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

Appendixes C – H

January 2006

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Appendix C

Integration Work Group Report

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Integration Work Group Report

January 2006

Copies of this report are available from the Michigan Public Service Commission's Web site, at: http://www.dleg.state.mi.us/mpsc/electric/capacity/cnf.

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1 Introduction

The Capacity Need Forum (CNF) was created as a collaborative industry-wide process to assess the projected need for electrical generating capacity in Michigan over the short-, intermediate-, and long-term future and to provide recommendations on the Commission's resource addition policy, if incumbent utilities seek to build additional generation. The Integration work group was responsible for modeling the State's electric generation resource needs and developing modeling scenarios. The process began with a an electric reliability assessment performed by the Midwest Independent System Operator (MISO). The reliability assessment was intended to determine whether Michigan's existing electric generating and transmission assets can satisfy electric reliability standards, given future load growth. The resource expansion modeling involved combining the demand forecast with the inventory of existing resources to determine when a capacity need is likely to develop, to identify the characteristics of the capacity need, and to select the a least cost set or resources the fill the future generation need. In addition, the Integration Group developed a set of scenarios likely to have a significant impact on resource plans, especially risks to which the plans are exposed. NewEnergy Associates was retained by the Integration Work Group to perform the modeling and to assist with data development.

1.1 Reliability Assessment

The reliability assessment was performed by MISO using the MARELI multi-area reliability model. The reliability assessment was performed for the ITC, METC, and ATC regions separately and for ITC and METC (MECS) collectively. The reliability model and results are discussed in part 2 of this report.

1.2 Comprehensive Electric Energy Resource Assessment

The balance of this report, parts 3-10, describe the assumptions, data, model format, and results of the resource expansion study.

The purpose of this Comprehensive Electric Energy Resource Plan was to evaluate a broad range of resource options across a number of market scenarios to determine the amounts and types of capacity that best fits the needs of the State of Michigan from a reliability and economic perspective. This study was designed to be a comprehensive planning process by evaluating a wide-ranging set of in-state resources and fully modeling economy energy options within the eastern interconnect markets. Unlike traditional Integrated Resource Planning, energy efficiency and renewable (non-traditional generating resources) were not included in a common model run with traditional utility central station options. Instead, scenarios were developed around each of these resource options. This was necessitated in part by our "top-down" approach to estimating energy efficiency performance, and our desire to better understand the cost/performance tradeoffs of various resource options. Selecting a single resource plan based upon cost alone may not provide the best resource plan for meeting future needs. How that plan performs under various scenarios and sensitivities provides valuable information for mitigating risk exposure in the future. Also, the Commission requested that potential options be provided to meet the future demand for electricity in Michigan. The scenario approach can readily be used to identify those options and the tradeoffs incurred in selecting among options.

The Comprehensive Electric Energy Resource assessment exhibited a number of key resource planning results. When Michigan’s transmission interconnection capacity is used for economy energy and not for external capacity purchases, the state of Michigan is in need of immediate capacity to meet planning reserve criteria. This need is demonstrated by the model’s adoption of two Combustion Turbines, as soon as practical, in 2007. After the model added sufficient capacity for reliability purposes, the model adopted intermediate and base load capacity for the State. As soon as available, the expansion plan selected energy producing, or base load, resources. Combined Cycles were the resource of preference until 2011, when Pulverized Sub-Critical Coal became the preferred resource the first year available due to construction lead time. Throughout the remaining study horizon, Coal was the preferred resource for the State of Michigan. The near term need for immediate capacity to meet planning reserve criteria and the need for intermediate and base loaded energy was further underscored in a variety of sensitivities and scenarios.

2 Reliability Study

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 load. Reliability modeling for the CNF was performed by the Midwest Independent System Operator (MISO). The MISO Staff used the Multi-Area Reliability Module (MARELI) computer model from New Energy Associates (A Siemens Transmission and Distribution Company) along with data from the CNF work groups to estimate future generation reliability in each region of the State.

2.1 Reliability Planning

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

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

If one were willing to relax the requirement of 100 percent certainty that demand always be met and, instead, assume a slightly reduced probability that demand could always be met through generation, then reserves, and associated costs, could be reduced significantly. The reduced probability that one is willing to assume is a measure of generation reliability. As indicated previously, the most widely accepted level of reliability is the willingness to tolerate the probability that generation is insufficient in one day out of ten years to meet load. This is the reliability standard that has been adopted by the CNF for generation/transmission planning purposes and the reliability standard used by MISO for the MARELI model runs.

2.2 MARELI Model

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

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

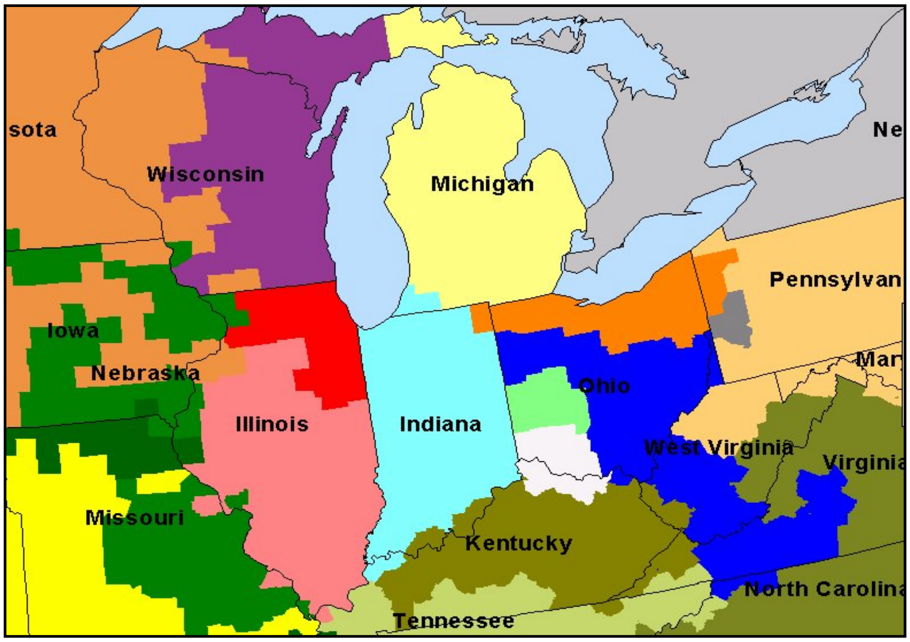
2.3 Michigan Study Results

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

The forecast loss of load probability was first calculated for each study region on a stand-alone basis. Stand-alone means that only native generation was considered available to meet load, and no transmission support was used to support load in the region. After these numbers were calculated, transmission intertie capacity (support from areas with direct ties) was included in the resource mix to meet the peak load. The amount of external support available depends, in part of the country the support is assumed to originate. The following regions were modeled to support the Michigan region: Mid-America Interconnected Network, Inc (MAIN), Mid-Atlantic Area Council (MAAC), Tennessee Valley Authority (TVA), Virginia and Carolinas Reliability Agreement (VACAR). MAIN and MAAC (also known as PJM) are some of the reliability councils defined by NERC (North American Electric Reliability Council). VACAR and TVA are part of the Southeastern Electric Reliability Council (SERC).

For Michigan's Upper Peninsula, transmission support was assumed from Michigan Electric Transmission Company, LLC (METC) and rest of the American Transmission Company (ATC) transmission system.

Figure 2-1: Transmission System Regions



Source: Midwest Independent System Operator

For the Base Case, the stand-alone loss of load probability numbers are shown below:

Figure 2-2: Stand-Alone Loss of Load Probability by Region

METC	.38 days/year
ITC	32.3 days/year
MECS	5.2 day/year
ATC Zone 2	289 days/year

Bearing in mind that the target LOLP is 0.1 day per year, the stand-alone results indicate that all regions violate the reliability standard.

The reliability study was performed a second time to include transfer capability as a source of support for meeting load. Two scenarios were studied. The first assumed phase shifter between Michigan and Ontario were set to allow zero flow to Ontario. The first scenario resulting LOLP's for each Michigan region, and based upon support sourced from various regions around Michigan are summarized in the following table:

Figure 2-3: First Scenario Results by Region

IESO Phase Shifter Flow = 0 MW								
			BaseCase		High Growth		Low Growth	
Sink	Imports From	Import Value	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

Source: Midwest Independent System Operator

Based on support from sources external to Michigan, METC satisfies the 0.1 day per year reliability test. MECS only requires 440 MW to meet the standard, but ITC requires an additional 1,050 MW to meet the LOLP standard. ITC will clearly be in violation of the standard, unless action is taken to improve reliability in that region.

Michigan reliability planning is significantly affected by the Ontario energy markets. Power flows originating from regions to Michigan's south and west and into Ontario are increasing, and this has an impact on Michigan's electric transmission capability. For example, in the preliminary MARELI run, the phase shifters between Michigan and Ontario were set to prohibit power flow between the regions. If this is not the case, then flows to Ontario may significantly increase the amount of needed capacity, because transmission available to Michigan decreases as flow to Ontario increases.

The second scenario is based on phase shifters allowing 1,500 Mw of flow from Michigan to Ontario and, again, allows external transmission support to meet reliability standards. As noted in the "Import Value" column, the amount of transfer capacity for reliability support decreases on an approximately one to one basis when transmission is used to supply electricity to Ontario. Results from this scenario are shown in the table below:

Figure 2-4: Second Scenario Results by Region

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

Source: Midwest Independent System Operator

Under Base Case assumptions, the ITC region experiences a significant violation of the LOLP reliability standards and METC experiences a marginal violation. Collectively, as MECS, the Lower Peninsula, likewise, experiences a violation of the LOLP reliability standard.

The Upper Peninsula's projected 2009 reliability was tested in two scenarios. The first scenario was peak demand, and the second was 70 percent of State-wide peak (off-peak) with the Ludington pumped storage facility in the pumping mode. This scenario tests the U.P.'s reliability when significant parallel flows are created through the U.P. by the Ludington plant in the pumping phase.

Native generation alone is insufficient to maintain acceptable reliability in the 2009 base case and off-peak scenarios. The LOLP resulting from native generation is calculated to be 289 days/year, which seriously violates the target level of 0.1 day/year. The relatively high LOLP is indicative of the mine loads in the region. Mine loads are constant loads so they have a high load factor (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 in the off-peak scenario, the U.P. needs an additional 60 MW's of transfer capacity. These results are consistent with previous LOLP studies performed by ATC in this region. These results are shown below:

Figure 2-5: Additional Off-Peak Transfer Needs

	ON PEAK	BaseCase		High Growth		Low Growth	
	Imports		Additional Imports		Additional Imports		Additional Imports
Sink	From	LOLP	Needed	LOLP	Needed	LOLP	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

Source: Midwest Independent System Operator

The MARELI studies were based upon a "no loss sharing" option. This means that areas adjacent to the study area are assumed to be a source of external support only if that adjacent area had excess reserves to share. Any generation deficiency in an adjacent area excluded support for the study area.

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

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

3 Introduction

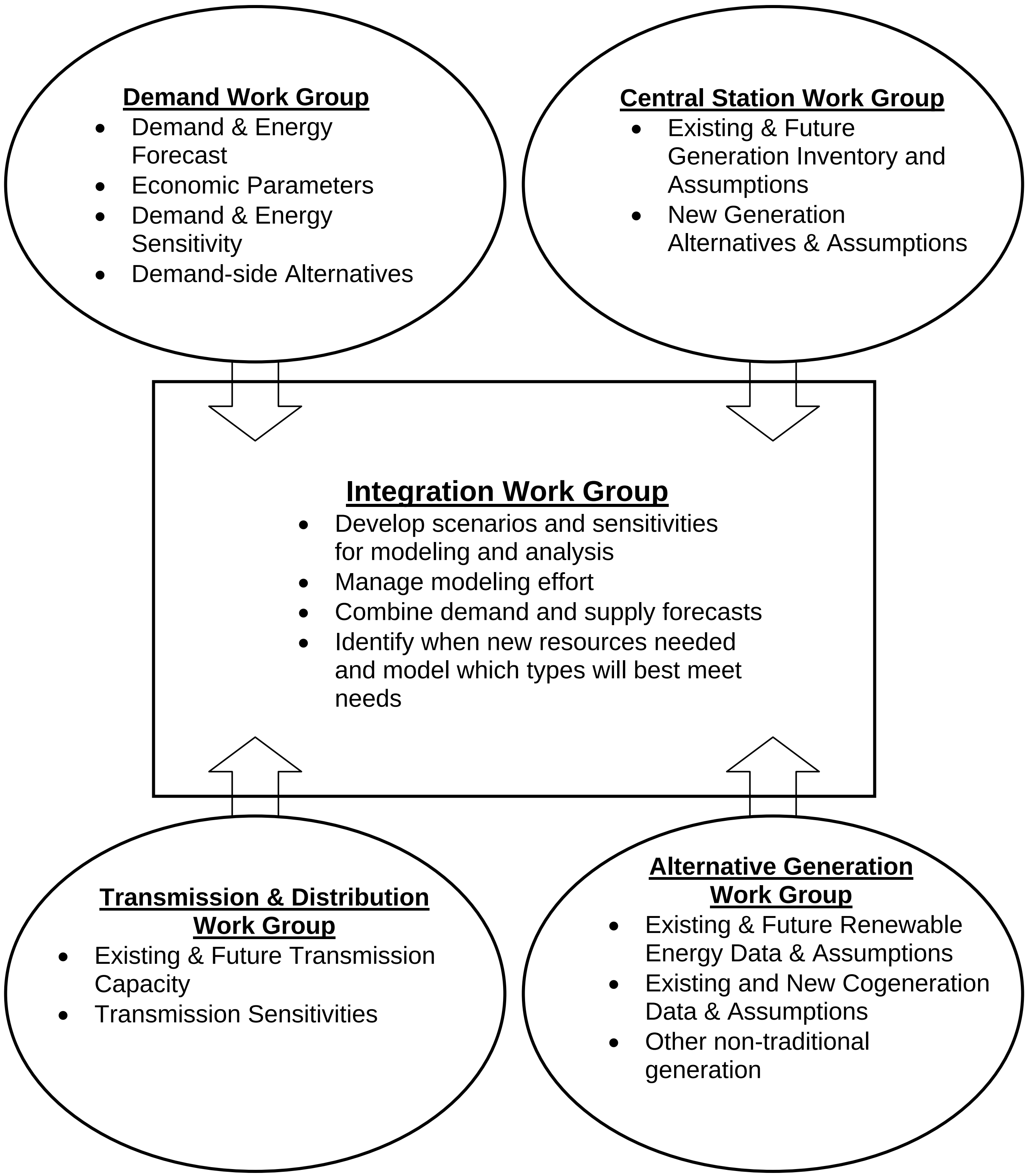
3.1 Capacity Need Forum Integration Working Group Modeling Overview

The Capacity Need Forum (CNF) relied on a three-part modeling effort to assess Michigan's future electric generating resource needs. First, it relied on ITC's MUST analysis to assess transmission import capacity in the base year, 2009. Second, it relied on MARELI reliability analysis performed by the Midwest Independent System Operator (MISO). Third, it relied on NewEnergy Associate's Strategist model to determine the best mix of resources for meeting future needs. Along, with the Strategist model, NewEnergy provided a forecast of future economy energy market prices from sources outside of Michigan.[1]

In order to provide the data necessary to undertake the three-part modeling effort, the Staff established five work groups from among participants to the CNF. Information from the Demand, Central Station, Alternative Generation, and Transmission work groups was provided to the IWG. The IWG completed resource expansion modeling. Figure 3-1 summarizes the work group configuration.

[1] Interconnected electric transmission networks can be used to deliver energy into Michigan, from sources outside the state. Michigan does have limited transmission import-export capacity, however. These issues are addressed by the Transmission and Distribution Work Group (see Appendix G).

Figure 3-1: Capacity Need Forum Work Groups



The IWG developed scenarios and sensitivities and managed the modeling effort. Inputs from the demand forecast and inventory of existing resources were utilized to determine both the timing and type of needs for additional capacity.

3.2 Purpose of the Comprehensive Resource Plan

The purpose of this Comprehensive Electric Energy Resource Plan was to evaluate a broad range of resource options across a number of market scenarios to determine the amounts and types of capacity that are most likely to best fit Michigan's future needs, based on analysis of both reliability and price. The Study evaluated a broad array of in-state resources along with economy energy purchases from out-of-state resources that could be transmitted to Michigan.

3.3 Overview of Integrated Resource Plan Process

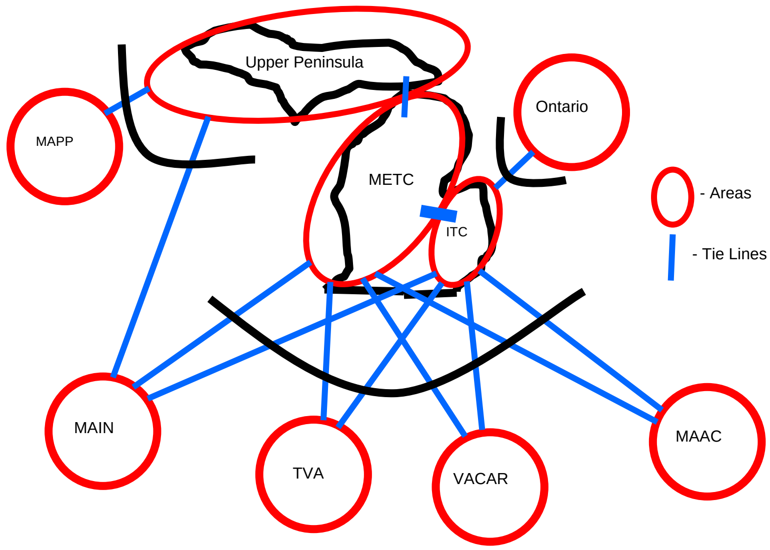
Step 1 Review Planning Policies and Develop Key Assumptions

- Identify and review CNF's Planning Policies including reliability criteria and other operational constraints and performance-measuring planning objectives
- Develop a Base Case forecast of projections for key system level assumptions such as:
    - Discount rates and inflation rates
    - Fuel prices
    - Load growth
- Identify sources of uncertainty and define and develop future scenarios to capture the range of potential variations in such uncertainties

The study was undertaken on a regional basis within Michigan. The three Michigan regions coincide with the service territories of the International Transmission Company (ITC), the Michigan Electric Transmission Company (METC), and the American Transmission Company (ATC) zone 2. In addition to three distinct regions, modeling of transmission exchanges, for reliability purposes and for importing and exporting energy and capacity, included ITC and METC collectively, referred to as the Michigan Electric Coordinated System (MECS). Economy energy, in the model, could be sourced from five regions beyond Michigan. This information is summarized in Figure 3-2.

The modeling assumptions did not include access to economy energy from Ontario. Instead, this interconnection was assumed to represent an energy sink in the minimum import sensitivity. Ontario's announced plan to retire approximately 7,000 MW of coal fired generation is one of the contingencies with which the Forum was concerned, and Ontario's energy market was modeled as a reduction in Michigan's import capacity. This contingency is discussed more thoroughly in other sections of this study.

Figure 3-2: Michigan System Representation



Comprehensive resource planning on a regional basis requires sophisticated representations of loads and of the generation and transmission systems that supply the load. While the loads and individual generating units can be readily modeled, individual transmission line representations are beyond the analytical capabilities of optimizing, multi-area, resource-planning computer models. Instead, the key aspects of the transmission system are captured in the model using transmission interfaces to represent the transmission interconnection(s) between adjacent zones.

The zonal/interface representation of the Michigan system, shown in Figure 2-2, is designed to capture the key transmission constraints within the Michigan transmission system. These constraints are South/North across the Straits and West/East across the Lower Peninsula. The North/South interconnection at the Straits is limited to 50 MW by constraints in the Northern portion of the Lower Peninsula. The West/East transfer capability, previously estimated at 2,850 MW, has recently been enhanced to approximately 4,000 MW in the base case year of 2009. This constraint has been a reliability issue in the past since most, recent generation has been built in the METC regions, but most load is in the ITC region. This imbalance has created transfer constraints in the past.

Data has been collected for the following types of existing and proposed resources:

- Supply-side resources
  - Existing generation units
  - Estimated retirements
  - Optional new construction
- Demand-side resources
  - Existing interruptible loads
  - Existing conservation programs
  - Possible additional interruptible loads
  - Optional additional conservation programs

  (New load management programs were not modeled. It was assumed that new load management may be an appropriate alternative to combustion turbines and, therefore, combustion turbine capacity represents peaking capacity that could be served by these units or, perhaps, by new load management programs.)
- Transmission interfaces
  - Existing capabilities
  - Optional enhancements

The data items compiled for each resource listed above include:

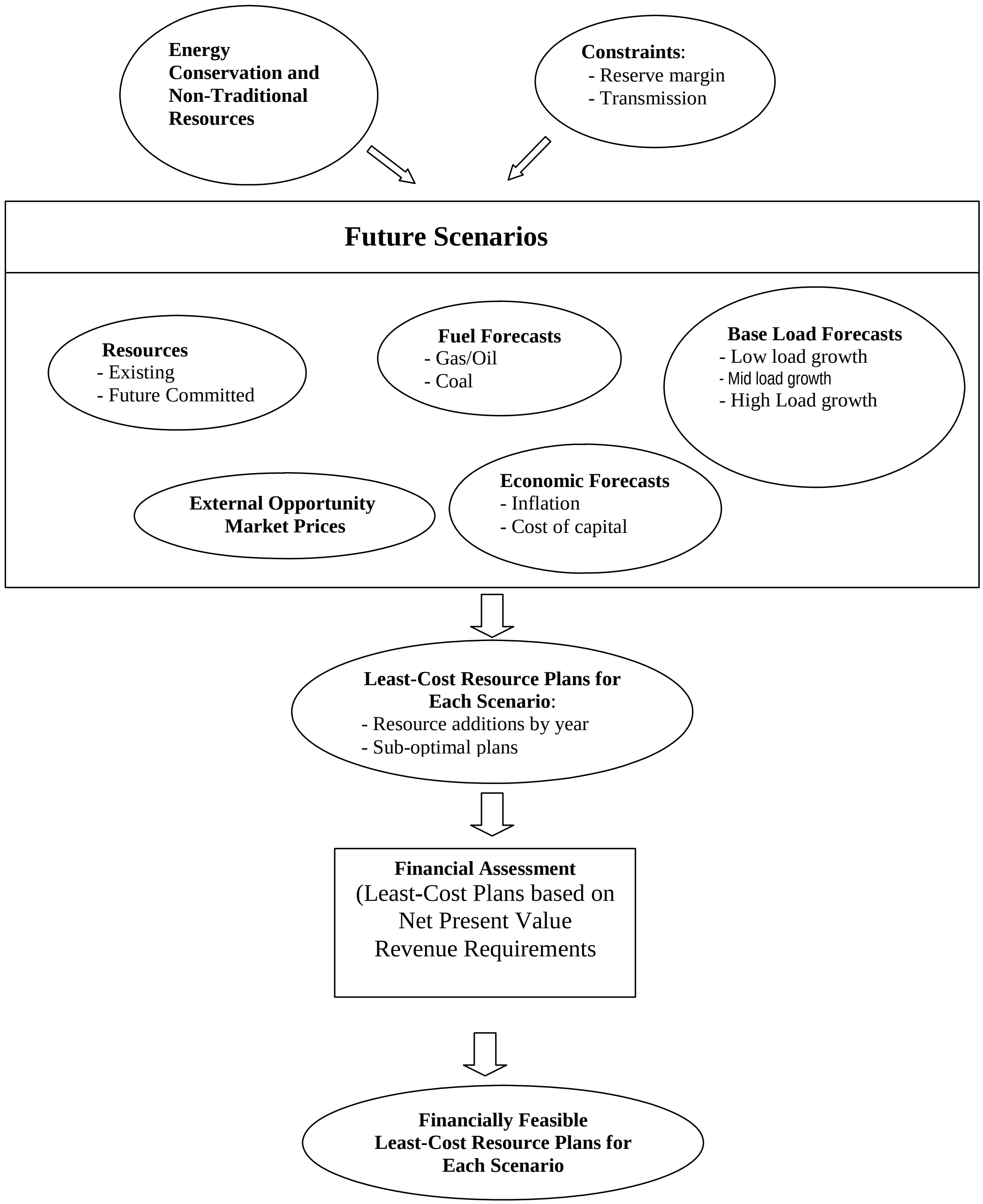
- Load representations
  - Forecast annual energy and peak demand growth
  - Consumption patterns: monthly peaks, energies, and hourly shapes
- Supply-side resource representations
  - Capital cost
  - Construction lead time, annual capital expenditure profile
  - Financing charges (e.g. levelized carrying charge rates)
  - Annual fixed O&M expenses
  - Annual capitalized O&M expenditures
  - Variable O&M expenses
  - Book and operating lives
  - Maximum and minimum net capacities
  - Seasonal capacity de-rates
  - Monthly maximum energy limits
  - Fuel type(s) and any limitation(s)
  - Plant-specific fuel price projections
  - Net heat rate curves
  - Annual planned maintenance requirements
  - Full and partial forced outage rates
  - Dispatchability/must-run constraints
  - Effluent emission rates
- Demand-side resource representations
  - Annual energy savings
  - Utility administrative costs (fixed and/or per participant)
- Transmission interface representations
  - Bi-directional MW capacities

In addition, the following system-level policies and assumptions were adopted:

- Performance measure (NPV utility cost)
- Planning period
- Inflation rates
- Discount rates
- Fuel price escalation rates
- Construction cost escalation rates
- System installed capacity reserve requirement
- Zonal installed capacity reserve requirement
- Emission constraints
- Sensitivity scenarios

Step 2 Optimize Michigan's Supply-Side Portfolio (w/o new Demand-Side Resources)

Figure 3-3: Optimization Process



Step 3 – Plan Integration

- Screen all available future resource types on a full life-cycle Present Value Levelized $/MWh bus-bar cost.
- Eliminate resources that are unable to compete economically over the study horizon.
- Schedule-in all alternative generation (i.e., Wind, LFG, Anaerobic Digestion, and CHP) and demand-side alternatives.
- Identify robust supply-side resources (resources selected under most scenarios)
- Resources which require short-term capital commitments are of particular concern
- Incorporate a transition period, in the near-term planning horizon, during which the 15 percent reserve margin target should be met.
- Identify key near term resource contingencies for the optional plans based upon quantifiable and subjective criteria:
    - Fuel Diversification
    - Flexibility
    - Other

4 Planning Process

4.1 Planning Tools

The Integration Work Group relied on software developed by New Energy Associates LLC to model electric generation resource needs. New Energy has developed several proprietary planning models to assist with electric capacity planning. The model is comprehensive, allowing comparisons of demand-side measures along with traditional and non-traditional generation options. The “Strategist” model uses a dynamic programming algorithm to search for and select an optimum resource solution, when additional resources are needed. The modeling procedures allow for a comparison, or ranking, among solutions as scenarios change. This option permits one to manage cost and risk associated with the various scenarios.

The Net Economy Interchange module uses a marginal cost algorithm to estimate economy energy prices among interconnected systems, while respecting transfer limits between adjacent systems. The module encompasses a broad geographical footprint comprising most of the utilities, and generating units, in the Eastern Interconnected System.

The principal objective of the model is to identify the best resource plan that will satisfy the electric generation needs of the State, subject to a reliability-based generation reserve constraint. A more detailed description of the model is attached as Appendix D.

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5 Modeling Requirements

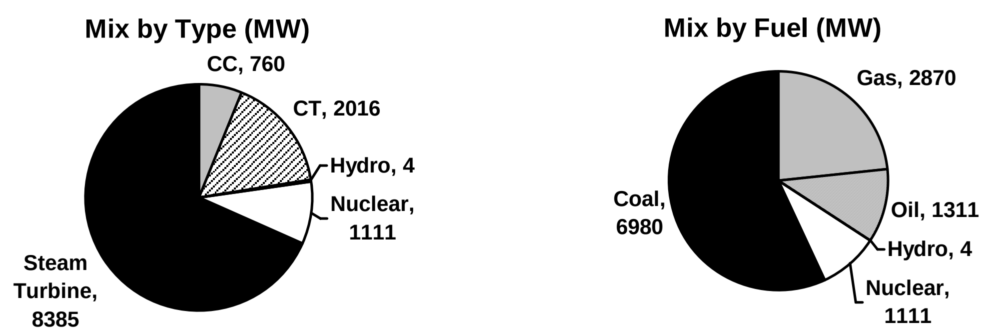
5.1 Existing System

5.1.1 Existing Traditional Generation Resources

All existing native generation was reviewed by Consumers, Detroit Edison, Wolverine, and the Lansing Board of Water and Light. Existing resources consisted of Combined Cycles, Gas Combustion Turbine, Oil Combustion Turbine, Hydro Run of River, Hydro Storage, Nuclear, Pumped Storage Hydro, Coal Steam Turbine, Gas Steam Turbine, and Oil Steam Turbine. The existing resources are contained in Appendix B – Generation Capability Tables.

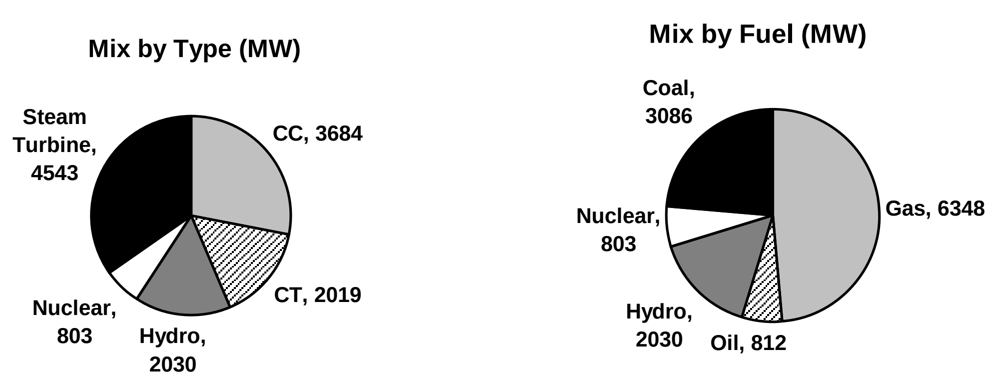
- ITC AREA see Appendix B – Generation Capability Tables Figure B - 1.

Figure 5-1: ITC Existing Capacity Mix



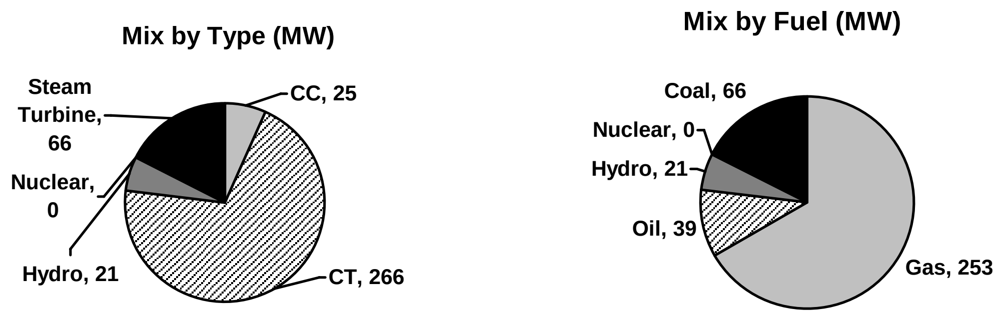
- METC Area see Appendix B – Generation Capability Tables Figure B - 2.

Figure 5-2: METC Existing Capacity Mix



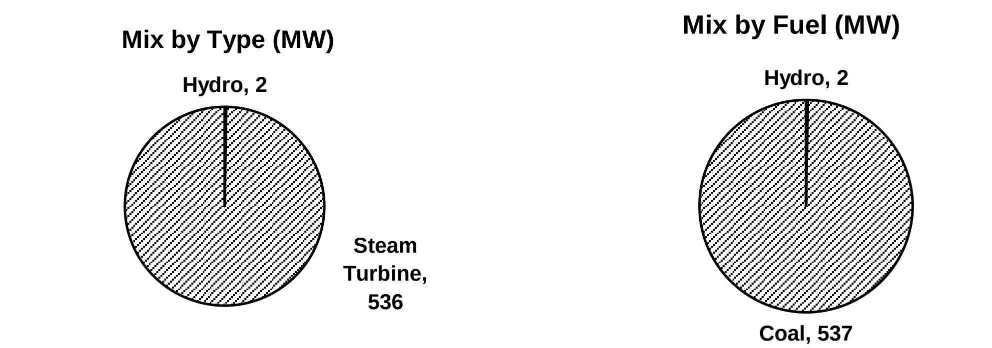
- Wolverine see Appendix B – Generation Capability Tables Figure B - 3.

Figure 5-3: Wolverine Existing Capacity Mix



- Lansing BWP see Appendix B – Generation Capability Tables Figure B - 4.

Figure 5-4: Lansing Existing Capacity Mix

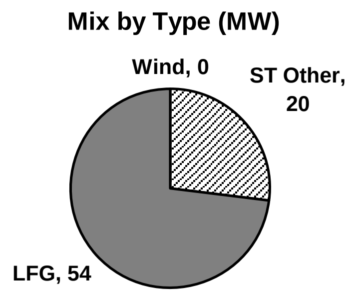


5.1.2 Existing Non-Traditional Generation Resources

All non-traditional generation was reviewed by Consumers, Detroit Edison, Wolverine, and the Lansing Board of Water and Light. Non-Traditional resources consist of Landfill Gas, Anaerobic Digestion, Other Steam Turbine (principally wood fueled), and Wind. The existing resources are contained in Appendix B – Generation Capability Tables.

- ITC Area see Appendix B – Generation Capability Tables Figure B - 1.

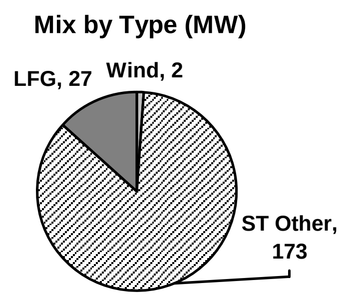
Figure 5-5: ITC Non-Traditional Mix



Note: “ST Other” refers to steam turbine generation, at waste-to-energy plants.

- METC Area see Appendix B – Generation Capability Tables Figure B - 2.

Figure 5-6: METC Non-Traditional Generation Mix



Note: “ST Other” refers to steam turbine generation, at waste-to-energy plants.

- Wolverine see Appendix B – Generation Capability Tables Figure B - 3.
    - No Non-Traditional Generation
- Lansing BWL see Appendix B – Generation Capability Tables Figure B - 4.
    - No Non-Traditional Generation

The Central Station Work Group provided the following assumptions for unit retirements.

- Coal units service life 65 years.
- Nuclear units service life 60 years
- Combined Cycle service life 40 years.

- Combustion Turbine service life 30 years.
- No existing Combustion Turbines will be retired during the study. It is assumed that all existing Combustion Turbines will be replaced in kind.

The detail schedule of unit retirements is outlined in Appendix B – Generation Capability Tables Figure B - 5. For summary purposes, the following table represents the total capacity retirements through the course of the study horizon.

Figure 5-7: Aggregate Unit Retirements

Year	Capacity (MW)
2013	129
2014	0
2015	301
2016	226
2017	204
2018	439
2019	375
2020	180
2021	402
2022	584
2023	400
2024	515

For the Emissions Case, the IWG assumed an additional 15 percent reduction in Mercury beyond that required by the Clean Air Mercury Rules (CAMR). In this case, we have assumed that Eckert 1-6 will not be able to meet more stringent Mercury reductions and was retired.

5.1.3 Existing Demand-side Resources

No existing demand-side resources were represented.

5.1.4 Existing Transmission Resources

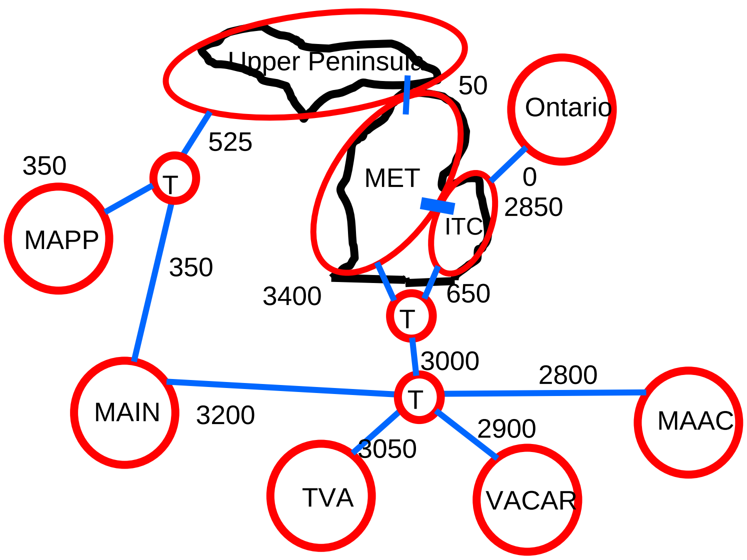
The Transmission and Distribution Work Group was responsible for estimating the transmission import capability into Michigan for the Capacity Needs Forum. The Work Group's specific responsibilities included:

1. Estimating the transmission import capability into Michigan in 2009 with no transmission system modifications beyond those planned or proposed in the 2005 Midwest ISO Transmission Expansion Plan (MTEP);

2. Identifying transmission upgrades that may be available to increase transmission transfer capability within Michigan and into Michigan;
3. Reviewing issues that may have an impact on the State's ability to utilize or expand its transmission system.

The following graphic represents the results of the T&D work group's estimation of import capability. These assumptions were augmented with import capabilities for the Upper Peninsula from ATC[2]. We assumed 50MW of interface capability between the Upper Peninsula to the METC. ATC interface capability with external markets is expected to increase to the following amounts: 224MW in 2005, 300MW in 2006, 325MW in 2008, and 525MW in 2010. These quantities represent on-peak, simultaneous import capabilities.

Figure 5-8: 2010 Transmission Interface Capability [3]



Interface	Capacity	ST from	ST to	Source File
All to MECS	3000	TN Hub	Michigan	CNF_transferstudy_results_05_10_2005 tables.xls
Into METC	3400	TN Hub	METC	CNF_transferstudy_results_05_10_2005 tables.xls
METC to ITC	2850	METC	ITC	CNF_transferstudy_results_05_10_2005 tables.xls
Into ITC	650	TN Hub	ITC	METC to ITC (I344) minus into ITC (I6)
Into Ontario	0	ITC	Ontario	Study Assumption
Notes: "TN" means transmission node hub. "ST from" means source for a transmission transaction and "St to" means the sink of a transmission transaction				

[2] August 4, 2005 conference call with Jay Schmidt of ATC

5.2 Resource Options

5.2.1 Options Overview

The Central Station working group selected the base technologies for traditional utility generation options. The generation options include:

- Pulverized coal (super-critical and sub-critical)
- Circulating Fluidized Bed Boilers (CFB)
- Nuclear
- Integrated Gasification Combined Cycle (IGCC)
- Traditional combined cycle combustion turbines
- Simple cycle combustion turbines.

For pulverized coal it was assumed that new source environmental compliance would require selective catalytic reduction (SCR) for NOx removal, a scrubber for SO_2 removal, a fabric filter or precipitator for particulate control and some type of sorbent injection for removal of mercury.

5.2.2 Generation Options

The following table summarizes the Central Station Working Group's estimate of costs for the generation options. All dollar figures are represented in 2005 Dollars.

Figure 5-9: Generation Options Cost Table

Type	Capacity (MW)	Construction ($/kW)	Fixed O&M ($/kW)	Variable O&M ($/MWh)	Heat Rate (Btu/kWh)	Construction Lead Time
PC, Sub-critical	500	1,370	42.97	1.80	9,496	6 years
PC, Super-critical	500	1,437	43.60	1.70	8.864	6 years
Fluid Bed	300	1,505	44.70	4.24	9,996	6 years
IGCC	550	1,647	59.52	0.95	9,000	6 years
IGCC-PRB	550	1,845	59.52	0.95	10,080	6 years
Nuclear	1,000	2,180	67.90	0.53	10,400	11 years
CC	500	467	5.41	2.12	7,200	5 years
CT	160	375	2.12	3.71	10,450	3 years

The Work Group assumed that new coal fired generation would burn Powder River Basin (PRB) coal. The only exception was a new IGCC unit which was priced with eastern and

PRB coal. The following table summarizes the Central Station Working Group's estimate of emissions for the generation options.

Figure 5-10: Generation Options Emissions

Type	SO_2	NOx	Hg	CO_2
PC, Sub-critical	0.05	0.08	1.22×10^{-6}	201
PC, Super-critical	0.05	0.08	1.22×10^{-6}	201
Fluidized Bed	0.02	0.10	1.22×10^{-6}	200
IGCC	0.03	0.06	8.05×10^{-7}	195
Nuclear	0.00	0.00	0.00	0.00
CC		0.03	0.00	120
CT		0.03	0.00	120
Note: All units expressed in pounds of emissions per million Btu input.				

5.2.3 Other Assumptions

To more accurately represent the expected operating costs of Combined Cycle Generation, $20.52/kW (2005) was added to the plant's fixed O&M to represent the cost of reserving annual pipeline capacity. Pipeline capacity is needed to support the transmission of gas from Louisiana to Michigan. For Combustion Turbines, $5.13/kW (2005) was added to the fixed O&M for the summer months to support the transmission of gas from Louisiana to Michigan.

The sources of the natural gas firm transportation rates were the currently effective tariff rates for ANR pipeline (Tariff FTS-1) and Trunkline Gas Company (Tariff FT). The final fixed price adder was the result of a straight average between the two pipeline tariffs. In addition, a commodity charge of $0.014/MMBTU was added to the commodity price for gas delivered under the reserved pipeline capacity.

In addition to more stringent mercury emissions standards, the Emissions Scenario included a regulatory carbon tax. As a strategy to address the carbon dioxide tax, three plants were modified to capture carbon. The following table of costs represents the modifications to the existing generation options for carbon sequestration. All dollar figures are represented in 2005 Dollars.

Figure 5-11: Coal Sequestration Cost Table

Type	Capacity MW	Construction $/kW	Fixed O&M $/kW	Variable O&M $/MWh	Heat Rate Btu/kWh	Construction Lead Time
PC-Super	500	2,502	75.87	2.95	12,437	6 years
IGCC	550	2,299	73.38	1.18	10,959	6 years
IGCC-PRB	550	2,575	73.38	1.18	12,274	6 years

All future generation options include a transmission interconnection fee based on 5 percent of the capital investment for a generic coal unit ($74.49/kW, 2005 Real Dollars). This is in addition to the onsite transmission related costs that are included in the construction costs shown in Figures 4-9 and 4-11.

5.2.4 Non-Traditional Options

The Alternate Generation Resource Option Group was responsible for compiling an inventory of existing renewable energy, distributed generators, combined heat and power (CHP), and other generation resources in Michigan. The group was also responsible for identifying and compiling data on new renewable, distributed generators, CHP, and new, innovative electric generating options that are likely to be available to meet Michigan's electric generating capacity needs. The Alternate Generation Resource Option work group provided estimates for the capacity potential for renewable resources, investment costs, operating costs, and operating characteristics. Non-Traditional options considered for this study include: Landfill Gas, Anaerobic Digestion, On-shore Wind, and cogeneration.

The following table outlines the schedule of cumulative estimated available capacity (MW) by renewable resource type.

Figure 5-12: Renewable Capacity (MW)

	LFG	Digestion	Wind	CHP
2006	24	10	99	0
2007	47	20	198	68
2008	71	31	272	137
2009	94	41	346	205
2010	118	51	420	274
2011	120	51	420	342
2012	123	51	420	410
2013	126	51	420	479
2014	128	51	420	547
2015	131	51	420	547
2016	134	51	420	547
2017	136	51	420	547
2018	139	51	420	547
2019	142	51	420	547
2020	145	51	420	547
2021	147	51	420	547
2022	150	51	420	547
2023	153	51	420	547
2024	155	51	420	547

Landfill Gas and Anaerobic Digestion were assumed to operate at a capacity factor of 65 percent. Wind was estimated to operate at a capacity factor of 25 percent and Cogeneration was estimated to operate at a capacity factor of 95 percent. All non-traditional resources were modeled as purchase power agreements and the generators were paid 7¢/kWh (2005) and then escalated annually at the GDP deflator escalation rate. Wind was assumed to have zero emissions. Cogeneration, Landfill Gas, and Anaerobic Digestion emissions were assumed to result in zero net emissions.

5.2.5 Demand-side Options

The estimated potential impacts of energy efficiency programs were represented as a resource in the Energy Conservation Cases. Figure 5-13 represents the annual cumulative capacity and energy associated with the energy conservation program. Achievable energy savings for Michigan were based on estimates, including projections of savings calculated by the American Council for an Energy-Efficient Economy (ACEEE). The Working Group utilized only the savings potential estimated by ACEEE from utility programs. This amount was estimated to by 50 percent of the entire savings potential projected by ACEEE for Michigan, and was the amount adopted by the Demand Working Group for planning/modeling purposes. The utilities' costs of the energy conservation programs were estimated to be $110,000,000 (2005$) per year and escalated at GDP.

Figure 5-13: Energy Efficiency Estimates of Capacity and Energy

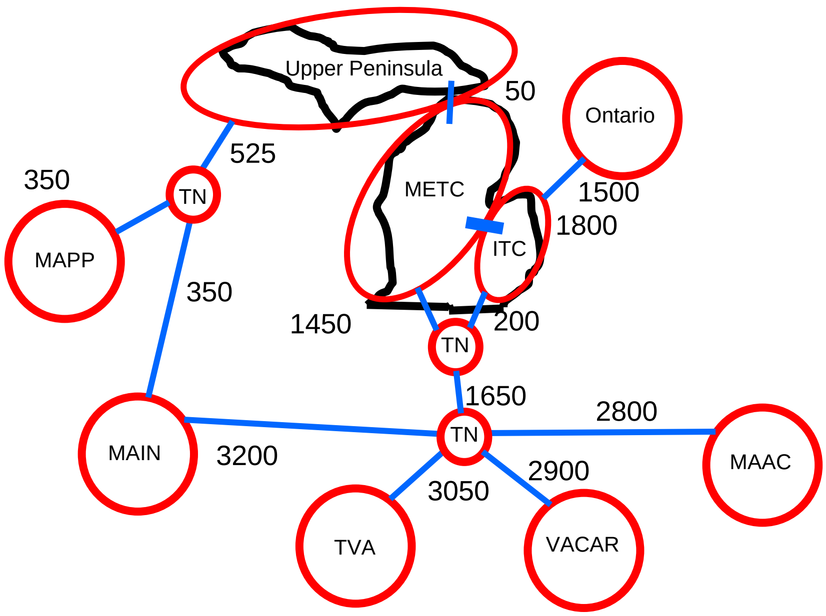
Energy efficiency							
	Capacity (MW)	Energy (GWh)			Capacity (MW)	Energy (GWh)
2006	145	1,108		2016	716	5,465
2007	200	1,523		2017	802	6,122
2008	255	1,943		2018	892	6,807
2009	313	2,386		2019	985	7,516
2010	371	2,831		2020	1,081	8,247
2011	425	3,240		2021	1,100	8,391
2012	479	3,653		2022	1,119	8,537
2013	536	4,086		2023	1,138	8,684
2014	593	4,525		2024	1,158	8,834
2015	654	4,992				

5.2.6 Transmission Options

For the purpose of the Michigan comprehensive resource study, external capacity selling into or from the Michigan market was excluded. The external market was utilized for non-firm economy energy interchange only.

Two transmission scenarios, representing a Low Import and a High Import case, were used. The Low Import case assumed 1500 MW of sales going across Michigan from MISO to Ontario Hydro. Transfers to Ontario, through Michigan, produce significant reductions in transfer capability for Michigan's use from other regions. The following figure represents the impact to transfer capabilities of 1,500 MW flow through Michigan to Ontario.

Figure 5-14: 2010 Low Import Capabilities (MW)



The High Import case assumed adoption of the Tier 1 improvements to Michigan's transmission system. Tier 1 improvements are categorized as southern (external into Michigan) and west/east within Michigan. Transmission projects needed to increase import capabilities into Michigan beyond those included in the base case 2009 projections to the first planning "plateau" are referred to as Tier 1 southern improvements and include:

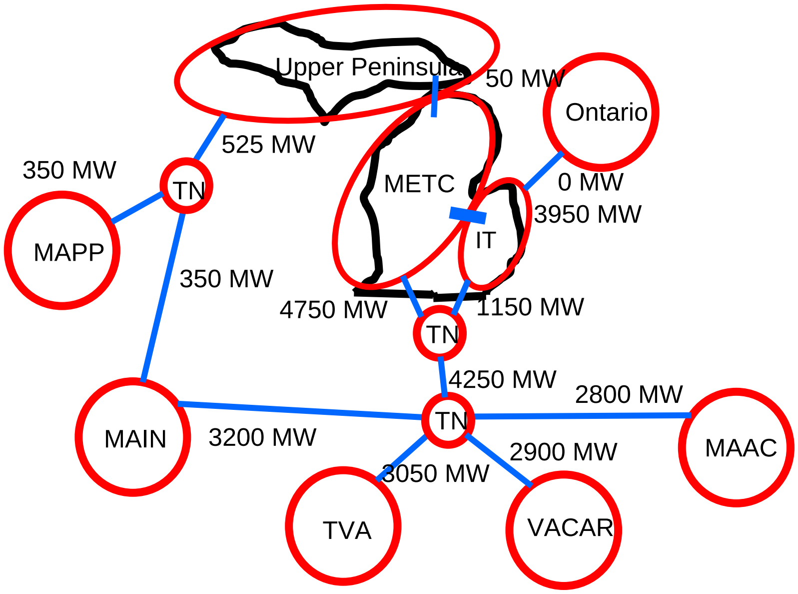
1. Adding transmission in western ITC.
2. Building a station in southwestern ITC, and
3. Reconfiguring some southern ITC circuits.

The west/east Tier 1 METC-ITC upgrades were designed to increase west to east flows within Michigan and include:

1. Building a new 345/230 kV interconnection between the METC system and the ITC system in the northern portion of the METC-ITC interface.
2. Build a new 138/120 kV interconnection between the METC system and the ITC system in the southern portion of the METC-ITC interface.

The following figure represents the impact to Transfer capability.

Figure 5-15: 2010 High Import Transfer Capability



The High Import case assumed Tier 1 improvements with a cost of $100 million to the transmission system. The $100 million cost for Tier 1 upgrades were not included in the costs of the Michigan study. The estimated 2009 transfer capabilities into Michigan's Lower Peninsula under the base, high import, and low import cases are shown in the following table:

Figure 5-16: Key Interface Capabilities

Transmission Interface	Base Case	High Import	Low Import
Into Michigan	3,000	4,250	1,650
Into METC	3,400	4,750	1,450
Into ITC	650	1,150	200
MECS	2,850	3,950	1,800
Note: All units shown in MW.			

5.3 Miscellaneous

5.3.1 System Requirements

For the purpose of this study, the Michigan statewide reserve margin was set to 15 percent. This figure was not representative of each participant's individual planning criterion, which may differ from this statewide criterion. The 15 percent statewide reserve margin criterion is supported by the results of the reliability study performed by MISO. Native generation, together with external support necessary to provide a 1-day in 10 years loss of load probability, equates to approximately a 15 percent reserve margin above forecast peak load for 2009. However, as noted in the reliability section of this study, reliability is affected by the size and availability of generating units among other factors. Differences are likely to exist between regions based on these reliability determinants, and, therefore, differing reserve margins among regions is not unusual.

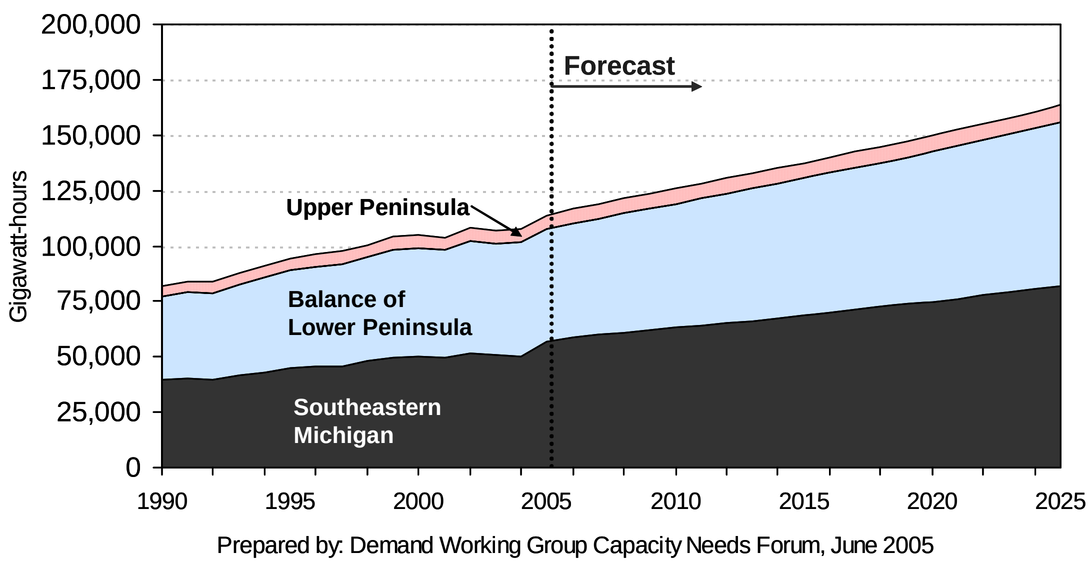
Interchange with the external market represented non-firm spot market purchases and sales of energy only. As indicated previously, no attempt was made to simultaneously include external capacity and economy energy markets.

5.3.2 Demand Forecast

The Demand Work Group was charged with preparing a base electric demand and energy forecast for the period running from 2005 to 2025 for use by the Capacity Need Forum's Integration Group. The projections rely primarily on forecast data provided by members of the working group including: Consumers Energy, Detroit Edison, Wolverine Power Cooperative, Michigan municipal utilities, WE Energies and WPS Energy. Due to the uncertainties in forecasting electric demand, forecast scenarios were also completed by the Demand Work Group base on low load growth and high load growth assumptions.

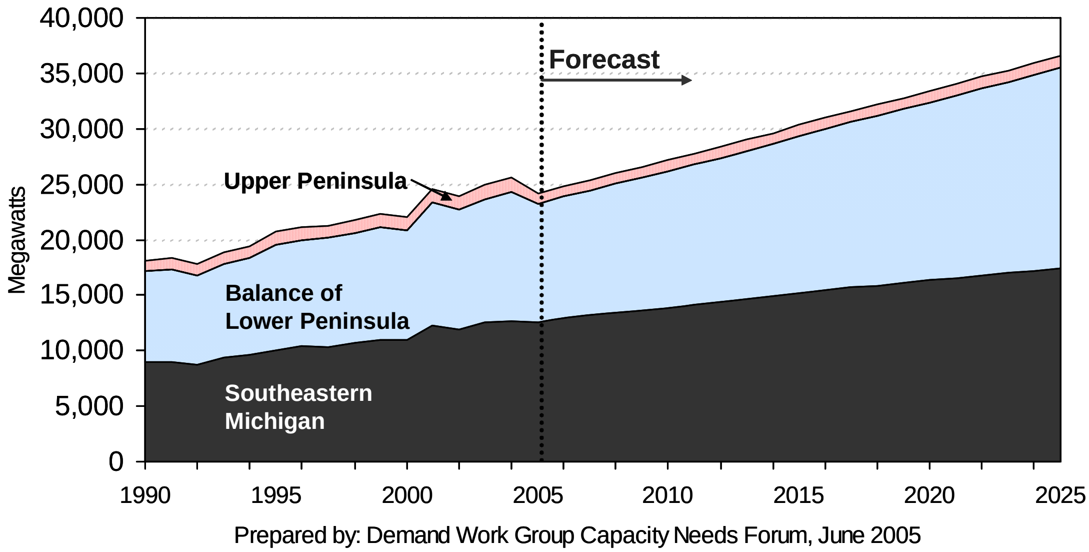
Michigan's total electricity needs are expected to grow by 1.8 percent from 2005 to 2025, from 113,782 GWh to 163,411 GWh.

Figure 5-17: Base Michigan Energy Forecast



Peak demand is expected to grow from 24,101 MW to 36,589 MW, or at a rate of 2.1 percent from 2005 to 2025.

Figure 5-18: Base Michigan Demand Forecast



5.3.3 Fuel Forecast

5.3.3.1 COAL FORECAST

Delivered Coal forecasts were generated for 10 of the 13 Department of Energy, Energy Information Agency (EIA), defined coal demand regions. These forecasts were sourced from 4 of the 14 EAI defined coal supply regions.

Figure 5-19: Coal Demand Regions

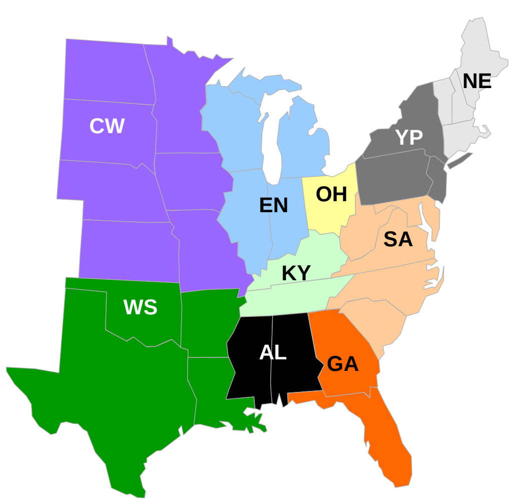
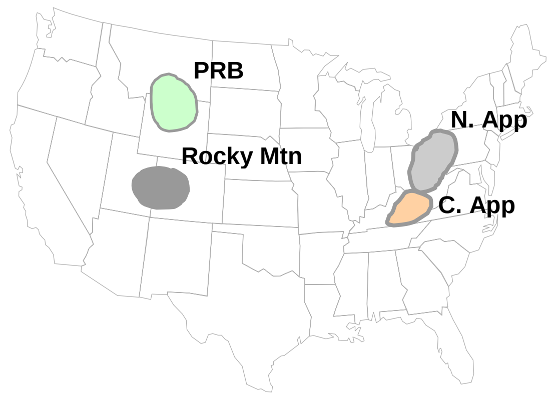


Figure 5-20: Coal Supply Regions



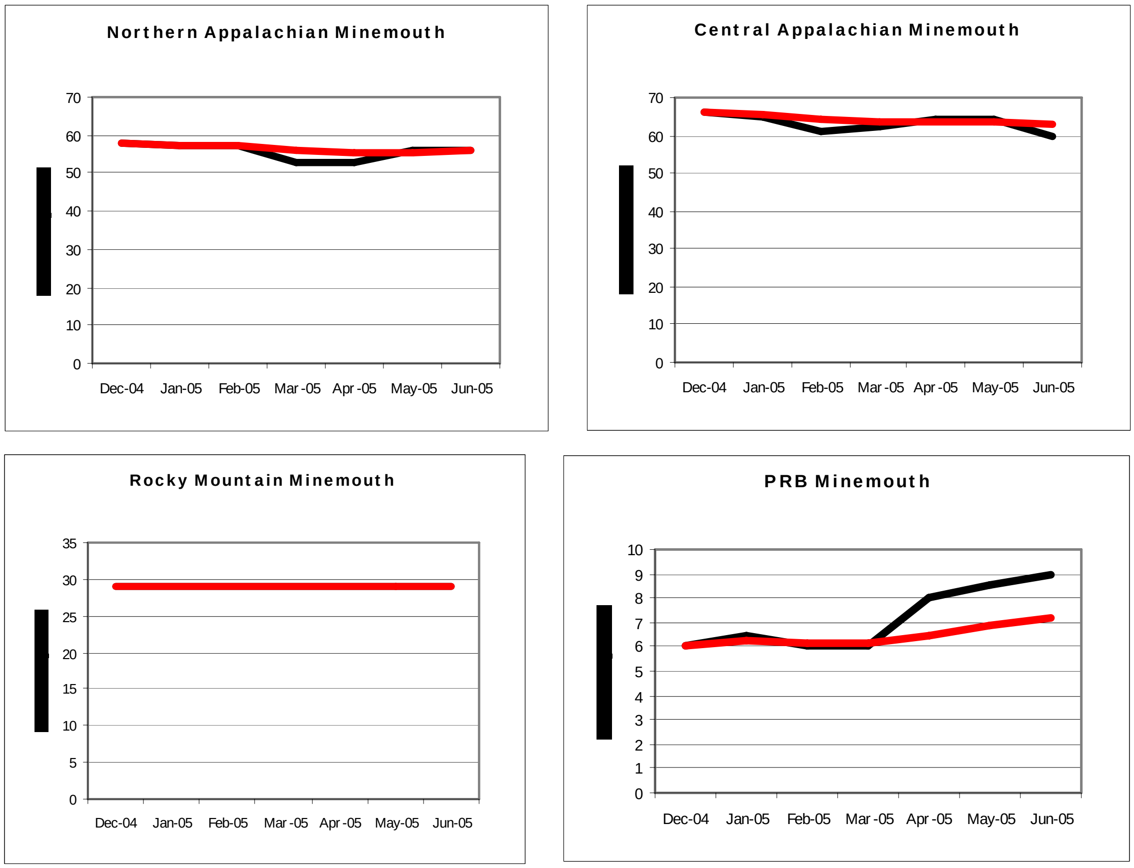
The average transportation cost between each supply and demand region was extracted from the EIA 2005 Annual Energy Outlook. Additionally, a transportation escalation rate of 2 percent was adopted, which is the rate from the EIA 2005 Annual Energy Outlook. The following table enumerates the transportation charges between each of the supply regions and the "EN" region, where Michigan is based.

Figure 5-21: EN Transportation Costs

Demand Region	Supply Region	Average Transportation Cost (2003 Dollars)
EN	PRB	13.05
EN	NA	8.83
EN	CA	10.32
EN	RM	20.68

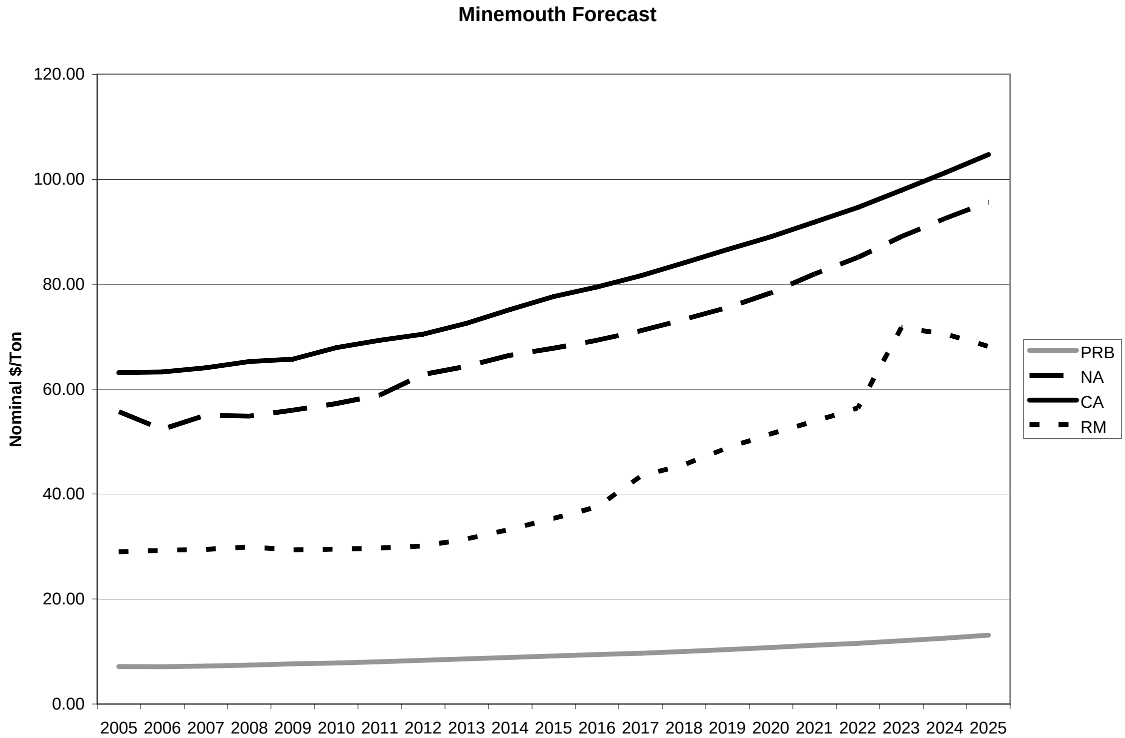
The starting FOB mine price for coal was calculated for the four supply regions within the United States: the Powder River Basin (PRB), Rocky Mountain, Central Appalachia, and Northern Appalachia. For each of the supply regions, the initial coal cost was calculated based on a 7 month average of historical mine mouth prices (December '04 to June '05). This rate was then escalated each year. The annual year-to-year percent change from the EIA 2005 Annual Energy Outlook mine mouth forecast for PRB, Rocky Mountain, Central Appalachian, and Northern Appalachian supply regions were utilized to preserve the base trends of the EIA forecast.

Figure 5-22: Historical Mine Mouth Prices[4,5]



[4] Source: EIA Coal News and Markets
[5] The red line reflect the running average

Figure 5-23: Mine Month Forecast



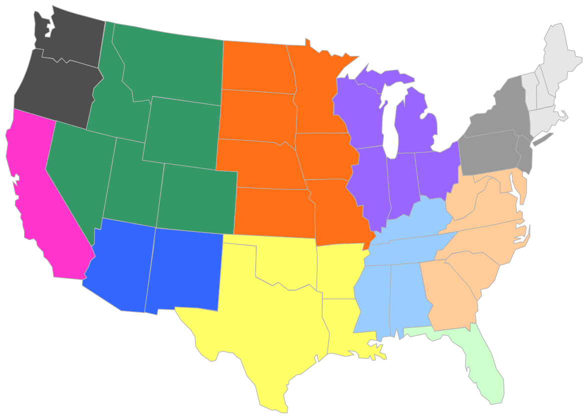
A blend of coal for each Michigan plant was developed based upon FERC Form 423 and client input. The final delivered price of coal was the sum of the mine mouth forecast and the average transportation charges, weighted by the blend of coal used at each power plant.

5.3.3.2 NATURAL GAS PRICE FORECAST

The starting point for the Natural Gas Price Forecast was the Lower 48 Average Wellhead price forecast[6] from the EIA 2005 Annual Energy Outlook. The process for forecasting Natural Gas prices concluded with a delivered price for 12 EIA defined distribution regions.

