Reliability Option, a utility would file an application indicating its need for additional capacity and its plan for meeting that need. If, after a public hearing, the Commission concludes that the utility's plan is the best method of addressing the need, the Commission would authorize the utility to collect a reliability charge from all customers and to include the construction work in progress in its rate base without an AFUDC offset. The Reliability Option would only be available if ownership rights in the plant are extended to other stakeholders and the plant construction is done through a competitive process.
- The least expensive plan selected by the resource model for meeting Michigan's expected electricity demand over the next ten years produces a present value revenue requirement of approximately \$ 29.6 billion. The present cost of meeting Michigan's single year 2005 electricity demand using existing resources is estimated to be \$ 3.3 billion. However, current resources will not be able to meet the projected growth over the next ten years and the State's electric reliability will be compromised unless some action is taken.

The specific details on all of these points are, of course, discussed in much greater detail in the Report.

**Michigan Capacity Need Forum:
Staff Report to the Michigan Public Service Commission**

January 2006

Copies of this report are available from the Michigan Public Service Commission's Web site, at:
http://www.michigan.gov/mpsc/electric/capacity/cnf/cnf_report_1-3-06.pdf

The report was prepared by Operations & Wholesale Markets Division, P.O. Box 30221, Lansing MI 48911-5990. Phone: (517) 241-6070. [Mailto:mpscowmd@michigan.gov](mailto:mpscowmd@michigan.gov).

Acknowledgements

The Capacity Need Forum (CNF) has been conducted as a collaborative effort, comprising participants from throughout the industry. As noted in the July 1, 2005 Status Report, the CNF represents the first major electric energy planning effort coordinated by an agency of the State of Michigan since the Michigan Electric Options Study (MEOS) was completed, in 1985. Since the MEOS study, the need to more fully integrate transmission planning and external markets in the generation planning process has added significant complexity to this study. The CNF's charge to examine and provide guidance on rate-making procedures for new generation also added a goal beyond that of any other previous Michigan electricity planning process. This broad scope of responsibility could not have been successfully completed without the active support of CNF participants. Organizations that participated in the CNF's proceedings are listed in Appendix A. I am grateful for their contributions of time, talents, personal energy, and other resources.

I am also grateful to those individuals who have taken time to travel to Lansing and provide valuable information and insights to CNF participants. For a brief description of these presentations, please see Appendix B. These presenters are:

Jack Hawks, Electric Power Supply Association
Kim Warren, Independent Electric System Operator (Ontario)
Tom Mallinger, Midwest Independent System Operator
Mike Robinson, Midwest Independent System Operator
Jeff Bladen, PJM Interconnection
Vinson Hellwig, Michigan Department of Environmental Quality
Ellen Lapson, Fitch Investor Service
Jonathan Cho, Fitch Investor Service

A number of individuals undertook leadership roles and devoted special attention and expertise to this project. These include individuals who volunteered to serve as the chairpersons of the working groups:

Eric Baker and Kim Molitor, Wolverine Power Supply Cooperative, Demand Work Group
Tom Vitez, International Transmission Company, Transmission & Distribution Work Group
Robert Palmer, DTE Energy, Central Station Work Group
Donald Johns, Michigan Independent Power Producers Assoc., Alternative Generation Work Group
John Dellas, Consumers Energy, Integration Work Group

The assessment of Michigan's electric generating capacity needs could not have been possible without a complex, three-part modeling effort. I am grateful for the dedication and expertise provided by Tom Vitez, International Transmission Company, and Kerry Marinan, American Transmission Company, for power flow modeling and Rao Konidena, Midwest Independent Transmission Company, for reliability modeling. Likewise, I want to thank Charles Adkins and Eric Hughes of NewEnergy Associates for their roles in assuring that the resource expansion modeling was completed in a thorough, impartial, and professional manner.

Finally, I would be remiss in not expressing special thanks to MPSC Staff members Paul Proudfoot, Patricia Poli, Sheila Aleshire, Beth Schafer, Stacy Stiffler, and Tom Stanton for their indispensable assistance in conducting the Capacity Need Forum and preparing this report.

George Stojic, Director
Operations and Wholesale Markets Division
Michigan Public Service Commission

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Table of Contents

TABLE OF FIGURES	v
TABLE OF TABLES	v
EXECUTIVE SUMMARY	1
ES-1. INTRODUCTION AND MAJOR GOALS OF THE CAPACITY NEED FORUM STUDY	1
ES-2. CNF MODELING METHODOLOGY	2
ES-3. MAJOR FINDINGS	2
<i>ES-3.1 Meeting Power Demand with Existing Resources</i>	<i>3</i>
<i>ES-3.2 Long-Term Need for Additional Resources.....</i>	<i>4</i>
<i>ES-3.3 Adding New Resources to Meet Demand</i>	<i>6</i>
<i>ES-3.4 Resource Tradeoffs.....</i>	<i>7</i>
<i>ES-3.5 MPSC Staff Resource Recommendation for Lower Peninsula.....</i>	<i>8</i>
<i>ES-3.6 MPSC Staff Resource Recommendation for Upper Peninsula.....</i>	<i>9</i>
ES-4. OPTIONS FOR MEETING MICHIGAN CAPACITY NEEDS	9
<i>ES-4.1 Recent History of Michigan Electric Generation Resource Additions.....</i>	<i>9</i>
<i>ES-4.2 Existing Commission Policies for New Electric Generation Facilities.....</i>	<i>10</i>
<i>ES-4.3 Proposed Changes to Commission Policies.....</i>	<i>11</i>
ES-5. ORGANIZATION OF CNF REPORT.....	12
1 INTRODUCTION.....	13
2 RESOURCE ASSESSMENT.....	17
2.1 STUDY FORMAT	17
2.2 ELECTRICITY DEMAND FORECAST	19
2.2.1 <i>Energy Efficiency.....</i>	<i>20</i>
2.3 EXISTING MICHIGAN GENERATING ASSETS	22
2.4 NEW CENTRAL STATION OPTIONS.....	24
2.5 ALTERNATIVE GENERATION.....	25
2.6 TRANSMISSION & DISTRIBUTION WORK GROUP.....	26
2.6.1 <i>Lower Peninsula Transmission.....</i>	<i>26</i>
2.6.2 <i>Upper Peninsula Transmission.....</i>	<i>28</i>
2.7 RELIABILITY MODELING.....	30
2.8 RESOURCE MODEL.....	33
2.8.1 <i>Modeling Format.....</i>	<i>33</i>
2.8.2 <i>Modeling Sensitivities.....</i>	<i>33</i>
2.8.2.1 <i>Demand Sensitivity.....</i>	<i>33</i>
2.8.2.2 <i>Natural Gas Sensitivity.....</i>	<i>34</i>
2.8.2.3 <i>Transmission Capability Sensitivity.....</i>	<i>34</i>
2.8.3 <i>Major Model Assumptions.....</i>	<i>35</i>
2.8.3.1 <i>Reliability Constraint.....</i>	<i>35</i>
2.8.3.2 <i>Model Selection Criteria.....</i>	<i>35</i>
2.8.3.3 <i>Resource Screening.....</i>	<i>35</i>
2.8.3.4 <i>Air Quality Rules.....</i>	<i>36</i>
2.8.3.5 <i>Limitation on Resource Adoption.....</i>	<i>36</i>
2.8.4 <i>Modeling Results.....</i>	<i>37</i>
2.8.4.1 <i>Upper Peninsula.....</i>	<i>41</i>
2.8.4.2 <i>Energy Efficiency.....</i>	<i>41</i>
2.8.4.3 <i>Air Quality Programs.....</i>	<i>42</i>
2.9 RESOURCE RECOMMENDATIONS.....	43
2.9.1 <i>Near-Term Resource Options.....</i>	<i>43</i>

2.9.1.1	Combustion Turbines and Combined Cycle Units.....	43
2.9.1.2	Transmission	44
2.9.1.3	Load Management and Energy Efficiency.....	44
2.9.1.4	Renewable Energy Projects	44
2.9.2	<i>Staff Recommendation For Near-Term Planning Period</i>	45
2.9.3	<i>Staff Recommendation for Long-Term Period Planning</i>	46
2.9.4	<i>Staff Recommendation for the Upper Peninsula</i>	48
3	REVIEW OF COMMISSION’S RATE-MAKING POLICY	49
3.1	CURRENT RATE-MAKING METHODOLOGY	49
3.1.1	<i>Rate Base</i>	49
3.1.2	<i>Power Supply Cost Recovery Clause</i>	50
3.2	HISTORICAL EXPERIENCE	50
3.3	RECENT EVENTS.....	51
3.4	MICHIGAN’S RESOURCE NEEDS	54
3.5	CONSTRUCTION OPTIONS.....	55
3.5.1	<i>Merchant Plant Construction</i>	55
3.5.2	<i>MISO Resource Adequacy</i>	55
3.6	ADEQUACY OF CURRENT POLICY	56
3.7	PARTICIPANT RECOMMENDATIONS	57
3.8	STAFF PROPOSAL	58
3.8.1	<i>Staff Recommendation</i>	60
APPENDIX A: LIST OF CNF PARTICIPANTS		A-1
APPENDIX B: SYNOPSES OF CNF PRESENTATIONS		B-1
APPENDIX C: INTEGRATION WORK GROUP REPORT		C-1
APPENDIX D: DEMAND WORK GROUP REPORT		D-1
APPENDIX E: CENTRAL STATION WORK GROUP REPORT.....		E-1
APPENDIX F: ALTERNATIVE GENERATION WORK GROUP REPORT.....		F-1
APPENDIX G: TRANSMISSION & DISTRIBUTION WORK GROUP REPORT		G-1
APPENDIX H: POLICY RECOMMENDATIONS & REPLIES FROM INTERESTED PARTIES TO STAFF POLICY PROPOSAL		H-1

Table of Figures

FIGURE ES-1: LOWER PENINSULA FORECAST DEMAND AND SUPPLY	4
FIGURE ES-2: UPPER PENINSULA FORECAST DEMAND AND SUPPLY.....	5
FIGURE ES-3: CNF TRADITIONAL BASE-CASE EXPANSION PLAN SCHEDULE, 2005-2011	7
FIGURE 1: CAPACITY NEED FORUM WORK GROUP STRUCTURE AND ASSIGNMENTS.....	14
FIGURE 2: MICHIGAN ELECTRICITY HISTORICAL SALES AND PROJECTIONS	19
FIGURE 3: MICHIGAN ELECTRICITY NON-COINCIDENT SUMMER PEAK DEMAND	20
FIGURE 4: ELECTRICITY SALES FORECAST WITH MODELED ENERGY EFFICIENCY PROGRAMMING	21
FIGURE 5: EXISTING MICHIGAN ELECTRIC GENERATING CAPACITY, BY FUEL TYPE AND REGION	22
FIGURE 6: MICHIGAN MAJOR ELECTRIC GENERATING UNIT ADDITIONS, 1952 TO 2004	23
FIGURE 7: LOWER PENINSULA TRANSMISSION IMPORT CAPABILITIES FROM NEIGHBORING MARKETS ...	28
FIGURE 8: ATC ZONE 2 SIMULTANEOUS IMPORT CAPABILITIES FOR 2009 SUMMER PEAK.....	29
FIGURE 9: RESOURCE ADDITIONS FOR ITC AND METC IN TRADITIONAL BASE CASE SCENARIO	38
FIGURE 10: MICHIGAN 2003 SUMMER GENERATION CAPACITY BY FUEL TYPE.....	52
FIGURE 11: MICHIGAN ENERGY PRODUCTION BY FUEL TYPE	53
FIGURE 12: CINERGY AND HENRY HUB WEEKDAY AVERAGE PRICE BY MONTH, JANUARY 2002 THROUGH SEPTEMBER 2005.....	53

Table of Tables

TABLE ES-1: GENERATION OPTIONS INCLUDED IN CNF MODELING	6
TABLE ES-2: ESTIMATED 10-YEAR PRESENT VALUE COSTS FOR CNF SCENARIOS.....	8
TABLE 1: NEW GENERATION OPTIONS MODELED BY CENTRAL STATION WORK GROUP	24
TABLE 2: TECHNOLOGIES MODELED BY ALTERNATIVE GENERATION WORK GROUP	25
TABLE 3: RELIABILITY MODEL FOR LOWER PENINSULA TRANSMISSION REGIONS ASSUMING NO GENERATION FROM OUTSIDE OF MICHIGAN	30
TABLE 4: RELIABILITY MODEL FOR LOWER PENINSULA TRANSMISSION REGIONS ASSUMING GENERATION IMPORTS FROM OUTSIDE OF MICHIGAN	31
TABLE 5: RELIABILITY MODEL FOR LOWER PENINSULA TRANSMISSION REGIONS ASSUMING CONSTRAINTS DUE TO INCREASED TRANSMISSION THROUGH MICHIGAN TO SERVE ONTARIO	32
TABLE 6: RELIABILITY MODEL FOR UPPER PENINSULA.....	32
TABLE 7: REVENUE REQUIREMENTS FOR SCENARIOS AND SENSITIVITIES	40
TABLE 8: ECAR FORECAST SUMMER RESERVE MARGINS, 2005-2014.....	54

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Executive Summary

ES-1. Introduction and Major Goals of the Capacity Need Forum Study

This is the final staff report on the Michigan electric Capacity Need Forum (CNF) initiated by the Michigan Public Service Commission in its October 14, 2004 Order in Case No. U-14231. The purpose was to conduct a comprehensive study of Michigan's electric system in order to determine when the State will need additional electric generating resources and to advise the Commission on its rate-making policies. The study was conducted during the past year and involved the participation of over 160 people from 60 organizations. To complete this study, individuals from this group were divided into five work groups. Each Work Group prepared a separate report on its activities.¹ The Forum received the benefit of the input of many industry experts on important issues related to energy markets and electric generating capacity.

In initiating the CNF, the Commission directed that the report address the following:

1. The anticipated short-, intermediate-, and long-term demand for power.
2. An analysis of the ability to meet projected demands from existing resources.
3. If additional resources are needed, an analysis of the potential resource options that are available within each of the timeframes, including, but not necessarily limited to: (a) technical considerations relevant to various options; (b) anticipated capital and operating costs; (c) relevant financing, ownership, and organizational considerations; (d) risks associated with various options; and (e) a discussion of any synergistic effects or the extent to which the choice of some options may enhance or foreclose others.
4. Recommendations. (Order, p. 4).

The Commission summarized its directions, which called for Staff, utilities, and other interested parties:

...working in unison to accumulate, assess, and evaluate data concerning the construction of new generation capacity and to recommend policies tailored to facilitate the development of new baseload generation facilities in this state. (Order, p. 6).

Thus, the Commission established two major goals for the CNF: (1) determine whether Michigan's electric generating capacity will be adequate to meet the growing demand for electricity, especially given the prospective retirements of some of Michigan utilities' older generating units; and (2) provide guidance to the Commission on rate-making policies and methodologies to recover utility investment in electric generation resource additions.

The first goal was achieved through a major modeling effort involving cooperation among jurisdictional and non-jurisdictional utilities, independent transmission companies, the Midwest Independent Transmission System Operator (MISO), and numerous other parties. This modeling effort resulted in a comprehensive assessment of Michigan's electric generating capacity needs. The Forum also compiled an inventory of Michigan's existing electric generating capacity and completed an examination of many technology options, including: new central station generating facilities; energy efficiency, renewable

¹ Work Group Reports are bound separately, as Appendixes C through G. All CNF Reports are accessible on the MPSC Web site, at <http://www.dleg.state.mi.us/mpsc/electric/capacity/cnf>.

energy, and other non-traditional technologies; transmission expansion options; and opportunities for increased economy-energy purchases, via transmission, from out-of-state markets.

The second goal was to provide guidance to the Commission on rate-making policies and methodologies for allowing recovery of new generating plant investment. Participants proposed various modifications to the Commission's rate-making methodology, and the Staff developed a rate-making approach which focuses on system reliability. This Staff CNF Report includes summaries of those various proposals.

ES-2. CNF Modeling Methodology

The CNF followed a three step process for modeling the Michigan electric system. The first step in modeling was to estimate the transmission capacity available in the base year, 2009. That base year was selected because it coincides with MISO's 2005 transmission expansion plan and therefore provides a consistent basis for modeling both generation and transmission expansions. The state was divided into three regions for analysis, generally reflecting the territories covered by the three major transmission companies that serve the state. Base year transmission capacity was estimated at approximately 3,000 MW into the Lower Peninsula and 500 MW into the Upper Peninsula.

The next step was to use the State's estimated transmission and generation capacity for 2009 to determine if the available capacity will be adequate to serve expected demand. MISO performed the reliability analysis, using a multi-area reliability model called MARELI.

The final step used a dynamic programming model to identify the lowest cost resource combinations available to meet future electricity demands, based on a variety of scenarios and sensitivities. The dynamic programming was conducted by NewEnergy Associates, using its "Strategist" computer model.

ES-3. Major Findings

The major conclusions of the CNF are:

- Peak electric power demand is projected to increase at an annual rate of about 2.1 percent.
- Electric energy use is projected to increase at an annual rate of about 1.9 percent.
- Existing generation resources are presently adequate to meet Michigan demand, with significant reliance on the interconnected transmission system for capacity needed to meet reliability criteria.
- By 2009, unless there are some significant enhancements to existing supplies, growing demand will cause existing electric generation and transmission capacity to be insufficient to maintain reliability standards in the Lower Peninsula.
- Resource enhancements available could include a wide variety of near-term options including additional demand-side options (energy efficiency improvements, load management, and demand-response programs) and generally faster-to-complete supply-side options such as transmission improvements, natural gas combustion turbines or combined cycle generators, renewable energy, and combined heat and power systems.
- New baseload power plants will be needed as soon as the construction schedule allows, which is about 2011.
- Demand growth, coupled with the expected retirements of some of Michigan's existing baseload power plants, will necessitate the addition of multiple replacement plants during the 20-year period of the study.

When viewing the dates for resource additions adopted by the strategist model, the reader should note that 2005 was the first forecast year used by the Integration Work Group. Since 2005 is now past, the initial dates selected by the model for each resource addition type, are delayed by one year. For example, a combustion turbine selected for 2007 should be understood as a combustion turbine for 2008. Throughout this CNF Report, Staff has used the original dates reported by the Strategist model to maintain consistency with the Appendixes. This schedule modification, however, applies only to the schedule for resource additions but not the reliability need identified for 2009.

ES-3.1 Meeting Power Demand with Existing Resources

For the immediate future, Michigan's electric energy resources (generation and transmission) are sufficient to maintain electric reliability in the State. These resources include generating plants owned by traditional utilities, municipal utilities, and independent power producers, along with transmission interconnections to MISO and PJM members.

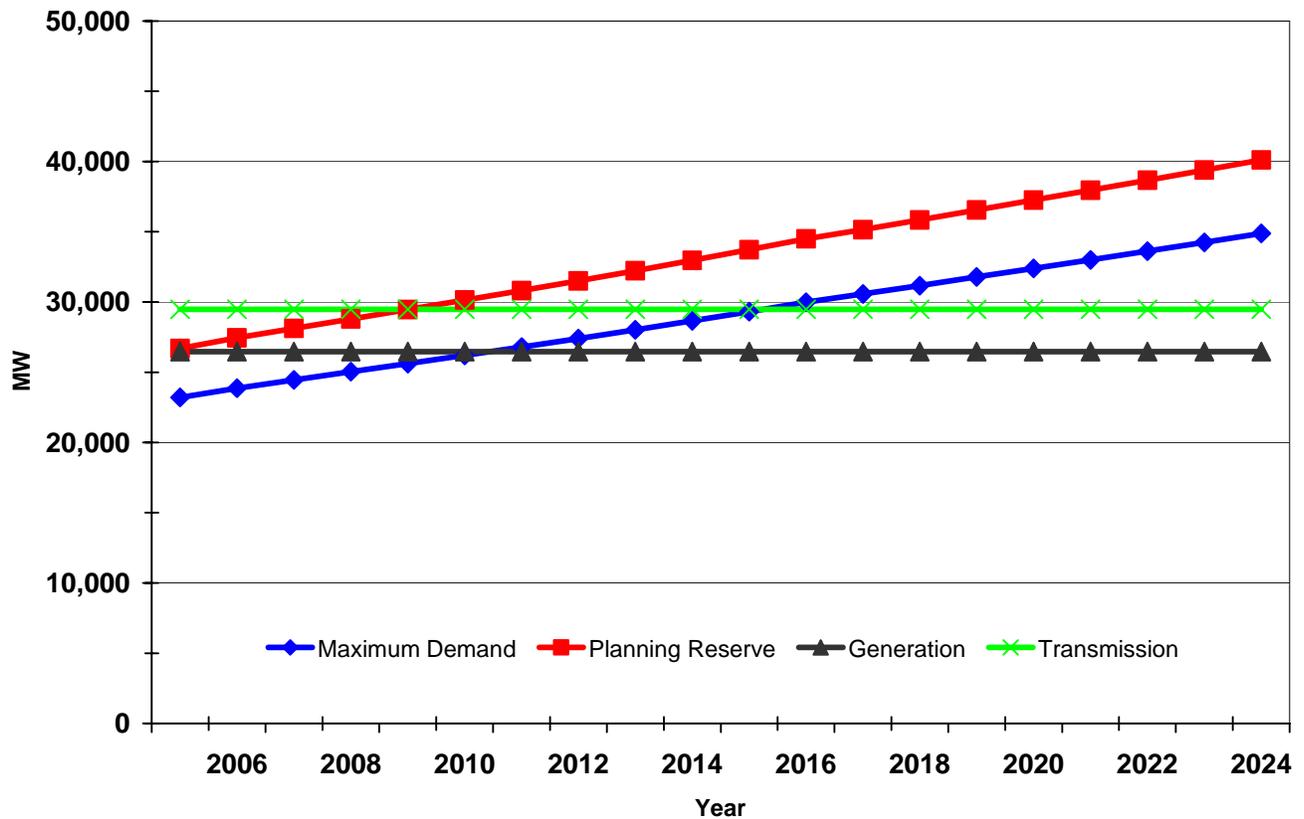
By 2009, however, Southeast Michigan, in particular, and the Michigan Electric Coordinated System (MECS), in general, will not have enough generating and transmission resources to meet electric reliability criteria. Assuming the Lower Peninsula's entire electric transmission system can be devoted to supporting peak demand, an additional 400 to 500 MW of generation or transmission capacity will be needed to satisfy the one day in ten years loss of load probability standard. This deficiency grows with forecast load growth beyond 2009, since, with the exception of a modest increase of renewable power units, Staff is unaware of any generation construction plans in Michigan.