6 Table 102. Lower 48 Natural Gas Production and Wellhead Prices by Supply Region

Figure 5-24: EIA Distribution Regions



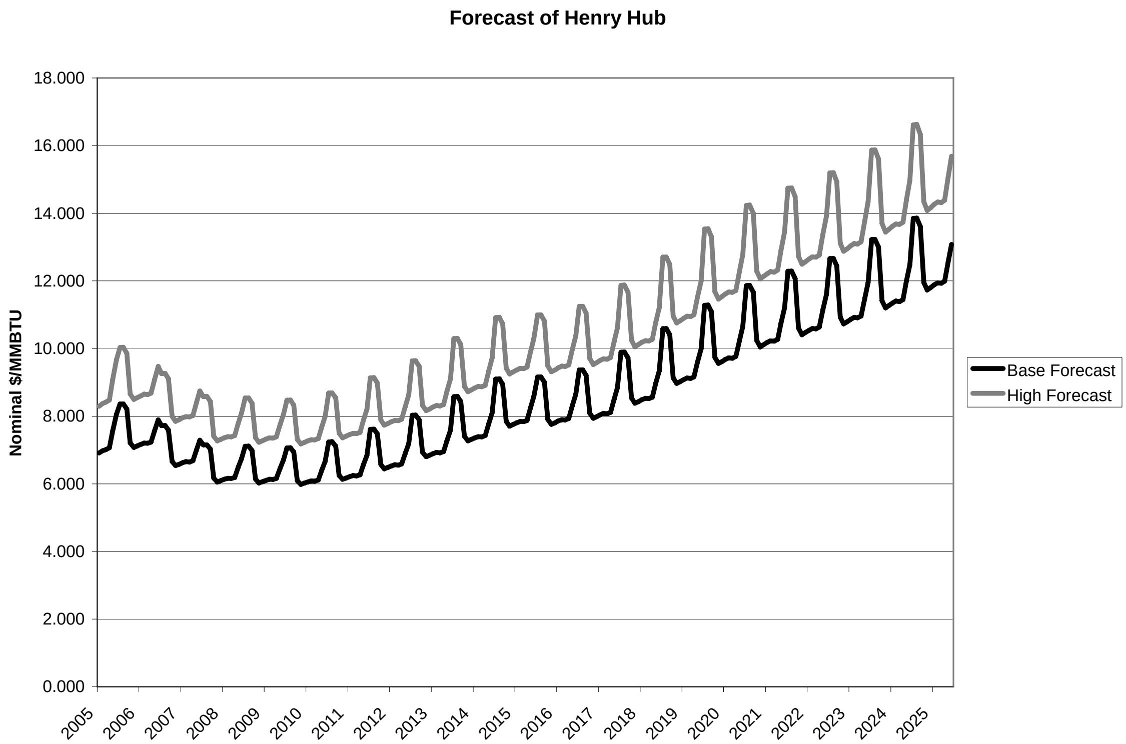
The EIA Wellhead forecast was adjusted upward by 12.2 percent to account for the median historical difference between wellhead prices and Henry Hub Prices. The upward adjustment was based on an analysis that compared historical wellhead prices and historical Henry Hub prices for their correlation, standard deviation, average percentage difference, and median percentage difference. The median percent difference was used to scale the Wellhead price to Henry Hub. This is the same methodology employed by EIA[7]. The difference between the EIA Delivered Price forecast[8] and the Henry Hub forecast was used to create a matrix of basis points between Henry Hub and the Delivery Regions.

The annual year-to-year percent change from the Wellhead Price forecast from the EIA 2005 Annual Energy Outlook was used to preserve the base trends of the EIA forecast. The starting point for the forecast is based on a rolling one-month average of 18-month NYMEX futures strips (5/16/2005 through 6/23/2005).

[7] http://www.eia.doe.gov/oiaf/analysispaper/henryhub/index.html

[8] Table 106. Natural Gas Delivered Prices by End-Use Sector and Census Division

Figure 5-25: Natural Gas Price Forecast



5.3.3.3 EMISSIONS PRICE FORECAST

To comply with air emission requirements, the Integration Group did not forecast the cost of retrofitting existing plants with control technology. Instead, the work group calculated the cost of compliance by assuming that the emitting plant would purchase necessary allowances in emission allowances markets. Therefore, forecasts of emission allowance costs were made for each of the primary air contaminants: SO_2, NOx, Mercury, and Carbon Dioxide for the emissions scenario.

The SO_2 price forecast began with the 6-month average of historical index prices (October ’04 through March ’05) and then escalated at same rate as the 2004 EPA forecast[9] (7.38 percent). The NO_x price forecast began with the 6-month average of historical index prices (October ’04 through March ’05). The NO_x forecast remains flat until the 2004 EPA forecast begins in 2009. The NO_x forecast then follows the same trend as the 2004 EPA forecast until 2020. After 2020, the same downward trend in NO_x is followed until the end of the study horizon.

[9] Analysis of S. 1844, the Clear Skies Act of 2003; S. 843, the Clean Air Planning Act of 2003; and S. 366, the Clean Power Act of 2003

Figure 5-26: Historical Index Prices

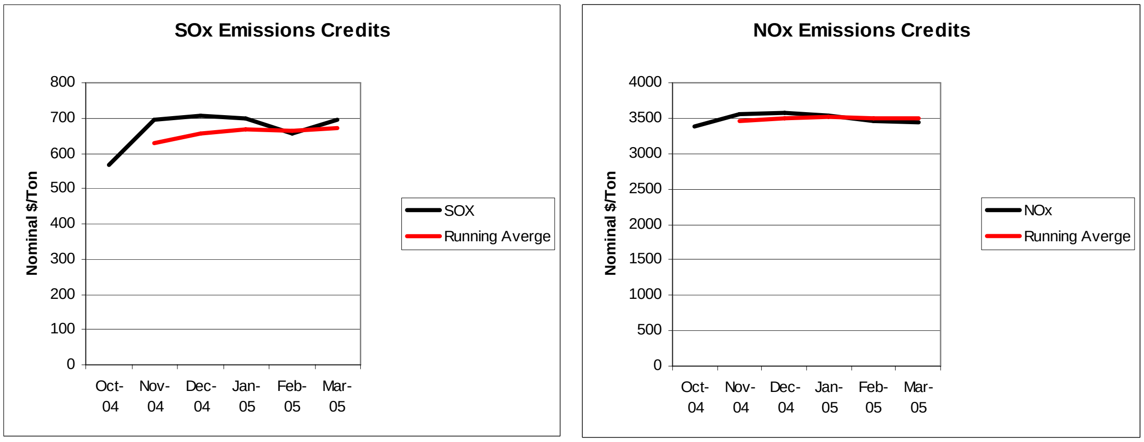
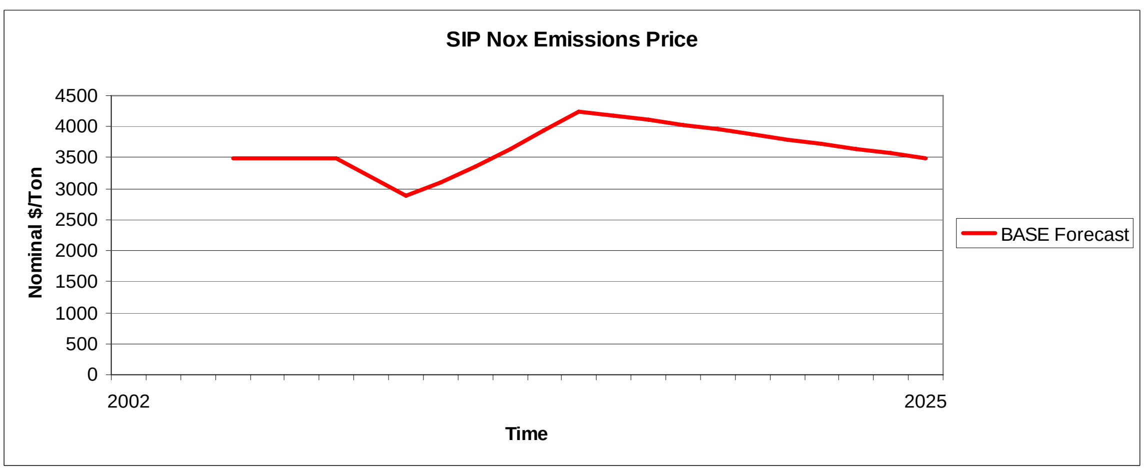


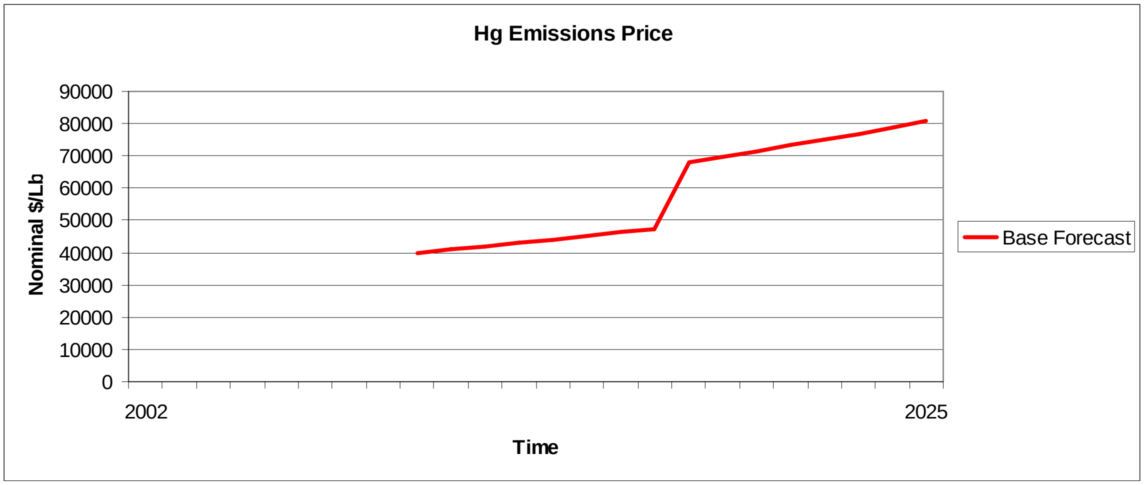
Figure 5-27: SO2 Emission Price Forecast

Figure 5-28: NOX Emission Price Forecast



The mercury (Hg) forecast began with an emission price of $40,000/lb in 2010 and was then escalated at the same rate as the GDP deflator. In 2018, the price was adjusted up by 40 percent to reflect the effects of Phase II of the EPA's Clean Air Mercury initiative (CAMR) and was then escalated at the GDP deflator rate.

Figure 5-29: HG Emission Price Forecast

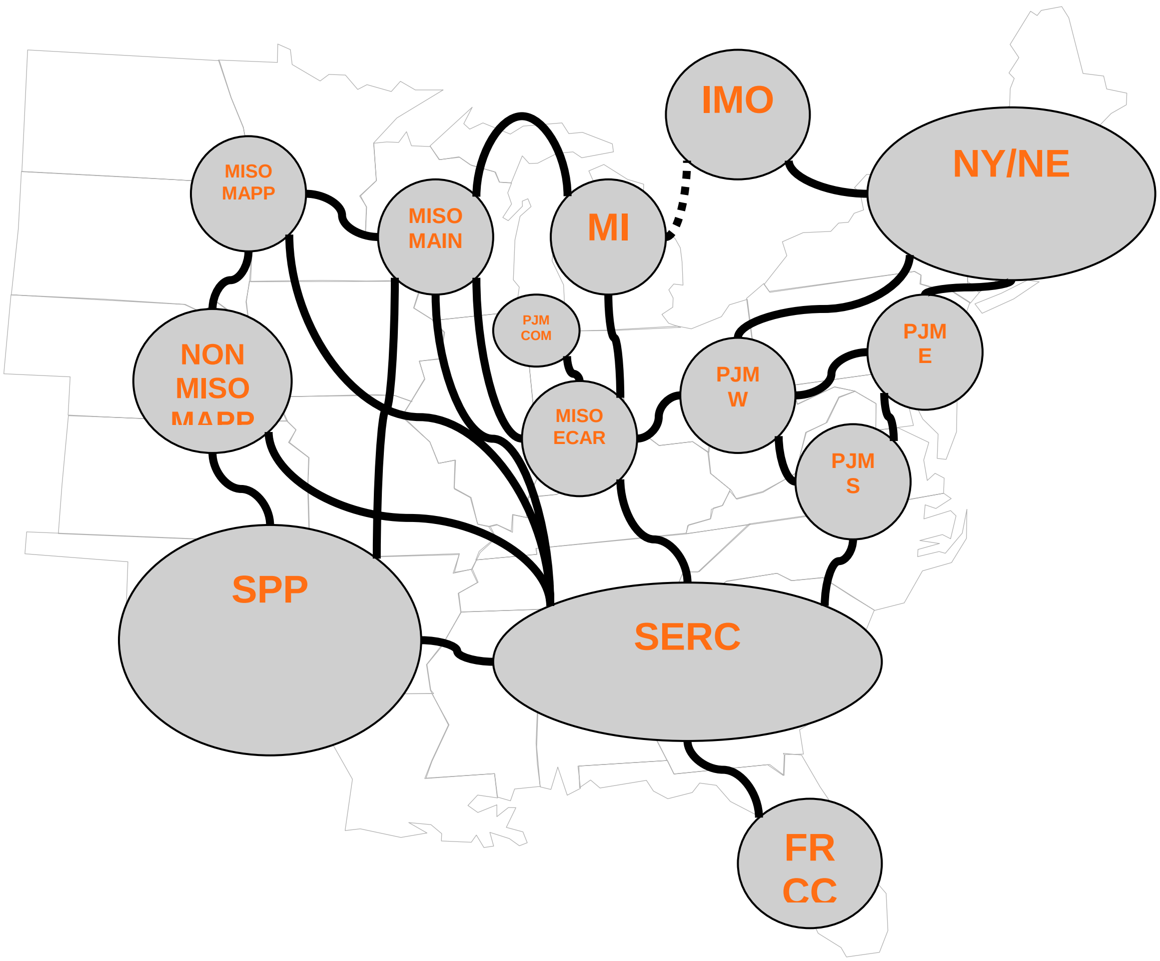


5.3.4 External Market Forecast

The external non-firm energy market forecast was developed using NewEnergy's MarketPower system. MarketPower® is a regional capacity and energy market forecasting system. MarketPower produces the capacity and energy price forecasts. This software simulates regional power markets at a macro-economic level. MarketPower performs the dispatch based on bid prices derived from a percentage of operating costs plus fixed adders. Prices are determined by matching generator bids to demand for each area subject to transmission transfer limits, tariffs, and generation energy limits (hydro inflow energy, NUG contract limits, and pumped storage). MarketPower, additionally, assesses when and where new capacity would be added based on market drivers. Existing generators may also be mothballed, restarted or converted to a different technology based on market conditions. Separate prices may be produced for capacity and energy, or a single "all-in" commodity price may be produced.

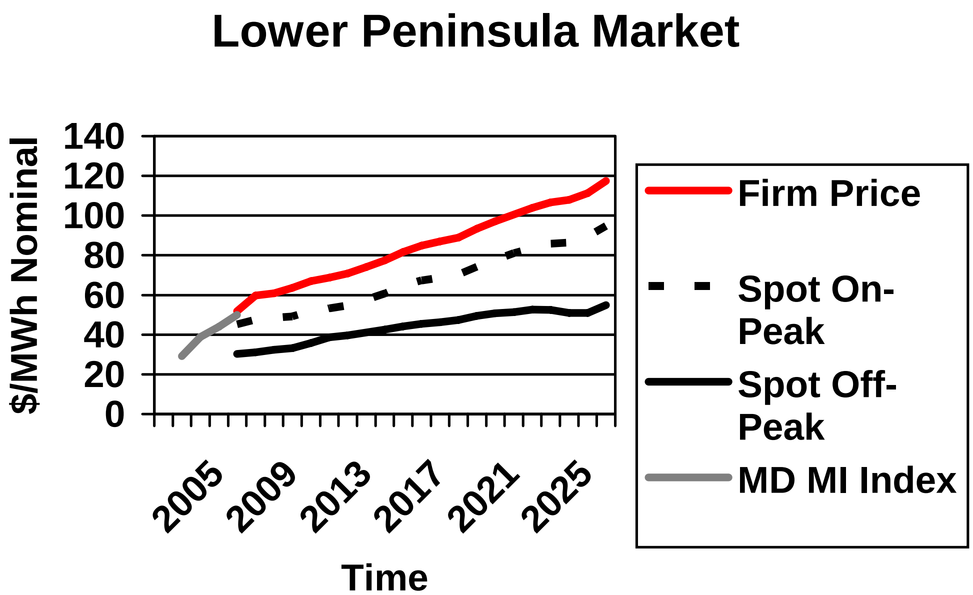
The assumptions for the broader market were consistent with the assumptions made for the Michigan study. The following figure represents the broader regional market:

Figure 5-30: External Market Footprint



The following chart contains the external market price information. The Spot On and Off Peak values represent the external spot energy forecast available to Michigan on a non-firm basis. The Firm price represents an all in price with the value of capacity allocated to all on-peak hours. This forecast is provided as a reference to the Megawatt Daily historical hub price for Michigan. The Megawatt Daily Historical hub price represents a firm 16-hour product.

Figure 5-31: External Market Price Forecast



5.3.5 Economic Forecast

The following table contains the remaining economic assumptions from the Demand Working Group and the Integration Working Group.

Figure 5-32: Economic Assumptions

				Notes:
Construction Escalation			2.47%	Construction Escalation uses GDP
Fuel Escalation	Coal	N. AppAppalachian	2.64%	
		C. Appalachian	2.48%	Fuel Escalations represent delivered costs
		Rocky Mountain	3.42%	
		Powder River Basin	2.29%	
	Gas		2.50%	
	Uranium		2.80%	
Variable O&M Escalation			2.47%	O&M escalation uses GDP
Fixed O&M Escalation			2.47%	
GDP			2.47%	http://www.eia.doe.gov/oiaf/aeo/pdf/aeotab_19.pdf
Debt Interest Rate			9.28%	Calculated to Yield an After Tax Cost Of Capital of 8.04%

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6 Resource Plans

6.1 Overview

The objective function for the Michigan resource plan optimization was to minimize the present worth of utility costs over the planning period. Resource plans were subject to a long-run minimum target reserve margin of 15 percent for the Michigan System. Individually, METC and ITC, experienced minimum reserve margins of 10 percent over the planning horizon. The maximum reserve margin was set to allow the largest alternative to be selected to cover a 1 MW shortfall. In addition, no more than one 500 MW unit was commissioned per area per year.

The table below shows the projected, future reserve margins if no additional resources are added to Michigan's resource portfolio.

Figure 6-1: Lower Peninsula Reserve Margins

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Peak Demand (MW)	22,643	23,285	23,868	24,435	24,997	25,565	26,137	16,725	27,336	27,966
Installed Capacity (MW)	26,029	26,017	26,017	26,017	26,017	26,017	26,017	26,017	26,017	25,897
Reserve Margin	14.96%	11.73%	9.01%	6.48%	4.08%	1.77%	-0.46%	-2.65%	-4.82%	-7.40%

Due to the construction lead times of the resources, the shortest being just over 2 years to construct a CT, and the near term reserve margins on the Lower Peninsula (see Figure 6-1) the actual minimum reserve margin was allowed to fall somewhat below the long run 15 percent minimum required for the study period. The minimum reserve margin was then "feathered" back up to the desired 15 percent by the year 2014 (see Figure 6-2). This was done to avoid overbuilding with CTs (available in 2007), or with CCs (available in 2008) until baseload coal resources become available in 2011.

Figure 6-2: Minimum Reserve Margin Constraints

	2005	2006	2007	2008	2009
Reserve Margin Minimum	14.50%	11.00%	9.70%	9.75%	10.50%
	2010	**2011**	**2012**	**2013**	**2014**
	11.50%	12.50%	13.50%	14.25%	15.00%

The following tables provide an overview of the best plan for each of the scenarios considered in the Michigan comprehensive planning process. Details of all cases are found in Appendix C – Results.

Figure 6-3: 20-Year Summary of Scenarios 2005-2024

Plan Name	Total Capacity Added MW (Firm)	CT Capacity MW	CC Capacity MW	PC Capacity MW	Nuclear Capacity MW	IGCC Capacity MW	Other Capacity MW (Firm)	Ending Reserve Margin %	Ending Peak Demand MW	PVRR 2005 $M
Base	17,040	3,040	3,000	11,000	0	0	0	15.16%	34,880	$ 54, 596.8
Base High Load	21,320	4,320	4,500	12,500	0	0	0	15.00%	38,368	$ 60,895.9
Base Low Load	12,780	1,280	2,000	9,500	0	0	0	15.42%	31,392	$ 48,707.3
Base High Gas	16,880	2,880	2000	12,000	0	0	0	15.03%	34,880	$ 56,282.2
Base High Import	16,900	2,400	1,500	13,000	0	0	0	15.38%	34,880	$ 54,238.5
Base Low Import	16,880	2,880	2,000	12,000	0	0	0	15.03%	34,880	$ 54,870.9
Emissions	16,820	2,720	1,000	4,500	8,000	0	600	15.03%	34,880	$ 66,002.9
Emissions High Load	21,320	2,720	3,000	6,000	9,000	0	600	15.87%	38,368	$ 77,407.4
Emissions High Gas	17,660	2,560	1,000	4,500	9,000	0	600	17.55%	34,880	$ 67,779.9
Energy efficiency	15,799	3,040	2,500	10,000	0	0	259	15.07%	33,722	$ 54,066.4
Energy efficiency High Load	20,139	2,880	4,500	12,500	0	0	259	15.34%	37,210	$ 60,335.7
Energy efficiency Low Load	11,539	1,280	1,500	8,500	0	0	259	15.33%	30,234	$ 48,156.2
Energy efficiency High Gas	15,799	3,040	2,000	10,500	0	0	259	15.22%	33,722	$ 55,639.9
Non-Traditional	17,105	3,520	1,000	0	0	11,550	1,035	15.57%	34,880	$ 57,477.8
Non-Traditional High Load	21,395	4,160	3,000	0	0	13,200	1,035	15.28%	38,368	$ 67,023.5
Non-Traditional Low Load	12,535	1,600	0	0	0	9,990	1,035	15.51%	31,392	$ 53,523.5
Non-Traditional High Gas	17,105	3,520	1,000	0	0	11,550	1,035	15.57%	34,880	$ 59,149.8
Non-Traditional with PC as an option	16,895	3,360	1,000	11,500	0	0	1,035	15.00%	34,880	$ 55,864.4

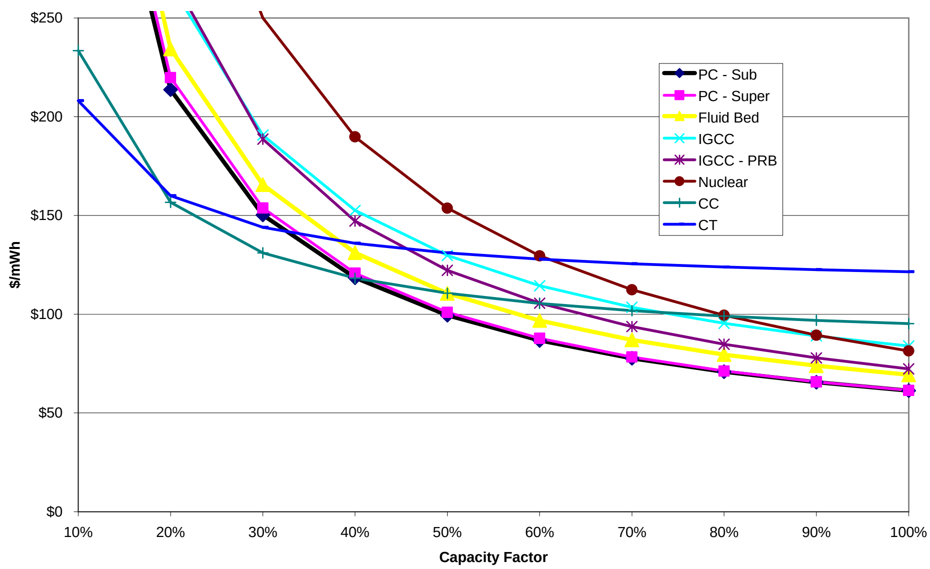
Figure 6-4: 10-Year Summary of Scenarios 2005 - 2014

Plan Name	Total Capacity Added MW (Firm)	CT Capacity MW	CC Capacity MW	PC Capacity MW	Nuclear Capacity MW	IGCC Capacity MW	Other Capacity MW (Firm)	Ending Reserve Margin %	Ending Peak Demand MW	PVRR 2005 $M
Base	6,780	1,280	1,500	4,000	0	0	0	15.85%	28,664	$ 29,640.9
Base High Load	10,240	2,240	3,500	4,500	0	0	0	15.14%	31,530	$ 32,282.9
Base Low Load	3,500	0	1,000	2,500	0	0	0	16.40%	25,797	$ 27,146.3
Base High Gas	6,780	1,280	1,500	4,000	0	0	0	15.85%	28,664	$ 30,794.9
Base High Import	6,780	1,280	1,500	4,000	0	0	0	15.85%	28,664	$ 29,608.2
Base Low Import	6,780	1,280	1,500	4,000	0	0	0	15.85%	28,664	$ 29,740.4
Emissions	6,680	2,080	1,000	3,000	0	0	600	15.19%	28,664	$ 33,543.9
Emissions High Load	10,180	2,080	3,000	4,500	0	0	600	15.31%	31,530	$ 38,373.4
Emissions High Gas	6,680	2,080	1,000	3,000	0	0	600	15.19%	28,664	$ 34,737.7
Energy efficiency	6,012	1,280	1,000	3,500	0	0	232	15.34%	28,099	$ 29,802.9
Energy efficiency High Load	9,672	1,440	3,000	5,000	0	0	232	15.58%	30,030	$ 34,422.9
Energy efficiency Low Load	2,552	320	0	2,000	0	0	232	15.18%	24,987	$ 27,317.7
Energy efficiency High Gas	6,012	1,280	1,000	3,500	0	0	232	15.34%	28,099	$ 30,873.8
Non-Traditional	6,839	1,760	1,000	0	0	3,300	779	15.86%	28,664	$ 30,368.9
Non-Traditional High Load	10,259	2,080	3,000	0	0	4,400	779	15.10%	31,530	$ 34,728.5
Non-Traditional Low Load	3,249	800	0	0	0	1,650	779	15.88%	25,797	$ 29,187.3
Non-Traditional High Gas	6,839	1,760	1,000	0	0	3,300	779	15.86%	28,664	$ 31,473.1
Non-Traditional with PC as an option	6,879	1,600	1,000	3,500	0	0	779	16.06%	28,664	$ 30,106.3

6.2 Results

For each scenario, the generic resource options were first evaluated using screening curves to eliminate alternatives that would not be as economically viable. The screening curves calculate a full life cycle present value levelized $/MWh busbar cost for each resource alternative over a range of potential capacity factors. The calculations include overnight construction costs, fixed and variable operating costs including fuel costs, construction and operating cost escalations, AFUDC, capital depreciation, property and income taxes, and insurance costs. The Screening Curve for the Base Case cost assumptions is depicted in Figure 6-5.

Figure 6-5: Base Case Screening Curve



It is evident from the curves, for example, that the levelized cost of nuclear units exceeds the costs of other technologies over the entire range of plant capacity factors. On this basis, nuclear units were “screened-out” of the base model run. Similarly, other resource options were screened out of Base, Emissions, Energy Efficiency, and Non-traditional scenarios.

On the basis of this screening curve, the following resources were screened out of the traditional power sensitivity analyses:

- Pulverized Super-Critical Coal
- Fluidized Bed Coal
- IGCC
- IGCC – PRB Coal
- Nuclear

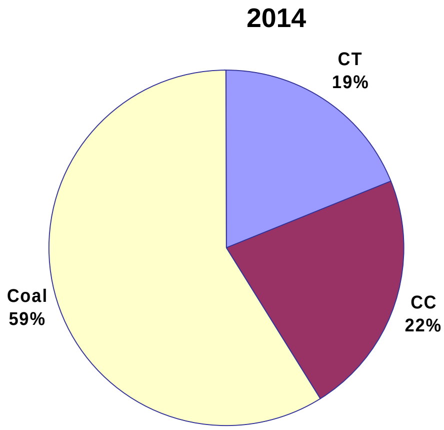
The remaining alternatives: Combustion Turbine, Combined Cycle, and Pulverized Sub-Critical Coal were included in the resource optimization. Note that the Pulverized Super-Critical Coal is

nearly the same cost as Sub-Critical; so the Sub Critical can be thought of as a "placeholder" for coal base load capacity for the purposes of the Base Case.
The results of the base case are summarized below.

Figure 6-6: Base Case Summary Results

Capacity Additions (Firm MW)	2005 to 2014	2005 to 2024
CT	1,280	3,040
CC	1,500	3,000
PC	4,800	11,000
Nuclear	0	0
IGCC-Seq	0	0
Other	0	0
TOTAL	**6,780**	**17,040**
Annual Demand Growth (%)	2.38	2.17
Reserve Margin (%)	15.85	15.16
Plan Costs (2005 Million $)		
NPV Utility Cost	$ 29,640.9	$ 54,596.8
NPV Emissions	$ 4,084.0	$ 7,642.3
NPV CO_2	$ 0.0	$ 0.0

Figure 6-7: Base Case Capacity Mix



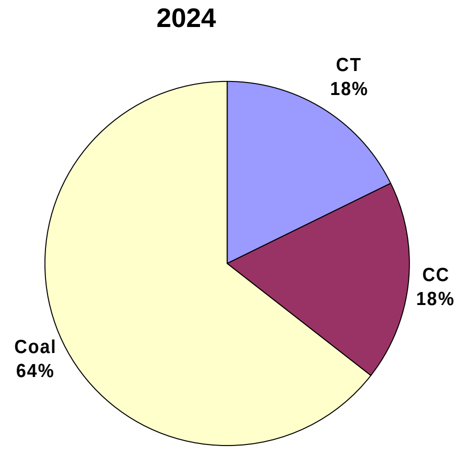


Figure 6-8: Base Case Expansion Plan

	Base Case	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
11	CT - METC	-	-	-	1	2	1	-	-	-	-
7	CT - ITC	-	-	2	-	-	2	-	-	-	-
1	CT - ATC2	-	-	-	-	-	-	-	-	-	-
1	CC - METC	-	-	-	-	-	-	-	-	-	-
5	CC - ITC	-	-	-	1	1	1	-	-	-	-
0	CC - ATC2	-	-	-	-	-	-	-	-	-	-
12	COAL - METC	-	-	-	-	-	-	1	1	1	1
10	COAL - ITC	-	-	-	-	-	-	1	1	1	1
0	COAL - ATC2	-	-	-	-	-	-	-	-	-	-

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CT - METC	-	1	-	1	1	1	1	-	1	1
CT - ITC	-	-	-	-	-	-	1	1	1	-
CT - ATC2	-	-	-	-	1	-	-	-	-	-
CC - METC	-	-	-	-	-	-	-	-	1	-
CC - ITC	-	-	-	-	-	-	-	-	1	1
CC - ATC2	-	-	-	-	-	-	-	-	-	-
COAL - METC	-	1	1	1	1	1	1	1	-	1
COAL - ITC	1	1	1	-	1	1	-	1	-	-
COAL - ATC2	-	-	-	-	-	-	-	-	-	-

The Base Case Expansion plan exhibited a number of key resource planning results. The state of Michigan is in need of immediate capacity to meet planning reserve criteria. This is exhibited by the fact that 2 Combustion Turbines were added, as soon as practical, in 2007. After achieving the capacity necessary for reliability, the state of Michigan was in need for intermediate and base loaded energy. As soon as available, the Base Case expansion plan selected energy producing resources. Combined Cycles were the resource of preference until 2011, when Pulverized Sub-Critical Coal became the preferred resource. Throughout the remaining study horizon, Coal was the preferred resource for the State of Michigan.

6.3 Sensitivities Analysis

The following sensitivities were performed on the Base Case: High Load, Low Load, High Gas, High Imports, and Low Imports. The High Load sensitivity represented a 2.26 percent demand growth rate; the base case demand growth rate was 1.83 percent. The Low Load sensitivity represented a 1.34 percent demand growth rate. The High Gas sensitivity represented a 20 percent increase in forecasted natural gas prices. The High and Low Import sensitivities were defined in Section 5.2.6. The results of the Base Case sensitivities are contained in Appendix C – Results. The table below shows a summary of the sensitivities from the base case assumptions for the entire twenty-year planning period.

Figure 6-9: Summary of Base Case across all Scenarios 2005-2024
(in MW for each generation type)

Case	CT	CC	PC	Present Value of Renewable Requirement ($ Mill)
Base Case	3,040	3,000	11,000	54,596.8
High Load	4,320	4,500	12,500	60,895.9
Low Load	1,280	2,000	9,500	48,707.3
High Gas	2,880	2,000	12,000	56,282.2
High Imports[10]	2,400	1,500	13,000	54,238.5
Low Imports	2,880	2,000	12,000	54,870.9

The need for immediate capacity for reliability in the form of Combustion Turbines in 2007 was common across all of the sensitivities except the Low Load Sensitivity. As soon as CT's were available for construction, they were built. In the Low Load Sensitivity, the reduced load requirements offset the need for reliability capacity. Across all of the sensitivities, the need for energy production capacity was prevalent. Under all scenarios, Combined Cycle (CC) units were placed in service as soon as they could be constructed, which was 2008. The Low Load Sensitivity delayed this need for one year and placed a CC into service in 2009. Coal was built, as soon as available, in 2011 under all scenarios, including the Low Load Sensitivity. This observation underscored the need for base load capacity in the State of Michigan.

Resource construction lead time proved to be a major driver of the expansion plan choices in the near term. As soon as capacity was available, it is built for the capacity needs of the Michigan system, as noted by the addition of CT and CC capacity in the 2007 to 2010 time frame. As soon as coal was a viable option, PC sub-critical units dominate the expansion plan from 2011 through the end of the study horizon.

The High and Low Imports did not make a substantial impact on the expansion plans in the near term. Through 2015, the expansion plans across all scenarios were identical. This was due to the assumption, as stated previously, that no external capacity is bought or sold. One key observation of High Import scenario was that there was approximately $358.3M in benefits associated with greater access to external markets.

6.4 Scenarios

The Emissions Case Scenario was based on greater restrictions on mercury and carbon dioxide emissions than was assumed for the base case. The Emissions Case scenario contained the following assumptions:

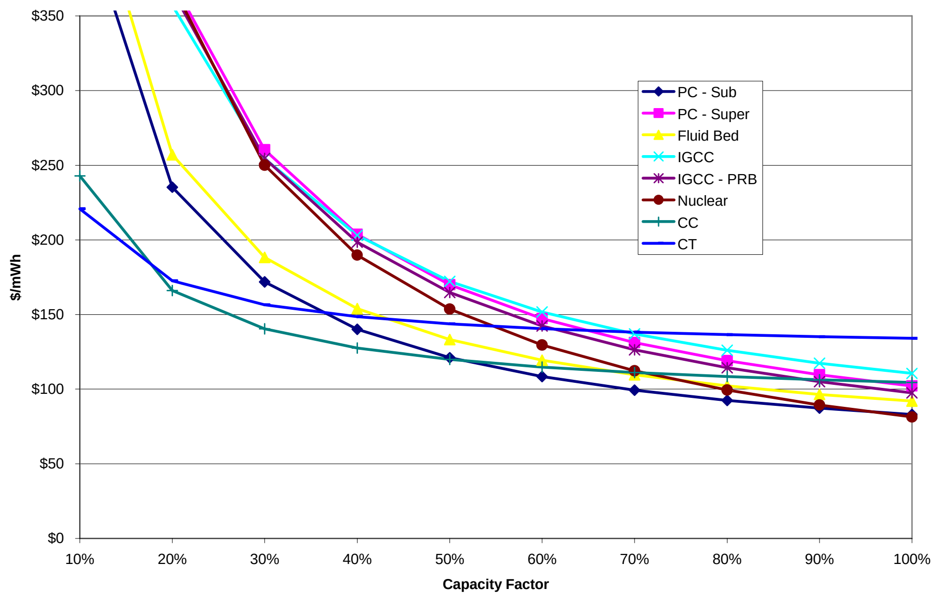
- A 15 percent increase to the Hg emission allowance prices to reflect an additional requirement to reduce Hg emission by 85 percent of CAMR base period levels

[10] Cost figures do not include the transmission investment for TIER 1 improvements

- A Nominal Carbon Tax on CO_2 emissions starting in 2010 at $10/ton and escalating to $30/ton in 2018
- IGCC with CO_2 sequestering is a viable resource option
- Wind and Cogeneration resource are scheduled into the resource mix when available.

The Emissions Case resource options were evaluated on a levelized bus-bar cost to screen out alternatives that would have limited economic viability.

Figure 6-10: Emission Case Screening Curve



On the basis of this screening curve, Fluidized Bed Coal and Pulverized Super-Critical Coal were screened out of the analysis.

The remaining alternatives: Combustion Turbine, Combined Cycle, and Pulverized Sub-Critical Coal, IGCC Sequestered and Nuclear were included in the resource optimization.

Figure 6-11: Expansion Plan Comparison 2005-2024
(in MW for each generation type)

Case	CT	CC	PC	Nuclear	Alternative Sources
Base Case	3,040	3,000	11,000	0	0
Emissions Case	2,720	1,000	4,500	8,000	600

Under the Emission Case, the need for immediate reliability capacity was still apparent. The longer term need for energy production was met through the addition of Nuclear resources. Combined Cycle and Coal units were built in the near term to meet the energy requirements of Michigan until new nuclear generation became available in 2017. IGCC with carbon sequestration capability was not selected in this scenario because current cost estimates place its fixed cost at more than the fixed costs of a new nuclear unit.

A major difference emerging from the Emissions Scenario was the added costs associated with emission allowances. The following table outlines the differences in the cost components.

Figure 6-12: Emissions Case Cost Components 2005-2024
(in million $)

Case	PVRR	PV Total Emission[11]	PV Total Carbon
Base Case	54,596.8	7,642.3	0.0
Emissions Case	66,002.9	20,195.6	12,751.3

The Emission Case was further subjected to High Load and High Gas Sensitivities.

Figure 6-13: Emission Case Sensitivities 2005-2024

	Capacity Additions by Generation Type (MW)					
Case	CT	CC	PC	Nuclear	Wind/Cogen	Present Value of Reserve Requirement ($ mill)
Emissions Case	2,720	1,000	4,500	8,000	600	66,002.9
High Load	2,720	3,000	6,000	9,000	600	77,407.4
High Gas	2,560	1,000	4,500	9,000	600	67,779.7

6.5 Energy Efficiency

The Energy Conservation Case Scenario was focused on the effects of greater emphasis on energy efficiency investment and energy alternatives. The Energy Conservation Case scenario contained the following assumptions:

- Energy Conservation programs are scheduled in and the cost of the program is incorporated into the present value cost calculation
- No direct load control was included
- Landfill Gas, Digestion, and Wind resources will be scheduled in according to availability

[11] Includes cost of Carbon emissions

The Energy Efficiency Case resource options are shown below:

Figure 6-14: Energy efficiency Comparison 2005-2024

	Capacity Additions by Generation Type (MW)				
Case	**CT**	**CC**	**PC**	**LFG, Digestion, and Wind**	**Present Value of Reserve Requirement ($ mill)**
Base Case	3,040	3,000	11,000	0	54,596.8
Energy Efficiency Case	3,040	2,500	10,000	259	54,066.4

Under the Energy Conservation Case, the need for immediate reliability capacity was still apparent. The longer term need for energy production was met through the addition of Coal resources along with energy efficiency investment. Over the entire twenty year planning horizon, the Energy Efficiency scenario resulted in approximately $500 million in lower present value revenue requirements than the Base scenario.

The Energy Efficiency Case was further subjected to High Load, Low Load, and High Gas Sensitivities.

Figure 6-15: Energy Efficiency Case Sensitivities 2005-2024

	Capacity Additions by Generation Type (MW)				
Case	**CT**	**CC**	**PC**	**LFG, Digestion, and Wind**	**Present Value of Reserve Requirement ($ mill)**
Energy Efficiency Case	3,040	2,500	10,000	259	54,066.4
High Load	2,880	4,500	12,500	259	60,335.7
Low Load	1,280	1,500	8,500	259	48,156.2
High Gas	3,040	2,000	10,500	259	55,639.9

6.6 Non-Traditional

The Non-Traditional Case Scenario was focused on the effects of targeted non-traditional generation alternatives. The Non-Traditional Case scenario contained the following assumptions:

- Mandated renewable portfolio standards: 3 percent of energy in 2008, 5 percent of energy in 2010, and 7 percent of energy in 2015
- Landfill Gas, Digestion, Wind, and Cogeneration resources will be scheduled in according to portfolio standards
- Coal and Combined Cycle resources were not allowed.

The Non-Traditional Case resource options were identical to the Base Case, with the exception of Combined Cycle and Coal technologies. However, due to resource construction lead times, Combined Cycle resources were allowed as a bridge alternative until IGCC units were available in 2011. Given the assumptions for a mandated renewable portfolio as described on the previous page, the non-traditional resources projected to be available in Michigan by the Alternate Generation Work Group (Landfill Gas, Digestion, Wind and Cogen), were unable to meet the requirements. Therefore, each non-traditional resource was scaled-up in order to meet the renewable portfolio standards of 3 percent in 2008, 5 percent in 2010 and 7 percent in 2015. Figure 6-16 reflects the projected available capacity compared to the scaled-up amounts utilized in the scenario.

Figure 6-16: Scaled Up Renewable Capacity

	LFG	Digestion	Wind	Cogen
2006	24	10	99	
2007	47	20	198	68
2008	71	31	272	137
2009	94	41	346	205
2010	118	51	420	274
2011	120	51	420	342
2012	123	51	420	410
2013	126	51	420	479
2014	128	51	420	547
2015	138	54	443	576
2016	145	55	454	590
2017	151	56	463	602
2018	157	58	474	615
2019	164	59	484	628
2020	170	60	495	642
2021	177	61	506	655
2022	185	63	517	669
2023	192	64	528	683
2024	199	66	539	697

Figure 6-17: Non-Traditional Comparison 2005-2024

	Capacity Additions by Generation Type (MW)					
Case	**CT MW**	**CC MW**	**PC MW**	**IGCC MW**	**LFG, Digestion, Cogen and Wind MW**	**Present Value of Reserve Requirement ($ mill)**
Base Case	3,040	3,000	11,000	0	0	54,596.8
Non-Traditional Case	3,520	1,000	0	11,550	1,035	57,477.8

Under the Non-Traditional Case, the need for immediate reliability capacity was still apparent. The longer term need for energy production was met through the addition of IGCC resources.

The Non-Traditional Case was further subjected to High Load, Low Load, High Gas and pulverized coal was made available as an option in the "Coal Available" sensitivities.

Figure 6-18: Non-Traditional Sensitivities 2005-2024

	Capacity Additions by Generation Type (MW)					
Case	**CT**	**CC**	**PC**	**IGCC**	**LFG, Digestion, Cogen and Wind**	**Present Value of Reserve Requirement ($ mill)**
Non-Traditional Case	3,520	1,000	0	11,550	1,035	57,477.8
High Load	4,160	3,000	0	13,200	1,035	67,023.5
Low Load	1,600	0	0	9,900	1,035	53,523.5
High Gas	3,520	1,000	0	11,550	1,035	59,149.8
Coal Available	3,360	1,000	11,500	0	1,035	55,864.4

The following tables examine the sensitivities across scenarios

Figure 6-19: Base Sensitivities Comparison 2005-2024

	Capacity Additions by Generation Type (MW)					
Case	**CT**	**CC**	**PC**	**Nuclear/ IGCC**	**LFG, Digestion, Cogen and Wind**	**Present Value of Reserve Requirement ($ mill)**
Base Case	3,040	3,000	11,000	0	0	54,596.8
Emissions Case	2,720	1,000	4,500	8,000	600	66,002.9
Energy efficiency	3,040	2,500	10,000	0	259	54,066.4
Non-Traditional	3,520	1,000	0	11,550	1,035	57,477.8

Figure 6-20: Sensitivities across High Load Scenario 2005-2024

	Capacity Additions by Generation Type (MW)					
Case	**CT**	**CC**	**PC**	**Nuclear/ IGCC**	**LFG, Digestion, Cogen and Wind**	**Present Value of Reserve Requirement ($ mill)**
Base Case	4,320	4,500	12,500	0	0	60,895.9
Emissions Case	2,720	3,000	6,000	9,000	600	77,407.4
Energy efficiency	2,880	4,500	12,500	0	259	60,335.7
Non-Traditional	4,160	3,000	0	13,200	1,035	67,023.5

Figure 6-21: Sensitivities across Low Load Scenario 2005-2024

	Capacity Additions by Generation Type (MW)					
Case	**CT**	**CC**	**PC**	**Nuclear/ IGCC**	**LFG, Digestion, Cogen and Wind**	**Present Value of Reserve Requirement ($ mill)**
Base Case	1,280	2,000	9,500	0	0	48,707.3
Energy efficiency	1,280	1,500	8,500	0	259	48,156.2
Non-Traditional	1,600	0	0	9,900	1,035	53,523.5

Figure 6-22: Sensitivities across High Gas Scenario 2005-2024

Case	**CT**	**CC**	**PC**	**Nuclear/ IGCC**	**LFG, Digestion, Cogen and Wind**	**Present Value of Reserve Requirement ($ mill)**
Base Case	2,880	2,000	12,000	0	0	56,282.2
Emissions Case	2,560	1,000	4,500	9,000	600	67,779.7
Energy efficiency	3,040	2,000	10,500	0	259	55,639.9
Non-Traditional	3,520	1,000	0	11,550	1,035	59,149.8

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Appendix A – Demand and Energy Forecast

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Figure A - 1: Energy Forecast

Energy Forecast (GWh)			
Year	**Southeast Michigan**	**Balance of Lower Peninsula**	**Upper Peninsula**
2005	56,758	50,576	6,448
2006	58,552	51,570	6,526
2007	59,857	52,621	6,565
2008	60,982	53,877	6,624
2009	61,979	54,977	6,684
2010	63,037	56,058	6,754
2011	64,098	57,180	6,821
2012	65,186	58,424	6,875
2013	66,315	59,444	6,929
2014	67,509	60,598	6,991
2015	68,729	61,747	7,053
2016	69,996	63,029	7,116
2017	71,138	64,077	7,180
2018	72,341	65,259	7,243
2019	73,612	66,474	7,306
2020	74,910	67,693	7,370
2021	76,231	68,923	7,434
2022	77,575	70,164	7,499
2023	78,942	71,417	7,564
2024	80,334	72,682	7,632
2025	81,751	73,959	7,701

Figure A - 2: Demand Forecast

Demand Forecast (MW)			
Year	**Southeast Michigan**	**Balance of Lower Peninsula**	**Upper Peninsula**
2005	12,551	10,652	898
2006	12,896	10,965	903
2007	13,174	11,285	910
2008	13,415	11,626	918
2009	13,648	11,970	926
2010	13,888	12,313	938
2011	14,125	12,663	946
2012	14,377	13,014	953
2013	14,650	13,367	962
2014	14,939	13,724	971
2015	15,218	14,101	979
2016	15,505	14,484	988
2017	15,697	14,871	997
2018	15,898	15,265	1,008
2019	16,108	15,671	1,016
2020	16,318	16,071	1,025
2021	16,532	16,472	1,036
2022	16,748	16,877	1,044
2023	16,967	17,283	1,054
2024	17,189	17,692	1,063
2025	17,413	18,103	1,073

Figure A - 3: High Energy Forecast

High Energy Forecast (GWh)			
Year	**Southeast Michigan**	**Balance of Lower Peninsula**	**Upper Peninsula**
2005	57,325	51,082	6,513
2006	59,723	52,601	6,657
2007	61,652	54,200	6,762
2008	63,421	56,032	6,889
2009	65,078	57,726	7,018
2010	66,820	59,421	7,160
2011	68,584	61,183	7,299
2012	70,401	63,098	7,425
2013	72,283	64,794	7,552
2014	74,260	66,657	7,690
2015	75,601	67,922	7,759
2016	76,995	69,332	7,828
2017	78,251	70,485	7,897
2018	79,575	71,785	7,967
2019	80,973	73,121	8,037
2020	82,401	74,462	8,107
2021	83,854	75,815	8,178
2022	85,332	77,181	8,249
2023	86,837	78,559	8,321
2024	88,368	79,950	8,395
2025	89,926	81,355	8,471

Figure A - 4: High Demand Forecast

High Demand Forecast (MW)			
Year	**Southeast Michigan**	**Balance of Lower Peninsula**	**Upper Peninsula**
2005	12,677	10,759	907
2006	13,154	11,185	921
2007	13,569	11,624	937
2008	13,951	12,091	954
2009	14,331	12,568	972
2010	14,721	13,051	994
2011	15,114	13,550	1,013
2012	15,527	14,055	1,029
2013	15,969	14,570	1,048
2014	16,433	15,097	1,068
2015	16,740	15,512	1,077
2016	17,056	15,932	1,086
2017	17,267	16,358	1,096
2018	17,488	16,791	1,108
2019	17,719	17,238	1,118
2020	17,950	17,678	1,128
2021	18,185	18,120	1,139
2022	18,423	18,564	1,148
2023	18,663	19,011	1,159
2024	18,907	19,461	1,169
2025	19,155	19,913	1,180

Figure A - 5: Low Energy Forecast

Low Energy Forecast (GWh)			
Year	**Southeast Michigan**	**Balance of Lower Peninsula**	**Upper Peninsula**
2005	56,190	50,071	6,384
2006	57,381	50,538	6,396
2007	58,061	51,043	6,368
2008	58,543	51,722	6,359
2009	58,880	52,228	6,350
2010	59,255	52,694	6,349
2011	59,611	53,178	6,344
2012	59,971	53,750	6,325
2013	60,346	54,094	6,305
2014	60,758	54,538	6,292
2015	61,856	55,572	6,348
2016	62,996	56,726	6,405
2017	64,024	57,669	6,462
2018	65,107	58,733	6,519
2019	66,251	59,826	6,575
2020	67,419	60,923	6,633
2021	68,608	62,031	6,691
2022	69,817	63,148	6,749
2023	71,048	64,275	6,808
2024	72,301	65,414	6,869
2025	73,576	66,563	6,931

Figure A - 6: Low Energy Forecast

Low Demand Forecast (MW)			
Year	**Southeast Michigan**	**Balance of Lower Peninsul a**	**Upper Peninsula**
2005	12,426	10,545	889
2006	12,638	10,746	885
2007	12,779	10,946	882
2008	12,878	11,161	881
2009	12,966	11,371	879
2010	13,055	11,574	881
2011	13,136	11,777	880
2012	13,227	11,973	877
2013	13,332	12,164	875
2014	13,445	12,352	874
2015	13,696	12,691	881
2016	13,955	13,035	889
2017	14,128	13,384	897
2018	14,308	13,738	907
2019	14,497	14,104	914
2020	14,687	14,463	923
2021	14,878	14,825	932
2022	15,073	15,189	939
2023	15,270	15,555	948
2024	15,470	15,922	957
2025	15,672	16,292	965

Appendix B – Generation Capability Tables

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Figure B - 1: ITC Resources

Area	Category Level 3	Generator	Generator Annual Maximum Capacity (MW)
Detroit Edison Co.	Combined Cycle (existing)	Dearborn Industrial Generation LLC:CC1	760.00
Detroit Edison Co.	CT Gas	Ann Arbor GT:1	3.20
Detroit Edison Co.	CT Gas	Belle River:GT1	75.00
Detroit Edison Co.	CT Gas	Belle River:GT2	75.00
Detroit Edison Co.	CT Gas	Belle River:GT3	75.00
Detroit Edison Co.	CT Gas	Delray:11-1	63.00
Detroit Edison Co.	CT Gas	Delray:12-1	64.00
Detroit Edison Co.	CT Gas	DTE East China:GT10	76.00
Detroit Edison Co.	CT Gas	DTE East China:GT7	76.00
Detroit Edison Co.	CT Gas	DTE East China:GT8	76.00
Detroit Edison Co.	CT Gas	DTE East China:GT9	76.00
Detroit Edison Co.	CT Gas	Greenwood:GT1	75.00
Detroit Edison Co.	CT Gas	Greenwood:GT2	75.00
Detroit Edison Co.	CT Gas	Greenwood:GT3	75.00
Detroit Edison Co.	CT Gas	Hancock (DETED):1	11.00
Detroit Edison Co.	CT Gas	Hancock (DETED):2	18.00
Detroit Edison Co.	CT Gas	Hancock (DETED):3	17.00
Detroit Edison Co.	CT Gas	Hancock (DETED):4	17.00
Detroit Edison Co.	CT Gas	Hancock (DETED):5	38.00
Detroit Edison Co.	CT Gas	Hancock (DETED):6	40.00
Detroit Edison Co.	CT Gas	Hutzel Hospital:GTGS2	1.60
Detroit Edison Co.	CT Gas	Main Street (SEAW):GTGS6	6.13
Detroit Edison Co.	CT Gas	MPPA : Belle River	234.00
Detroit Edison Co.	CT Gas	Northeast (DETED):1	14.75
Detroit Edison Co.	CT Gas	Northeast (DETED):2	14.75
Detroit Edison Co.	CT Gas	Northeast (DETED):3	14.75
Detroit Edison Co.	CT Gas	Northeast (DETED):4	14.75
Detroit Edison Co.	CT Gas	Pine Street (SEAW):GTGS4	5.00
Detroit Edison Co.	CT Gas	Sumpter Township:GT1	72.25
Detroit Edison Co.	CT Gas	Sumpter Township:GT2	72.25
Detroit Edison Co.	CT Gas	Sumpter Township:GT3	72.25
Detroit Edison Co.	CT Gas	Sumpter Township:GT4	72.25
Detroit Edison Co.	CT Gas	Ubly:GTGS2	4.04
Detroit Edison Co.	CT Gas	Wayne County Airport:GTGS3	17.10
Detroit Edison Co.	CT Oil	Belle River:GTOL5	13.75
Detroit Edison Co.	CT Oil	Caro:GTOL6	8.55

Area	Category Level 3	Generator	Generator Annual Maximum Capacity (MW)
Detroit Edison Co.	CT Oil	Colfax (DETED):GTOL5	13.75
Detroit Edison Co.	CT Oil	Conners Creek:GTOL2	5.50
Detroit Edison Co.	CT Oil	Croswell Plant:3	1.21
Detroit Edison Co.	CT Oil	Croswell Plant:GTGS4	4.02
Detroit Edison Co.	CT Oil	Dayton (DETED):GTOL5	10.00
Detroit Edison Co.	CT Oil	Fermi:GTOL4	51.00
Detroit Edison Co.	CT Oil	Harbor Beach:GTOL2	4.00
Detroit Edison Co.	CT Oil	Michigan Automotive Research:1-8	0.00
Detroit Edison Co.	CT Oil	Mistersky:GT1	30.00
Detroit Edison Co.	CT Oil	Monroe (DETED):GTOL5	13.75
Detroit Edison Co.	CT Oil	Northeast (DETED):5	17.00
Detroit Edison Co.	CT Oil	Northeast (DETED):6	19.50
Detroit Edison Co.	CT Oil	Northeast (DETED):7	19.50
Detroit Edison Co.	CT Oil	Oliver:GTOL5	13.75
Detroit Edison Co.	CT Oil	Pine Street (SEAW):GTOL2	2.28
Detroit Edison Co.	CT Oil	Placid 12:GTOL5	13.75
Detroit Edison Co.	CT Oil	Putnam (DETED):GTOL5	13.75
Detroit Edison Co.	CT Oil	River Rouge:GTOL4	11.00
Detroit Edison Co.	CT Oil	Slocum:GTOL5	13.75
Detroit Edison Co.	CT Oil	St. Clair:11	19.00
Detroit Edison Co.	CT Oil	St. Clair:GTOL2	5.50
Detroit Edison Co.	CT Oil	Superior:GTOL4	52.00
Detroit Edison Co.	CT Oil	Ubly:GTOL5	4.51
Detroit Edison Co.	CT Oil	Wilmont:GTOL5	13.75
Detroit Edison Co.	Hydro Run-of-River	DETED Small Hydros:HYOP2	1.40
Detroit Edison Co.	Hydro Run-of-River	Ford Lake:HYOP1	0.85
Detroit Edison Co.	Hydro Run-of-River	French Landing Dam:HYOP1	1.80
Detroit Edison Co.	Interruptible Load	DETED Interruptible:1	0.00
Detroit Edison Co.	Landfill Gas	Ann Arbor Generating Station:1	1.60
Detroit Edison Co.	Landfill Gas	Arbor Hills Generating Facilit:CC	17.40
Detroit Edison Co.	Landfill Gas	Carleton Farms Generating Project:1	6.40
Detroit Edison Co.	Landfill Gas	EQ - Waste Energy Services Inc:GTGS4	1.40
Detroit Edison Co.	Landfill Gas	Lyon Generating Facility:GTGS7	4.50
Detroit Edison Co.	Landfill Gas	Pine Tree Acres:GTGS5	4.00
Detroit Edison Co.	Landfill Gas	Riverview Energy Systems:GTGS2	6.60
Detroit Edison Co.	Landfill Gas	Sumpter Energy Assoc.:GTGS10	12.00
Detroit Edison Co.	Nuclear (existing)	Fermi:2	1111.00

Area	Category Level 3	Generator	Generator Annual Maximum Capacity (MW)
Detroit Edison Co.	ST Coal	Belle River:ST1	509.00
Detroit Edison Co.	ST Coal	Belle River:ST2	517.00
Detroit Edison Co.	ST Coal	Harbor Beach:1	103.00
Detroit Edison Co.	ST Coal	Monroe (DETED):1	770.00
Detroit Edison Co.	ST Coal	Monroe (DETED):2	785.00
Detroit Edison Co.	ST Coal	Monroe (DETED):3	785.00
Detroit Edison Co.	ST Coal	Monroe (DETED):4	775.00
Detroit Edison Co.	ST Coal	NAO GM Pontiac Power Plant:1	28.94
Detroit Edison Co.	ST Coal	River Rouge:2	238.00
Detroit Edison Co.	ST Coal	River Rouge:3	272.00
Detroit Edison Co.	ST Coal	St. Clair:1	153.00
Detroit Edison Co.	ST Coal	St. Clair:2	162.00
Detroit Edison Co.	ST Coal	St. Clair:3	171.00
Detroit Edison Co.	ST Coal	St. Clair:4	158.00
Detroit Edison Co.	ST Coal	St. Clair:6	321.00
Detroit Edison Co.	ST Coal	St. Clair:7	450.00
Detroit Edison Co.	ST Coal	Trenton Channel:7	0.00
Detroit Edison Co.	ST Coal	Trenton Channel:8	210.00
Detroit Edison Co.	ST Coal	Trenton Channel:9	520.00
Detroit Edison Co.	ST Coal	Wyandotte (WYAN):7	30.00
Detroit Edison Co.	ST Coal	Wyandotte (WYAN):8	22.00
Detroit Edison Co.	ST Gas	Conners Creek:15	0.00
Detroit Edison Co.	ST Gas	Conners Creek:16	215.00
Detroit Edison Co.	ST Gas	River Rouge:1	234.00
Detroit Edison Co.	ST Gas	Wyandotte (WYAN):5	20.00
Detroit Edison Co.	ST Oil	Greater Detroit Resource Recov:GEN1	30.75
Detroit Edison Co.	ST Oil	Greenwood:1	785.00
Detroit Edison Co.	ST Oil	Mistersky:5	34.29
Detroit Edison Co.	ST Oil	Mistersky:6	38.96
Detroit Edison Co.	ST Oil	Mistersky:7	46.75
Detroit Edison Co.	ST Other	Refuse 2:1	20.00

Figure B - 2: METC Resources

Area	Category Level 3	Generator	Generator Annual Maximum Capacity (MW)
Consumers Energy Co.	Combined Cycle (existing)	Ada Cogeneration Limited Partn:CC	29.40
Consumers Energy Co.	Combined Cycle (existing)	Covert:CC3	384.00
Consumers Energy Co.	Combined Cycle (existing)	Covert:CC4	384.00
Consumers Energy Co.	Combined Cycle (existing)	Covert:CC5	384.00
Consumers Energy Co.	Combined Cycle (existing)	Covert:CCGS3	48.00
Consumers Energy Co.	Combined Cycle (existing)	Jackson:CCA	280.00
Consumers Energy Co.	Combined Cycle (existing)	Jackson:CCB	280.00
Consumers Energy Co.	Combined Cycle (existing)	Michigan Power L.P.:CC	123.00
Consumers Energy Co.	Combined Cycle (existing)	Midland Cogeneration Venture (MCV):CC	1240.00
Consumers Energy Co.	Combined Cycle (existing)	Zeeland (MIR):CC1	532.00
Consumers Energy Co.	CT Gas	491 E. 48th Street:7	37.60
Consumers Energy Co.	CT Gas	491 E. 48th Street:8	37.60
Consumers Energy Co.	CT Gas	491 E. 48th Street:9	83.50
Consumers Energy Co.	CT Gas	B.E. Morrow:GTGS2	34.00
Consumers Energy Co.	CT Gas	Clinton (CLIN):6	2.00
Consumers Energy Co.	CT Gas	Coldwater:GTGS2	8.50
Consumers Energy Co.	CT Gas	Diesel Plant (GHLP):GTGS3	11.90
Consumers Energy Co.	CT Gas	Diesel Plant - STURGI:6	6.00
Consumers Energy Co.	CT Gas	Gaylord:GTGS5	85.00
Consumers Energy Co.	CT Gas	Grand Rapids East:1	0.00
Consumers Energy Co.	CT Gas	Hart:GTGS4	4.82

Area	Category Level 3	Generator	Generator Annual Maximum Capacity (MW)
Consumers Energy Co.	CT Gas	Hillsdale:GTGS4	17.70
Consumers Energy Co.	CT Gas	Kalamazoo River Generating Station:GT	68.00
Consumers Energy Co.	CT Gas	Livingston Generating Station:1	42.90
Consumers Energy Co.	CT Gas	Livingston Generating Station:2	42.43
Consumers Energy Co.	CT Gas	Livingston Generating Station:3	42.43
Consumers Energy Co.	CT Gas	Livingston Generating Station:4	42.43
Consumers Energy Co.	CT Gas	Renaissance Power Project:GT1	171.00
Consumers Energy Co.	CT Gas	Renaissance Power Project:GT2	171.00
Consumers Energy Co.	CT Gas	Renaissance Power Project:GT3	171.00
Consumers Energy Co.	CT Gas	Renaissance Power Project:GT4	171.00
Consumers Energy Co.	CT Gas	Straits:1	21.00
Consumers Energy Co.	CT Gas	Thetford:1	37.00
Consumers Energy Co.	CT Gas	Thetford:2	37.00
Consumers Energy Co.	CT Gas	Thetford:3	37.00
Consumers Energy Co.	CT Gas	Thetford:4	37.00
Consumers Energy Co.	CT Gas	Thetford:GTGS5	86.00
Consumers Energy Co.	CT Gas	Weadock:A	17.00
Consumers Energy Co.	CT Gas	Zeeland (MIR):GT1	149.00
Consumers Energy Co.	CT Gas	Zeeland (MIR):GT2	149.00
Consumers Energy Co.	CT Gas	Zeeland (ZBPW):GTGS7	24.00
Consumers Energy Co.	CT Oil	Alma Modular:GTOL7	0.00

Area	Category Level 3	Generator	Generator Annual Maximum Capacity (MW)
Consumers Energy Co.	CT Oil	APG Four Mile Substation (PPA):GTOL1	18.25
Consumers Energy Co.	CT Oil	APG Long Lake Road (PPA):GTOL1	9.00
Consumers Energy Co.	CT Oil	APG Michigan Limestone (PPA):GTOL1	18.25
Consumers Energy Co.	CT Oil	APG Rockport (PPA):GTOL1	9.13
Consumers Energy Co.	CT Oil	Campbell (CEC):A	17.00
Consumers Energy Co.	CT Oil	Chelsea Modular:GTOL3	0.00
Consumers Energy Co.	CT Oil	Clinton (CLIN):GTOL5	2.20
Consumers Energy Co.	CT Oil	Coldwater Modular:GTOL10	0.00
Consumers Energy Co.	CT Oil	Coldwater:GTOL2	3.50
Consumers Energy Co.	CT Oil	Diesel Plant (GHLP):5	3.00
Consumers Energy Co.	CT Oil	Diesel Plant (GHLP):7	5.10
Consumers Energy Co.	CT Oil	Diesel Plant - STURGI:GTOL4	2.80
Consumers Energy Co.	CT Oil	Frank Jenkins:5	1.70
Consumers Energy Co.	CT Oil	Frank Jenkins:GTOL2	0.38
Consumers Energy Co.	CT Oil	Henry Station:GTOL2	15.40
Consumers Energy Co.	CT Oil	Hillsdale:2	1.90
Consumers Energy Co.	CT Oil	Marshall (MCWEW):GTGS5	10.70
Consumers Energy Co.	CT Oil	Saginaw Station:GTOL2	12.60
Consumers Energy Co.	CT Oil	Sixth Street Mi:1	22.00
Consumers Energy Co.	CT Oil	St. Louis (STLO):GTGS2	2.50
Consumers Energy Co.	CT Oil	St. Louis (STLO):GTOL2	1.70

Area	Category Level 3	Generator	Generator Annual Maximum Capacity (MW)
Consumers Energy Co.	CT Oil	Whiting (CEC):A	17.00
Consumers Energy Co.	CT Oil	Zilwaukee:1-12	0.00
Consumers Energy Co.	CT Oil	Zilwaukee:13-33	0.00
Consumers Energy Co.	Hydro Run-of-River	Ada Dam:HYOP1	1.40
Consumers Energy Co.	Hydro Run-of-River	Alcona:HYOP2	8.00
Consumers Energy Co.	Hydro Run-of-River	Allegan Dam:HYOP3	2.50
Consumers Energy Co.	Hydro Run-of-River	Beaverton (PPA):HYOP1	0.50
Consumers Energy Co.	Hydro Run-of-River	Black River (PPA):HYOP1	0.84
Consumers Energy Co.	Hydro Run-of-River	C.W. Tippy:HYOP3	21.00
Consumers Energy Co.	Hydro Run-of-River	Cascade Dam:HYOP1	1.40
Consumers Energy Co.	Hydro Run-of-River	CEC Small Hydros:HYOP20	0.00
Consumers Energy Co.	Hydro Run-of-River	Cheboygan:HYOP1	0.00
Consumers Energy Co.	Hydro Run-of-River	Commonwealth (Hubbardston PPA):HYOP1	0.22
Consumers Energy Co.	Hydro Run-of-River	Commonwealth (Irving PPA):HYOP1	0.24
Consumers Energy Co.	Hydro Run-of-River	Commonwealth (LaBarge PPA):HYOP1	0.70
Consumers Energy Co.	Hydro Run-of-River	Commonwealth (Middleville PPA):HYOP1	0.20
Consumers Energy Co.	Hydro Run-of-River	Cooke:HYOP1	1.50
Consumers Energy Co.	Hydro Run-of-River	Cooke:HYOP2	3.00
Consumers Energy Co.	Hydro Run-of-River	Cooke:HYOP3	3.00
Consumers Energy Co.	Hydro Run-of-River	Croton:HYOP4	8.40
Consumers Energy Co.	Hydro Run-of-River	Edenville:HYOP2	11.00

Area	Category Level 3	Generator	Generator Annual Maximum Capacity (MW)
Consumers Energy Co.	Hydro Run-of-River	Five Channels:HYOP1	3.20
Consumers Energy Co.	Hydro Run-of-River	Five Channels:HYOP2	3.20
Consumers Energy Co.	Hydro Run-of-River	Foote:HYOP1	3.30
Consumers Energy Co.	Hydro Run-of-River	Foote:HYOP2	3.30
Consumers Energy Co.	Hydro Run-of-River	Foote:HYOP3	3.30
Consumers Energy Co.	Hydro Run-of-River	Four Mile Dam:HYOP3	1.80
Consumers Energy Co.	Hydro Run-of-River	Grenfell Hydro (PPA):HYOP1	0.30
Consumers Energy Co.	Hydro Run-of-River	Hodenpyl:HYOP1	9.20
Consumers Energy Co.	Hydro Run-of-River	Hodenpyl:HYOP2	9.20
Consumers Energy Co.	Hydro Run-of-River	Hydro Plant - STURGI:HYOP4	1.50
Consumers Energy Co.	Hydro Run-of-River	Loud:HYOP1	2.20
Consumers Energy Co.	Hydro Run-of-River	Loud:HYOP2	2.20
Consumers Energy Co.	Hydro Run-of-River	Michiana Hydro (PPA):HYOP1	0.08
Consumers Energy Co.	Hydro Run-of-River	Mio:HYOP1	2.20
Consumers Energy Co.	Hydro Run-of-River	Mio:HYOP2	2.20
Consumers Energy Co.	Hydro Run-of-River	Ninth Street Dam:HYOP3	1.20
Consumers Energy Co.	Hydro Run-of-River	Norway Point Hydropower Projec:HYOP2	4.00
Consumers Energy Co.	Hydro Run-of-River	Rogers:HYOP1	1.50
Consumers Energy Co.	Hydro Run-of-River	Rogers:HYOP2	1.50
Consumers Energy Co.	Hydro Run-of-River	Rogers:HYOP3	1.50
Consumers Energy Co.	Hydro Run-of-River	Rogers:HYOP4	1.50

Area	Category Level 3	Generator	Generator Annual Maximum Capacity (MW)
Consumers Energy Co.	Hydro Run-of-River	Sanford:HYOP3	0.00
Consumers Energy Co.	Hydro Run-of-River	Secord:HYOP1	0.00
Consumers Energy Co.	Hydro Run-of-River	Smallwood:HYOP1	0.00
Consumers Energy Co.	Hydro Run-of-River	Webber:HYOP1	2.30
Consumers Energy Co.	Hydro Run-of-River	Webber:HYOP2	1.00
Consumers Energy Co.	Hydro Run-of-River	Whites Bridge Hydro (PPA):HYOP1	0.82
Consumers Energy Co.	Hydro Storage	Hardy:HYOP1	10.80
Consumers Energy Co.	Hydro Storage	Hardy:HYOP2	10.80
Consumers Energy Co.	Hydro Storage	Hardy:HYOP3	10.80
Consumers Energy Co.	Interruptible Load	CEC Interruptible:1	0.00
Consumers Energy Co.	Landfill Gas	Adrian Energy Assoc. LLC:GTGS3	2.50
Consumers Energy Co.	Landfill Gas	Brent Run Generating Station:GTGS2	1.60
Consumers Energy Co.	Landfill Gas	C & C Generating Facility:GTGS3	2.75
Consumers Energy Co.	Landfill Gas	Grand Blanc Generating Station:GTGS3	3.81
Consumers Energy Co.	Landfill Gas	Granger Electric Generating Station I:GTGS4	3.04
Consumers Energy Co.	Landfill Gas	Granger Electric Generating Station II:GTGS5	3.79
Consumers Energy Co.	Landfill Gas	Ottawa Generating Station:GTGS6	4.57
Consumers Energy Co.	Landfill Gas	Peoples Generating Station:1	3.06
Consumers Energy Co.	Landfill Gas	Seymour Road Generating Statio:GTGS2	0.75
Consumers Energy Co.	Landfill Gas	Venice Resources Gas Recovery:GTGS2	1.50
Consumers Energy Co.	Nuclear (existing)	Palisades (CEC):1	803.00

Area	Category Level 3	Generator	Generator Annual Maximum Capacity (MW)
Consumers Energy Co.	Pumped Storage Hydro	Ludington:PSOP6	1871.70
Consumers Energy Co.	ST Coal	Campbell (CEC):1	260.00
Consumers Energy Co.	ST Coal	Campbell (CEC):2	360.00
Consumers Energy Co.	ST Coal	Campbell (CEC):3	820.00
Consumers Energy Co.	ST Coal	Cobb:4	160.00
Consumers Energy Co.	ST Coal	Cobb:5	160.00
Consumers Energy Co.	ST Coal	Endicott:1	55.00
Consumers Energy Co.	ST Coal	James De Young:3	10.50
Consumers Energy Co.	ST Coal	James De Young:4	20.50
Consumers Energy Co.	ST Coal	James De Young:5	27.00
Consumers Energy Co.	ST Coal	Karn:1	255.00
Consumers Energy Co.	ST Coal	Karn:2	260.00
Consumers Energy Co.	ST Coal	S. D. Warren Co. #1 Muskeg:GEN5	0.00
Consumers Energy Co.	ST Coal	S. D. Warren Co. #1 Muskeg:STCL2	0.00
Consumers Energy Co.	ST Coal	TES Filer City Station:1	60.00
Consumers Energy Co.	ST Coal	Weadock:7	155.00
Consumers Energy Co.	ST Coal	Weadock:8	155.00
Consumers Energy Co.	ST Coal	Whiting (CEC):1	102.00
Consumers Energy Co.	ST Coal	Whiting (CEC):2	102.00
Consumers Energy Co.	ST Coal	Whiting (CEC):3	124.00
Consumers Energy Co.	ST Gas	Cobb:1	68.00

Area	Category Level 3	Generator	Generator Annual Maximum Capacity (MW)
Consumers Energy Co.	ST Gas	Cobb:2	61.00
Consumers Energy Co.	ST Gas	Cobb:3	52.00
Consumers Energy Co.	ST Gas	Karn:4	638.00
Consumers Energy Co.	ST Oil	Karn:3	638.00
Consumers Energy Co.	ST Oil	Recycled Board Division:STOH2	0.00
Consumers Energy Co.	ST Other	Cadillac Renewable Energy:1	34.00
Consumers Energy Co.	ST Other	Genesee Power Station:1	35.00
Consumers Energy Co.	ST Other	Grayling Generating Station:1	36.17
Consumers Energy Co.	ST Other	Hillman:1	16.00
Consumers Energy Co.	ST Other	Jackson County Resource Recove:1	0.00
Consumers Energy Co.	ST Other	Kent County Waste-to-Energy Fa:ST2	15.68
Consumers Energy Co.	ST Other	Lincoln Power Station:1	18.00
Consumers Energy Co.	ST Other	McBain Power Station:1	18.00
Consumers Energy Co.	Wind	Mackinaw City:WIOP5	1.80

Figure B - 3: Wolverine Resources

Area	Category Level 3	Generator	Generator Annual Maximum Capacity (MW)
Wolverine Power Supply Coop, Inc.	Combined Cycle (existing)	Claude Vandyke (Burnips):6	25.00
Wolverine Power Supply Coop, Inc.	CT Gas	Claude Vandyke (Burnips):GT8	24.00
Wolverine Power Supply Coop, Inc.	CT Gas	Gaylord [WPSC]:GT1	25.00
Wolverine Power Supply Coop, Inc.	CT Gas	Gaylord [WPSC]:GT2	25.00
Wolverine Power Supply Coop, Inc.	CT Gas	Gaylord [WPSC]:GT3	25.00
Wolverine Power Supply Coop, Inc.	CT Gas	George Johnson:GT10	25.00
Wolverine Power Supply Coop, Inc.	CT Gas	George Johnson:GT9	25.00
Wolverine Power Supply Coop, Inc.	CT Gas	Lowell:GTGS3	3.60
Wolverine Power Supply Coop, Inc.	CT Gas	Tower:GT4	25.00
Wolverine Power Supply Coop, Inc.	CT Gas	Traverse City:GT	50.00
Wolverine Power Supply Coop, Inc.	CT Oil	Beaver Island:GTOL6	0.00
Wolverine Power Supply Coop, Inc.	CT Oil	Lowell:GTOL2	2.20
Wolverine Power Supply Coop, Inc.	CT Oil	Tower:GTOL3	3.60
Wolverine Power Supply Coop, Inc.	CT Oil	Vestaburg:GTGS8	25.00
Wolverine Power Supply Coop, Inc.	CT Oil	Vestaburg:GTOL5	7.70
Wolverine Power Supply Coop, Inc.	Hydro Run-of-River	Kleber:HYOP2	1.20
Wolverine Power Supply Coop, Inc.	Hydro Run-of-River	Saint Marys Falls:HYOP5	19.96
Wolverine Power Supply Coop, Inc.	Interruptible Load	WPSC Interruptible:1	10.00
Wolverine Power Supply Coop, Inc.	ST Coal	Sims:3	66.30

Figure B - 4: City Of Lansing Resources

Area	Category Level 3	Generator	Generator Annual Maximum Capacity (MW)
Lansing Board of Water & Light	Hydro Run-of-River	LBWL Small Hydros:HYOP2	1.06
Lansing Board of Water & Light	Hydro Run-of-River	Moores Park:HYOP2	1.00
Lansing Board of Water & Light	Interruptible Load	LBWL Interruptible:1	12.00
Lansing Board of Water & Light	ST Coal	Eckert:1	45.63
Lansing Board of Water & Light	ST Coal	Eckert:2	46.62
Lansing Board of Water & Light	ST Coal	Eckert:3	50.79
Lansing Board of Water & Light	ST Coal	Eckert:4	78.23
Lansing Board of Water & Light	ST Coal	Eckert:5	79.35
Lansing Board of Water & Light	ST Coal	Eckert:6	77.33
Lansing Board of Water & Light	ST Coal	Erickson:1	158.53

Figure B - 5: Unit Retirements

Plant Name	Unit #	Retire Year	Capacity MW
COBB	1	2013	68
COBB	2	2013	61
COBB	3	2015	52
MSTERSKY	5	2015	39
TRNTNCHN	8	2015	210
JMSDYUNG	3	2016	11
CNNRSCRK	16	2016	215
WHTNGCEC	1	2017	102
WHTNGCEC	2	2017	102
WHTNGCEC	3	2018	124
STCLAIR	1	2018	153
STCLAIR	2	2018	162
ECKERT	1	2019	46
STCLAIR	3	2019	171
STCLAIR	4	2019	158
WEADOCK	7	2020	155
PRSQISLE	1	2020	25
COBB	4	2021	160
RVRROUGE	1	2021	242
COBB	5	2022	160
WEADOCK	8	2022	155
RVRROUGE	2	2022	247
WYNDTTWY	5	2022	22
ECKERT	2	2023	47
MSTERSKY	6	2023	47
RVRROUGE	3	2023	280
ESCANABA	2	2023	26
KARN	1	2024	255
KARN	2	2024	260

Appendix C – Results

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Figure C - 1: Base Case Results

Capacity Additions (Firm MW)	2005 to 2014	2005-2024
CT	1,280	3,040
CC	1,500	3,000
PC	4,000	11,000
Nuclear	0	0
IGCC-Seq	0	0
Other	0	0
TOTAL	**6,780**	**17,040**
Annual Demand Growth (%)	2.38	2.17
Reserve Margin (%)	15.85	15.16
Plan Costs (2005 $ million)		
NPV Utility Cost	$ 29,640.9	$ 54,596.8
NPV Emission	$ 4,084.0	$ 7,642.3
NPV CO_2	$ 0.0	$ 0.0

Figure C - 2: Base Case Mix

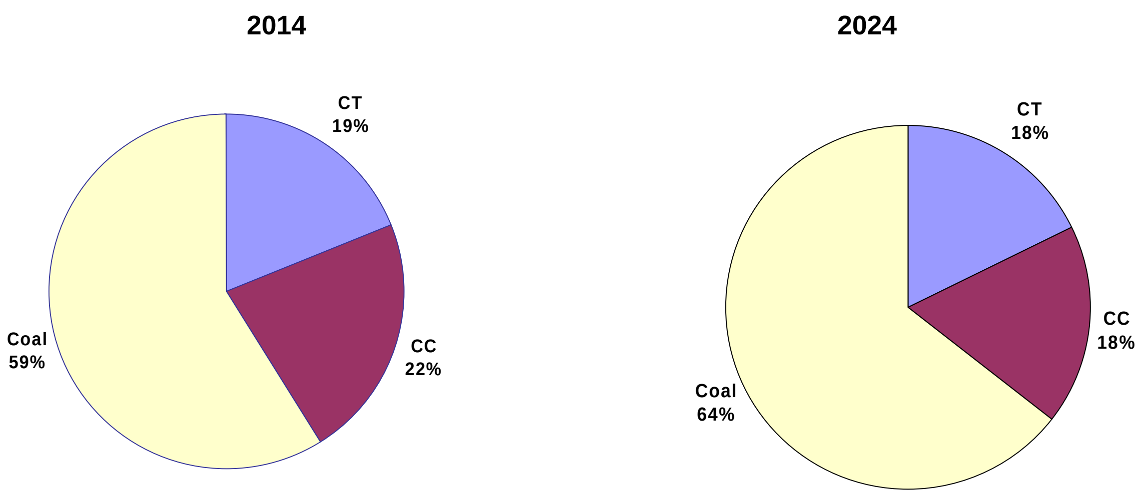


Figure C - 3: Base Case Plan

Base Case		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
11	CT - METC	-	-	-	1	2	1	-	-	-	-
7	CT - ITC	-	-	2	-	-	2	-	-	-	-
1	CT - ATC2	-	-	-	-	-	-	-	-	-	-
1	CC - METC	-	-	-	-	-	-	-	-	-	-
5	CC - ITC	-	-	-	1	1	1	-	-	-	-
0	CC - ATC2	-	-	-	-	-	-	-	-	-	-
12	COAL - METC	-	-	-	-	-	-	1	1	1	1
10	COAL - ITC	-	-	-	-	-	-	1	1	1	1
0	COAL - ATC2	-	-	-	-	-	-	-	-	-	-

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CT - METC	-	1	-	1	1	1	1	-	1	1
CT - ITC	-	-	-	-	-	-	1	1	1	-
CT - ATC2	-	-	-	-	1	-	-	-	-	-
CC - METC	-	-	-	-	-	-	-	-	1	-
CC - ITC	-	-	-	-	-	-	-	-	1	1
CC - ATC2	-	-	-	-	-	-	-	-	-	-
COAL - METC	-	1	1	1	1	1	1	1	-	1
COAL - ITC	1	1	1	-	1	1	-	1	-	-
COAL - ATC2	-	-	-	-	-	-	-	-	-	-

Figure C - 4: Base Case/High Load Results

Capacity Additions (Firm MW)	2005 to 2014	2005 to 2024
CT	2,240	4,320
CC	3,500	4,500
PC	4,500	12,500
Nuclear	0	0
IGCC-Seq	0	0
Other	0	0
TOTAL	**10,240**	**21,320**
Annual Demand Growth (%)	3.35	2.63
Reserve Margin (%)	15.14	15.00
Plan Costs (2005 $ million)		
NPV Utility Cost	$ 32,282.9	$ 60,895.9
NPV Emission	$ 4,107.3	$ 7,771.3
NPV CO_2	$ 0.0	$ 0.0

Figure C - 5: Base Case/High Load Mix

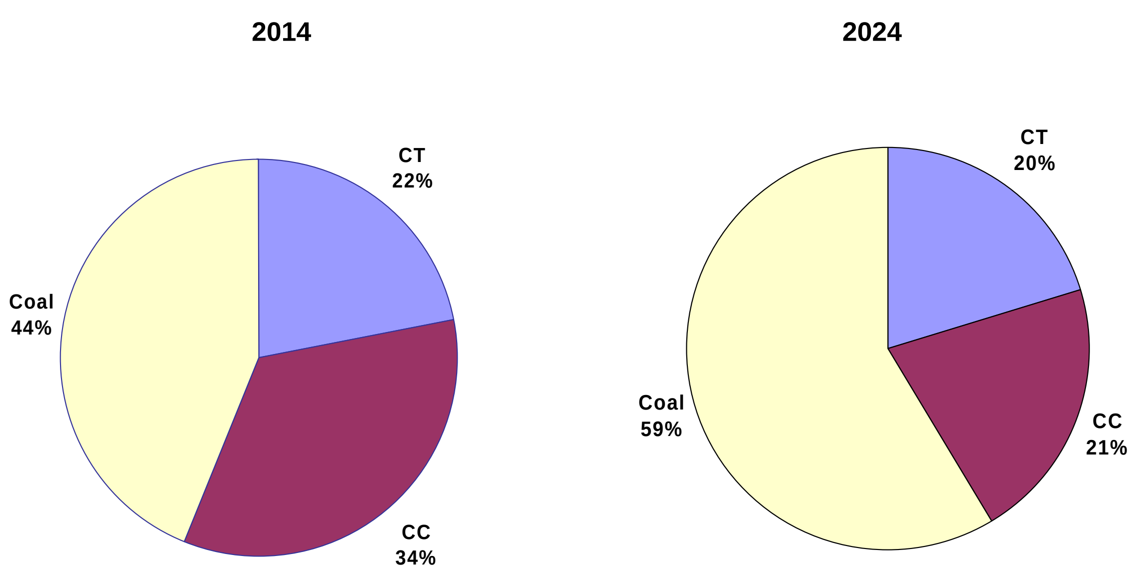


Figure C - 6: Base Case/High Load Plan

	BC High Load	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
12	CT - METC	-	-	2	-	2	-	1	-	1	-
13	CT - ITC	-	-	2	2	-	2	-	-	1	-
2	CT - ATC2	-	-	-	-	-	-	-	-	1	-
3	CC - METC	-	-	-	-	-	1	-	-	-	1
6	CC - ITC	-	-	-	2	2	1	-	-	-	-
0	CC - ATC2	-	-	-	-	-	-	-	-	-	-
13	COAL - METC	-	-	-	-	-	-	1	1	1	1
12	COAL - ITC	-	-	-	-	-	-	2	1	1	1
0	COAL - ATC2	-	-	-	-	-	-	-	-	-	-

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CT - METC	-	-	-	1	1	-	1	1	1	1
CT - ITC	-	-	-	1	1	1	1	1	1	-
CT - ATC2	-	-	-	-	-	-	1	-	-	-
CC - METC	-	-	-	-	-	-	-	-	-	1
CC - ITC	-	-	-	-	-	-	-	-	-	1
CC - ATC2	-	-	-	-	-	-	-	-	-	-
COAL - METC	1	1	1	1	1	1	1	1	1	-
COAL - ITC	1	1	1	-	1	1	-	1	1	-
COAL - ATC2	-	-	-	-	-	-	-	-	-	-

Figure C - 7: Base Case/Low Load Results

Capacity Additions (Firm MW)	2005 to 2014	2005 to 2024
CT	0	1,280
CC	1,000	2,000
PC	2,500	9,500
Nuclear	0	0
IGCC-Seq	0	0
Other	0	0
TOTAL	**3,500**	**12,780**
Annual Demand Growth (%)	1.30	1.66
Reserve Margin (%)	16.40	15.42
Plan Costs (2005 $ million)		
NPV Utility Cost	$ 27,146.3	$ 48,707.3
NPV Emission	$4,046.1	$ 7,529.5
NPV CO_2	$ 0.0	$ 0.0

Figure C - 8: Base Case/Low Load Mix

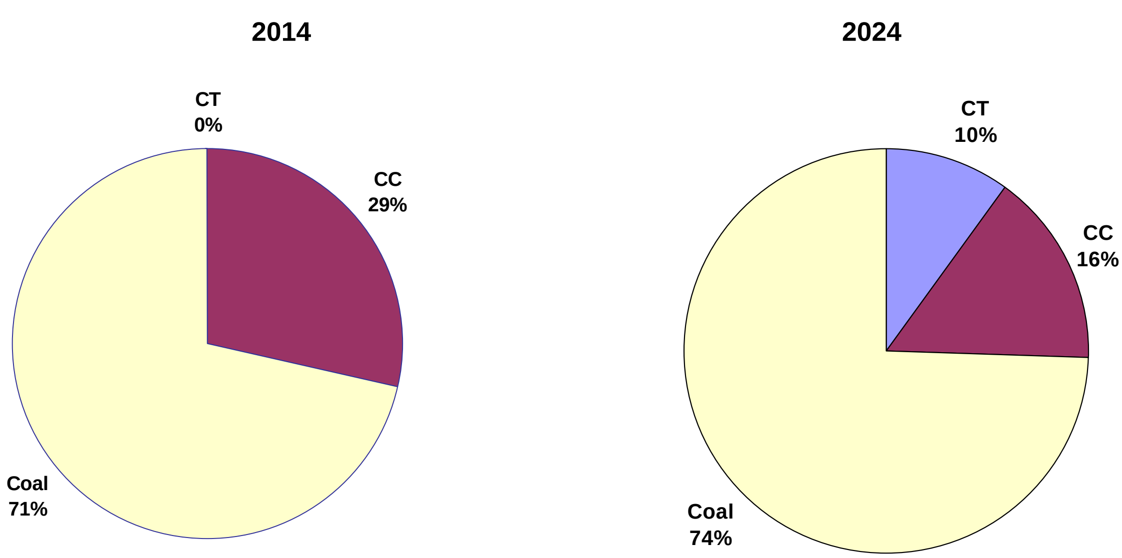


Figure C - 9: Base Case/Low Load Plan

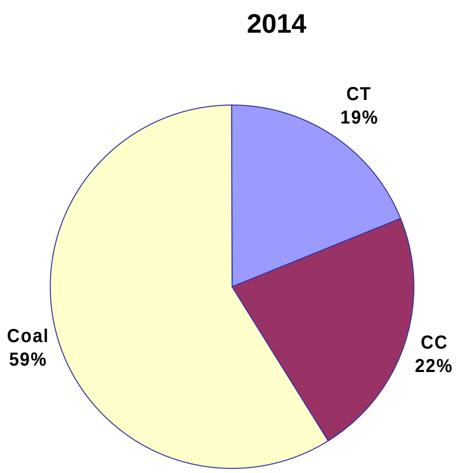
BC Low Load		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
7	CT - METC	-	-	-	-	-	-	-	-	-	-
1	CT - ITC	-	-	-	-	-	-	-	-	-	-
0	CT - ATC2	-	-	-	-	-	-	-	-	-	-
1	CC - METC	-	-	-	-	-	-	-	-	-	-
3	CC - ITC	-	-	-	-	1	1	-	-	-	-
0	CC - ATC2	-	-	-	-	-	-	-	-	-	-
9	COAL - METC	-	-	-	-	-	-	1	-	1	-
10	COAL - ITC	-	-	-	-	-	-	-	1	1	1
0	COAL - ATC2	-	-	-	-	-	-	-	-	-	-

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CT - METC	-	-	1	1	1	-	1	1	1	1
CT - ITC	-	-	-	1	-	-	-	-	-	-
CT - ATC2	-	-	-	-	-	-	-	-	-	-
CC - METC	-	-	-	-	-	-	-	-	-	1
CC - ITC	-	-	-	-	-	-	-	-	1	-
CC - ATC2	-	-	-	-	-	-	-	-	-	-
COAL - METC	1	1	-	-	1	1	1	1	1	-
COAL - ITC	-	1	1	1	1	1	-	1	-	1
COAL - ATC2	-	-	-	-	-	-	-	-	-	-

Figure C - 10: Base Case/High Gas Results

Capacity Additions (Firm MW)	2005 to 2014	2005 to 2024
CT	1,280	2,880
CC	1,500	2,000
PC	4,000	12,000
Nuclear	0	0
IGCC-Seq	0	0
Other	0	0
TOTAL	**6,780**	**16,880**
Annual Demand Growth (%)	2.38	2.17
Reserve Margin (%)	15.85	15.03
Plan Costs (2005 $ million)		
NPV Utility Cost	$ 30,794.9	$ 56,282.2
NPV Emission	$4,049.5	$ 7,588.1
NPV CO_2	$ 0.0	$ 0.0

Figure C - 11: Base Case/High Gas Mix



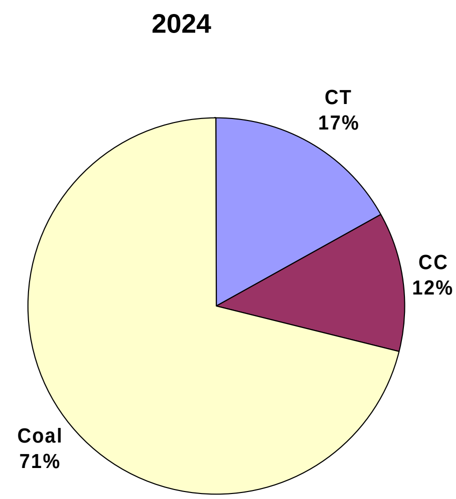


Figure C - 12: Base Case/High Gas Plan

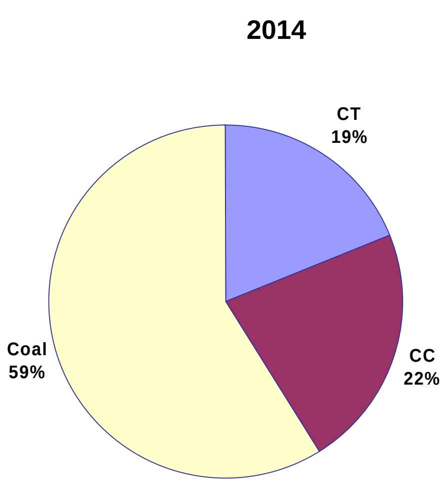
High Import		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
11	CT - METC	-	-	-	1	2	1	-	-	-	-
6	CT - ITC	-	-	2	-	-	2	-	-	-	-
1	CT - ATC2	-	-	-	-	-	-	-	-	-	-
0	CC - METC	-	-	-	-	-	-	-	-	-	-
4	CC - ITC	-	-	-	1	1	1	-	-	-	-
0	CC - ATC2	-	-	-	-	-	-	-	-	-	-
12	COAL - METC	-	-	-	-	-	-	1	1	1	1
12	COAL - ITC	-	-	-	-	-	-	1	1	1	1
0	COAL - ATC2	-	-	-	-	-	-	-	-	-	-

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CT - METC	-	1	-	1	1	1	1	1	1	-
CT - ITC	-	-	-	-	-	-	1	-	1	-
CT - ATC2	-	-	-	-	1	-	-	-	-	-
CC - METC	-	-	-	-	-	-	-	-	-	-
CC - ITC	-	-	-	-	-	-	-	-	-	1
CC - ATC2	-	-	-	-	-	-	-	-	-	-
COAL - METC	-	1	1	1	1	1	-	1	1	1
COAL - ITC	1	1	1	-	1	1	1	1	1	-
COAL - ATC2	-	-	-	-	-	-	-	-	-	-

Figure C - 13: Base Case/High Import Results

Capacity Additions (Firm MW)	2005 to 2014	2004 to 2024
CT	1,280	2,400
CC	1,500	1,500
PC	4,000	13,000
Nuclear	0	0
IGCC-Seq	0	0
Other	0	0
TOTAL	**6,780**	**16,900**
Annual Demand Growth (%)	2.38	2.17
Reserve Margin (%)	15.85	15.38
Plan Costs (2005 $ million)		
NPV Utility Cost	$ 29,608.2	$ 54,238.5
NPV Emission	$ 4,089.3	$ 7,739.8
NPV CO_2	$ 0.0	$ 0.0

Figure C - 14: Base Case/High Import Mix



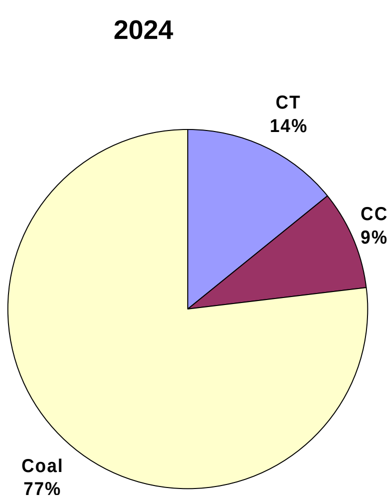


Figure C - 15: Base Case/High Import Plan

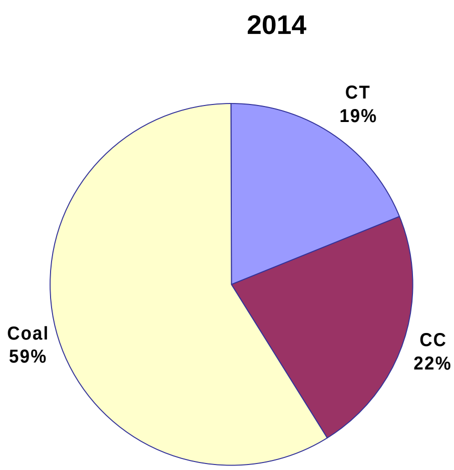
High Import		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
7	CT - METC	-	-	-	1	2	1	-	-	-	-
7	CT - ITC	-	-	2	-	-	2	-	-	-	-
1	CT - ATC2	-	-	-	-	-	-	-	-	-	-
0	CC - METC	-	-	-	-	-	-	-	-	-	-
3	CC - ITC	-	-	-	1	1	1	-	-	-	-
0	CC - ATC2	-	-	-	-	-	-	-	-	-	-
13	COAL - METC	-	-	-	-	-	-	1	1	1	1
13	COAL - ITC	-	-	-	-	-	-	1	1	1	1
0	COAL - ATC2	-	-	-	-	-	-	-	-	-	-

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CT - METC	-	1	-	-	-	-	1	-	1	-
CT - ITC	-	-	-	-	-	-	1	-	1	1
CT - ATC2	-	-	-	-	1	-	-	-	-	-
CC - METC	-	-	-	-	-	-	-	-	-	-
CC - ITC	-	-	-	-	-	-	-	-	-	-
CC - ATC2	-	-	-	-	-	-	-	-	-	-
COAL - METC	-	1	1	1	1	1	1	1	1	1
COAL - ITC	1	1	1	1	1	1	-	1	1	1
COAL - ATC2	-	-	-	-	-	-	-	-	-	-

Figure C - 16: Base Case/Low Import Results

Capacity Additions (Firm MW)	2005 to 2014	2005 to 2024
CT	1,280	2,880
CC	1,500	2,000
PC	4,000	12,000
Nuclear	0	0
IGCC-Seq	0	0
Other	0	0
TOTAL	**6,780**	**16,880**
Annual Demand Growth (%)	2.38	2.17
Reserve Margin (%)	15.85	15.03
Plan Costs (2005 $ million)		
NPV Utility Cost	$ 29,740.4	$ 54,870.9
NPV Emission	$ 4,070.6	$ 7,405.5
NPV CO_2	$ 0.0	$ 0.0

Figure C - 17: Base Case/Low Import Mix



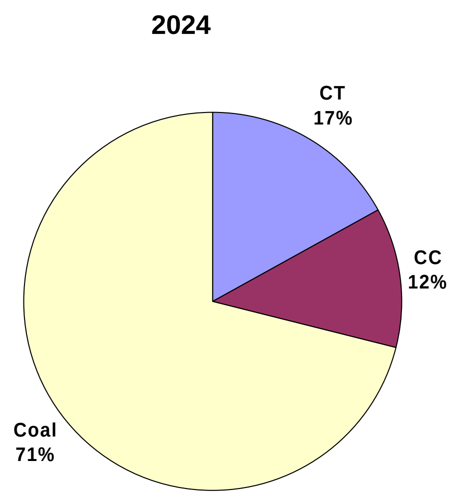


Figure C - 18: Base Case/Low Import Plan

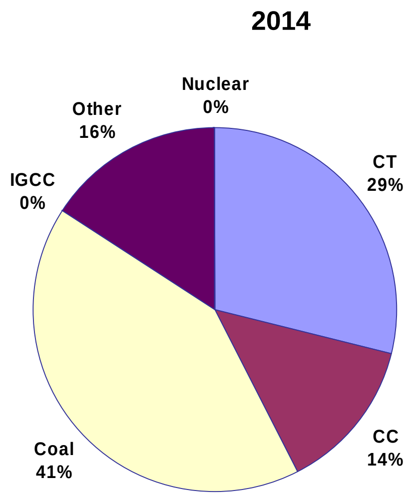
	BC Low Import	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
11	CT - METC	-	-	-	1	2	1	-	-	-	-
6	CT - ITC	-	-	2	-	-	2	-	-	-	-
1	CT - ATC2	-	-	-	-	-	-	-	-	-	-
0	CC - METC	-	-	-	-	-	-	-	-	-	-
4	CC - ITC	-	-	-	1	1	1	-	-	-	-
0	CC - ATC2	-	-	-	-	-	-	-	-	-	-
12	COAL - METC	-	-	-	-	-	-	1	1	1	1
12	COAL - ITC	-	-	-	-	-	-	1	1	1	1
0	COAL - ATC2	-	-	-	-	-	-	-	-	-	-

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CT - METC	-	1	-	1	1	1	1	1	1	-
CT - ITC	-	-	-	-	-	-	1	-	1	-
CT - ATC2	-	-	-	-	1	-	-	-	-	-
CC - METC	-	-	-	-	-	-	-	-	-	-
CC - ITC	-	-	-	-	-	-	-	-	-	1
CC - ATC2	-	-	-	-	-	-	-	-	-	-
COAL - METC	-	1	1	1	1	1	-	1	1	1
COAL - ITC	1	1	1	-	1	1	1	1	1	-
COAL - ATC2	-	-	-	-	-	-	-	-	-	-

Figure C - 19: Emissions Case

Capacity Additions (Firm MW)	2005 to 2014	2005 to 2024
CT	2,080	2,720
CC	1,000	1,000
PC	3,000	4,500
Nuclear	0	8,000
IGCC-Seq	0	0
Other	600	600
TOTAL	**6,680**	**16,820**
Annual Demand Growth (%)	2.38	2.17
Reserve Margin (%)	15.19	15.03
Plan Costs (2005 $ million)		
NPV Utility Cost	$ 33,543.9	$ 66,002.9
NPV Emission	$ 7,851.0	$ 20,195.6
NPV CO_2	$ 3,724.5	$ 12,751.3

Figure C - 20: Emission Case Mix



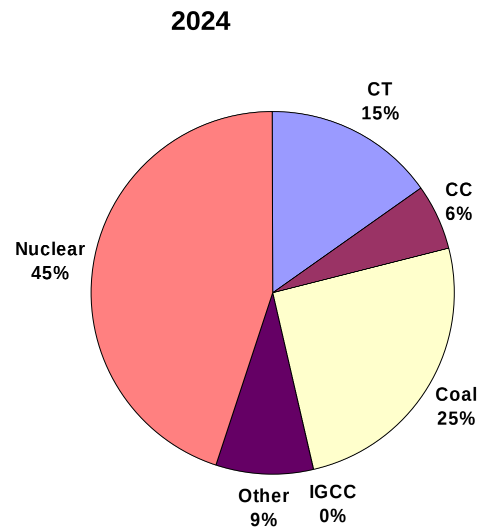


Figure C - 21: Emissions Case Plan

Emissions Case		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
9	CT - METC	-	-	-	2	1	2	-	1	-	1
7	CT - ITC	-	-	1	2	1	1	-	-	-	1
1	CT - ATC2	-	-	-	-	-	-	-	-	-	-
0	CC - METC	-	-	-	-	-	-	-	-	-	-
2	CC - ITC	-	-	-	-	1	1	-	-	-	-
0	CC - ATC2	-	-	-	-	-	-	-	-	-	-
4	COAL - METC	-	-	-	-	-	-	1	-	1	-
5	COAL - ITC	-	-	-	-	-	-	1	1	1	1
0	COAL - ATC2	-	-	-	-	-	-	-	-	-	-
4	NUC - METC	-	-	-	-	-	-	-	-	-	-
4	NUC - ITC	-	-	-	-	-	-	-	-	-	-
0	IGCC - METC	-	-	-	-	-	-	-	-	-	-
0	IGCC - ITC	-	-	-	-	-	-	-	-	-	-

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CT - METC	-	1	-	-	-	-	-	-	-	1
CT - ITC	-	1	-	-	-	-	-	-	-	-
CT - ATC2	-	-	-	-	-	-	1	-	-	-
CC - METC	-	-	-	-	-	-	-	-	-	-
CC - ITC	-	-	-	-	-	-	-	-	-	-
CC - ATC2	-	-	-	-	-	-	-	-	-	-
COAL - METC	1	1	-	-	-	-	-	-	-	-
COAL - ITC	1	-	-	-	-	-	-	-	-	-
COAL - ATC2	-	-	-	-	-	-	-	-	-	-
NUC - METC	-	-	-	1	1	-	1	-	1	-
NUC - ITC	-	-	1	-	1	-	-	1	1	-
IGCC - METC	-	-	-	-	-	-	-	-	-	-
IGCC - ITC	-	-	-	-	-	-	-	-	-	-

Figure C - 22: Emissions Case/High Load Results

Capacity Additions (Firm MW)	2005 to 2014	2005 to 2024
CT	2,080	2,720
CC	3,000	3,000
PC	4,500	6,000
Nuclear	0	9,000
IGCC-Seq	0	0
Other	600	600
TOTAL	**10,180**	**21,320**
Annual Demand Growth (%)	3.35	2.63
Reserve Margin (%)	15.31	15.87
Plan Costs (2005 $ million)		
NPV Utility Cost	$ 38,373.4	$ 77,407.4
NPV Emission	$ 8,491.7	$ 22,443.2
NPV CO_2	$ 4,160.9	$ 14,575.1

Figure C - 23: Emissions Case/High Load Mix

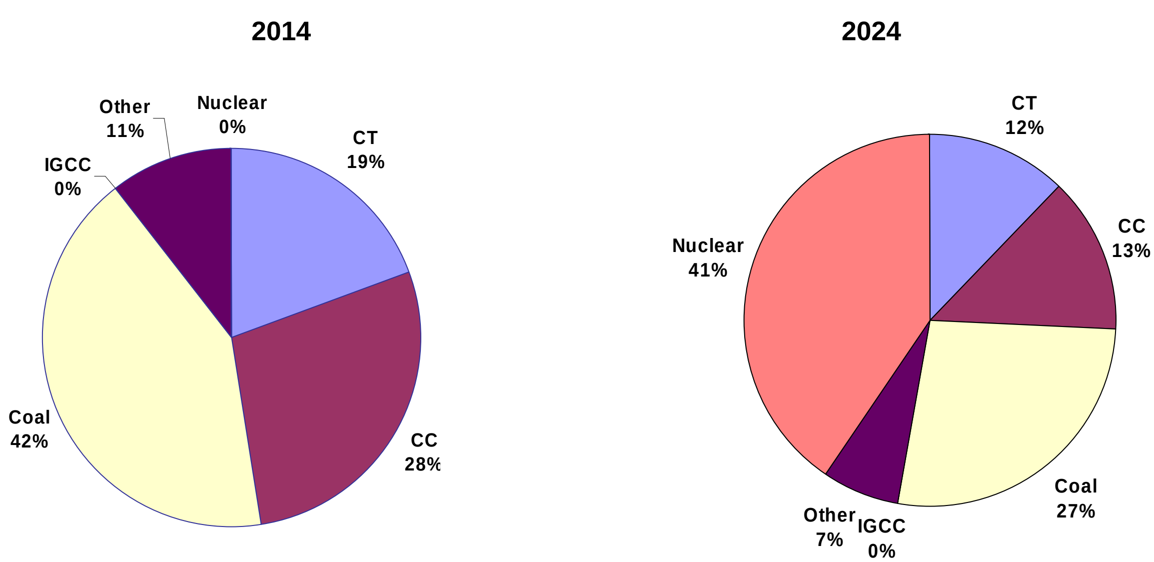


Figure C - 24: Emissions Case/High Load Plan

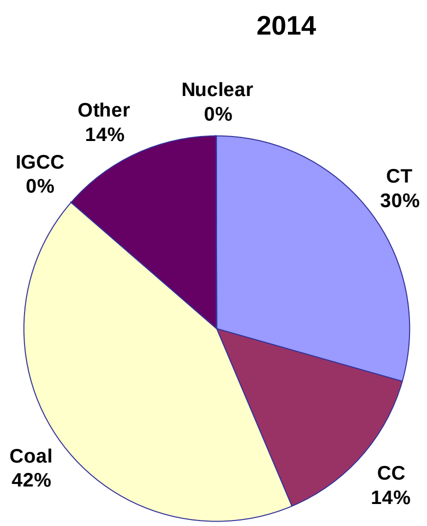
Emissions High Load		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
6	CT - METC	-	-	1	-	1	-	1	1	-	1
10	CT - ITC	-	-	2	1	1	1	1	1	-	1
1	CT - ATC2	-	-	-	-	-	-	-	-	-	-
1	CC - METC	-	-	-	-	-	1	-	-	-	-
5	CC - ITC	-	-	-	2	2	1	-	-	-	-
0	CC - ATC2	-	-	-	-	-	-	-	-	-	-
7	COAL - METC	-	-	-	-	-	-	1	1	2	1
5	COAL - ITC	-	-	-	-	-	-	1	1	1	1
0	COAL - ATC2	-	-	-	-	-	-	-	-	-	-
5	NUC - METC	-	-	-	-	-	-	-	-	-	-
4	NUC - ITC	-	-	-	-	-	-	-	-	-	-
0	IGCC - METC	-	-	-	-	-	-	-	-	-	-
0	IGCC - ITC	-	-	-	-	-	-	-	-	-	-

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CT - METC	1	-	-	-	-	-	-	-	-	-
CT - ITC	1	1	-	-	-	-	-	-	-	-
CT - ATC2	-	-	-	-	-	-	1	-	-	-
CC - METC	-	-	-	-	-	-	-	-	-	-
CC - ITC	-	-	-	-	-	-	-	-	-	-
CC - ATC2	-	-	-	-	-	-	-	-	-	-
COAL - METC	1	1	-	-	-	-	-	-	-	-
COAL - ITC	-	1	-	-	-	-	-	-	-	-
COAL - ATC2	-	-	-	-	-	-	-	-	-	-
NUC - METC	-	-	-	1	1	-	1	-	1	1
NUC - ITC	-	-	1	-	1	1	-	1	-	-
IGCC - METC	-	-	-	-	-	-	-	-	-	-
IGCC - ITC	-	-	-	-	-	-	-	-	-	-

Figure C - 25: Emissions Case/High Gas Results

Capacity Additions (Firm MW)	2004 to 2014	2004 to 2024
CT	2,080	2,560
CC	1,000	1,000
PC	3,000	4,500
Nuclear	0	9,000
IGCC-Seq	0	0
Other	600	600
TOTAL	**6,680**	**17,660**
Annual Demand Growth (%)	2.38	2.17
Reserve Margin (%)	15.19	17.55
Plan Costs (2005 $ million)		
NPV Utility Cost	$ 34, 737.7	$ 67,779.7
NPV Emission	$ 7,747.5	$ 19,925.8
NPV CO_2	$ 3,652.7	$ 12,525.2

Figure C - 26: Emissions Case/High Gas Mix



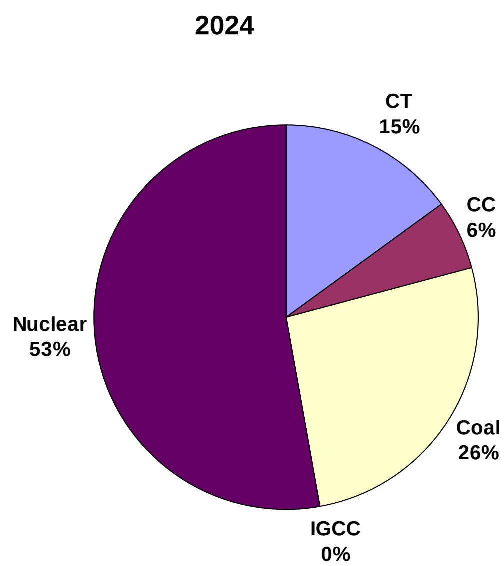


Figure C - 27: Emissions Case/High Gas Plan

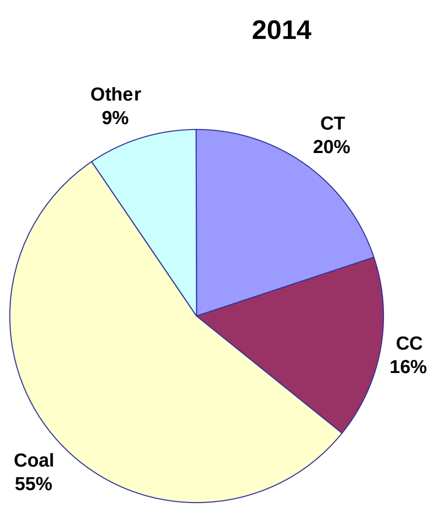
	Emissions High Gas	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
7	CT - METC	-	-	-	2	1	2	-	-	-	1
8	CT - ITC	-	-	1	2	1	1	-	-	1	1
1	CT - ATC2	-	-	-	-	-	-	-	-	-	-
0	CC - METC	-	-	-	-	-	-	-	-	-	-
2	CC - ITC	-	-	-	-	1	1	-	-	-	-
0	CC - ATC2	-	-	-	-	-	-	-	-	-	-
4	COAL - METC	-	-	-	-	-	-	1	1	1	-
5	COAL - ITC	-	-	-	-	-	-	1	1	-	1
0	COAL - ATC2	-	-	-	-	-	-	-	-	-	-
5	NUC - METC	-	-	-	-	-	-	-	-	-	-
4	NUC - ITC	-	-	-	-	-	-	-	-	-	-
0	IGCC - METC	-	-	-	-	-	-	-	-	-	-
0	IGCC - ITC	-	-	-	-	-	-	-	-	-	-

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CT - METC	-	1	-	-	-	-	-	-	-	-
CT - ITC	-	1	-	-	-	-	-	-	-	-
CT - ATC2	-	-	-	-	-	-	1	-	-	-
CC - METC	-	-	-	-	-	-	-	-	-	-
CC - ITC	-	-	-	-	-	-	-	-	-	-
CC - ATC2	-	-	-	-	-	-	-	-	-	-
COAL - METC	1	-	-	-	-	-	-	-	-	-
COAL - ITC	1	1	-	-	-	-	-	-	-	-
COAL - ATC2	-	-	-	-	-	-	-	-	-	-
NUC - METC	-	-	1	-	1	-	1	-	1	1
NUC - ITC	-	-	1	-	-	1	-	1	1	-
IGCC - METC	-	-	-	-	-	-	-	-	-	-
IGCC - ITC	-	-	-	-	-	-	-	-	-	-

Figure C - 28: Energy Efficiency Case

Capacity Additions (Firm MW)	2005 to 2014	2005 to 2024
CT	1,280	3,040
CC	1,000	2,500
PC	3,500	10,000
Nuclear	0	0
IGCC-Seq	0	0
Other	232	259
TOTAL	**6,012**	**15,799**
Annual Demand Growth (%)	2.15	2.00
Reserve Margin (%)	15.34	15.07
Plan Costs (2005 $ million)		
NPV Utility Cost	$ 29,802.9	$ 54,066.4
NPV Emission	$ 4,054.4	$ 7,509.6
NPV CO_2	$ 0.0	$ 0.0

Figure C - 29: Energy Efficiency Mix



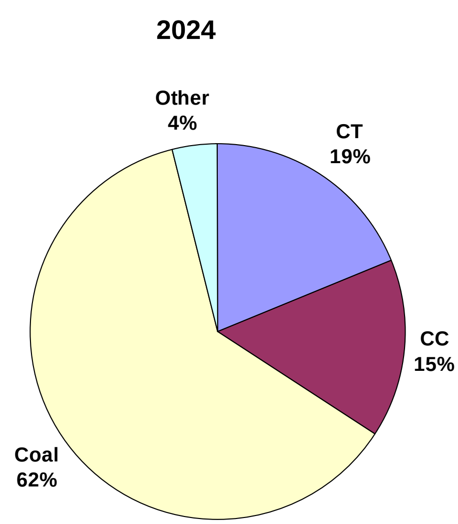


Figure C - 30: Energy Efficiency Plan

Conservaton		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
8	CT - METC	-	-	-	-	2	2	-	-	-	-
10	CT - ITC	-	-	-	1	2	1	-	-	-	-
1	CT - ATC2	-	-	-	-	-	-	-	-	-	-
1	CC - METC	-	-	-	-	-	-	-	-	-	-
4	CC - ITC	-	-	-	1	-	1	-	-	-	-
0	CC - ATC2	-	-	-	-	-	-	-	-	-	-
11	COAL - METC	-	-	-	-	-	-	1	1	-	1
9	COAL - ITC	-	-	-	-	-	-	1	1	1	1
0	COAL - ATC2	-	-	-	-	-	-	-	-	-	-

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CT - METC	-	-	1	1	-	-	1	-	1	-
CT - ITC	1	-	1	1	-	-	1	-	1	1
CT - ATC2	-	-	-	-	-	-	-	-	1	-
CC - METC	-	-	-	-	-	-	-	-	-	1
CC - ITC	-	-	-	-	-	-	-	-	1	1
CC - ATC2	-	-	-	-	-	-	-	-	-	-
COAL - METC	-	1	1	1	1	1	1	1	1	-
COAL - ITC	1	1	-	-	1	1	-	1	-	-
COAL - ATC2	-	-	-	-	-	-	-	-	-	-

Figure C - 31: Energy Efficiency/High Load Results

Capacity Additions (Firm MW)	2005 to 2014	2005 to 2024
CT	1,440	2,880
CC	3,000	4,500
PC	5,000	12,500
Nuclear	0	0
IGCC-Seq	0	0
Other	232	259
TOTAL	9,672	20,139
Annual Demand Growth (%)	3.15	2.47
Reserve Margin (%)	15.58	15.34
Plan Costs (2005 $ million)		
NPV Utility Cost	$34,422.9	$ 60,335.7
NPV Emission	$ 4,092.3	$ 7,611.2
NPV CO_2	$ 0.0	$ 0.0

Figure C - 32: Energy efficiency/High Load Mix

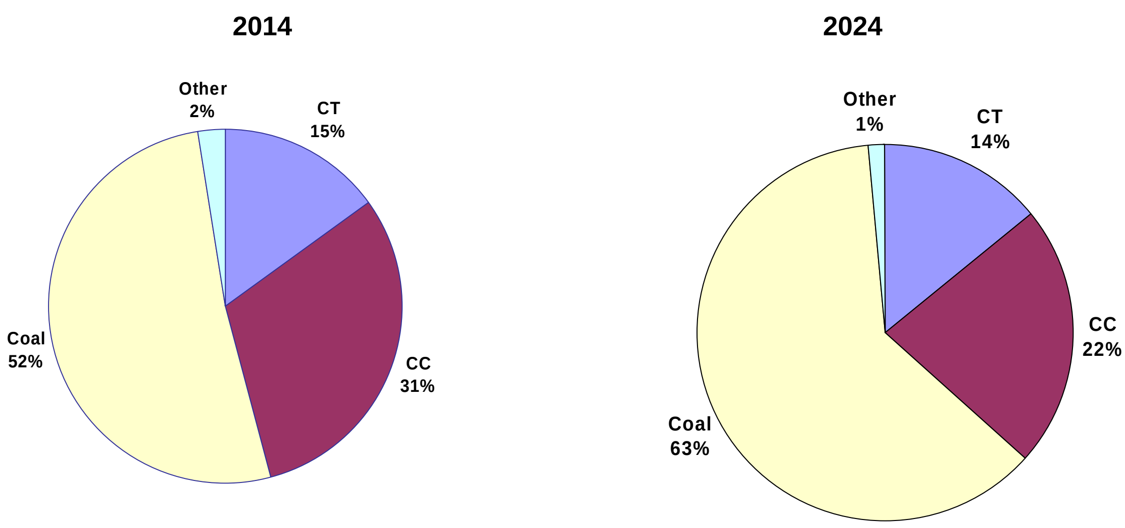


Figure C - 33: Energy Efficiency/High Load Plan

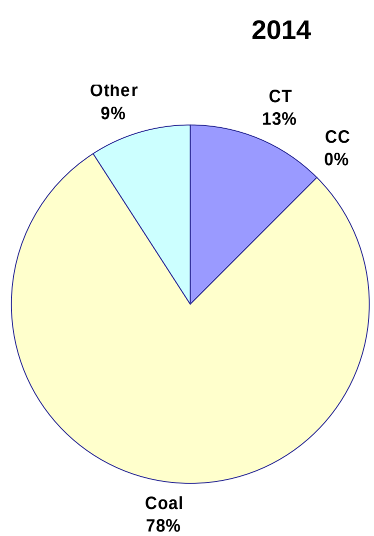
Cons High Load		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
7	CT - METC	-	-	1	-	1	-	-	-	1	-
9	CT - ITC	-	-	1	1	1	1	-	1	-	-
2	CT - ATC2	-	-	-	-	-	-	-	-	1	-
2	CC - METC	-	-	-	-	-	1	-	-	-	-
7	CC - ITC	-	-	-	2	2	1	-	-	-	-
0	CC - ATC2	-	-	-	-	-	-	-	-	-	-
14	COAL - METC	-	-	-	-	-	-	2	1	1	1
11	COAL - ITC	-	-	-	-	-	-	1	1	1	2
0	COAL - ATC2	-	-	-	-	-	-	-	-	-	-

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CT - METC	1	-	-	1	-	-	-	-	1	1
CT - ITC	-	-	-	1	-	-	-	1	1	1
CT - ATC2	-	-	-	-	-	-	1	-	-	-
CC - METC	-	-	-	-	-	-	-	-	-	1
CC - ITC	-	-	-	-	-	-	1	-	-	1
CC - ATC2	-	-	-	-	-	-	-	-	-	-
COAL - METC	1	1	1	1	1	1	1	1	1	-
COAL - ITC	-	1	1	-	1	1	-	1	1	-
COAL - ATC2	-	-	-	-	-	-	-	-	-	-

Figure C - 34: Energy Efficiency/Low Load Results

Capacity Additions (Firm MW)	2005 to 2014	2005 to 2024
CT	320	1,280
CC	0	1,500
PC	2,000	8,500
Nuclear	0	0
IGCC-Seq	0	0
Other	232	259
TOTAL	**2,552**	**11,539**
Annual Demand Growth (%)	1.05	1.47
Reserve Margin (%)	15.18	15.33
Plan Costs (2005 $ million)		
NPV Utility Cost	$ 27,317.70	$ 48,156.2
NPV Emission	$ 3,990.4	$ 7,359.9
NPV CO_2	$ 0.0	$ 0.0

Figure C - 35: Energy Efficiency/Low Load Mix



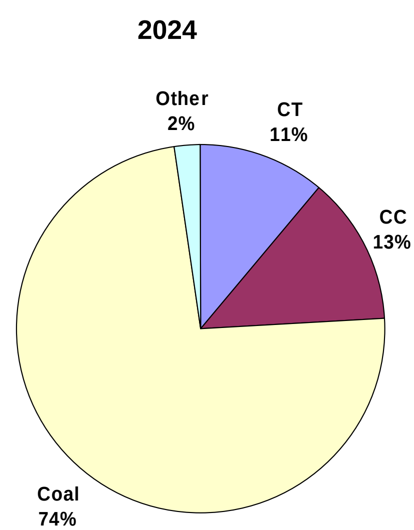


Figure C - 36: Energy Efficiency/Low Load Plan

Cons Low Load		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
5	CT - METC	-	-	-	-	-	1	-	-	-	-
3	CT - ITC	-	-	-	-	-	1	-	-	-	-
0	CT - ATC2	-	-	-	-	-	-	-	-	-	-
0	CC - METC	-	-	-	-	-	-	-	-	-	-
3	CC - ITC	-	-	-	-	-	-	-	-	-	-
0	CC - ATC2	-	-	-	-	-	-	-	-	-	-
9	COAL - METC	-	-	-	-	-	-	-	1	-	-
8	COAL - ITC	-	-	-	-	-	-	1	-	1	1
0	COAL - ATC2	-	-	-	-	-	-	-	-	-	-

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CT - METC	-	-	1	1	-	-	1	-	1	-
CT - ITC	-	-	1	-	-	-	-	-	1	-
CT - ATC2	-	-	-	-	-	-	-	-	-	-
CC - METC	-	-	-	-	-	-	-	-	-	-
CC - ITC	-	-	-	-	1	-	-	-	1	1
CC - ATC2	-	-	-	-	-	-	-	-	-	-
COAL - METC	1	-	-	1	1	1	1	1	1	1
COAL - ITC	1	1	1	-	-	1	-	1	-	-
COAL - ATC2	-	-	-	-	-	-	-	-	-	-

Figure C - 37: Energy Efficiency/High Gas Results

Capacity Additions (Firm MW)	2005 to 2014	2005 to 2024
CT	1,280	3,040
CC	1,000	2,000
PC	3,500	10,500
Nuclear	0	0
IGCC-Seq	0	0
Other	232	259
TOTAL	**6,012**	**15,799**
Annual Demand Growth (%)	2.15	2.00
Reserve Margin (%)	15.34	15.22
Plan Costs (2005 $ million)		
NPV Utility Cost	$ 30,873.8	$ 55,639.9
NPV Emission	$ 4,023.7	$ 7,452.9
NPV CO_2	$ 0.0	$ 0.0

Figure C - 38: Energy Efficiency/High Gas Mix

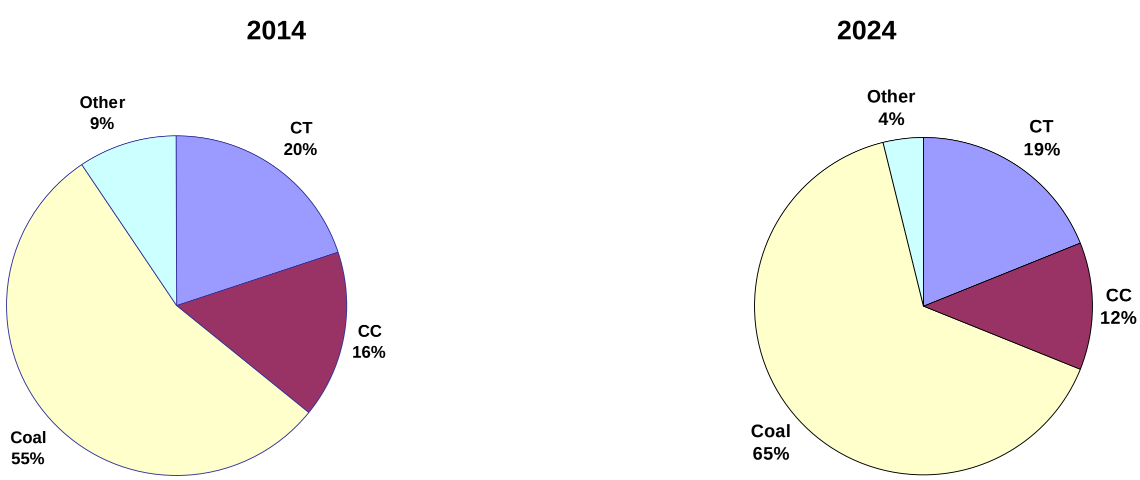


Figure C - 39: Energy Efficiency/High Gas Plan

Cons High Fuel		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
8	CT - METC	-	-	-	-	2	2	-	-	-	-
10	CT - ITC	-	-	-	1	2	1	-	-	-	-
1	CT - ATC2	-	-	-	-	-	-	-	-	-	-
1	CC - METC	-	-	-	-	-	-	-	-	-	-
3	CC - ITC	-	-	-	1	-	1	-	-	-	-
0	CC - ATC2	-	-	-	-	-	-	-	-	-	-
11	COAL - METC	-	-	-	-	-	-	1	1	-	1
10	COAL - ITC	-	-	-	-	-	-	1	1	1	1
0	COAL - ATC2	-	-	-	-	-	-	-	-	-	-

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CT - METC	-	-	1	1	-	-	1	-	1	-
CT - ITC	-	1	1	1	-	-	1	-	1	1
CT - ATC2	-	-	-	-	-	-	-	-	1	-
CC - METC	-	-	-	-	-	-	-	-	-	1
CC - ITC	-	-	-	-	-	-	-	-	-	1
CC - ATC2	-	-	-	-	-	-	-	-	-	-
COAL - METC	1	-	1	1	1	1	1	1	1	-
COAL - ITC	1	1	-	-	1	1	-	1	1	-
COAL - ATC2	-	-	-	-	-	-	-	-	-	-

Figure C - 40: Non-Traditional Results

Capacity Additions (Firm MW)	2005 to 2014	2005 to 2024
CT	1,760	3,520
CC	1,000	1,000
PC	0	0
Nuclear	0	0
IGCC-Seq	3,330	11,550
Other	779	1,035
TOTAL	**6,839**	**17,105**
Annual Demand Growth (%)	2.38	2.17
Reserve Margin (%)	15.86	15.57
Plan Costs (2005 $ million)		
NPV Utility Cost	$ 30,368.9	$ 57,477.8
NPV Emission	$ 4,040.4	$ 7,444.1
NPV CO_2	$ 0.0	$ 0.0

Figure C - 41: Non-Traditional Mix

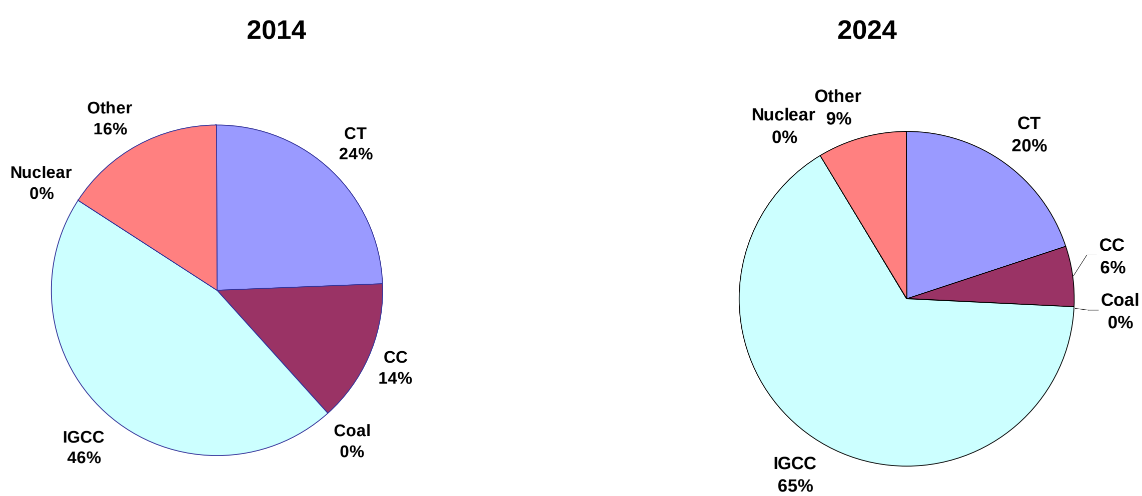


Figure C - 42: Non-Traditional Plan

	NonTraditional	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
12	CT - METC	-	-	-	1	2	1	1	-	1	-
9	CT - ITC	-	-	1	2	-	1	1	-	-	-
1	CT - ATC2	-	-	-	-	-	-	-	-	-	-
0	CC - METC	-	-	-	-	-	-	-	-	-	-
2	CC - ITC	-	-	-	-	1	1	-	-	-	-
0	CC - ATC2	-	-	-	-	-	-	-	-	-	-
0	COAL - METC	-	-	-	-	-	-	-	-	-	-
0	COAL - ITC	-	-	-	-	-	-	-	-	-	-
0	COAL - ATC2	-	-	-	-	-	-	-	-	-	-
0	NUC - METC	-	-	-	-	-	-	-	-	-	-
0	NUC - ITC	-	-	-	-	-	-	-	-	-	-
10	IGCC - METC	-	-	-	-	-	-	-	1	-	1
11	IGCC - ITC	-	-	-	-	-	-	1	1	1	1

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CT - METC	1	1	1	1	-	-	1	-	1	-
CT - ITC	-	1	1	1	-	-	1	-	-	-
CT - ATC2	-	-	-	-	-	-	1	-	-	-
CC - METC	-	-	-	-	-	-	-	-	-	-
CC - ITC	-	-	-	-	-	-	-	-	-	-
CC - ATC2	-	-	-	-	-	-	-	-	-	-
COAL - METC	-	-	-	-	-	-	-	-	-	-
COAL - ITC	-	-	-	-	-	-	-	-	-	-
COAL - ATC2	-	-	-	-	-	-	-	-	-	-
NUC - METC	-	-	-	-	-	-	-	-	-	-
NUC - ITC	-	-	-	-	-	-	-	-	-	-
IGCC - METC	-	1	1	-	1	1	1	1	1	1
IGCC - ITC	1	-	-	1	1	1	-	1	1	1

Figure C - 43: Non-Traditional/High Load Results

Capacity Additions (Firm MW)	2005 to 2014	2005 to 2024
CT	2,080	4,160
CC	3,000	3,000
PC	0	0
Nuclear	0	0
IGCC-Seq	4,400	13,200
Other	779	1,035
TOTAL	**10,259**	**21,395**
Annual Demand Growth (%)	3.35	2.63
Reserve Margin (%)	15.10	15.28
Plan Costs (2005 $ million)		
NPV Utility Cost	$ 34,728.5	$ 67,023.5
NPV Emission	$ 4,235.3	$ 7,862.3
NPV CO_2	$ 0.0	$ 0.0

Figure C - 44: Non-Traditional/High Load Mix

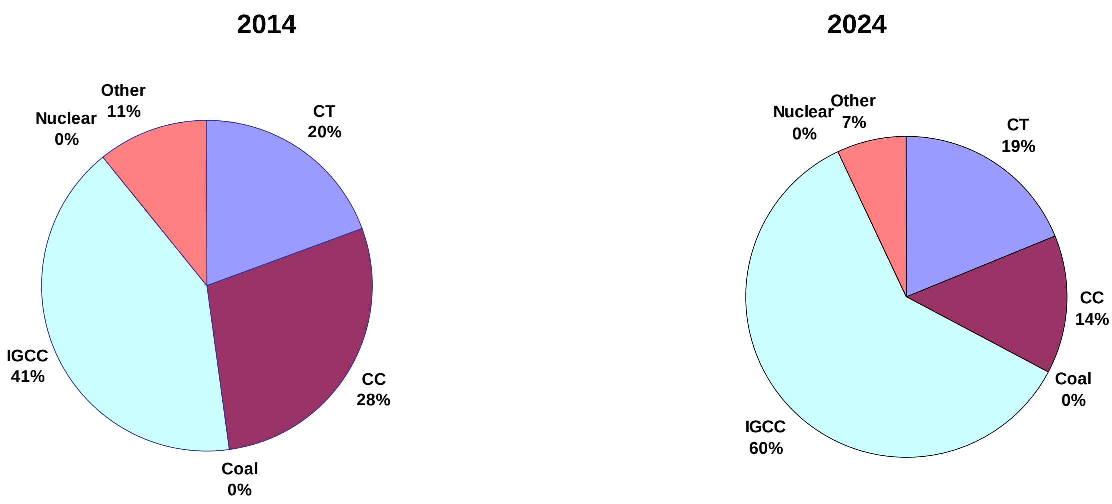


Figure C - 45: Non-Traditional/High Load Plan

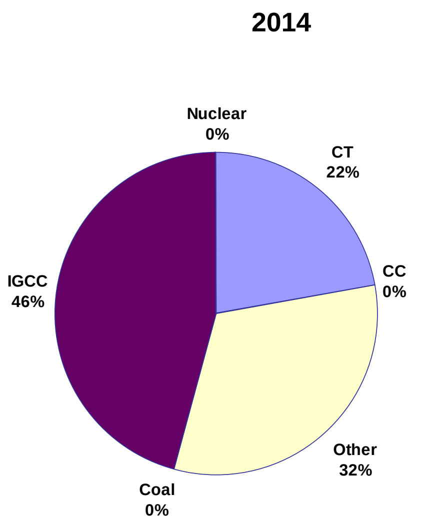
NonTrad High Load		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
12	CT - METC	-	-	-	-	1	-	1	1	1	1
12	CT - ITC	-	-	2	1	1	1	-	-	1	1
2	CT - ATC2	-	-	-	-	-	-	-	-	1	-
1	CC - METC	-	-	-	-	-	1	-	-	-	-
5	CC - ITC	-	-	-	2	2	1	-	-	-	-
0	CC - ATC2	-	-	-	-	-	-	-	-	-	-
0	COAL - METC	-	-	-	-	-	-	-	-	-	-
0	COAL - ITC	-	-	-	-	-	-	-	-	-	-
0	COAL - ATC2	-	-	-	-	-	-	-	-	-	-
0	NUC - METC	-	-	-	-	-	-	-	-	-	-
0	NUC - ITC	-	-	-	-	-	-	-	-	-	-
13	IGCC - METC	-	-	-	-	-	-	1	1	1	1
11	IGCC - ITC	-	-	-	-	-	-	1	1	1	1