Modeling scenarios have demonstrated that if a significant portion of the Lower Peninsula's transmission capacity is used to move power to Ontario, that capacity will be unavailable to meet Michigan's electricity needs. This could result in an even greater amount of additional generation and transmission capacity being needed to serve the Lower Peninsula in 2009.

ES-3.2 Long-Term Need for Additional Resources

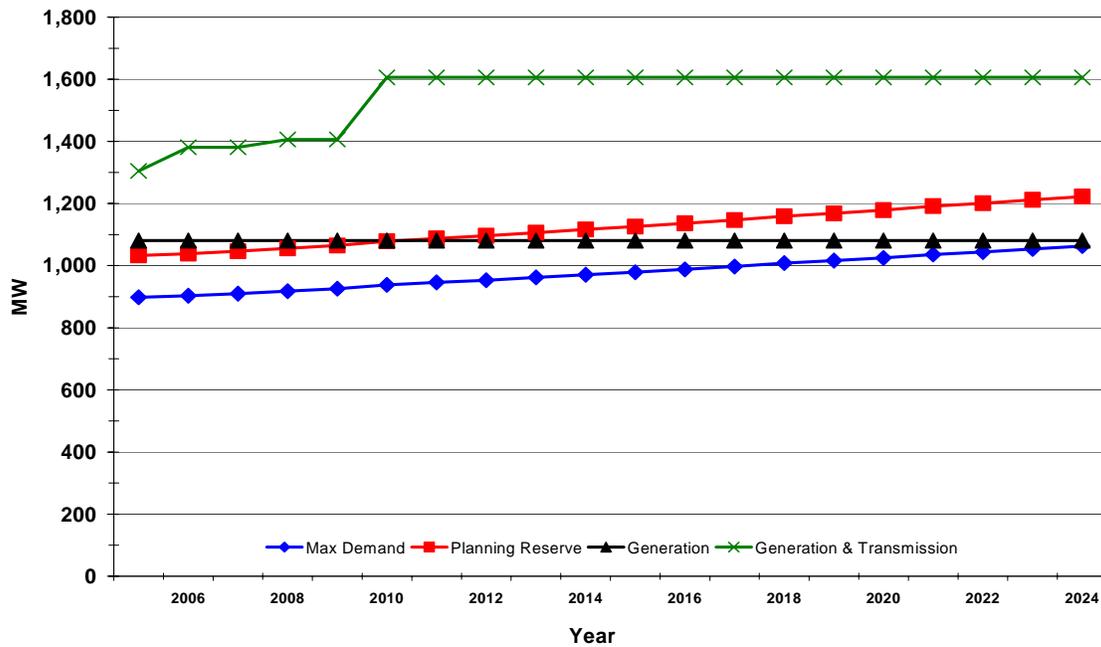
The Integration Work Group has adopted a 15 percent reserve margin for planning purposes. This reserve margin serves as a reliability standard that the resource expansion model plans to meet. In-state reserve margins are projected to decline to approximately four percent in 2009 unless action is taken to remedy this erosion of electric reliability. The need to reach and maintain the 15 percent reserve margin, along with projected load growth, will cause the capacity need to continue growing over the entire study period. Additional capacity is necessary to meet reliability criteria and to assure stable, future prices of electric energy. Depending on the scenario and sensitivity, by the end of 2014, the expansion model selects six to seven thousand megawatts of additional capacity on the Michigan system. The projected need for the Lower Peninsula is summarized in Figure ES-1.

Figure ES-1: Lower Peninsula Forecast Demand and Supply



The Upper Peninsula’s electric generating capacity needs are dependent on American Transmission Company’s successful completion of its Northern Umbrella Project (NUP) on schedule. The NUP, when completed, is intended to connect the Western Upper Peninsula to Wisconsin’s 345 kV transmission system. This will increase transmission capability into the Upper Peninsula from 215 MW today to 500 MW by the end of 2009. Long-term generation adequacy in the Upper Peninsula is also dependent on operation of the Presque Isle coal-fueled power plant. For modeling purposes, Staff has assumed operation of all units at the plant. Units 1-4, however, may be retired in 2012 under terms of the We Energies consent decree with the United States Environmental Protection Agency (EPA). Retirement of these units could undermine Upper Peninsula generation adequacy in the long-term. The Upper Peninsula’s electric capacity supply and peak loads are shown in Figure ES-2.

Figure ES-2: Upper Peninsula Forecast Demand and Supply



ES-3.3 Adding New Resources to Meet Demand

A broad set of possible resources was considered to meet Michigan’s electric generating needs. The resources considered are shown in Table ES-1.

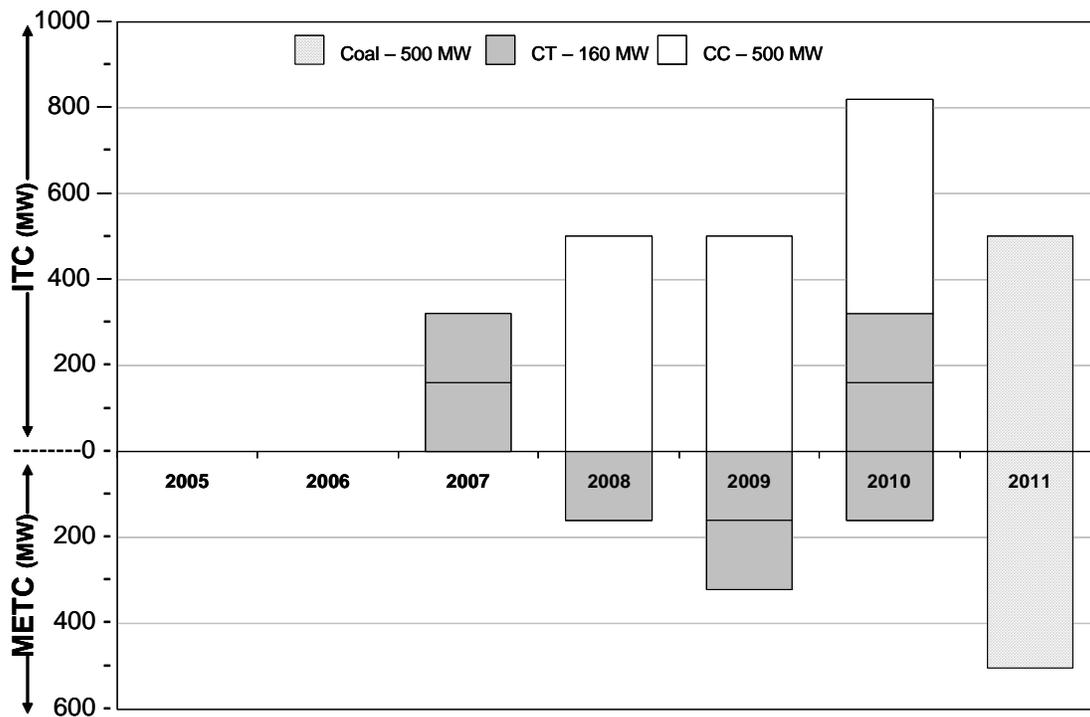
For the Traditional Scenario, the model first selects peaking units. This is due, in part, to the need to maintain reliability standards (reserve margins) and the construction schedules of the various units. The schedules assume at least six years to construct a baseload unit. Although, in the short-term, the capacity expansion model selected natural gas-fired combustion turbines and combined cycle units to satisfy the reliability criteria, reliability needs could also be met through some combination of load management programs, adoption of “short-schedule” renewable energy options, and expanded transmission capacity. For example, Staff estimates that 400-500 MW of load management is available to reduce peak demand.

Table ES-1: Generation Options Included in CNF Modeling

<p>Central station plants:¹</p> <ul style="list-style-type: none"> Pulverized coal, sub-critical (PC) Pulverized coal, super-critical (PCS) Circulating fluidized bed coal (CFB) Integrated gasification combined cycle coal (IGCC) Nuclear Natural gas combined cycle (CC) Natural gas combustion turbine (CT) <p>Alternative Generation plants:²</p> <ul style="list-style-type: none"> Anaerobic Digestion (AD) Combined heat and power (CHP) Landfill gas (LFG) Wind <p>Transmission:³</p> <ul style="list-style-type: none"> First Level Transmission Upgrades, South/North (TIER I) First Level Transmission Upgrades, West/East (TIER I) Major Transmission Upgrades (TIER II)
<p>Notes: ¹ Central station plant types are described in Appendix E.</p> <p>² Alternative Generation plant types are described in Appendix F.</p> <p>³ Transmission projects are described in Section 2.6. ITC has identified transmission upgrades that the company has submitted to MISO for possible implementation in <i>MTEP '06</i>. Those upgrades are identified by ITC as either TIER I or TIER II. Those same TIER identifiers are used throughout this report.</p>

As soon as the model's construction schedules allow, baseload coal units are also selected by the expansion model. Over the first ten years of the planning period, more coal units are selected than combustion turbines or combined cycle units. This indicates a need for baseload generation (high capital cost/low fuel cost resources) to supply energy at stable prices. New generating plants added by the model in the initial years of the planning period are shown in Figure ES-3. Although multiple baseload plants are selected by the model during the first 10 years of the forecast period, Staff does not recommend undertaking a construction program of that scope. Instead, Staff recommends beginning one or two plants on a staged basis and then periodically assessing the need for additional baseload units.

Figure ES-3: CNF Traditional Base-Case Expansion Plan Schedule, 2005-2011



ES-3.4 Resource Tradeoffs

In order to examine alternatives that are available to satisfy future electric generating needs, as requested by the Commission, the CNF examined three scenarios in addition to the Traditional one. The Integration Work Group Report (Appendix C) discusses the scenarios in more detail. These scenarios help identify the tradeoffs between specific resources and their dollar costs. The Integration Work Group also developed and modeled several sensitivities, to further evaluate contingencies possibly associated with each scenario. The scenarios and sensitivities were intended to evaluate risks associated with (a) demand growth; (b) greenhouse-gas emissions regulation; (c) transmission capacity, especially as it may be impacted by Ontario's plan to decommission its baseload coal fleet; and (d) fuel price escalation.²

² Detailed modeling results, including scenarios and sensitivity analyses, are discussed in detail in this report (Section 2.8.2) and the Integration Work Group Report (Appendix C).

In the Traditional Scenario, the model selects a portfolio consisting of combustion turbine, combined cycle, and baseload coal plants. These generating units, however, represent “capacity types” that could be satisfied by a variety of resource options. The Energy Efficiency Scenario indicates that a statewide energy efficiency program, for example, would displace the need for about 593 MW of capacity and 4.5 million MWh of energy, annually, after ten years without a material increase in utility costs over the Traditional scenario results. Or, the model indicates that more extensive use of renewable energy would add modestly to costs, but would also diversify the State’s electric energy resource portfolio through the addition of what could be long-term, fixed price assets.

Table ES-2: Estimated 10-Year Present Value Costs for CNF Scenarios

Scenario:	Traditional	Emissions	Energy Efficiency	Non-Traditional
10-Year Costs (\$ millions):	\$29,641	\$33,544	\$29,803	\$30,369

The 10-year present value cost of each scenario is shown in Table ES-2. The figures include fuel, variable and fixed operations and maintenance costs (O&M), and incremental capital costs (going forward costs) over the first ten years of the planning horizon, aggregated for all existing and new generation plants selected by the planning model in Michigan. The annual 2005 costs for these items are approximately \$3,300 million (\$3.3 billion). However, the current generation and transmission system cannot accommodate the additional load growth forecast for Michigan over the next 10 years. Unless additional generation and transmission is built, Michigan’s electric reliability will be compromised. The costs shown in the above table represent the least cost plan, as modeled for each scenario, that will maintain reliability and satisfy energy requirements.

ES-3.5 MPSC Staff Resource Recommendation for Lower Peninsula

Staff recommends a portfolio of options be used to meet Michigan’s future generating resource needs and to manage contingencies. The near-term need for reliability can be satisfied by load management, combustion turbines, selected renewable energy and other alternative generation options, expanded transmission, and, energy efficiency. Some load management options are being used today, and Staff recommends a more intensive use of similar options where possible. The utilities should examine any tariff and operational modifications necessary to allow these options to be used for satisfying reliability criteria or reserve requirements.

Some renewable resource and alternative generation options have the potential to help reduce total energy costs for some customers. Combined heat and power (CHP) applications, for example, might provide the dual benefits of assisting customers in managing their energy costs while also securing additional capacity support for their interconnected utility system. Staff recommends expanded analysis of CHP and collaborative discussions among all interested parties to identify, and remove, if possible barriers to more widespread adoption of such systems where cost effective.

Other renewable options can become operational fairly quickly. For example, landfill gas systems at existing facilities might be expanded quickly. Other short lead-time, dispatchable renewable energy projects like landfill gas or anaerobic digestion should also be adopted. These generators provide fuel diversity and long-term fuel price stability to a utility's generation mix.

Transmission upgrades also provide greater reliability and enhance the State's capability to access out-of-state power to help meet short-term needs. State supports a more robust transmission system to help maintain reliability in the short-term and; perhaps, might also offer access to new generation outside of Michigan, for help in meeting longer-term power needs.

Staff notes that a baseload unit is selected as soon as the schedule permits, even under the scenario which models the most restricted growth in demand and sales. The Energy Efficiency Scenario, low-growth sensitivity, uses a 0.5 percent growth rate over the first 10 years of the planning period, but still results in a baseload plant being selected for completion as soon as practical.

When the construction schedule allows, Staff recommends that one or two baseload plants should be added to meet the State's electric generation needs. While multiple baseload units will be needed, it may be prudent to stagger construction. This will help mitigate financial stress that can be created by the high cost and duration of construction, while allowing for close monitoring of the continuing need for more baseload capacity and other options available to meet the need. Staff also recommends a balanced Michigan portfolio to meet energy production needs, which would include at least baseload generators, energy efficiency options, and renewable energy projects.

ES-3.6 MPSC Staff Resource Recommendation for Upper Peninsula

Electric generation in the U.P. appears adequate over the planning horizon. Its adequacy, however, is dependent on the completion of ATC's NUP project on schedule and the continued operation of all Presque Isle units.

ES-4. Options for Meeting Michigan Capacity Needs

ES-4.1 Recent History of Michigan Electric Generation Resource Additions

Michigan, like most of the states in this region of the country, has experienced two major electric generating construction cycles over the past thirty years. The first began in the early 1970s and ended about 1990. This cycle consisted of the construction of major utility baseload generating units and numerous PURPA³ facilities. The second began in 1998 and ended in 2004 and consisted of the

³ Public Utilities Regulatory Policy Act of 1978 (PURPA): This federal legislation established the rights of non-utility generators to interconnect with the utility grid. It established a class of cogeneration facilities called Qualifying Facilities (QFs), and also defined Small Power Producers. QFs and Small Power Producers were afforded the right to sell excess power to incumbent utilities, at avoided-cost rates which were to be determined by state public utility commissions. Sections 1251-1254 of the Federal Energy Policy Act of 2005 amend PURPA by requiring state public utility commissions to consider: net metering service; demand-response and time-based metering and communications (also known as "smart metering") and time of use or peak use rates; changes in cogeneration and small power production purchase and sale requirements; and interconnection standards.

construction of approximately 4,000 MW of merchant generating plants. These merchant plants are all fueled by natural gas, and were principally built to serve the evolving wholesale energy market. Many of these merchant plants were built without long-term contracts to sell energy.

Although both construction cycles produced additional generating capacity in the State, both ended in unsatisfactory terms. The first ended with many customer groups expressing opposition to the cost overruns and abandonment costs associated with the Fermi II and Midland nuclear units. Likewise, the utilities' investors were not satisfied with the regulatory treatment afforded by the Commission for these plants.

The second construction cycle has resulted in the bankruptcy of a number of the merchant plant owners. The financial distress experienced by the owners was due to high natural gas prices that have caused their plants to operate at lower capacity factors than originally planned, initial overcapacity in the wholesale markets, and the lack of long-term contracts that could provide for some fixed cost recovery by the merchant plant developers.

The electric energy industry has experienced several major changes during the past ten years. These include the creation of an open access transmission system, the development of independent transmission companies, the implementation Midwest Markets,⁴ and provision of retail customer choice in Michigan. These changes, especially the advent of retail customer choice, have added uncertainty to any load serving entity's customer base. The uncertainties created by customer choice and changes in the wholesale markets have made generation construction, especially baseload, more difficult to finance. It is unlikely that either traditional utilities or independent power producers (IPP) will build additional baseload generation without some departure from past practices for regulatory approval and rate treatment.

ES-4.2 Existing Commission Policies for New Electric Generation Facilities

The historical/existing cost recovery process is intended to protect ratepayers from the costs incurred in building or securing additional capacity until the plant actually begins operating or power is delivered under a power purchase agreement. The burden of demonstrating the need for additional capacity, for financing and securing the capacity, and for assuring that the resulting power is reasonably priced, is intended to fall on the entity seeking cost recovery.

Jurisdictional utilities have two methods to recover the costs of additional electric generating capacity. A utility has the option to buy or build a plant, or it can enter into a power purchase agreement with another entity to secure capacity and energy.

If a utility decides to build a new generating plant, the utility would need Commission authorization to recover from its ratepayers the cost of building the plant, along with a return to compensate its investors. This cost recovery method would add the plant to the utility's rate base. In exchange for meeting that burden for a utility constructed power plant, the utility is allowed a reasonable opportunity to recover its operating costs, plant investment, and a fair return to investors.

⁴ MISO previously referred to what is now called the "Midwest Market" as the "Day-Two Market." The function of the market is to improve reliability by providing efficient use of generation and transmission through constant evaluation and management of the generation and transmission assets throughout the large region that falls under MISO operational control. See <http://www.midwestmarket.org>.

If the utility contracts for electric power with a generator owner, in the form of a power purchase agreement (PPA), the utility must seek recovery of the costs through its Power Supply Cost Recovery (PSCR) clause. With the PPA, the utility still has a burden of proof regarding the reasonableness of the purchase price and other contract terms, but is only allowed recovery of its payments under the contract: no return on investment is provided to the utilities' shareholder.

ES-4.3 Proposed Changes to Commission Policies

Several parties propose alterations to the Commission's current rate-making methodology. Generally, utility companies recommend reducing the risks associated with power plant construction by modifying the Commission's after-the-fact review of plant construction. They also indicate there is a need for enhanced revenue certainty as a prerequisite for being able to finance new construction. Other parties respond that no modifications are necessary. Some participants advocate competitive bidding for new capacity, rate-making methods to encourage energy efficiency and renewable energy, and joint (multi-party) construction of any new baseload plant.⁵

The Commission Staff has weighed the recommendations of the CNF participants and proposes a specific modification to the Commission's current rate-making methodology.⁶ The proposal, which Staff calls a reliability option, emphasizes the need to preserve system reliability and recognizes the benefit that all customers, bundled and unbundled, receive from electric reliability. A utility seeking to recover generating plant costs could either use the traditional approach or could request recovery through this option. Staff believes its proposed option will adequately address the risk and revenue uncertainty issues in a manner that preserves the customer choice options required under 2000 PA 141.

Staff's reliability option begins with a utility application leading to a contested case. In the contested case, the utility would retain the burden to demonstrate: (1) the need for additional capacity; (2) the type of capacity needed; and, (3) that its recommended plant is the best option for meeting future capacity needs. This demonstration would encompass analysis of energy efficiency, load management, and renewable resource options, and, to the extent they contribute to making the portfolio the best choice for meeting future needs, inclusion of these resources in a portfolio of generation options. The utility would also be required to commit to a cost and a construction schedule for any new plant. To help assure the cost of a new plant is reasonable, Staff strongly recommends that a fair and transparent competitive bidding process be used.

After review, and prior to commencing a construction project, the utility would receive Commission recognition of the reasonableness of its resource choices and Commission approval of a related reliability charge. The reliability charge would be assessed to all distribution customers of the utility, thus providing the utility with a significant measure of revenue certainty. Choice customers who pay the charge would be allocated a *pro rata* share of the reliability component of the new plant. The utility could also receive construction work in progress (CWIP)⁷ in rate base without an allowance for funds used during construction (AFUDC)⁸ offset.

⁵ CNF Participants' reviews and suggestions for changes to current Commission policy, and comments on Staff's proposed reliability option, are included in Appendix H.

⁶ The Staff policy proposal is discussed in more detail in Section 3.8.

⁷ Construction work in progress (CWIP): The balance shown on a utility's balance sheet for construction work not yet completed but in process. This balance line item may or may not be included in the rate base. Source: U.S. Dept. of Energy, Energy Information Administration *Glossary*; <http://www.eia.doe.gov/glossary>.

⁸ Allowance for Funds Used During Construction (AFUDC; sometimes also referred to as Interest During Construction): The accounting mechanism used to reflect either the financing or carrying charges on monies

Staff believes this approach will provide sufficient prior recognition of the need and cost of the plant, and sufficient revenue certainty to allow it to be financed. To assist with financing and minimize the risk associated with a construction project of this magnitude, and in order to qualify for the reliability option, Staff would also require an applicant utility to be willing and ready to engage in joint construction and ownership with other entities in Michigan.

ES-5. Organization of CNF Report

The CNF Report is composed of an introduction that describes the CNF background and organization, and two principal topical areas. Section two describes the process undertaken to model Michigan's future electric generating needs along with the results of that modeling. That portion of the report ends with Staff recommendations for near- and long-term resource selection. Section three discusses the Commission's rate recovery methods, changes that have occurred in the industry over recent years, proposals from various CNF participants, regarding the Commission's rate recovery procedures, and the Staff reliability option. Separately bound as Appendixes are the five individual work group reports. These reports explain the resources selected, the data sources used for analysis, major input assumptions, the models used, and the modeling results.

invested in an ongoing construction project. AFUDC treatment may be applied to long-term construction projects which have a total estimated cost, as prescribed by the Commission. AFUDC may be charged on a construction project until it is placed into operation or is otherwise determined to be ready for service.

1 Introduction

The Commission established two goals for the Michigan Electric Capacity Need Forum (CNF). The first was to assess Michigan's existing electric generating capacity, for its ability to meet growing demand for electricity, especially considering possible unit retirements. The second was to provide guidance to the Commission on its existing policies and methodologies that provide rate recovery for electric generation resource additions. The Commission directed its Staff to undertake a collaborative effort with representatives of the electric power industry and other interested parties to accumulate, assess, and evaluate data on the adequacy of electric generating capacity in Michigan. It also directed its Staff to prepare a status report and final report. The Commission listed the following topics to be addressed in the Report:

1. The anticipated short-, intermediate-, and long-term demand for power.
2. An analysis of the ability of existing generation resources to meet projected demands.
3. If additional resources are needed, an analysis of the potential resource options that are available within each of the timeframes, including, but not necessarily limited to:
 - (a) technical considerations relevant to various options;
 - (b) anticipated capital and operating costs;
 - (c) relevant financing, ownership, and organizational considerations;
 - (d) risks associated with various options; and
 - (e) a discussion of any synergistic effects or the extent to which the choice of some options may enhance or foreclose others.
4. Recommendations (Order 14231, p. 4)

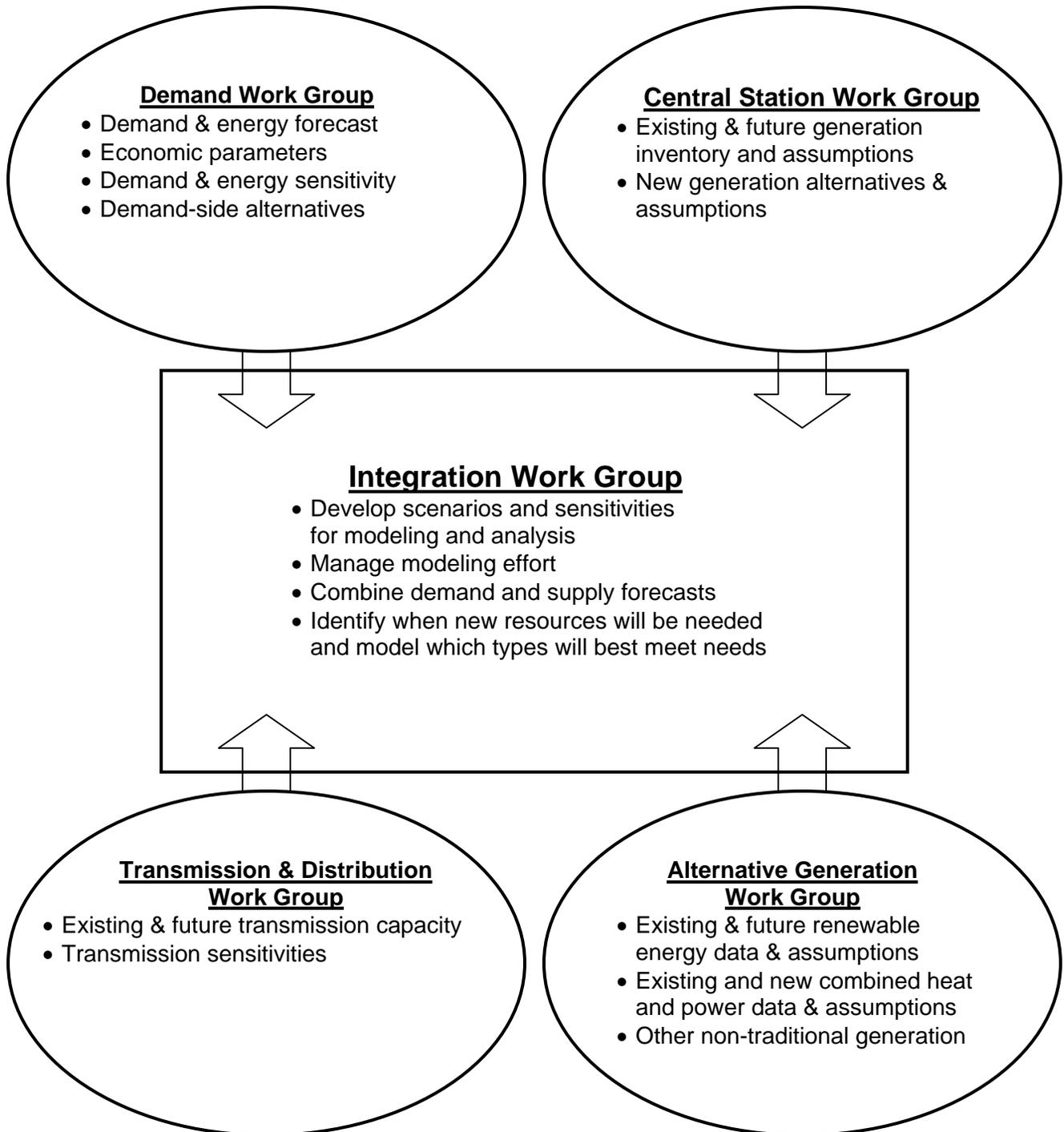
In order to satisfy these goals and provide the requested information, Staff conducted the CNF along two tracks. The first track developed a forecast of demand growth and an assessment of the adequacy of Michigan's electric power generation resources, given various assumptions regarding the pending retirements of any existing power plants. In addition, many options that could be used to help meet future electricity demand were also modeled. To accomplish modeling goals, CNF participants were organized into five work groups. Four work groups were tasked with compiling data, performing analyses, and providing information to a fifth, the CNF Integration Work Group. This organizational setup is depicted in Figure 1. The modeling was conducted by three separate entities under the management of the Integration Work Group.

The second track was to provide guidance to the Commission on its rate-making policies regarding resource additions. If jurisdictional utilities are to build new generating plants, the Commission sought guidance on "issues related to a utility's recovery of its construction expenditures."⁹ The Commission's jurisdiction extends to investor-owned electric utilities and cooperatively-owned electric distribution companies in Michigan, and the Commission's resource addition policy comprises the rate recovery methods and rate-making procedures that authorize jurisdictional utilities to recover their investments in utility facilities, including power plants.

The second track involved all participants in the Capacity Need Forum and explored the Commission's resource addition policy to determine whether that policy should be modified. Circumstances have changed profoundly for Michigan's jurisdictional utilities – along with the entire U.S. electric industry – since the last major baseload power plants were completed in the mid-1980s. These changes have resulted in considerable discussion about the appropriate roles of incumbent utilities and traditional state regulatory agencies in assuring that adequate electric generating capacity will be available to meet forecast demand. CNF participants' views differed widely, however, on proposed approaches and whether there is a need for the Commission to modify its policy.

⁹ October 18, 2004 Order in Case No. U-14231, p. 4; <http://efile.mpsc.cis.state.mi.us/efile/docs/14231/0001.pdf>.

Figure 1: Capacity Need Forum Work Group Structure and Assignments



The Staff actively sought input and welcomed participation from all individuals and organizations involved or interested in Michigan's electric industry and energy future. Representatives from customer groups, business groups, jurisdictional and non-jurisdictional utilities, independent transmission companies, environmental groups, energy efficiency advocates, independent power developers, and alternative and renewable energy providers were active in the Forum and work group meetings and contributed substantially to the Forum's work. In total, about 160 individuals representing nearly 60 different organizations have been involved with the CNF. Representatives from the Midwest Independent System Operator (MISO) also participated and provided significant contributions. Given the breadth of the CNF's work, this study would not have been possible without the active participation of these many contributors. The list of participants is included in Appendix A.

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2 Resource Assessment

The first track was intended to determine whether Michigan's existing generating resources will be adequate to satisfy the future demand for electricity in Michigan. This was a six-step process:

1. Forecast electricity demand and energy consumption over the next twenty years;
2. Compile an inventory of existing electric power generation assets, traditional and non-traditional;
3. Determine current and planned electric transmission capacity available for power interchanges with markets outside the state of Michigan;
4. Determine whether existing generation resources will satisfy future demand;
5. Determine what additional generating resource options could be available, if needed, to meet future demand for electric generation or transmission capacity; and
6. Provide information on the economic costs and characterize other impacts associated with the use of those options.

These steps were completed with the assistance of three modeling initiatives and the efforts of the five work groups attended by CNF participants. Support for the project also came from MISO, which performed the reliability analyses included in the study. To ensure consistency in the planning process between various participants and between generation and transmission options, the CNF adopted 2009 as a base study year, which coincides with MISO's *Midwest ISO Transmission Expansion Plan 2005 (MTEP '05)*.¹⁰

2.1 Study Format

The study partitioned the State of Michigan into three geographical regions: the southeast portion, the balance of the Lower Peninsula, and the Upper Peninsula. The southeast portion is the territory served by the International Transmission Company (ITC). It generally corresponds to the Detroit Edison Company (Edison) service territory. The balance of the Lower Peninsula is the region served by Michigan Electric Transmission Company (METC). It generally corresponds to the service territories served by Consumers Energy Company (Consumers), Wolverine Power Supply Cooperative (Wolverine), and most of Michigan's largest municipal electric utilities. The Upper Peninsula is served by the American Transmission Company (ATC), zone 2. These partitions were used because they reflect the electric power transfer limits that have historically existed between the regions.

This study excluded the southwest corner of Michigan. Most of this area represents the service territory of Indiana Michigan Power Company (I&M). Electric generating capacity requirements for this corner of the State are addressed by the PJM resource adequacy requirement.¹¹

Demand forecasts, generating plant resource inventories, transmission transfer capabilities, and electric generating need assessments were separately developed for each geographical region. In addition, transmission capacity and reliability assessments were performed collectively for the combined ITC and METC regions, also known as the Michigan Electric Coordinated System (MECS).

¹⁰ See <http://www.midwestmarket.org/page/Expansion%20Planning>.

¹¹ For further explanation about this region's exclusion, please consult Staff's July 1st Status Report on the CNF, Page 2: http://www.dleg.state.mi.us/mpsc/electric/capacity/cnf/cnf_7-1-05.pdf.

This study made use of three major, interrelated planning and operations models.¹² The three modeling initiatives are:

1. Managing and Utilizing System Transmission (MUST) – a power flow model to assess transmission capability into Michigan’s three regions and within Michigan for the base year, 2009. Power flow modeling was performed by the International Transmission Company (ITC) for the ITC, METC, and MECS regions and by the American Transmission Company (ATC) for the Upper Peninsula (ATC zone 2).
2. Multi-Area Reliability Module (MARELI) – a reliability model to assess whether generating and transmission assets will be sufficient to satisfy electric reliability criteria in the base year of 2009. This modeling was performed for the CNF by MISO.
3. Strategist – a resource expansion model to explore which additional resource options are most appropriate to meet future needs and the tradeoffs incurred in selecting various resource options. This modeling was performed for the CNF by NewEnergy Associates, LLC.

In order to provide the data necessary to undertake the three-part modeling effort, the Staff established five work groups, one for each of the principle types of data inputs used in modeling electricity resource needs and power supply technology choices and the fifth, to integrate data from the first four work groups through applications of the planning and operations models. The work groups, as shown in Figure 1, are Demand, Central Station, Alternative Generation, Transmission & Distribution, and Integration.

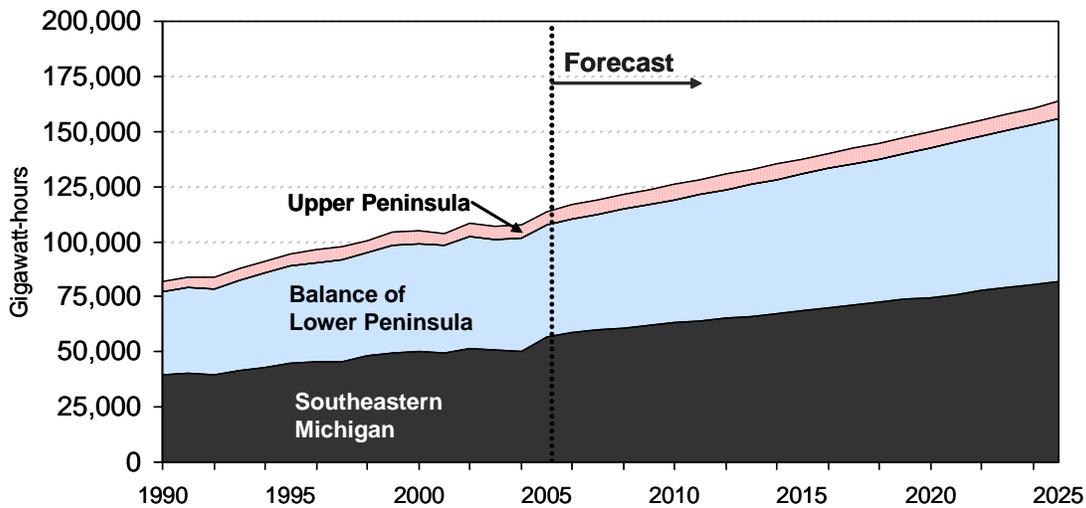
Unlike more traditional electric utility integrated resource planning (IRP) modeling efforts, the CNF study format did not include simultaneous assessments of all resources. Instead, the format used scenario and sensitivity analyses to assess the effects of energy efficiency, renewable energy, and transmission upgrades. This format was followed in order to provide the Commission with a review of a large set of potential resource options and estimates of their comparative costs and revenue impacts.

¹² For further explanation of the modeling see the Integration Work Group Report, Appendix C.

2.2 Electricity Demand Forecast

The Demand Work Group was responsible for developing a consensus-based, 20-year forecast of electric energy and peak demand for each of the three designated regions. The Work Group predicted an increase in annual electric energy consumption, from 113,782 gigawatt hours (GWh) in 2005 to 163,411 GWh in 2025. This reflects a statewide average growth rate of 1.9 percent per year. The forecasts are for total service territory sales for ITC, METC, and ATC zone 2. Each forecast encompassed all sales in the region by jurisdictional utilities, alternative electric suppliers, and municipal utilities. Figure 2 depicts Michigan historical electric energy sales along with the statewide composite of the Demand Work Group's three regional 20-year forecasts.

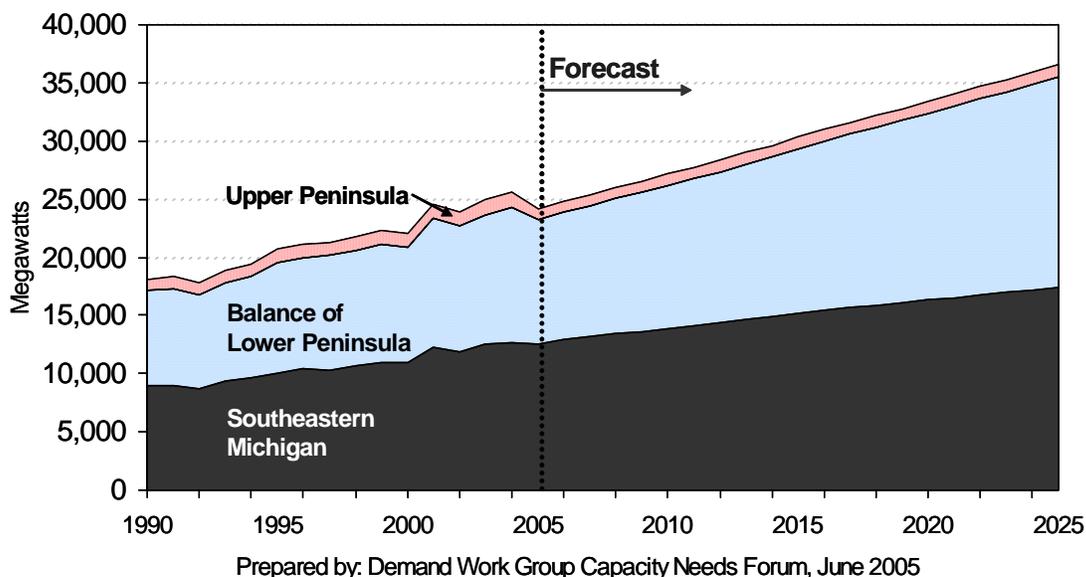
Figure 2: Michigan Electricity Historical Sales and Projections



Prepared by: Demand Work Group Capacity Needs Forum, June 2005

Note: Data excludes Indiana Michigan Power Company service territory.

Peak demand is expected to grow from 24,101 MW in 2005 to 36,589 MW in 2025, an average annual growth rate of 2.1 percent. Historical and forecast peak demand is shown in Figure 3. Peak demand is expected to grow somewhat faster than energy sales, due to expected increases in air conditioning penetration in regions that have not previously experienced significant air conditioning load. This is depicted in Figure 3, which shows the most growth in the “Balance of Lower Peninsula” region, representing peak demand in the METC region. Peak demand is forecast to grow at 1.7 percent annually in the ITC region, 2.7 percent in the METC region, and 0.9 percent in the Upper Peninsula.

Figure 3: Michigan Electricity Non-Coincident Summer Peak Demand

Note: Data excludes Indiana Michigan Power Company service territory.

The demand and energy forecasts used in this study represent the aggregated product of individual forecasts made by investor-owned, municipal, and cooperative utilities. Consumers Energy and Detroit Edison sales accounted for about 78 percent of Michigan's retail electric sales in 2002, and sales to customers in their service territories – combining the sales by both the utilities and alternative energy suppliers – accounted for about 90 percent of the statewide total. Thus, the forecasting methodologies used by Consumers and Edison have a large impact on the resulting sales forecast. Both utilities make use of econometric estimation models for a five- to 10-year period, and then use growth rates produced by those models to project future sales. This forecasting method was also used by Wolverine. Details of the demand and energy forecasts used in this study are reviewed in the Demand Work Group Report (Appendix D).

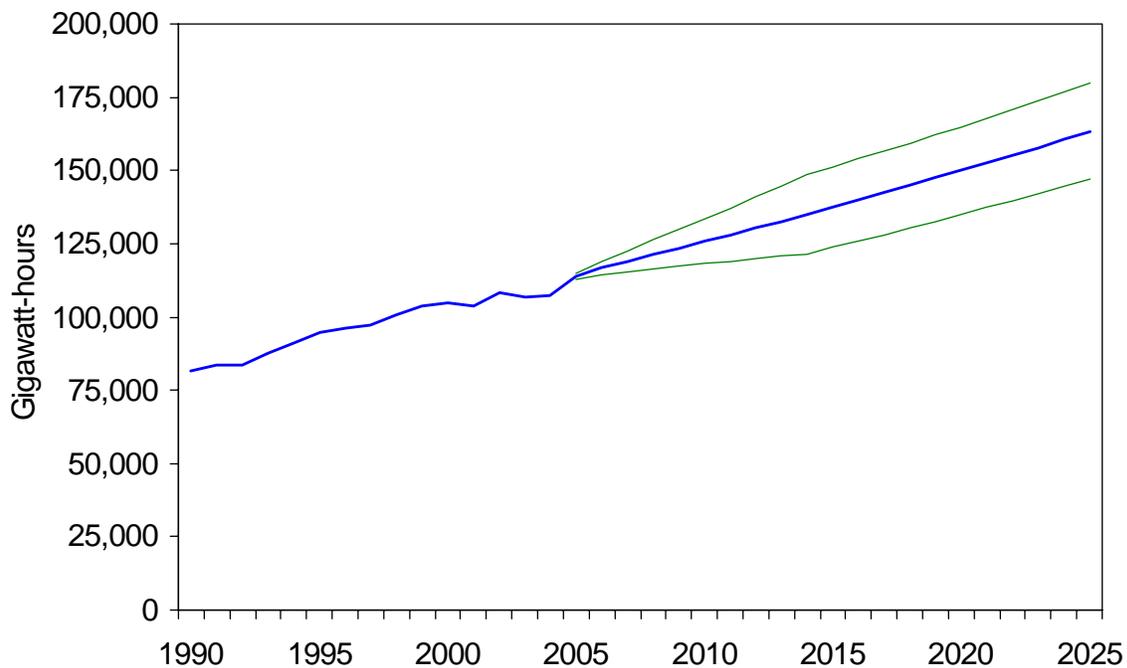
A common feature of most energy modeling methodologies is the use of sensitivities and scenarios to evaluate a variety of risks and uncertainties, which generally arise from the need to project energy requirements quite far into the future. The CNF utilized scenarios and sensitivities in its modeling. Sensitivities adopted by the Demand Work Group were “high” and “low” growth-rate forecasts. These sensitivities produced demand and energy forecasts that were, respectively, 10 percent higher and lower than the base forecast. The high and low growth-rate demand sensitivities vary by 1,629 MW in 2010 and 3342 MW in 2020.

2.2.1 Energy Efficiency

The Demand Work Group was also responsible for providing an estimate of the potential for demand and energy use reductions associated with programmatic efforts to assist Michigan electric utility customers with increasing their energy use efficiency. Little, if any, energy efficiency programming has been undertaken by Michigan jurisdictional utilities since the last major programs were ended in the mid--1990s. Therefore, market potential, program scope and cost, details on specific program designs, and

other related issues have not been addressed in over a decade. The lack of current data on Michigan-specific programs led to the use in this study of a “top-down” modeling approach, where estimates of Michigan energy efficiency potential were based on program monitoring and evaluations completed for other states that have more recently implemented substantial energy efficiency programs. Based on data from ongoing programs in other states, the Demand Work Group forecast a phase-in of energy efficiency programming with the potential to reduce statewide electric energy consumption by approximately 4.5 million MWh per year (about 3.33 percent) in the tenth year of the programming. The estimated impact also includes a demand reduction of 593 MW (about two percent) in the tenth year. The potential energy efficiency impact on the study’s sales forecast is shown in Figure 4 and is discussed in greater detail in the Demand Work Group Report (Appendix D).

Figure 4: Electricity Sales Forecast with Modeled Energy Efficiency Programming



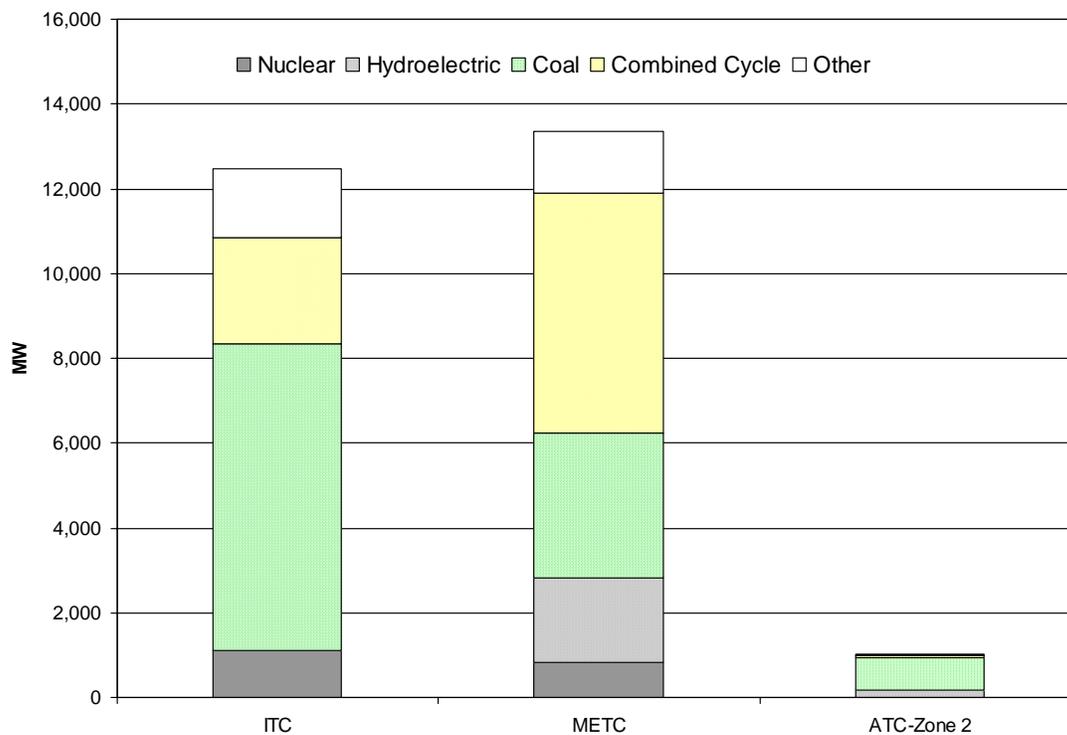
Prepared by: Demand Work Group Capacity Needs Forum, June 2005

On October 18, 2005, the Commission issued an Order in Case No. U-14667, initiating a Staff study on energy efficiency in Michigan. The Commission’s order directed Staff to prepare and file a report on energy efficiency in Michigan by January 31, 2006, and then conduct a public meeting intended to seek input on a course of action. Issues related to the scale, scope, and design of energy efficiency programs will be addressed in the U-14667 process.