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CT - METC	1	1	1	1	-	-	1	-	1	1
CT - ITC	1	-	1	1	-	-	1	1	-	-
CT - ATC2	-	-	-	-	-	-	-	1	-	-
CC - METC	-	-	-	-	-	-	-	-	-	-
CC - ITC	-	-	-	-	-	-	-	-	-	-
CC - ATC2	-	-	-	-	-	-	-	-	-	-
COAL - METC	-	-	-	-	-	-	-	-	-	-
COAL - ITC	-	-	-	-	-	-	-	-	-	-
COAL - ATC2	-	-	-	-	-	-	-	-	-	-
NUC - METC	-	-	-	-	-	-	-	-	-	-
NUC - ITC	-	-	-	-	-	-	-	-	-	-
IGCC - METC	1	-	1	1	1	1	1	2	-	1
IGCC - ITC	-	2	-	-	1	1	-	-	2	1

Figure C - 46: Non-Traditional/Low Load Results

Capacity Additions (Firm MW)	2005 to 2014	2005 to 2024
CT	800	1,600
CC	0	0
PC	0	0
Nuclear	0	0
IGCC-Seq	1,650	9,900
Other	779	1,035
TOTAL	**3,249**	**12,535**
Annual Demand Growth (%)	1.30	1.66
Reserve Margin (%)	15.88	15.51
Plan Costs (2005 $ million)		
NPV Utility Cost	$ 29,187.3	$53,523.5
NPV Emission	$ 4,143.6	$ 7,603.2
NPV CO_2	$ 0.0	$ 0.0

Figure C - 47: Non-Traditional/Low Load Mix



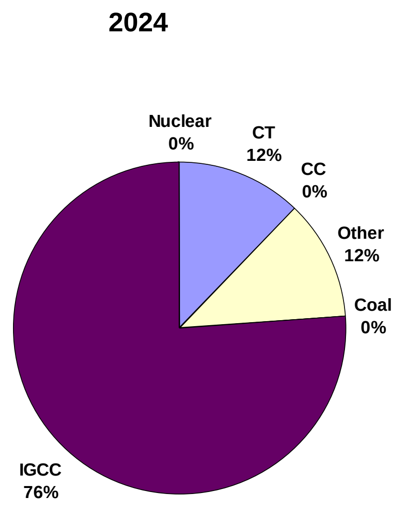


Figure C - 48: Non-Traditional/Low Load Plan

NonTrad Low Load		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
3	CT - METC	-	-	-	-	-	-	-	1	-	-
7	CT - ITC	-	-	-	-	1	1	-	1	-	1
0	CT - ATC2	-	-	-	-	-	-	-	-	-	-
0	CC - METC	-	-	-	-	-	-	-	-	-	-
0	CC - ITC	-	-	-	-	-	-	-	-	-	-
0	CC - ATC2	-	-	-	-	-	-	-	-	-	-
0	COAL - METC	-	-	-	-	-	-	-	-	-	-
0	COAL - ITC	-	-	-	-	-	-	-	-	-	-
0	COAL - ATC2	-	-	-	-	-	-	-	-	-	-
0	NUC - METC	-	-	-	-	-	-	-	-	-	-
0	NUC - ITC	-	-	-	-	-	-	-	-	-	-
9	IGCC - METC	-	-	-	-	-	-	-	-	-	1
9	IGCC - ITC	-	-	-	-	-	-	1	-	1	-

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CT - METC	-	-	1	-	1	-	-	-	-	-
CT - ITC	-	-	-	1	1	-	1	-	-	-
CT - ATC2	-	-	-	-	-	-	-	-	-	-
CC - METC	-	-	-	-	-	-	-	-	-	-
CC - ITC	-	-	-	-	-	-	-	-	-	-
CC - ATC2	-	-	-	-	-	-	-	-	-	-
COAL - METC	-	-	-	-	-	-	-	-	-	-
COAL - ITC	-	-	-	-	-	-	-	-	-	-
COAL - ATC2	-	-	-	-	-	-	-	-	-	-
NUC - METC	-	-	-	-	-	-	-	-	-	-
NUC - ITC	-	-	-	-	-	-	-	-	-	-
IGCC - METC	-	1	-	1	1	1	1	1	1	1
IGCC - ITC	1	1	1	-	-	1	-	1	1	1

Figure C - 49: Non-Traditional/High Gas Results

Capacity Additions (Firm MW)	2005 to 2014	2005 to 2024
CT	1,760	3,520
CC	1,000	1,000
PC	0	0
Nuclear	0	0
IGCC-Seq	3,300	11,550
Other	779	1,035
TOTAL	**6,839**	**17,105**
Annual Demand Growth (%)	2.38	2.17
Reserve Margin (%)	15.86	15.57
Plan Costs (2005 $ million)		
NPV Utility Cost	$ 31, 473.1	$ 59,149.8
NPV Emission	$ 4,010.0	$ 7,381.4
NPV CO_2	$ 0.0	$ 0.0

Figure C - 50: Non-Traditional/High Gas Mix

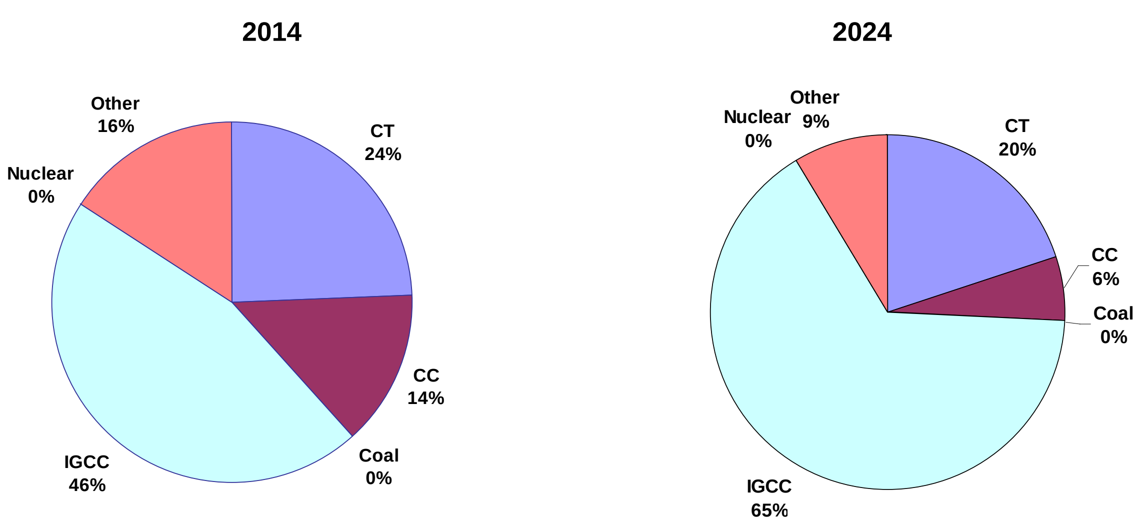


Figure C - 51: Non-Traditional/High Gas Plan

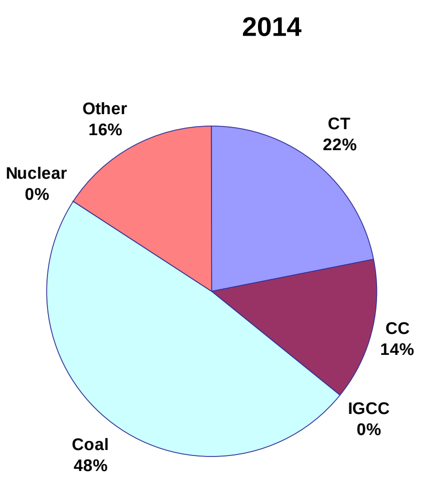
	NonTrad High Fuel	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
12	CT - METC	-	-	-	1	2	2	-	-	1	-
9	CT - ITC	-	-	1	2	-	-	-	1	1	-
1	CT - ATC2	-	-	-	-	-	-	-	-	-	-
0	CC - METC	-	-	-	-	-	-	-	-	-	-
2	CC - ITC	-	-	-	-	1	1	-	-	-	-
0	CC - ATC2	-	-	-	-	-	-	-	-	-	-
0	COAL - METC	-	-	-	-	-	-	-	-	-	-
0	COAL - ITC	-	-	-	-	-	-	-	-	-	-
0	COAL - ATC2	-	-	-	-	-	-	-	-	-	-
0	NUC - METC	-	-	-	-	-	-	-	-	-	-
0	NUC - ITC	-	-	-	-	-	-	-	-	-	-
10	IGCC - METC	-	-	-	-	-	-	1	-	-	1
11	IGCC - ITC	-	-	-	-	-	-	1	1	1	1

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CT - METC	1	1	1	1	-	-	1	-	1	-
CT - ITC	-	1	1	1	-	-	1	-	-	-
CT - ATC2	-	-	-	-	-	-	1	-	-	-
CC - METC	-	-	-	-	-	-	-	-	-	-
CC - ITC	-	-	-	-	-	-	-	-	-	-
CC - ATC2	-	-	-	-	-	-	-	-	-	-
COAL - METC	-	-	-	-	-	-	-	-	-	-
COAL - ITC	-	-	-	-	-	-	-	-	-	-
COAL - ATC2	-	-	-	-	-	-	-	-	-	-
NUC - METC	-	-	-	-	-	-	-	-	-	-
NUC - ITC	-	-	-	-	-	-	-	-	-	-
IGCC - METC	-	1	1	-	1	1	1	1	1	1
IGCC - ITC	1	-	-	1	1	1	-	1	1	1

Figure C - 52: Non-Traditional with PC Results

Capacity Additions (Firm MW)	2005 to 2014	2005 to 2024
CT	1,600	3,360
CC	1,000	1,000
PC	3,500	11,500
Nuclear	0	0
IGCC-Seq	0	0
Other	779	1,035
TOTAL	**6,879**	**16,895**
Annual Demand Growth (%)	2.38	2.17
Reserve Margin (%)	16.06	15.00
Plan Costs (2005 $ million)		
NPV Utility Cost	$ 30,106.3	$ 55,864.4
NPV Emission	$ 4,064.2	$ 7,557.1
NPV CO_2	$ 0.0	$ 0.0

Figure C - 53: Non-Traditional with PC Mix



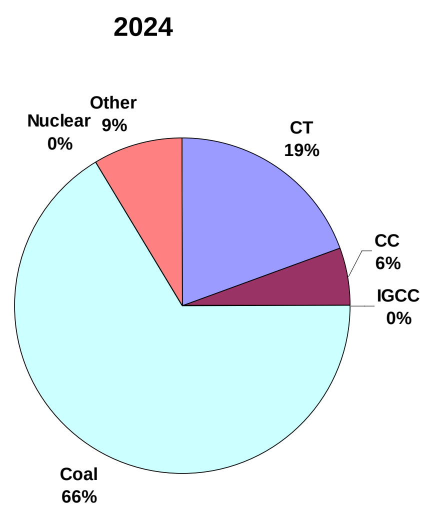


Figure C - 54: Non-Traditional with PC Plan

NonTrad with PC		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
11	CT - METC	-	-	-	1	2	2	-	1	-	-
9	CT - ITC	-	-	1	2	-	-	-	1	-	-
1	CT - ATC2	-	-	-	-	-	-	-	-	-	-
0	CC - METC	-	-	-	-	-	-	-	-	-	-
2	CC - ITC	-	-	-	-	1	1	-	-	-	-
0	CC - ATC2	-	-	-	-	-	-	-	-	-	-
11	COAL - METC	-	-	-	-	-	-	1	-	1	1
12	COAL - ITC	-	-	-	-	-	-	1	1	1	1
0	COAL - ATC2	-	-	-	-	-	-	-	-	-	-
0	NUC - METC	-	-	-	-	-	-	-	-	-	-
0	NUC - ITC	-	-	-	-	-	-	-	-	-	-
0	IGCC - METC	-	-	-	-	-	-	-	-	-	-
0	IGCC - ITC	-	-	-	-	-	-	-	-	-	-

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CT - METC	-	1	-	1	1	-	1	-	1	-
CT - ITC	1	1	-	1	-	-	1	-	1	-
CT - ATC2	-	-	-	-	-	-	1	-	-	-
CC - METC	-	-	-	-	-	-	-	-	-	-
CC - ITC	-	-	-	-	-	-	-	-	-	-
CC - ATC2	-	-	-	-	-	-	-	-	-	-
COAL - METC	1	-	1	-	1	1	1	1	1	1
COAL - ITC	-	1	1	1	1	1	-	1	1	1
COAL - ATC2	-	-	-	-	-	-	-	-	-	-
NUC - METC	-	-	-	-	-	-	-	-	-	-
NUC - ITC	-	-	-	-	-	-	-	-	-	-
IGCC - METC	-	-	-	-	-	-	-	-	-	-
IGCC - ITC	-	-	-	-	-	-	-	-	-	-

Appendix D

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D.1 Strategist Model

Strategist, a computer software system developed by New Energy Associates, LLC, supports electric utility decision analysis and corporate strategic planning. The Strategist system consists of the following application modules:

- Load Forecast Adjustment (LFA)
- Generation and Fuel (GAF)
- PROVIEW (PRV)
- Capital Expenditure and Recovery (CER)
- Financial Reporting and Analysis (FIR)

Strategist's advantage as an integrated planning system is its strength in all functional areas of utility planning. Strategist allows analysts to address all aspects of an integrated planning study at the depth and accuracy level required for informed decisions. Hourly chronological load patterns are recognized. Production cost simulations are comprehensive. Financial analyses are accurate and thorough. Rate-level determinations reflect each utility's customer class definition and cost-of-service allocation factors. The system employs dynamic programming to develop optimal portfolios of resources. Sophisticated screening methodologies are available to develop and refine strategic marketing initiatives, identify market potential, and build portfolios of initiatives.

In Strategist, integrated resource screening and optimization is accomplished within a single system that handles strategic marketing programs, production costing, environmental reporting, capital budgeting and financial, tax, and revenue forecasts on a rate class basis. Using a single, integrated software system for demand- and supply-side analysis of all resource types makes these studies much more manageable, ensures consistency in data assumptions, and provides credible, auditable results.

Strategist provides a wide variety of standard reports ranging from unit by unit generating statistics to construction project accounting reports to comprehensive pro forma financial results. The system includes full input summaries and detailed diagnostics

D.2 Supply Side Representation

The Generation and Fuel (GAF) Module simulates power system operation using proven probabilistic methods. It provides production costs and generation reliability measures that are essential to supply and demand planning. The GAF Module fulfills a strategic planning role in that it requires less computer resources than more detailed production costing modules, without sacrificing overall accuracy.

The general capabilities of the GAF include:

- The GAF Module uses probabilistic production costing techniques to simulate the effects of forced outages.

- Most module calculations are performed seasonally, where seasons are defined by number of seasons and by number of days per season.
- Sales, purchases, and hydro generation are accounted for on a seasonal basis.
- The user can explicitly define an hour-by-hour schedule for a transaction or simply specify when the transaction tends to occur (during peak load hours, low load hours, or randomly) and the GAF will schedule the transaction appropriately.
- Thermal generating units are represented by capacity segments; each segment may have a distinct heat rate, which may be input as average, incremental, or coefficients of a quadratic input/output equation. Availability is defined for the entire unit; a partial availability may also be input to represent times when a unit may only operate at minimum capacity. The units which are classified as must-run are committed first, followed by enough other units to satisfy a user-input commitment criterion. The remaining units are committed on an economic start-up and dispatch basis, subject to fuel limits and spinning reserve requirements.
- The dispatch of thermal units and economy energy may be performed on a seasonal or annual basis.
- Pumped hydro projects and direct load control programs are economically dispatched on a seasonal basis, based on marginal cost.
- Units are dispatched to conform to upper and lower limitations on fuel usage.
- Unit dispatch is performed on an 'as burned' or replacement cost of fuel basis.
- Unit, company and system emissions are calculated based on actual runtimes and fuel usage. Emissions allowances are purchased or sold on the basis of system performance and the inputs for allowance cost and allowance base for each effluent. The cost of allowances is reflected in the dispatch lambda used in dispatch order decisions.
- Environmental externalities are calculated for emissions, emergency energy, and direct load control.
- Multicompany dispatch with interchange accounting for holding companies or power pool simulation is provided.
- Numerous diagnostic reports which document detailed calculations are provided.

The production costing procedure consists of two stages. In the first stage, the operation of hydro generation and sale and purchase transactions are simulated. The pumped storage facilities and direct load control programs are then economically dispatched based on the constructed marginal cost curve of the system. The result of this first stage is the remaining annual or seasonal thermal load duration curve. In the second stage, the expected operations of the thermal generating units within the year are simulated by a probabilistic technique. The results are the production costs and system reliability indices.

System load data is passed in the form of a typical 168-hour weekly load shape to the GAF from the LFA Module. Then, the dispatch of non-thermal resources is performed. The user may specify the order in which these resources are dispatched, or use the following default order:

1. The transactions (sales or purchases) that are input in the form of hourly values for each season are added to (in the case of sales) or subtracted from (in the case of purchases) the chronological load curves.
2. The transactions that are characterized by seasonal capacity and energy are scheduled. For each sale transaction, the user chooses whether the sale is a valley fill or peak build sale, or is to be applied uniformly to the load curves. For each purchase transaction, the user chooses whether the purchase is a peak shave or valley reduction purchase, or is to be applied uniformly to the load curves.
3. The hydro generating units are dispatched one at a time. Each hydro unit has a minimum (must-run) MW capacity, a maximum MW capacity, and a total energy (MWH) for the season. The remaining load, after steps 1 and 2, is first modified by subtracting from it the minimum hydro generation for every hour. The remaining hydro energy is used for peak shaving. This peak-shaving energy is calculated by subtracting the minimum hydro generation from the total hydro energy. The peak-shaving capacity is the difference between the maximum MW capacity and the minimum MW capacity of the unit.
4. Pumped storage hydro is scheduled. Storage dispatch is based on the expected generation cost at each hour before storage, pond storage limitations, cycle efficiency, and minimum savings. The storage algorithm works from highest cost hour down for generation and from lowest cost hour up for pumping, reducing the remaining load at high cost hours and increasing the load at low cost hours. This process is performed subject to the minimum savings and pond limit constraints. An option is available for the capacity of storage not used for economic reasons to be used for reliability purposes.
5. Direct load control devices are scheduled. The LFA Module provides information on underlying loads that are available for control and DLC dispatch parameters. All DLC devices are dispatched simultaneously so as to achieve the greatest possible savings and in such a way that a new peak is avoided. However, there is the added flexibility of defining a user-specified order in which the DLC devices will be dispatched. Payback is explicitly considered in addition to contractual constraints such as maximum number of interruptions and maximum hours of interruptions for each program.

If several companies are being modeled, non-thermal resources may be dispatched for a specified company or group of companies. This allows modeling of different types of systems such as a Genco and Disco where the generating company's non-thermal resources will be dispatched to meet the load of the distribution company. This type of logic is also useful for interconnected power systems where a resource should be scheduled based on market value in addition to native load requirements. After the dispatch of non-thermal resources is completed, the remaining load is served by thermal generating units. The thermal dispatch is performed on a seasonal or an annual basis as determined by the user for each water year. If annual dispatch is chosen, the modified seasonal load curves are combined into an annual load curve.

Each generating unit may be represented with up to seven capacity segments. Each capacity segment may have a distinct heat rate. A unit may be designated as a must-run unit, in which case its minimum segment is dispatched before any upper segment in the system. Other thermal unit inputs include commission date, retirement date, immature forced outage rate, mature forced outage rate, and partial forced outage rate at the minimum capacity level.

Planned maintenance may be explicitly modeled for each generating unit by specifying the start and end dates for each maintenance, or by entering a start date and number of weeks of maintenance in each year. Maintenance may be handled as either a deration of the unit's capacity, or as an adjustment to its forced outage rate.

The widely accepted probabilistic production costing procedure is used to project the operation of each generating unit. The minimum segments of the must-run units are dispatched first, followed by enough other minimum segments to satisfy a user-defined dispatch commitment criterion. The remaining segments are dispatched in an economic order approximating the economic dispatch procedure of a system operator. Sufficient on-line capacity reserves are maintained to satisfy user-defined spinning reserve requirements. Fuel limits are monitored during the thermal unit dispatch. If fuel limits are exceeded, the system modifies the fuel mixtures and/or energy outputs of the generating units, resulting in a departure from economic dispatch. The impact of economy energy purchases and sales are determined on an economic basis.

After all available resources have been utilized, several reliability indices are determined. Among these are:

- Expected hours with negative margin (Loss of Load Hours, or LOLH)
- Expected emergency energy
- Reserve Margin

Alternatively, reliability measures, such as LOLH and expected emergency energy, may be fixed so that equivalent capacity benefits for DSM programs may be calculated. The GAF has the ability to calculate the equivalent capacity benefit of an incremental change in load based on a broad reliability measure. This relieves the user of the uncertain task of estimating a capacity benefit which for many DSM programs (e.g. direct load control) may be difficult to measure. This is a significant improvement over the traditional calculation of the impact on the reserve margin (peak hour impact).

Emissions are calculated each season on a unit-by-unit basis. Removal efficiency characteristics of each unit are input. The individual unit results are then aggregated into company and system emissions totals and rates. The cost of emissions, whether such cost is in the form of allowance purchase price, emissions tax, or emissions externalities result from the thermal dispatch. Separate inputs allow these emissions costs to be included in a unit's dispatch price if desired.

D.3 Demand-side Representation

The Load Forecast Adjustment (LFA) Module is a multi-purpose tool for creating and modifying load forecasts and evaluating marketing and conservation programs. Using the

LFA, a strategic planner may address key issues related to future electricity or gas demand and impacts attributed to each customer group. Results from this analysis can be automatically transferred to other Strategist modules to determine production costs, system reliability, cost-effectiveness of marketing initiatives, financing and revenue requirements, and a variety of other indicators affected by loads.

Because availability of load data is often limited, the LFA is designed to process data at the level of detail readily available. Load data is processed in the LFA by user-defined load groups. It is possible to define these load groups as very detailed or very summary in scope. The LFA categorizes group data based on availability of hourly load shapes. Customer groups for which shapes are not available are processed differently than those with shapes.

A key feature of the LFA is its ability to accommodate different levels of detail for different categories of load. If load shapes are unavailable or not needed for some customer groups, the user can easily organize the data to allow the LFA to approximate the missing information. For example, a study which analyzes the loss of a large industrial customer may need detailed modeling of only those rate classes affected by the reallocation of costs. Hourly load shapes could be entered for these classes, and the user need only enter peak, energy, and coincidence factors for any remaining classes.

D.4 External Market and Transmission Representation

The Network Economy Interchange (NEI) feature of the GAF helps reduce operating costs for a group of interconnected utilities by developing the most beneficial unit dispatch schedule for the group.

In a situation where there is unlimited transmission capacity between interconnected systems, the interchange process reaches economic equilibrium. At equilibrium, the marginal costs of all systems are virtually identical. To reach the point of equilibrium, the NEI feature performs interchange among interconnected systems in order to levelize the marginal costs. Interchange is economical as long as the difference in marginal cost is greater than the connection charges among systems.

In power systems, particularly large systems covering major geographical areas, unlimited transmission capacities seldom exist, due to physical or contractual transmission limits. To neglect transmission capacity limits is to overestimate the benefit of economy interchange. This problem may not be severe if transmission constraints are not binding. However, in transmission-poor systems, overestimation of economy interchange benefits may distort overall system production costs.

The NEI feature provides a marginal cost-based algorithm for economy interchange among connected systems, while considering losses on transmission lines and enforcing transmissions limits for all hours. NEI accomplishes this by systematically matching potential buyers and sellers and incrementally equalizing their marginal costs.

The billing and accounting logic of the Network Economy Interchange reflects the market clearing price of the system. Therefore, if there are no losses, no connection charges, and no tie constraints, the marginal cost of the buyer will equal the marginal cost of the seller and the energy generated will equal the energy received. If there are differences between the buyer's cost and seller's revenue, the losses or surplus revenue is split between them based on the transfer point. If a third party is involved, then the losses and surplus revenue are allocated to the buyer, seller, and/or third parties based on their ownership.

After all other load modifications are complete (transactions, hydro, pumped hydro, and direct load control), the GAF implements economy interchange. Interchange results are used to modify hourly loads of the internal companies. The GAF then executes the thermal dispatch for every internal company. If there is more than one internal company, the NEI feature sums company outputs to obtain the pool results.

D.5 Resource Evaluation Process

The PROVIEW (PRV) Module is a resource planning model which determines the least-cost balanced demand and supply plan for a utility system under prescribed sets of constraints and assumptions. PROVIEW incorporates a wide variety of expansion planning parameters including alternative technologies, unit conversions, cogenerators, unit capacity sizes, load management, marketing and conservation programs, fuel costs, reliability limits, emissions trading and environmental compliance options in order to develop a coordinated integrated plan which would be best suited for the utility. PROVIEW is integrated with the GAF Module to simulate the operation of a utility system. PROVIEW's optimization logic then determines the cost and reliability effects of adding resources to the system or modifying the load through demand-side management (DSM) or marketing programs.

The module allows modeling of emissions-related constraints, emissions allowance trading, and emissions reduction alternatives (e.g. scrubbers, fuel switching). These capabilities are used both to develop optimal environmental compliance strategies and to incorporate resource planning.

Programs are screened by using the LFA Module in conjunction with Differential Cost Effectiveness (DCE) Module and the GAF Module. Programs in the LFA Module database are evaluated one at a time by the DCE and are ranked based on industry standard cost effectiveness measures such as participant cost, utility cost, total resource cost, societal cost, and ratepayer impact measure (average rate). Groups of programs are then developed into portfolios based on the results of the ranking process. The LFA allows detailed treatment of system, class or end-use loads, enabling you to specify demand-side or marketing programs on an hourly chronological basis. Capacity deferral benefits or costs are calculated using the capacity credit logic in the LFA and/or the reliability equalization logic in the GAF. Energy benefits or costs are calculated with a separate GAF production cost run for each program.

Once portfolios of programs have been developed, the LFA Module is used in conjunction with PROVIEW to perform integrated demand and supply optimization. LFA load groups representing DSM or marketing programs or portfolios of programs are specified as explicit PROVIEW alternatives. In this way, the programs compete on a "level playing field" with supply options. The optimal demand/supply plan is then developed using PROVIEW's dynamic programming capability. In addition to the optimal plan, PROVIEW retains multiple suboptimal demand/supply plans for further scenario and sensitivity analysis.

The final step in evaluation of DSM or marketing programs involves use of the LFA Module in conjunction with all modules of Strategist. The CER Module provides the annual capital expenditure impacts of the programs and allows assessment of program costs which are capitalized. The FIR Module allows the evaluation of the impact of the programs on average rates, rate increase requirements and timing, and financial performance. The impact of programs on class rates and cross subsidy issues may be thoroughly evaluated in the Class Revenue Module (CRM).

The general capabilities of PROVIEW include:

- Data input is structured in a similar manner to Strategist GAF data.
- PROVIEW provides quick turn-around time by eliminating options that are not feasible and by eliminating unnecessary detail.
- PROVIEW allows for a full enumeration of all combinations of expansion options and/or demand-side management or marketing programs through its Dynamic Programming option. The system can thus be highly rigorous in its determination of a least-cost expansion plan for the entire planning period.
- Production cost calculations are performed for each alternative through the execution of the GAF Module. Demand-side programs and associated sales impacts are computed through the execution of the LFA Module.
- PROVIEW uses the economic carrying charge as the capital cost representation during the study period optimization. After the study period rankings have been determined, the plans will be re-ranked over the planning period horizon using actual year by year revenue requirements. If these are not input, then levelized revenue requirements will be used.
- PROVIEW explicitly handles end effects in determination of the least cost plan. The end effects analysis approximates the capital and production cost of replacing the resulting utility system in kind over the user-input end effects period.
- PROVIEW provides for one of five objective functions to be used in the least-cost optimization: minimization of utility costs, minimization of average study period rates, minimization of total societal cost (total resource cost), minimization of total resource costs, or maximization of total unit profitability.
- PROVIEW will also evaluate any expansion plan optimized by one of the five objective functions mentioned above with regard to financial performance. The expansion plans may be re-ranked based on electric revenue, corporate value of the firm, economic value added, earnings per share, or value per share.

- PROVIEW provides numerous constraints for the user to reduce the number of options to consider. Minimum and maximum number to add, minimum and maximum reserve or loss of load hours, and first year available to add are but a few. PROVIEW can define alternatives as mutually exclusive or inclusive in a year. It can also restrict alternatives to be dependent upon certain other alternatives being in service (the second unit in a station is dependent upon the first unit having been constructed). PROVIEW also allows options such as phased construction of combined cycle units to be evaluated quickly. Maximum emissions levels can also be specified to reduce the alternatives considered.
- A PROVIEW optimization may be performed for the entire pool when multi-company summation logic is used. PROVIEW allows constraints to be entered at both the system level and for each company in the pool.
- When using Multi-Company, PROVIEW allows the addition of alternatives which are owned by a company other than the company (or pool) which is being optimized.
- PROVIEW allows complete evaluation of suboptimal plans. All plans are saved in PROVIEW's database for subsequent reporting and analysis. The user may specify the ranking of significantly different plans. Significantly different plans are developed as of a certain year of the analysis.
- Numerous diagnostics which explain in detail how PROVIEW reaches its optimal plan decision are available.

PROVIEW requires the data supplied by the user to be separated into two sections: the first section characterizes the existing utility system and the other section characterizes the potential expansion or marketing initiative options. The existing utility system data set is composed of the Strategist GAF and LFA Module data sets, which are fully described in the GAF Module online help and LFA Module online help. Briefly, data requirements for the existing system are grouped according to load, hydro unit, transaction, thermal unit, storage unit, fuel type, fuel class, and general parameter data. Data requirements for the existing load forecast are grouped according to load group, load shape, load class, and parameter data.

The data required for the planning alternatives section contains information relating to alternative resources that may be added or marketing programs that may be implemented. Data in this section defines alternative unit characteristics, construction costs, resource addition limits, and resulting system reliability constraints. Alternative option information is specified in a general manner so that any proposed available option can be commissioned at any time during the study period.

PROVIEW's Dynamic Programming calculations are summarized as follows:

1. A capital cost table is constructed. This table contains the economic carrying for every alternative for each year of the study.
2. Feasible current-year states (combinations of alternatives) are determined by examining every combination of user-defined resource additions or marketing programs. Feasible states are those which meet reliability dependency and tunnel

constraints. One-year capital and production costs are calculated and used to determine the accumulated cost-to-date. Each feasible state description is saved along with the associated accumulated cost-to-date.

3. The module repeatedly analyzes and saves feasible states for each year during the planning period. At the end of this planning period, a matrix of possible states for each year has been constructed. Note that each feasible state in the final year represents the end product of a different expansion plan.
4. Each potential expansion plan is subjected to end effects analysis. The end effects analysis adds to the accumulated cost-to-date of the capital and production cost of replacing the resulting utility system in kind, over a user-specified end effects period.
5. The module traces back through the matrix of feasible states to identify the components of the optimal plan and the components of each sub-optimal plan.
6. The optimal plan is set up in the LFA and GAF for subsequent analysis and reporting. All plans are saved in the database.

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Appendix D

Demand Work Group Report

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Michigan Capacity Need Forum:
Demand Work Group

Michigan Electric Sales and Peak Demand Forecast
2005 – 2025

January 2006

Copies of this report are available from the Michigan Public Service Commission's Web site, at: http://www.dleg.state.mi.us/mpsc/electric/capacity/cnf.

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.

1 Introduction

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

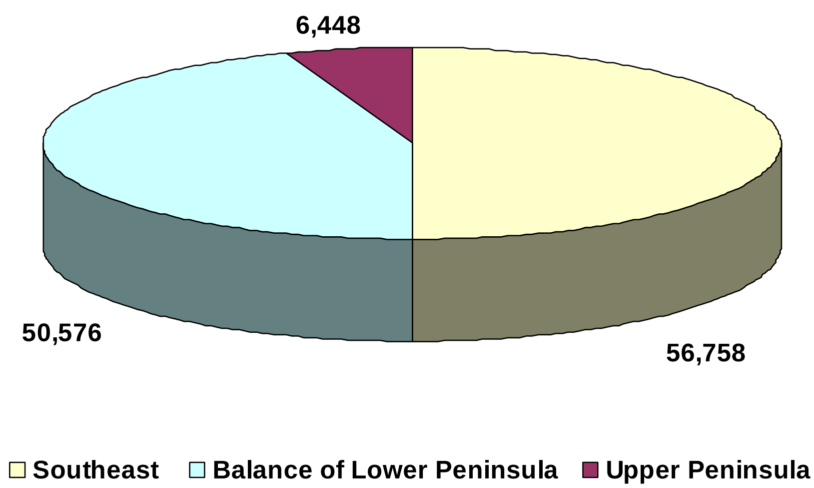
The purpose of the forecast is to provide the Capacity Need Forum's Integration Group with demand and energy projections for use in modeling the State of Michigan's electric generating needs in the near to longer-term future. The Midwest Independent System Operator (MISO) has used the forecast prepared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

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

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

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

Figure 1: Michigan 2005 Forecasted GWh Sales

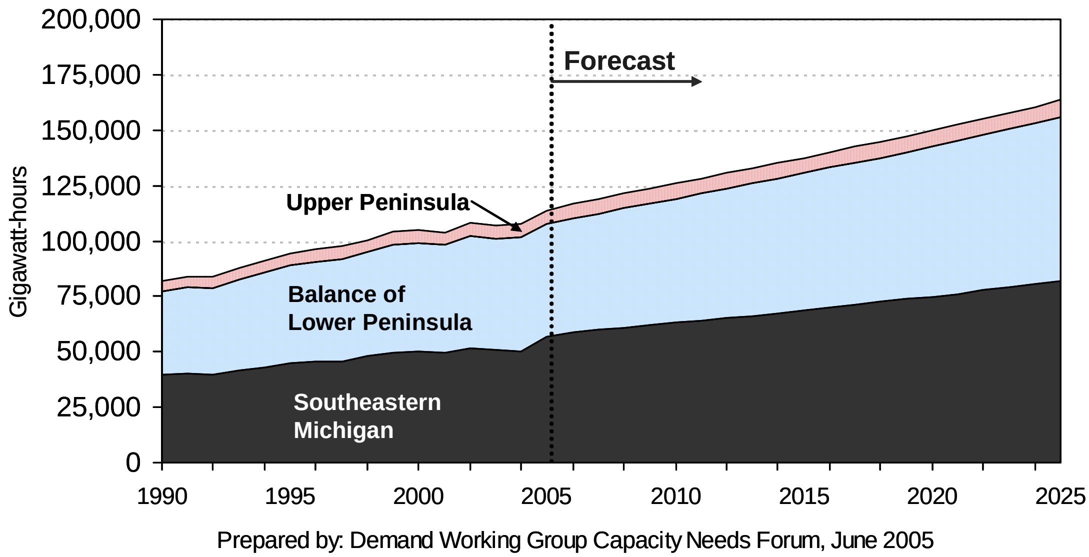


After the enactment of Public Act 141 of 2000, Michigan electric customers were allowed to select electric generation service from non-regulated, competitive, suppliers. According to the Staff's most recent report on electric competition, alternate electric suppliers were serving approximately 4 million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

2 Forecast Results

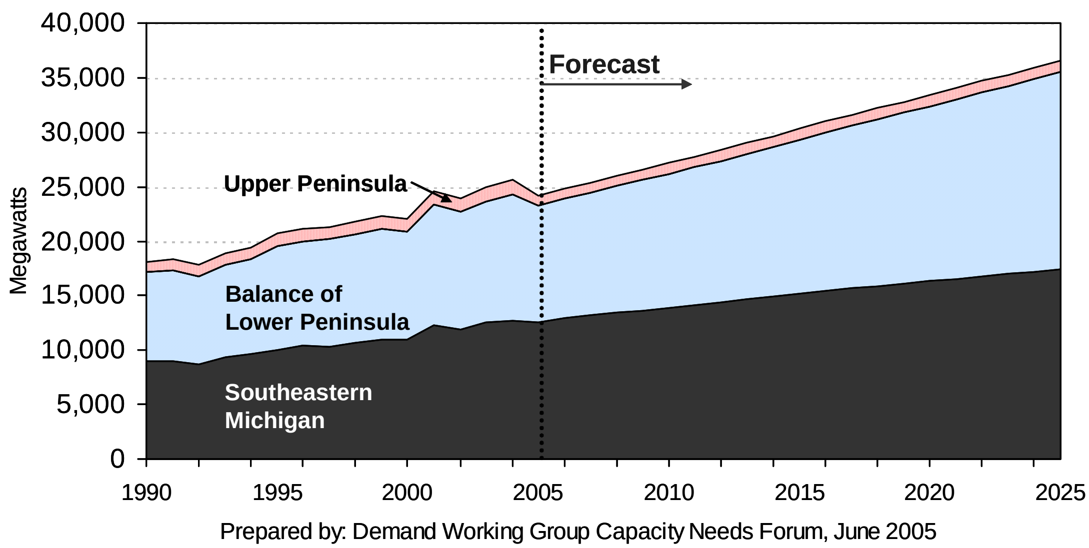
In the base case, Michigan's total electricity needs are expected to grow by 1.8 percent from 2005 to 2025, from 113,782 GWh to 163,411 GWh. Southeast Michigan is expected to experience a growth rate of 1.8 percent, the balance of the Lower Peninsula is expected to grow at 1.9 percent and the Upper Peninsula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

Figure 2: Michigan Electricity Historical and Forecasted Sales



Peak demand is expected to grow from 24,101 MW to 36,589 MW, or at a rate of 2.1 percent from 2005 to 2025. The expected peak load growth for southeast Michigan is 1.7 percent, for the balance of the Lower Peninsula it is 2.7 percent, and for the Upper Peninsula it is 0.9 percent. The graph below depicts forecast demand growth:

Figure 3: Michigan Electricity Forecast Demand Growth



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

3 Discussion

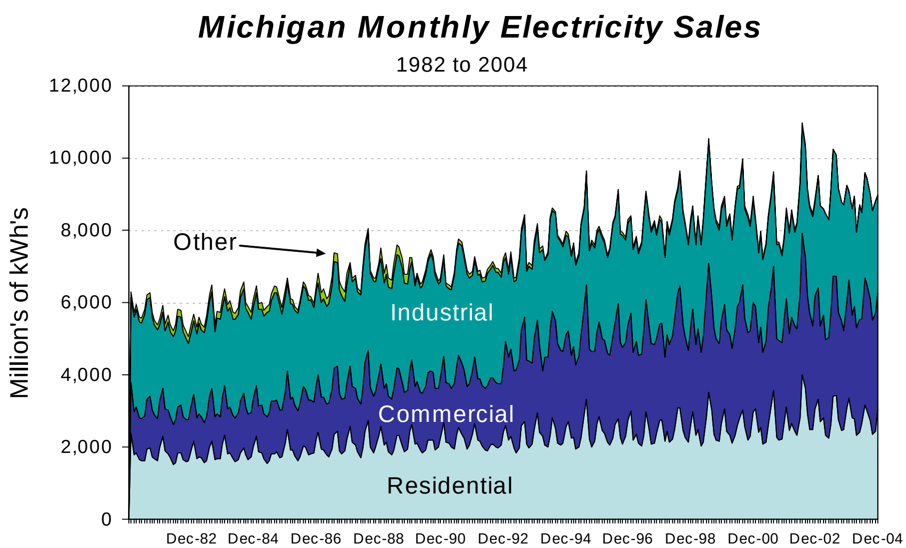
Southeast Michigan's near-term forecast reflects a resumption of economic growth in 2005, but at a relatively slow rate. This growth is not projected to increase employment, however. Manufacturing, especially related to the auto and truck industry, drives much of southeast Michigan's demand for electricity.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

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

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

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

Figure 4: Michigan Monthly Electricity Sales: 1982 to 2004



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

3.1 Forecasting Methods

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

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

Consumers Energy's forecast was updated in April of 2004 and is for the period 2005 through 2019 with all years after 2009 based on forecast trends. Annual adjustments to energy (848 GWh) and demand (330 MW) were applied to the 2019 forecast data to trend the demand and energy forecasts from 2020 through 2025. The economic parameter forecast has been created by Consumers Energy and is based upon data and forecasts from Global Insight and include: the U.S. industrial production eight sector average, the

Michigan industrial production six sector average, the composite Michigan transportation index and Michigan housing starts. Consumers' key forecast inputs also include cooling-degree and heating-degree days based on a fifteen-year average, an adjustment for leap days as appropriate and adjustments have been made for expected major industrial plant closings. Consumers' forecasts are based on the following:

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

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

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

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

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

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

3.2 Impact of Energy Efficiency

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

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

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

Table 1: Total Estimated Percent of Sales by Michigan Customer Class

Description	Residential	Commercial	Industrial	Total
Percent of Sales	17.2%	7.2%	1.6%	7.9%
Cost of Conserved Energy: *cents/kWh*	1.0-2.0	1.0-2.5	0.5-1.0	

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

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

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

Table 2: ACEEE Estimated Saving Available to Michigan:

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

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

Table 3: Results from Consumers Energy's Energy Efficiency Program (1990's)

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

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

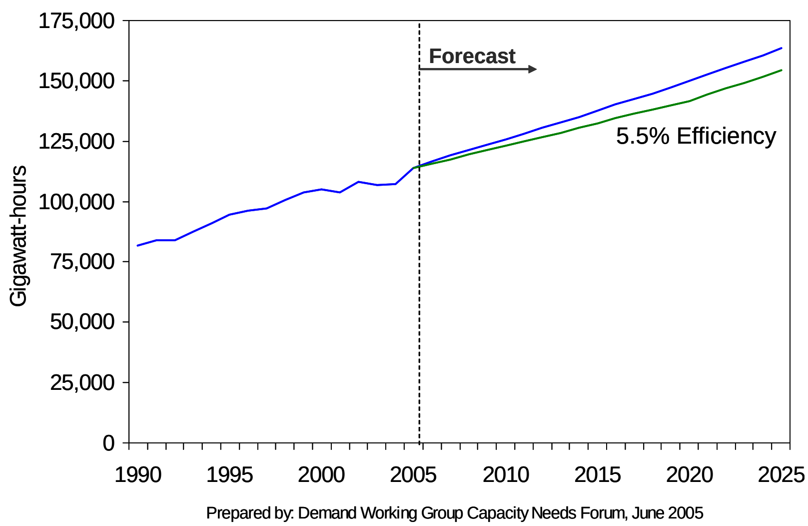
Both Michigan historical data and data from other states indicate that use of three cents per kWh for conserved energy would be reasonable. However, it should be noted that not everyone reporting the cost of conserved energy from their programs uses the same discount rate or measure lifetime in their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

The results are as follows:

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

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

Figure 5: Michigan Electricity Sales Forecast

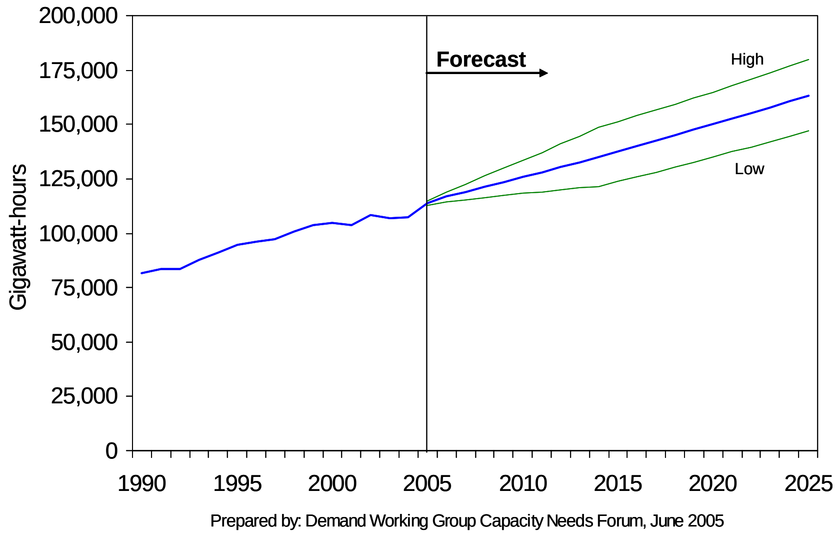


The ACEEE study estimates provide the basis for developing an "energy efficiency scenario." We also recommend that the estimates be used in an "environmental scenario," since the electric efficiency savings may be the least cost option available.

Risk and Uncertainties

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

Figure 6: Michigan Electricity Sales Forecast Range



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

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

Table 4: Michigan Electricity High and Low Growth Forecasts

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

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Attachment I

Base Demand Forecast and Sensitivities

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I - 1: Annual Non-Coincident Peak in Megawatts - Base Case

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

I - 2: Annual Non-Coincident Peak in Megawatts - Low Growth Case

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

I - 3: Annual Non-Coincident Peak in Megawatts - High Growth Case

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

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Attachment II

Base Sales Forecast and Sensitivities

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II - 1: Annual Sales (GWh) Base Case

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

II - 2: Annual Sales (GWh) - Low Growth Case

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

II - 3: Annual Sales (GWh) - High Growth Case

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

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Attachment III

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

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

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

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Appendix E

Central Station Work Group Report

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Michigan Capacity Need Forum:
Central Station Work Group Report

January 2006

Copies of this report are available from the Michigan Public Service Commission's Web site, at: http://www.dleg.state.mi.us/mpsc/electric/capacity/cnf.

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1 Introduction

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

2 Generation Inventory

The Work Group conformed to the modeling format of evaluating generating units and issues within the State in three geographical areas. These areas are the southeastern Lower-Peninsula (ITC's service territory), "out-state" Lower Peninsula (METC's service territory), and the Upper Peninsula (ATC's zone 2). Southeastern Lower Peninsula and the out-state Lowe Peninsula have important differences because of the relatively greater concentration of demand in the southeastern Lower Peninsula compared to the relatively greater concentration of generation in the balance of the Lower Peninsula. This distinction is important because of the transmission constraints experienced by west-to-east energy flows in the recent past. The Upper Peninsula has chronic constraints caused by the lack of robust transmission interconnections with the Lower Peninsula and Wisconsin, its low concentration of load, and its reliance on one large indigenous power plant, Presque isle.

One of the tasks assigned to this Work Group was to provide an inventory of existing generation within Michigan. The purpose was to provide a descriptive summary of the generation and to provide likely service lives, capacities, and fuel requirements for modeling purposes. The MPSC Staff obtained details on Michigan generating units used by the Midwest Independent System Operator (MISO) and originally provided by generation owners to support the startup of MISO operations. The data was subsequently reviewed by the generation owners through the CNF working group and corrected where appropriate. This generation data is summarized in Figure 1.

Figure 1: Michigan Electrical Generating Unit Inventory

Eastern Michigan	Summer Capacity (MW)	Winter Capacity (MW)	Maximum Unit (MW)	Minimum Unit (MW)	Ave/Unit Size (MW)	Number of Units
IOU						
Nuclear	1,110	1,125	1,110	1,110	1,110	1
Steam Generator	8,248	8,275	775	83	317	26
Combine Cycle/GT	969	1,188	82	11	31	31
Internal Comb	152	152	3	0.8	2.5	61
Muni/Coop/Public Auth						
Steam Generator	470	472	118	20	59	8
Combine Cycle/GT	25	30	25	25	25	1
Internal Comb	39	40	3	0.4	1.1	36
Non-Utility						
Steam Generator	326	338	199	1	47	7
Combine Cycle/GT	1,502	1,515	570	2	65	23
Hydro	5	6	2	0.5	1.0	5
Internal Comb	76	77	5	0.1	1.0	76
TOTAL	12,922	13,218				275

Western Michigan	Summer Capacity (MW)	Winter Capacity (MW)	Maximum Unit (MW)	Minimum Unit (MW)	Ave/Unit Size (MW)	Number of Units
IOU						
Nuclear	2,820	2,898	1,060	760	940	3
Steam Generator	3,932	3,937	737	52	281	14
Combine Cycle/GT	358	438	30	2	17	21
Hydro	95	113	10	0.2	1.4	69
Pump Storage	1,872	1,872	159	153	156	12
Muni/Coop/Public Auth						
Steam Generator	840	860	158	8	40	21
Combine Cycle/GT	428	459	73	11	29	15
Hydro	8	9	1	0.1	0.4	23
Internal Comb	171	171	8	0.1	2.2	77
Wind	1	1	0.6	0.6	0.6	1
Non-Utility						
Steam Generator	355	374	30	2	14	26
Combine Cycle/GT	4,896	4,909	671	0.8	119	41
Hydro	22	22	3	0.1	0.6	38
Internal Comb	241	241	59	0.5	5	49
Wind	2	2	0.9	0.9	0.9	2
TOTAL	16,039	16,306				412

UP Michigan	Summer Capacity (MW)	Winter Capacity (MW)	Maximum Unit (MW)	Minimum Unit (MW)	Ave/Unit Size (MW)	Number of Units
IOU						
Steam Generator	613	613	90	25	68	9
Combine Cycle/GT	24	28	24	24	24	1
Hydro	139	142	8	0.1	1.1	121
Internal Comb	5	5	3	2	2	2
Muni/Coop/Public Auth						
Steam Generator	82	82	44	13	21	4
Combine Cycle/GT	23	24	23	23	23	1
Hydro	10	10	1.6	0.3	1.0	10
Internal Comb	17	17	2.5	0.5	1.7	10
Non-Utility						
Steam Generator	146	155	50	2.4	21	7
Hydro	22	22	5	0.4	2.4	9
TOTAL	1,081	1,097				174
Michigan Total	30,042	30,621				861

3 Central Station Cost Analysis

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

3.1 Pulverized Coal

Pulverized coal generating units rely on the conversion of coal to a fine dust, which is injected into a boiler and burned as a fuel to produce steam. The steam is used to rotate a turbine, which turns a generator and produces electricity. This process, known as the Rankine cycle, is the basis for steam-based generation throughout the world. A majority of U.S. coal plants operate at sub-critical pressures, 2,400 pounds per square inch (psi) or less, with superheat and reheat steam temperatures normally limited to 1050^0 degrees Fahrenheit. New sub-critical plants can operate at design net plant efficiencies of approximately 9,500 Btu/kWh. Design efficiencies are the heat rates expected at full load and do not include losses to efficiency due to bringing the unit online, ramping up, ramping down, or operating at partial loads. In the late 1960s super-critical pressure steam plants were introduced which operate at main steam pressures of approximately of 3,600 psi and provide net plant design efficiencies of about 8,900 Btu/kWh.

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

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

3.2 Nuclear

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

Over the last decade, a number of factors have contributed to a renewed interest in nuclear production technology in the U.S., including significantly improved safety and operational performance. For example, by 2002, average net capacity factor was over 90 percent with all safety indicators exceeding targets. Another important factor is that fuel needs for nuclear plants can be satisfied from domestic sources. Thus, unlike natural gas, nuclear power development does not result a growing reliance on foreign sources of fuel. Also, nuclear units do not emit SO_2, NOx, Hg, particulate or carbon dioxide, and, therefore, do not contribute significantly to acid rain, ground level ozone, or global warming. From an air emissions viewpoint, nuclear plants offer both low emissions and virtually no risk to new air emission regulations. Therefore, they are not likely to be subject to air quality technology retrofit costs.

Reactor designs have evolved considerably over the past thirty years, with the latest advanced reactor models designed to achieve a number of goals, namely: standardized and simpler designs; improved performance and reliability; higher fuel utilization rates; and superior safety features. Achieving these goals is expected to result in reduced construction time and costs, reduced likelihood of reactor accidents and core melt, more efficient use of fuel, and easier plant operation. Several of the designs incorporate passive safety features that rely on physics to assure major accidents do not occur.

Because no new nuclear plants have been started in the U.S. in a quarter of a century, significant uncertainties exist with respect to new plant development costs. Changes to the U.S. Nuclear Regulatory Commission's plant certification and licensing policies, intended to clarify and streamline the process, are one major source of uncertainty. While cost estimates for constructing new, advanced reactors are available from engineering studies and from construction costs incurred in Japan and plants under construction in Korea, these do not address uncertainties surrounding new U.S. licensing rules. The estimates used in this study are based on DOE's cost estimates for an advance light water reactor. However, until one is actually constructed, this cost estimate should be considered tentative. Finally, the decommissioning cost of a nuclear plant is significant and must be considered in any evaluation of new nuclear plant costs.

3.3 Circulating Fluidized Bed

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

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

3.4 Integrated Gasification Combined Cycle

Integrated gasification combined cycle (IGCC) is an emerging technology with four coal-fired IGCC facilities in operation today. IGCC technology makes use of two power cycles; these facilities use the Brayton cycle in the combustion turbine and the Rankine cycle in the heat recovery steam generator cycle (HRSG). Two of these were built as demonstration facilities located in the U.S. and now operate commercially. Two additional units were built in Europe. All are approximately 275 MW single train plants. The two U.S. plants include one in Florida, a Tampa Electric IGCC plant employing the GE/ChevronTexaco gasification method, and the other in Indiana, the Wabash River Coal Gasification Repowering Project utilizing the E-Gas/ConocoPhillips gasification method. Two different gasification technologies are in use in Europe, the Shell technology is being used at one plant in the Netherlands, and the Prenflo technology is being used at a plant in Spain.

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

Although gasifying coal is a commercially proven process and is used throughout the world in the chemical industry, its integration with a combined cycle combustion turbine cycle results in operational complexity beyond that of a PC plant.

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

To date IGCC technology has not been commercially deployed because of its higher capital cost and its technology risk. American Electric Power (AEP) is in the process of performing an engineering study in concert with GE and Bechtel on the design of a 600 MW IGCC plant for 2010 operation in Ohio, West Virginia, or Kentucky with potential plans for a second 600 MW unit for operation at a later date. This would represent the first commercial U.S. application of this technology beyond the demonstration plants currently operating. To support the construction of this new technology AEP is requesting that ratepayers contribute to its development costs and to be provided with the certainty of recovery of its costs. At this time it is uncertain if AEP will receive this regulatory treatment for implementation of IGCC technology.

Engineering studies with GE and Bechtel show that the 600 MW IGCC plant being developed for AEP will have air emissions that are inherently, depending on the individual pollutant, either equivalent to or substantially lower than those from a fully controlled (i.e. with SCR and scrubber) pulverized coal plant. Sulfur dioxide (SO2) and carbon monoxide (CO) emissions from an IGCC plant are expected to be substantially lower than those from a fully controlled pulverized coal plant, while NOx, particulate matter (PM) and Volatile Organic Carbon (VOCs) emissions from the IGCC plant are expected to be similar to those of a fully controlled pulverized coal plant. The IGCC plant will also have a mercury removal component that is expected to result in a removal of at least 95 percent of the mercury in the gas stream prior to combustion.

Another major advantage of IGCC technology that has drawn adherents is the potential of IGCC plants to allow more economic capture of carbon dioxide than might be achievable with PC boilers. This would be important should carbon dioxide become a future controlled emission in the U.S., and if sequestration becomes a proven technology. Again, capital or operating costs to achieve carbon sequestration are not known at this time and, therefore, are not included in the technology cost table.

3.5 Combined Cycle Combustion Turbines

Combined cycle combustion turbines rely on a two-stage process of electricity production. Although these plants can also utilize #2 fuel oil, the vast majority of CCCT's operate with natural gas as their only fuel option. Natural gas is first combusted and used to turn a gas turbine. The hot exhaust air from the gas turbine is routed though a heat recovery steam generator, which produces steam. The steam is then used to turn a conventional steam turbine, which turns an electric generator for additional electrical energy. By capturing the exhaust gas from the gas turbine in order to produce a steam cycle, the combined cycle plants can reach design net plant efficiencies of 7,200 Btu/kWh. A number of combined cycle plants have been built in Michigan since 2000. These include the CMS DIG (760 MW), Kinder Morgan (Jackson, 550 MW), Renaissance (Carson City, 546 MW), Mirant Zeeland (830 MW), and Covert Township (1170 MW).

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

3.6 Combustion Turbines

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

4 Technology Cost Estimates

Table 1, Technology Price Estimates summarizes the Central Station Working Group’s estimates of the costs and typical emissions profiles associated with construction and operation for each type of plant described above. Plant construction costs include land, boiler, turbine and electrical switchyard components. Plant cooling water, coal transportation and transmission connection costs are unknown until specific plant locations are selected, but have been included as generic costs. Transmission system upgrades necessary to move the power from a new plant to electrical load centers is not included in any estimates provided and could vary widely dependent on plant location and current transmission design and loadings.

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

Figure 2: Current Ozone Non- Attainment Counties in Michigan

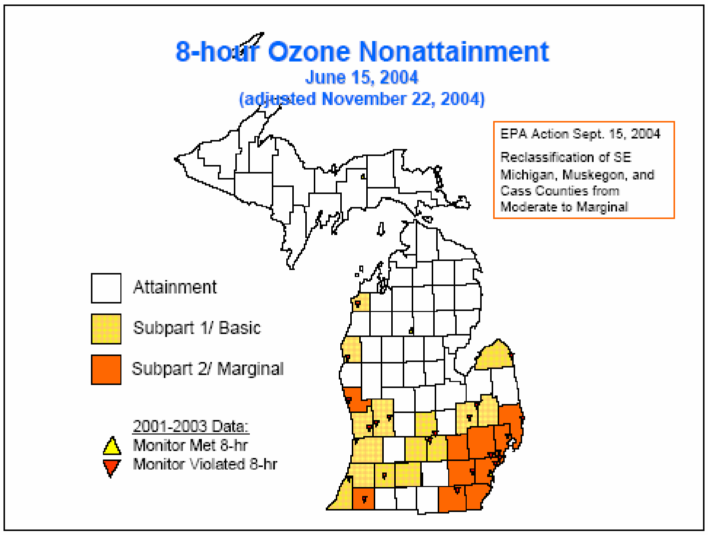

Figure 3: Southeastern Michigan Counties Currently Designated as Non-Attainment for PM 2.5

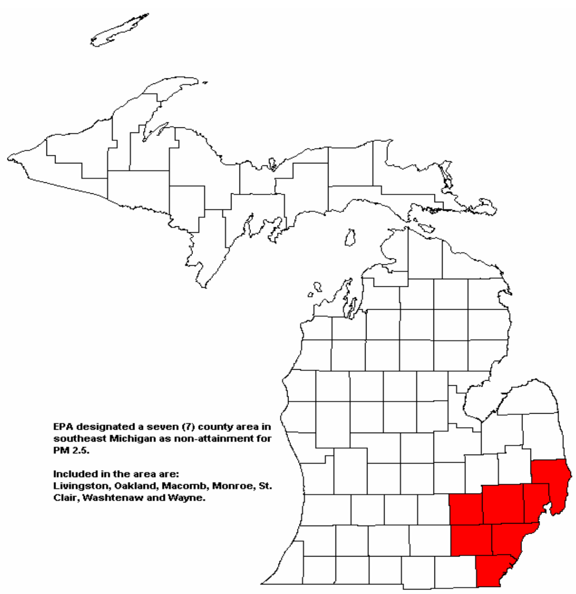

Table 1: Technology Cost Estimates (2005 Dollars)

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

The construction cost estimates shown in Table 2 were completed in 2004 and are based on the EIA/DOE Annual Energy Outlook 2005, a DOE and National Coal Council report entitled "Opportunities to Expedite the Construction of New Coal-Based Power Plants"[1] and CNF Work Group participant inputs. It should be noted that the construction forecasts do not reflect the current major cost run ups in steel and concrete commodity price that have been the result of China's major building program. Mercury control equipment construction costs and operating costs are similarly not included in the above estimates. Both of these could impact price forecasts by 15 percent or more. As previously stated the above costs do also not include any transmission system upgrade costs that would be required to move the generation to the load demand center.

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

Figure 4: Relative Construction Costs for Various Technologies

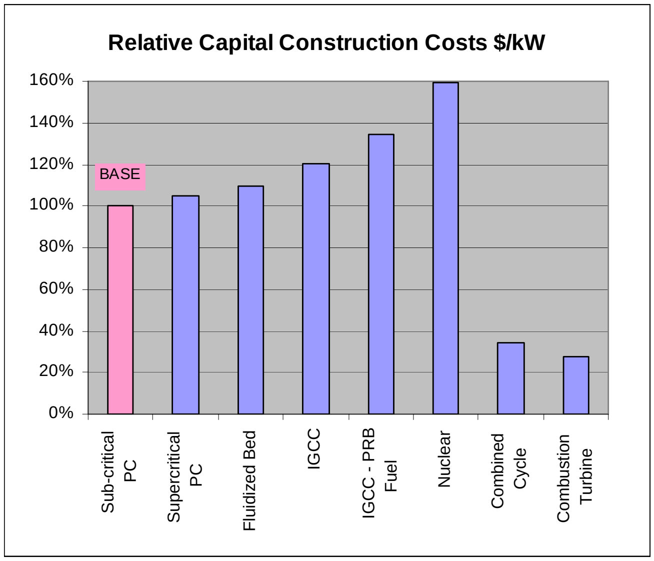

Figure 4 shows the relative construction costs of the various technologies analyzed. This data is consistent with multiple forecasts reviewed by the working group. For modeling purposes it was deemed more important for cost information on competing technologies to have the correct relative position and magnitude than it was to improve accuracy by obtaining precise construction cost estimates developed through more complete engineering analyses. In part, this was a necessity; since more accurate cost estimates are dependent on unit size, permit standards, the specific site location, etc. There are no proposed units for construction in Michigan currently at a stage that would allow this more specific information to be compiled. As the planning process moves forward and more detailed information becomes available, more specific cost estimates may be possible.

5 Technology Emission Characteristics

Emission rates are shown for a typical plant assuming PRB coal for the PC, CFB and IGCC units. Data sources are the National Coal Council Report[2] and "Financial Incentives for Deployment of IGCC: A Coal Fleet Working Paper", Senate Committee on Energy & Natural Resources Bipartisan Coal Conference March 20, 2005, Washington, DC.

[2] See Footnote 1.

Table 2: Plant Typical Emission (pounds per million Btu)

	SO_2	NO_x	Particulate	Hg	CO_2
Pulverized Coal					
Sub-critical	.05	.08	.015	1.22E-06	201
Super-critical	.05	.08	.015	1.22E-06	201
Fluidized Bed	.02	.10	.015	1.22E-06	200
IGCC	.03	.06	.006	8.05E-07	195
Nuclear	.00	.00	.00	.00	.00
Combined Cyde	.001	.03	.00	.00	120
Combustion Turbines	.001	.03	.00	.00	120

6 Major Assumptions and Issues

6.1 Plant Retirements

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

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

Since the late-1950s, the basic thermodynamic design of steam electric generating units has changed little due to metallurgical limits of high temperature steel alloys. In the late 1950s main steam pressures of 2400 psi with 1000/1000^{o}F main steam/reheat temperatures became typical. Modern sub-critical electric central generating units are being built today to these same basic parameters. The most notable change of the last 50 years in sub-critical boiler design has been increased unit output capacity (unit size). A typical late 1950s unit would have been capable of producing 250-300MW, new units are now built in the 600-700MW size. The advantage of the increased size is less operating and maintenance costs per megawatt hour of electricity produced.

This Work Group discussed these issues and agreed that units built since 1950 should expect to realize longer economic life than older units. The group recommends a 65 year retirement age be used for modeling of coal fired generating units. While it is likely that some will retire sooner than 65 years old and some will retire later, 65 years is a reasonable modeling assumption.

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

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

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

6.2 Environmental Issues

The Work Group identified two major issues related to air quality standards. First, seeking an air permit for a new coal fired central generating unit will require addressing a number of critical issues, many of which are currently uncertain or speculative. The uncertainty arises because no new coal units have been placed in service in Michigan since 1985. Therefore, air quality permitting remains potentially uncertain, lengthy and difficult. The second major issue is the uncertainty of future air emission regulations both with regard to tightening of existing limits and the potential regulation of additional combustion byproducts such as carbon dioxide.

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

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

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

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

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

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

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

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

For a more detailed discussion of the Clean Air Act history and emission standards, please see Appendix I to this report.

7 Summary

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

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Appendix I

Electric generating plants, including coal-fired 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 come from coal-fired power plants. For example, Michigan's electric generating plants burned 34 million tons of coal and emitted 317,611 tons of SO_2 and 105,825 tons of nitrogen oxides into the atmosphere in 2003. This represented 88 percent of Michigan's total emissions of SO_2 and 84 percent of the State's total NOx emissions. Emissions from these generating plants are subject to requirements of the Clean Air Act (CAA).

The original CAA was signed into law in 1963 and was considered the first modern environmental law enacted by the US Congress. The CAA of 1970, reviewed and amended in 1975 and 1977, forms the basis of the Federal air pollution control program currently in place. The CAA of 1970 represented a major public policy initiative to assure maximum acceptable levels of pollutants for outdoor air by setting National Ambient Air Quality Standards (NAAQS). The NAAQS established maximum limits for six criteria pollutants. The criteria pollutants are sulfur dioxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO), ozone, lead, and particulate matter (PM).

A preconstruction permitting process for new major sources of criteria pollutants and modified major sources of criteria pollutants called New Source Review (NSR) was required. In areas of the country in attainment for NAAQS, the NSR process imposed emission limits to prevent deterioration of air quality and sources were required to meet Prevention of Significant Deterioration (PSD) standards. In areas of the country not meeting NAAQS (in nonattainment), a different NSR process requires emission limits that are more restrictive than PSD limits. Under nonattainment NSR, the source must obtain emission reductions at other sources so that no net increase in overall area emissions occurs in order to achieve attainment of the NAAQS in the applicable areas.

As part of the CAA of 1970, eight substances were listed as hazardous air pollutants (HAPs) and National Emissions Standards for Hazardous Pollutants (NESHAPS) were promulgated for sources of seven of these pollutants. EPA promulgated New Source Performance Standards (NSPS) that set emission limits on specific new sources and modifications of existing sources. Additionally, states were required to develop State Implementation Plans (SIPs) to achieve acceptable air quality within the state.

The Clean Air Act Amendments (CAAA) of 1990 further addressed the attainment of health-based air quality standards along with continuing concerns about the CAA itself. Nonattainment for one or more of the NAAQS was separated into categories (marginal, moderate, serious, severe and extreme) with differing deadlines to attain the NAAQS. The Air Toxics program identified 189 chemicals as HAPs and adopted new technology standards to reduce emissions of HAPs. Identified sources that emit HAPs will need to comply with the new technology standards and achieve Maximum Available Control Technology (MACT) limits. If necessary, further reduction in HAP emissions may be required if there remains a significant residual health risk after implementation of MACT.

The Acid Rain program was part of the CAAA of 1990 and is a two-phase utility power plant program for reducing sulfur dioxide emissions by 10 million tons from 1980 levels. It was the nation's first emissions cap and trade program. The cap and trade program offered emission sources the choice of capital investments to comply with emission caps or the possession of emission allowances that could be purchased in allowance markets. The amendment required that major sources have operating permits, and that the permits specify the sources compliance requirements. Operating permits are granted for no longer than five years.