2.3 Existing Michigan Generating Assets

Michigan had an estimated 28,000 MW of installed generating capacity in 2003, excluding the Cook nuclear plant in southwest Michigan.¹³ The State's capacity consisted of fossil-fueled, nuclear and renewable generating plants including hydroelectric production. Although peak demand in the ITC region is presently higher than in the METC region, the METC region is home to more generating capacity, as shown in Figure 5. METC has a significant concentration of natural gas-fired combined cycle plants, while ITC has a concentration of larger, coal-fueled units. The last baseload unit to be added to the State's generation portfolio was the Fermi II nuclear unit, which became operational in 1989. Almost all of the generation added since 1989 has been fueled by natural gas, and most of this was constructed in the METC region.

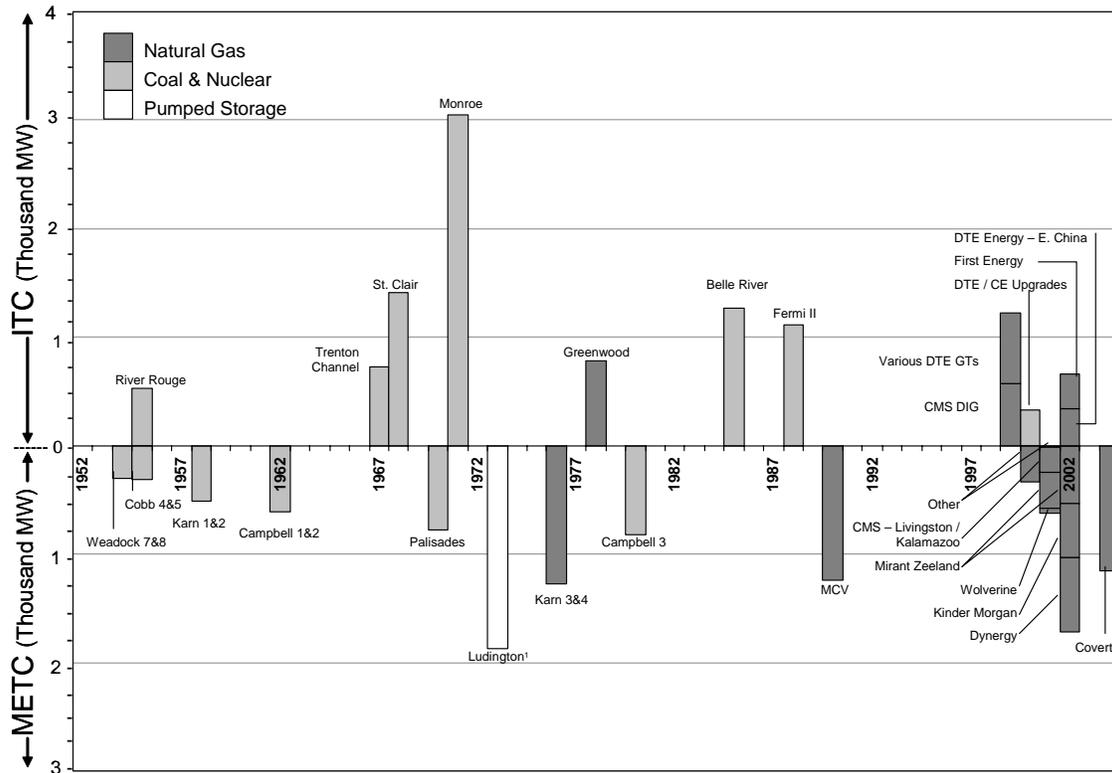
Figure 5: Existing Michigan Electric Generating Capacity, by Fuel Type and Region



¹³ The Cook nuclear plant is located in the southwest portion of the State and is not included in this study.

Figure 6 shows the major generating units added in Michigan since 1952.¹⁴

Figure 6: Michigan Major Electric Generating Unit Additions, 1952 to 2004



¹The Ludington Pumped Storage Facility is jointly owned by Consumers Energy and Detroit Edison, and is operated to serve capacity needs in both service territories.

¹⁴ More detailed information regarding existing units in Michigan and their capabilities is included in the Integration Work Group Report (Appendix C) and Central Station Work Group Report (Appendix E).

2.4 New Central Station Options

The Central Station Work Group compiled cost and operating data on new generation options that could be used to meet Michigan's future electric energy needs. The major parameters of the new plants considered are shown in Table 1.

Table 1: New Generation Options Modeled by Central Station Work Group

Plant Type ¹	Size (MW)	Construction Cost (\$/kW) ²	Fixed O&M (\$/kW)	Variable O&M (\$/MWh)	Heat Rate (Btu/kWh)
Pulverized Coal Sub-critical	500	1,370	42.97	1.80	9,496
Pulverized Coal Super-critical	500	1,437	43.60	1.70	8,864
Fluidized Bed Coal	300	1,505	44.77	4.24	9,996
IGCC Coal	550	1,647	59.52	0.95	9,000
IGCC PRB Coal	550	1,845	59.52	0.95	10,080
Nuclear	1,000	2,180	67.90	0.53	10,400
Combined Cycle gas	500	467	5.41	2.12	7,200
Combustion Turbine gas	160	375	2.12	3.71	10,450

Notes: All costs presented are in 2005 dollars.

1 Please refer to the Central Station Work Group Report, in Appendix E for information on plant operating characteristics and efficiencies.

2 Investment costs are based on overnight costs, greenfield sites, construction of a single unit at a site, and includes on-site switchyards for interconnection to the utility grid. Overnight costs refers to construction costs without any allowance for financing or carrying charges on the funds used for construction.

Air quality control programs play a major role in selecting new generating plant options as well as maintaining and retrofitting existing plants. An Emissions Scenario was developed by the Integration Work Group. The purpose was to investigate the potential impacts on electricity costs and resource selection, if regulations were to impose an allowance cost for carbon dioxide emissions and tighter controls on mercury emissions. In order to test generating technologies against this scenario, the Central Station group developed costs and operating characteristics for integrated gasification combined cycle (IGCC) and pulverized coal (PC) units, with the inclusion of carbon capture capability.

Appendix E is the Central Station Work Group Report. That report includes details on the assumptions regarding central station options and the associated data developed for use with the resource expansion model. Included in that report are cost estimates and emissions profiles for the various new generating resources, along with a discussion of air quality programs that affect generation planning.

2.5 Alternative Generation

A number of technologies were reviewed by the Alternative Generation Work Group for possible inclusion in the Study. The Alternative Generation Work Group Report is presented in Appendix F. After reviewing preliminary cost and available operational data, the Work Group chose to develop data on four technologies and recommend them to the Integration Work Group for modeling. The four technologies and their estimated available capacities over the initial phase of the planning horizon are included in Table 2.

Table 2: Technologies Modeled by Alternative Generation Work Group

Technology¹	Available Capacity (MW)
Landfill Gas	148
Anaerobic Digestion	51
Wind	410
Combined Heat and Power	547
Total	1,156
Notes: ¹ See the Alternative Generation Work Group Report (Appendix F) for more detailed information on technologies modeled.	

The Alternative Generation Work Group coordinated efforts with participants in the Michigan Renewable Energy Program (MREP) Collaborative, to develop estimates of alternative technology resource potential in Michigan. The approach taken was to cultivate near-term estimates, based on the best available data about Michigan resources and recent construction costs for alternative technologies. The estimates provided are for projects that could be available over the first five or six years of the planning period. They were not intended to represent renewable resources available over the entire 20-year planning period. Both MREP and Alternative Generation Work Group participants recognize the limits of these estimates due to the many uncertainties regarding resource potential, limited Michigan experience with some of the technologies, continuous improvements in technological capabilities, and the potential for significant public policy changes regarding both energy and environmental issues.¹⁵ The Alternative Generation Work Group generally believes that the resource potential it has identified will be achievable in the near future, as long as policies necessary to support development are implemented. Noting the continued development and enhancements to renewable options, the Work Group designated a number of technologies as emerging. The Work Group recommends that alternative generation technical and economic potential be revisited frequently to reflect improved resource assessments and changing economic, policy, and technical conditions, as well as the continued development of emerging technologies.

¹⁵ For example, the federal Energy Policy Act of 2005 was enacted in August 2005, in the midst of the CNF project. That act establishes a variety of federal incentives for alternative generation technologies, but at least some of the policy changes incorporated in that Act were not considered in establishing the resource potentials reported to the Integration Work Group.

2.6 Transmission & Distribution Work Group

Michigan's electric transmission system consists of 2,943 miles of 345 kV lines, 108 miles of 230 kV lines and 5,757 miles of 138 and 120 kV lines. All of Michigan's transmission assets, except those owned by I&M, are owned by independent transmission companies, ITC, METC, and ATC. The Michigan transmission system, except for the I&M service territory in Southwest Michigan, is operated by MISO. Traditionally this transmission system has been used to purchase economy energy, for reliability support, and for capacity purchases.

The Transmission & Distribution Work Group provided estimates of the State's transfer capability by region and for MECS. The estimates were made consistent with the planned and proposed projects included in the *Midwest ISO Transmission Expansion Plan 2005 (MTEP '05)*.¹⁶ The MTEP serves both as an important planning tool for MISO and a reliability assessment for MISO's entire footprint. It identifies transmission projects intended to enhance reliability and upgrades expected to be helpful in facilitating wholesale market transactions.

The base year for *MTEP '05* is 2009 and in the course of completing its planning process, MISO analyzed transmission interchange capability into and within Michigan. For the CNF, ITC estimated transmission capability into ITC, METC, and MECS. Transmission interchange capability into the Upper Peninsula was estimated by ATC. The estimates of capability are based on thermal limits, although voltage limits were also analyzed and incorporated into the studies.

2.6.1 Lower Peninsula Transmission

Transmission capacity varies considerably, dependent on line loadings along with the source and sink of each transaction. The CNF modeling estimated on-peak capacities for transmitting electricity from various regions outside of Michigan (sources) and into various regions within Michigan (sinks). The four major source regions outside of Michigan are: Mid-Atlantic Area Council (MAAC, part of PJM); VACAR (Virginia and the Carolinas); Tennessee Valley Authority (TVA); and Mid-American Interconnected Network, Inc. (MAIN, in Illinois).

CNF modeling confirmed that transmission available to serve Michigan customers is dependent on non-Michigan flows over the ITC and METC systems. Power flows over the Michigan system by transmission users outside of Michigan tend to reduce transmission capability available to Michigan customers on a nearly one-to-one basis. Michigan has historically experienced non-scheduled power-flows created by out-of-state transmission users. West-to-east power flows are presently occurring, in part, as a result of American Electric Power and Chicago's Commonwealth Energy participating in the PJM Regional Transmission Organization (RTO). Also, Ontario has announced plans to retire its entire fleet of coal-fueled power plants, approximately 7,000 MW of capacity by 2009.¹⁷ It appears that much of this capacity will be replaced by natural gas-fired generation in Ontario, supplemented by purchases from outside of Ontario. This has raised concerns among participants that Ontario will rely more on MISO energy markets, even further increasing west-to-east flows over the Michigan system.

Concerns arising from increasing west-to-east flows in this region have created a major contingency that has been modeled by the Transmission & Distribution and Integration Work Groups. The Transmission & Distribution Work Group created a base power-flow model that assumed zero power flowing through

¹⁶ See <http://www.midwestmarket.org/page/Expansion%20Planning>.

¹⁷ See http://www.ieso.ca/imoweb/pubs/marketreports/10YearOutlook_2005jul.pdf, page v.

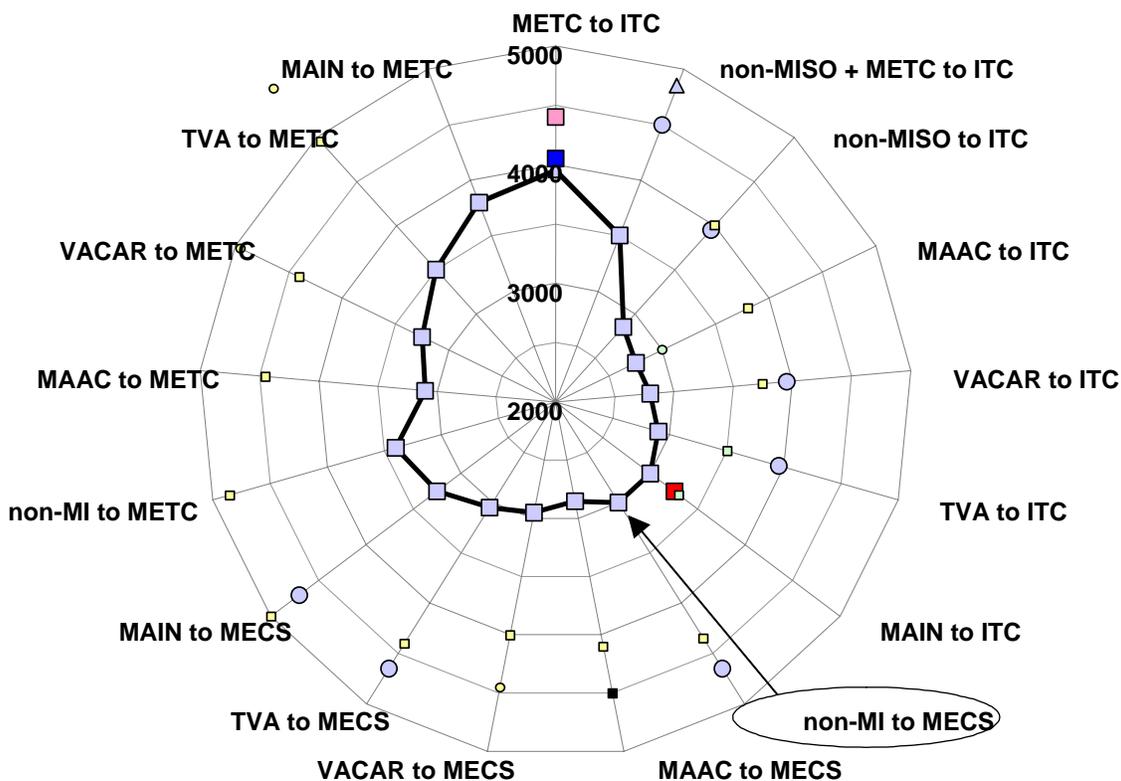
Michigan to Ontario (see Table 4). An alternate scenario was also modeled that permitted 1,500 MW to flow through Michigan to Ontario (see Table 5). These results were then used by the Integration Work Group for resource expansion modeling.

The Integration Work Group also provided options for expanding transmission into and within Michigan's Lower Peninsula. The first set of improvements consisted of projects that did not require acquisition of additional rights-of-way or major capital expenditures. These were referred to as TIER I projects. The TIER I projects were estimated to increase transmission capability into Michigan, from south-to-north, by 1,000 MW and within Michigan, from west-to-east, by 1,000 MW. These improvements were estimated to cost \$50 million for each project, south-to-north and west-to-east. It should be noted that these are gross capability estimates that do not fully account for voltage constraints or increased energy losses that may accompany more intense line loadings in Michigan and in adjoining states.

A group of TIER II improvements was also identified by the Transmission & Distribution Work Group. TIER II consisted of three competing projects, each of which would require major expenditures. Either project would serve the same purpose, which is to increase the available transfer capability into southeast Michigan. The first project is construction of a new high capacity (765 kV) line, from the Cook power plant in Bridgman to Southeast Michigan, which would require additional right-of-way. One competing project is a major direct current (DC) line from Cook to Southeast Michigan, using the currently existing right-of-way, and perhaps the existing towers. The third option is a new double circuit 345 kV line covering the same route. These projects were estimated to cost between \$500 and \$700 million each and are initially estimated to increase import capability by approximately 1,500 MW.

The Lower Peninsula base case transfer capability between various sources and sinks for 2009 is shown on Figure 7. Of particular interest is the transfer capacity from all regions external to Michigan simultaneously providing energy to MECS. This amount is estimated to be 3,000 MW of transfer capability, on-peak.

Figure 7: Lower Peninsula Transmission Import Capabilities from Neighboring Markets



- Notes: ¹ Values shown are MW, normalized to represent import capability if the other entity in MECS were importing 0 MW from Michigan. Actual Traditional Base-Case Imports: ITC = +1,860 MW, METC = - 510 MW (representing transmission across METC to ITC), and MECS = +1,350 MW.
- ² Only the first few limits are shown and the most restrictive limits are shown for groups of limits that are highly correlated. The heavy black line connecting data points near the center of the graph represents the first limit on each transmission interconnection between Michigan's Lower Peninsula and neighboring systems. Reading outward from the center along each spoke on the graph, subsequent marks indicate what the next transmission limit would be on each interconnection if the transmission system were upgraded in some way to remove the previous transfer constraint.
- ³ Contingencies considered included: units dispatched off; units tripping off; single transmission; and single transmission with units dispatched off.
- ⁴ Traditional Base-Case has 0 MW flowing between Michigan and Ontario, controlled by phase-shifting transformers.

2.6.2 Upper Peninsula Transmission

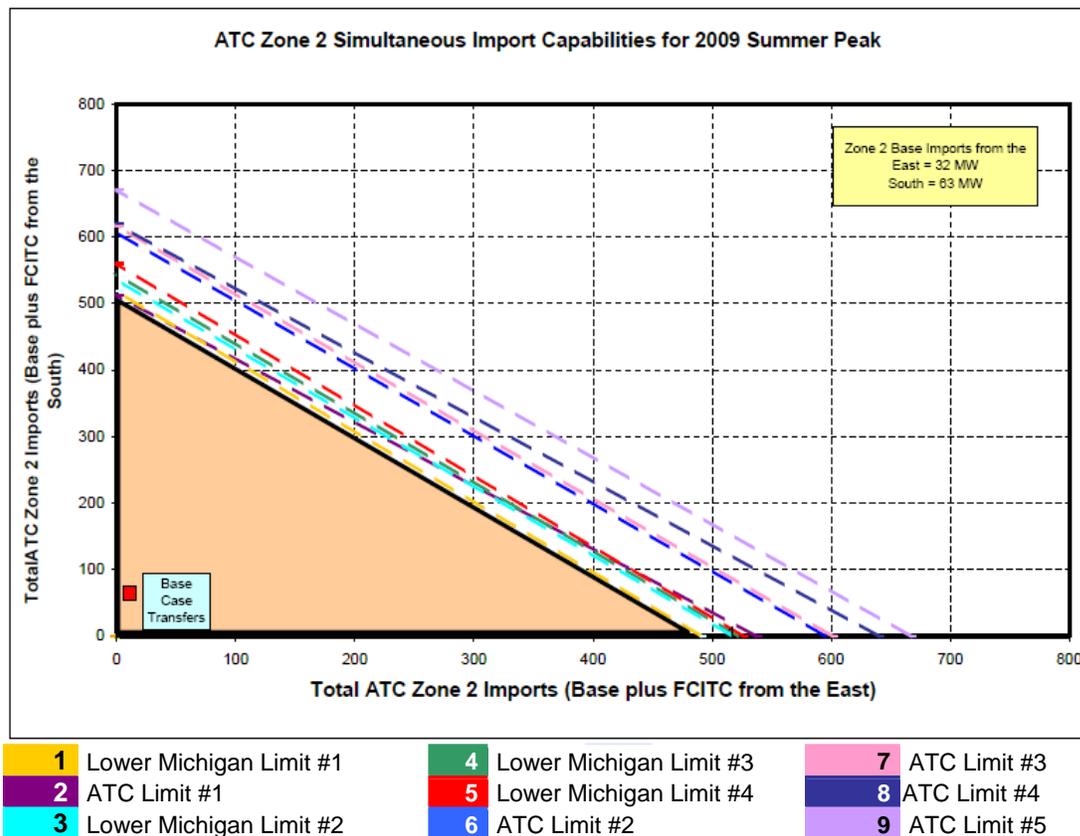
Transmission into and out of the Upper Peninsula is currently heavily constrained. The principal transmission lines consist primarily of one 345 kV line that "dead ends" into the 138 kV heavily

congested Green Bay system, and a double circuit 138 kV line that is over fifty years old. First contingency conditions presently constrain transmission into the U.P. to about 220 MW.

The American Transmission Company is currently engaged in a major project to upgrade electric transmission in the Upper Peninsula and northern Wisconsin. This project is referred to as the Northern Umbrella Project (NUP). When completed, it will interconnect the Western U.P. with Wisconsin’s 345 kV system. According to the schedule, the NUP is expected to be substantially complete by the end of 2009 and is expected to increase transfer capability to 500 MW. Staff has used this expanded transfer capability to analyze U.P. reliability. Upper Peninsula electric reliability and access to economic sources of power are heavily dependent on the timely completion of the NUP. The 2009 Upper Peninsula Transfer capability is shown in Figure 1.

The Transmission & Distribution Work Group Report is attached as Appendix G. It contains a thorough discussion of transmission issues and options for Michigan. It also provides transmission capacity by source (representing generation) and sink (representing load) for the Traditional Base Case, TIER I, and TIER II options.¹⁹

Figure 8



¹FCITC – ‘First Contingency Incremental Transfer Capability’

¹⁹ ITC has identified transmission upgrades which the company has submitted to MISO for possible implementation in MTEP '06. Those upgrades are identified by ITC as either TIER I or TIER II. Those same TIER identifiers are used throughout this report.

2.7 Reliability Modeling

The initial modeling phase of this study was the transmission power flow modeling, which produced estimates of Michigan’s electric transmission import and export capability. This capability, along with the State’s native generation,¹⁹ represents resources available to meet the demand for power. The purpose of reliability modeling is to determine whether existing native generation, together with existing electric transmission infrastructure and available external generation support, can reliably meet projected hourly peak-loads. Reliability modeling for the CNF was performed by the Midwest Independent System Operator (MISO) for the 2009 base year. The MISO Staff used the Multi-Area Reliability Module (MARELI) computer model from NewEnergy Associates²⁰ along with data from the CNF work groups to estimate future generation reliability in each region of the State.

Although there is no official reliability standard used consistently throughout the U.S., the most widely accepted industry standard is a loss of load probability (LOLP) of one day in ten years. The reliability modeling was calculated for each of the three regions within Michigan, based on two different sets of assumptions. The first was based on native generation alone, without including generation support from outside Michigan. This analysis, as shown in Table 3, has been labeled “Stand Alone System.” The second analysis (as shown in Table 4) assumes the availability of up to 3,000 MW of external generation support through the transmission system.

**Table 3: Reliability Model for Lower Peninsula Transmission Regions
Assuming No Generation from Outside of Michigan**

STAND ALONE SYSTEM						
	Sensitivity Cases					
	BaseCase		High Growth		Low Growth	
	LOLP	Support (MW)	LOLP	Support (MW)	LOLP	Support (MW)
METC	0.4	450	1.6	1000	0.1	(-) 100
ITC	32.3	> 1000	49.8	> 1000	20.5	> 1000
MECS	5.2	> 1000	11.6	> 1000	1.8	> 1000
ATC zone2	289.1	315	338.6	355	204.3	275

¹⁹ The term “native generation” is often used to refer to the power plants that belong to or are under the control of a utility (or other load serving entity), which are dedicated to serving its own customers. In this context, however, the term refers to generation located in Michigan, regardless of ownership.

²⁰ NewEnergy Associates is a wholly owned subsidiary of Siemens Power Generation, Inc. See <http://www.newenergyassoc.com/>.

Although none of the regions satisfies the LOLP criteria of 0.1 day in 1 year on a stand-alone basis, METC violates the standard by the least amount. When transmission is included to add generation support, the reliability numbers change significantly, as shown in the Base Case LOLP column of Table 4. With transmission used to provide capacity support, METC satisfies the criteria, but ITC (southeast Michigan) fails the criteria significantly. When METC and ITC are combined into MECS, the region fails to satisfy the commonly accepted reliability criterion, but it is not too far off the mark.

**Table 4: Reliability Model for Lower Peninsula Transmission Regions
Assuming Generation Imports from Outside of Michigan**

IESO Phase Shifter Flow = 0 MW								
Sink	Imports From	Import Value	BaseCase		High Growth		Low Growth	
			LOLP	Additional Imports Needed	LOLP	Additional Imports Needed	LOLP	Additional Imports Needed
ITC	MAIN	3000	0.69	880	2.2	1540	0.16	None
	TVA	2800	1.03	1050	3.03	1700	0.26	400
	VACAR	2700	1.24	1100	3.55	1800	0.33	450
	MAAC	2500	1.76	1350	4.75	1980	0.51	630
	ALL	2800	1.03	1050	3.03	1700	0.26	400
METC	MAIN	3800	0	(-) 3360	0	(-) 2800	N/A	
	TVA	3500	0	(-) 2645	0	(-) 2375	N/A	
	VACAR	3250	0	(-) 3720	0	(-) 2160	N/A	
	MAAC	3000	0	(-) 2530	0	(-) 1980	N/A	
	ALL	3500	0	(-) 2645	0	(-) 2375	N/A	
MECS	MAIN	3250	0.13	120	0.8	1440	0	(-) 1200
	TVA	3000	0.2	440	1.03	1540	0	(-) 880
	VACAR	3000	0.2	440	1.03	1540	0	(-) 880
	MAAC	2800	0.28	630	1.24	1890	0	(-) 630
	ALL	3000	0.2	440	1.03	1540	0	(-) 880

As discussed in the Transmission & Distribution Work Group Report, one contingency faced by the CNF is the plan by Ontario to retire its coal-fueled baseload generation. Although Ontario's energy policy has highlighted this contingency the restricted transmission sensitivity accounts for broader experience with unscheduled flows through Michigan. This caused the Transmission & Distribution Work Group to create a contingency that dedicated 1,500 MW of transmission through Michigan to serve Ontario. This situation would decrease transmission capability available to serve Michigan customers. With this contingency, the LOLP numbers are as shown in Table 5. Under this contingency, all regions of the Lower Peninsula violate the reliability standard.

**Table 5: Reliability Model for Lower Peninsula Transmission Regions
Assuming Constraints Due to Increased Transmission through Michigan to Serve Ontario**

IESO Phase Shifter Flow = 1500 MW								
Sink	Imports From	Import Value	BaseCase		High Growth		Low Growth	
			LOLP	Additional Imports Needed	LOLP	Additional Imports Needed	LOLP	Additional Imports Needed
ITC	MAIN	1750	5.62	2080	11.33	2700	2.14	1430
	TVA	1750	same as above					
	VACAR	1500	7.63	2145	14.33	> 2200	3.22	1650
	MAAC	1500	same as above					
	ALL	1500	same as above					
METC	MAIN	1000	0.02	(-) 560	0.13	70	0	(-) 1120
	TVA	1000	same as above					
	VACAR	1000	same as above					
	MAAC	1000	same as above					
	ALL	1000	same as above					
MECS	MAIN	1500	1.33	1870	3.9	> 2200	0.3	660
	TVA	1500	same as above					
	VACAR	1500	same as above					
	MAAC	1250	1.68	1800	4.87	> 1800	0.43	900
	ALL	1250	same as above					

For the Upper Peninsula, native generation alone is insufficient to maintain acceptable reliability in the 2009 Traditional Base-Case and Off-Peak case. The Off-Peak case simulates demands at 70 percent of peak load with the Ludington pumped storage facility in the “pumping” mode. This combination of events can cause considerable congestion of the Upper Peninsula’s transmission system. The LOLP resulting from native generation alone is calculated to be 289 days/year (see Table 3, column 2 for LOLP in ATC Zone 2), which seriously violates the target level of 0.1 day/year. The relatively high LOLP is indicative of the mine loads in the region and the single, large fossil-fueled plant, Presque Isle. Mine loads are nearly constant, high load-factor loads (ratio of hourly load to peak-load). It is not uncommon to find regions with mine loads having load factors as high as 85 percent. To meet the 0.1 day/year LOLP Off-Peak Scenario, the U.P. needs an additional 60 MW of transfer capacity, which will be satisfied upon completion of the NUP. These results are consistent with previous LOLP studies performed by ATC in this region. These results are shown in Table 6.

Table 6: Reliability Model for Upper Peninsula

Sink	ON PEAK Imports From	BaseCase		High Growth		Low Growth	
		LOLP	Additional Imports Needed	LOLP	Additional Imports Needed	LOLP	Additional Imports Needed
ATC zone2	South (300 MW) East (50 MW)	0	(-) 40	0.19	10	0	(-) 80
	OFF PEAK						
ATC zone2	South (210 MW) East (50 MW)	1.07	60	4.38	100	0.22	20

For the Lower Peninsula, the general conclusion that must be drawn from the MARELI analysis is that unless some new capacity is added in the interim, violations of reliability criteria should be expected to occur in southeast Michigan and MECS by 2009.

2.8 Resource Model

As discussed in the reliability section, Southeast Michigan in particular and MECS in general are forecast to require additional generation or transmission by 2009 to maintain electric reliability within the parameters adopted by the Integration Work Group. This need for additional generation and transmission resources grows over time, as demand increases. Analyzing how best to meet that need – whether to rely on baseload, cycling, or peaking generation, or whether energy efficiency and alternative generation options make sense – is the purpose of resource expansion modeling.

The Integration Work Group was responsible for managing the expansion modeling, which was conducted by NewEnergy Associates, LLC. The resource expansion programming relied on data provided by the four work groups: (1) the Central Station Work Group for existing and new generation unit operating and cost data; (2) the Demand Work Group for the demand and energy forecasts, including potential reductions in demand associated with the modeled statewide energy efficiency programming; (3) the Alternative Generation Work Group for existing and new alternative and renewable generation units; and (4) the Transmission & Distribution Work Group for existing and planned increases in intertie (that is, import-export) capabilities.

2.8.1 Modeling Format

The resource expansion modeling undertaken to support this study represents a comprehensive resource assessment for Michigan. The study included existing resources, new generation options, expanded transmission options, and access to economy energy²¹ markets throughout the region. Instead of modeling all resource options collectively, the Integration group used scenarios to evaluate the cost and contribution of energy efficiency and renewable energy (non-traditional) options to satisfying Michigan's future energy needs. Because of its importance to resource planning, given the current state of production technology, an additional scenario was also used to estimate the impact of expanded air quality controls.

2.8.2 Modeling Sensitivities

2.8.2.1 Demand Sensitivity

Three contingencies were identified by the Integration group for more in-depth analysis through the use of sensitivities. The first addresses uncertainty that arises from demand forecasts that span twenty years. Over this period of time, considerable change is likely to occur in the numbers, types, and efficiencies of end-use devices, the economy of Michigan, the population of Michigan, possibly weather patterns, and other factors that drive energy consumption. To test how responsive the selected resource plan is to changes in demand, high and low demand growth sensitivities were modeled with each scenario. These

²¹ The term “economy energy” refers to short-term purchases of energy, which are now most likely to be made through the MISO Midwest Market. Economy energy purchases can be used to reduce system costs, whenever the price of energy plus transmission-delivery charges will be lower than a utility's cost of dispatching its own generating plants to produce the same quantity of energy.

sensitivities phase in alternate forecasts that deviate from the base forecast by 1 percent per year for ten years. Thereafter, the alternate forecasts are 10 percent above and below the base forecast.

Energy planning is a dynamic process that calls for continuing attention to actual and forecast demand changes in the State. Although forecast sensitivities have been used in this study, sensitivities generally represent perturbations from a standard forecast methodology. Sensitivity modeling was not intended to account for energy demand changes that could occur in response to fundamental market changes, like major shifts in the structure of the State's economy or population.

2.8.2.2 Natural Gas Sensitivity

The second major contingency evaluated through the use of sensitivities was variability in the price of natural gas. The base forecast for natural gas prices begins with the average of 18-month-forward NYMEX²² prices and is then projected to increase at the natural gas price escalation rate reported in the U.S. Department of Energy's Energy Information Agency (EIA) 2005 long-term forecast, which runs to 2025. This produces an initial price of approximately \$8.50 per thousand cubic feet (Mcf). The High Gas Price Scenario uses a price that is 20 percent higher than the base case forecast.

Notwithstanding the recent surge in natural gas drilling, no sensitivity analysis for low natural gas price was modeled. To meet the growing demand for natural gas, EIA forecasts increased supply from three unconventional sources: (1) liquefied natural gas (LNG); (2) a new Alaskan natural gas pipeline; and (3) substantial supply increases from non-traditional sources (tight sands, coal-bed methane, etc.). For example, by 2025 the EIA forecasts that 21 percent of the nation's supply of natural gas will come from overseas through LNG. This will require a huge expansion of both overseas liquefied gas production and shipping capability and U.S. re-gasification facilities. The EIA forecast predicts first a decline and then increase in real natural gas prices between 2005 and 2025. Based upon the assumptions made by the EIA, staff considers gas price risk, at this time, to be asymmetrical: Future price deviations from the prediction are more likely to be higher, rather than lower.

2.8.2.3 Transmission Capability Sensitivity

A third contingency revolves around the State's electric transmission capability. The 2009 forecast transmission capability may be low if the TIER I or TIER II upgrades are completed, but may be too high if predominant west-to-east power flows continue to grow.

The Transmission & Distribution Work Group has identified two groups of potential upgrades to the Lower Peninsula's transmission system. First, to account for the increased capabilities, the Integration Work Group developed a "high" import sensitivity, reflecting TIER I transmission upgrades.

The second contingency models a reduction in the State's transmission capability and is generally due to loop flows, heightened by Ontario's intention to retire its entire fleet of coal-fueled generating plants. The result of this retirement would be the removal from service of a significant portion of this region's baseload generation in Ontario. It appears at this time that much of this capacity will be replaced by natural gas-fired generation. Although the capacity may be replaced to assure reliability standards are met, the need for daily energy production could well cause Ontario to rely more on MISO markets, increasing prices and tying-up transmission capacity through Michigan. As Michigan's transmission

²² NYMEX, the New York Mercantile Exchange, Inc., is the world's largest physical commodity futures exchange and a trading forum for energy and precious metals. See <http://www.nymex.com>.

system is used to transmit power through the State, from west-to-east and south-to-north, less capacity is available for Michigan customers. The Integration Work Group developed a “low import” sensitivity to model this reduction in capability. This is discussed more thoroughly in the Transmission Work Group Report (Appendix G).

2.8.3 Major Model Assumptions

2.8.3.1 Reliability Constraint

The Strategist model is a dynamic programming model that solves for all possible resource combinations that satisfy operative constraints. It first solves for all resource sets that satisfy reliability constraints. The Integration Work Group used a 15 percent reserve margin requirement as the basis for resource planning. The Strategist model then evaluates in-state generating options and economy purchases in external markets to fill the capacity and energy needs. Solution sets are likewise found for the sensitivities designated for each scenario. Solution sets that satisfy the resource needs can then be ranked by various optimization criteria.

The use of a 15 percent reserve margin for the entire State conforms to the results of the reliability study performed by MISO, which is based on a standard of one day in ten years loss of load probability (LOLP). This standard is used throughout the industry for generation planning purposes. The LOLP is affected by the sizes, types, and total quantity of generating units within a service territory. As noted in the reliability section of the Integration Work Group Report, the forced outage rate of generators has a major effect on the resulting LOLP.

Due to the concentration of natural gas-fired generating units in the METC service territory, it is likely that the reserve margin produced by a LOLP study for that region alone would be different from a reserve margin calculated for the ITC territory. The ITC region has a concentration of large, coal-fueled generating units with planned and forced outage characteristics different from the natural gas units in the METC region. For this study, a State composite reserve margin of 15 percent was employed, but it should be recognized that this number would likely be different if calculated for each individual region in Michigan.

2.8.3.2 Model Selection Criteria

The Integration Work Group selected the minimum present value of revenue requirements (PVRR) as the optimization criterion for choosing among the universe of possible resource plans. The model selects from among all feasible solution sets for each scenario and sensitivity, the solution set that produces the lowest PVRR. PVRR is comprised of all fuel, variable O&M, fixed O&M, and emissions allowance costs for all existing and new generators, along with the fixed costs of newly selected generators. The fixed costs of existing generators are not included. The costs are calculated for all in-state generators, both jurisdictional and non-jurisdictional.

2.8.3.3 Resource Screening

Due to the volume of calculations made by the Strategist model as it solves for all solutions that satisfy the model’s constraints, not all possible resources are made available for selection in every scenario. Some resources will be too expensive to be considered and are therefore screened out before the scenario

is actually modeled. The screening process involves calculating the levelized cost of the resources over the entire dispatch universe, or 0 to 100 percent of the unit's available hours. These levelized costs take the shape of output price curves. If a resource's levelized output price curve has no appreciable probability of selection as a least-cost option, it is not considered in that scenario. For example, it is not likely that a first-generation integrated gasification combined cycle (IGCC) plant will be preferred instead of a pulverized coal (PC) plant in the Traditional Base Case Scenario. The IGCC fuel cost is not significantly different from a modern PC, but its capital costs are significantly higher. The expected emissions profile of the standard IGCC, though superior to a PC, does not result in sufficient savings on emissions allowance costs to offset its added capital costs. Therefore, in the Base Case Scenario, IGCC, given its cost and operating parameters, is screened out of consideration, before the scenario is actually modeled.

The modeling approach used for transmission capability followed a similar resource screening concept. Two options could be modeled for use of the State's transmission assets. Transmission could be considered to be available either for economy energy transactions or for capacity purchases, but not for both. Michigan's reliance on external markets in the past has probably been oriented more toward economy energy, rather than capacity purchases, although it has been used for both.

The Integration Work Group elected to model transmission capability use for economy energy and not for capacity purchases. This decision would not necessarily preclude the use of transmission for capacity purposes, however. In fact, the capacity additions selected by the expansion model can be understood to represent resource types (for example peaking capacity or baseload capacity). Even though the transmission capability was modeled for the provision of economy energy, it could also be available for satisfying peaking or baseload capacity needs. By modeling transmission in this fashion, the Integration Work Group was able to estimate the likely value of external spot markets energy purchases without compromising the potential use of the transmission system for capacity purchases.

2.8.3.4 Air Quality Rules

A major consideration in energy planning is air quality control requirements. The U.S. Environmental Protection Agency (EPA) is in the process of instituting several programs that establish restrictions on pollutant emissions from both existing and new electric generating plants. These programs are discussed in further detail in the Air Quality Section of the Central Station Work Group Report (Appendix E). Some of the programs may require retrofits (that is, capital additions) to existing plants.

The CNF modeling did not attempt to estimate construction related compliance costs, however. Instead, it is recognized that these new EPA programs have cap and trade options, designed to allow power plant owners to purchase allowances to emit specific quantities of regulated pollutants. To estimate compliance costs under various clean air requirements, emissions were calculated for each of the existing power plants and for those selected by the model. Emission allowances for the plants selected by the model were then valued at the estimated market price of the allowances, and the total cost of those allowances was added to the revenue requirement.

2.8.3.5 Limitation on Resource Adoption

It should also be noted that the Integration Work Group also adopted a convention of precluding the selection of more than one baseload unit being constructed in any one region in any one year. If more than one baseload unit is added in a year, only one may be added to each region. This convention was adopted to address the financial stress that would likely be incurred in building multiple baseload units simultaneously.

A thorough discussion of assumptions, scenarios, and sensitivities is included in Appendix C, the Integration Work Group Report.

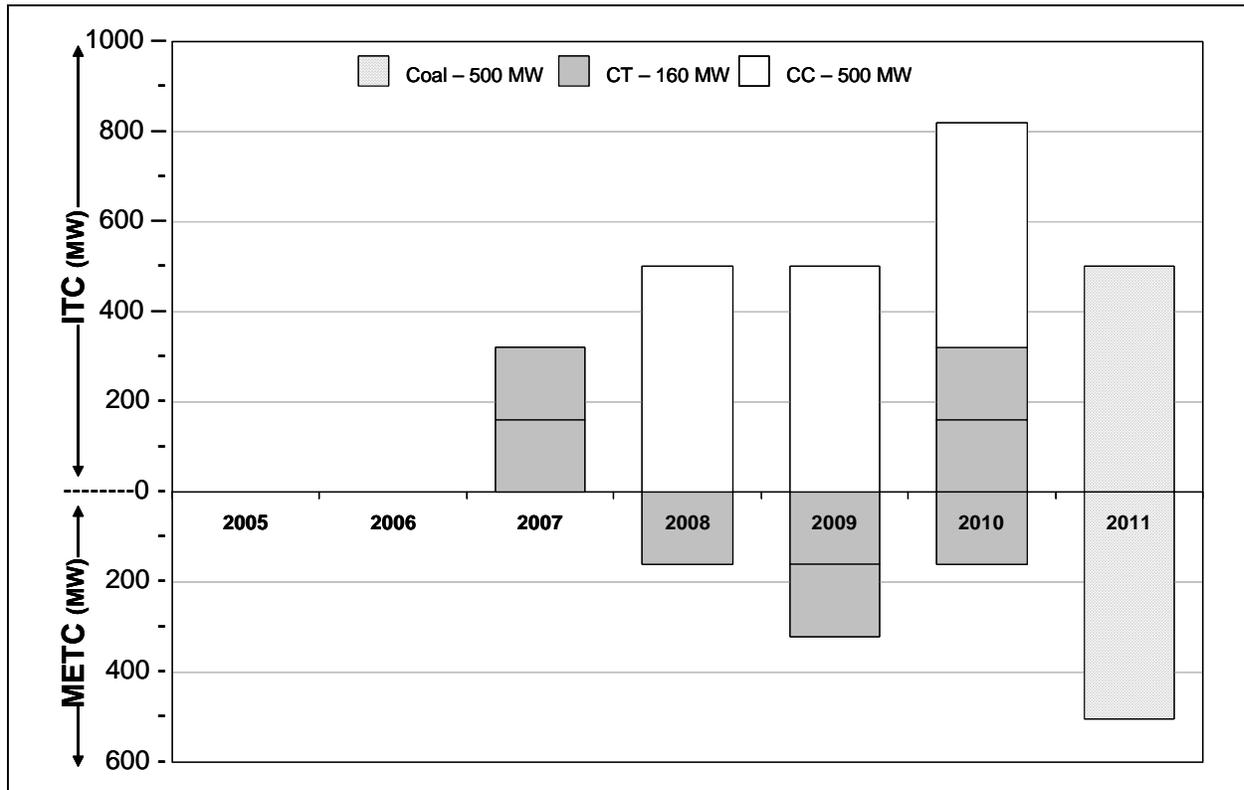
2.8.4 Modeling Results

Modeling results are driven by three major factors: (1) the need to maintain reserves for reliability purposes; (2) the forecast growth in energy consumption; and (3) the lack of any significant generation projects currently being planned for or constructed in Michigan. Reserve margins, especially in southeast Michigan, are projected to decline below levels necessary to maintain the target reliability standard. The Integration Work Group adopted a target reliability standard represented by a 15 percent reserve margin. Projected in-state reserve margins, however, are forecast to decline to approximately four percent by 2009, if Michigan does not take action sooner to reduce the continuing decline. This initial reliability need causes combustion turbines to be constructed as soon as possible. Since a two-year construction schedule was assumed, and the first forecast year was 2005, combustion turbines are added in 2007 in most scenarios and sensitivities. The need to add additional generation is delayed by one year in the Energy Efficiency Scenario and by one or more years in all the Low Growth sensitivity analyses.

In most scenarios and sensitivities, the model begins selecting baseload coal units when available. The Integration Work Group assumed a six-year construction schedule for PC, IGCC, and CFB, which means the first baseload units become available in 2011. Nuclear units were assumed to have an eleven-year construction schedule. For the time period between adoption of combustion turbines and adoption of the first base load unit, the model generally chooses between combustion turbines and natural gas combined cycle units. These natural gas unit adoption schedules are delayed significantly in the Low Growth sensitivity analyses.