The CAA and its amendments now consist of six titles: (I) Air Pollution Prevention and Control, (II) National Emission Standards Act, (III) General, (IV) Acid Deposition Control, (V) Permits, and (VI) Stratospheric Ozone Protection. Three of these apply directly to the electric generating industry.

Although the Federal government has relied upon states to implement the standards adopted by the CAA and its amendments, the EPA has been active in a number of important programs. Among these programs are the acid rain, air toxics, and interstate transport programs. Titles I and IV of the CAA are particularly relevant to the electric generating industry. These titles, together with the permitting process imposed by Title V, have a direct affect on electric generation planning and plant siting.

I.1 New Generating Plant Construction and Major Modifications to Existing Plants

New electric generating plants and modifications of existing plants require preconstruction permits to install and operate. Generally, permits require that the new plants or modifications meet certain standards for air emissions. These sources must go through an NSR process and at a minimum must meet NSPS. These requirements are part of Title I of the CAAA.

If construction occurs in an attainment area, NSR requires use of the Best Available Control Technology (BACT). The BACT technology is used to determine the allowable rate of emissions of criteria pollutants. For example, one of our modeling assumptions was that BACT required flue gas desulphurization (FGD or scrubber), selective catalytic reduction (SCR), and a fabric filter (bag house) for a new pulverized coal plant built in an attainment area. The rate of emission for a new coal plant might be expressed as a concentration standard such as pounds of emissions per million BTU of energy input. In addition to the concentration standard, NSR may require a mass emission standard to limit potential to emit, for example in pounds per hour or tons per year.

New source standards also require that a new emissions source does not cause an existing attainment area to degrade into a nonattainment area. Therefore, even if a new source meets the rate of emissions established by BACT, it must also satisfy a PSD review. A PSD review requires an ambient air analysis to assure that the proposed new source will not cause a significant deterioration in applicable ambient air concentrations. This includes the emissions from the new source along with emissions from existing sources. To protect against excessive degradation in the existing ambient air concentrations, NSR may require a concentration based emissions limit and a mass emissions limit in the permit.

Applicable BACT technology may differ from area to area and through time. BACT reflects the use of the best technology available taking into account site specific environmental, energy, and cost factors. Because of the consideration of these factors, the required emission rates may not be the lowest achievable, but are the best available.

NSR standards for nonattainment areas require use of Lowest Achievable Emission Rate (LAER). In addition to complying with LAER control technology requirements and emission rates, a new installation in a nonattainment area requires that offsets be secured for each criteria pollutant not in attainment. Offset standards require that more offsets be secured than the facility is expected to emit. For example, a permit for an electric generator expected to emit 300 tons of NOx in a nonattainment area would require that offsets totaling more than 300 tons be secured by the new source. The amount of offset depends on the classification of the nonattainment area, for example whether the area is classified as marginal or moderate.

LAER standards are not based upon the same environmental, energy, and economic considerations, like BACT. Instead, LAER standards for nonattainment areas require adoption of the lowest emissions technology for the process being permitted. However, the processes must be comparable. For example, a new coal fired source must be compared to the lowest emission rates for other coal-fired sources, not gas fired sources.

Eight counties in southeast Michigan and two counties in western Michigan are marginal nonattainment areas for ozone. Fifteen counties are basic (unclassified) nonattainment areas for ozone. Seven counties in southeast Michigan are also nonattainment areas for PM 2.5. Therefore, new construction in these areas would require LAER standards as part of the NSR process and would require offsets for the applicable criteria pollutants.

I.2 Acid Rain, CAIR, CAMR and Regional Haze

New generating units along with existing units must also meet emission limits established for the Acid Rain Program, NOx SIP Budget Program, Clean Air Interstate Rule (CAIR), Clean Air Mercury Rule (CAMR), and Regional Haze program standards. These programs set maximum state and region-wide emission caps in tons per year for SOx and NOx, and pounds per year for mercury. These programs do not control the emission rates, but do limit the total emissions from power plants in Michigan.

The Acid Rain rules limit SO_2 using a cap and trade compliance strategy and NOx by setting an emission limit based on the type of coal-fired boiler in use. The Acid Rain program was initiated by the CAAA of 1990 and was implemented in two phases. Phase one began on January 1, 1995 and ended on December 31, 1999 and affected two units at one facility. Phase two began on January 1, 2000 and 79 units at 25 existing sources were allocated SO_2 allowances. All new affected sources were not allocated allowances and are required to purchase SO_2 allowances through the cap and trade program to cover any SO_2 emissions.

The NOx SIP Budget Program went into effect in Michigan in May of 2004. This program places state and region-wide emission caps in tons per ozone season for NOx. This program will remain in effect until the CAIR state regulations are promulgated and approved. Sources affected are located in the fine grid zone area only (roughly all counties south of a line from Pentwater to Harbor Beach). The electric generating units (EGUs) are limited to 29,038 tons for 2004 through 2006 ozone seasons. The EGUs are limited to 28,150 tons from 2007 until the CAIR requirements are in affect

CAIR rules are currently being written by the Department of Environmental Quality. These rules are aimed at controlling NOx as a precursor to ozone. The rules also aim at controlling SO_2 and NOx as precursors to PM 2.5. Phase I of the CAIR rules will limit NOx annual emissions in Michigan to 65,304 tons beginning in 2009 and limit SO_2 emissions to 178,605 tons. Beginning in 2015, Phase II will limit the NOx annual emissions to 54,420 tons and the SO_2 emissions to 125,024 tons, statewide. The annual NOx and SOx regulations will only affect EGUs larger than 25 MW, statewide.

The ozone season portion of the CAIR NOx requirements will affect EGUs larger than 25 MW statewide and other large boilers (greater than 250 MMBtu per hour heat input) in the fine grid area only. The EGUs will be limited to 28,971 tons during the ozone season for Phase I (2009 through 2014) and to 24,142 tons for Phase II (beginning in 2015).

EPA revised its December 2000 regulatory finding issued pursuant to Section 112, removing coal and oil-fired electric steam generating units from the CAA Section 112c source category list. This means coal-fired electric utility steam generating units are a “delisted source category” from Section 112c and are no longer subject to a MACT regulation. However, these plants are subject to the Clean Air Mercury Rule. State mercury rules have not been drafted as of this writing. CAMR calls for a two-phase reduction approach and implements an NSPS for mercury emissions from new EGUs. The first phase limits Michigan to 2,606 pounds per year by 2010 and the second phase limits Michigan to 1,034 pounds per year by 2018 (66 percent reduction). States, however, are permitted to adopt more stringent standards, and these are under consideration for Michigan.

The Regional Haze standards apply to those EGUs going into service between 1962 and 1978 that have the potential to emit more than 250 tons of SOx, NOx, volatile organic compounds (VOCs), or PM. EGUs and other sources also have a demonstrated significant impact on the visibility of any Class 1 area, regardless of distance.

Two Michigan plants that fall into this category are We Energies Presque Isle Plant in the Upper Peninsula and Detroit Edison Monroe Plant in the Lower Peninsula. Others EGUs and non-electricity generating sources may be impacted as well. Control standards call for adoption of the Best Available Retrofit Technology (BART). BART technology is not particularly well defined. It depends on numerous factors including plant characteristics, current control levels, control costs, technology options, and the economic impacts to the company.

Appendix F

Alternative Generation Work Group Report

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Michigan Capacity Need Forum

Alternative Generation Work Group Report

January 2006

Copies of this report are available from the Michigan Public Service Commission's Web site, at: http://www.dleg.state.mi.us/mpsc/electric/capacity/cnf.

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1 Introduction

In Case No. U-14231 the Michigan Public Service Commission (MPSC) established the Capacity Needs Forum (CNF). The goal of this forum is to develop forecasts of optimum power supply and demand for Michigan. As part of the forum, the Alternate Generation Work Group was formed to evaluate nontraditional power supply options that would be feasible within Michigan. Specific tasks include: (1) Define the most promising alternates to traditional generation; (2) Quantify the cost structure of these alternatives; and (3) Determine the capacity that could be on-line by approximately 2009, and detail the location of that capacity by three geographic areas in Michigan (Upper Peninsula, Southeast Michigan, and the balance of the Lower Peninsula).

2 Promising Alternatives

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

Unlike central station power, there is relatively little cost and operating history available in the public domain for alternative generation, including those technologies that the Work Group identified as promising. While the Work Group compiled sufficient data to develop estimated fixed and operating costs and quantities of alternative generation, it should be noted that the results are current estimates and that technological improvements are continuing. As more information becomes available, the Work Group may update the findings that have been included in this report.

2.1 Combined Heat and Power (CHP)

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

There is an estimated 4,580 MW of CHP currently installed in Michigan. Of this, 2,419 MW (52%) of CHP is at the Midland Cogeneration Venture (MCV) and the Dearborn Industrial Generation sites, serving Dow Chemical and Dow Corning and the Ford/Rouge industrial complex, respectively. An additional 990 MW (22%) of installed CHP capacity is at eight different utility-owned sites. The installed base of remaining 26 percent of Michigan's CHP capacity is divided among six main sectors, as shown in Table 1.

Table 1: Michigan CHP Capacity

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

Data from the Michigan Boiler Permit database, U.S. EPA E-Grid database, and Midwest CHP Applications Center database, suggests there is up to 1,471 MW of additional base load capacity for CHP that could be developed in Michigan. The Work Group believes that 37 companies that have existing large boilers (100,000+ lbs/steam/hr) have the best potential, to provide an estimated 1,084 MW of CHP capacity. This potential capacity by sector is depicted in Table 2.

[1] The conversion of fuel energy to useful work in a typical central-station electric generator is typically on the order of 30-40% efficient, and then from 5-15% of that electricity can be lost in transmission and distribution, so that the total efficiency of conversion from fuel to customer's electric outlet is frequently between 1/4 to 1/3. That is, for each 1 unit of energy delivered to the customer in the form of electricity, about 3 to 4 units of fuel energy are used. CHP systems increase efficiency very substantially by converting fuel energy to two or more forms of useful energy, typically making electricity and using as much of the residual thermal energy as practical for some on-site purposes. By locating CHP units as close as practical to both electric and thermal loads, much less energy is lost in transmission and distribution, too. Total system efficiencies for CHP applications can often be roughly twice that of central station power plants. See Web sites of the U.S. Combined Heat & Power Association, http://www.uschpa.org and Midwest CHP Applications Center http://www.chpcentermw.org/home.html.

Table 2: Michigan Estimated CHP Potential

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

The potential industrial CHP shown in Table 2 is divided by region as shown in Table 3.

Table 3: Michigan Potential CHP by Region

Source of Potential CHP	ITC	METC	ATC	Total
Industrial/Institutional w/Large Boilers[1]	543	504	37	1,084
Industrial/Institutional w/Mid-sized Boilers	70	209	41	320
Total	**613**	**713**	**78**	**1,404**

[1] The Alternative Generation Work Group recommended for inclusion in CNF modeling only 547 MW, 1/2 of the potential from large boilers.

An itemization of installed and potential CHP by fuel type and by Service Territory is shown in Table 4.

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

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

Table 4: Installed and Potential Michigan CHP by Fuel Type

Fuel Type	Coal			Gas			Oil			Total
Transmission Area	ITC	METC	ATC	ITC	METC	ATC	ITC	METC	ATC	
Installed CHP (excluding MCV & DIG)	2	67	5	1,113	39	50	0	0	67	1,343
Potential CHP w/Large Boilers	140	166	0	315	316	17	0	0	0	954
Potential CHP w/Mid-sized Boilers	0	18	14	60	175	17	10	12	6	312
Total Potential	140	184	14	375	491	34	10	12	6	1,266
Total Potential by Fuel	Coal = 338			Gas = 900			Oil = 28			

The Work Group's assumptions regarding the estimated cost structure for large-scale CHP systems is presented in Table 5.

Table 5: Large Scale CHP Estimated Cost Structure

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

[1] For illustrative purposes.

The Work Group believes it is also important to note that there is a huge untapped potential market for CHP at smaller industrial facilities. Changes in the economics – through any combination of changes in fuel costs, technology improvements, or utility rate structures – could lead to rapid deployment. For the time being, however, the Work Group considered small scale CHP to be an emerging technology.

2.2 Wind Energy

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

Based on data from the National Renewable Energy Laboratory (NREL), approximately 830 MW of Class 4 (high quality) or higher wind capacity exists on-shore in Michigan.[2] Taking into account siting issues, transmission constraints, the need for large tracts of land to achieve economies of scale, and lack of specific wind data at the potential sites, the Work Group decided to take a conservative approach and estimate approximately 50 percent or 415 MW of capacity could feasibly be installed within the timeframe of the study. Of this amount, an estimated 95 MW exists in the Upper Peninsula, 50 MW in Southeast Michigan and the balance of 270 MW is available in the remainder of the Lower Peninsula. The estimated cost structure for Class 4 and higher wind systems is shown in Table 6.

Capital cost was based on five 1.5 MW wind turbines at an elevation of 80 meters. These costs are based on an estimated 25 percent annual capacity factor and monthly on and off peak average wind speeds to calculate capacity factors that would equate to the 25 percent annual number. Capacity factor calculations are difficult for wind generation because wind speed varies significantly both by location and due to variable weather and climate conditions. The capacity factors used by the Work Group, as shown in Table 7, are based on average wind speeds recorded at the Muskegon Airport.

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[2] See the report, *Potential for MI Offshore Wind Energy*, at http://www.dleg.state.mi.us/mpsc/electric/capacity/cnf/othergen/other.htm.

Table 6: Michigan Estimated Cost Structure for Class 4 and Higher Wind Systems

Assumptions	
Capital Installed Costs ($/kW)	$ 1,200
Capital Recovery Rate (%)[1]	14%
Annual Operating Hours	8,760
Capacity Factor (%)	25%
Efficiency (Btu/kWh)	-
Fuel Costs ($ per million Btu)	$ 0.00
Resulting Costs per kWh	
Capital Recovery	$ 0.077
Fuel	$ 0.000
O&M	$ 0.010
PTC (10 Years Only)[2]	($ 0.018)
Average Cost of Wind Power:	$ 0.069

[1] For illustrative Purposes.
[2] The Federal Production Tax Credit (PTC) for wind power was originally enacted as part of the Energy Policy Act of 1992 and was first scheduled to sunset on June 30, 1999. The PTC has been extended by Congress four times. The most recent extension, in the Energy Policy Act of 2005, is through December 31, 2007. The PTC provides a 1.9-cent per kWh incentive for the first ten years of a facility's operation.

Table 7: Capacity Factors Based on Average Wind Speeds at the Muskegon Airport

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

2.3 Landfill Gas

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

Currently there are 79 MW of landfill gas generators in Michigan. Expansion potential at these sites is estimated to be 54 MW to provide a total of 123 MW of capacity. New sites are also expected to be developed, which are estimated to be capable of providing another 104 MW of capacity over the next ten years. The geographic locations of these sites and existing and potential capacity are shown in Table 8.

Table 8: Geographic Location of Existing Michigan Landfill Sites and Potential Capacity at sites.

	Existing	Expansion	New	Total
Upper Peninsula	0	0	2	2
SE Michigan	53	29	62	144
Balance of Lower Peninsula	26	15	40	81
Total	**79**	**44**	**104**	**227**
Source: Data on landfills from Michigan Department of Environmental Quality.				

Since new landfill gas sites will be smaller in size, require transmission, and will not likely be able to utilize the existing interconnect, the capital costs are estimated to be approximately 30 percent higher than for expansions at existing sites. The typical unit size is 800 kW and all expansion would be in 800 kW increments. Capacity factors were based on sufficient landfill gas being available for all on-peak periods to provide full generator output. The estimated cost structure for landfill gas generation is shown in Table 9.

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

Table 9: Estimated Cost Structure for Landfill Gas Generation

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

2.4 Anaerobic Digesters

Like landfill gas, anaerobic digesters produce methane from farm waste (typically cattle waste, but sometimes blended with other agricultural or food processing waste materials) and use it to fuel engines for power generation as well as for farm heat. Farm digesters require that a digester dome be constructed to capture the methane as it is produced. This process becomes economically feasible for herds of over 500 head of cattle. Due to the manure management practices of different types of farms, this usually means that large dairy farms are the most likely candidates for anaerobic digesters. The Work Group estimates that there are farms in Michigan that could use anaerobic digesters to produce approximately 51 MW. The geographic locations of these farms are shown in Table 10.

Table 10: Estimated MW Production by Anaerobic Digesters in Three Michigan Regions

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

It should be noted that very limited cost and operational data is available about anaerobic digestion. The Work Group's best estimates are presented in Table 11.

Table 11: Estimated Cost and Operational Data of Anaerobic Digesters

Assumptions	
Capital Installed Costs ($/kW)	$ 2,500
Capital Recovery Rate (%)[1]	14%
Annual Operating Hours	8,760
Capacity Factor (%)	90%
Efficiency (Btu/kWh)	10,000
Fuel Costs ($ per million Btu)[2]	($ 0.00)
Resulting Costs per kWh	
Capital Recovery	$ 0.044
Fuel	$ 0.000
O&M	$ 0.025
Average Cost of Power	$ 0.069

[1] For illustrative purposes.

[2] Fuel costs are shown as zero. It should be noted that the residue that remains after anaerobic digestion usually can be land-applied as a fertilizer and soil amendment. Thus, there may be some additional residual value to more than offset any costs associated with delivering waste materials, as feedstocks, to an anaerobic digester.

3 Summary

The four technologies studied have the potential to provide nearly 1,200 MW of capacity in Michigan by approximately 2009. The capacity and cost by technology is summarized in Table 12.

Table 12: Technology Capacity and Cost

Technology	MW	$/kWh
CHP – Coal	182	$0.052
CHP – Gas	365	0.061
Landfill Gas – Expansion	44	0.066
Landfill Gas – New	104	0.069
Anaerobic Digesters	51	0.069
Wind	415	0.069
Total/Average	**1,161**	**$0.064**

This analysis did not include any incentives for emissions reductions or subsidies for green/renewable energy programs. It did assume that the current wind energy production tax credit program would be extended. Such programs can be instrumental in improving the cost structure of the four technologies that were evaluated.

Alternative generation resources can play a significant role in capacity growth within Michigan. Due to their generally smaller size and lower environmental impacts, alternative units typically could be brought on line within a shorter timeframe compared to central station power plants. This generation could provide a stopgap solution for meeting projected capacity needs.

Extensive data analyses have been performed to support the conclusions in this report. Information detailing the data compiled and analyses undertaken is described in the following reports:[3]

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

4 Emerging Energy Technologies

As noted in the beginning of this report, there are a number of emerging energy technologies that could play significant roles in satisfying Michigan's future electric infrastructure needs. Unfortunately, at this time, there are too many unknowns associated with these technologies to make any reasonable projections of the contributions they might make to Michigan's energy future. The Alternative Generation Work Group recommends regular review and update of technology information, through the Michigan Renewable Energy Program Collaborative process and as a follow-up to the CNF, to prepare and maintain current analyses of alternative options.

4.1 Solar Photovoltaic Systems

Photovoltaic (PV) technology, including some commercial applications, has been in existence for decades. It was born in the U.S. in 1954 when Bell Labs researchers developed the first silicon photovoltaic cell. However, for purposes of the Electric Capacity Need Forum and utility scale electric generation, PV systems are still fairly expensive. This is due in part to the high cost of semi-conductor materials. For purposes of the CNF, this technology is still considered an emerging technology. It should be noted, however, that PV systems are already cost effective in many niche applications, especially for off-grid and portable power (e.g., calculators, watches and other small

[3] To learn more about these topics, the reader is encouraged to visit the CNF website and consult the Alternate Generation Work Group's products. These reports are available on the CNF Web site at: http://www.cis.state.mi.us/mpsc/electric/capacity/cnf/othergen/other.htm.

consumer products, mobile highway signs, solar attic fans, battery charging on boats and recreational vehicles, etc.).

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

4.2 Urban Wind Generators

The wind generators most familiar throughout the U.S have horizontal axis blades. Vertical axis rooftop wind turbines are being developed by McKenzie Bay International. Wind resource evaluations are being performed for a number of buildings including a 22-story condominium complex in downtown Toronto and five Michigan sites.[4] Vertical axis wind generators are also being considered for the Freedom Tower that will be built on the former site of the World Trade Towers in New York City. The Freedom Tower is to rise 70 floors and be topped by wind turbines that designers predict will provide 20 percent of the building's electricity. If plans to commercialize the technology are successful, these systems are likely to be cost competitive in many installations.

Other new types of small wind generators are being developed for use by homeowners. For example, Aerotecture, a small company in Illinois, is developing a 1,500-watt (1.5 kW) wind generator for urban use. The generator could be installed on the roofline of a house and would have very low startup speeds. According to the manufacturer, the low speed operation and rigid structure eliminates maintenance and noise concerns and improves performance throughout the year. Unless combined with battery storage, however, it is not likely that these systems would significantly reduce peak loads.[5] In Michigan, wind speeds tend to be low during the same weather patterns that lead to the highest demands for air conditioning, and therefore the highest summer peak loads.

4.3 Offshore Wind Generators

New wind energy resource maps for Michigan indicate a significant energy resource offshore in the Great Lakes. Wind speeds in the offshore areas are considered excellent for wind energy development. The National Renewable Energy Laboratory has estimated that Michigan has over 44,000 MW of wind energy potential in the area between 5 and 10.8 nautical miles offshore (about 10-20 kilometers). Exclusions include all areas less

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[4] McKenzie Bay has already broken ground for its first Michigan project, which is in Ishpeming. See http://web.mckenziebay.com/.
[5] See *Wind Capacity Credits* draft report and presentation, at http://www.dleg.state.mi.us/mpsc/electric/capacity/cnf/othergen/other.htm.

than 5 nautical miles from shore and 2/3 of the area between 5-10.8 nautical miles.[6] Although the costs associated with offshore development are presently higher than on land, it is expected that the superior offshore wind production capability will more than make up for the cost differential. That has been the experience with offshore wind developments in Europe, which have been growing very rapidly. In Europe, installed wind generation capacity in offshore areas grew from zero in the early 1990s to 613 MW by October 2004. An additional 20,000 MW of offshore capacity is now being explored or already under development in Europe. A large number of issues – environmental, economic, regulatory, and technical – would need to be addressed before any development could take place in the Great Lakes. However, it is expected that significant development could occur before the end of the 20-year time horizon being addressed by the CNF.

4.4 Fuel Cells

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

According to Allied Business Intelligence, Inc., the current $40 million stationary fuel cell market will grow to more than $10 billion by 2010, and the overall fuel cell energy capacity will increase by a factor of 250, with global stationary fuel cell capacity jumping to over 15,000 MW by 2011 from just 75 MW in 2001.[7]

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[6] See *Wind – MI Energy Potential, 2006-2020, Draft Report*, pp. 7-8, at http://www.dleg.state.mi.us/mpsc/electric/capacity/cnf/othergen/other.htm.
[7] "Fuel Cell Vehicles to Number 800,000 by 2012, According to ABI," Oyster Ball, New York www.alliedworld.com

Appendix G

Transmission & Distribution Work Group Report

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Michigan Capacity Need Forum:
Transmission & Distribution Work Group Report

Michigan Transmission Assessment for 2009

January 2006

Copies of this report are available from the Michigan Public Service Commission's Web site, at: http://www.dleg.state.mi.us/mpsc/electric/capacity/cnf.

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1 Executive Summary

The Transmission and Distribution Work Group was responsible for estimating the transmission import capability into Michigan for the Capacity Needs Forum. The Work Group was assigned the added task of identifying transmission upgrades that could be implemented to increase transmission transfer capability within Michigan and into Michigan. Finally, the Work Group also reviewed issues that may have an impact on the State's ability to utilize or expand the transmission system.

The Work Group focused on the projected 2009 summer peak electric demand condition and found:

- Approximately 3,000 MWs of power can be imported into the Lower Peninsula of Michigan under peak load conditions, if only "thermal" transmission facility limits are considered and when there is no power flow from Michigan to Ontario;
- Approximately 400 MWs of power can be imported into the Upper Peninsula of Michigan under peak load conditions, if only "thermal" transmission facility limits are considered;
- There is a significant reduction in Michigan import capability if power is flowing from Michigan to Canada (Michigan import capability is reduced approximately 1 MW for every 1 MW of power flow to Ontario);
- Voltage limitations may exist that restrict import capability more than "thermal" limits;
- Transmission upgrades that significantly increase import capability can be made within Michigan;
- Both real and reactive losses will significantly increase as the import level into Michigan increases and the greater the distance between generation and load.

Two groups of transmission system upgrades – TIER I and TIER II – were developed to mitigate "thermal" facility limits and increase transmission import capability. Transmission system upgrades to improve transmission system voltage performance were not developed as part of the CNF effort. However, it is expected that the TIER II upgrades would improve the transmission system voltage performance at a given transfer level (TIER I upgrades are expected to have little voltage impact, therefore, additional projects may be needed to achieve the appropriate voltage performance). TIER I upgrades consist of new transmission facilities in the ITC transmission system that are designed to (1) increase transmission import capability across Michigan into the ITC footprint from the METC footprint by approximately 1,000 MWs for approximately $50 million in transmission facility investment and (2) increase transmission import capability into the Lower Peninsula of Michigan by 1,000 MWs for an additional estimated $50 million investment. In other words, transfer capability within Michigan and into Michigan can be improved by 1,000 MWs for approximately $100 million under peak load conditions. TIER II upgrades consisted of major transmission system expansion into or across the lower portion of the Lower Peninsula of Michigan. The TIER II projects are designed to further increase transmission import capability into the Lower Peninsula of Michigan. TIER II upgrades would increase import capability by 2,500 MWs total (1,500 MWs above that achieved by the TIER I upgrades) for an approximate $500 to $700 million investment.

2 Introduction

The Transmission and Distribution Work Group was responsible for:

1. Estimating the transmission import capability into Michigan in 2009 with no transmission system modifications above those planned or proposed in the 2005 Midwest ISO Transmission Expansion Plan (MTEP);
2. Identifying transmission upgrades that may be available to increase transmission transfer capability within Michigan and into Michigan;
3. Reviewing issues that may have an impact on the State's ability to utilize or expand its transmission system.

The initial focus of the transmission capabilities study was to determine the amount of transmission import capability into Michigan for the year 2009 given the transmission system planned and proposed to be in place at that time. For the purposes of this study, Michigan was divided into three regions: International Transmission Company (ITC), Michigan Electric Transmission Company (METC) and American Transmission Company "zone 2" (ATC-z2)[1] footprints in the State. Imports into the portion of southwestern Michigan served by American Electric Power (AEP) were not studied. Generation in the Michigan portion of AEP (I&M) far exceeds the load in that area, as does the transfer capability of the transmission system in that portion of I&M's service territory.

The transmission regions defined in the study are "geographical" areas. In the Lower Peninsula, there is substantial overlap between ITC and the Detroit Edison service territory and between METC and the Consumers Energy service territory. However, in some cases, distribution utilities own generation in one transmission region, but serve load outside its "primary" transmission region (or may not own all the generation or serve all the load within its "primary" transmission region). Therefore, the transmission area numbers reported herein cannot be applied to the associated load serving utility. For example, the base case power flow model assumptions for these studies include 1,860 MWs of power imports into ITC. This does not mean, however, that Detroit Edison's load exceeds its generation by 1,860 MWs under the base case conditions. In fact, Detroit Edison owns approximately 900 MWs of capacity at the Ludington pumped storage facility that is not included as capacity within the ITC footprint while MPPA and WPSC in the METC footprint own and/or have purchased over 400 MW of Detroit Edison's generating capacity. In addition, up to 1,500 MW of load in the Detroit Edison area is served by alternative suppliers. Some, if not most, of these suppliers procure power from outside of the Detroit Edison area and this adds to the imbalance between load and generation in this particular geographical area.

For convenience, this report may refer to ITC, METC, ATC-z2, or MECS "imports". These transmission companies are not actually contracting for those imports. Instead,

[1] American Transmission Company serves more than Michigan, this study focused on an area ATC refers to as "zone 2" which largely lies within the Upper Peninsula of the state.

this convention was adopted as a more convenient way of stating “imports into the area served by” ITC, METC, ATC-z2, or MECS”.

After determining the amount of transmission import capability into Michigan for the year 2009, given the transmission system planned and proposed for that time, the Work Group began analyzing conceptual transmission system enhancements designed to achieve certain import capability targets. These analyses were performed to provide a rough estimate of the transmission transfer expansion that might be achievable for various levels of investment and to provide an indication of the types of system upgrades that might be involved. Much more detailed analysis would be needed (including a more robust review of alternatives) before any of the conceptual transmission system enhancements could be considered as proposed projects for purposes of transmission planning. Some of the alternatives considered were major new additions, and as such, they could have an impact over a broad area. The full impact of these enhancements would need to be studied more thoroughly (including analysis of resultant system voltages and losses), if they were selected as resource options.

The analyses were performed using the MISO 2005 transmission expansion plan power flow model that included all the planned and proposed transmission system upgrades that are contained in the MISO 2005 MTEP, Appendix A. Electric load modeled for the Michigan companies (except for the Michigan portion of AEP) reflected the peak electric demand forecasted by the Demand Work Group.

Michigan’s electric transmission network is a portion of a very large and complex electrical system comprising North America’s eastern interconnect. Flows through the transmission system (and the ability to move power from one point to another) can be influenced by many factors. The physical factors that influence flows through the transmission system include the amount and location of electric load across geographical areas, the amount and location of operating generation across the geographical areas, and the addition or retirement of new transmission facilities in Michigan or surrounding states or provinces. In turn, these physical factors are influenced by the local market and the amount of local load being served by imports and suppliers as well as by the other markets in the region including those in MISO, PJM and Ontario. Changes in the assumptions surrounding these variables can and do change transfer capability results. As part of the effort to review issues that may have an impact on the State’s ability to utilize or expand the transmission system, the Transmission and Distribution Work Group attempted to identify sensitivities to the most critical variables (large generator outages and flows due to non-Michigan load and generation). However, it is possible that the actual transfer capabilities could differ significantly from those estimated in this report. This is especially true because of the forward looking nature of this analysis and the assumption that all of the planned and proposed projects in the MISO MTEP 05 will be constructed and operational by the end of 2009.

This report focuses on import capability into Michigan. It should be noted that import capabilities can differ depending on whether the imports are occurring for reliability purposes or for economic purposes. For example, when imports into an area are needed to maintain service to load ("reliability"), the likely condition causing the need is a large, perhaps multiple large, generating unit that is not available (that is forced off-line). In general, large units tend to be more economical on a marginal cost basis and, therefore, operate when available – assuming sufficient energy is needed. On the other hand, if transfers are occurring for economic purposes, it is likely that a collection of the smaller units may not be operating. Scenarios with large units out ("reliability") can result in different import capabilities than scenarios with small unit outages ("economics"). Further, unit outages in neighboring regions (Ohio, Indiana, METC when considering ITC, etc.) have an impact on transfer capability into a study region. It is possible that a neighboring region has a large unit forced off-line at the same time there is a need for imports to support reliability needs within a study region. The probability of this occurring, however, is expected to be lower than other contingencies reviewed by this study. It may prove valuable, on the other hand, to determine a study area's import capability for economic purposes under a neighboring area's large unit -out scenario. Given the study's schedule, it was not possible to look at "reliability" and "economic" scenarios separately. The Transmission and Distribution Work Group study focused on "reliability."

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3 Major Assumptions

In order to keep the scope of the studies manageable within the CNF's schedule, the Transmission and Distribution Work Group made several assumptions. Major assumptions are:

- "The market will provide" – there will be sufficient generation capacity outside Michigan available as a source to be brought through the transmission system.
- For imports into the Lower Peninsula, there is sufficient transmission capacity outside of the AEP, FE, ITC and METC (the Lower Peninsula study area) to allow outside generation capacity to get into that study area.
- For imports into the Upper Peninsula, there is sufficient transmission capacity outside of ATC, MAIN, ITC and METC (the Upper Peninsula study area) to allow outside generation capacity to get into that study area.
- Any transfer capability impacts of additional generation in Michigan are either negligible or would be mitigated by transmission upgrades (in other words, new generation and associated transmission added will not result in a net change in transfer capabilities).
- All "planned" and "proposed" projects listed in Appendix A of the 2005 MISO Transmission Expansion Plan are implemented[2]. These are the projects that have been identified to enhance MISO system performance. Listed below are projects of particular significance to the Upper and/or Lower Peninsula of Michigan import capability that have been included in the study.

    - Morgan-Falls-Pioneer-Stiles 138 kV rebuild
    - Plains-Stiles 138 kV double circuit rebuild
    - West Marinette-Amberg 69 kV to 138 kV voltage conversion
    - Gardner Park two 345/115 kV transformers
    - Cranberry-Conover-Plains 138 kV
    - Indian Lk-Hiawatha 138 kV double circuit
    - Hiawatha-Pine River-Straits 69 kV to 138 kV voltage conversion
    - Tippy- Hodenpyl 138 kV rebuild
    - North Belding-Eureka 138kV rebuild
    - American Bumper-David Junction 138kV rebuild
    - Tallmadge 345/138kV third transformer
    - Edenville Junction-Warren 138kV rebuild

[2] The Morgan-Werner West 345 kV project, a significant component of ATC's Northern Umbrella Plan, was not included in the study due to the fact the new project is for a winter 2009 completion date.

- Mullins-Wealthy 138kV rebuild
- Battle Creek-Morrow 138kV rebuild
- Brickyard-Felch Road 138kV rebuild
- Stover-Clearwater 138 kV rebuild
- Thetford transformer reactors
- Almeda-Saginaw River 138 kV rebuild
- Four Mile-Mullins 138 kV rebuild
- Keystone-Clearwater 138 kV rebuild
- Gaylord-Livingston 138 kV rebuild
- David Junction-Bingham 138 kV rebuild
- Barnum Junction-Verona 138 kV rebuild
- Sag clearance improvement on several 138 & 345 kV lines
- Numerous capacitor additions
- Numerous terminal upgrades and CT changes
- West Thumb Loop rebuild
- Wixom-Quaker 230 kV
- Majestic 345/120 kV transformer and Majestic-Madrid 120 kV
- Bismarck-Troy 345 kV

- Limited consideration was given to facility constructability – however, in general, uncertainty over the ability to construct did not preclude inclusion of a conceptual future project.
- A reasonable approximation of the projected 2009 off-peak conditions in Michigan could be achievable by reducing load in the relevant area and altering the generation units dispatched to meet load.
- The phase shifters controlling the Michigan-Ontario interface have adequate phase angle range to control the flow. If they are not able to control flow, at least they are able to reduce flow from East to West[3] across Ontario such that facilities on that path would not be limiting.

[3] The inability of the phase shifters to control flow west to east (more west to east flow than targeted) would not be expected to result in causing facilities on the Ontario path to be limiting. However, as noted in this report, flow from Michigan to Ontario increases loadings on the facilities through which Michigan imports flow. Therefore, this condition would result in a decrease in Michigan import capability relative to what it would be if the phase shifters were able to control west to east flow to the targeted level.

4 Study Results

The results discussed in this section are the total transfer capabilities into the three regions discussed previously. Caution must be used when considering these numbers because transfer capabilities are identified for regions separately, but it is not possible to simultaneously achieve all these transfers. For example, the imports into METC may be reported as X while the imports into ITC are Y. The imports into the combined METC and ITC areas (MECS) would not be X + Y. Rather imports into MECS were determined independently and reported as into MECS. In the peak base case, there are significant imports into ITC and exports from METC. The base case METC import numbers have been "normalized" so that they reflect how much METC could import if there were no simultaneous imports into ITC. Similarly, in the peak base case, flows are coming out of the METC area and the ITC numbers were "normalized" to reflect how much ITC could import if METC were not exporting in the base case.

The study included sensitivity runs to analyze the impacts of simultaneous outages of major generating units in the area immediately surrounding Michigan, including the impact of the generating units which are in Michigan, but are owned and operated by AEP. When these external generating units are forced off-line, transfer limits are created outside of Michigan that are close to the limits within Michigan. Under certain conditions, it is possible that if these external generating units were not dispatched, they could restrict imports into Michigan. Further, for generating unit outages in the portion of the study with conceptual transmission upgrades identified, these limits could limit transfer capabilities into Michigan. While this is a possible simultaneous condition (non-Michigan generator out with heavy transfers into Michigan), the transfers are reported with the non-Michigan generator in-service. This assumption is supported by additional analysis that indicates these generator outages could be mitigated by redispatching limited remaining non-Michigan generators in a manner different than that reflected in the study case.

The base analysis was performed with the flows between Michigan and Ontario held to 0 MW by phase angle regulating transformers (phase shifters). A sensitivity analysis was also performed by assuming a 1,500 MWs flow from Michigan to Ontario (again flow is held by phase shifters). The analysis revealed that a nearly one-for-one correlation exists between flows to Ontario and Michigan import capabilities. When flows from Michigan to Ontario increase from 0 to 1,500 MWs, transfer capabilities into Michigan are reduced by approximately 1,500 MWs. Without the phase shifter control, imports into Michigan flow partly through Ontario. It is possible that the Ontario system or the International Transmission Company ties to Ontario could limit transfer capabilities, particularly if Ontario is simultaneously importing (eastern Ontario facilities might limit) or if there are significant east to west loop flows (western Ontario facilities or International Transmission Company ties to Ontario could limit). The "no phase shifter control", or free flow, scenario was not studied.

The spider diagram attached as Chart 1 reveals transfer capabilities based on thermal limits resulting from the base case assumptions. The transfer capabilities were estimated based upon the source and sink of the projected power flow. For example, the source might be the Tennessee Valley Authority (TVA) and the sink might be ITC. Numerous other combinations were calculated including a proportional flow from "around the compass", that is from all sources simultaneously (denoted as non-Michigan in the diagrams) to ITC and METC separately and MECS collectively. As noted in the diagram, the estimated total transfer capability into MECS from all sources proportionally for 2009, based on MTEP05 planned and proposed projects, is approximately 3,000 MWs. This assumes that the phase shifters hold the power flow to Ontario to zero. Chart 7 shows that the capacity for the same source-sink combination declining to approximately 1,500 MWs if phase shifters are holding the flow to Ontario to 1,500 MWs.

The spider diagrams attached as Chart 2-9 show other thermal related limits. In summary these charts show:

- Chart 2 – based on thermal capability, imports into ITC, METC and MECS can be increased by about 500-1,500 MWs from the south by implementing TIER I south projects (although not contained in these charts, voltage related limits and losses may preclude these transfer enhancements from being fully realized or attempted without additional upgrades)
- Chart 3 – based on thermal capability, imports into ITC from METC can be increased by about 1,000 MWs by implementing TIER I cross-state projects (although not contained in these charts, voltage related limits and losses may preclude these transfer enhancements from being fully realized or attempted without additional upgrades)
- Chart 4 – based on thermal capability, TIER II projects result in increasing import capabilities into ITC, METC and MECS from all external areas included in the modeling (non-Michigan) by about 2,400 MWs above the base case and about 1,100 MWs more than the TIER I projects. While not tested, it is expected that the TIER II projects could also help alleviate voltage limitations and would likely result in lower losses for a given transfer level. Some of the upgrade scenarios tested in TIER II were found not to be as effective.
- Chart 5 – based on thermal capability, TIER II projects result in increasing import capabilities into ITC from METC by about 700 MWs more than the base case and about 600 MWs more than the TIER I south projects. While not tested, it is expected that the TIER II projects could also help alleviate voltage limitations and would likely result in lower losses for a given transfer level. Some of the upgrade scenarios tested in TIER II were found not to be as effective. The TIER I cross-state projects were not modeled in this analysis. Had they been modeled, the transfer capability differences between TIER I and the base case and between TIER II and the base case would likely be significantly higher.

- Chart 6 – shows that if particular units outside of MECS were off-line simultaneously with the imports into ITC from "non-Michigan", the import capabilities would decrease by about 700 MWs for the TIER I south and TIER II upgrade scenarios. Some of the upgrade scenarios tested in TIER II were found not to be as sensitive to unit outages outside of MECS. Although not reflected in the chart, analysis indicated that a relatively small redispatch of units outside of MECS could offset the impact of the non-MECS generator outage so that the transfer level that did not consider non-MECS generator outages could be achieved.
- Chart 7 – shows that the import capability into Michigan is significantly decreased as flows from Michigan to Ontario go from 0 MWs to 1,500 MWs. Although not reflected in the chart, the converse would also be true. Michigan import capability would increase as flows increase from Ontario to Michigan. There is an upper limit on these increases. The upper limit is realized when facilities in Ontario or in the Michigan-Ontario interface begin to reach their limits.
- Chart 8 – ATC zone 2 peak load results – shows the thermal transfer capability into ATC zone 2 to be around 400 MWs for peak load conditions, regardless of whether the incremental transfers were from the South or from the East. It should be noted, however, that the Northern Lower Peninsula transmission system can only accommodate about a 125 MW transfer at the Straits of Mackinaw on a first contingency basis. Other facilities in the Northern Lower Peninsula are even more limiting.
- Chart 9 – ATC zone 2 70 percent of peak load results – shows the thermal transfer capability into ATC zone 2 to be 150-250 MWs for 70 percent of peak load with the Ludington Pumped Storage Plant operating in pumping mode. The maximum incremental import transfer capability from the South the ATC zone 2 was 250 MWs. The maximum incremental transfer import capability was 150 MWs from the East. This simulation represented the system conditions when the Ludington pumped storage facility is consuming 2040 MWs.
- Chart 10 – shows that import capabilities into Michigan under 70 percent of peak load conditions and with Ludington pumping 6 units are approximately 2,400 MWs from the south. This is only slightly higher than the base case imports for this scenario of 2,147 MWs.

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5 Upgrade Scenarios

The general approach used to find conceptual upgrades was to identify "plateaus" where multiple limits in different areas were found to exist simultaneously. These "plateaus" were assumed to be logical breakpoints, because addressing all these simultaneous limits would require a significant increase in the level of transmission upgrades. The limits for the upgrade scenarios were based on thermal capabilities (that is how much power can flow through the transmission facilities without loading the facilities beyond applicable ratings). A number of other factors such as voltages and losses would have to be considered in a more detailed study before adopting any of these upgrade scenarios. It is quite possible that low voltages or unacceptably high losses could result in limiting transfers to levels below the values shown herein, unless additional projects are undertaken.

5.1 TIER I Improvements for Transfers from the South

In the 2009 system as currently planned and proposed, for transfers into ITC, METC and MECS (other than METC to ITC transfers), the limits were generally found in the southern part of the ITC system. Several scenarios were tested to relieve these limits. In performing these analyses, it quickly became apparent that improvements in southern ITC shifted the problem to another facility in western ITC with little gain in import capabilities. Therefore, an upgrade to relieve the western ITC facility would also be needed in order to expand transmission capacity from the South. The first "plateau" was found after the western and southern ITC limits were addressed.

Transmission projects needed to increase Michigan import capabilities from their levels given the projected 2009 system to the first "plateau" are referred to as TIER I southern improvements and include:

1. Adding transformation in western ITC.
2. Building a station in southwestern ITC, and
3. Reconfiguring some southern ITC circuits.

Reconfiguring the southern ITC circuits would take the construction of some new double circuit towers. Almost all of this new construction is believed to be on Detroit Edison property, which may make acquisition of any necessary right-of-way easier. Besides this line construction, these upgrades can be implemented largely by working on existing ITC sites. Or, in the case of the new station, on property that is currently owned by ITC but is largely undeveloped. The conceptual TIER I southern project is believed to require minimal investment from transmission companies other than ITC. Of course, should a decision be made to work toward implementing this level of upgrades, much more detailed analysis would be needed which could result in a different set of projects ultimately being chosen which may involve greater investment outside of ITC. Overall, the TIER I southern projects are conceptually estimated to be $50 million, again subject to more detailed analysis. Although not tested, these set of TIER I improvements are not expected to improve the ability to move power into Michigan under the 70 percent peak load with Ludington pumping scenario nor are they expected to be effective in mitigating the potential voltage limits identified.

5.2 TIER I Improvements for Cross-State Transfers

In 2004 under the MISO umbrella, ITC, with cooperation from METC, investigated and began implementing improvements on transmission facilities between ITC and METC resulting in some mitigation of the west to east limits within Michigan. West to east limits within Michigan remain a concern to reliability within Southeastern Michigan, so projects designed to increase transfer capability from west to east within the State were identified. TIER I projects are those that are projected to increase west to east, and east to west, flows, but do not require large investments or additional right of way.

The TIER I METC-ITC upgrade scenario analyzed included:

1. Building a new 345/230 kV interconnection between the METC system and the ITC system in the northern portion of the METC-ITC interface.
2. Build a new 138/120 kV interconnection between the METC system and the ITC system in the southern portion of the METC-ITC interface.

Overall, the TIER I cross-state projects are conceptually estimated to be $50 million, again subject to more detailed analysis. Although not tested, TIER I improvements are not expected to improve the ability to move power into Michigan under the 70 percent peak load with the Ludington pumping scenario, nor are they expected to be effective in mitigating potential voltage limits.

5.3 TIER II Improvements for Transfers from the South

Analysis of the TIER I South upgrades revealed that these projects pushed transfer limitations outside of Michigan. Further, in the absence of significant new infrastructure, a high level analysis and engineering judgment suggests that losses and voltages may be of increasing concern at some of the higher transfer levels for either the base system or if only the TIER I upgrades are implemented. In order to mitigate these losses and voltage performance concerns and to facilitate higher transfers available from TIER I upgrades only, TIER II upgrades were developed and analyzed.

The projects analyzed in TIER II include several new high voltage direct current (DC) links with 1,000 or 2,000 MWs of capacity, new 345 kV double circuit tower (DCT) lines or new 765 kV scenarios. All of the TIER II projects involve significant and lengthy new transmission lines and involve much larger investment and, in some cases, the need for additional right of way. The 345 kV DCT and 765 kV alternatives would require development of significant new transmission corridors. While it is uncertain, it may be possible to site a DC line in an existing corridor, instead of creating a new corridor. All of these projects achieve the same basic goal of strengthening the link between Michigan and the south as well as across Michigan.

Overall, the TIER II projects are conceptually estimated to cost $500-700 million, again subject to more detailed analysis. Although not tested, these set of TIER II improvements would be expected to improve the ability to move power into Michigan under the 70 percent peak load with Ludington pumping scenario and would be expected to be effective in mitigating (at least partially) some of the potential voltage limits identified in the power flow models.

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6 Voltage Performance

The resulting degradation of voltage performance related to increasing reactive losses may constrain transmission transfer capabilities before thermal limitations are reached. For example, Chart 11 shows that METC voltage limit A would limit ITC import capability to approximately 2,350 MWs for incremental transfers from METC under base transmission configuration conditions. The thermal limits shown on Chart 1 show that for the same conditions (incremental transfers from METC to ITC), the thermal limit would be approximately 4,000 MWs.

Similarly Chart 12 shows that lower Michigan voltage limit #1 would restrict ATC zone 2 imports to around 330 MWs while the thermal results shown on Chart 8 indicate the thermal ATC import limit to be approximately 400 MWs.

Finally, for peak load conditions, Chart 14 shows that the Central Ohio 138 kV voltage limit is only slightly higher (approximately at 3,250 MWs imports) than the comparable thermal transfer limit.

For 70 percent peak load Ludington pumping conditions, METC voltage limit B was found to limit Michigan imports to around 2,950 MWs, or approximately 500 MWs more than the thermal limit under the same condition. This is shown on Chart 13.

Other voltage charts were developed in this effort. However, only those with the most significant results are discussed in this report.

Care must be taken when attempting to interpret future results. This is especially true for future results showing voltage limits related to transfers, since these results can be particularly sensitive to assumptions about reactive load and compensation contained in the power flow models. Further, given the locations of the voltage limits and the thermal limits, it appears that the voltage limits would be much more sensitive to the direction of the transfers than would the thermal limits. It should also be noted that the cost to mitigate voltage transfer limits can vary significantly depending on a number of factors. It may be possible to mitigate some voltage limits via the addition of capacitors, while other voltage limits may require much more comprehensive measures be used.

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7 Transmission Losses

Some analysis was performed under the Transmission and Distribution Work Group umbrella related to the impact on real and reactive losses of the high power transfers across the transmission system. Due to the complexity of such an analysis, it is not possible to make specific definitive statements in this report based on the limited scope of the loss study. However, the loss study, logic and experience all point to several observations.

1. The greater the distance between generation and load, the higher the losses.
2. As transfers increase, losses increase at a faster rate (for a given facility, losses are related to the square of the current through that facility)
3. As reactive losses increase, voltage performance degrades.
4. Transmission system loss implications should be considered when selecting the portfolio of options to address the State's capacity needs
5. For the Lower Peninsula study area (AEP, FE, ITC and METC) real losses under heavy import scenarios can be hundreds of MWs higher than in the case with no transfers. Similarly reactive losses can be thousands of MVAR higher.

Only TIER II type transmission upgrades would be expected to reduce losses incurred under heavy transfer conditions.

8 Generation Deliverability

As part of the MTEP 05, the MISO has examined the deliverability of generation into the transmission grid to see if any generation was "bottled up." In other words, the MISO test examined whether existing generation could be utilized to its fullest extent. With a few possible minor limitations on some small peaking units, the MISO has found that generation in Michigan is generally "deliverable."[4]

[4] Although it passed the MISO test (due to the presence of a special relaying scheme), it should be noted that the generation at Greenwood can be forced off-line following a single transmission line outage. Given the apparent need to keep as much generation as possible available for use, consideration should be given to whether it is in the state's interest to make the out-of-plant transmission at Greenwood more robust so that the plant could remain in-service following the single most critical transmission outage.

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9 Conclusion

The Transmission and Distribution Work Group evaluated various scenarios related to import and transfer capability into and within Michigan as documented by the various charts attached to this report. Overall, the current transmission system is reliable but can be further enhanced via the type of transmission system upgrades defined throughout this report. TIER I would increase transfer capability within Michigan and into Michigan by approximately 1,000 MW for a projected cost of $100 million. The TIER II option would increase import capability into the Lower Peninsula by another 1,500 MW for an estimated cost in the range of $500 to $700 million. In either case, further, more detailed analysis is needed before work could begin on implementing either of these type options. This report is based on several significant assumptions included (1) transmission could be built in the Lower Peninsula in a timely manner; (2) there will be suppliers to provide the needed generation capacity; (3) there is sufficient transmission capacity outside of Michigan and Northern Ohio to support these imports; (4) voltage degradation due to reactive losses will be compensated (this could drive additional transmission expansion expenditures to reach the stated improvements particularly for TIER I options) ; and (5) real power losses will not be restrictive (estimated to be more likely a concern for the TIER I options). These assumptions will have to be addressed in any scenario involving increasing or modifying the sources of capacity to serve the State. The attached charts identify impacts into ITC, METC and MECS based on the TIER I and TIER II options.

Transmission flows between Michigan and Ontario also have a significant impact on import capability. The base case analysis showed that approximately 3,000 MWs can be imported into the Lower Peninsula and approximately 400 MWs into the Upper Peninsula at peak conditions under the assumption that flows between Michigan and Ontario are negligible. A sensitivity to analyze import capability was performed assuming 1,500 MWs flow from Michigan to Ontario. This analysis revealed the almost one-for-one correlation between decreased Lower Peninsula import capability and increased flow from Michigan to Ontario.

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Attachments to

Michigan Transmission Assessment

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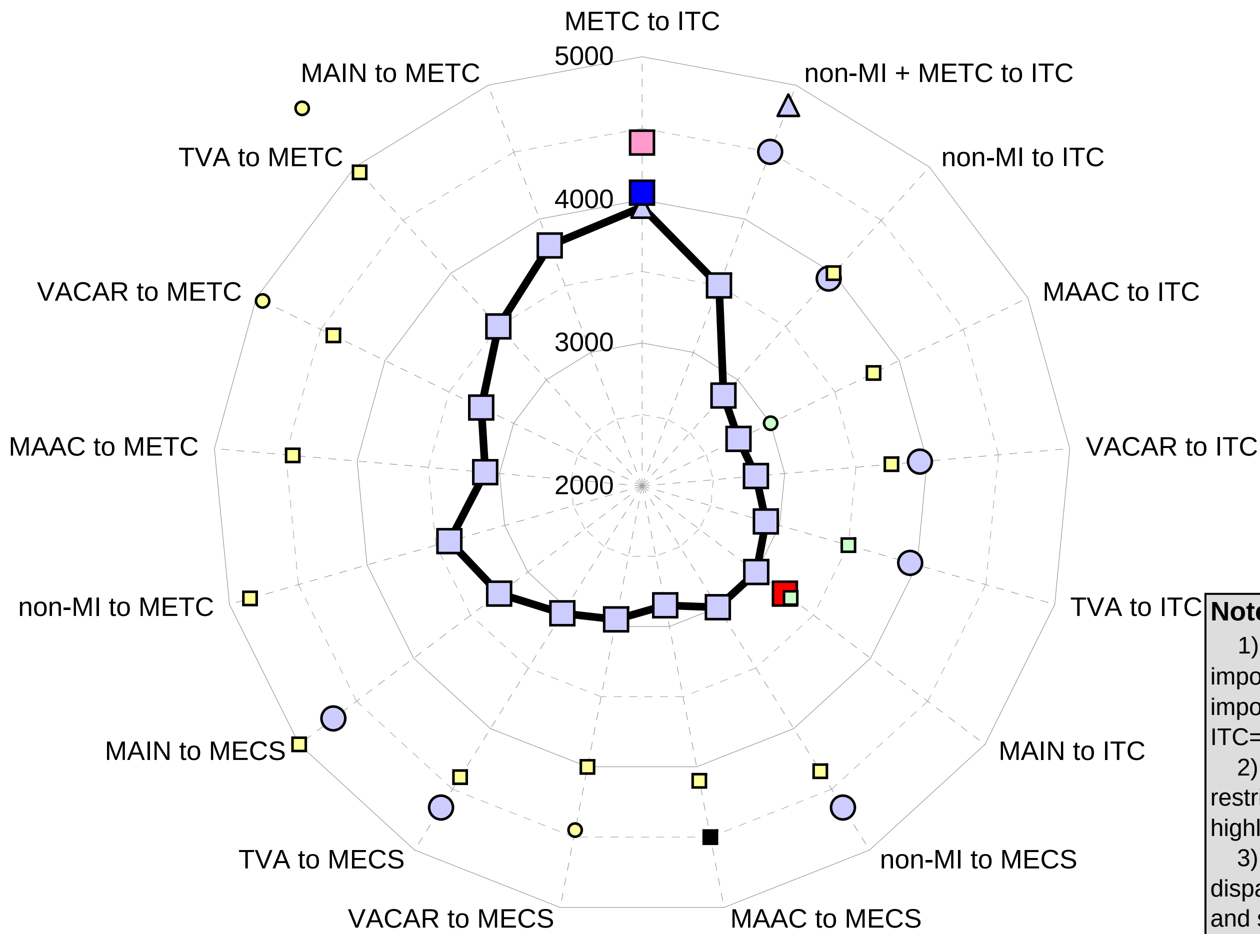
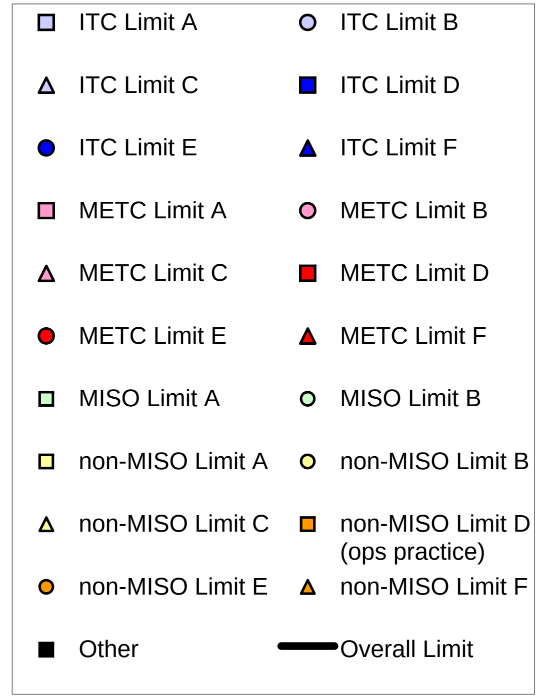
Chart 1

Currently Planned System[4]

2009 Summer -- Total Normalized[1] Import Capabilities for Various Incremental Transfer Scenarios





Notes:

1) Values Shown are normalized to represent import capability if the other entity in MECS were importing 0 MWs.. Actual Base Case Imports ITC=1860, METC=-510 and MECS=1350.

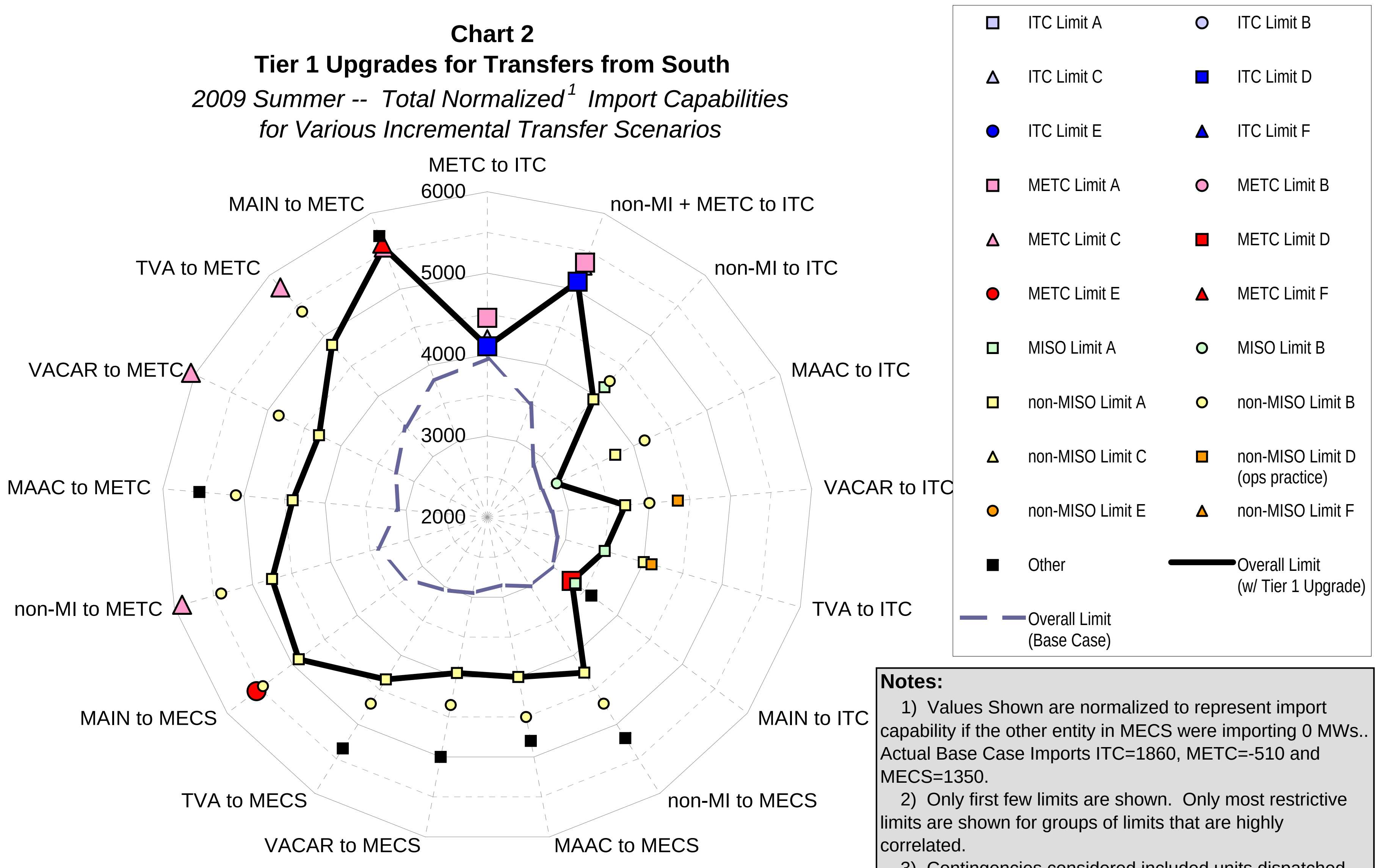
2) Only first few limits are shown. Only most restrictive limits are shown for groups of limits that are highly correlated.

3) Contingencies considered included units dispatched off, units tripping off, single transmission and single transmission with units dispatched off.

4) Base Case has 0 MWs flowing between Michigan and Ontario controlled by phase shifting transformers.

Chart 2
Tier 1 Upgrades for Transfers from South

2009 Summer -- Total Normalized[1] Import Capabilities for Various Incremental Transfer Scenarios



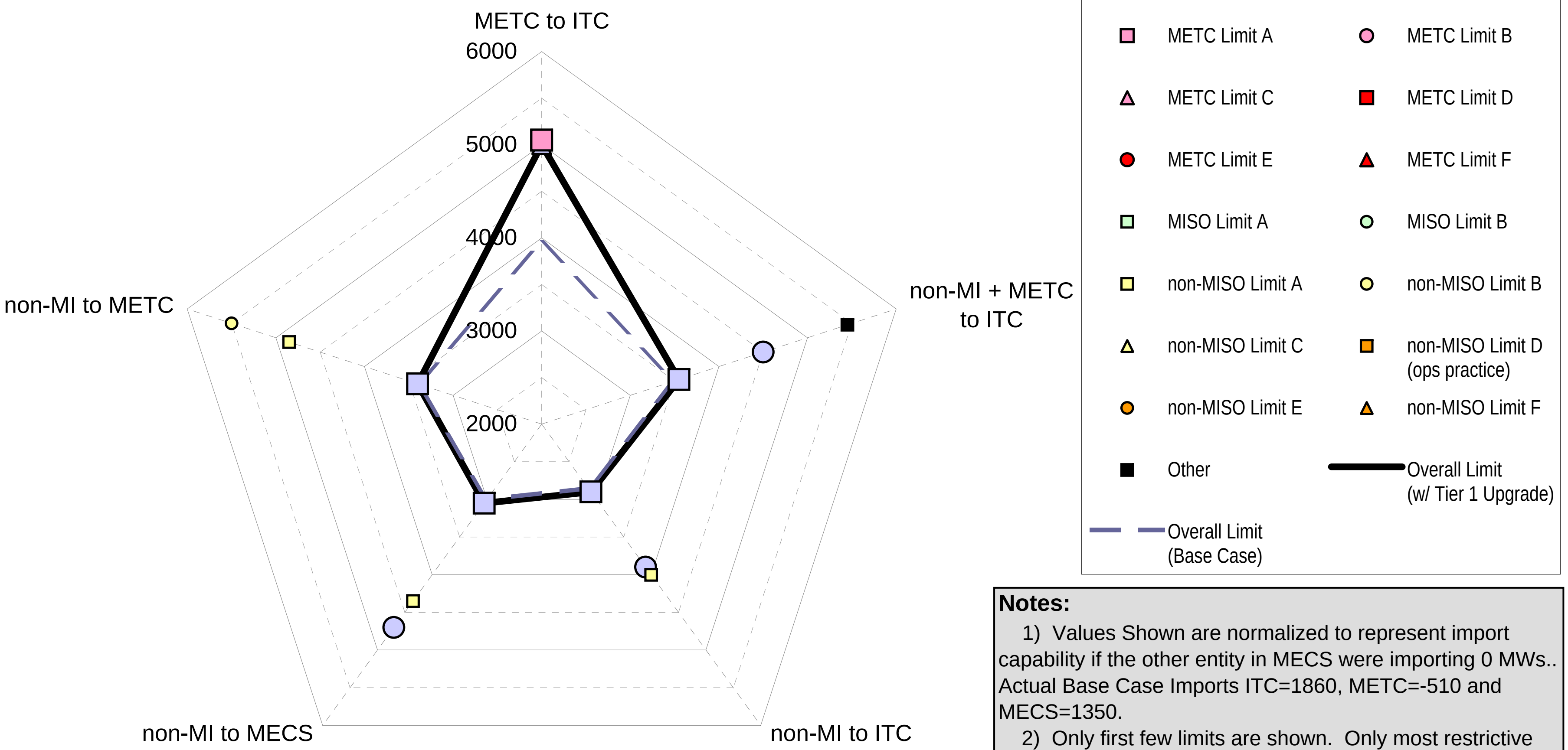
Notes:

1) Values Shown are normalized to represent import capability if the other entity in MECS were importing 0 MWs.. Actual Base Case Imports ITC=1860, METC=-510 and MECS=1350.

2) Only first few limits are shown. Only most restrictive limits are shown for groups of limits that are highly correlated.

3) Contingencies considered included units dispatched off, units tripping off, single transmission and single transmission with units dispatched off.

Chart 3
Tier 1 Upgrades for Cross State Transfers
2009 Summer -- Total Normalized[1] Import Capabilities
for Various Incremental Transfer Scenarios



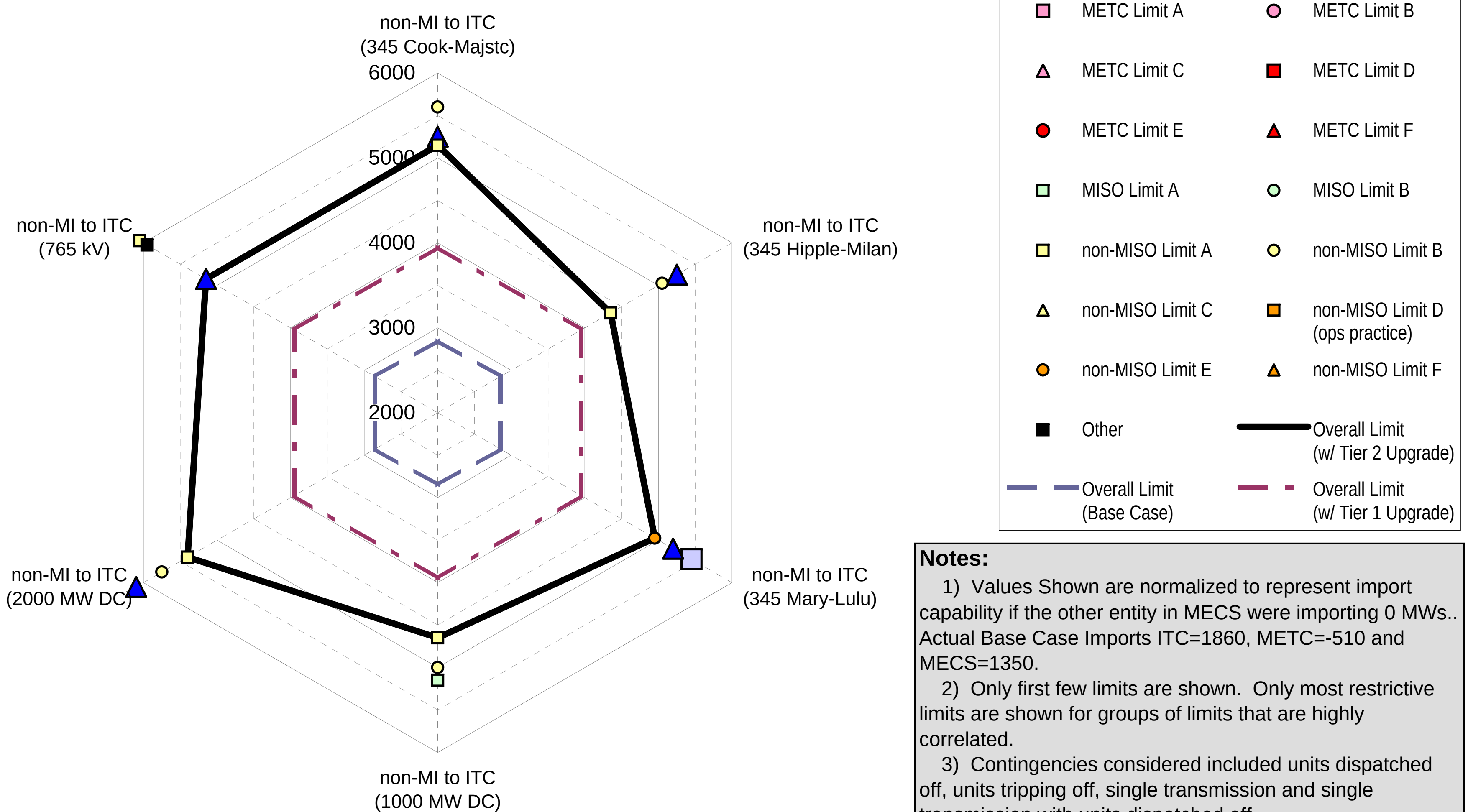
Notes:

1) Values Shown are normalized to represent import capability if the other entity in MECS were importing 0 MWs.. Actual Base Case Imports ITC=1860, METC=-510 and MECS=1350.