The Integration Work Group used a 20-year planning horizon in this study. The Staff, however, has focused most attention on the modeling results over the first 10-years. Although use of a 20-year horizon provides planning continuity and an opportunity to evaluate the expected comparative financial impacts of various resource options over a longer in-service phase, the confidence that can be placed in assumptions and results must decline as the planning horizon is extended further into the future. Over time, changes in both technology efficiency and cost conditions increase the margin by which modeling assumptions, for power plant unit costs and performance, will likely deviate from actual circumstances in fifteen or twenty years. Likewise, the confidence that one can have in demand and energy forecasts declines as the forecast period is extended. Energy planning is an inherently dynamic process and there are numerous opportunities to adjust a long-term plan. The first 10-year period, however, encompasses the timeframe necessary to begin implementing the electric energy resource plan.

During the first 10-year period, the model selects between 6,000 and 7,000 MW of additional generating resources, depending on the scenario and sensitivity. Figure 9 shows the amount and type of capacity added in the initial years of the planning period in the Traditional Base Case expansion model. It should be noted that in some cases, these resources should be considered to be representative of resource types. For example, combustion turbines are meant to serve a peaking need that, in many cases, could be satisfied by either a combustion turbine or by load management programs, which were not explicitly modeled as available resources. Staff, for example, estimates that 400 to 500 MW of load management options are available to help offset short-term demand-related capacity needs and some load management programs are already in use. Likewise, the modeling format used transmission exclusively for economy energy purchases. Transmission capability, however, could also be used for capacity, or firm energy purposes. Using transmission for this purpose would offset the need for baseload generation.

Figure 9: Resource Additions for ITC and METC in Traditional Base Case Scenario

Over the first half of the modeling period, the Traditional Base Case Scenario results show no appreciable present value cost difference compared to the Energy Efficiency Scenario. Non-Traditional costs are only modestly higher for the first 10-year period. Costs for the first 10-year period, however, would be expected to increase significantly under the Emissions Scenario, which models a greenhouse gas mitigation charge of \$10 per ton of beginning in 2010 and \$30 per ton in 2018. The ten year present value costs of emissions are approximately 3.84 billion more under the Emission Scenario when compared to the Traditional Base Case.

For the 20-year results, present value costs are somewhat lower under the Energy Efficiency Scenario than the remaining scenarios. The Traditional Base Case Scenario reflects the second lowest cost over the 20-year period, followed by the Non-Traditional Scenario. The Emissions Scenario produces a significantly higher PVRR total, due to the costs associated with carbon dioxide emissions. It should be noted that the Non-Traditional Scenario includes adoption of IGCC baseload units, which increases the costs of that scenario relative to the others and obscures the more modest cost increase resulting from additional renewable energy sources. The impact of the higher IGCC costs can be seen in comparison to the last sensitivity of the Non-Traditional Scenario (the “with PC” sensitivity). This sensitivity allows the model to select PC baseload instead of IGCC. As noted, the PVRR declines significantly in that case.

Table 7 summarizes the 10- and 20-year PVRR of each scenario and sensitivity. The annual 2005 costs for these items are approximately \$3,300 million (\$3.3 billion). However, the current generation and transmission system cannot accommodate the additional load growth forecast for Michigan over the next 10 years. Unless additional generation and transmission is built, Michigan’s electric reliability will be

compromised. The costs shown in Table 7 represent the least cost plans that will maintain reliability and satisfy energy requirements.

Over the first 10-year planning period, high loads and more restrictive emissions requirements would have the greatest impact on total present value costs. Although higher loads are associated with higher revenue requirements, this may or may not lead to higher unit costs (rates). Because the modeling strategy concentrated only on incremental generation costs, which could be jurisdictional or not, it would be difficult to translate the resulting revenue requirements into rates that can be compared to today's jurisdictional rates.

In this modeling, high gas costs do cause new capacity revenue requirements to rise, and gas costs do represent a planning risk. Natural gas costs are already so high, however, that gas-fired technologies are not competitive for baseload production. Instead, natural gas technologies are used principally for reliability purposes, and to some extent, those purposes could alternatively be served by load management or other options. Planning risk is also represented by tighter emissions restrictions, especially of greenhouse gases. With approximately 60 percent of the State's electricity generation fueled by coal, any potential greenhouse gas mitigation charges would result in a significant increase in production costs.

One common outcome from the various scenarios is the turnabout in Michigan's role as a net importer of power from adjacent regions. The model predicts that after baseload units are built in the State, Michigan would become a net exporter of power. The model does not build Michigan baseload units for the purpose of exporting power; however, once built for meeting domestic needs, excess baseload power would likely be available to be sold into adjacent regions. The net effect of exporting power would be to lower the revenue requirement for Michigan ratepayers. This is seen in the High Import sensitivity results from the Traditional Base Case Scenario (see Table 7, Model Run T-BC), which produces the lowest 10-year PVRR of any of the four Base Case Scenarios.

Table 7: Revenue Requirements for Scenarios and Sensitivities

Scenario		10-Year PVRR (\$ millions)	20-Year PVRR (\$ millions)	Model Run
Traditional Base Case		\$29,640.9	\$54,596.8	T-BC
Sensitivity Analyses	High load	\$32,282.9	\$60,895.9	T-1
	Low load	\$27,146.3	\$48,707.3	T-2
	High gas	\$30,794.9	\$56,282.2	T-3
	High import	\$29,608.2	\$54,238.5	T-4
	Low import	\$29,740.4	\$54,870.9	T-5
Emissions Base Case		\$33,543.9	\$66,002.9	E-BC
Sensitivity Analyses	High load	\$38,373.4	\$77,407.4	E-1
	High gas	\$34,737.7	\$67,779.7	E-2
	With energy efficiency	\$33,464.9	\$64,806.3	E-3
Energy Efficiency Base Case		\$29,802.9	\$54,066.4	EE-BC
Sensitivity Analyses	Without non-traditional generation	\$29,659.2	\$53,813.4	EE-1
	High load	\$32,422.9	\$60,335.7	EE-2
	Low load	\$27,317.7	\$48,156.2	EE-3
	High gas	\$30,873.8	\$55,639.9	EE-4
Non-Traditional Base Case		\$30,368.9	\$57,477.8	NT-BC
Sensitivity Analyses	High load	\$34,728.5	\$67,023.5	NT-1
	Low load	\$29,187.3	\$53,523.5	NT-2
	High gas	\$31,473.1	\$59,149.8	NT-3
	With PC	\$30,106.3	\$55,864.4	NT-4

2.8.4.1 Upper Peninsula

The Upper Peninsula's electric generating capacity needs are highly dependent on American Transmission Company's successful, on-schedule completion of its Northern Umbrella Project (NUP). The NUP, when completed, is intended to connect the Western Upper Peninsula to Wisconsin's 345 kV transmission system. This will increase transmission capability into the Upper Peninsula from 215 MW today to 525 MW in 2010. Long-term generation adequacy in the Upper Peninsula is also dependent on operation of the Presque Isle coal-fueled power plant. For modeling purposes, the Integration Work Group has assumed operation of all units at the plant. Units 1-4, however, may be retired in 2012 under terms of the We Energies consent decree with the U.S. EPA. If the capacity provided by Presque Isle Units 1-4 (175 MW) were unavailable, and not replaced by a similar amount of new, in-state capacity, then the U.P. would face serious challenges in meeting required baseload capacity needs.

2.8.4.2 Energy Efficiency

In many cases, the modeled Energy Efficiency Scenario produced costs that are lower than those produced by other scenarios. For modeling purposes, the Integration Work Group decided not to run energy efficiency head-to-head with traditional generation options. Energy efficiency has not been used as a resource option in Michigan's electric utility industry for a decade.²³ Therefore, there has been no recent experience to draw on to assess specific measure profiles for modeling purposes. The modeling approach in this study has been to take a top-down approach to assessing energy efficiency programming, which is conducive to evaluating energy efficiency as a distinct scenario instead of as a measure or group of measures. Staff believes that the scenario approach provides valuable information on the potential value of energy efficiency for policy makers, and structured scenarios and sensitivity analyses accordingly.

Appendix D, Demand Forecast, discusses the derivation of energy efficiency impacts for the CNF study purposes. As indicated by the modeling results, energy efficiency has the potential to provide significant benefits to ratepayers. The Traditional Base Case PVRR totaled \$29.6 and \$54.6 billion over the ten- and 20-year planning horizons. The Energy Efficiency Scenario "hard wires" the energy efficiency savings discussed in Appendix D into the scenario and adds the costs to the revenue requirement. The resulting 10- and 20-year revenue requirements are \$29.8 and \$54.1 billion (see Table 7, Model Run, EE-BC). Since the energy efficiency effects are phased into the plan over fifteen years, the impacts appear more pronounced over the longer planning period.

Of added interest are the results of the Emissions Scenario. In this case, the energy efficiency programming results in a lower revenue requirement than a portfolio of standard generating resources along with renewable energy options. Although the 10-year PVRR changes only a small amount when energy efficiency is modeled as a part of the Emissions Scenario, the 20-year PVRR shows a more pronounced effect. The 20-year present value revenue requirement for the Emissions Base Case Scenario is approximately \$66 billion, this amount declines to \$64.8 billion when energy efficiency is scheduled into the model run (see Table 7, Model Run E-BC).

²³ See the Commission's October 18, 2005 Order in Case No. U-14667, p. 4

Although the energy efficiency option appears to reduce utility costs, the cost calculations associated with energy efficiency options in the CNF modeling are incomplete. While the utility's costs associated with the programs have been included along with the energy savings resulting from the programs, the participants' costs were not included. Most energy efficiency measures require participants to contribute some of the costs necessary to purchase energy efficient options, but participants' costs were not included in the CNF modeling. The Energy Efficiency Scenarios and sensitivities may understate the total costs of achieving the projected energy efficiency demand and energy savings.

It is clear from the scenarios evaluated for the CNF that energy efficiency programs have the potential to be financially beneficial and to mitigate risks associated with both fuel costs and emissions standards. Nevertheless, modeling utility costs alone does not provide a complete picture of the benefit-cost profile of the energy efficiency programs.

Based on the results of CNF modeling, energy efficiency should be considered as a resource option for meeting Michigan's growing need for electric generating resources. The Commission's October 18, 2005 Order in Case No. U-14667 directs Staff to analyze this potential in greater detail, provide a report by January 31, 2006, and then engage in a public comment process regarding that report.²⁴ Staff anticipates that the following issues will be analyzed and reviewed in that venue:

- What funding mechanisms should be used to support energy efficiency programming?;
- What are the expected rate effects due to utility expenditures on energy efficiency?; and
- Should utility rate-making be adjusted to remove utility financial disincentives associated with efficiency improvements?

Staff expects the CNF analysis will assist in making those determinations. It should be understood, however, that the energy efficiency assumptions represented in the CNF modeling are not definitive, by any means. Staff recommends a more substantial effort to more accurately estimate efficiency savings potentials and costs. Furthermore, such estimates should be revisited from time to time, to properly inform future modeling efforts.

2.8.4.3 Air Quality Programs

As demonstrated by the Emissions Scenario, air quality regulations play a major role in electric energy planning. Electric generating plants, especially coal-fueled plants, are major sources of air contaminants. Approximately 40 percent of Michigan's electric generating capacity and 60 percent of the energy produced in Michigan comes from coal-fueled power plants. For example, Michigan's electric generating plants burned approximately 34 million tons of coal and emitted 317,611 tons of sulfur dioxide and 105,825 tons of nitrogen oxides into the atmosphere in 2003. This represented 88 percent of Michigan's total emissions of SO₂ and 84 percent of the State's total NO_x emissions. Emissions from these generating plants are subject to requirements of the federal Clean Air Act (CAA).

The Clean Air Act represents a major public policy initiative to assure minimum air quality standards throughout the nation.²⁵ Titles I, III, and IV of this Act have a direct impact on electric utilities that own generation facilities. Permits to build and operate a new generating plant, especially a new coal-fueled plant, are subject to New Source Review, Prevention of Significant Deterioration standards, and New Source Performance standards. New plants and existing plants must both satisfy Acid Rain, NO_x State Implementation Plan (SIP), Clean Air Interstate Rule (CAIR), Clean Air Mercury Rule (CAMR), and

²⁴ See the Commission's October 18, 2005 Order in Case No. U-14667, p. 5

²⁵ Clean Air Act programs are discussed in greater detail in Appendix E.

Regional Haze emissions limits. This has required major investment in some existing plants to comply with overall limits.

Air quality standards have a direct impact on electric energy planning. Emissions standards can limit the type of plants that can be built for electric generation, as well as requiring retrofit construction on existing generating plants.

2.9 Resource Recommendations

The Commission requested an analysis of options that are available to satisfy resource requirements in the short-, intermediate-, and long-term future. The options available for the short-term and intermediate-term futures are similar, so they were combined into the “short-term” future. Resources are needed in this period for achieving reliability standards and for limited energy production. Resource options do not change substantially until baseload units can be constructed. Staff considers the time period after the first base load plant could be completed as being the start of the long-term planning period, that begins with 2011. The modeling undertaken by the CNF has produced several resource options for each period and has produced estimated costs associated with the various options for comparison purposes.

2.9.1 Near-Term Resource Options

The near-term forecast for the base year 2009, shows a reliability deficiency for Michigan’s Lower Peninsula. As that year approaches, Michigan’s in-state reserve margin is projected to fall to approximately four percent, which is well below the target level of 15 percent. In-state reserves, even with the external capacity support that can be expected to be provided through the interconnected transmission system, will no longer be sufficient to provide acceptable reliability.

The expansion model begins adding gas combustion turbines to provide reliability support as early as 2007. Combined cycle units are added to the resource mix when their construction schedules permit, which is 2008 at the earliest. Approximately, 2,800 MW of combustion turbine and combined cycle capacity is added in the Traditional Base Scenario through 2010. This capacity is added by the model to increase the State’s reserve margin from 10 to 15 percent, a process that would not be completed under the Traditional Base Case Scenario until 2013.

2.9.1.1 Combustion Turbines and Combined Cycle Units

Combustion turbines (CTs) represent a relatively quick method of boosting reliability without incurring onerous capital costs. Fuel costs for these plants, however, are prohibitive, so they are intended to run for very brief periods and only to meet peak demands. Siting, financing, and constructing combustion turbines can be done relatively quickly. The Integration Work Group assumed a two-year construction schedule to bring combustion turbines on-line. Combined cycle units (CCs) are selected by the model to meet reliability needs and to provide more energy than combustion turbines. The combined cycle units are forecast to operate at capacity factors between 13 and 19 percent. Since combined cycle units are much more efficient than combustion turbines, during the near-term reliability period, the model selects the combined cycle units when a plant is needed for more than a few hours during the year. Even though these plants are much more efficient than combustion turbines, the current and forecast cost of natural gas results in these plants not playing a major role in energy production. The Integration Work Group assumed a three-year construction schedule for natural gas combined cycle units.

2.9.1.2 Transmission

A second option for meeting the reliability need over the next five years is reliance on external capacity support through transmission access. When selecting nearly 2,800 MW of capacity over the immediate five-year future, the model did not consider the use of transmission for capacity support. As noted previously, the Lower Peninsula is forecast to have 3,000 MW of transfer capability available in 2009. Much of this transmission could be used for securing capacity from facilities in adjacent states. It should also be pointed out that TIER I and TIER II transmission upgrades could also be available to increase transmission capability into Michigan. TIER I enhancements are already included into *MTEP '06* and will contribute to improving reliability if implemented. The TIER II imports are estimated to increase transfer capability by nearly 1,500 MW into southeast Michigan. TIER II upgrades are currently estimated to cost between \$500 million and \$700 million and require three to four years to complete. The TIER II upgrades offer a major increase in transfer capability which could be used to purchase external capacity to satisfy reliability needs. For a more detailed discussion of the TIER I and TIER II options, please refer to the Transmission & Distribution Work Group Report (Appendix G).

2.9.1.3 Load Management and Energy Efficiency

A third option for meeting this reliability need is load management. Staff has not included load management programs in the modeling. Instead, Staff considers the selection of a combustion turbine as representing a particular, peak related capacity need. Staff believes that at least some of this need could also be satisfied by load management programs. In total, Staff believes that approximately 400 to 500 MW of load management programming is available in Michigan to help meet peak demand needs. Some load management programs are already being operated in Michigan, but not all of these programs are being used to satisfy reserve requirements. Staff recommends that the utilities explore the requirements and program changes necessary to allow these programs to satisfy capacity reserve requirements.

Energy efficiency measures are also available for meeting demand and energy needs over this period. Due to the phase-in nature of the energy efficiency programming as modeled, and its primary goal of saving energy consumption rather than capacity, the results from this option are more pronounced in the 20-year data. In total, demand is projected to be reduced by 371 MW in 2010 through aggressive energy efficiency programs.

2.9.1.4 Renewable Energy Projects

The fourth option is short lead-time renewable energy installations. Most of the renewable options identified by the Alternative Generation Work Group could be sited and constructed within a comparatively short timeframe. Landfill gas, anaerobic digesters, and combined heat and power installations can be relied on for on-peak energy production. The Integration Work Group projected approximately 440 MW of these resources would be available by the end of 2010. A significant portion of this capacity is combined heat and power (CHP), which would be installed at utility customer facilities, generating electric power and utilizing thermal energy for various combinations of industrial process, space, and water heating and cooling. This also represents one way by which utilities could assist their larger customers with managing energy costs. Staff recommends that the utilities explore this option with their customers. Renewable energy installations could reduce the costs of complying with future emissions regulations, especially any future greenhouse gas program.

2.9.2 Staff Recommendation For Near-Term Planning Period

It is important to make choices for this near-term period which complement the resource choices available in the longer-term. Specifically, Staff recognizes the need for long-term stable energy prices as well as the need to maintain reliability standards over the longer-term. An energy plan must meet these goals while providing sufficient planning flexibility to accommodate major contingencies. Among these contingencies are demand growth changes, emissions requirements, fuel costs, and future transmission options. In order to meet electric reliability needs and address future contingencies, Staff recommends that a balanced, portfolio approach be taken to meet the resource needs over this timeframe.

Combustion turbines and combined cycle units represent a relatively easy approach for satisfying reliability needs. At this time, it appears that additional combustion turbines will be needed to meet reliability in the southeast portion of the State during this near-term period. However, the number of these units can be postponed or even avoided by maintaining current load management programs, expanding energy efficiency and load management program options, securing new renewable resources, and expanding transmission capability.

Transmission is capable of helping to meet reliability needs. Expanded transmission also offers the opportunity to reevaluate the level of planning reserves needed to maintain reliability. As the region and the State's transmission system expands and becomes more robust, it may be possible to meet target reliability levels with a lower level of planning reserves. This is important because planning reserves come with a cost, and the lower the planning reserves, the lower the fixed costs to which electric generation customers are exposed.

To meet reliability needs, transmission provides access to reserves in adjacent states. Whether these states will have sufficient reserves to support Michigan during peak periods is evaluated by MISO through its planning process. At this time, MISO has indicated that there are sufficient reserves within its footprint to provide support to Michigan, if needed, at least through 2009. Staff's assessment of transmission as an option for providing access to capacity outside Michigan and for satisfying reliability needs is heavily dependent on MISO's *MTEP* process, and MISO's determination that sufficient reserves exist to provide needed support.

While reliance on other MISO members for reliability over the short-term may be advantageous, Staff is concerned about the viability of this option over the long-term solution. It is not likely that other states will allow Michigan to benefit from any available capacity in those states over the long-term, without adequate compensation. Staff expects that the Energy Policy Act of 2005 will result in mandatory reliability standards and that these standards may require load serving entities to provide generating reserves equivalent to planning reserves. If this occurs, it is uncertain how external support will be treated, or if a capacity payment will be necessary to access reserves external to Michigan. MISO has recently undertaken the Michigan exploratory study performed on behalf of the CNF, which seeks to determine if transmission can cost-effectively satisfy southeast Michigan's reliability need. Staff currently is reviewing that study to determine if TIER II transmission options can play a significant role in satisfying southeast Michigan's reliability requirements. Staff will continue working with the parties to identify all possible reliability options and assure that these transmission options are considered on an equal basis with generation options for meeting the State's electric generating needs.

Costs do not appear to differ substantially among the scenarios over this immediate period, with the exception of the Emissions Scenario. Although the PVRR is somewhat higher under the Non-Traditional Scenario, alternative generation options offer other benefits. Based on the modeling results, cost differences among the resource scenarios are not a major selection determinant over the near-term. On the other hand, a balanced portfolio of resources consisting, in part, of load management, short-lead time

renewable energy projects, and energy efficiency programs could provide insurance against fuel price volatility. Developing these programs in the short-term will provide the added benefits of reducing the exposure to future emissions control costs and long-term fuel price escalation. In short, these resources can and should be used as risk mitigation measures to manage exposure to future contingencies, as well as satisfy reliability needs.

2.9.3 Staff Recommendation for Long-Term Period Planning

Long-term planning contingencies center on energy market prices and possible emissions costs. Demand growth is a continual planning concern, but is not a major determinate of Staff's recommendations. As noted in the Integration Work Group Report, numerous scenarios and sensitivities, representing several market conditions, have resulted in the adoption of baseload generation by the planning model over the long-term future. The low-growth sensitivity along with an aggressive energy efficiency program slow the schedule of baseload adoption, but a unit is still selected in 2011. The low-growth sensitivity assumes a small annual growth rate of 0.5 percent. Since the last baseload unit was added in 1989, 22 years will have passed before another baseload unit could be added to the State's generation mix assuming a new baseload plant is added in 2011. Between 1990 and 2004, energy consumption in the State grew over 30 percent, without additional baseload generation. Considering these facts, it is not a surprise that the model selects a baseload plant as soon as the schedule permits. Barring a catastrophic collapse in electricity demand, Staff does not consider variability in the CNF demand forecast to be a critical planning contingency at this time.

An unexpected outcome of the modeling has been the sale of Michigan energy into markets outside of the State once additional baseload generation is built in Michigan. This outcome was unexpected since Michigan has traditionally been a net importer of power from adjacent states. Off system sales from Michigan are modeled because the Strategist forecast of economy energy market (spot market) prices exhibits an upward trend, reflecting generally higher energy prices in short-term markets. These market price estimates seem consistent with recent experience in this region. Electricity market prices have trended up over the past few years and have experienced periods of considerable volatility.