2) Only first few limits are shown. Only most restrictive limits are shown for groups of limits that are highly correlated.

3) Contingencies considered included units dispatched off, units tripping off, single transmission and single transmission with units dispatched off.

Chart 4
Tier 1 + Tier 2 Upgrades for Transfers from South
2009 Summer -- Total Normalized[1] Import Capabilities
for non-MI to ITC Incremental Transfer Scenarios



Notes:

1) Values Shown are normalized to represent import capability if the other entity in MECS were importing 0 MWs.. Actual Base Case Imports ITC=1860, METC=-510 and MECS=1350.

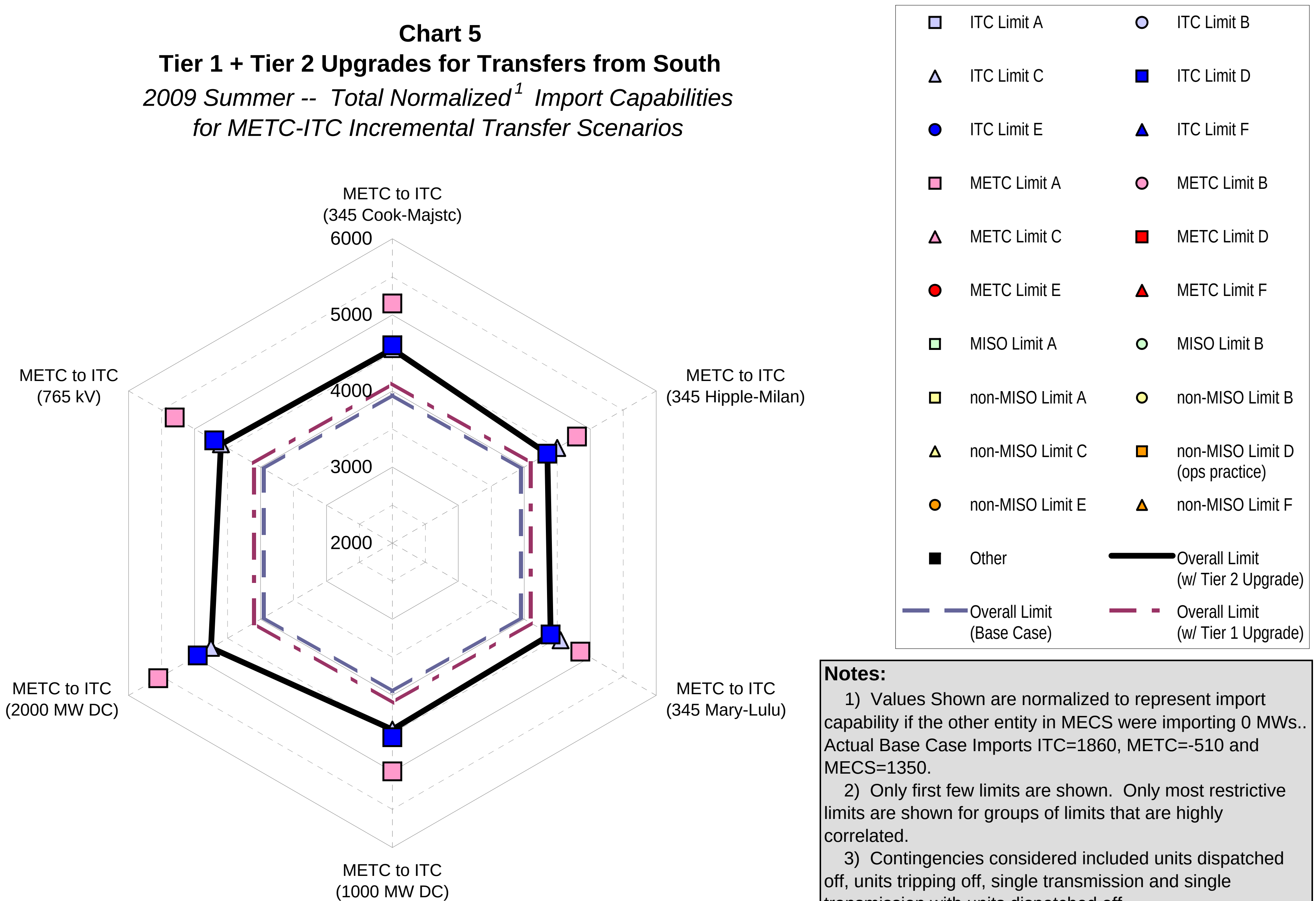
2) Only first few limits are shown. Only most restrictive limits are shown for groups of limits that are highly correlated.

3) Contingencies considered included units dispatched off, units tripping off, single transmission and single transmission with units dispatched off.

Chart 5

Tier 1 + Tier 2 Upgrades for Transfers from South

2009 Summer -- Total Normalized[1] Import Capabilities for METC-ITC Incremental Transfer Scenarios



Notes:

1) Values Shown are normalized to represent import capability if the other entity in MECS were importing 0 MWs.. Actual Base Case Imports ITC=1860, METC=-510 and MECS=1350.

2) Only first few limits are shown. Only most restrictive limits are shown for groups of limits that are highly correlated.

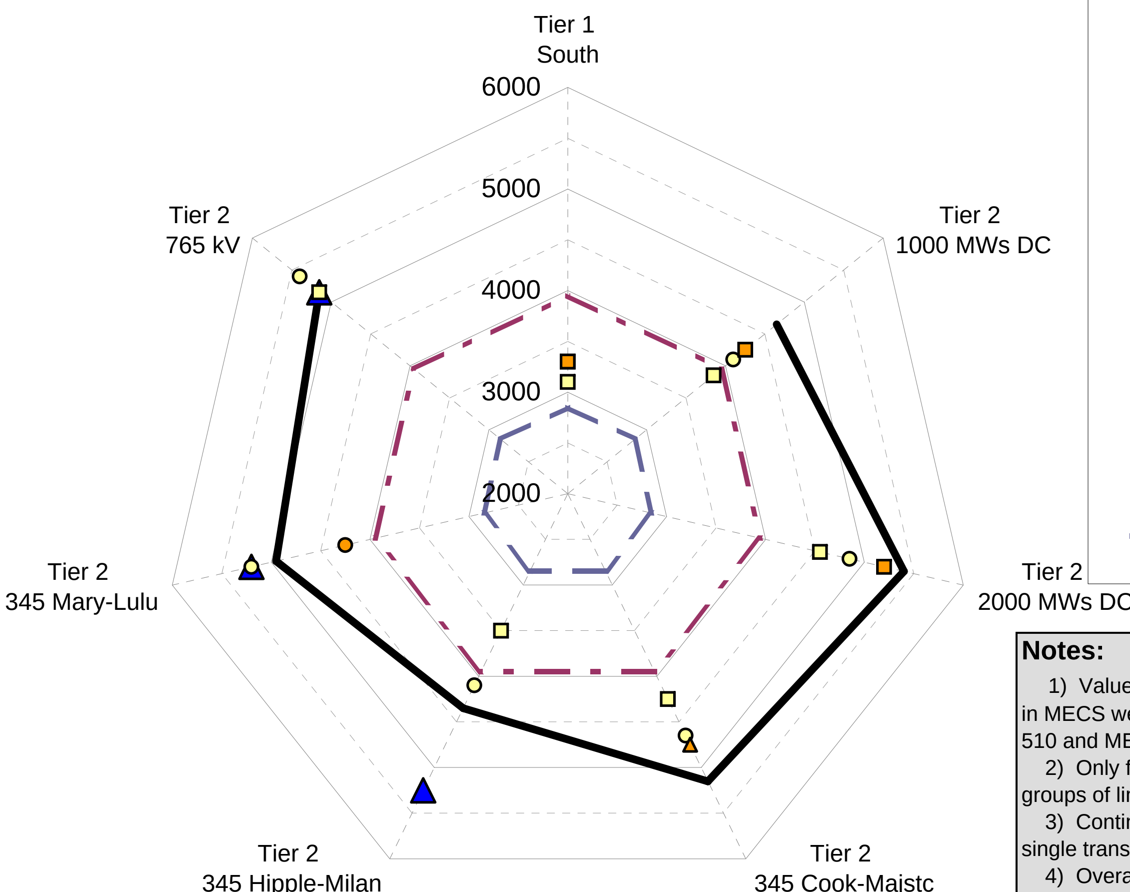
3) Contingencies considered included units dispatched off, units tripping off, single transmission and single transmission with units dispatched off.

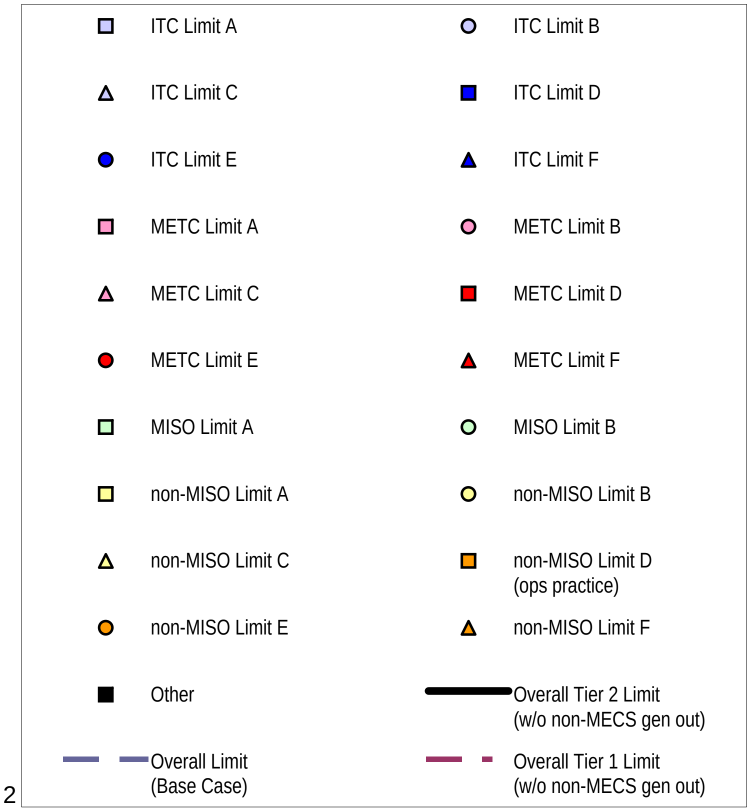
Chart 6

Sensitivity of Limits to non-MECS Generator Outages

2009 Summer -- Total Normalized[1] Import Capabilities

for non-MI to ITC Incremental Transfer Scenarios





Notes:

1) Values Shown are normalized to represent import capability if the other entity in MECS were importing 0 MWs.. Actual Base Case Imports ITC=1860, METC=-510 and MECS=1350.

2) Only first few limits are shown. Only most restrictive limits are shown for groups of limits that are highly correlated.

3) Contingencies considered included units dispatched off, units tripping off, single transmission and single transmission with units dispatched off.

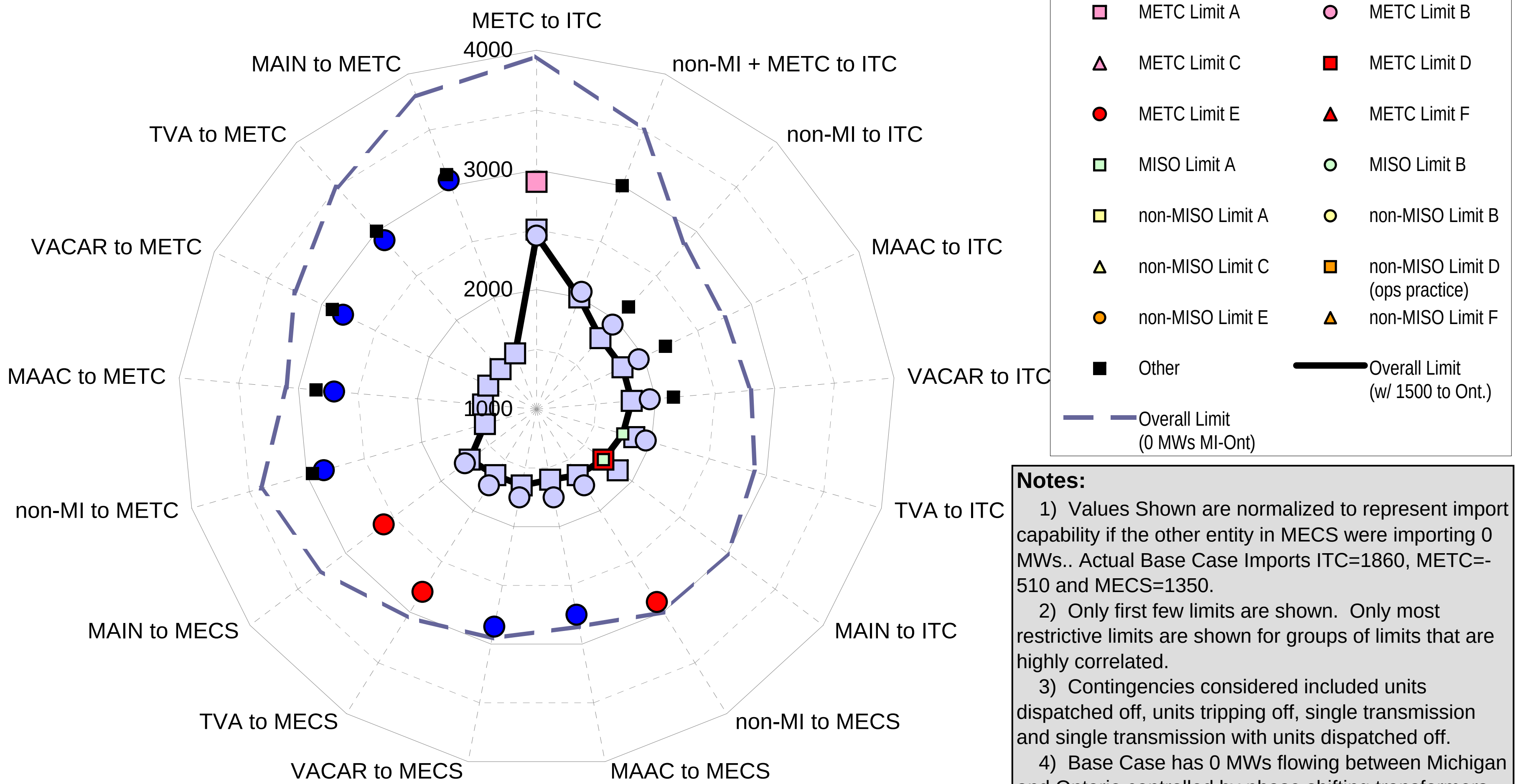
4) Overall limit in base case not impacted by a single generator dispatched off outside of MECS.

Chart 7

Impact of 1500 MWs Flow from Michigan to Ontario[4]

2009 Summer -- Total Normalized[1] Import Capabilities

for Various Incremental Transfer Scenarios



Notes:

1) Values Shown are normalized to represent import capability if the other entity in MECS were importing 0 MWs.. Actual Base Case Imports ITC=1860, METC=-510 and MECS=1350.

2) Only first few limits are shown. Only most restrictive limits are shown for groups of limits that are highly correlated.

3) Contingencies considered included units dispatched off, units tripping off, single transmission and single transmission with units dispatched off.

4) Base Case has 0 MWs flowing between Michigan and Ontario controlled by phase shifting transformers.

Chart 8

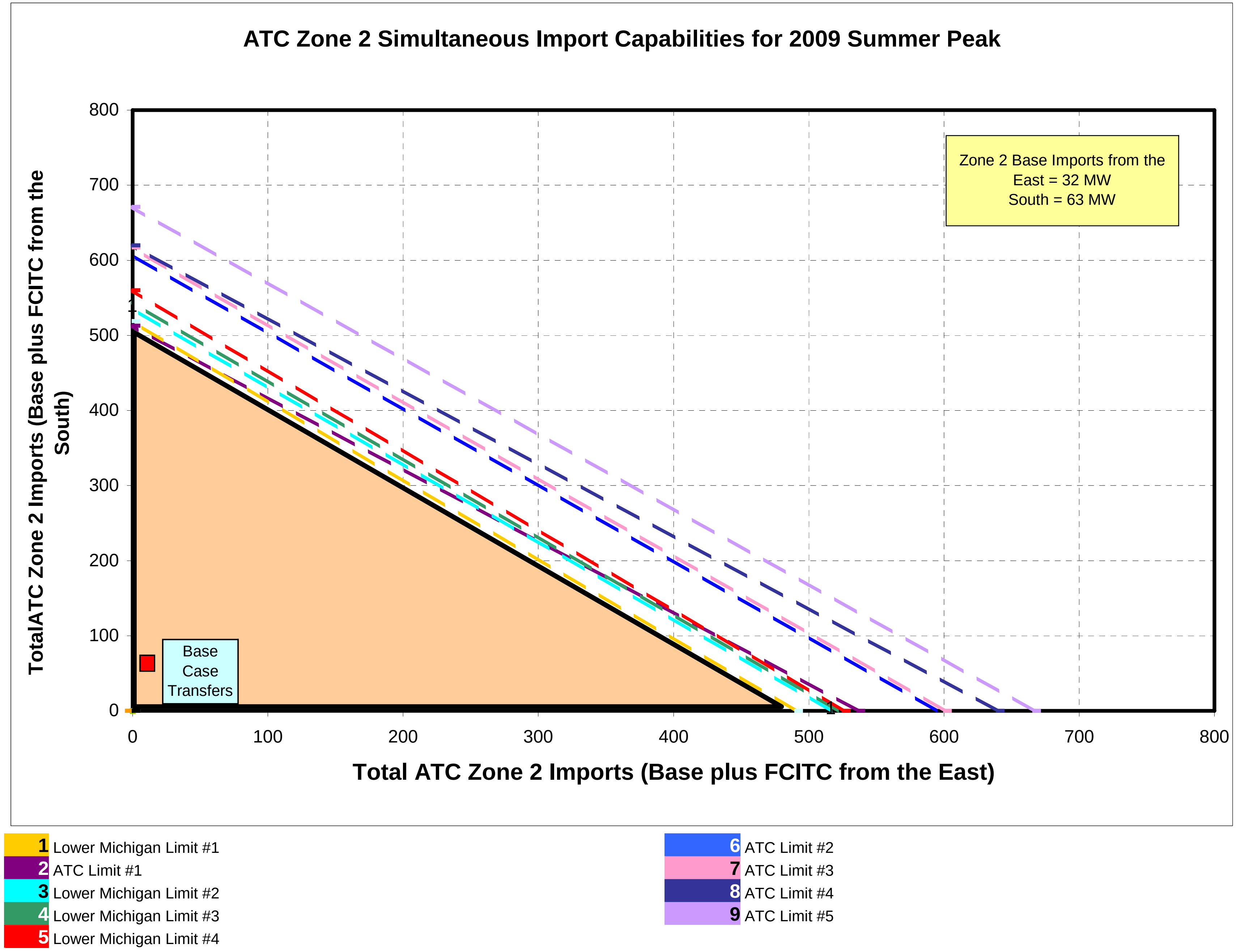
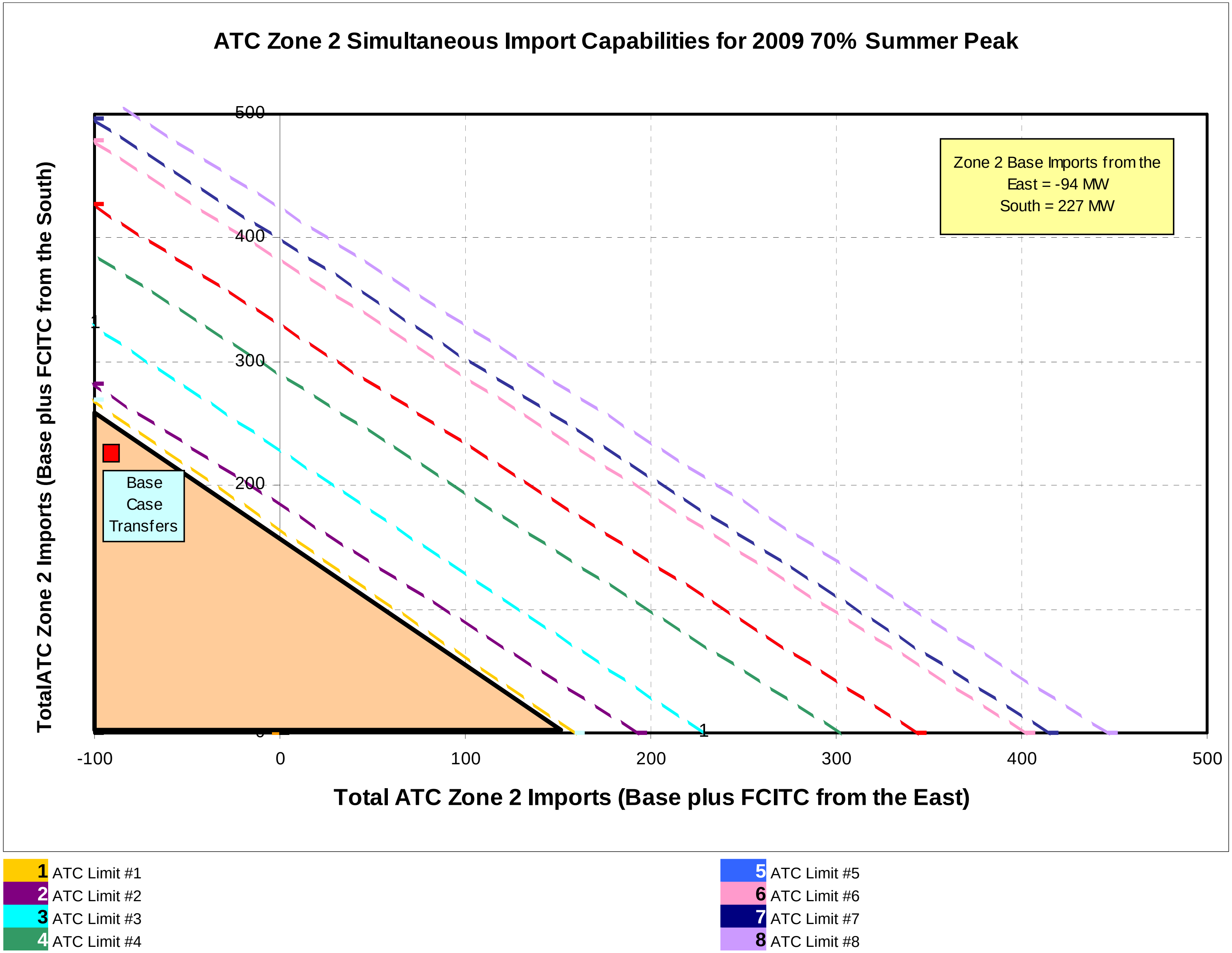

ATC Zone 2 Simultaneous Import Capabilities for 2009 Summer Peak
Zone 2 Base Imports from the
East = 32 MW
South = 63 MW
Base
Case
Transfers
800
700
600
500
400
300
200
100
0
0
100
200
300
400
500
600
700
800
TotalATC Zone 2 Imports (Base plus FCITC from the South)
Total ATC Zone 2 Imports (Base plus FCITC from the East)
1 Lower Michigan Limit #1
2 ATC Limit #1
3 Lower Michigan Limit #2
4 Lower Michigan Limit #3
5 Lower Michigan Limit #4
6 ATC Limit #2
7 ATC Limit #3
8 ATC Limit #4
9 ATC Limit #5

Chart 9

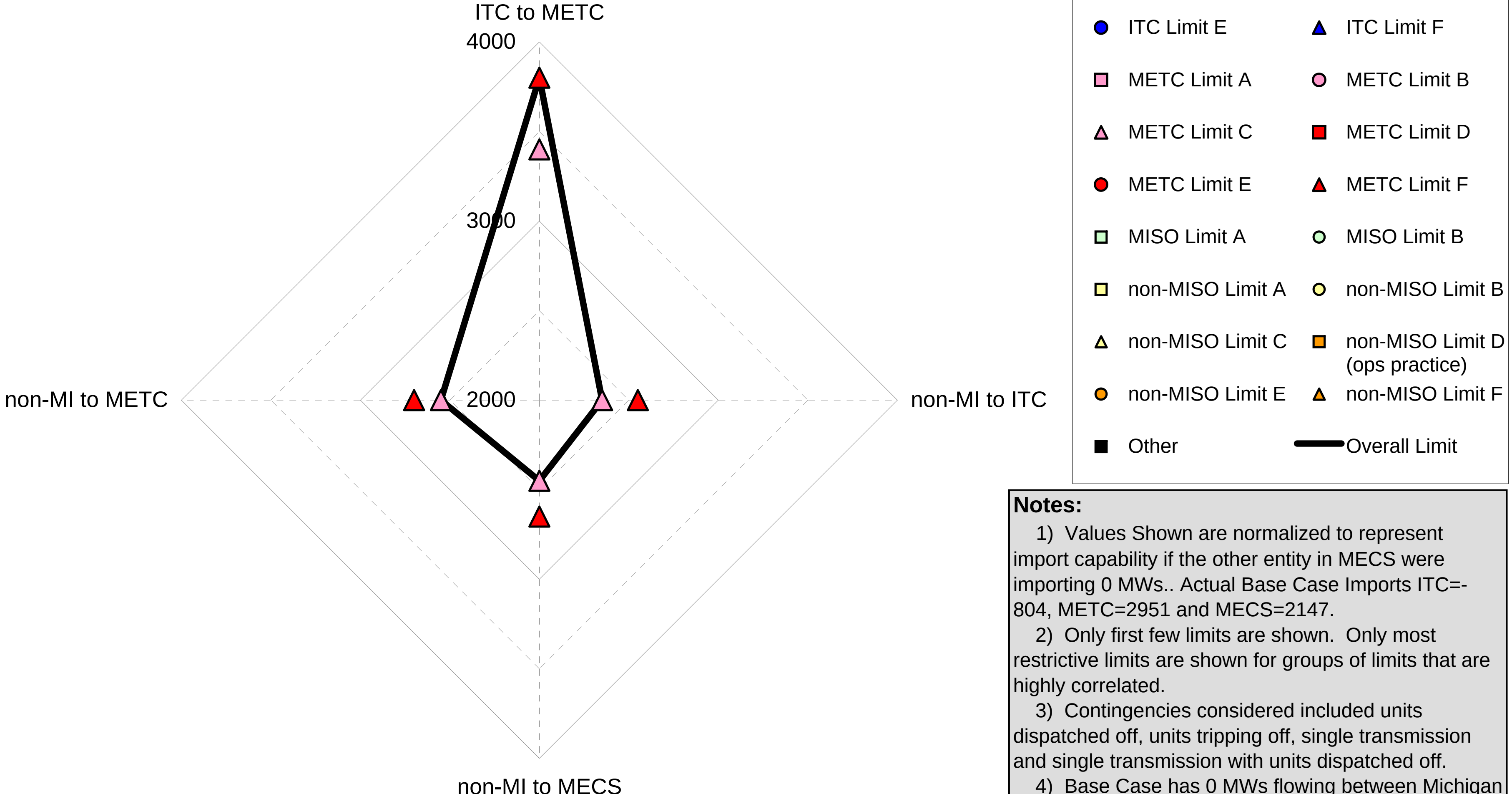


ATC Zone 2 Simultaneous Import Capabilities for 2009 70% Summer Peak
Zone 2 Base Imports from the East = -94 MW South = 227 MW
Base Case Transfers
TotalATC Zone 2 Imports (Base plus FCITC from the South)
Total ATC Zone 2 Imports (Base plus FCITC from the East)
500
400
300
200
0
-100
0
100
200
300
400
500
1
1
1 ATC Limit #1
2 ATC Limit #2
3 ATC Limit #3
4 ATC Limit #4
5 ATC Limit #5
6 ATC Limit #6
7 ATC Limit #7
8 ATC Limit #8

Chart 10

70% Peak Load with Ludington Pumping[4]

2009 Summer -- Total Normalized[1] Import Capabilities
for Various Incremental Transfer Scenarios



Notes:

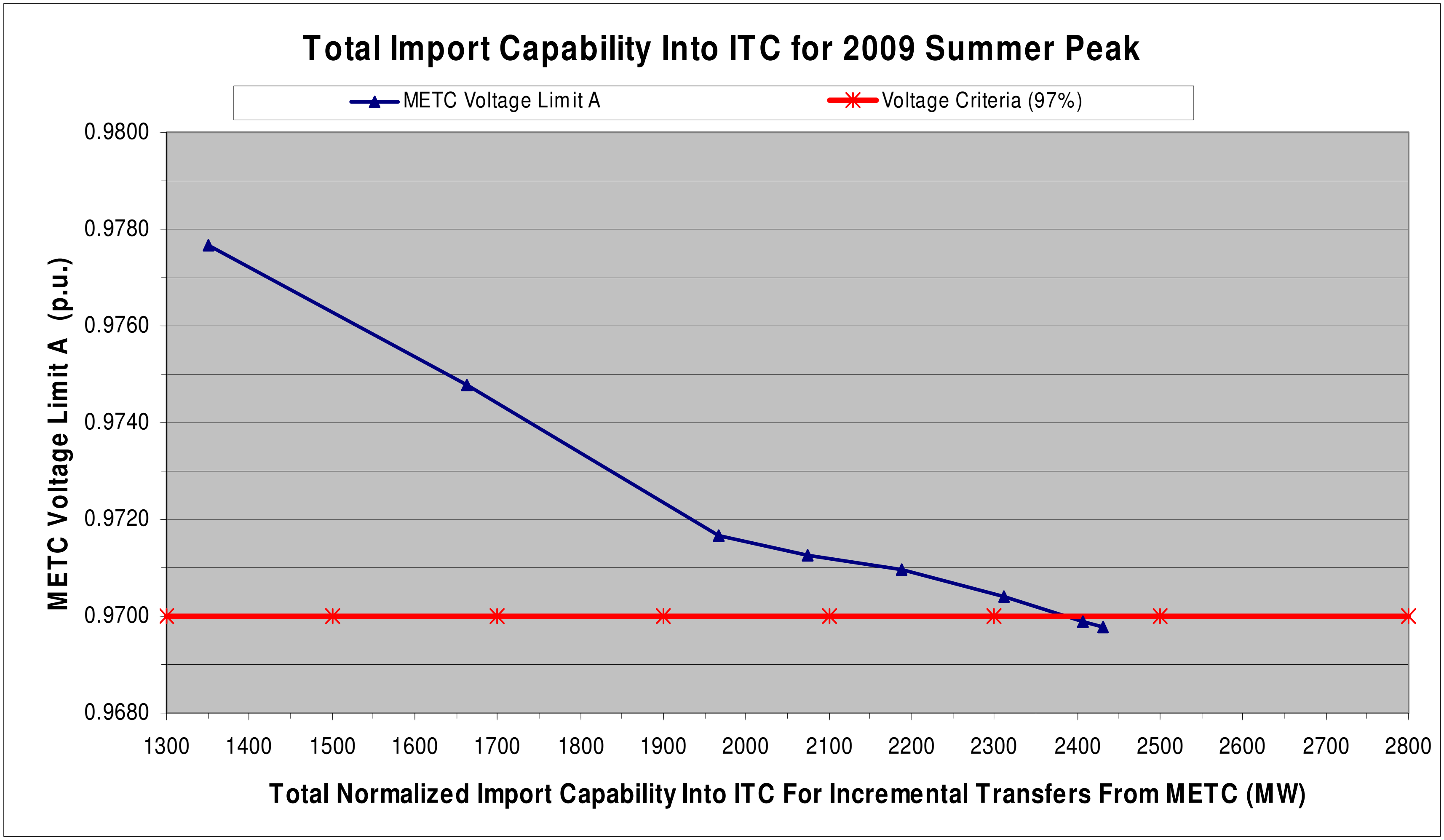
1) Values Shown are normalized to represent import capability if the other entity in MECS were importing 0 MWs.. Actual Base Case Imports ITC=-804, METC=2951 and MECS=2147.

2) Only first few limits are shown. Only most restrictive limits are shown for groups of limits that are highly correlated.

3) Contingencies considered included units dispatched off, units tripping off, single transmission and single transmission with units dispatched off.

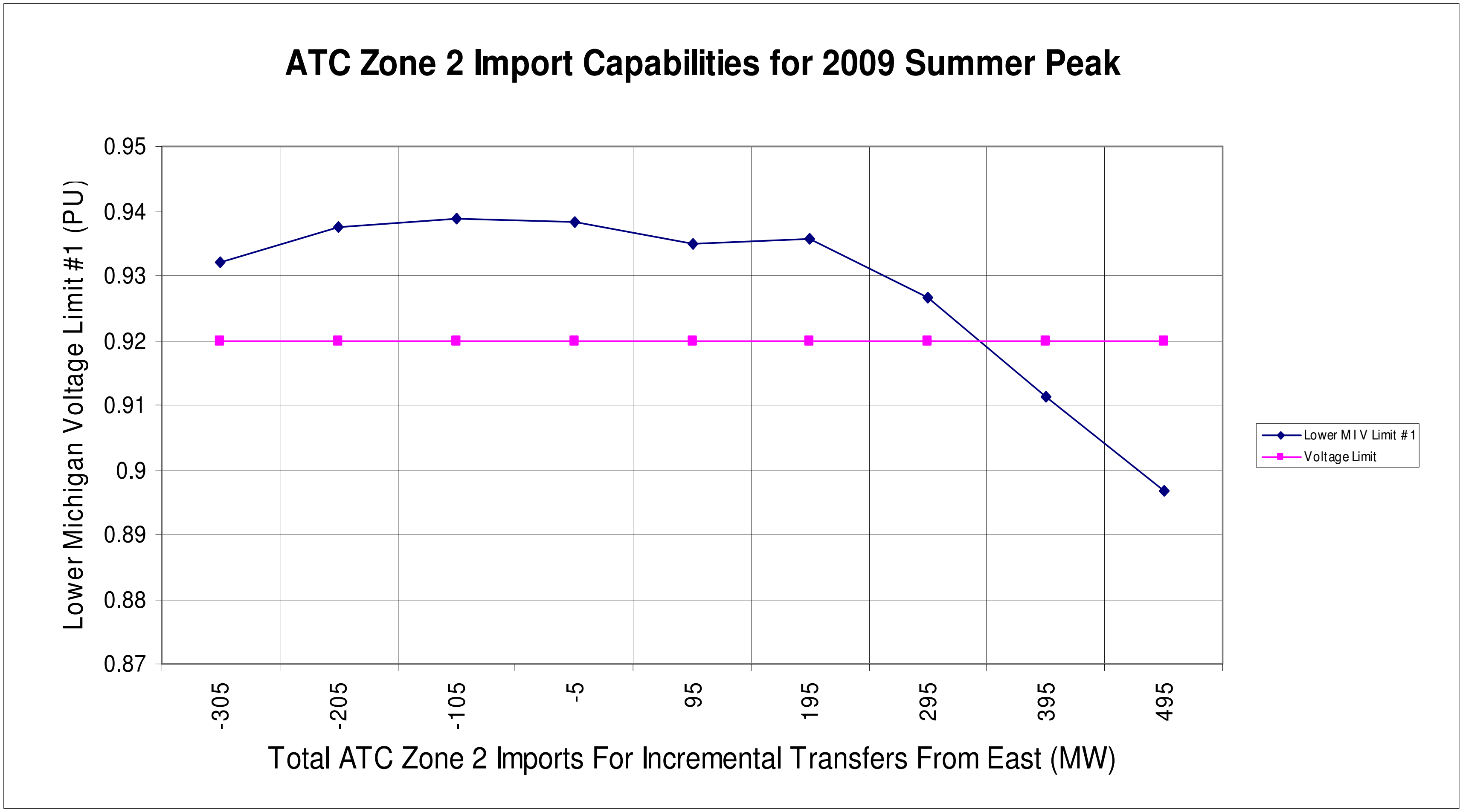
4) Base Case has 0 MWs flowing between Michigan and Ontario controlled by phase shifting transformers.

Chart 11



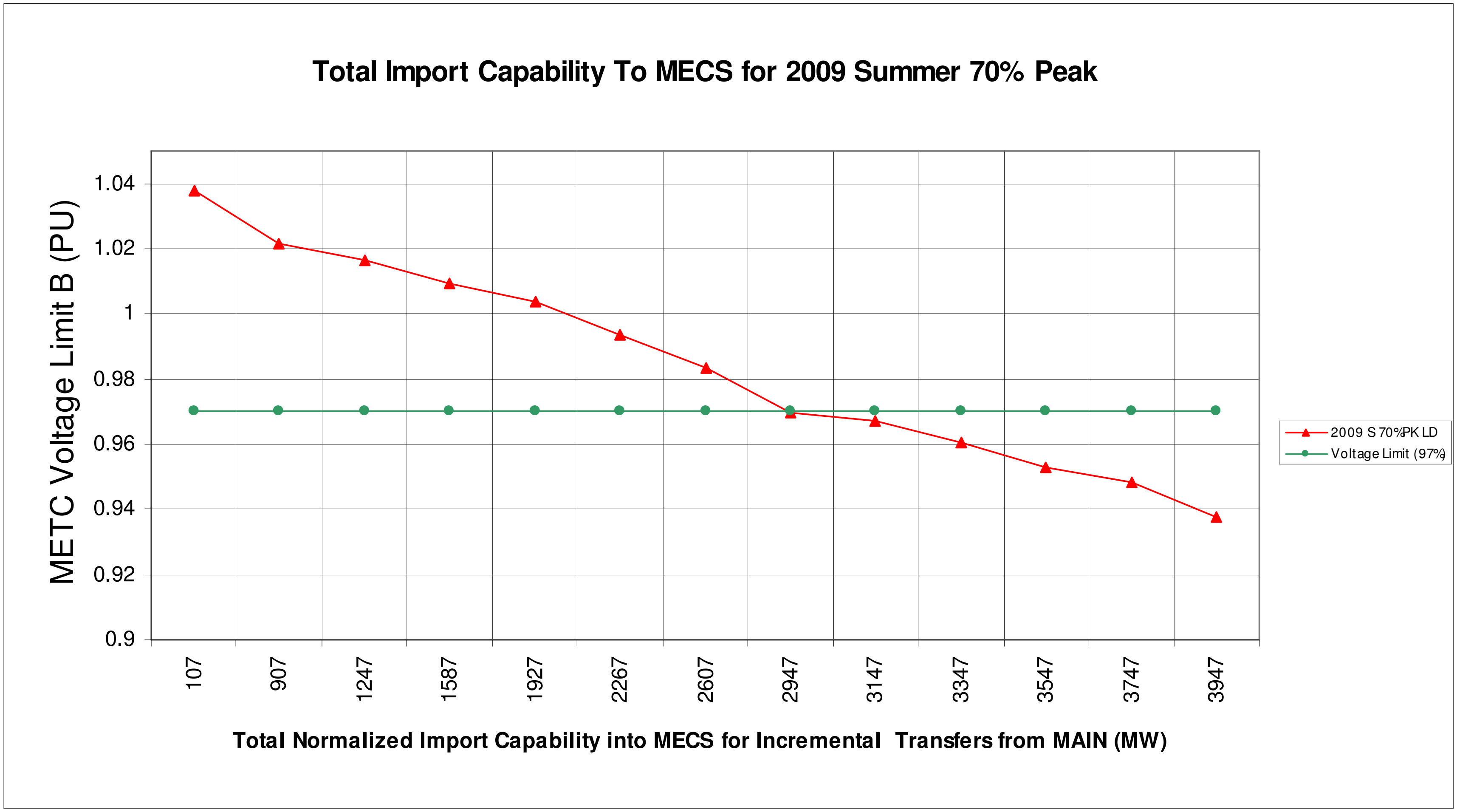
Total Import Capability Into ITC for 2009 Summer Peak
METC Voltage Limit A
Voltage Criteria (97%)
METC Voltage Limit A (p.u.)
0.9800
0.9780
0.9760
0.9740
0.9720
0.9700
0.9680
1300
1400
1500
1600
1700
1800
1900
2000
2100
2200
2300
2400
2500
2600
2700
2800
Total Normalized Import Capability Into ITC For Incremental Transfers From METC (MW)

Chart 12



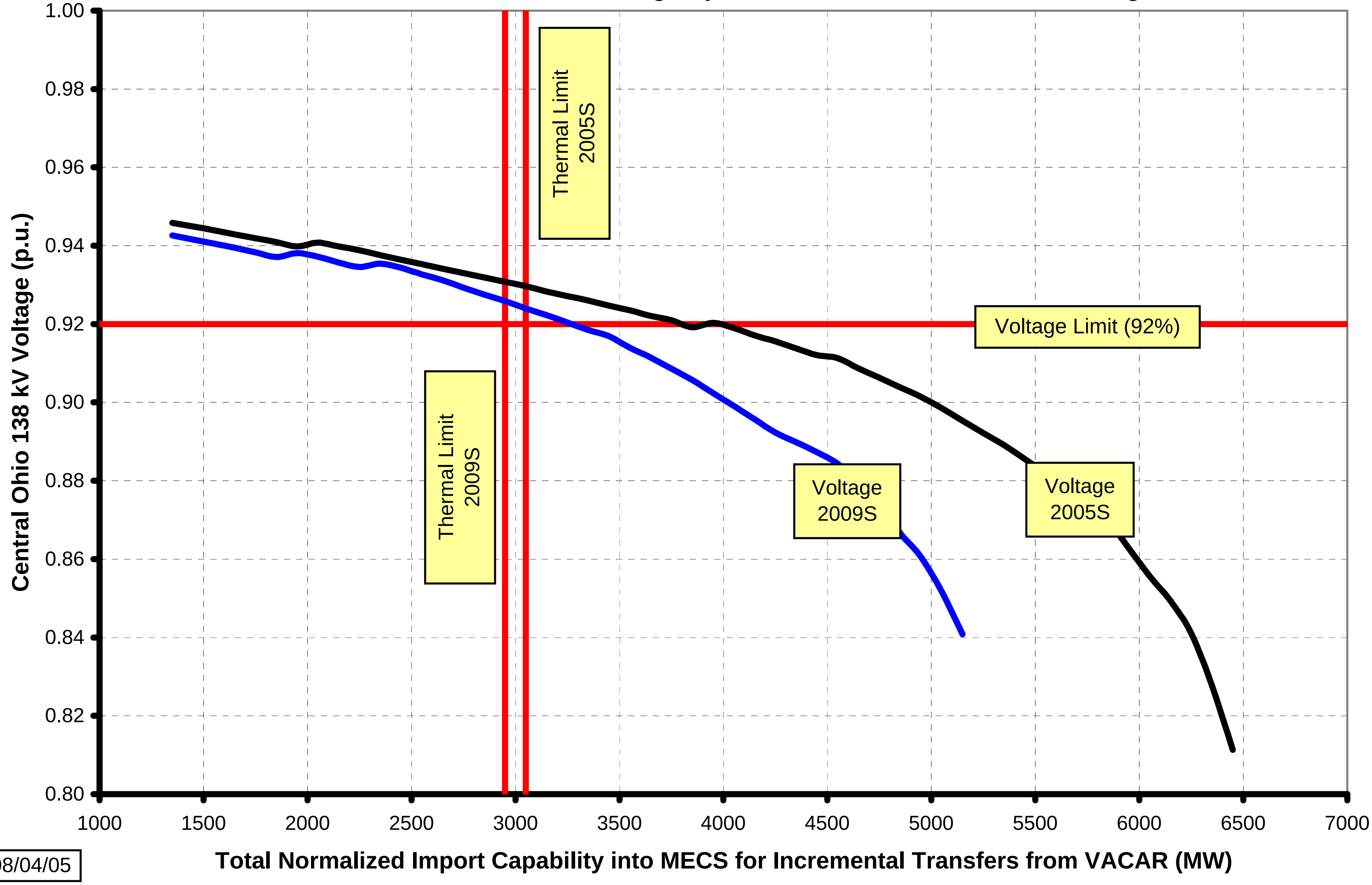
ATC Zone 2 Import Capabilities for 2009 Summer Peak
0.95
0.94
0.93
0.92
0.91
0.9
0.89
0.88
0.87
Lower Michigan Voltage Limit #1 (PU)
-305
-205
-105
-5
95
195
295
395
495
Total ATC Zone 2 Imports For Incremental Transfers From East (MW)
Lower M I V Limit # 1
Voltage Limit

Chart 13



Total Import Capability To MECS for 2009 Summer 70% Peak
METC Voltage Limit B (PU)
1.04
1.02
1
0.98
0.96
0.94
0.92
0.9
107
907
1247
1587
1927
2267
2607
2947
3147
3347
3547
3747
3947
Total Normalized Import Capability into MECS for Incremental Transfers from MAIN (MW)
2009 S 70%PK LD
Voltage Limit (97%)

Chart 14
Capacity Needs Forum 2009 Summer Assessment of Transmission System Performance
Central Ohio EHV Transformer Outaged plus Central Ohio Generation Outaged



08/04/05

Appendix H

Policy Recommendations and Replies to Staff Proposal from Interested Parties

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Michigan Capacity Need Forum:

Policy Recommendations
and Replies to Staff Proposal
from Interested Parties

September 2005

Copies of this report are available from the Michigan Public Service Commission's Web site, at: http://www.dleg.state.mi.us/mpsc/electric/capacity/cnf.

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.

Jennifer M. Granholm
GOVERNOR

STATE OF MICHIGAN
PUBLIC SERVICE COMMISSION
DEPARTMENT OF LABOR & ECONOMIC GROWTH
DAVID C. HOLLISTER
DIRECTOR

J. Peter Lark
CHAIRMAN

Laura Chappelle
COMMISSIONER

Monica Martinez
COMMISSIONER

October 10, 2005

During the August Capacity Need Forum meeting, George Stojic presented Staff's recommendations for changing the Commission's current resource addition policy (for reference, see Presentation 3 on CNF website (http://www.cis.state.mi.us/mpsc/electric/capacity/cnf/index.htm). Attached are the comments submitted by CNF participants, regarding Staff's recommendations.

Pat Poli

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STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion, to	**)**	
Commence an Investigation into Future Capacity	**)**	
Requirements.	**)**	**Case No. U-14231**
____	**)**	

Comments of the
Michigan Independent Power Producers Association
On the Commission Staff August 25, 2005 Proposal

September 16, 2005

I.
Introduction

The Michigan Independent Power Producers Association files these comments in response to the Commission Staff's proposal circulated on August 25, 2005 to participating parties in the Commission's Capacity Needs Forum ("CNF") established pursuant to the Commission's October 10, 2004 order in Case No. U-14231. MIPPA has been an active participant in the CNF because of the critically important nature of the issues the Commission is attempting to address through the Forum on MIPPA's members collective businesses, the Michigan electric generation industry, and the State as a whole.

II.
About MIPPA

The Michigan Independent Power Producers Association ("MIPPA") is a voluntary association with its principal place of business at 1845 S. Cedar Street, Suite 100, Mason MI 48842. MIPPA is comprised of independent energy companies whose business is producing electric power for sale. Currently all member facilities are powered by renewable resources. Power is produced primarily for sale to Consumers Energy Company ("Consumers") and Detroit Edison ("DECO") from hydroelectric, wood, landfill gas, and wind resources. Members include Qualifying Facilities ("QFs") operating under the provisions of the Public Utilities Regulatory Policies Act of 1978 ("PURPA"). MIPPA members that are QFs operate their facilities and supply electricity pursuant to contracts approved by this Commission under procedures established by the Commission to implement PURPA as required by Federal Energy Regulatory Commission ("FERC") rules.

MIPPA was formed to promote and support the common interests of its members, to protect the continuing viability of the facilities they own and operate, to promote the role of independent power producers in a deregulated Michigan generation market, and to enhance the viability of renewable energy in Michigan.

III.
General Comments

How the Commission and its Staff frame the issues to be resolved by the CNF will have a monumental impact on how the Michigan electric generation market evolves from this point forward. MIPPA is extremely supportive of the Commission's efforts to build consensus and find practical, workable options to what everyone agrees are complex, controversial issues. MIPPA's comments are from the perspective of existing, Michigan based, suppliers of generation powered primarily by renewable resources that seek the opportunity to expand their Michigan operations affording the State the economic benefits associated with the construction and operation of new generating facilities. In the last several years development opportunities for renewable based generation have been relatively scarce despite the existence of promising sites. Some members have shifted development activities to other states due to lack of opportunity in Michigan. MIPPA members consider their target markets to be Michigan utilities through Power Purchase Agreement ("PPAs"), wholesale generation markets for both capacity and energy, Alternate Electric Suppliers ("AES"), and end users of energy, capacity, and ancillary services. Having a sound market structure is a prerequisite for continuing development of new generation in this State whether by MIPPA or anyone else including the State's electric utilities. At present, all indications are -- based on MIPPA's assessment of the CNF's review to date—1) that there is an overwhelming need for new base load capacity and 2) that Michigan's current capacity expansion planning scheme, based on traditional utility regulation, no longer works. Nor does relying upon merchant plants to simply build new capacity on the chance that someone might buy it. Under existing conditions neither the State's utilities nor the non-utility/ merchant power industry are considered creditworthy by Wall Street. The clear message is that ownership form is not the root cause to be addressed. Rather it is establishment of a workable market structure that provides a reasonable level of risk relative to the potential reward (earnings) inherent in the generation investment refined to meet reliability and energy requirements. Such a structure has not been close to existing in Michigan since the last round of utility construction (1980's) was followed by the demise of PURPA (1990's). Both options were closed with the rise of deregulation. Since the passage of 2000 PA 141 certain trends have become evident. Utilities will not or cannot commit to new power purchases because they lack assurances that they will recover purchase costs. Nor can they build new generation for the same reasons. AES companies run the same risks without any guarantee of recovery other than the contractual commitments to purchase power of creditworthy customers for a period generally 3 years or less in length... Consequently AES power requirements are typically fully hedged with futures contracts matching the contractual commitments on a customer to customer basis. The need to match generation costs to revenue leads to a heavy reliance upon hedged short term wholesale purchases among AES firms During this same period, high gas prices and lack of markets have led to widespread merchant plant bankruptcies and an abrupt halt to new construction in the once booming merchant power business. In the meantime, Michigan's retail electric users continue to consume existing capital stock (generating plants) as load growth continues. The end result is that the time when the State will be perilously short of generation capacity is drawing closer. Based upon current CNF projections and the long lead times associated with constructing most new base load generation options this time may already be upon us.

Despite the above mentioned struggles of the existing Michigan market place, MIPPA supports a competitive market for Michigan's generation future and pleads with the Commission and participants in the CNF not to abandon the concept at the first sign that new generation needs to be added. There is more than enough demand for all competitors including the incumbent utilities to have a fair opportunity at supplying very significant amounts of generating capacity to the Michigan market over the next twenty years. Recommending how it can be best supplied is the task assigned to the CNF. It is not the responsibility of the CNF to attempt to change the existing regulatory model but to make it work. If the CNF is to fulfill the purpose expressed in the Commission's October 14, 2004 order it needs to put forth recommendations regarding how reasonable returns on new investments can be earned and how all parties will have a fair opportunity to compete for those returns.

IV.
Competition Best Meets the Needs of Ratepayers.

Ratepayers do come first, but it is almost universally accepted that a truly competitive market is the very best vehicle to meet ratepayer needs in the long run. The generation sector of the electric utility industry has been clearly shown since the passage of PURPA in 1978, to be fully capable of sustaining and thriving in a competitive environment. Michigan's capacity expansion policy simply must be allowed to foster competition among generation suppliers, if rate payers truly come first. If every retail customer had the opportunity and the obligation to pick a supplier and make a contractual commitment to that supplier or run the risk that service would either not be available or be forced to pay whatever current conditions will bear then the Michigan retail electric market would take care of itself. The Commission is likely not empowered to go this far in establishing a true market even if it is willing. Given that the Michigan generation market is a hybrid of competition and regulation, MIPPA recommends that the Commission consider taking steps to foster an independent entity capable of making such decisions for customers without any bias or vested interest. An entity similar to the New York Power Authority capable of issuing state backed financial instruments may be needed to provide the necessary risk mitigation and equal access to capital for all entities in need of generation to meet customer load. Establishing such an organization will undoubtedly require legislative action but may be a necessary step toward a workable generation market and a level playing field.

V.
Allocating Capacity Costs to AES Customers is Unfair Competition Unless AES' Have Equal Access to the Generation

Retail Open Access is not a program; it is a fundamental change in market structure mandated by State Law and has not been introduced at the benevolence of the local distribution utility. It is the obligation of the Commission to take necessary steps to insure that the transition to a competitive environment continues to take place. It is still necessary for this Commission to carefully balance market power concerns while creating a level playing field. Staff noted in its proposal that Detroit Edison has raised market power restrictions as a potential problem under the utility build option. Those concerns voice a very real problem with increased utility ownership with rate base treatment under the current regulatory scheme. The State is still in the process of a massive effort to help the State's utilities recoup the investment that in theory, at least would be unrecoverable or stranded in the State's competitive market when implemented. The prospect of charging future customers participating in "Customer Choice" for capacity built by the State's utilities to serve bundled customers could well be a death sentence for retail competition in Michigan.

Accordingly Staff's Proposal does not seem complete. As described in the paragraph titled "Background," the MPSC Policy for resource addition applies to jurisdictional utilities only. What it does not mention is that under the current regulatory scene, essentially NO capacity addition is financiable whether through a PPA or traditional construction and rate base treatment. Staff’s reliability option appears to fix the regulated utilities’ inability to obtain financing by forcing an obligation onto competitor’s customers. Quite likely it violates the requirements of 2000 PA 141. Clearly more attention needs to be given to the competitive impact of various options to add new generation.

VI
The Commission Should Expand Renewable Purchase and Energy Efficiency As Soon As Possible

MIPPA strongly supports recent efforts of this Commission and its Staff to revitalize and expand the use of Michigan's renewable resources to produce electricity for the benefit of the State's ratepayers. MIPPA believes that renewable energy resources are under-utilized in the State of Michigan. MIPPA has previously taken a position in Case No. U-13843 that unutilized renewable energy resources could support 300 to 600 megawatts of additional renewable electric generation facilities in the near term if effective policies and programs aimed at achieving this end are put in place. Results of the Alternate Generation Work Group of the CNF confirm potentially available capacity from such sources in this range and similar levels from cogeneration/CHP opportunities can be obtained.

Still, if all this capacity could be combined and brought on line as quick as it could be constructed it would probably not be possible to meet all the State’s projected demand growth requirements between now and when the first coal fired baseload unit could be brought on line. The other options available are to make power purchases relying upon out-of-state generation or build new gas fired units. Neither of these options is particularly attractive from the standpoint of ratepayer cost. Bringing all economically feasible renewable and cogeneration/CHP feasible capacity online as quickly as practical is clearly a sound move from a planning perspective given the growth currently forecast and options available to meet it. However, even these options require some lead time and the window of opportunity to take advantage of them will quickly slip away if not acted upon. Now is the time to get started. There will be many details to be worked out as a program is assembled and begins to function, but MIPPA is convinced the Commission has adequate authority to proceed if it chooses to do so.

The Michigan Public Service Commission was directed to establish the Michigan Renewables Energy Program by Public Act 141 of 2000. Subsection 10r(6) of Act 141 states:

> The commission shall establish the Michigan renewables energy program. The program shall be designed to inform customers in this state of the availability and value of using renewable energy generation and the potential of reduced pollution. The program shall also be designed to promote the use of existing renewable energy sources and encourage the development of new facilities. MCL 460.10r(6).

In short, this directive requires the Commission to promote the use of electricity generated using renewable resources and then cause that demand to be met by new and existing Michigan generating plants. Based on CNF findings to date there is ample justification to invoke this directive and move forward as rapidly as practiced.

MIPPA suggests that the CNF support opening solicitations for renewable facilities and onsite cogeneration/CHP opportunities as soon as practical until all legitimate candidates for development have been presented with contractual opportunities that can be used as the basis for obtaining construction financing. The focus of the contractual portion of the commission's policy should be establishing a fair and reasonable contract structure that can be used to obtain financing by the generation units that respond to solicitations when issued. In particular, for this program to be successful there must be an ultimate assurance that costs incurred by utilities for reasonable and prudent purchases of renewable energy are recoverable. Fortunately, there is already in place a legislative vehicle that would allow such a recovery to take place—1987 P.A. 81. The relatively small amounts of capacity available under this option will provide a year or two window of opportunity to address the broader recovery issues in time to get new generation on line by the time we need it early in the next decade. Given the lead times associated with virtually all other development options this is about the only realistic option MIPPA sees to add cost effective base load generation in the near term. Only energy efficiency offers a credible alternative. Given the projected need for capacity identified by the New Energy analysis it should be apparent the Commission will need all it can get from both renewable/CHP/cogeneration and energy efficiency sources.

The Staff proposal discusses competitive bidding and the establishment of a cost cap for the reliability option. MIPPA has raised concerns with the practical workability of competitive bidding as a means to procure capacity. In general the concerns revolve around the need to spend substantial sums in order to develop reliable costs for bidding purposes. Gamesmanship is a constant risk with competitive bidding where there is no truly serious downside to failing to honor the bid. A low bid that results in a cancelled project because it cannot be financed at the bid price leaves the bidder in no worse shape than if it had lost the bid in the first place. Nevertheless, for purposes of acquiring new renewable and CHP/cogeneration capacity some sort of bidding /solicitation with a preset cost cap based on the findings of the CNF would probably function reasonably well. Bidders would be able to approach financial institutions with reasonable expectations for revenue streams of successful projects based on the cap. The Commission could set a level of recovery that could be considered pre-approved again based on the cost cap.

VII.

There will be a Need for Some Sort of Renewable Portfolio Standard or Other Commitment to Fully Utilize Available Renewable and CHP Resources

It is obvious from work done to date by the various CNF work groups that Michigan faces a very difficult task to obtain sufficient generation resources to meet customer requirements over the next twenty years and to maintain the accustomed and mandated level of system reliability the state has enjoyed and depended upon for decades. As stated earlier, MIPPA members support continuing efforts to utilize the State's renewable energy resources. The definition of renewable energy from sources to be disclosed to customers by eligible power suppliers should encompass the full range of full technologies which 1) are capable of improving Michigan's environment; 2) are currently produced from locally available renewable resources; and 3) help conserve scare fossil fuels. These technologies include electric power generated from organic waste, biomass, municipal solid waste, waste wood, tires, landfill gas, solar, wind, hydro at existing dam sites photovoltaic and any other qualifying renewable energy resource as well as cogeneration/CHP applications that meet minimum efficiency standards. Only a few technologies are likely to provide significant capacity but all should be given an opportunity including emerging technologies whose potential may not be fully known or understood at this time.

In order to implement the plan outlined above a Renewable Portfolio Standard or other similar purchase obligation with associated recovery guarantees would likely be needed. Such a renewable energy portfolio standard target should be developed for each utility based on the need to actively support the renewable energy projects in the long term to meet and bring potential projects online as quickly as possible. MIPPA recommends the following determination for the purpose of establishing such a standard:

> Set the base standard equal to the total amount of electricity generated from renewable energy resources for the year 2004 (estimated at 3 to 4%) for each utility divided by the amount of electricity sold in Michigan for the year 2004—84,564,628 MWh. The required amount of electricity generated from renewable energy resources shall be escalated annually by 1% of the amount of total energy sold in the state each year and allocated on a pro-rata percent of sales basis. New purchases should continue to be made through 2011 and then reassessed based on experience regarding future purchase levels.

This calculation will provide a realistic and achievable renewable portfolio minimum and will work to support the continued efforts of the CNF and the Commission to achieve the target reserve margin of 15 % deemed prudent by the CNF to maintain an adequate level of reliability until more Traditional resources can be added. When implemented, such a requirement should result in purchases of approximately 100 MW per year of new renewable and cogeneration/CHP generation. based on 2004 data.

VIII.
Generation is not a Public Good but it can be Made One

Reliability is a "Public Good" only if the traditional utility model of generation service is followed with respect to generation capacity. MIPPA does not agree that <u>has to be</u> treated as a "Public Good" or necessarily <u>should be</u> treated as a "Public Good". Adopting a narrow viewpoint on this critical issue runs the risk of forcing Michigan back into a utility monopoly structure and all the inherent inefficiencies that led to the passage of 200 PA 141 in the first place. It would waste the years of regulatory and legislative effort spent to create a competitive Michigan Market in addition to the billions of dollars Michigan utilities have already been allowed to recover through stranded costs and securitization.

IX.
The Commission Must Reconcile Its Reliability Role Relative to MISO

Perhaps the most vexing question facing the Commission and its Staff through the CNF is what is the proper role of the Commission and jurisdictional regulated utilities within the Federal scheme for reliability administered by the FERC and delegated to the Midwest Independent System Operator?

The Reliability Option proposed by staff is a continuation of traditional state monopoly utility regulation and simply does not fit within the Federal model entrusted to MISO for implementation within this region. It would be far better for the CNF, and ultimately the Commission, to focus its efforts to plan for the state's generating capacity needs within the Parameters established by MISO even if it must take on the task of helping create those parameters.

X.

Summary

In closing, MIPPA would like to thank the MPSC, specifically those taking the initiative to advance the tough questions facing Michigan's electric energy future. We look forward to working cooperatively with all the stakeholders to create effective solutions for success which are supportive of the State's economic and social success. In so doing, MIPPA hopes to provide its portion of the generating capacity which will fulfill the overall needs of the State.

Respectfully submitted,

THE MICHIGAN INDEPENDENT POWER PRODUCERS ASSOCIATION

Donald W. Johns
Director
September 16, 2005

New Covert's response, pages 17 - 24

COMMENTS OF NEW COVERT GENERATING COMPANY, LLC

MICHIGAN PUBLIC SERVICE COMMISSION

RESOURCE ADDITION POLICY

CAPACITY NEEDS FORUM

SEPTEMBER 16, 2005

New Covert Generating Company, LLC ("New Covert") appreciates this opportunity to comment on the August 25, 2005 proposal by the staff of the Michigan Public Service Commission ("MPSC") regarding Michigan's future resource addition policy ("Staff Proposal") and issues raised in the Capacity Needs Forum. This forum raises very important issues concerning how to provide for Michigan's future capacity needs. New Covert urges the staff to balance many competing factors so as to avoid anticompetitive and economically wasteful results and unintended consequences that could impair reliability.

The Staff Proposal encourages the establishment of a process whereby plant construction could be pre-approved by the MPSC and revenue stability would be ensured through a surcharge to ratepayers for the reliability component of a generating facility. The Staff Proposal is based on three broad principles or values:

(1) The ratepayers come first;
(2) Electric reliability is a public good;
(3) We need to adhere to a fairness doctrine (you get what you pay for).[1]

New Covert owns a 1,170 MW natural gas-fired, combined-cycle generating facility in Covert Township, Van Buren County, within the Michigan Electric Coordinated System ("MECS"). The facility commenced operations in early 2004. The facility's energy and

[1] Email from George R. Stojic dated September 2, 2005, entitled "Capacity Needs Forum Comments on Reliability Options."

capacity are sold primarily to Michigan's jurisdictional utilities. New Covert is an environmentally clean and efficient source of electricity, with low levels of emissions and the lowest (most efficient) heat rate in the State of Michigan. As a result, New Covert makes significant economic, environmental and reliability contributions to Michigan's jurisdictional utilities and ratepayers.

Although New Covert understands that the MPSC regulates only jurisdictional utilities, New Covert is concerned that the Staff Proposal is not balanced in that it does not take into consideration the role of competitive power suppliers in Michigan's electric markets. Although competitive suppliers are not directly regulated by the MPSC, the proposal has significant implications for future competitive investments and existing competitive suppliers. Rules incorporating a command-and-control, regulated rate of return model, where regulated utilities may function as monopolists in the generation sector, would represent a giant step backwards, would create a significant disincentive to competitive suppliers, and may strand existing investments, resulting in a loss of needed capacity.

Comments on the Staff Proposal

New Covert wishes to draw the MPSC's attention to four specific concerns regarding the Staff Proposal.

A. Existing Needed Energy Resources Must Not Be Stranded

The Staff Proposal presents a model of plant pre-approval and revenue stability which extends a strong preference to utility-owned generation,[2] to the detriment of competitive

[2] New Covert focuses here on policy issues and reserves its rights with respect to legal issues, including whether new legislation would be required to effect the model in the Staff Proposal.

generators. Rules adopted by the MPSC should not strand existing energy resources in an economically inefficient, anti-competitive or environmentally unsound manner.

For example, New Covert has been under-utilized and has run at under a 10% capacity factor since it achieved commercial operations in early 2004. If the Michigan electric energy market were efficient, then, theoretically, lower marginal cost resources were available at times when New Covert sat ready and idle. If new authorizations provide economic incentives to construct new base load capacity with lower marginal running costs, then New Covert may be idle more. Yet, this result may be economically inefficient. The all-in costs customers must pay to support the new vertically-integrated, rate-based investment would exceed the cost of capacity and energy from New Covert to the detriment of rate payers and New Covert. Staff may justify this result on the basis that new capacity is needed and achieved through the regulated utility investments. The consequences of such a policy, however, may have the opposite result. If new, no-risk, regulated generation investments displace energy sales from competitive generators, then their already-inadequate revenue streams will be further reduced. Such reductions in revenues may force this capacity out of the Michigan market through retirements, mothballing or relocation of turbines. These capacity and energy losses have: (a) economic ramifications as Michigan is pressed to make up this loss of capacity; (b) environmental ramifications as environmentally dirtier resources may be required more; and (c) supply adequacy ramifications if the capacity losses would result in shortages.

Moreover, if utilities are allowed to recover the costs of new generation investments, including a rate of return, through a reliability surcharge while merchant generators must recover the fixed and variable costs of their facilities through competitive rates, the reliability surcharge could pose a potentially anti-competitive subsidy to jurisdictional utilities and would discriminate against parties that invested in Michigan's market. Energy market revenues to independent power producers are limited: for example, gas turbines with marginal costs frequently above locational marginal prices ("LMP") may not be dispatched. Further, during those times when energy prices would be high, reflecting scarcity, prices available in the market reflect mitigation, thereby reducing the revenue stream available to generators that depend on these high-load periods to recover a substantial majority of their costs. Additionally, regular, substantial reliance by the Midwest Independent System Operator ("MISO") on out-of-merit generation causes artificial movement down the bid stack and results in lower market clearing prices. Unlike the utilities under the Staff Proposal, competitive generators would not receive payments covering their fixed costs and return on equity. They depend on these administratively limited market revenues. As noted, if merchant generators do not receive sufficient market revenues, plants may be mothballed, permanently retired or relocated to a more favorable market. The result – less available capacity – would be unfavorable to Michigan's ratepayers and reliability.