The price volatility experienced by energy markets represents a major concern. In MISO's markets, power is priced at the marginal cost of the last unit brought online, or opportunity cost if higher. Due to a number of reasons, this can cause customer costs to swing quickly and wildly. As load grows, proportionally more of Michigan's energy consumption could be exposed to these market prices unless a more stable power source is secured. Base-load units provide the relatively stable power source that can provide a more predictable and, generally, lower life-cycle electric energy price.

Staff strongly believes that in order to assure a long-term stable price for electric energy, new baseload units must be added to Michigan's generation portfolio. The Strategist model selects several thousand megawatts of additional baseload units over the next 20 years, driven by the need to maintain reserve margins, demand growth and the retirement of several aging baseload units. For several reasons though, Staff does not feel that it is prudent to plan to construct more than one or two additional baseload plants on a staggered basis at this time. The dynamic nature of the planning process requires review and modification to plans as circumstances change and better information and technology become available. Nevertheless, due to the time required to site, permit, and construct a major baseload plant, the process of building a plant in Michigan needs to begin soon. The model's selection of a baseload plant as soon as the schedule permits in practically every scenario and sensitivity analysis modeled indicates and reinforces the need to build baseload as soon as possible.

The baseload units selected by the model are pulverized coal units. These are the least expensive baseload units considered in this modeling effort. Other coal technologies are also available to meet baseload needs and the decision on which coal-fueled technology may be the most appropriate for any particular circumstance will depend on costs, air quality permit requirements, site location, and the ability to mitigate future risks. Nuclear generating plants also serve a baseload need. The expansion model did select a nuclear unit in the Emissions Scenario. Since the construction schedule for nuclear technology is eleven years, however, the nuclear unit does not come on-line until the second part of the planning period. As noted in the Central Station report, nuclear generating technology has advanced since the last generation of nuclear plants was built in the United States. However, no new plants have been commenced in the United States since the 1970s. Although the Nuclear Energy Commission (NRC) has implemented a design certification process, the process has not yet been tested. At the same time, unresolved issues related to spent nuclear fuel create additional risk with nuclear technology. Staff does not recommend adoption of a nuclear plant until the new NRC permitting process has been used to site one or two new plants and the spent fuel disposal issue is resolved.

Another major planning contingency is the course of future air quality regulations. The Emissions Scenario indicates that a greenhouse gas control program could cause a significant increase in generation costs, both in Michigan and within this region. Staff recommends that the near-term renewable energy and energy efficiency programs continue to be included in the long-term energy supply portfolio. These resources can serve to satisfy a part of the growing demand for electric energy and offer protection from future emissions costs.

Staff studied the option of increasing transmission into the State in order to provide access to additional generation resources. Staff believes that this can provide valuable options, particularly in meeting more immediate reliability needs. Staff is not convinced, however, that increased transmission capability represents a long-term solution to Michigan's baseload power needs at this time. MISO transmission pricing includes a congestion component that cannot always be hedged over the long-term. This exposes long-term power purchase contract with a generation source outside of Michigan to unknown delivery costs for extended periods of time. Efforts are underway at FERC and MISO to devise long-term transmission hedging options, but none are available at this time. Moreover, Staff is not confident that these instruments will be available in sufficient amounts for load serving entities in this region to make long-term decisions within the timeframe needed to bring new baseload capacity online by 2011. This leaves Staff to recommend that new baseload generation be built in Michigan as soon as practicable. At the same time, Staff recognizes that the scope of the resource addition plan adopted by the Strategist model is ambitious. The long-term capacity needs for the State could be augmented by a more robust transmission system that would permit access to adjacent markets to help meet capacity needs. Staff is in the process of reviewing the financial results of the Michigan Exploratory Study performed by MISO. This will provide us with information in making recommendations regarding resource additions. As indicated previously, Staff considers electric capacity planning to be a dynamic process. Any long-term plan can and should be evaluated from time to time and assumptions and data inputs adjusted when appropriate.

Staff's final recommendation regarding resource selection is to review the planning assumptions and results in two years. It will prove useful to assess whether the CNF technology assessments need to be modified and whether critical assumptions remain valid. A review at that time would also help determine if the recommended capacity schedule should be modified.

2.9.4 Staff Recommendation for the Upper Peninsula

Reliability and affordable energy in the Upper Peninsula are dependent on the timely completion of the ATC's Northern Umbrella Project and on continued operation of the Presque Isle units. Staff intends to continue monitoring the Northern Umbrella Project status and We Energies plans for the Presque Isle plants. If the Northern Umbrella Project schedules change materially or a final decision is made to retire Presque Isle Units 1-4, Staff will re-evaluate Upper Peninsula electric generating needs, and make recommendations as appropriate.

3 Review of Commission's Rate-Making Policy

3.1 Current Rate-Making Methodology

3.1.1 Rate Base

The Commission's resource addition policy has been developed over a number of years. The policy applies only to utilities that come under the Commission's rate-making jurisdiction. Thus the policy does not directly apply to independent power producers, municipal utilities, industrial facilities, or other wholesale power producers. The policy can be separated into two categories: (1) the addition of rate base assets; and, (2) the acquisition of power through power purchase agreements. Rate base assets are those generating facilities that are built and owned, or purchased, by the utility. A utility purchase power agreement is a contract that entitles the utility to the capacity and energy produced by a generating facility that is owned by another, usually non-jurisdictional, entity.

Most of the generating assets available to Michigan utilities are rate base assets. The Michigan regulatory process for recovering new generating plant investment is summarized below:

1. Utility identifies need for additional generating capacity and determines the type of plant that best satisfies that need;
2. Utility finances and manages construction of plant;
3. Construction Work in Progress (CWIP) is added to rate base, but offset with an Allowance for Funds Used During Construction (AFUDC); and
4. After completion, the utility requests rate recovery of plant and must meet a used and useful test.

The Commission's process is intended to place the burden of rate recovery on the utility seeking rate base treatment for a generating facility. It requires the utility to demonstrate a need for the power, that the type of plant constructed was the proper plant to build, and that the plant's cost was reasonable and prudent – in short, that the plant was used and useful. The intention of the policy is to place the utility at risk for planning to meet its customer's loads and acquiring the necessary resources. By requiring an AFUDC offset for CWIP during construction and by allowing rate recovery only after the plant is built, the Commission's historical policy is designed to protect the ratepayers from unsuccessful plant investment. It also made the utility responsible for financing the plant until it produced electric power for the benefit of its ratepayers. In exchange, the process provided a reasonable opportunity to the utility to recover its plant investment and to earn a "normal" rate of return. Until recently, this procedure has been followed, with minor variations, by regulatory agencies throughout the United States.

The only significant modification to this policy occurred in Case U-8869-DE/U-9798, issued July 22, 1992. In that case, the Commission required that the utilities competitively bid future capacity needs. Except for the recent Consumers Energy solicitation for a small quantity of capacity from renewable energy suppliers, however, no competitive solicitations have been undertaken to date.²⁶

²⁶ Information about the Consumers Energy Renewable Resources RFP can be found in <http://efile.mpsc.cis.state.mi.us/cgi-bin/efile/viewcase.pl?casenum=14626>

3.1.2 Power Supply Cost Recovery Clause

Building baseload generation is one method that utilities have used to secure power generation assets for their customers. The other method has been through power purchase contracts with non-utility producers. Contracts that include a payment by the utility to the producers for capacity costs in excess of six months must be approved through the utility's Power Supply Cost Recovery (PSCR) case. Act 304, which requires Commission approval for these capacity costs, requires a hearing in which the utility must demonstrate that the contract results in reasonable and prudent costs. Again, the procedures are intended to place on the utility seeking approval for cost recovery, the burden of demonstrating the need for capacity and showing that the resulting costs are reasonable.

3.2 Historical Experience

During the period running from the mid-1970s to about 1990, a major surge of electric generation construction activity resulted in the completion of nearly 5,400 MW of rate base capacity in Michigan, of which approximately 3,000 MW was baseload. An additional 1,500 MW was added through long-term purchase power agreements, the largest of which was the gas-fired MCV at 1,240 MW of capacity.

The results of these rate base additions have been mixed. Campbell Unit 3 was built at a cost of about \$760/kW, has maintained a high availability, and has operated at a relatively low fuel cost. Belle River cost approximately \$1,400/kW, but has performed at a nearly 85 percent availability. Its fuel cost is also relatively low, at about \$15/MWh.

Nuclear construction under the Commission's policy, however, has not been as successful. Fermi II was completed and went into service in 1989. Over the past ten years, though, its reliability has improved dramatically. Fermi II has averaged approximately 90 percent availability over the five years ending with 2003. Fermi II's fuel cost is only \$5/MWh, which compares favorably with baseload coal fuel costs of approximately \$15/MWh. The plant's fixed capital cost, however, was over \$3,600/kW. These fixed costs have caused Fermi II to be the most expensive baseload plant in the Michigan generation portfolio and the source of stranded costs in the customer choice program. The Midland (now MCV) units were not completed as nuclear units. Consumers invested nearly \$3.5 billion into the plants before abandoning the plant as a nuclear unit. The plant was eventually finished as a natural gas-fired PURPA facility.

It has been noted by participants throughout the CNF process that this model is imperfect. The overruns at Fermi II and costs associated with the abandonment of Midland are both cited as instances in which ratepayers have shared a significant measure of the risk of plant construction, whether or not the plant was completed. These examples could be multiplied throughout the United States with many states sharing this experience. Notwithstanding the cost to ratepayers, this process was successful in facilitating the construction of major baseload plants.

3.3 Recent Events

Beginning in the early 1990s, the Federal government began a major policy initiative aimed at increasing competition in the wholesale electricity markets. One component of the initiative has been to increase the number and diversity of power suppliers. The Federal government created a new category of generators known as exempt wholesale generators who were authorized to sell power into wholesale markets at market based rates.

In 1996, the Federal Energy Regulatory Agency (FERC) issued Order 888 which provided for non-discriminatory, open access to the nation's transmission system, and required functional unbundling of generation from transmission. Order 888 created a means by which new power supply competitors could obtain and utilize transmission service on the same basis as incumbent utilities. To further provide nondiscriminatory access to transmission service, FERC has encouraged the creation of Regional Transmission Organizations (RTOs). These organizations provide independent control of transmission systems within their operational service territories. Order 888 and the RTOs, along with the functional unbundling of generation and transmission, are intended to provide nondiscriminatory access for all transmission customers.

Another major policy undertaking by FERC was reliance on supply and demand, working within power markets, to set the wholesale price of power. This represented a major departure from the cost-based rate setting process that FERC formerly followed. FERC's goal has been to encourage competition in wholesale markets to provide power to customers, instead of traditional cost-based prices. In the Great Lakes region both MISO and PJM manage hourly wholesale electricity markets and facilitate the market operation with day-ahead scheduling. Prices in these markets generally represent marginal costs of production of the last unit brought on-line to serve load in an area.

In response to 2000 PA 141, Detroit Edison, Consumers Energy, and the Upper Peninsula utilities divested their transmission assets. In the case of Detroit Edison and Consumers Energy, these assets have been bought by independent transmission companies. Instead of transmission services being provided by traditional, vertically integrated utilities, the facilities are now owned by independent transmission companies and operated by MISO.

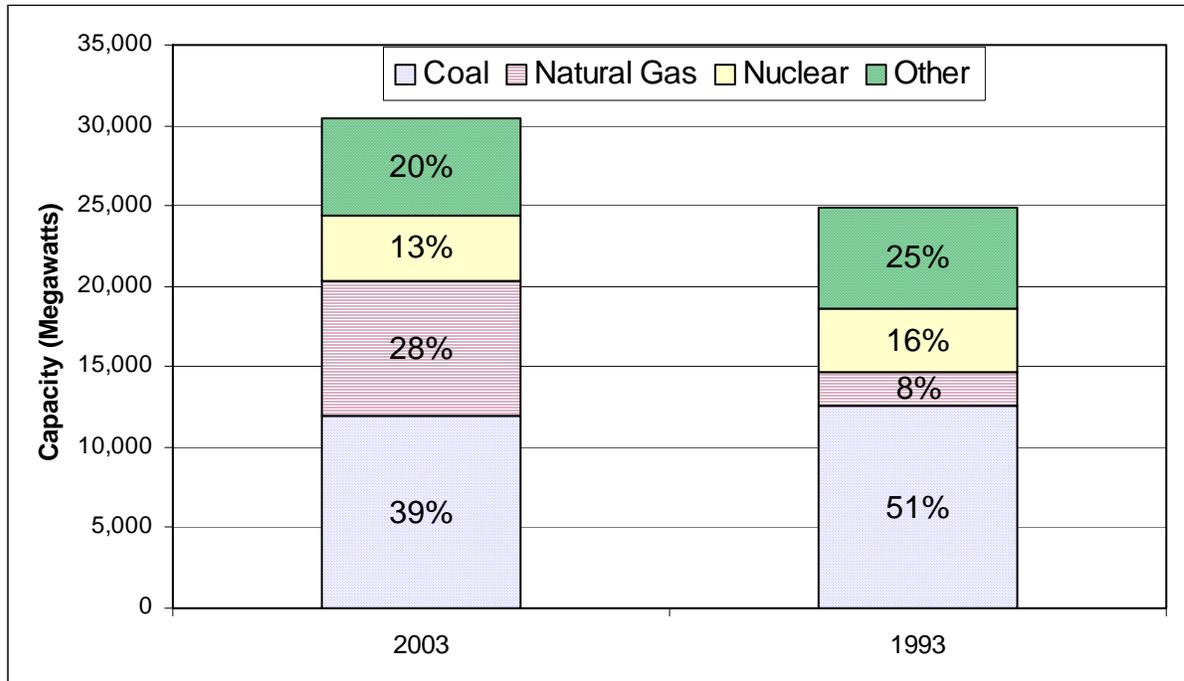
In 2000, with the passage of PA 141, the State of Michigan restructured its retail electric utility industry. Michigan retained its regulated utilities but also provided customers with the right to choose alternative electric suppliers. Since the inception of PA 141, most customers and sales have remained with the incumbent utilities, but alternative electric suppliers (AESs) captured significant sales in some of Detroit Edison's and Consumers Energy's key market segments.²⁷ Customer choice, and the other changes that have occurred throughout the region, have profoundly changed the electric utility industry from the structure that existed when the Commission last provided rate recovery for major generating plant additions.

Collectively, these initiatives have been the impetus for changes in the electric generation industry, that are still being worked out in most regions of the country. One of the chief changes was a second burst of electric capacity construction activity that resulted in approximately 4,800 MW of natural gas-fired generation being constructed in Michigan over the period 1998 to 2004. Nearly all the construction was undertaken by non-regulated firms building merchant plants for

²⁷ Data on AES sales are included in a series of MPSC Reports on the Status of Electric Competition in Michigan (see <http://www.dleg.state.mi.us/mpsc/electric/restruct/status.htm>).

the newly evolving wholesale markets and for Michigan retail customers.²⁸ Michigan's capacity by fuel type (Figure 10) depicts the dramatic increase in the use of natural gas as a fuel, from 1993 to 2003. In 1993, natural gas represented about 8 percent of Michigan's electric generating capacity, and much of that amount was represented by the Midland Cogeneration Venture (MCV). By 2002, natural gas represented 25 percent of the State's electric generating capacity.

Figure 10: Michigan 2003 Summer Generation Capacity by Fuel Type

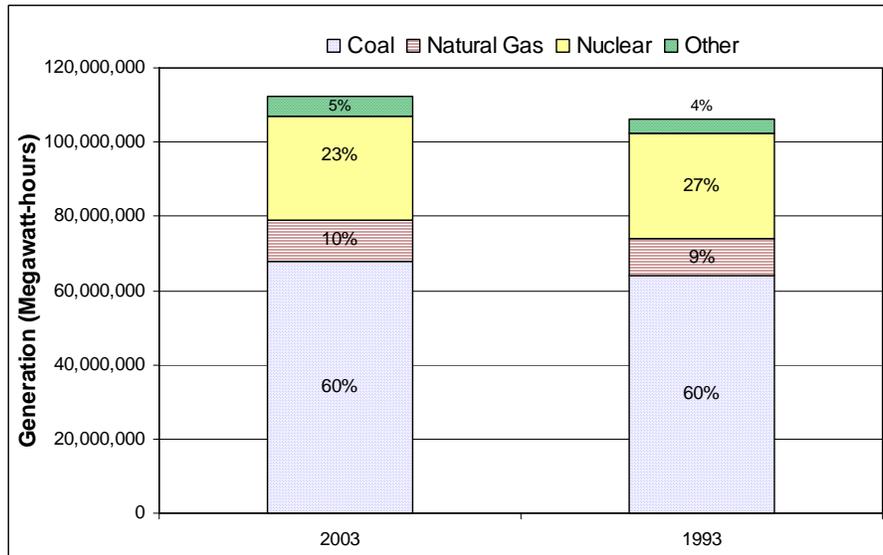


Michigan's increased reliance on natural gas is similar to the experience of other parts of the nation over the past fifteen years. Natural gas generating capacity now accounts for approximately 25 percent of U.S. generating capacity.

Despite the growth of natural gas generating capacity, however, energy production has remained chiefly concentrated in coal and nuclear generating units, which combined accounted for approximately 83 percent of the Michigan's 2003 electric generation. Figure 11 depicts energy production by generating source for 1993 and 2003.

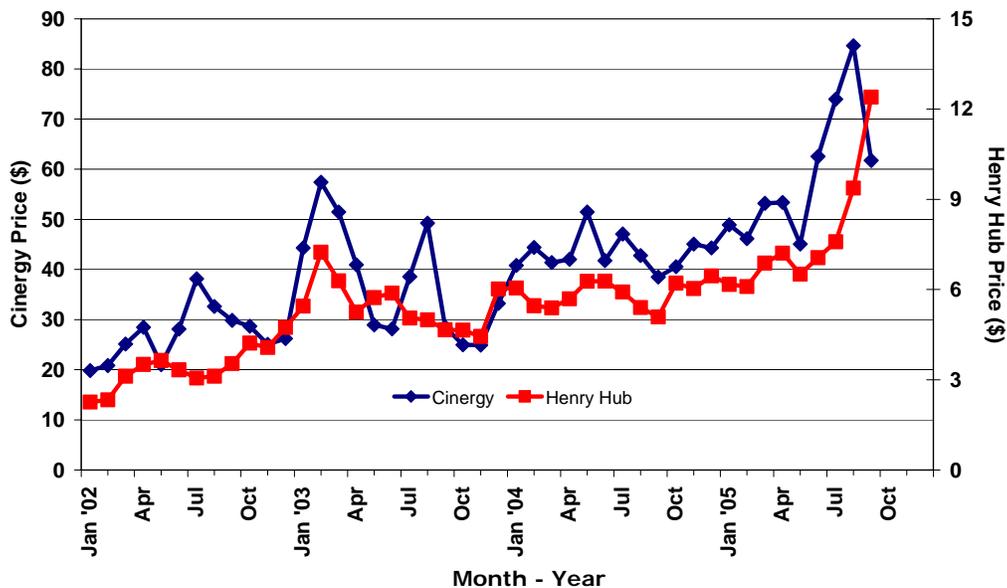
²⁸ One of the purposes of 2000 PA 141, the Michigan Customer Choice and Electricity Reliability Act, is, "To encourage the development and construction of merchant plants which will diversify the ownership of electric generation in [Michigan]" ([MCL 460.10\(2\)\(c\)](#)). See also, the MPSC *Merchant Power Plants in Michigan* Web page, at <http://www.cis.state.mi.us/mpsc/electric/restruct/merchantplants.htm>.

Figure 11: Michigan Energy Production by Fuel Type



During the 1990s, relatively inexpensive natural gas combined cycle and peaking plants served as the basis for rapidly developing wholesale power markets. However, beginning in 2002, rapidly rising natural gas prices, exacerbated by electric generating overcapacity in some regions, contributed substantially to the financial collapse of some of the most prominent developers of merchant power plants. High gas prices pushed up electricity prices in short-term wholesale markets. Figure 12 shows the course of natural gas market prices. From the graph it is not difficult to understand that the extensive construction of natural gas units and rising gas prices have been creating elevated, and at times volatile, electricity prices.

Figure 12: Cinergy and Henry Hub Weekday Average Price by Month, January 2002 through September 2005



Staff believes this electricity price trend will continue as long as gas prices remain high. Both the advent of large quantities of gas-fired generation and the commencement of Midwest Markets have caused short-term electricity costs to rise dramatically.

Two additional factors contribute to this belief. The first is the announced retirement of Ontario's baseload coal generation by 2009, totaling 7,000 MW of capacity, which could cause the Province to rely more on energy purchases from suppliers in U.S. markets. The second factor is progressively tightening reserve margins within ECAR. The reserve margins projected by ECAR for the 2005 – 2014 period are shown in Table 8.

Table 8: ECAR Forecast Summer Reserve Margins, 2005-2014

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Margin	18.3%	15.9%	15.3%	14.0%	12.7%	11.9%	10.4%	9.1%	7.8%	6.3%

Source: ECAR Assessment of ECAR-Wide Capacity Margins 2005-2014. 05-GRP-07. August 2005

Major merchant plants recently built in Michigan are the Zeeland plant (Mirant), Renaissance (Dynergy), Jackson (Kinder-Morgan), Covert Township (initially constructed by PG&E and later sold to New Covert Generating Co.), Dearborn Industrial Generation (CMS), and Sumpter Township (First Energy). The Zeeland, Renaissance, and Covert Township plants were constructed without long-term contracts with load serving entities. Since their construction, natural gas prices have quadrupled, making energy production from these facilities very expensive. Without long-term contracts and with prices for natural gas escalating rapidly, three of the original developers – Mirant, Dynergy, and PG&E – have since filed for bankruptcy. Due to high fuel costs, these developers have been unable, thus far, to recover their plant investment costs in MISO's daily markets.

3.4 Michigan's Resource Needs

Resource modeling completed by the Capacity Need Forum demonstrates the need for additional electric generating resources in Michigan for reliability purposes and for a stable, economic supply of generation services. This conclusion is thoroughly discussed in the resource modeling section of this report and in the CNF Work Group reports (Appendixes C through G). The modeling effort also makes clear that under a broad set of scenarios, representing numerous market conditions, additional baseload generation will be needed as a least cost option for the State. Numerous other resource options are available, including transmission, renewable resources, and energy conservation. In order to best manage fuel and environmental risks these options should be included in Michigan's future resource mix. Even with these resources included, however, the modeling results show a need for baseload generation as soon as a unit can be constructed.