B. Legitimate Investment Expectations Must Be Honored

When investing in competitive generating facilities, such as New Covert, investors expect a reasonable opportunity to cover their fixed costs and earn a return on their investment. The MPSC should not upset the legitimate investment expectations of new entrants by essentially stranding such facilities, as discussed above. The three principles set forth by Staff do not take into account fairness or balance to investors in Michigan's electric markets, including existing competitive suppliers like New Covert. This element is critical to encouraging and retaining investment by entities unaffiliated with jurisdictional utilities in Michigan's electric markets.

As sure as utilities with regulated rates want a fair opportunity to earn a reasonable rate of return, unregulated generators want an opportunity to earn a competitive rate of return. In either case, investors are entitled to this opportunity. In Michigan, the decision was made to proceed with competitive markets to provide this opportunity, but administrative intrusion in those markets has limited it. Well-settled law, however, dictates that utility regulators may not act solely in the interests of customers. Instead, they have a constitutional duty to balance the interests of ratepayers and their service providers.[3] The Staff Proposal and principles must not overlook those who made competitive investments based on the promise of competitive markets.

C. Capacity Solicitations Must Include Merchant Generators

The Staff Proposal advocates the establishment of a bidding process for solicitations undertaken by jurisdictional utilities to obtain needed energy or capacity.[4] Any rules adopted by the MPSC must allow existing independent power producers with uncommitted capacity to participate in the capacity solicitation process.[5]

Some parties in the Capacity Needs Forum have suggested a return to a regulated rate base option which would effectively preclude or impair merchant generating facilities from participating in the competitive bidding process. The playing field is not level between two entities where one has a guarantee of cost recovery and the other is subject to market forces. Merchant generators that are not committed to load must be given the opportunity to compete. If Michigan were to change its legal-regulatory regime to allow regulated, integrated utilities to

3 See FPC v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944) ("The rate-making process under the [Federal Power] Act, i.e., the fixing of 'just and reasonable' rates, involves a balancing of the investor and the consumer interests.")

4 "Create fair and transparent bidding process with performance standards and proper risk allocation." Presentation to Michigan Electric Capacity Need Forum at 8 (Aug. 25, 2005).

5 If the energy market does not permit independent power producers to recover adequate revenue, then in addition to the potential to mothball, permanently retire or relocate gas turbines, they may seek to sell capacity and energy out-of-state, raising economic and supply adequacy issues in Michigan.

develop new resources in the state, then it is crucial to have a clear and transparent process. Such a process must hold utilities responsible for cost overruns and provide for one set of rules applicable to all competitors. Before Michigan considers embarking on such a radical change in legislation and regulation, it is essential to ensure that all sources of supply are treated in a fair and non-discriminatory or preferential manner. Michigan also should review closely the extensive efforts of other markets to solve for resource adequacy.

D. Developed Capacity Market Designs Provide A Valuable Model

Before embarking on a substantially different course that could impair competition, rather than facilitate it, New Covert urges Staff to review how neighboring independent system operators and regional transmission organizations ("ISO/RTO") are solving for resource adequacy. The three adjacent ISO/RTOs, the PJM Interconnection, Inc. ("PJM"), New York Independent System Operator, Inc. ("NYISO") and ISO New England, Inc. ("ISO-NE"), have designed capacity markets with forward demand curves and auctions to establish capacity prices. These three ISO/RTOs, comprising very substantial markets to the east of Michigan, have already devoted substantial work efforts to the best means to both ensure that necessary energy and capacity resources remain available, and to stimulate new investment when and where it is needed.

The solutions reached by the three ISO/RTOs are surprisingly similar. For example, the Federal Energy Regulatory Commission ("FERC") approved NYISO's proposal to establish an Installed Capacity Demand Curve in the Installed Capacity ("ICAP") markets in the Spring of 2003 in Docket No. ER03-647. FERC noted that the use of such demand curves will send "better price signals to investors for the construction of new generation, encourage the formation of long-term bilateral transactions and reduce incentives to withhold capacity."[6] ISO-NE is currently litigating its proposed locational installed capacity ("LICAP") mechanism before FERC in Docket No. ER03-563. It also includes a demand curve and capacity auction, so that entities providing capacity in particularly congested areas would be adequately compensated for reliability.[7]

These ISO/RTOs have recognized that administrative limitations on energy market revenues in the form of price caps and mitigation must be balanced with opportunities to augment revenues – such as through capacity markets – so that generators can sustain themselves as viable resources. These structures send transparent, competitive price signals to all investors and avoid bias in favor of regulated utility investment over unregulated competitive investment. They are symmetrical in that at times of relative scarcity, they do not allow capacity prices to spike from market power and at times of modest surplus, they prevent prices from plummeting. In the long-term, they are designed to smooth volatile boom-bust cycles. Locational capacity markets with demand curves work in tandem with competitive forces so ratepayers are not left holding the bag on non-competitive generation investments. Michigan should at least consider the PJM, NYISO and ISO-NE models to solve for future capacity requirements through competitive processes. Further, although the MISO markets are new and do not yet include functioning capacity markets, expanding common or similar capacity products to markets including AEP and Exelon may increase liquidity and competition for the benefit of Michigan's consumers.

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6 See New York Independent System Operator, Inc., 103 FERC ¶ 61,201 at P. 1 (2003).

7 See Devon Power, LLC, 111 FERC ¶ 63,063 (2005) (Initial Decision of Presiding Administrative Law Judge regarding parameters of the proposed demand curve, capacity transfer limits, capacity transfer rights and market power mitigation), 112 FERC ¶ 61,179 (2005) (order granting oral argument on issues related to the initial decision and delaying LICAP implementation to October 1, 2006).

Conclusion

Michigan embarked on a path of deregulation which allowed market forces to shape its energy markets. If Michigan now adopts a capacity policy that will harm existing investors and discourage further investment by entities unaffiliated with jurisdictional utilities, it is taking a step backward where only monopolists may prosper and customers may bear costs undisciplined by competitive pressures.

Whatever long-term capacity adequacy process Michigan considers, parties independent of regulated utilities that invested capital based on Michigan's competitive paradigm must be allowed to compete fairly in meeting Michigan's capacity needs. It would be manifestly unfair and unlawful to allow utilities to recover all of the fixed and variable costs of new generation while existing merchant generation becomes stranded. In a properly structured competitive solicitation process, merchant generators would be permitted to obtain a competitive price for their capacity and energy. Finally, in considering new resource adequacy models, Michigan should review the capacity market designs implemented or being developed by the three eastern ISOs/RTOs. New Covert looks forward to participating constructively in satisfying Michigan's capacity needs.

Respectfully submitted,

James D. Neidhart, Chief Executive Officer
New Covert Generating Company, LLC

ACEEE's response, pages 26 - 38

COMMENTS TO THE MICHIGAN CAPACITY NEEDS FORUM
(second set)

By

Martin Kushler, Ph.D.
Director, Utilities Program
American Council for an Energy Efficient Economy
1751 Brookshire Court
Williamston, Michigan 48895
(517) 655-7037
September 30, 2005

PLEASE NOTE: I am submitting comments in two parts. First, I am re-submitting my comments from August 1, 2005 because they explain key background factors underlying my new comments, and because I would like them to be a part of the record of comments to staff's current proposal. [Those earlier comments are attached as "Appendix A" at the end of this document.]

Second, I am submitting new comments in the form of "track changes" wording changes and comment insertions applied to the staff's proposal document. Those comments follow, beginning on the next page. [Comments are in CAPS, suggested wording changes are in lower case.]

Thank-you very much for the opportunity to file comments in this Capacity Needs Forum process.

Sincerely,

Martin Kushler, Ph.D.
ACEEE
(517) 655-7037

COMMENTS FROM MARTIN KUSHLER ON THE STAFF PROPOSAL (09/30/05)

Background

In order U-14238, the Commission asked for policy recommendations regarding its resource addition policy. This policy relates to jurisdictional utilities alone. The Commission does not approve, disapprove, or control plant construction by non-jurisdictional entities but does have jurisdiction over rate recovery of generating plant from customers of regulated utilities. The Commission has requested policy recommendations on this rate recovery method. Some participants have indicated that fundamental changes are needed to the Michigan market, including legislative changes. We have encouraged participants to make recommendations within the Commission's existing jurisdiction and rate recovery methods, and we intend to do that throughout the Forum's proceedings.

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IN MY ORIGINAL COMMENTS ON AUGUST 1, 2005, I INCLUDED THE FOLLOWING:

<<< I would like to strongly emphasize the need for staff to pose two additional questions:

- ***Assuming that energy efficiency and other related demand side programs have the potential to cost-effectively reduce the amount of additional generation needed, will the Commission's current policy induce the necessary implementation?***
- ***If not, what changes need to be made to the Commission's current policy?***

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I would submit that the answer to the first of these additional questions is "no", and that the prima facia evidence for that answer is that ever since the Commission allowed the utilities to terminate their energy efficiency programs in 1995, there has not been a single incidence of a Michigan electric utility requesting Commission approval, or even self-initiating, an energy efficiency resource program.
>>>

I WOULD LIKE TO CLARIFY THAT WHILE I BELIEVE THAT THE COMMISSION'S CURRENT POLICY WILL NOT RESULT IN UTILITY IMPLEMENTATION OF ENERGY EFFICIENCY PROGRAMS, I **DO** BELIEVE THAT THE COMMISSION **COULD** IMPLEMENT POLICIES THAT WOULD RESULT IN UTILITY IMPLEMENTATION OF ENERGY EFFICIENCY PROGRAMS, UNDER THE "COMMISSION'S EXISTING JURISDICTION". NEW LEGISLATION IS NOT REQUIRED. THE COMMISSION POSSESSES THE TOOLS AND AUTHORITY WHICH, IF PROPERLY EXERCISED, COULD RESULT IN SIGNIFICANT UTILITY ENERGY EFFICIENCY PROGRAMS. I URGE THE COMMISSION TO CREATIVELY EXERCISE THE TOOLS AND AUTHORITY IT DOES POSSESS, TO ADDRESS THE CRUCIAL ENERGY CHALLENGES WE FACE.

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Participants in the Capacity Need Forum have identified several aspects of the Commission's policies that they either affirm or argue need to be changed. These issues are:

Pre-approval of plant construction
Revenue certainty for recovering investment costs
Competitive bidding
CWIP in rate base without an AFUDC offset
Energy Efficiency
Market Power

In the July Capacity Need Forum meeting, Staff requested comments on the issues listed above. The comments generally reinforced earlier positions taken by various parties.

During the July meeting, Staff also discussed its belief that electric reliability is a public good. With characteristics of a classical economic public good, Staff noted that electric reliability is not likely to be provided by a competitive market alone. In fact, regional transmission organizations and states take an active role in promoting electric reliability, including those jurisdictions that rely on markets to provide electric generation services. Governmental intervention into the electric energy markets, where these markets exist, is widely practiced and accepted. Most recently, Congress has intervened to assure the reliability of the bulk power system by mandating the adoption of electric reliability standards in the Energy Policy Act of 2005. This critical public interest in electric reliability has served as a guiding principle in Staff's assessment of the comments received to date. In order to bridge the gulf between parties regarding the Commission's current policy, Staff offers the following suggestions for consideration by participants.

Reliability Option

SOME SUGGESTED WORDING CHANGES INSERTED BELOW.

If it chooses to do so, a utility can choose to acquire a new electricity resource in the traditional manner, that is it could finance the resource without public involvement and then request rate base recovery after the resource is completed. However, the utility could instead seek to acquire electricity resources under the reliability option discussed herein.

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Under the reliability option, the utility would file an application with the Commission containing the following: (1) details of its proposed electricity resource, including expected cost and anticipated in-service date; (2) an analysis of why the proposed resource or package of resources is the appropriate resource to meet the expected need and an analysis of the public benefits associated with the proposed approach; (3) if desired, a request for placement of the electric resource'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

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retail distribution service from the utility. The level and timing of the reliability charge would be designed to be commensurate with the public benefits associated with the electric resources proposed..

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A contested case public hearing would be held on the utility's application. If the Commission determined that the electric resource's expected reliability value warranted it, the Commission would 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 electric resource and an in-service date.

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In exchange for paying a reliability charge, all customers would be credited with their pro-rata share of the electric resource's reliability value in 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 electric resource.

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Competitive Bidding

Major plant construction involves large capital costs and financial risks. It is crucial for Michigan to secure the right type of power (base load, 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. That alternative might be a proposal by another entity to build the same plant at a lower cost. Therefore, any cost cap proposed by a utility in a reliability option hearing should be given considerable deference if the utility has undertaken a fair and open competitive bid.

Energy Efficiency

None of the parties submitting comments have opposed energy efficiency, and we consider energy efficiency to be an eligible resource option. We expect that any utility's proposal for acquiring electric resources would include a demonstration that a proposed electric resource, or package of electric resources, is the appropriate resource to meet an identified need, and would include an analysis of cost effective energy efficiency as a resource option.

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THE PROPOSED LANGUAGE ABOVE IS A GOOD START. HOWEVER, THE LANGUAGE IS TOO GENERAL TO HAVE ANY EFFECT ON THE HISTORICAL REFUSAL OF MICHIGAN'S UTILITIES TO VOLUNTARILY IMPLEMENT ENERGY EFFICIENCY ELECTRICITY RESOURCES. IN ORDER TO OVERCOME THAT DEMONSTRATED HISTORICAL FAILURE, SPECIFIC REGULATORY ADJUSTMENTS ARE GOING TO BE NECESSARY. FOR EXAMPLE, STAFF SHOULD PROPOSE THAT THE COMMISSION GIVE SERIOUS CONSIDERATION TO ADOPTING A REVENUE DECOUPLING MECHANISM, WHEREBY ENERGY EFFICIENCY PROGRAMS THAT REDUCE ELECTRICITY SALES WOULD NOT

ADVERSELY AFFECT THE UTILITY'S ABILITY TO RECOVER ITS AUTHORIZED FIXED COSTS. REMOVAL OF THAT EXISTING DISINCENTIVE TO PURSUING ENERGY EFFICIENCY SHOULD HELP UTILITIES BE ABLE TO MORE FAIRLY ASSESS THE POTENTIAL FOR ENERGY EFFICIENCY AS AN ELECTRIC SYSTEM RESOURCE. THIS TYPE OF REVENUE DECOUPLING HAS BEEN SUCCESSFULLY ADOPTED IN TWO STATES, IS UNDER ACTIVE CONSIDERATION IN SEVERAL MORE, AND PROVIDES A VALID AND PRACTICAL MECHANISM FOR OVERCOMING UTILITY RELUCTANCE TO IMPLEMENT ENERGY EFFICIENCY PROGRAMS. IN ADDITION, THERE IS PRECEDENT AND DEMONSTRATED SUCCESS IN MICHIGAN, AND IN MANY OTHER STATES, FOR THE USE OF SPECIFIC UTILITY SHAREHOLDER INCENTIVE MECHANISMS FOR DOCUMENTED GOOD PERFORMANCE BY A UTILITY IN IMPLEMENTING ENERGY EFFICIENCY PROGRAMS. SUCH MECHANISMS SHOULD ONCE AGAIN BE EMPLOYED IN MICHIGAN.

I WOULD LIKE TO CLOSE WITH THREE BOTTOM LINE CONCLUSIONS:

1) THE ABILITY OF ENERGY EFFICIENCY PROGRAMS TO SAVE ELECTRICITY AT A COST WELL BELOW THAT OF ACQUIRING NEW SUPPLY-SIDE ELECTRICITY (E.G., 3 CENTS PER KWH OR LESS VS. PERHAPS 6 CENTS PER KWH) IS WELL DOCUMENTED. MANY STATES ARE SUCCESSFULLY CAPTURING ENERGY EFFICIENCY RESOURCES FOR THEIR ELECTRIC SYSTEM, THEREBY SECURING HUNDREDS OF MILLIONS, AND IN SOME CASES BILLIONS, OF DOLLARS OF ECONOMIC BENEFITS FOR THEIR STATES.

2) MICHIGAN HAS HAD NO SUCH UTILITY ELECTRIC ENERGY EFFICIENCY PROGRAMS FOR 10 YEARS, AND ABSENT CONSTRUCTIVE ACTION BY THE MPSC, THERE IS NO REASON TO BELIEVE THAT MICHIGAN'S UTILITIES WILL INCLUDE ENERGY EFFICIENCY PROGRAMS AS A PART OF THEIR STRATEGY TO ENSURE ELECTRIC RELIABILITY IN MICHIGAN.

3) THERE ARE A NUMBER OF STEPS THAT THE MPSC COULD TAKE, WITHIN EXISTING STATUTES AND CASE HISTORY AUTHORITY, TO HELP ENCOURAGE UTILITIES TO SERIOUSLY IMPLEMENT ENERGY EFFICIENCY PROGRAMS.

I URGE THE COMMISSION TO EXAMINE THIS ISSUE AND MOVE AGGRESSIVELY TO IMPLEMENT ACTIONS WHICH WILL HELP PRODUCE SUCCESSFUL UTILITY ENERGY EFFICIENCY PROGRAMS, THEREBY ENHANCING ELECTRIC SYSTEM RELIABILITY IN MICHIGAN WHILE SIMULTANEOUSLY PROVIDING CUSTOMERS WITH CRUCIAL RESOURCES TO HELP THEM REDUCE THEIR ENERGY BILLS.

Construction Partnerships

As method to mitigate the risk of construction, Staff expects that utility proposal made under the reliability option would include an offer to other Michigan load serving entities to become partners in the plant.

Market Power

Detroit Edison has articulated a concern that any new proposal to construct plant may cause it to violate market power provisions of 2000 PA 141. Other parties have indicated 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.

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 a more broad based participation in a construction project should decrease the concentration of ownership and allow parties to secure long-term power at stable prices.

IT IS ALSO WORTH NOTING THAT PROVIDING ENERGY EFFICIENCY PROGRAMS IS ANOTHER IMPORTANT WAY TO HELP CUSTOMERS HAVE MORE MARKET "POWER" IN THEIR RELATIONSHIP TO ELECTRICITY PROVIDERS, BY ASSISTING CUSTOMERS TO BE ABLE TO EFFICIENTLY REDUCE THEIR ELECTRICITY PURCHASES REGARDLESS OF WHO SUPPLIES THEIR ELECTRICITY.

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APPENDIX A

COMMENTS TO THE MICHIGAN CAPACITY NEEDS FORUM

By

Martin Kushler, Ph.D.
Director, Utilities Program
American Council for an Energy Efficient Economy
1751 Brookshire Court
Williamston, Michigan 48895
(517) 655-7037
August 1, 2005

Let me say at the outset that I appreciate the opportunity to offer comments in this very important forum, and that I am very pleased that staff is conducting this process to address the crucial issue of future electric capacity needs in Michigan. Let me also say that I applaud the key principles espoused by Staff that "the ratepayer comes first" and that "electric reliability is a public good". My comments and recommendations will be very consistent with those principles.

The remainder of this document will be organized around two fundamental points:

- Any assessment of future electric capacity needs in Michigan needs to consider both supply side and demand side resources; and
- In order for demand side resources such as energy efficiency to play a role in Michigan, additional regulatory policies and mechanisms are going to be required.

1) Any assessment of future electric capacity needs in Michigan needs to consider both supply side and demand side resources.

It is a truism that assuring electric system reliability is a matter of balancing electricity supply and customer demand. Achieving and maintaining that balance can be done through adding additional electric supply generation, reducing customer demand, or a combination of the two. There is now over two decades of experience with various states and utilities using energy efficiency programs on the demand side as a cost-effective "resource" to help assure electric system reliability and reduce overall system costs, including several years of very effective utility energy efficiency programs in Michigan in the early 1990's. (See Attachment A) In the most aggressive example, California has now mandated that energy efficiency will be the first priority resource in their future electricity supply "loading order", and they expect that energy efficiency will meet over half of all future projected electric resource needs. A just-released report from the California Energy Commission found that California's utility energy efficiency programs over the 2000-2004 period saved electricity at a levelized cost of 2.9 cents per kWh. (See Attachment B.)

In contrast, it appears that the current debate in this forum regarding capacity needs in Michigan is almost entirely dominated by discussion of additional generation (e.g., there was only a brief mention by Staff of energy efficiency under "Other Issues" in the July 18th public meeting; and the MISO representative didn't mention energy efficiency at all -- other than admitting, in response to a question, that MISO was not really considering any role in fostering energy efficiency). If only supply side generation options are considered in Michigan, our electric system will be more costly, less reliable, and more polluting than it will be if demand side resources such as energy efficiency programs are fully included.

Therefore, my **first recommendation is that any assessment of future electric system capacity needs in Michigan fully incorporate the potential for energy efficiency and other demand side programs to reduce the amount of new generating plants needed to serve Michigan.**

2) In order for demand side resources such as energy efficiency to play a role in Michigan, additional regulatory policies and mechanisms are going to be required.

MPSC Staff has identified a number of issues relating to the questions:

- *If additional generation is needed, will the Commission's current policy induce needed construction?*
- *If not, what changes need to be made to the Commission's current policy?*

and has requested comment.

I would like to strongly emphasize the need for staff to pose two additional questions:

- ***Assuming that energy efficiency and other related demand side programs have the potential to cost-effectively reduce the amount of additional generation needed, will the Commission's current policy induce the necessary implementation?***
- ***If not, what changes need to be made to the Commission's current policy?***

I would submit that the answer to the first of these additional questions is "no", and that the prima facia evidence for that answer is that ever since the Commission allowed the utilities to terminate their energy efficiency programs in 1995, there has not been a single incidence of a Michigan electric utility requesting Commission approval, or even self-initiating, an energy efficiency resource program. Meanwhile, many other states have continued aggressive energy efficiency programs, helping to save their ratepayers hundreds of millions of dollars. [1] Michigan's current regulatory policy and structure is

[1] For example, in the last 5 years, California's utility energy efficiency programs have produced incremental savings of over 6,700 GWh and 1,550 MW of peak demand (see Attachment B).

clearly not sufficient to influence utility energy efficiency program implementation, as Michigan's complete lack of such programs amply demonstrates.

As for the second additional question, there are a number of regulatory mechanism and strategies that other states employ to help bring about utility sector energy efficiency programs, including providing convenient and reliable cost-recovery mechanisms; offering financial incentives for good utility performance in delivering savings (Michigan successfully employed that in the early 1990's); implementing regulatory adjustments to "de-couple" utility profits from their sales volume; and providing various other regulatory and public relations items important to utilities.

In this regard, my **second recommendation is that this current Capacity Needs Forum process (1) explicitly acknowledge the fact that Michigan is currently failing to incorporate energy efficiency as a resource; (2) explicitly conclude that current regulatory policy is inadequate to induce utility energy efficiency resource programs; and (3) recommend that a specific initiative be launched by the MPSC on an expedited timeline to develop practical solutions to these problems, so that Michigan can capture the significant benefits of aggressive implementation of energy efficiency resource programs.**

Conclusion

Michigan is wisely taking time to examine its future electric generation capacity needs. In doing so, it is crucial to bear in mind that energy efficiency programs and other demand side measures need to be a significant part of that assessment. There is substantial evidence, compiled in Michigan as well as in a number of other states, that energy efficiency can be the cheapest and fastest electricity resource available. In addition, Michigan's almost total dependence on imported energy fuels,[2] and the enormous dollar drain that causes on our economy,[3] provide further compelling reasons to seriously examine the potential for energy efficiency to help reduce the amount of new electricity generation needed. Lastly, there are significant environmental benefits from using energy efficiency to reduce electricity generation, and many states and utilities are also realizing that energy efficiency can help reduce risks associated with future environmental costs associated with mercury and carbon emissions.

For all of these reasons, I strongly encourage that energy efficiency be fully considered as a resource in any examination of future electric capacity needs in Michigan, and that all necessary regulatory policies and mechanisms be developed to assure that energy efficiency programs can and will be fully incorporated as an electricity resource in Michigan.

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[2] Michigan imports 100% of the coal; 100% of the uranium; 96% of the petroleum products; and nearly three-fourths of the natural gas we use.
[3] Michigan's cost for imported energy fuels is now estimated to be approximately $18 billion per year.

ATTACHMENT A

Table 3: Energy Efficiency Program Spending and Savings[1]

	Budgets		Electricity Savings			Year	Notes
	$ millions	% of revenues	MWh	% of sales	MW		
AZ	2.0	0.1%	NA	NA	NA	2002	NA = Not Available
CA	240.0	1.5%	933,365	0.8%	103	2003	Based on IOU PGC funding only
CT	87.1	3.1%	246,000	0.8%	98.7	2002	Reflects CT performance prior to 2003 funding raids
DC	——	——	——	——	——	——	D.C. has low-income programs only
DE	——	——	——	——	——	——	No utility or PGC energy efficiency programs; LI and RE only.
IL	2.0	0.02%	NA	NA	NA	2003	Reflects $1 million decrease due to state budget shortfall
MA	138.0	3.0%	241,000	0.7%	48	2002	EE includes low-income efficiency improvements.
MD	——	——	——	——	——	——	Low-income only, no EE/RE to date; may begin EE programs in 2004; some load management programs still offered—data on them not included here.
ME	2.9	0.3%	25,500	0.3%	NA	2003	Projected values; Efficiency Maine was created in 2002; 2003 was first full program year and included interim programs; EE includes LI-EE; full EE program budgets to be about $9 million/year
MI	7.8	0.1%	NA	NA	NA	2002	EE only; 88% of LI and EE fund grants have gone for LI programs, including payment assistance.
MT	14.3	2.0%	NA	NA	NA	2002	
NH	5.2	0.5%	12,039	0.1%		2002–2003	Partial--start-up was June 2002—data for 10 months: June 1, 2002-March 31, 2003. Annual savings based on estimates of lifetime savings/15 years.
NJ	99.6	1.5%	171,692	0.2%	242	2002	Includes LI energy efficiency. Does not include payments on "standard offer" contracts established in earlier program years.
NY	129.0	1.3%	290,000	0.3%	382	2002	Annual data for 2002 estimated used reported cumulative data, 1999–2003
NV	11.2	0.5%	NA	NA	NA	2003	
OH	14.3	0.1%	NA	NA	NA	2002	
OR	19.1	0.9%	112,100	0.4%	NA	2002	Partial year data; programs began March 1, 2002.
PA	——	——	——	——	——		Sustainable Energy Fund primarily RE and R&D
RI	16.4	2.7%	50,568	0.8%	14.6	2002	Narragansett Electric data only (~entire state ee program)
TX	69.0	0.4%	455,700	0.2%	135.2	2002	
VT	16.8	3.3%	38,400	0.8%	NA	2002	
WI	49.7	1.4%	214,800	0.4%	35.9	FY2003	Does NOT include effects from public benefits cuts, which affect FY04 and FY05 funding cycles
Total	924.4		2,780,254		1,059.3		

[1] Percentages given are based on revenues and sales of utilities affected by public benefits funding requirements.

Table 5: Energy Efficiency Program Cost-Effectiveness

State	Benefit/Cost All Programs	Benefit/Cost Comm./Ind. Programs	Benefit/Cost Residential programs	Cost of Saved Energy ($/kWh)	Notes
California				0.03	
Connecticut	NA	2.4–2.6	1.5–1.7	0.023	
Maine	1.3–7.0				Range of ratios for individual programs
Massachusetts	2.1	2.4-2.7	1.3–2.1	0.04	
New Jersey				0.03	
New York				0.044	
Rhode Island	2.5	3.3	1.5		
Vermont				0.03	
Wisconsin	3.0	2.0	4.3		
Median	2.1–2.5	2.5–2.6	1.6–1.7	0.03	

Note: Median value for the "all programs" column was estimated using assumed value of 2.0 for Connecticut and reported data for Massachusetts, Rhode Island, and Wisconsin. Maine is not included in this estimate because of the wide range of individual program values. Median value for the C/I programs column was estimated using assumed values of 2.5 for Connecticut and 2.6 for Massachusetts. Median value for the residential programs column was estimated using assumed values of 1.6 for Connecticut and 1.7 for Massachusetts. (Those two states did not report point estimate values for those variables, just the ranges shown.) We developed the median range estimates shown in the last row of the table in order to give a rough indication of overall program cost-effectiveness across this set of states. Readers are advised not to put too much emphasis on these exact figures, but regard them as broad indicators.

Source: *Five Years In: An Examination of the First Half-Decade of Public Benefits Energy Efficiency Policies*. Washington, D.C.: Amercian Council for an Energy-Efficient Economy, April 2004.

COST OF CONSERVED ENERGY ACHIEVED[1]
[from states with high quality evaluation data]

California	1.6 cents to 2.9 cents/kWh (U.S. $)
Connecticut	2.3 cents/kWh
Massachusetts	3.2 cents/kWh
Minnesota	1.3 cents/kWh
Mich CPCo	2.6 cents/kWh
Mich DECo	1.5 cents/kWh
Vermont	2.6 cents/kWh

Typical current market cost, generation only: 5.0 cents/kWh
Fully loaded costs, incl. generation, transmission, distribution:
6.0 to 10.0 cents/kWh

[1] Levelized cost of saving electricity, over the useful lifetimes of the measures installed. As reported in various forums since the mid-1990's.

Source: Martin Kushler, Presentation at the NARUC Summer Regulatory Studies Program, August 13, 2004.

ATTACHMENT B

[Please refer to report entitled *Funding and Savings for Energy Efficiency Programs for Program Years 2000 Through 2004*, which I had previously sent over as a pdf file.]

ABATE’s response, pages 40 - 49

CLARK HILL PLC
ATTORNEYS AT LAW

MEMORANDUM

TO: George Stojic

FROM: Robert A. W. Strong

DATE: September 30, 2005

SUBJECT: ABATE Comments on Staff Proposal

LEGAL ISSUES

ABATE relies on its earlier Memorandum dated June 16, 2005 for a discussion of the applicable legal issues and the scope of Commission authority. By way of supplement, the Commission issued in the early 1990s several orders requiring Consumers Energy Company ("Consumers") and The Detroit Edison Company ("Edison") to acquire new capacity through competitive bid solicitations. (Case Nos. U-9586 and U-8869-DE; Case U-9798). Whether the Commission can require a utility to acquire new capacity through a competitive bid solicitation has not been tested in the courts and is probably doubtful given the holdings in the *Union Carbide* case and in the *Consumers* case to the effect that the Commission essentially has the ability to economically regulate utilities and set terms of service, but cannot interfere with management prerogative. From ABATE's viewpoint, under current law the decision to build, the type of plant to build, the specifications of the plant, the timeline, etc., are matters all within the purview of utility management. However, until the Court of Appeals or the Michigan Supreme Court holds otherwise, the Commission thinks it has the authority to impose a competitive bidding requirement on regulated utilities at least as it relates to the determination of a utility's avoided cost under PURPA. Thus, competitive bidding falls within the current regulatory framework, dubious legality or not.

The Staff's proposal also eliminates the used and useful test required by law. *See* MCL 460.557(2). Michigan law currently requires an after the fact review of both the just and reasonableness of a utility's building expenditures (i.e., "prudence review") and whether the plant is, in fact, used and useful in providing utility service.

In *Attorney General v MPSC*, 412 Mich 385 (1982), the Michigan Attorney General ("AG") and the Michigan Citizens' Lobby ("MCL"), asked the Michigan Supreme Court to interpret the scope of the review under the utility securities act which has subsequently been repealed. The AG and MCL claimed that the scope of the review of an application to sell securities included a determination of whether the project to be financed by the issuance of securities was reasonable. The Supreme Court held that under the utility securities act the inquiry is limited to whether there is a need to issue securities to obtain funds for a lawful utility purpose and does not extend to whether, to accomplish that purpose, there is a need for the project to which the funds will be devoted. *Id*. at 396. The Supreme Court stated that whether the utility needs the additional generating capacity and whether the additional generating capacity should be fossil- or nuclear-fueled, or whether the plant is cost efficient are separate questions not covered by the utility securities act:

> "It is a separate question whether the utility needs the additional generating capacity, as is whether that additional generating capacity should be fossil- or nuclear-fueled, or whether the proposed plant is cost-efficient or 'reasonable'. We have already stated our conclusion that these separate questions cannot be raised in a utility securities act proceeding."

Id., at 400-401.

The utility securities act was the only arguable basis to conduct a review of whether a particular plant was cost effective and whether it should be fueled by a particular type of fuel, since the general statutes certainly do not give the Commission this type of authority. Consequently, Staff's proposal is well beyond the authority conferred upon the Commission.

The Court of Appeals, in reviewing issues arising under PURPA, held that the Commission did not have the authority to limit the size of any one qualifying facility dealing with Consumers or to limit the total capacity which may be supplied by any one type of fuel. The Court of Appeals held:

> "There is no state or federal authority, however, for the PSC's attempt in its interim order to limit the size of any one QF dealing with Consumers or its final decision to limit the total capacity which may be supplied by any one type of fuel. Congress could have limited the absolute size of a qualifying cogenerating facility. It did not. Congress could have required that capacity from QFS be accepted in some manner which would allocate among fuel sources the capacity supplied. It did not. Although the PSC's stated goal of encouraging a diversity of QFS with a variety of fuel types is laudable, as is its concern that the MCV facility is so large as to crowd out other potential applicants, it is not for the PSC to determine questions of public policy. As noted above, the PSC is entirely a creature of statute and must find its powers and purposes under those statutes. In this case, the PSC is operating under both state and federal statutory and regulatory authority. That authority does not grant the PSC the sweeping powers it claims to possess in this case."

Consumers Power Co. v PSC, 189 Mich App 151 (1991) p. 179 (footnote omitted).

From these cases, it is clear that the Staff's proposal is not within the bounds of the Commission's authority and, in fact, violates MCL 460.557. The Commission simply cannot engage in a pre-approval of a particular project and fuel source among competing projects and fuel sources and cannot require ratepayers to pay for a generating unit before it is used and useful.

The Staff's proposal would shift all risk from shareholders to ratepayers that the plant, when finished would actually be used for public utility service. For example, assume a utility builds an IGCC electricity plant over the course of six years at a cost of $1.5 billion and that CWIP has been included in rate base, but the plant under-performs or does not perform at all. What protections could the Commission put in place to safeguard ratepayers' investment? Obviously, the Commission could order that all future collections for the IGCC plant should cease, but what about all of the dollars that had been previously collected from ratepayers under the assumption that the plant would be used and useful to them? One way to partially protect ratepayers in the event the plant under-performed or did not work at all would be to collect the rates under bond and subject to refund as such is done in connection with an order granting partial and immediate rate relief.[1] However, this is not total protection as the Commission lacks the power to award appropriate damages. There is no general section similar to MCL 460.6j(16) which states explicitly what the interest rate should be for over recoveries. On the other hand, the Staff proposal may be a flat out guarantee regardless of whether the plant performs as initially projected but this would be totally unfair.

[1] Collecting rates under bond and subject to refund will probably add risk to the project in the eyes of the parties financing a generating plant. However, this method has been used extensively in the past without controversy but has not been tested in the courts. There is no specific provision in MCL 460.6a or elsewhere addressing a bonding and refund requirement.

If the Staff proposal is that there should be performance and price guarantees then under what statute would the Commission operate to enforce those guarantees? There is no such statute that would provide the Commission with the necessary powers, so the Staff proposal really does not provide any real benefits to ratepayers. It does shift substantial risk to ratepayers with no effective protections.

There is a legal doctrine that if the Legislature intended to confer a power onto an administrative agency such as the Commission, then it must be directly addressed or there is an implied exclusion of that power. The Michigan Supreme Court held:

> "*Expressio unius est exclusio alterius.* Express mention in the statute of one thing implies the exclusion of similar things. *Perry v. Village of Cheboygan*, 55 Mich 250; *Weinberg v. Regents of the University of Michigan,* 97 Mich 246; *Marshall v. Wabash Railway Co.,* 201 Mich 167 (8 ALR 435); *Taylor v. Public Utilities Commission*, *supra; Van Sweden v. Van Sweden*, 250 Mich 238. When a statute creates an entity, grants it powers and prescribes the mode of their exercise, that mode must be followed and none other. *Taylor v. Public Utilities Commission, supra* (4 Justices); (2 Lewis' Sutherland Statutory Construction [2d ed], § § 491-493). When powers are granted by statute to its creature the enumeration thereof in a particular field must be deemed to exclude all others of a similar nature in that same field. So held in *Bank of Michigan v Niles*, 1 Doug (Mich) 401 (41 Am Dec 575), in which this Court, in considering powers conferred upon a bank by its charter, said:
>
> > 'The very grant of specified power under restrictions, is an exclusion of other powers in reference to the same subject matter, not granted by the charter.'
>
> Similarly as it relates to the powers of a corporation created under a general statute, 4 members of this Court, speaking in *People v Gansley*, 191 Mich 357 (Ann Cas 1918E, 165), said:

> 'It has been held that the powers are simply such as the statute confers, and that the enumeration of them implies exclusion of all others. *Thomas v Railroad Co.*, 101 US 71 (25 L Ed 950); *Pennsylvania R. Co. v Railroad Co.*, 118 US 290, 309 (6 Sup Ct 1094, 30 L Ed 83).'"

Sebewaing Industries, Inc. v Village of Sebewaing, 337 Mich 530, p. 545-546 (1953).

Therefore, if the Legislature in Act 304 granted the Commission the power to impose interest to compensate for the time value of money in the event of GCR or PSCR over recovery and there is no corresponding general statute that does the same, then the implication is that the Commission does not have the power to award ratepayers interest in the event that the plant under-performs or does not work.

The same principle would also apply to prior approval of capacity additions. MCL 460.6j(13)(b) is the only statutory authorization for prior approval of capacity purchases. This would imply that under only those circumstances recognized in the statute can the Commission give prior approval to capacity additions.

In summary, under the current statutory regime governing what powers the Commission has or does not have, the Commission cannot eliminate the used and useful test and cannot adequately protect ratepayers even if the Commission tried to do so in the event that the new plant under-performed or did not work. Yet, the Commission has already previously held that new QF capacity must be acquired through a competitive bid solicitation.

POLICY ISSUES

A fundamental assumption made by the Staff is that the rules need to be changed in order to induce utilities to build new power plants. In doing so, the Staff would ignore the statutory requirements that have been employed by this Commission for literally decades and ignore the economies available as a result of an integrated dispatch of all generation located in MISO.

There are at least two major incentives that would cause utilities to build new power plants. The first is that securitization has shrunk the size of the utilities and reduced earnings by converting rate base into securitization debt. Utilities want to grow their business and the only way to do that in the traditional sense is to add to rate base.

The second inducement is that the utilities can make wholesale sales in excess of their native load and these sales will settle out at the marginal cost on the MISO system. This means that solid fuel projects with low operating costs can be paid the system marginal cost which should be very high during peak hours. Consequently, there is major reward available to owners of generating equipment with a low marginal running cost.

In theory, customers of utilities which have joined the MISO should see the benefits of joint dispatch of all of the generating plants located in MISO's footprint. This means that the mine mouth pulverized coal unit which does not require expensive transportation of fuel should be able to serve Michigan loads and be more cost effective than a new plant located in Michigan. The Staff's proposal, even though it incorporates a competitive bid, almost seem to rule this option out in favor of building in Michigan. If this is the case, then ratepayers' investment in MISO will not result in the savings that were identified as justification for creating a RTO in the first place.

A second issue is whether there truly is a need to change the rules so that utilities can finance new capacity additions. Based upon the data posted on the Commission's website, participation in retail open access is clearly in decline. We suspect that is because alternative electric suppliers cannot find power in the wholesale market that is not priced at the margin. Utilities and other owners are clearly unwilling to enter into bilateral transactions for a significant period of time at other than marginal prices. Consequently, there is less risk of lending to a utility even though, on paper, there is the opportunity present for its customers to purchase power from other suppliers. This fact reduces the risk and increases the willingness of lenders to loan money for large capital projects and does not require a change in how capacity additions are treated in Michigan.

If the concern is financing, then the only way that the Staff's proposal would work would be to guarantee cost recovery up to the capped rate. However, who bears the risk if MISO does not dispatch the plant because it is too expensive? Ratepayers should not bear this risk even though there was an upfront assessment which is a very iffy process. One needs only to look at what happened when this Commission established artificially high avoided costs for the two major utilities. Consumers was allowed to collect capacity costs more than three times higher than the cost of a gas plant and then when gas prices rose as predicated at the time, Consumers ran to the Commission for a fundamental change in the way the MCV facility was dispatched. While this saved MCV a ton of money, it deprived ratepayers of the benefits that should have been associated with levelized (instead of backloaded) capacity payments they have been paying since 1989.

The Staff proposal calls for a "comprehensive planning assessment that evaluates the risks and costs of traditional plant, renewable plant, energy efficiency and load management."

This concept seems very similar, if not identical, to integrated resource planning ("IRP") that was once practiced by several utilities. Consumers and Edison have filed IRPs in the past, but only did so under the caveat that this was voluntary effort on their part and not something that the Commission had the power to require. Accordingly, this concept is legally vulnerable as being outside of the authority conferred upon the Commission.

Again, the same issue is present in connection with the concept that the alternate supplier would have a one time opportunity to make a pro-rata investment in the new generation. The *Consumers* case dealing with PURPA issues clearly held that the Commission did not have power to allocate capacity among the competing parties.

The Staff proposal to require mandatory competitive bidding prior to deciding whether the utility could build a plant is not workable under the current statutory framework. From a public policy perspective, any type of competitive bidding system would have to create the expectation that it would be conducted fairly and that a third-party supplier had a <u>real</u> opportunity to be chosen as the supplier. Once the solicitation is considered less than legitimate then potential suppliers are not going to go through the effort of trying to respond to a Request for Proposal, which is an expensive process. There is also a structural problem with allowing a utility to build its own facility once the results of the competitive bidding solicitation are known. At the very least, a competitive bidding solicitation would have to be structured using a third-party as a bid evaluator and the utility would be treated as simply another bidder. However, one wonders whether the incumbent utility would have such an inherent advantage such that prospective alternative suppliers would not consider submitting a bid. The incumbent utilities have current locations where generation could be easily expanded and a major financing advantage of having the opportunity to have CWIP included in rate base without an AFUDC offset. That stacks the financing in favor of the incumbent and possibly could eliminate any of the advantages associated with having a competitive bid as a gauge of what is reasonable to pay for new generation in the market place.

In summary, the Staff's goals and objectives are laudable but clearly unworkable under the present statutory framework governing utility regulation. Moreover, changes such as those proposed by the Staff, do not represent good policy because they will effectively eliminate the protections afforded to ratepayers. The Staff proposal would result in the wholesale shift of risk from the utility and its shareholders to ratepayers with no corresponding reductions in rates and no upside return if the plant were successful. Risk and reward go together. Staff's proposal leaves reward with the utility and it should, but moves all risk to ratepayers. These policies could end up making Michigan's retail rates even more uncompetitive than they already are.

EPSA's response, pages 51-59

Michigan Public Service Commission
Case No. U-14231 – Capacity Need Forum
Joint Comments of
Electric Power Supply Association,
Energy Michigan and
Midwest Independent Power Suppliers

Introduction and Summary

The Electric Power Supply Association (EPSA), Energy Michigan and Midwest Independent Power Suppliers (collectively, "Competitive Suppliers")[1] applaud the Michigan Public Service Commission (Commission) for its investigation into Michigan's future electric capacity requirements through the Capacity Need Forum (CNF) and for providing the opportunity for the competitive sector to participate in Case No. U-14231. As capacity and reserve margins continue to shrink, and as states in every region face the prospect of how to meet future generation needs, it is imperative that proper market mechanisms are in place to ensure that new generation requirements are satisfied in a manner that most efficiently allocates risks, costs and resource adequacy obligations – while maintaining long-term system reliability to the benefit of all customers.

Further, the Commission has the opportunity in this proceeding to make a significant contribution to the economic climate of the state in terms of job creation and retention, infrastructure investment and tax revenues. This is especially true if the Commission maintains its current policy of fostering competition and providing for adequate sources of supply. An open capacity procurement process and a workably competitive market will lead to a secure future with an adequate number of power plants and sufficient supply sources. Providing for a competitive foundation will ensure that Michigan's citizens and electricity customers receive the most efficient and most reliable supply of electric power.

To move away from an open capacity procurement process would send the Commission and the state on the road to a repeat of what consumers experienced prior to the advent of competition in the mid-1990s. History shows that a high-cost utility structure, cost overruns, unnecessary ratepayer assumption of utility construction and

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[1] EPSA is the national trade association representing competitive power suppliers, including generators and marketers. Energy Michigan is a trade group consisting of competitive power suppliers at the retail and wholesale level and end users who support the goal of competitive power markets. MWIPS is a group of leading competitive power suppliers who joined together with a common goal of achieving full and fair competition in the wholesale power industry in the Midwest. These suppliers, who all have members or member affiliates that conduct business in Michigan and elsewhere in the Midwest, are united in their policy preference for satisfying Michigan's future resource adequacy needs through a Commission-sanctioned open solicitation process that optimizes choices and benefits for consumers. That these suppliers are the parties that would participate in such a solicitation process and ensure Michigan's future resource adequacy. The comments contained in this filing represent the position of Competitive Suppliers as a filing entity, but not necessarily the view of any particular member with respect to any specific issue.

operational risks, a high level of stranded costs and finally, little to no customer choice in purchasing electricity from anyone other than the monopoly provider. Captive utility customers will not be left to bear those costs if the Commission stays the course on competitive markets and competitive supply.

Ensuring Benefits for Customers

The primary method for ensuring optimal benefits for Michigan electricity customers is a well-functioning Midwest ISO wholesale market that provides the necessary incentives for new investments in generation and transmission capacity through timely and transparent pricing signals, working in concert with a robust retail competitive choice program. Under these conditions, alternative electric suppliers compete for all classes of load and the transmission would be controlled by an independent third party. Further, under these conditions, wholesale suppliers and competitive generators compete to furnish electricity supply to not only the alternative electric supplier (AES) community, but, in the interim, also to the state's utilities who are still serving retail load.

The Midwest ISO already operates an energy market, and is in the process of complying with a Federal Energy Regulatory Commission order to implement a long-term resource adequacy construct. Well-designed protocols for resource adequacy will allow for needed capacity, including renewable sources. These markets, in tandem with competitive suppliers, will work together to ensure that: (1) customers in Michigan have access to generation supply in the long run, and (2) that generation investment for the benefit of Michigan consumers is made when and where it is needed.

Unfortunately, the fact that the state's utilities still own generation paid for by their jurisdictional customers is a situation that is not conducive to competitive markets. While the operating environment for all plants in the state is similar, the risk and cost-recovery profiles of competitive plants and utility rate-based plants are different. This bifurcated model creates an economic distortion in the energy and capacity markets, and perpetuation of an artificially induced boom-bust construction cycle. In view of this, the PSC should consider the existing industry structure in the state and market design as it determines how best to meet future capacity needs.

Another consequence is that advantages for rate-based plants (e.g., minimal market risk, assured cost recovery) become more pronounced, as do the disadvantages for competitive plants (e.g., greater market risk, no assurance of capital recovery). While such disadvantages can irreparably harm the merchant generation companies and AES community, more disturbing is the fact that consumers are denied the benefits that true competitive markets deliver.

Specific Comments on the Staff "Reliability Option" Proposal

The CNF process, thus, makes certain assumptions about the electricity market that are acknowledged for the limited purpose of these comments. In that context, Competitive Suppliers offer the following comments and recommendations in response to the PSC staff's "Reliability Option," presented at the Aug. 25, 2005, Capacity Need Forum policy meeting. These comments and recommendations should not, however, be read as an endorsement of the assumptions made in the staff proposal.

Staff states that reliability is a public good, which means that, as a classical economic public good, reliability is collective in nature. It can be realized and shared by all customers without diminishing access by others. If this is true, all customers must share in the cost of maintaining system reliability. To do this, and avoid cross-subsidization problems and 'free-rider' issues, providing for a competitive procurement process for new capacity would minimize this common public good problem.

Fully supporting a competitive market and working with the Midwest ISO and the entire region to help identify the best competitive solution to meet reliability needs should be the policy outcome from this CNF process. Isolating the state from the broader regional market leads to over-cost scenarios and the other problems that states faced prior to competition. Again, a focus only on Michigan supply risks inefficient construction and other states in Midwest ISO "free-riding."

To the extent that a decision is made to focus on Michigan capacity needs without regard to the regional resource adequacy paradigms of the Midwest ISO, Competitive Suppliers strongly encourage the Commission to direct Michigan's utilities to hold a transparent fair and conclusive Commission-approved competitive procurement process for any PSC-deemed capacity needs in the context of all available Midwest ISO resources. The competitive procurement, which is open to all potential suppliers, provides, at a minimum, the opportunity to contract for capacity.

To the extent that questions are raised in the CNF to address issues such as financial hedging and risk management, fuel mix, and resource allocation, competitive markets have demonstrated repeatedly that when allowed to function properly, they are the most efficient and most reliable means of managing these tasks. Certainly, PJM today (and the Midwest ISO in the future) is emblematic of this efficiency and reliability, given the largely positive annual reports filed by PJM's Market Monitoring Unit each year.

A competitive procurement process that results in pay-for performance contracts is much superior and preferred to having a utility build generation on a cost-plus basis or a purchase power agreement (PPA) with a utility affiliate as the only vehicles to satisfy the proposed "Reliability Option" in the Staff CNF Proposal. An MPSC directive on competitive procurement for capacity would ensure that many risks are shifted away from Michigan utility customers to the commercial entity providing the capacity. Further, it would prevent another long-term, burdensome "mortgage" (in the form of new utility generation in base rates for many years), with the attendant risks of stranded investment or non-performance, being placed on Michigan's manufacturing, commercial, residential and educational sectors.

Competitive Suppliers support a CNF that encourages an efficient, effective capacity market for the reliability region that covers Michigan, as well as an open competitive procurement process in Michigan that satisfies the objectives of Order U-14231 regarding the inventory of Michigan's base-load generating capacity. Such an approach achieves the stated PSC Staff core values of: consumers come first; electric reliability is a public good; adherence to the fairness doctrine of allowing all consumers access to the most efficient supply; and, getting the supply and service for which they pay. Competitive Suppliers believe these values should be fulfilled through a process that includes all competitive supply options. There are many reasons for this position, which are incorporated into the observations on the Staff CNF Proposal outlined (by section) below:

- **Background –** Contrary to the assertion that the competitive market cannot provide for electric reliability, the facts speak otherwise. Since enactment of the Customer Choice and Electric Reliability Act in 2000 (MCL 460.10 et seq.), competitive generators have brought on-line approximately 5,000 megawatts (MW) of new generating capacity – all in response to the competitive environment presumed under the Act and under the establishment of the Midwest ISO bid-based markets.

  Nationwide, the competitive sector brought approximately 187,000 MW of generating capacity into operation between 1993 and 2003, and all of those facilities were financed outside of the traditional rate base – either through long-term PPAs, on a non-recourse, project-financed basis, through the balance sheet, or a combination of these and other approaches. An affirmative commitment by the Commission and Michigan utilities to foster and accelerate competitive wholesale and retail market development, as well as the continuing maturation of the Midwest ISO spot energy markets and bilateral forward markets, will result in sufficient supply adequacy in the future. A positive market environment and regulatory certainty attracts the necessary capital for investment, and the market transparency that can be provided by the Commission will ensure that capital is spent in Michigan where and when needed.

  The entire industry, including the competitive sector and the financial community, has learned a great deal from the revenue inadequacies of the mitigated energy markets that occurred in recent years. Among those factors are firm commitments for longer-term supply arrangements, stronger balance sheets in the competitive sector, better market rules, greater market liquidity, better price signals and risk management tools, and more certain opportunities for recovery of invested capital. All of these positive developments mean that competitive generation can continue to fulfill the supply adequacy role it has successfully adopted during the past decade.

  Furthermore, given these improved market circumstances, there is no reason to believe that future generation development and financing should, or will, automatically default back to the utility rate base. The risk and cost implications for captive ratepayers – starting with the unpleasant specter of a new round of stranded costs in the next decade – are just too significant for the competitive option not to continue to flourish. These risks are better managed by competitive power suppliers.

- **Reliability Option –** Competitive Suppliers have several questions and concerns.

  1. Does the Reliability Option obviate or circumvent the need for a competitive Request for Proposals (RFP) process?

     Because the staff proposal speaks only to a utility application with an associated contested case hearing, Competitive Suppliers are very concerned that capacity from merchant generating plants would be precluded from consideration as a Reliability Option. The result would be an unproductive retreat from competition. Further, the problem of generation market power already possessed by the public utilities in Michigan would be exacerbated if the Reliability Option means a return to utility self-build generation only. As discussed below, this outcome is neither warranted nor equitable –either for consumers or suppliers in Michigan.

  2. Despite the acknowledgement that a utility self-built or owned generating plant is an option "so long as a better alternative is not available," it appears that this reliability construct is geared toward a utility-sponsored plant. This begs the question: does the Reliability Option serve as an effective default back to re-regulation of generation, where IOU's are the only option for new generation?

     If so, Competitive Suppliers would respectfully ask the Commission to reconsider the implications of the Staff CNF Proposal in view of the consequences of such an outcome – namely, no choice of supply source, higher cost of new supply and less access to more efficient supply sources, greater risks to consumers as they reassume those business risks previously managed by the competitive sector, and the prospect of a new round of stranded costs that consumers will be obligated to assume.

     Also, given the regulatory difficulties, cost hurdles and delays that have already surfaced with respect to those states that have re-entered rate-based generation (e.g. Wisconsin and Colorado), and the prospect of multiplying these difficulties and delays many times over in the next few years, there is a reliability question associated with utilities being the sole source of future generation. Michigan would be well-served, especially in the current period of declining reserve margins, to ensure that opportunities for all sources of new supply are able to compete to maintain supply adequacy.

  3. Can a non-regulated or competitive entity propose a more economic alternative that will serve as a Reliability Option unto itself or as a utility's Reliability Option through a longer-term PPA offer?

     Competitive Suppliers submit that the reliability option should accommodate both approaches. Also, unlike the recovery of costs for a utility plant put in rate base, the competitive plant and longer-term PPA options are financed outside of the rate base. Therefore, Competitive Suppliers further submit that the Commission can utilize its existing approval process of the Power Supply Cost Recovery

Clause, rather than require a lengthy and costly contested case proceeding for competitive/PPA projects that otherwise satisfy the requirements of the Reliability Option contemplated in the Staff CNF Proposal.

- **Impact of Reliability Option on AES Customers –** In its current form, Staff's CNF proposal would severely hamper, if not effectively eliminate, electric choice service in Michigan. The proposal calls for both utility and AES customers to pay a "reliability charge" for a utility plant built to satisfy the Reliability Option. Further, the proposal states that all customers would be credited with their pro-rata share of the plant's "reliability value" (presumably, this is the capacity cost component) and that AES entities will have a one-time opportunity to make a pro-rata investment in the generating station on behalf of their customers.

  The problem with this approach is that the utility plant will be designated to serve only its retail customers, not AES customers. Without a competitive resource procurement process, any charge for non-utility customers would have them, in effect, subsidizing the utility-owned plants, while still having to secure their own supply at an additional cost. Obviously, this cross subsidy will eliminate the benefit of having switched to AES in the first place. And the pro-rata investment by AES would not offset this subsidy. Thus, should the utility be allowed, to purchase capacity, it should be paid for by the utility's retail generation customers, not its "wires" customers.

  As previously stated, when additional generation is to be built then that capacity should either be built or contracted in the most efficient manner. To guarantee the most efficient means, a market test in the form of a competitive solicitation is needed – even when the utility self-build option is under consideration. Once a competitive procurement process has been completed, the costs associated with that reliability resource should be recovered by those customers served by the decision-maker, the utility's retail customers. Without this safeguard, the benefits of AES service would largely be lost and a migration of approximately 2,500 MW of capacity back to the utilities would occur.

- **Competitive Bidding/Procurement --** Commission staff rightly acknowledged that any self-build proposal "by a utility in a reliability option hearing should be given considerable deference if the utility has undertaken a fair and open competitive bid."[2] Competitive Suppliers, however, encourage the Commission and Commission staff to take this thought one step further. If a utility that performs a "fair and open competitive bid" deserves "considerable deference" in its resource proposal, why not construct a Commission-approved, reliable, transparent and fair competitive procurement process that would be required for all utility generation additions? The Commission could establish a rebuttable presumption that the result of the competitive procurement process was just and reasonable and allow the utility to fully recover its costs, thus avoiding costly and time-consuming contested cases for every individual utility resource application.

[2] Background paper of CNF proceedings prepared by George Stojic, Page 2

This would not require new legislation because current Michigan law allows for a utility to recover the full costs of a PPA with a third party;[3] nor, is it a new or untested policy since 15 states[4] and the District of Columbia have competitive power procurement rules or legislation. It is important to note that the procurement rules in many of these states encompass longer-term PPAs that include capacity, energy and ancillary services – not just shorter-term contracts for a specified amount of energy.

A major goal of competitive solicitations is to evaluate a full range of resources in the wholesale marketplace and to obtain the best possible deal for all electric utility retail customers. In this specific sense, competitive solicitations, when conducted in a fair, accurate and transparent manner, are an important tool at both the state and federal levels for determining the prudence of utility purchases and investment decisions and allaying concerns about affiliate bias.[5]

To help regulators form a credible competitive process, EPSA published "Getting the Best Deal for Electric Utility Customers: A Concise Guidebook for the Design, Implementation and Monitoring of Competitive Power Supply Solicitations." This guidebook was prepared by the Boston Pacific Company, Inc., which has served as the independent third-party evaluator (IE) for competitive solicitations in other states and currently is the market monitor for the Southwest Power Pool (SPP) regional transmission organization (RTO). The guidebook, along with a follow-up booklet on resource procurement and debt-equivalency,[6] has been attached to these comments for your reference.

For a credible, competitive solicitation to take place, two main requirements must be fulfilled. The first is the development of a process that will give all market participants the assurance that they will be participating on equal terms. If potential participants feel that they are not playing on a level playing field and have significant hurdles toward securing a successful contract, they will ultimately decide not to participate. The departure of market participants will not only bring the credibility of the solicitation process into question, but in the end, will also harm electricity consumers. Consumers benefit when companies compete against each other on the grounds of price, innovation and service.

Therefore, to ensure that a credible solicitation occurs, it is critical that all parties be aware of and agree on important issues such as the type of product to be procured and the evaluation criteria to be used. Bidders must be aware of exactly what type of

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[3] Power Supply Cost Recovery Clause; MCL 460.6j.

[4] Arizona, California, Colorado, Connecticut, Georgia, Maine, Maryland, Massachusetts, New Jersey, Ohio, Oregon, Pennsylvania, Rhode Island, Utah and Virginia

[5] *Getting the Best Deal for Electric Utility Customers: A Concise Guidebook for the Design, Implementation and Monitoring of Competitive Power Supply Solicitations,* Boston Pacific Co., Inc., 2004, Pages v-vi

[6] *Electric Utility Resource Planning: The Role of Competitive Procurement and Debt Equivalency*, GF Energy LLC, 2005

capacity the buyer is seeking so that a true competitive bid can be formulated. In this regard, to the extent the soliciting entity anticipates submission of a self-built alternative; it should be required to identify in the draft RFP, the location of its self-build alternative and the relative size of the facility. In addition, in order to have as successful a process as possible, bidders must be aware of the criteria on which their bids will be judged. By taking these additional steps, the Commission and market participants will have the security of knowing that a credible process was used, which, in the end, will better serve consumers.

The second main requirement is the establishment of an IE that will oversee the process to ensure that there is no bias and that will act as a complement to the Commission's staff. The benefit of an IE is that the Commission, staff, market participants and customers will have an extra pair of experienced eyes watching over the solicitation process. The IE will know the mistakes that can be made and will possess the technical expertise to delve into the details of the utility's evaluation to determine any biases. The Commission and the bidders both have a high degree of confidence, knowing that a fair and impartial entity is reviewing the details of the solicitation. [7] One of the main tasks for the IE would be that of a conduit for all communications between the soliciting utility and its bidding affiliate(s).

Although many more details must be examined, with both a strong collaborative stakeholder process and an IE, the Commission can be sure that the groundwork for a reliable competitive bidding process would be laid. Please see the attached guidebook for further discussion on these topics.

The value produced by competitive power suppliers goes beyond the possibility of rate savings. **What many consider the greatest benefit of non-utility generation is the transfer of risk from the captive utility customer to the competitive supplier.** When a utility builds a plant it sets an initial budget that is approved by the state Commission. Yet if, as is often the case in plant development, there are construction delays or cost-overruns it is the captive utility customer of the utility that pays the price. The utility is often entitled to recoup its construction expenses through rate increases that put a significant burden onto the customer. Even if the Commission staff's recommendation is accepted and a cost cap proposed by the utility, customers would still be responsible for CWIP without an offset for AFUDC, as well as a reliability charge.

Competitive suppliers on the other hand can offer different types of supply options with fixed prices upfront. These options properly allocate the risks associated with the development, construction, ownership and operation of power generation facilities. Developers and generation owners price these risks into their bids and proposals and at a lower risk-adjusted cost to consumers than would be the case from a utility plant. Some examples of the types of risks that are negotiated features in PPAs are:

[7] Ibid, Pages 7 & 8.

- set prices for capacity (which protect against construction, operation or other cost overruns);
- guaranteed completion schedule for new construction;
- guaranteed unit availability;
- guaranteed reliability related performance measures;
- protection against changes in a utility's cost of capital;
- price reductions or liquidated damages if guarantees are not met;
- flexible contract terms/duration (e.g., a PPA for five or 10 years may be preferable under some circumstances to the 30-year commitment associated with a utility acquisition or construction); and
- no residual charge for retirement, demolition or site clean-up.

These risk mitigation measures can result in lower and/or more stable rates for consumers. Finally, PPAs allow utilities to conserve its capital for other much-needed infrastructure investments, such as distribution enhancements.[8]

- **Energy Efficiency –** Competitive Suppliers have no comments or suggestions on this section.

- **Construction Partnerships –** Not only can Michigan utilities bring in partners for their self-build options, but competitive suppliers can also have partners for their plants.

- **Market Power –** There is no question that greater concentration of utility ownership in generation will exacerbate the market power problem. And more broad-based partnerships in utility power plant building programs are not likely to mitigate market power problems. In addition to the reasons cited above to include the competitive generation sector as a full participant in the reliability option concept, Competitive Suppliers respectfully suggest that market power concerns are another reason for the Commission to "hardwire" the competitive procurement option in its final rule in Case No. U-14231.

Conclusion

Competitive Suppliers again applaud the Commission for establishing the CNF and the Commission staff for the work done in re-examining the state's electric resource addition policy. With the inclusion of a transparent and fair competitive procurement process, and staying the course on fully functioning competitive markets, the Commission would provide equity, comparability and regulatory certainty in the development of a workable policy on resource additions – all to the benefit of Michigan's retail electricity customers.

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[8] EPSA White Paper *Buy or Build? Power Purchases or Power Plant Ownership: Making the Best Choice for Customers*, July 2004, Page 4

Consumers Energy's response, pages 61-65

CONSUMERS ENERGY RESPONSE
TO MPSC's CNF POLICY CHANGE PROPOSAL

SEPTEMBER 30, 2005

INTRODUCTION

Consumers Energy commends the Michigan Public Service Commission Staff (Commission staff) for its efforts in evaluating the need for new generation in the State of Michigan.

Consumers Energy remains concerned, however, that the current market structure in Michigan does not create appropriate market incentives to invest in new energy resources, and thus creates doubt about whether those resources can be financed on reasonable, affordable terms for Michigan's utility customers. Similarly, the current market structure does not adequately recognize the value of supply reliability or the market benefits from adding a new facility that generates low cost energy that keeps energy prices down. Consumers Energy believes that base load generation and fuel diversity (beyond natural gas) provide significant public value in the form of more predictable and stable prices. Long-term reliability, affordability, and price stability should be the focus of the Capacity Need Forum. Sole reliance upon emerging energy-only electricity markets is unwise, because such reliance will not meet these objectives.

Without targeted policy changes that substantially increase revenue certainty and provide cash flow support for the financing of large-scale, long-term power generation, Consumers Energy doubts that new generating facilities will be built in the State of Michigan in the foreseeable future. Michigan's utilities do not have revenue certainty in the current regulatory model and cannot provide revenue certainty to a potential third-party investor in the form of a long-term PPA.

Given this context, we believe that the Commission staff's current proposal, although an excellent starting point, does not go far enough in creating the stable and predictable regulatory and financial environment required to permit the financing of new base load generation on reasonable terms. Also, since new base load generation will take a number of years to develop and construct, it is imperative that these policy issues are resolved in a timely manner to meet the State's increasing electrical demand. We are encouraged by the policies and the broad general direction that the Commission staff has suggested and have included some additional comments on these and other aspects of the current regulatory environment below.

1. The uncertainty of a customer base makes financing a large-scale new generation facility unworkable. Without a firm customer base or cost recovery certainty provided through firm and predictable ratemaking treatment, the potential migration of customers to alternative electric suppliers (AESs) makes new generating facility construction an extraordinarily risky proposition and potentially unfinanceable. Historically, the utility's customers have paid for both the cost of energy and the

associated costs of reliability. The current market structure encourages reliance on short-term energy transactions, and discourages long-term, reliability-based investments. This will ultimately impact all customers.

2. The current inability to recover construction costs in rates during construction expands already significant cash flow requirements pending project completion, and increases financing costs. A policy of deferring consideration of cost recovery issues until the plant enters commercial operation creates additional financial, regulatory and business risks.

3. A competitive bid process that goes beyond engineering, procurement and construction (EPC) injects further uncertainty into the construction decision and financing process.

4. Any policy revisions must be broad enough to ensure optimal results. Major investments in existing facilities should be treated on terms equal to investments in new generation assets. Thus, any reliability charge should not be restricted to only new generation assets. Extending the life or further reducing the emissions of existing units as technology continues to develop may have greater value than would new construction in some instances. We believe a policy that places a non-bypassable reliability charge only on new generation may have unintended and uneconomical consequences.

MPSC'S POLICY RECOMMENDATIONS

Binding Pre-Approval

The Commission staff has appropriately identified a mechanism that can abate some of the financial risks of new generation. While the Commission has certain authority to adopt the related recommendations, their current decisions regarding ratemaking may not necessarily bind future Commissions, adding to long-term investment uncertainty.

We see a strong, binding formal mechanism administered by the Commission, such as the issuance of a Certificate of Public Convenience and Necessity, as a key aspect in mitigating some of the risk associated with an investment of this magnitude. Consumers Energy further believes that, in light of the long-term nature of the financial commitments at stake, the changes under discussion would ultimately require targeted legislative action.

Construction Work in Progress

The Commission staff has recognized the importance of receiving a cash return on Construction Work in Progress (CWIP) during the construction period of the new facility. The time frame for carrying debt of this magnitude is too burdensome for the utility without such a mechanism. Comparable ratemaking treatment would be appropriate for any major energy infrastructure investment, whether new generation or in existing generation assets.

Competitive Bidding
A competitive bid process introduces additional uncertainty into the construction decision process. We remain convinced that customer's interests can be fully protected if competitive bidding is limited to the Engineering, Procurement and Construction (EPC) aspects of the plant development.