3.5 Construction Options

3.5.1 Merchant Plant Construction

The Forum's policy discussions produced no clear indication about who would build additional generating plant in Michigan, when it is needed. However, it was obvious that financial distress recently experienced by the Independent Power industry makes it highly unlikely that new merchant plants – built to sell into the market, without long-term contracts – will be appearing in Michigan in the foreseeable future. It is nearly impossible to conceive of a project developer undertaking the substantial financial burden of constructing a major generating facility, especially a baseload electric generating plant, without having a long-term power purchase agreement with a credit-worthy counter party, like a load serving entity²⁹. Indeed, it is not likely that any new plant, natural gas or baseload, could now be financed without a long-term contract for most of the plant's capacity. Staff discussions with Forum participants confirm this observation.

It is also clear from the Forum's discussions that traditional utilities are not likely to sign long-term power purchase agreements with independent power producers, unless the agreements have "out" clauses, which provide for relief in the event of either regulatory changes or significant losses of load to customer choice. The traditional utilities repeatedly emphasized the uncertainty associated with Michigan's customer choice program. They have indicated that due to the potential for sales loss, they cannot commit to long-term contracts without regulatory out clauses. Unfortunately, these same clauses that would serve to protect utility stakeholders would also make it difficult if not impossible for independent power producers to secure financing.

The incumbent utilities also express reluctance to build any additional generation, and unwillingness to build additional baseload plant, under the existing policy. According to the utilities, the customer choice program makes it impossible for them to finance a major plant, since it makes it impossible to forecast their future loads and revenues.

3.5.2 MISO Resource Adequacy

Some Forum participants recommend that Michigan rely on MISO to site additional generation. It is clear from the presentations made to the Forum and MISO's proposed resource adequacy proposal, however, that MISO has no intention of filling this role in the foreseeable future. As stated repeatedly by representatives of MISO and as evidenced by its resource adequacy proposal, MISO intends to operate short-term energy imbalance markets. It has eschewed any interest in the capacity markets being operated by other RTOs, like the reliability pricing model now being proffered by PJM.

²⁹ A "load-serving entity" (LSE) is a utility company or alternative electric supplier. LSE refers to a company that has obligations to provide service to retail end-use customers of electricity.

From all appearances, MISO intends to serve a role in identifying reliability related issues through its MTEP planning process and to assist individual states in their planning activities. As discussed at greater length in the modeling section of this report, MISO has provided valuable support to the CNF through reliability modeling and by undertaking the Michigan exploratory transmission study. These studies, together with the load-deliverability analysis provided in the MTEP plans, provide valuable information to policy makers and planners on electric reliability needs and represent one method by which MISO contributes to assuring sufficient generating resources will be available to meet demand.

The second method by which MISO indicates it will assist with new generation is the Midwest Markets. MISO's philosophical approach is to encourage generation additions, where most appropriate, through price signals created by supply and demand working through the short-term, energy imbalance markets. MISO has recognized, however, that capped prices may not provide sufficient incentives to construct enough new generation. During a presentation to the CNF, a representative of MISO suggested a dual price initiative. MISO would cap prices from generation that is rate-based or committed under contracts at one level, for example \$1,000/MWh. For non-committed or non-rate-based generation, MISO would create a much higher cap. Whether or not this remains an integral part of MISO's resource adequacy proposal, it demonstrates MISO intention to rely on market prices to encourage generating plant investment.

MISO's two-part strategy includes use of a marginal cost energy market along with traditional utility planning. But, most state regulators probably would not be willing to tolerate the market prices that MISO deems necessary to provide sufficient incentive for new construction. However, reliance on this market is one way that states can encourage construction of additional generating plant. For those states preferring not to rely entirely on Midwest Markets, MISO can provide valuable planning support. Unless states are willing to tolerate repeated instances of very high prices, though, under MISO's resource adequacy proposal the responsibility to site new generation remains with the states.

Unless new baseload generation is built, Michigan will experience a growing reliance on MISO energy markets, which are frequently driven by short-term gas prices and are not intended to be a long-term source of power. Unless adjacent states undertake large baseload construction programs that Michigan customers can take advantage of, this reliance on short-term markets would likely expose Michigan ratepayers to significantly increased and volatile power costs.

3.6 Adequacy of Current Policy

Staff is convinced that in today's market, major new plant, especially baseload electric generators, cannot be built without some type of revenue certainty, and that this certainty is not likely without some type of government intervention. From Staff's review of the PJM reliability pricing model, for example, it is clear that this proposal is one attempt to provide certainty for recovery of electric generation capacity costs. In one way or another, RTOs in the Northeast and Mid-Atlantic region have intervened in their markets to require customers to make capacity payments, as a means of encouraging plant construction.

Some states, like Wisconsin and Minnesota, do not have retail customer choice programs and do not experience the same revenue certainty problems faced by states that have competitive markets, like Michigan. In these traditionally regulated states, utilities finance and manage construction and recover fixed costs through regulated rates. These regulated rates provide the revenue certainty that seems essential to secure financing for major plant construction.

Michigan fits neither of these models. Instead, Michigan represents a hybrid system with both regulated utilities and a customer choice program. There are strong interactions between the regulated and choice markets in Michigan that make generation planning particularly difficult. Information, presentations, and discussions with participants regarding current rate-making policy and the State's regulatory structure have convinced the Staff that needed generation, at least baseload, will not be built without some change to rate-making procedures.

Based on the recent history of the industry, it is not clear who might build new electric generating facilities in Michigan when they are needed. Incumbent utilities are reluctant to commit to construction and operation of new plant since the industry has been restructured and customers can switch suppliers. Independent power producers, on the other hand, are not likely to build plant unless they have secured long-term power sales contracts with distribution utilities or customers. Distribution utilities, however, indicate they are unwilling to sign such contracts unless the contracts contain regulatory out clauses that could be triggered by increased customer choice participation. Finally, it does not appear that MISO's resource adequacy proposal will fill this gap.

3.7 Participant Recommendations

When initiating this Forum, the Commission requested advice on its resource addition policy. Responding to this directive, Staff requested that participants assess the Commission's policy, given the Commission's current scope of authority.

Participants differ widely on whether a change in policy is necessary and how any changes should be structured.³⁰ Participants recommending a change in policy cite as sources of uncertainty that necessitate policy modification: (a) whether a new generating unit's cost will be recoverable; and (b) whether customers will be there to provide revenue when the plant is operational. These parties, chiefly composed of utilities, assert that major new construction cannot be financed without removing some of the uncertainty that currently clouds the Commission's policy and Michigan's electric industry. Specifically, proponents of changing the Commission's policy recommend the following:

1. Pre-approval of the need for a new plant, including the type, and cost of the plant;
2. Revenue certainty, provided through a non-bypassable charge on all distribution customers that will cover the plant's fixed costs;
3. CWIP in rate base without an AFUDC offset; and
4. Provisions for new investment in existing plant.

To assure continuance of these changes, the proponents also argue that one Commission cannot tie a subsequent Commission to its decisions. They propose that in order to provide sufficient certainty, legislation is necessary to bind future Commissions' policies and rate-making decisions to the initial determination of need and rate recovery. Thus, they would also recommend changes to the scope of the Commission's authority.

Proponents of these changes argue that the undertaking of major new construction, particularly new baseload power plants, exposes a utility or independent power producer (IPP) to considerable financial risk, both for the efficient building of the proper plant and, eventually, for the recovery of its investment. Proponents further assert that the proposed changes are necessary to provide

³⁰ Recommendations from various participating parties and replies to Staff's proposals are included in Appendix H.

risk mitigation and revenue certainty, without which they claim financing and construction will not be possible. They point out that even in some states that have not adopted customer choice programs, construction pre-approval policies have been adopted.

Numerous other parties contest the need for these changes. They argue that pre-approval is not supported by Michigan law, and that these changes would force ratepayers to assume too much of the risk of new plant construction. They also suggest that allowing a utility to build additional generation would risk the creation of future stranded costs. Some parties propose that the threat of PSCR disallowances should be used to induce utilities to build new generation without the need to change the current rate-making policy. Some Forum participants do not want regulated utilities to build additional electric generating units; therefore, they see no need to change the Commission's resource addition policy. Finally, they recommend that markets or MISO should be relied upon to initiate the construction of future generation resources. Many parties have also advocated adoption of a transparent bidding process as a means for selecting from among competing proposals for the construction of new generation.

Staff would be remiss not to identify other issues identified by participants, some of which Staff embraces. These include market power issues. To address this, Staff strongly recommends that new units be a joint undertaking of multiple entities. Due to the emerging need for power in the State, Staff recommends participation in these units by municipal utilities, electric cooperatives, and others. These entities should be allowed to participate directly with regulated utilities or with non-utility developers. Flexible joint participation options will be necessary in order to secure reliable power at stable prices.

Also, some participants advocate more energy efficiency and renewable energy resource acquisition. Staff strongly endorses significant roles for both of these resource options in Michigan's energy portfolio.

3.8 Staff Proposal

Staff has developed a proposal for recovery of proposed generating plant costs, through a new, optional regulatory approach, which Staff terms a "reliability option." This option, as an alternative to the Commission's traditional rate-making method, would be available to a jurisdictional utility planning to build baseload generation. The reliability option addresses the Commission's overriding interest in reliable electricity for Michigan's ratepayers, removes a great deal of risk and uncertainty from the construction process, and assures a significant measure of revenue certainty to jurisdictional utilities electing to construct new generating facilities.

Staff has repeatedly characterized electric reliability as a public good, and this belief serves as the foundation for the reliability option. Electric reliability has many characteristics of a classical economic public good, which is not likely to be provided by a competitive market alone. And, because electric reliability is a public good, every customer, bundled or unbundled, receives the benefit of electric reliability. In fact, regional transmission organizations and states already play active roles in promoting electric reliability, including those jurisdictions that rely primarily on markets to provide electric generation services. Governmental intervention into electric energy markets, where these markets exist, is widely practiced and accepted, and a primary goal of that intervention is to assure electric reliability. Most recently, Congress has intervened, in the Energy Policy Act of 2005, to assure the reliability of the bulk power system by mandating the adoption of electric reliability standards. This critical public interest in electric reliability served as a guiding principle for Staff, as it prepared recommendations befitting Michigan's hybrid electric market, regarding the Commission's resource addition policy.

Staff's proposal is to offer a utility the choice of building under the current policy, or as an alternative it could seek recovery under a reliability assurance option. Under the reliability option, the utility would file an application with the Commission containing the following:

1. Details of the proposed plant, including expected cost and anticipated in-service date;
2. An analysis of why the proposed plant is the appropriate resource to meet the expected need and an analysis of the public benefits associated with the plant;
3. If desired, a request for placement of the plant's construction work in progress (CWIP) in rate base without an offset for allowance for funds used during construction (AFUDC); and
4. If desired, a request for a reliability charge on all customers receiving retail distribution service from the utility.

A contested case public hearing would be held on the utility's application. In the hearing, the utility would need to submit, along with its forecast of demand, a comprehensive electric energy plan including traditional generation sources, load management options, energy efficiency programs, renewable energy projects, and transmission options. The plan would need to demonstrate that the proposed plant is part of a portfolio of options that best meets the needs of its customers.

If the Commission determined that the plant's expected reliability value warranted it, the Commission could permit CWIP in rate base without an AFUDC offset and would authorize a reliability charge on all distribution customers. In exchange for placing CWIP in rate base without AFUDC, the utility would commit to capping the recoverable value of the plant and an in-service date.

In exchange for paying a reliability charge, all customers would be credited with their pro-rata share of the plant's reliability value towards satisfying any regional reliability standard. Further, if customers of an alternative electric supplier (AES) pay a reliability charge, the AES shall have a one-time opportunity to make a pro-rata investment in the generating station. By virtue of the interconnected system, Staff stresses that electric reliability serves all customers who take electric service, regardless of whether they pay for the infrastructure necessary to provide that reliability. Thus all customers of an electric utility receiving rate treatment under this option receive the benefit of electric reliability. In the future, Staff anticipates the reliability component of electricity costs could be fungible.

Since major plant construction involves large capital costs, financial risks, and, eventually, rate recovery, it is crucial for Michigan to secure the right type of power (baseload, cycling, peaking, renewable, fossil, etc.) at the lowest possible costs. Utility construction, ownership, and operation of new generating plant is an option for securing that power, so long as a better alternative is not available. However, a better alternative might be a proposal by another entity, to build essentially the same plant at a lower cost. This is so important that Staff believes competitive bidding should be strongly encouraged. Any cost cap proposed by a utility in a reliability option hearing should be presumed to be reasonable, if it is the product of a fair and open competitive bid.

Encouraging multiple party participation in any new plant construction should help alleviate market power concerns. This is not likely to eliminate those concerns, but allowing broad-based participation in new baseload plant would be expected to decrease the concentration of ownership while allowing multiple parties to secure long-term power at stable prices. Multiple ownership should also mitigate construction risk. Staff expects that any utility proposal made under the reliability option would include an offer to other Michigan load serving entities to become partners in the plant.

Detroit Edison has articulated a concern that any new proposal to construct plant may cause it to violate the market power provisions of 2000 PA 141.³¹ Other parties have expressed concern that allowing utilities to build additional generation will cause generation to become more concentrated in a few entities and cause an increase in market power.

None of the parties submitting comments have opposed energy efficiency. Staff expects a utility's demonstration that a proposed plant is the appropriate resource to meet an identified need would include an analysis and adoption of cost effective energy efficiency and renewable resource options as part of a portfolio of energy resources.

Staff would expect a jurisdictional utility that intends to build new generation and desires to use the reliability option to file a contested case, commensurate with the framework discussed above.

3.8.1 Staff Recommendation

After exhaustive discussions with numerous participants of the CNF, Staff has concluded that it is unlikely that major new plant additions will be constructed in Michigan in the foreseeable future without some change in the Commission's current rate-making methodology. Staff strongly believes that independent power producers will not construct additional generation without long-term contracts. All indications are that long-term contracts containing regulatory out clauses cannot be financed, and that incumbent utilities are not likely to sign long-term contracts unless they contain these clauses. Staff also believes that in Michigan's hybrid regulatory market, some non-traditional revenue certainty and regulatory pre-recognition of the need for new plant will need to be adopted. Staff believes that its reliability option satisfies that need while preserving the hybrid structure established by the legislature.

Staff recommends that the Commission offer optional rate treatment for new jurisdictional generating plant additions, along the lines described in Staff's reliability option. Staff recognizes that other potential options can be devised to promote revenue and rate-making certainty for new plant investment. Therefore, Staff also recommends that the Commission allow utilities or other parties to propose modifications to the reliability proposal, necessary to best suit their investment plans and customer needs.

³¹ Market power is discussed in 2000 PA 141, Michigan's Customer Choice and Electricity Reliability Act, Section 10f (MCL 460.10f). Provisions in that Act may, under certain circumstances, trigger market power mitigation. See <http://www.legislature.mi.gov/mileg.asp?page=getObject&objName=mcl-460-10f>.

Appendix A:

List of CNF Participating Organizations

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Appendix A

Participating Organizations

ABATE	Michigan Electric Co-Op Association
American Council for an Energy Efficient Economy (ACEEE)	Michigan Electric Transmission Company, LLC
American Electric Power	Michigan Energy Office
American Transmission Company	Michigan Environmental Council (MEC)
CMS Energy	Michigan Independent Power Production Association
Constellation/New Energy	Michigan Public Power Agency
Consumers Energy	Michigan Senate Majority Policy Office
Competitive Power Ventures (CPV)	Midwest Energy Efficiency Alliance
DTE Energy	Midwest ISO
Energy Advantage Consulting, Inc.	Mirant Corporation
Energy Michigan	Michigan Municipal Electric Association
Energy Options & Solutions	Michigan Public Service Commission
Environmental Resources Trust	MMA-NET
First Energy	National Wildlife Federation
Ford Motor Land Services	Great Lakes Office
Governmental and Public Affairs	NextEnergy Center
Granger Energy	Peabody
Holland Board of Public Works	PJM Interconnection
Howard and Howard	Premier Energy
International Brotherhood of Electrical Workers	Quest Energy/WPS
Independent Electric System Operator	Small Business Association of Michigan (SBAM)
International Transmission Company	Shepherd Advisors
Lansing Board of Water and Light	Strategic Energy
LS Power Development LLC	Technology, Energy, and Marketing
Mackinaw Power	Upper Peninsula Power Company
Michigan Attorney General, Special Litigation Division	We Energies
Michigan Buildings Trade	Whitecase
Michigan Department of Environmental Quality	Wisconsin Public Service Corporation
Michigan Electric and Gas Association (MEGA)	Wolverine Power Cooperative
	WPS Energy Services, Inc.

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Appendix B:
Synopses of CNF Presentations

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Appendix B:

Synopses of CNF Presentations

The Capacity Need Forum conducted formal meetings from April to September. The purpose of the meetings was twofold: to discuss ongoing progress of the workgroups and to provide speakers and topics on the wide range subjects impacting the electric industry in Michigan. Below is a summary of these speakers and a brief synopsis of their presentations.

April 22, 2005

Ellen Lapson and Jonathan Cho of Fitch Advisors spoke on issues relating to electric generation investment. This presentation was oriented towards Michigan's current market structure, which Ms. Lapson characterized as an unusual hybrid type in which the utilities retain ownership of generation assets that are included in regulated rate base.

Ms. Lapson summarized alternatives to foster generation additions in Michigan and suggested the current hybrid market structure would need a 'carve out' for new generation in the form of a non-bypassable charge that could be levied on all electric customers and therefore provide a certain revenue stream required by financing agencies.

Rao Konidena of the Midwest Independent System Operator (MISO) provided preliminary electric reliability estimates using the MARELI model. After Mr. Konidena described the model assumptions and the three modeling regions, he provided results showing that the stand alone capacity in the southeast Michigan region was significantly deficient and would not meet reliability standards for 2009.

May 27, 2005

-Vinson Hellwig, Chief of the Air Quality Division (AQD) of the Department of Environmental Quality, gave a summary of new air quality regulations and how they would impact air quality permitting for new electric generating units (EGU). Mr. Hellwig reports that a proposal for a sub-critical or super-critical coal plant would likely trigger an extensive public hearing phase that could delay permitting. There are several IGCC plants proposed around the country and if this type of plant becomes permitted, this technology could redefine the best available control technology (BACT) for EGU's.

-Rao Konidena of MISO provided another update on the reliability estimates for each of the three regions in the state. Mr. Konidena described recent revisions to the model inputs with subsequent results for stand-alone reliability in the Lower Peninsula regions and discussed planned future modeling runs using updated forecasting inputs.

-Tom Vitez of ITC and chairman of the Transmission & Distribution Work Group provided an overview of the transmission transfer studies and described the modeling assumptions. Mr. Vitez used a simple example to provide a description of the factors that influence transfer capability across the transmission system, including the amount and location of electric load, operating generation and transmission. He provided a summary of further work to be completed.

June 23, 2005

Jeff Bladen, Manager of Retail Markets for PJM, spoke about PJM's experience with capacity markets. Mr. Bladen explained that the purpose of capacity markets is to ensure capacity resource adequacy, provide coordinated planning of capacity resources, and support development of a robust, competitive marketplace. The problems experienced by PJM arise because the capacity payments are not coupled to locational value, operational reliability, or value provided and that has resulted in a generation net revenue shortfall and expected reliability violations by 2008. Mr. Bladen described the solution proposed by PJM as a Reliability Pricing Model (RPM). This model relies on locational price signals to encourage generation and transmission investment in the proper locations.

Charles Adkins, Vice President of Consulting with NewEnergy Associates, presented data related to gas price forecasting for use in the modeling initiative. Three scenarios were offered for discussion.

July 18, 2005

George Stojic presented a review of the Commission's current resource addition policy used if a traditional utility builds new generating capacity or seeks recovery of capacity purchases. He also presented a synopsis of CNF Steering Committee responses to the two questions posed by Staff regarding whether the Commission's current policy would induce construction of base load electric generation and if not, what changes could be made in Commission policy to do so.

Mike Robinson of MISO explained the various responsibilities that MISO has undertaken for its members, market participants, and the states within its footprint. Mr. Robinson addressed the issue of resource adequacy and long-term financial transmission rights. MISO was required by the Federal Energy Regulatory Agency (FERC) to develop a long-term resource adequacy proposal. Mr. Robinson explained that, unlike PJM, MISO has no interest in operating a capacity market. Instead, MISO's plan is to rely on energy markets to provide incentives to build additional generation in appropriate locations.

August 25, 2005

George Stojic presented the straw man proposal for comment by the CNF participants. The proposal addressed the issue that who will build and operate a new plant in Michigan and who will pay for it.

Tom Mallinger, Director of Interregional Coordination & Policy for MISO provided an update on the MISO/Ontario IESO seams agreement. Mr. Mallinger explained that an Interim Coordination Agreement (ICA) has been in effect since 7/1/2004 and provides for typical seams agreement issues (coordination of operations of interconnections, scheduling transmission service, voltage and reactive support, emergency assistance, security coordination and reliability assessment of outages, information exchange and confidentiality, adopt/enforce/comply with reliability standards etc.). The agreement, however, does not have a market to market congestion management process and a coordinated planning process. This is mainly due to the future operation of the Michigan-Ontario interface that will limit parallel path flows, reducing the need for coordination.

Kim Warren, Manager of Regulatory Affairs, Ontario IESO, explained Ontario's Off-Coal Transition initiative and how that may impact Michigan. Mr. Warren began by describing that the Ontario government is requiring the phasing out 6500 remaining MW of coal-fired generation by 2009. He summarized various proposals and timeframes for replacing this lost generation with transmission upgrades, renewable energy projects, hydroelectric sources, gas fired and nuclear generation. Most significantly from the perspective of Michigan, Mr. Warren explained that Ontario does not expect to rely on the interconnections for capacity requirements during the coal replacement transition, other than for extreme weather.

Sept 29, 2005

Jack Hawks, Vice President of Public Affairs & Planning for Electric Power Supply Association (EPSA) made a presentation on the competitive procurement process. Mr. Hawks discussed the advantages to competitive solicitations and components of a credible solicitation process. According to Mr. Hawks, the process should begin with a collaborative approach to the RFP overseen by the Commission, include an independent third part evaluator, and be open and fair. This means that all parties should have access to the same information and that decisions be open to public scrutiny. If a utility affiliate bids, special safeguards were recommended.

Mr. Hawks also discussed issues related to RFP format and bid evaluation. He explained the issue of debt equivalency that arises from purchase power agreements. According to Mr. Hawks, the best venue for addressing the debt equivalency issue is in a cost of capital proceeding, not in the bid evaluation process.

Paul Proudfoot, MPSC Staff, presented the results of the NewEnergy modeling. Mr. Proudfoot described major assumptions made by the Integration work group and the scenario/sensitivity approach used for modeling. He discussed the resources selected by the model and the major conclusions of the modeling effort.