Construction Cost Controls and a Commitment to In-Service Date
The Staff proposal includes a recommendation that the utility agree to a construction cost cap and commitment to an in-service date. If such commitment is required, the utility should be provided reasonable protection from Force Majeure events, as is typical in any major contract. Additionally, the utility should be provided a margin above the price cap for unanticipated cost changes not associated with Force Majeure events. The utility must be able to petition the Commission for recovery of for-cause prudent expenditures within this margin for rate recovery consideration. The utility would still be subject to a prudency test, but would be allowed latitude for scope changes as could relate to such things as regulatory changes or consequential swings in construction materials availability and price. Additionally, if the Utility it to accept a higher performance-based risk for construction guarantees, then due consideration should be paid to positive performance incentives as well.

Construction Partnerships
Since customer choice has established an environment whereby utilities must compete for customers with alternative energy suppliers, Consumers Energy will not accept a forced partnership with its direct competitors. A forced partnership with an AES is wholly inconsistent with such an environment. We would, of course, consider partnering with other load-serving entities with whom we are not competing to serve our customer base. Consumers Energy already has such arrangements and would not be opposed to future arrangements that provide for an equitable allocation of cost and benefits.

Revenue Certainty
Significant uncertainty surrounding a utility's future customer base makes financing a new generation facility extremely difficult. Without a firm customer base and cost recovery certainty provided through long-term, binding ratemaking treatment, the potential migration of customers to alternative electric suppliers makes new generation facility construction an extraordinarily risky proposition.

The Commission staff suggested a mechanism by which both bundled and ROA customers would be required to pay a portion of the plants reliability value. This mechanism includes a dedicated non-bypassable charge assessed to all jurisdictional electric customers designed to provide for recovery of certain costs related to reliability. This would ensure that the cost of carrying reserve capacity is borne equally by all customers that benefit from the additional electric reliability as a public good. This recommendation would also help the State of Michigan to maintain a reasonable reserve margin and reduce dependence on out-of-state generation.

However, Consumers Energy believes that the value of the plant to all customers exceeds the reliability value. The availability of additional base load capacity in the market will also hold down market prices to the benefit of all customers. This value also needs to be recognized in the overall structure of the non-bypassable charge.

Consumers Energy sees value in extending the concept of the non-bypassable charge to all major capital investments. Putting all large investments on an equal footing would avoid encouraging suboptimal capital spending decisions. We would require adequate protection from ROA-related risk in any large-scale investment or long-term commitment.

Given the extensive scope of this charge considerably more attention and discussion will be needed to assure that it is appropriately comprehensive and fair.

Long-Term PPAs

Under the current regulatory environment, the utility cannot accept the downside risk of a long-term power purchase commitment (PPA) while having neither revenue certainty from a fixed customer base, nor the opportunity to earn an adequate risk-adjusted return.

Under current accounting rules, a utility that enters into a long-term PPA will likely be required to record the present value of capacity payments over the term of the PPA as debt on the utility's balance sheet. In addition, credit rating agencies have imposed a rating penalty on those utilities that have entered into long-term PPAs to reflect the "debt-like" nature of capacity payments due under such contracts.

If Consumers Energy were to opt to pursue long-term PPAs in lieu of generating plant construction, the company would require the same type and level of revenue certainty for them as would be required for large-scale construction or infrastructure investment. Both PPAs and construction have associated loss of market risk under customer choice. Given the current policy environment Consumers Energy could not accept a long-term PPA obligation without appropriate consideration of equity and an assured return on that equity to offset the debt-like nature of the obligations.

Energy Efficiency and Conservation

Consumers Energy strongly believes that energy efficiency and conservation (demand management) should play a role in Michigan's energy future. We recognize, however, that efficiency, conservation and renewables, although important, will only be a portion of the complete picture of energy supply and demand in the State and that new base load generation will be the key element. To the extent that efficiency and conservation are economical choices for demand management, with an appropriate allocation of cost and benefits, then the market will support them. We must remain mindful of the controversy that accompanied the demand side management programs undertaken in the 1990s.

CONCLUSION

We applaud the Commission staff for its work in determining the need for additional base load capacity to be built in Michigan and look forward to working on the implementation of policies to accomplish that objective. While the Commission staff's proposed policy recommendations address several important regulatory hurdles that need to be overcome before implementation of a capacity addition program can commence, we believe that several enhancements to those recommendations are needed to achieve the desired objectives.

In particular, we believe that it will be necessary to have revenue assurance and cash flow support through binding pre-approval, a secure customer base and a non-bypassable charge for any capacity addition to occur. Consumers Energy deeply appreciates the opportunity to provide these comments and to participate in the Michigan Public Service Commission's Capacity Need Forum. We look forward to reviewing the Commission staff's final report and the final results of its capacity modeling efforts.

Wolverine's response, pages 67-74

MPSC Capacity Need Forum
Wolverine Response

Introduction

Wolverine supports this collaborative effort of the Michigan Public Service Commission (MPSC) to assess the future need for generating capacity in Michigan. Wolverine submits the following comments in response to the August 2005 Capacity Need Forum meeting in which Mr. Stojic, on behalf of MPSC Staff, proposed several policy principles and asked for comments from the participants.

Wolverine's response is based on several overriding factors in Michigan that ***cannot*** be ignored in the context of this debate.

1. Michigan's economy can only be strong if electric providers in Michigan can produce reliable supply for all consumers at rates that create an incentive for businesses to locate and remain in Michigan in the context of a global economy.

2. Michigan, as a peninsula state with few indigenous fuel choices, has limited options for specific types of base load generation. Michigan relies heavily, and will continue to rely heavily in the future, on major rail and Great Lakes transportation of coal and interstate transportation of natural gas.

3. Michigan currently relies on significant imports of power and thus will benefit from increased availability of interstate transmission and increased import capacity from the lower Midwest, where indigenous fuel options are more available, practical and competitive.

4. Additional base load generation must be built in Michigan. The last major base load coal facility built in Michigan was Belle River (circa 1984-1985). Since the time of its construction, the demand for electricity in lower Michigan has nearly doubled. If design for a new coal plant commenced today, it would not be operational ***before 2012***. Michigan must initiate policy efforts immediately if it is to have any competitive opportunities in the future.

5. The capacity additions of the late1990s were primarily natural gas-fired peaking and combined-cycle plants. These plants enjoyed fast permitting, short construction periods and relatively easy design specifications. They have provided an enormous benefit to Michigan by improving reliability. These plants cannot compete with coal and nuclear for base load operation however, unless, and until natural gas prices drop below $4.00/mmBTU.

6. While admittedly outside of its direct regulatory authority, MPSC Staff should consider the enormously more difficult challenge that power plant developers have today than existed when the current fleet of base load generation was constructed 20-40 years ago. There are significant and well-organized

opposition groups to nearly all types of generation. Additionally, Michigan has contemplated stricter rules than other parts of the Midwest for water withdrawal and mercury emissions. Lenders are nervous and organized opposition for any proposed site is very strong. Unless Michigan is willing to make development of a coal-fired plant more attractive than neighboring states, those infrastructure dollars will be built outside of Michigan further hindering growth of business in Michigan.

Response to the MPSC Staff Proposal

Core Values

The MPSC Staff put forth three values at the August 2005 Capacity Need Forum meeting:

a. *The ratepayers come first*

b. *Electric reliability is a public good*

c. *We need to adhere to a fairness doctrine (you get what you pay for)*

Wolverine and its members agree that the ratepayers come first. The very nature of a cooperative (the members/ratepayers are the owners) ensures that Wolverine's members and its member-customers come first. Since Wolverine and its members operate for and on behalf of their ratepayers/owners, the ratepayers and owners are one and the same.

Wolverine agrees that reliability is a public good. The highly interconnected nature of the electrical grid makes it impossible to identify which customer benefits more from a particular generator or networked transmission facility. Electrical reliability is a fundamental service essential to the competitiveness of Michigan businesses and can indeed be categorized as a public good. Reliability can be enhanced in a number of ways through generation and transmission projects, and recognition should go to all entities that enhance reliability without discrimination as to type or owner.

Wolverine acknowledges that MPSC Staff should adhere to a fairness doctrine; the difficulty comes with measuring "fair". If the MPSC Staff means that if customers who pay a "reliability premium" should get the benefit of that reliability and not have to "pay twice", then Wolverine agrees. Wolverine feels that the fairness doctrine should also recognize that efforts to stimulate development of generation in Michigan must be available to all interested parties and the extent of the parties' interests cannot be limited in any fashion. In other words, Consumers Energy and Detroit Edison who currently own and control approximately 90 percent of all base load generation in Michigan, cannot be the sole beneficiaries of revised regulatory policy.

"Reliability Option"

The MPSC Staff presented a concept of a "Reliability Option" that contains several provisions. Wolverine agrees that an "Upfront Regulatory Commitment" will lead to higher security and lower project financing costs over the long term. Wolverine would like to raise several additional points for consideration in the context of this dialogue:

***Market Power* –** The focus of the MPSC Staff proposal seems to be on setting rules for encouraging existing Michigan-regulated utilities to build generation. Wolverine hopes that the final outcome of this process will encourage all entities, whether cooperatives, municipalities, or independent companies, to participate on an equal footing. The fact is that approximately 90 percent of all base load generation in the two Lower Michigan zones contemplated in this collaborative effort is owned and controlled by Consumers Energy and Detroit Edison. Further concentration of this market power reduces wholesale competition. The parties must recognize that Detroit Edison and Consumers Energy will rightfully look to existing sites on which to construct modifications or additions to their generation fleet. All Michigan market participants should be allowed the opportunity to participate in project improvements regardless of location.

***Commitments to Capped Price and Schedule* –** This provision makes sense on the surface, especially in light of nuclear plant cost escalations during the late 1970s and 1980s. In practice, however, it will be very difficult and likely very expensive to make commitments to price and schedule at the outset of this process. With seemingly endless appeal opportunities afforded in the Air Quality permitting process, the MPSC Staff may be suggesting schedule guarantees that are impossible for any entity to adhere to in today’s market. Price guarantees can be achieved through Lump Sum Turnkey bidding processes with engineering, procurement and construction contractors. The stark reality, however, is that the likely size of any one base load project could easily exceed $2 billion. Today, in the United States, there are only two or three companies that have the financial resources to provide a guaranteed Lump Sum Turnkey price for projects this large and, if they do, it may come with a hefty premium.

Need For a Defined Process **–** Wolverine believes that a prescriptive process may be useful in the long run only if it is pre-established and yields some certainty at its conclusion. An exhaustive process that affords an absolute right to develop will speed the construction time and ultimately offer lower rates to Michigan residents. A process that affords delays and endless appeals will only add another layer of risk to an already risky development environment.

Encouraging Collaboration **–** The regulatory process as outlined may discourage entities from working together. The fact is that base load generation is so expensive, so controversial and so financially risky, that all Michigan projects will benefit from a diversity of owners. If each entity attempts to demonstrate its need for capacity in the absence of the other Michigan participants, Michigan customers will, in one form or another, pay higher utility rates in the end. The MPSC Staff proposal can be improved by mandating that the process be collaborative and that all interests are considered. According to early results presented by the Integration Work Group, Michigan needs several thousand MWs of new base load capacity in the next decade. Michigan entities owning pieces of different plants, all working together, will force coordinated planning efforts, lower construction costs and reduce life-cycle operating costs.

***One-time Option To Participate* –** The plan outlines a process that would give an AES a "one-time" opportunity to make a pro rata investment in the generating station. Wolverine is concerned that this will disadvantage non-IOU participants from participating in generation development. Other Michigan entities, including large retail customers, should be allowed to participate to the fullest extent of their interest and demonstrated financial capability to do so. How is Michigan and the competitiveness of its manufacturers hurt by having General Motors as an owner of base-load energy capacity?

***Competitive Bidding* –** Wolverine as a customer-owned entity is motivated to develop reliable power supply at the lowest possible cost. In this light, a not-for-profit entity may be the ideal ownership structure for new generating plants in Michigan. Based on Wolverine's experience in other projects, competitive bidding does not necessarily guarantee the lowest price for a plant. Sometimes this structure acts only to delay construction, and creates a circus-like environment for opponents to delay or block the project.

***Energy Efficiency* –** Wolverine agrees that energy efficiency programs should be pursued. Wolverine is opposed to the costly, time-consuming and human resource-intensive Integrated Resource Planning programs prevalent in the mid-1990s.

***Construction Partnerships* –** Wolverine believes that the MPSC Staff should, to the fullest extent possible, encourage Michigan utilities to work together in construction partnerships. Encouraging standard design and equipment and joint procurement will lead to considerable cost savings during construction, spread financial risk and lower life-cycle costs of the new plants.

Shepherd Advisors' response, pages 76-78

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September 30, 2005

George Stojic
Michigan Public Service Commission
6545 Mercantile Way, Suite 7
Lansing, MI 48911

Dear Mr. Stojic,

I appreciate the opportunity to respond to the Capacity Need Forum Staff Proposal and Policy Discussion of August 25, 2005.

Upon reading the proposal, there appear to be several dynamics at play:

1) The anticipated need to improve the reliability of Michigan's electrical grid,
2) The anticipation that new generation capacity will need to be built to improve grid reliability,
3) The unwillingness or inability of utilities to invest in new generation capacity without risk-free, guaranteed financing provided through rate recovery or other means,
4) The belief by staff that reliability is a "critical public interest"
5) Staff's belief that reliability's "critical public interest" status could provide an overriding rationale for a "reliability option" that would provide utilities with cost recovery (that utilities could not get otherwise) through a "reliability charge" levied on rate payers[1], and
6) The desire by the Commission to achieve targeted reliability in a least cost manner.[2]

I appreciate also the challenge of the Commission to balance the need for meet growing electrical demand in a competitive, choice environment, with the desires of utilities to build additional conventional generation in Michigan on a minimal or no risk basis.

If reliability is indeed the primary goal being pursued, there are numerous other strategies that the Commission and Staff should pursue first to can enhance reliability much more effectively and less expensively than the public financing of central power plants.

Power reliability is primarily a function of the frequency and duration of electric outages. Most outages occur at the distribution level, are relatively minor, and are caused by severe weather (lightening, ice, etc.), falling or sagging trees, animal intrusions and other hard-to-control factors. More serious brown outs, black outs, and disruptive voltage fluctuations, however, typically start with minor outages at the distribution level that then "cascade" into systemic (distribution and transmission) failures due to (1) local, regional, or system-wide imbalances and fluctuations between the demand and supply for power, and/or (2) exceeded thermal limitations or voltage capacities of specific transmission/distribution equipment that cause equipment performance to degrade or cease.

Thus, improving grid reliability on a systemic basis is primarily a function of (1) improving transmission and distribution equipment, and (2) reducing instances of large demand/supply imbalances and

[1] In the proposal, Staff states, "If it chooses to do so, a utiity can build a new generating plant in the traditional manner, that is it cound finance the plant without public involvement and then request rate recovery after the plant is completed. However, the utility could instead seek to build a generating plant under the relaibity option discussed herein"
[2] The proposal states, "It is curcial for Michigan to secure the right type of power (base load, cycling, peaking, renewable, fossil, etc.) at the lowest possible price."

fluctuations. Towards this end, I strongly urge Staff and the Commission to address reliability concerns applying the following strategies, ordered in priority:

1. Reduce demand, particularly at peak times, with robust energy efficiency and demand side management programs. The most effective way to enhance grid reliability is to enable users to easily demand less power, both in general and particularly at peak times. There are many examples of effective energy efficiency and demand side management programs that work to reduce load, especially peak load, and can be very cost-effectively applied here in Michigan.

2. Impose Congestion Fees at grid nodes particularly susceptible to reliability problems. Reliability problems often emerge simply because too many users are drawing more power than local distribution nodes in the grid can handle. The Commission should use the power of the market place to raise local penalties for congestion. Higher congestion costs will both send important price signals to users and will provide financial resources to upgrade transmission/distribution bottle necks.

3. Selectively upgrade transmission and distribution equipment. Reliability problems are often caused by single faulty pieces of equipment or systems. Often pinpointing problem equipment and system configurations is difficult. Fortunately, diagnostic tools are improving and can be used to make selected, cost-effective upgrades that can yield significant reliability gains.

   It is noteworthy that the Michigan Public Service Commission has provided grant funding to Intellicon Inc., a Michigan company, to developed very sophisticated software to diagnosis grid vulnerabilities. Intellicon has completed extensive analysis of much of Michigan's transmission and distribution infrastructure, and can provide the Commission with detailed equipment up-grade recommendations.

4. Promote the robust and wide-spread deployment of distributed generation (DG). The deployment of DG assets is a well accepted strategy to mitigate fragmented reliability problems. As described in a recent study prepared by Lisa Schwartz of Oregon's Public Utility Commission Staff[3], distributed generation produces electricity at or near the place where the electricity is used. DG involves the local use of:

   a. Combined heat and power (CHP)
   b. Small engines and turbines that run on diesel or natural gas, and
   c. Renewable energy systems such as solar power, wind power, small hydro, and biogas.

   These technologies offer numerous advantages over central-station power generation, particularly coal-fired generation. Benefits for DG result because DG is usually:

   - More energy efficient, extracting more value out of consumed resources,
   - Cleaner burning, reducing both the quantity and toxicity of pollution discharges and subsequent health and environmental quality problems,
   - Better able to follow and match electrical load changes, reducing demand-supply imbalance issues,
   - Provide on site peak power, reducing grid demand at high-congestion times
   - Lower transmission efficiency losses, improving costs and power quality
   - Providing power onsite, reducing the need for transmission and distribution upgrades.

   In addition, DG provides customers with abilities to better control electrical costs, have critical supply and back up power in case of grid failure, sell excess power back to the grid (and thereby improving

[3] See "Distributed Generation in Oregon: Overview, Regulatory Barriers, and Recommendations. February 2005. Lisa Schwartz.

economics for the user), and participate in demand response programs that augment supply at critical times.

DG can provide users with power flexibility (primary power, back up power, emergency power, co-generation, and peak shaving) and increase user power reliability and quality. If DG is located where the grid is constrained, it can reduce utility costs by delaying, reducing or even eliminating the need for investments in transmission, distribution, and centralized generation. In addition, DG, especially renewable DG, can significantly reduce the negative environmental impacts of power generation.

Finally, under favorable circumstances, DG can in many cases directly improve the financial performance and energy security of Michigan businesses, and can create significant numbers of Michigan jobs.

In addition to providing reliability benefits to users, DG provides disproportionate reliability benefits to grid reliability. Because most reliability problems occur at the distribution level, a DG in the right spot can have as much as 10x the reliability benefit to central generation. <u>In other words, 100 MW of distributed generation in the right place can provide the reliability improvement of 1000 MW of central generation</u>. At the transmission level, well-placed DG also has shown to have as much as twice the reliability benefit of central generation.

The use of energy efficiency, demand side management, congestion pricing, selected equipment upgrades, and distributed generation are well known and increasingly common strategies to mitigate both reliability and generation concerns. The benefits are well known to DOE[4] and system operators like PJM are on the forefront of developing and implementing these types of strategies.

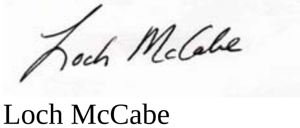
Many of these strategies can be encouraged and implemented in Michigan with regulatory and rule changes. Many strategies can be implemented on a cost-share basis with specific users and beneficiaries, reducing costs. Indeed, if aggressively pursued, many of these strategies could, over time, obviate many reliability and generation concerns at relatively little public expense, and significantly decrease the amount of new central generation needed for reliability enhancement.

Finally, if Staff feels that a Reliability Charge is still warranted to improve reliability, a use of these resources to FIRST MAXIMALLY ACHIEVE THE STRATEGIES ABOVE will lead to a far better expenditure of rate payer or public funds to build additional generation needed.

I hope my comments are helpful and will be taken to heart. As a rate payer, I want my energy expenses to be put to the best and highest use possible.

I truly appreciate your consideration.

Sincerely,



Loch McCabe
President

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[4] See for instance, "Distributed Generation: Benefit Values in Hard Numbers." DOE. www.eere.energy.gov/de/pdfs/benefit_numbers.pdf

MEGA's response, pages 80-88

MEGA COMMENTS ON STAFF CNF POLICY PROPOSALS

The Michigan Electric & Gas Association ("MEGA"), a trade association of electric and gas investor-owned public utilities, provides the following informal comments on the Michigan Public Service Commission Staff policy proposals in the Capacity Need Forum ("CNF") circulated on August 23, 2005. These are informal comments offered for the purpose of discussion and do not represent the formal policy position of MEGA or any of its individual member utilities. This disclaimer is included because the policy proposals are a conceptual framework for further discussion and subject to modifications based on input from various interested parties with different perspectives. MEGA understands that the MPSC Staff is considering policy recommendations to adopt and has not formally adopted the August 23, 2005 discussion as its proposal.

Major section headings below (identified by letters) are those used in the Staff proposal and the Staff proposal for each policy section other than the background is included in italics. Other bold headings are used to identify subjects addressed in these comments.

As an overall comment, MEGA expresses its appreciation to the MPSC Commissioners, Staff and participants in the CNF for the work and commitment associated with this project. The coordinators and group leaders have developed an excellent work product to date in this area of vital importance to our state.

Another overall comment arises from the multi-state service of certain MEGA member electric utilities. Some members are constructing or have constructed base load electric generation in other states, under the laws and regulations of those states which may include a process for advance certification. Any new MPSC regulatory policies should have the flexibility to incorporate regulatory approvals and treatments afforded to facilities by the state where a utility provides the bulk of its service, as appropriate.

A. Background

MPSC Jurisdiction: The report urges participants to make policy recommendations within the Commission's existing jurisdiction. Unfortunately, the boundaries of that jurisdiction are subject to interpretation and the very broad authority apparently granted by some of these laws is limited by later court interpretation. MEGA appreciates the Staff's desire to develop policies that can be implemented consistent with the existing MPSC jurisdiction. It is important, however, to recognize the limits of that jurisdiction and develop policies that are on firm legal ground.

Regulatory Statutes: Michigan public utility regulation is governed by public acts adopted over the last 100 years, which must be read together but are not written as an integrated code. The major acts establishing MPSC regulation of electric utilities were adopted in 1909, 1919, 1939, 1982 (adjustment clause amendments) and 2000 (retail customer choice amendments). Of particular relevance here are MCL 460.557(2) establishing a list of factors to be considered in setting rates, including a reasonable return on the fair value of all property *used in the service*; MCL 460.54 granting the

MPSC power to control and regulate all public utilities in the state; MCL 460.6 granting the MPSC broad authority to regulate public utility rates, services and all other necessary and incidental matters; and MCL 460.10b, granting the MPSC authority to establish rates and terms that promote and enhance development of new generating technologies and provide for reliable and lower cost competitive rates for all customers. The last of the above statutes is part of the recent Customer Choice and Electric Reliability Act of 2000 (CCERA) and has not been interpreted in court decisions. Section 13b of 1939 PA 3; MCL 460.6j(13)(b) is relevant to the issue of advance regulatory approval of power supply contracts. In recovering power supply costs through the annual PSCR rate proceedings, in order for a utility to recover capacity charges incurred via a long term power purchase agreement (in excess of 6 months), the utility must obtain prior approval from the MPSC. For certain “qualifying facilities” under federal law, the prior approval of the capacity charge recovery may not be modified during a financing period of 17.5 years.

These statutes appear to grant extremely broad authority to the MPSC; however, they are subject to court interpretations that restrict their meaning as discussed briefly below.

It may be difficult for outsiders, particularly the financial community, to understand the scope of the MPSC’s regulatory authority and the risks of adverse regulatory actions affecting the financial viability of a project. The hierarchy of authority is Constitution – Statute – Administrative Rule – MPSC Order. Any regulatory policy changes resulting from the CNF should be expressed clearly in the relevant order, rule or law and should not be in conflict with a higher level of authority.

Court Decisions: Huron Portland Cement Co v Public Service Comm, 351 Mich 255 (1958) holds that MCL 460.6 grants no specific regulatory power to the MPSC but instead is an “outline” of regulatory jurisdiction. Specific authority for MPSC action must be found elsewhere in the statutes. The limitation of this decision has been applied in subsequent cases. Attorney General v Public Service Comm, 412 Mich 385 (1982) holds that the question whether advance MPSC approval of power plant construction should be required is a policy matter for the legislature to decide. The Court recognized that the existing statutes did not provide for advance MPSC certification of power plant construction but only regulatory determination of the appropriate rate recovery after completion. Union Carbide Corp v Public Service Comm, 431 Mich 135 (1988) holds that the manner of operation of electric generating plants is a matter for utility management to determine and the MPSC’s broad ratemaking authority does not authorize the agency to make management decisions (although it can review the rate implications of such decisions). In this case, the Supreme Court likened a review of the regulatory statutes governing the MPSC’s powers to a “journey into the heart of darkness.” The Court was calling for modernization of the statutes, which has not occurred in subsequent years although the CCERA added a new legal framework to be considered along with the earlier laws.

The cases discussed above present a dilemma because they interpret the MPSC regulatory authority narrowly. As applied to the proposals, they indicate a risk in relying on the general, broad authority to support major changes in regulatory policy. At the same time, the Michigan courts tend to apply a "rule of deference" in evaluating MPSC actions, particularly if the subject of review involves rate-setting. Although Michigan does not have a "pre-approval" statute for generation additions, matters such as determination of recoverable costs, CWIP/AFUDC treatment and the role of bidding are matters which arguably fall within the ratemaking authority. Other matters, including market power and energy efficiency, are the subject of newer provisions in the CCERA. Policies should be crafted to minimize the risk of repeating the "experimental retail wheeling" situation, where the regulatory action was eventually overruled by the Supreme Court after several years.

The Staff should not rule out the possibility of legal revisions similar to the approach taken by some other states that have advance certification provisions in the applicable statutes. In Wisconsin, for example, new coal plants have been certified in advance of construction under WS 196.491 and the law provides for advance determination of the rate-making principles for recovery of the capital costs. WS 196.371. In July, State Senator Bruce Patterson held a press conference suggesting the possibility of a state statutory measure regarding energy policy similar to a New York model. Some legislators may believe that policy revisions should be made through statutory changes.

Recommendation on MPSC Jurisdiction: MEGA believes it would be appropriate for the MPSC Staff to consider obtaining legal memoranda from its counsel on policy proposals of this type, to determine the likelihood of an adverse decision if the policy is challenged in the courts. The MPSC has received many comments regarding the need for regulatory certainty for utilities to build and finance large base load generating stations. If new policies are implemented without solid legal authority, the required certainty will be lacking.

B. <u>Reliability Option</u>

> *If it chooses to do so, a utility can build a new generating plant in the traditional manner, that is it could finance the plant without public involvement and then request rate base recovery after the plant is completed. However, the utility could instead seek to build a generating plant under the reliability option discussed herein.*
>
> *Under the reliability option, the utility would file an application with the Commission containing the following: (1) details of its 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. The level and timing of the reliability charge would be designed to be commensurate with the public benefits associated with the plant.*
>
> *A contested case public hearing would be held on the utility's application. If the Commission determined that the plant's expected reliability value warranted it, the Commission would 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 in 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.

As noted, this option is not a matter directly addressed in the regulatory statutes and should be the subject of legal analysis. The underlying concept of reliability as a public good is addressed below.

The CNF needs to consider the rapidly changing environment of the regional wholesale markets and potential changes to reliability and market rules. Significant developments include the following:

- MISO began its “Day 2” market this Spring and will continue to evolve;
- MISO has not finalized its policy for resource adequacy;
- PJM is developing its Reliability Pricing Model;
- Joint and common markets are developing;
- Regional reliability councils are being consolidated;
- The federal Energy Policy Act f 2005 was adopted, with many new measures and creation of an Electric Reliability Organization.

Economic Concept of Public Good: The Staff report suggests that electric reliability is a classical economic public good. A public good is something that is difficult or impossible to produce for private profit because the market fails to account for large beneficial externalities. Once produced, everyone can benefit without reducing the enjoyment of others and it is difficult to prevent access to the good. Examples include national defense, a clean environment, law enforcement, lighthouses and street lights. See, Wikipedia internet encyclopedia (“Public Good”).

Under traditional regulation, reliability cost was included in the regulated rate structure, insofar as planning reserve margins were established by voluntary organizations such as NERC and the costs of incremental generating plants built to maintain reliability were recoverable from utility customers. Now, there is a serious “free riders” problem because of the ability of electric customers to avoid incremental costs if there is an AES available to bypass the utility adding a new generating plant. The financial risks associated with this situation are addressed in the Fitch Ratings comments of April 22, 2005 (“Fitch Comments”) provided to the CNF.

What is Reliability? Under traditional regulation, reliability is “built in” to the existing system, since an electric utility’s duty to serve encompasses the obligation to construct and maintain a system capable of rendering quality service to its existing customers plus new customers it is obligated to serve as a public utility. Reliability has not been viewed as a tangible asset, but only as an attribute of electric service which is made possible by a multitude of decisions involving the type of system owned and operated by the utility and its acquisition of additional resources. For example, a utility such as Alpena Power can maintain reliability by lining up sufficient capacity through wholesale power purchase agreements and elect to build no new generation. The CNF has considered various options, including demand side programs and renewable energy, in developing the modeling scenarios and MEGA commends the Staff for including these options. In focusing on the reliability option, the analysis should elaborate on how other options would be included and the degree of flexibility afforded to utilities to develop projects associated with reliability improvements. The proposal is founded on the assumption that the current environment is not providing sufficient incentive to encourage new capacity additions; therefore, regulatory intervention is needed and justified. MEGA agrees with Staff that the policy should provide sufficient revenue certainty to allow projects to be financed and constructed. Flexibility is important – utilities could propose differing solutions based on their individual circumstances. Examples include pre-authorized construction, pre-authorized rate of return, third party lease financing, purchase contracts, demand side programs and others, all contributing to reliability.

The Fitch Comments discussed this type of approach as its "hybrid market structure with a carve-out." Fitch did not use the "reliability" label although it spoke of socializing the costs of the reserve margin, which is the same thing. The Fitch option contemplated a non-bypassable charge for either: (1) new utility owned generation additions; or (2) long term contracts with independent developers. Ultimately Fitch concluded that the special carve-out for new construction under the current hybrid market structure is not a desirable option because uncertainty about the future market would undermine credit quality of the investor-owned utilities and there would be an eventual need to reform the market structure to remove the financial risk. Fitch preferred a return to a regulated market which would eliminate the risk of load migration (free riders avoiding costs) and provide stability needed for long term power purchase agreements.

Integrated Resource Planning: Part 2 of the reliability application calls for analysis of the resource, need and public benefits. The CNF process is examining these items and if the proposal is in accordance with the CNF final report, would that provide the required support? An ongoing or repeated process like the CNF would provide useful information for planning and background purposes.

Ratemaking Authority: The proposal to include CWIP in rate base without an AFUDC offset appears to lie solidly within the ratemaking authority and discretion of the MPSC. All utility customers would be charged interest on the expenditures for a new generating plant during the construction period, before the project is operational. This has the advantage of spreading out the rate impact over time and reducing the size of the rate increase, since the construction interest recovered via CWIP is not capitalized. The CWIP policy may reduce project risk and financing costs. In previous cases, the Commission has applied a "used and useful" test from common law and perhaps contained MCL 460.557(2) (return on fair value of property "used" in the business). Opposing parties might argue that the CWIP-without-offset provision is illegal because it allows recovery of costs for non-useful property. The courts have tended to defer to the MPSC on this issue however, for assets such as property held for future use or mothballed plants that might be needed in the future.

Project Risks: It may not be practical to develop an iron-clad rule that caps recoverable value of the plant and establishes a firm in-service date. An alternative would be to approve the targets and require justification of any increases beyond the cap if there are significant changes during the project construction, particularly matters beyond the utility's reasonable control. Michigan nuclear power projects experienced very large cost increases during the time of construction and multiple delays in the projected service dates. This was a function of the Three Mile Island incident, construction management issues and many other factors which remain as possibilities in the current environment and are difficult to predict. If there is a regulatory guarantee and the asset is needed, what happens if the project experiences overruns and delays and the contractors refuse to finish it without assurance that the additional costs will be paid and the utility balks at completion unless it is assured recovery? Naturally, the financial community prefers as much risk as possible be covered by utility customers. If such risks are not covered under the proposal, the availability and cost of financing may be affected.

Reliability Value Credit: It is unclear what is meant by the term "reliability value" associated with a new power plant. If some sort of financial rights are involved, more explanation is needed. Perhaps this refers to the enhanced reliability which exists because of the plant, due to its availability as a resource. All Michigan residents presumably get the benefit of the reliability, whether or not they use any of the power. The power can flow into the MISO wholesale market or the regulated state market, therefore the AES customers have theoretical availability.

More detail regarding this credit concept is needed to evaluate and comment on the overall reliability option proposal. MEGA recommends addressing the accounting and financial implications of the policy. Further, utilities should have flexibility, with the option of recovering CWIP from system supply customers but not choice customers. In such case, the choice customers would not have the capacity or financial rights contemplated in this proposal.

C. <u>Competitive Bidding</u>

> *Major plant construction involves large capital costs and financial risks. It is crucial for Michigan to secure the right type of power (base load, 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. That alternative might be a proposal by another entity to build the same plant at a lower cost. Therefore, any cost cap proposed by a utility in a reliability option hearing should be given considerable deference if the utility has undertaken a fair and open competitive bid.*

The Staff proposal discusses an alternative whereby a bidding process is developed for the utility seeking a capacity addition to allow independent project developers to build the entire plant instead of utility-managed construction. In exchange, the utility would receive deference in the reliability option process for its proposed cost cap.

It is assumed that project competitive bidding will provide cost benefits. This is open to question and there may be advantages to allowing flexibility in developing projects rather than establishing a fixed set of bidding requirements. We received an internal comment that competitive bids represent no more than opening gambits in the development process. A second round is needed to really pin down all the details at which point the anticipated leverage of competitive bidding disappears and the advantage turns to the successful bidder. Further, the use of bidding introduces more complexity and delay into the system because it requires policing and there would be many more parties with differing interests.

Astronaut John Glenn reported that his last thought before the first Mercury orbital flight was: "Here I am, sitting on top of the low bidder." This story illustrates the need to keep in mind the ultimate goal of a successful and good quality asset, not just a low cost. There should be some room for pragmatic judgment on non-cost considerations.

The use of competitive bidding in the development of new Michigan base load generation may occur for either: (1) a utility selecting the contractors and suppliers for its own project, or (2) solicitation of proposals from independent turnkey developers (IPPs, conservation projects, etc.) to fill an identified block of capacity. The following areas of potential difficulty should be addressed in the policy discussions of bidding:

- There may be a need for a new bureaucracy to police the bidding and the MPSC may lack statutory powers and resources to handle the task.
- Low-ball bidding could lead to serious problems down the road – the award based on lowest cost could come unraveled if the true costs prove to be higher and there are serious quality issues. You can't start over from scratch midway through the project.
- Disappointed bidders might sue and disrupt the process.
- Least cost bidding might lead to compromises on quality, unknown until some failure arises after the operational date.
- Mandating this type of bidding approach arguably intrudes on the utility's management function, and could lead to "Union Carbide" litigation unless there is a clear statutory provision.
- The MPSC Staff might be lobbied to favor alternate suppliers such as IPPs over the utility.
- Unions may object if the least cost approach favors or requires use of nonunion workers.
- Non-utility bidders may lack sufficient expertise to design their proposals to work well within the utility system.
- The bidding process could be susceptible to unethical practices such as disclosure of inside information and attempts to manipulate the result.
- Bids might be awarded to IPPs which have no public duties comparable to a utility's duty to serve. Also, the generating system becomes more fragmented and harder to manage.
- Bidding may result in a "race to the bottom" where low cost trumps all other considerations (mainly quality as noted above).

The overall point here is not to assume the virtues of competitive bidding without considering the risks. Wisconsin abandoned a former process involving a two-state CPCN and bidding.

Although Wisconsin does not have retail open access, wholesale electric customers have choice of suppliers and utilities gain and lose these wholesale customers. Even with this degree of wholesale choice, both We Energies and WPS have received advance approval from the PSCW to construct new coal-fired base load generating plants. If appropriate rules and frameworks are implemented, customer choice and rate of return regulation may be able to coexist. While the conceptual reliability option developed by the MPSC Staff may be within that framework, MEGA believes there needs to be more development and discussion.

D. Energy Efficiency

> *None of the parties submitting comments have opposed energy efficiency, and we expect that a demonstration that a proposed plant is the appropriate resource to meet an identified need would include an analysis of cost effective energy efficiency as a resource option.*

It is reasonable to allow consideration of demand options in resource planning. Utilities should have the ability to include demand side programs in any RFPs developed under the reliability policy, or in general ratemaking. Flexibility is preferable to mandates in this area. At the same time, technology, options and markets for energy efficiency continue to evolve. Customers should be allowed to react to the changes and be provided price signals that accurately reflect cost and values and do not create or promote subsidization.

E. Construction Partnerships

> *As method to mitigate the risk of construction, Staff expects that utility proposal made under the reliability option would include an offer to other Michigan load serving entities to become partners in the plant.*

In some situations it may be reasonable to seek participation by other LSEs in a generating project. Under the current market structure, the free riders risk is less with LSEs such as cooperatives and municipal utilities that are not full participants in retail open access. The LSEs should be allowed to negotiate the terms of participation in any project. At the same time, developing participation by others can be time consuming, difficult and impractical. Partnerships of competitors can lead to years of strife and eventual separation. Mandates in this area should be avoided.

F. Market Power

> *Detroit Edison has articulated a concern that any new proposal to construct plant may cause it to violate market power provisions of 2000 PA 141. Other parties have indicated 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.*
>
> *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 a more broad based participation in a construction project should decrease the concentration of ownership and allow parties to secure long-term power at stable prices.*

The market power issue arises from CCERA Section 10f, MCL 460.10f. With the relevant markets being defined as either the entire Lower Peninsula or the entire Upper Peninsula, the market power concerns do not affect Indiana Michigan Power Co or Alpena Power, MEGA's members in lower Michigan. Market power issues will arise in the Upper Peninsula, because any sizeable generating facility in that small market can reach the 30% threshold and be in excess of the owning utility's native load. Participation by other LSE's may spread the risk somewhat; however, such participation is would likely be minor in the Upper Peninsula. This issue does point to the potential need to involve the legislature in policy reforms, if the market power situation becomes an obstacle to needed reliability improvements.

CCERA Section 10f was adopted before the MISO Day 2 market and FERC processes for defining market power. MISO, its market monitor and the FERC may be in the best position to handle market power, which calls into question the very need and relevance of Section 10f.

Respectfully submitted,

Dated: September 30, 2005

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MEC/NWF's response, pages 90-91

COMMENTS TO THE MICHIGAN CAPACITY NEED FORUM

By

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September 30, 2005

On behalf of the National Wildlife Federation (NWF) and Michigan Environmental Council (MEC), we appreciate the Michigan Public Service Commission's (MPSC) invitation to participate in the Capacity Need Forum (CNF). The following comments represent a collective NWF-MEC response to the staff proposal received at the August 29 CNF meeting.

- NWF and MEC fully support the MPSC's conclusion that electric reliability is a public good—exhibiting non-rivalrous and non-excludable economic qualities—and that efficient and fair allocation of public goods across the demand schedule requires the prudent intervention of government and its agencies.

- In this case, the role of government should be to facilitate a dynamic process that ensures the public needs are met at a reasonable cost to both the consumer and the utility.

- Project review should be structured to evaluate the fiscal and reliability parameters of diverse projects (1) under likely future regulatory scenarios, such as the implementation of a renewable portfolio standard (RPS), state/federal mercury or carbon dioxide (CO_2) emissions standards; (2) that exhibit the greatest degree of "public benefit"; and (3) seek to minimize disadvantages for smaller firms attempting to enter the power market.

- Full rights of Michigan ratepayers must be protected in any bidding process. Therefore, ratepayers must not be asked to bear any of the financial risk that belongs more appropriately to utility company shareholders. Moreover, it is critical to acknowledge that ratepayers participate in the Michigan economy in a variety of other, equally legitimate roles. As a result, they shoulder external costs of energy generation and delivery that are not captured in the billing process, including but not limited to pollution-related healthcare expenses and an enormous energy trade imbalance due to the state's heavy reliance on imported fuels.

- In general, NWF and MEC support the Reliability Option detailed in the August 29 proposal. We strongly support the inclusion of "analysis of public benefits" listed under item (2) in this section. The term "public benefit" certainly deserves a lengthy qualification—extending well beyond a simple threshold of lowest cost. The MPSC's emphasis on *Construction Partnerships* should reflect an expansive consideration of such benefits. In fact, there are examples of collaborative utility planning, such as in the State of Colorado, that involve a wide range of stakeholders early in the utility permit development process. Bringing together industry, public interest advocates and regulators is this way can ultimately lead to better decisions that save time, money and litigation.

- Also pertaining to Reliability Option sub-head, consistent with items (3) and (4), cost-recovery measures for new investments establish a viable means to promote projects that enhance a variety of public benefits and should be explored at length in proposals submitted to the MPSC. This should include incentives that reward proactive investment in new technologies that enhance public benefits.

- U.S. Energy Policy Act of 2005, Subtitle A, Section 215 states, “The term 'reliability standard' … does not include any requirement to enlarge [existing bulk-power system] facilities or to construct new transmission capacity or generation capacity." NWF and MEC urge the CNF to similarly recognize that non-supply side options, which include energy efficiency and demand side management, should be considered as effective and legitimate means to achieve reliability requirements.

- There is extensive documentation that investments in energy efficiency often result in the cheapest, quickest new energy resource among competing options. The burden should therefore be on a utility making a proposal to demonstrate why energy efficiency is not the first, best option for a new energy resource, particularly since these projects could deliver increased domestic investment in Michigan’s struggling economy. Performance parameters of energy efficiency projects are well understood technically, and therefore can be assigned long-term values with a high degree of confidence. In contrast, future prices for traditional, fossil-based fuels can be highly volatile, and therefore carry greater risk exposure for Michigan’s ratepayers.

- It is vital that utility consumers have access to more information about price signals and a greater range of options in order to enable more nimble adjustments in customer behavior that improve overall market efficiency.

- Finally, in a pure economic sense, competitive bidding (or auctions), are often preferred as an efficient medium for resource allocation. Using this model the problem of asymmetric information over costs between large utilities (private) and governing agents (public) is often less problematic, particularly when evaluating winning bids among similar firms. The result is a cost minimization of something economist’s term “informational rents”. In other words, competitive bidding can prevent price-gouging when an information or resource advantage is present—which is of particular concern when addressing the allocation of public goods. It is important to note, however, that entering firms face significant disadvantages in these auctions due to production uncertainties, lack of bidding experience and incumbent market power. In addition, larger conglomerates possess a clear advantage in their ability to bid below, or short-side, actual project costs in order to win contracts, seeking compensating rents by means of rate recovery at a later date. For these reasons, bidding processes must be developed with clear parameters for contractual obligations and provide fair and equal opportunity to all parties large and small.

Knowledge Works' response, pages 93 - 98

September 30, 2005

To: Mr. George Stojic
Michigan Public Service Commission
Capacity Needs Forum

From: George Deljevic

RE: Comments on Staff's Values and Reliability Option

Thank you for the opportunity to comment on the issues in front of the Forum. This is important work for each of us individually and certainly for the state as a whole, and your willingness to encourage and entertain diverse viewpoints is appreciated.

We are submitting a set of assertions and ideas that may appear provocative and that could be interpreted as lying outside the scope of the current discussion. However, our intention is not to lay blame or to stir the pot, nor is it to blithely expand the scope of the Forum. Rather, our intention is to add an element to the debate that is currently missing, and to offer some novel proposals for exploring alternative avenues for the achievement of energy policy objectives that serve the state as a whole. It is therefore our belief that we can best contribute to the discussion by proffering assessments and ideas that lie a bit outside of the mainstream of what has been posited to now. That said, we respectfully submit our views for your consideration.

Overview and Commentary

In our view, the discussion around electric industry structure to this point has been excessively dogmatic and lacking the blending and balancing of views and possibilities that is necessary for a breakthrough solution that works for everyone. Over the past two years, we have seen the utilities work to undermine forces of choice and competition, and we have seen the competitive forces work to undermine the utilities. In the meantime, the Commission has been forced into split-the-baby type comprises that don't really work for anyone in the long term, and the Legislature has made an effort at reconciling these polar positions, understandably without great result.

It doesn't have to be this way – there are certainly alternative, creative structures that provide the benefits of choice and competition *and* fair outcomes for the utilities *and* reliability. The key is to ensure that the opposite polarity between stranded cost recovery and viable choice and competition based market structures is dissipated, so that both may survive together. We also must ensure that reliability is not sacrificed at the altar of free markets - and *vice versa* – that the mantra of reliability is not used to as a stake to be driven into the noble heart of customer choice and supplier competition. Both sides – the utilities with their desire to return to the monopoly days of guaranteed returns and low accountability, and the free-marketeers with their assault on utility stranded costs and *faith* in the market to provide for long term investment and reliability – are tending towards extremes and missing opportunities for innovative solutions.

Values and Policy Objectives
We hope that the industry and policy makers can find a different track that will lead to a more balanced and effective approach towards achieving the state's policy goals. With respect to these goals, the Staff has proposed the following values:

- Ratepayers come first
- Electric reliability is a public good
- We need to adhere to a fairness doctrine

These points are indisputable in the major sense, but they may not provide sufficient substance to formulate a truly effective policy regime. Of course ratepayers come first, but without serving the legitimate interests of the industry, neither will ratepayers be served. Taken to its extreme, this position would have suppliers provide energy resources without regard to profit.

The characterization of electric reliability as a public good - while correctly suggesting that market forces alone probably won't solve reliability issues - connotes a lack of choice and accountability in the system of delivering reliability. If reliability were delivered in the means of other 'public goods' like, say, roads and bridges, then fees would be collected from all without regard to impact or use, and there would be little incentive for conservation and proper resource allocation. It is our belief that a more nuanced and comprehensive view of the *system for provision* of reliability is called for.

Finally, the notion of adhering to a fairness doctrine is of course unobjectionable. However, fairness can be notoriously difficult to define, with each interested party characterizing their claims as legitimate in the name of 'fairness'. You have provided a skeletal interpretation (you get what you pay for), but we would suggest that the issue of fairness goes far beyond this realm. Is it fair to require all ratepayers to support resources that are chosen by the utilities, or by a government body? Is it fair to lock in a guaranteed rate of return to resource developers? Is it fair to put utilities in the driver's seat when it comes to the development and/or selection of new resources? Fairness is a wide ranging discussion that is at heart a question of balancing the values and interests of all participants.

We would suggest an alternative set of policy objectives:

- To promote reliable electric service, so that all electric consumers can be assured power supplies that are continuously available, save for interruptions due to acts of God.
    - To promote a measure of electricity price stability, allowing for moderate pricing signals to balance supply and demand, while avoiding the extreme volatility that hinders effective financial planning.
    - To achieve a balance in the allocation of risk and reward between producers and consumers, in the support of the other objectives.
- To conserve the resources used in the production and consumption of energy in the state, including human and material (financial) resources, natural resources, and environmental resources.
- To provide consumers of electricity with a reasonable opportunity to meet their varied needs and desires in the marketplace.
- To account and make provisions for the social issues surrounding the electric industry.

We believe this set of objectives is broad enough to allow a wide frame of debate, while substantial enough to serve as a useful touchstone in the development and evaluation of various policy proposals.

The Staff's Proposal

If our understanding is correct, the Staff has essentially proposed a utility driven system that would provide for new resources with substantial returns underwritten by ratepayer guarantees. Additionally - and laudably - the Staff has attempted to work in provisions to ensure competitiveness in the resource development and selection process, a doctrine of fairness for opportunities to participate in these developments, and a nod towards conservation.

The chief concern here is that there is a significant difficulty in allowing traditionally entrenched and powerful utilities to drive the resource selection and development process. Despite protective measures, oversight, or any other means to try and check the incumbents' power here, one can be assured that the utilities will in fact be in control of the process. People and organizations being what they are, they will likely attempt to use this control to their advantage - whether or not it generally serves the state's policy goals.

This is on the one side an issue of hard power, which can probably be addressed through various measures, but it is also on the other side an issue of soft power, which is much more difficult to contain. The soft power of which we speak is one of control of information, of the influence that comes from being the prime cause in a process, of the force of long reaching tentacles of organizations that have operated in every corner of the state for many decades. This sort of power is only seen behind the scenes and noted widely after the fact, and is therefore very difficult to control through standard policy measures. The best remedy is to break the chain of influence completely, to provide a system of 'checks and balances', where no one party, and especially no party that is generally unaccountable, can exert influence over the entire prospective resource base.

The Staff has made a strong effort at introducing a measure of fairness with regard to access to development opportunities and resource rights. Certainly there are aspects to the Staff's proposal that could serve as useful constructs in a rigorous system of reliability provision. However, when coupled with the power granted to utilities in the process, it is hard to see how things will work out for customers or their chosen suppliers in the long run. Customers will pay reliability charges for resources developed and/or selected by the utilities, which will almost certainly present less than optimal resource selections due to the factors cited above; and suppliers will be forced into a position of negotiating with the local leviathans – not a happy prospect for anyone that understands what this can be like when the utilities hold the cards. We believe some form of the Staff's proposals would work much better in a setting where the overall resource development and selection process was truly competitive.

Finally, it seems to us that nothing works better to promote conservation than accurate pricing signals, and this is an area where current and proposed Commission/utility policy falls *woefully* short. To wit, customers receive pricing signals that are *average cost* based, while the true value of conservation is in *incremental cost* avoidance. The swiftest and surest way to promote cost-effective conservation is to provide a mechanism that transmits accurate incremental cost pricing signals to those that are making the conservation decisions. (Witness the recent drop in gasoline consumption triggered by price increases at the pump.) This we see nowhere on the horizon, and indeed, we are in danger of moving ever further from this with the pending utility unbundling and rate re-alignment proceedings. Under these proposals, a typical general service customer will see only about $0.05/kWh of value for each kWh of generation they don't buy, while the true value of these kWh's is on the order of $0.07 - $0.08/kWh. If approved, these proposals will put the final nail in the coffin of Michigan's choice and competition program, and will put a lid on any future customer driven conservation programs.

A Sketch of An Alternative

As stated above, we believe the following objectives provide a useful frame for evaluating policy proposals, namely that any market structure should serve:

- To promote reliable electric service, so that all electric consumers can be assured power supplies that are continuously available, save for interruptions due to acts of God.
    - To promote a measure of electricity price stability, allowing for moderate pricing signals to balance supply and demand, while avoiding the extreme volatility that hinders effective financial planning.
    - To achieve a balance in the allocation of risk and reward between producers and consumers, in the support of the other objectives.
- To conserve the resources used in the production and consumption of energy in the state, including human and material (financial) resources, natural resources, and environmental resources.
- To provide consumers of electricity with a reasonable opportunity to meet their varied needs and desires in the marketplace.
- To account and make provisions for the social issues surrounding the electric industry.

It is our believe that only a market structure based on customer choice and supplier competition can best support the human and material resource conservation goals of point 2 and all of the goals of point 3, and that this assertion is generally self evident. It is also our belief that choice and competition are not incompatible with the other policy objectives (and may even be relatively supportive of these objectives measured against other options), but that certain structures are necessary to support the markets in these areas.

Since we won't argue the self-evident benefits of choice and competition in holding down costs, promoting efficiency, and meeting varied needs and values of customers, we will offer some ideas on how choice and competition can be structured to serve the other objectives.

First, the foremost criterion for the provision of adequate energy resources is that those that can provide these resources – the industry – be presented with adequate incentive to do so. While of course we clearly don't believe that a reversion to guaranteed 11% life-of-plant rates of return is reasonable, some form of market shaping is good and necessary. The primary financial risks facing resource developers are an oversupply of competitors, or a scarcity of customers. The first issue can be addressed by establishing a cap on the amount of generation capacity (or total resource availability if you want to include import capability) that may be installed in the state. The limit could be set at, say, 20% reserve margin, which would ensure that the market is at no time flooded, while providing freedom for any competitive developer to build up to this point.

On the customer side, the state may require all load serving entities to back sales to end use customers with two to five year contracts with generators or those ultimately controlling generating assets. This would ensure that signals would be sent for needed generation supplies, without tying retailers/customers into long term ‘marriages’ from which they cannot escape.

Finally, to protect against a general absence of load materialization, i.e., if load shrinks or doesn’t grow as projected, a system of price supports could be established that would provide resource developers with the ability to pay bank debt and return capital to investors without rewarding them with a guaranteed double digit rate of return. To those that scoff at this notion, we would only submit that the system of price supports in food production may well be credited with providing this country with an ample and stable supply efficiently produced at competitive prices.

Summary

In summary, in this paper we have argued the following points:

- In terms of the state of the industry, neither those that seem to want to stifle competitive markets in this state nor those that seem to want to throw the utilities to the wolves and place unquestioning faith in the markets are best serving the policy interests of the state.
- Consequently, policy makers have been forced into futile efforts to split-the-baby and to reconcile opposite polar positions, all with little to show in terms of substantive policy progress.
- It is time for an exploration of alternative and novel approaches that offer reasonable treatment for past investments, a system for the provision of reliability and resource adequacy, an opportunity for customers to choose and a requirement for suppliers to compete, and adequate provision for the social policy goals of the state.
- The Staff’s proposed value system, while generally unobjectionable, may not provide sufficient substance to formulate a truly effective policy regime. We have proposed an alternative set of objectives which do not contradict the Staff’s proposal but attempt to put in place a wider and stronger frame on which to hang various approaches.
- The critical flaw in the Staff’s resource addition proposal is to put utilities in the driver’s seat of the process. While regulatory structures may be able check the ‘hard power’ influence of these giants, it will be much more difficult to counter their ‘soft power’ capabilities.
- The Staff’s intentions with respect to introducing a measure of fairness in access to development opportunities and resource rights would be best served in a setting where the overall resource development and selection process was truly competitive.
- Thought the Staff attempts to address conservation, it is self-evident that the most effective means of conservation is through the transmission of timely and relevant incremental cost price signals to those making the conservation decisions (customers). This doesn’t seem to be on the horizon, and we are in fact in danger of killing conservation efforts through the current rate restructuring proposals before the Commission.
- Finally, we have argued that a market structure with customer choice and supplier competition at its center is, *prima facie*, the best means for meeting the varied needs and values of customers and for ensuring efficient use of resources; and that such a structure is not incompatible with, and can be supportive of, goals for reliability and other public goods.

- A system of capacity caps, resource contracting requirements for LSEs, and minimum price supports was proposed as a means to provide resource suppliers with some assurance they won’t lose their shirt investing in the state, while still allowing for competitive forces, accountability, and the absorption of a substantial degree of risk by the suppliers.

We thank you once again for affording us the opportunity to submit our views, and we appreciate your indulgence in reviewing them – we hope that we have added something to your efforts and to the development of the issue at large. Please do not hesitate to contact us if we can be of any service to you.

Best regards,

George Deljevic

President
Knowledge Works, LLC

ITC's response, pages 100-101

September 30, 2005

Mr. George Stojic
Director, Engineering and Service Quality Division
Michigan Public Service Commission
6545 Mercantile Way, Suite 7
Lansing, MI 48911

Re: Reliability Option Comments

Dear George:

International Transmission Company ("International Transmission") is supportive of the efforts of the Michigan Public Service Commission ("MPSC") to undertake an investigation into reliably meeting the energy needs of the State of Michigan. International Transmission is a stand-alone transmission company independent of market participants and is a member of the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO"). International Transmission owns and maintains, but does not functionally control, approximately 2,700 circuit miles of transmission facilities covering approximately 7,600 square miles throughout 13 counties in Southeastern Michigan used for the transmission of electric energy in interstate commerce. International Transmission's transmission facilities are under the operational control of the Midwest ISO. It indirectly serves a population of approximately 4.9 million in the State of Michigan. International Transmission is solely focused on electric transmission and offers the following limited comments on the Resource Addition Policy.

This letter addresses International Transmission's comments on the Staff's Capacity Need Forum reliability option policy proposal. It is International Transmission's understanding that an applicant seeking the reliability option treatment for proposed generation would be required to include an assessment of transmission alternatives as part of the process. The comments below are directed at this aspect of the proposal.

There is a lot of information and expertise needed to be able to make an accurate assessment of possible transmission capacity expansion projects, and the benefits of those expansion projects for end use customers. Such an assessment is required to accurately compare a transmission expansion project to a generator capacity expansion project as proposed under the Reliability Option. It will be very difficult for any single entity to gather all the information necessary to accurately make such an assessment as the transmission constraints could be spread across many transmission owners who may participate in a variety of regional transmission organizations ("RTO"). The Midwest

ISO is probably the most logical regional transmission expansion planning expert, but they lack the local expertise and system specific knowledge necessary to identify, evaluate, and price out transmission projects and moreover may not even have the required level of familiarity related to transmission constraints that could lie outside of their footprint. In addition to assessing possible transmission projects, such an analysis should include an indication of the availability of generation capacity that could be used to fill the new transmission capacity “pipe.” Like transmission constraints, available resources outside of Michigan that could be brought in through additional transmission capacity may lie in different footprints. It is highly unlikely that anyone applying to add generation capacity via the Reliability Option would have the technical expertise to properly and equitably evaluate transmission capacity alternatives and associated outside generation capacity nor could they hire a true expert in the alternative. Anything they would come up with is likely to be incomplete and potentially incorrect thereby requiring even more verification of the results. Finally, it will not be a simple matter of comparing capacities as consideration would also have to be given to the probabilistic availability of transmission capacity and both inside and outside generation capacity.

Because of these complexities, instead of doing ad hoc studies for each Reliability Option application, perhaps a periodic comprehensive effort, involving the RTO and the affected Transmission Owner(s), along the lines of what is being done in the capacity needs forum might be a better approach. As an alternative, a periodic evaluation of transmission expansion possibilities and available outside resources could be undertaken with any applicants using this as a basis for the transmission “alternative”.

Lastly, we would expect diminishing value and increased difficulty in performing these transmission assessments over time for two main reasons: i) after the “low hanging in-state fruit is picked” the constraints are likely going to be pushed outside of Michigan and potentially even out of the Midwest ISO footprint and less information will be available on what could be done to mitigate these constraints; and ii) entities are likely to tire of this type of required repeated effort and will end up putting less effort into assessing transmission, especially those who don't have a large direct stake in the process.

In sum, making an accurate assessment of possible transmission capacity expansion projects including an indication of the availability of generation capacity that could be used to fill the new transmission capacity “pipe” requires a collaborative effort between transmission owners, RTOs and others. International Transmission recommends the MPSC acknowledge the need for this to be a collaborative effort and the important role and expertise that independent transmission companies bring when evaluating capacity needs.

Respectfully submitted,

Thomas Vitez
Director, System Planning

Energy Michigan’s response, pages 103-108

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ERIC J. SCHNEIDEWIND E-MAIL ejschneidewind@varnumlaw.com

MEMORANDUM

TO: **George Stojic**

FROM: **Eric J. Schneidewind**

RE: **Energy Michigan Comments on MPSC Strawman Proposal**

DATE: **September 16, 2005**

Thank you for the opportunity to comment on the MPSC Staff "Reliability Option".

I. The MPSC Staff Proposal

The MPSC Staff "Reliability Option" appears to create a type of certificate of need process to acquire new generation which would be limited to regulated utilities. It is our understanding that hearings would be conducted in which the utility would describe the amount of capacity required, the timeframe of requirement and the type of technology (pulverized coal, IGCC, etc.) which would be utilized. Such a request could be accompanied by further requests for the right to charge customers for the cost of construction without an AFUDC offset and use of a non-bypassable surcharge applicable to all retail and competitive customers which would cover costs of the "reliability" component of the plant. The magnitude or items included in this "reliability" component have not been specified although it is stated that a "reliability credit" would be given for payment of the surcharge. While the MPSC Staff drafts mention the use of competitive bidding, the text of the Position Paper dated August 25, 2005 regarding competitive bidding appears to favor the regulated utility as the supplier of generation if its proposal is at all comparable with competitive bids.

II. Concerns Regarding the Staff Plan

A. The Staff Plan Must Be Coordinated With MISO Reliability Programs.

The Staff Plan attempts to address reliability issues associated with resource adequacy. However, resource adequacy is also an issue within the responsibility of regional transmission organizations such as MISO. There are significant economic risks associated with a failure to coordinate Michigan reliability / resource adequacy initiatives with any plan or approach adopted by MISO. Among these risks are diversion or redirection of power supply and inadequate or reduced dispatch of generating facilities. Energy Michigan urges the MPSC Staff to coordinate any resource adequacy initiative with MISO initiatives covering the same subject matter. Unilateral action by Michigan could result in significant, adverse financial consequences to the State.

B. The Staff Plan Appears To Minimize The Role Of Competition In Providing Michigan's Future Wholesale Power Requirements.

Many of the technologies which are mentioned as part of a solution to Michigan's future power requirements are as yet unproven at utility scale. A recent report issued by Standard & Poor's has highlighted the risks associated with IGCC plants and stated that financial interests either prefer not to finance such projects, will exact a premium to finance or will attempt to transfer performance and cost risks to customers because of the inherent risks of new technology. If the role of supplier is limited to utilities using a risky technology, Michigan loses the ability to force bidders to assume part or all of this risk and will not benefit from the downward pressure on pricing that results from competition to build new power plants. A shift of price and performance risk to customers also minimizes pressure on the utility as an operator which in turn may result in higher prices and worse performance than would be the case where the operator assumed performance risks. The result of the Staff approach is likely to be power costs which are higher than would be the case using truly competitive bid procedures.

C. The Staff's Framework Ignores Commission Policies Which Are Eliminating Competitive Sources Of Retail Electric Supply.

Both current Commission approved generation related surcharges such as securitization, nuclear decommissioning, transition and the proposed new Regulatory Adjustment Charges and "reliability surcharge" all tend to charge competitive customers for utility generation costs while denying these customers the use of such generation. The magnitude and unpredictability of these charges has reached a point where competitors cannot match utility prices (particularly in a high market) and still stay in business. The magnitude of current charges (5-10% of generation costs) and projected charges (adding an additional 10% or more in the case of Regulatory Adjustment Charges) make it impossible to save money by switching to competitive sources of supply. The result of these unfavorable economics could be a massive transfer of competitor load back to utilities thereby aggravating the alleged supply problem and forcing acquisition by regulated utilities of even greater amounts of expensive new capacity. The Commission clearly has the power to reject new utility proposals to collect generation related charges from competitive customers who do not benefit from utility generation. Staff's proposal appears to worsen this situation rather than address the problem.

Forcing competitive customers to pay the costs of a new utility power plant is particularly unfair considering that such plants are likely to be the most expensive resource operated by the utility. Thus, competitive customers would be forced to buy into the utility's most expensive power plant while retail customers are allowed to purchase power at rates that average older lower cost plants with new higher cost plants. The result of this unequal treatment will be to further erode the economics of Electric Choice.

D. Legality.

It may be argued that the Commission has authority to allow utilities to collect the cost of construction of power plant from customers before such plants enter service. It has even been said that the Commission has authority to examine utility costs while a power plant is under construction. AG v MPSC, 412 Mich 385.

However, the above referenced Supreme Court interpretation of Michigan's statutory law found no authority for the Commission to grant prior approval of a utility power plant project and commit customers to pay the cost of the plant.

The Michigan regulatory framework does include provisions which allow the Public Service Commission to give prior approval to utility purchases of power and then commit that utility customers will be billed for and pay such costs. That power is specified in PA 304 of 1982.

III. Proposed Revisions to MPSC Staff Reliability Option.

A. Capacity Acquisition.

Energy Michigan recommends that the Commission utilize the PA 304 framework to acquire needed power supplies in Michigan. Under that framework a utility could issue a RFP for power supply specifying amount, timing and a statement of emission compliance that is required. Proposals to provide this power supply at the least cost with the most performance guarantees would be evaluated and a winner selected. The winning bid and underlying power supply agreement could be submitted to the Commission for prior approval with the assurance that the resulting cost would be billed to and collected from retail customers through the PSCR process.

The criteria for just and reasonable rates would be satisfied through the bid process. Use of a bid process would also assure that price, timing and performance risk could be transferred to the maximum degree possible to the winning bidder rather than utility customers. Several jurisdictions offer examples of effective bid processes.

If financial institutions are concerned that the Public Service Commission may alter their approval Order during the term of the contract, amendments to PA 304 of the type adopted for PURPA contracts in 1987 PA 81 could be proposed.

B. Assuring the Role of Competitive Retail Suppliers.

The Staff proposal is eloquent testimony to the fact that the generation fleet of Michigan's regulated utilities is fully utilized and that the market for any excess power is more than adequate to pay the costs of embedded generation. Yet, competitive customers continue to pay securitization, nuclear decommissioning, transition charges, and may pay new Regulatory Adjustment Charges and a new "reliability" charge. Collectively these generation charges are already so burdensome that they cannot be paid in the current market without rendering Choice service uncompetitive. The logical consequence of this situation is that competitors have been priced out of the retail supply equation by Commission policies which are clearly outdated and unsupportable in the current economic environment.

The equitable solution to this situation is to recognize that competitive customer payments for utility generation such as securitization or nuclear decommissioning represent a revenue stream which is paying overall utility costs of generation. Under these circumstances the competitive customers should be entitled to receive an amount of power at average utility rates which is equal to generation related payments to a utility. This proposal would ensure continuation of a revenue stream adequate to fund existing securitization and nuclear decommissioning trust funds and would not result in stranded costs because power is taken in return for payments made much as is the case with a retail customer.

Continuation of the current MPSC pattern of requiring competitive customers to pay utility generation related costs in addition to the costs of competitive power is unsupportable in a market where all utility generation is either used by retail customers or commands a price in the marketplace that more than offsets existing costs of generation.

Conclusion

Energy Michigan appreciates the opportunity to comment on the Staff proposal and believes that the constructive comments offered above can make the Staff proposal more effective as a power supply mechanism and more equitable to all energy customers in Michigan.

LS Power's response, pages 110-113

COMMENTS OF LS POWER DEVELOPMENT CORPORATION TO THE
MICHIGAN ELECTRIC CAPACITY NEEDS FORUM

1. TO PERMIT DEVELOPMENT OF NEW ELECTRIC GENERATING CAPACITY IN MICHIGAN, THE STATE NEEDS TO REMOVE REVENUE UNCERTAINTY.

Prospective developers, owners and operators of new generating capacity can attract the equity and debt investment necessary to provide new generating capacity only under circumstances where there are reasonably predictable future revenues from the plant to provide a return of and return on investment. Revenues must be reliable for periods of 20 years or more. The greater the uncertainty of future revenues, the more expensive the capital, and the more expensive the power will be to consumers.
There is a point at which uncertainty over future revenues cannot be overcome by increases in required equity returns and interest rates. When Michigan eliminated the legal monopoly on access to retail customers without providing other means of revenue certainty to power plant investors, that point was reached.

2. ANY METHOD OF PROVIDING ASSURED REVENUE, AND THEREFORE FINANCIBILITY, TO POWER PLANT DEVELOPERS AND OWNERS MUST PROVIDE THE MEANS TO MAKE THAT REVENUE ASSURANCE AVAILABLE TO NON-UTILITY PARTICIPANTS.

In the best interest of electricity consumers, the state of Michigan should devise a system which would extend to non-utility developers the same degree of certainty of future revenues that it provides utilities. If this forum succeeds in devising means to eliminate unacceptable revenue uncertainty to utilities, by a process like that described below or some other,

that revenue stream can as easily be used to make payments to a non-utility plant owner for power purchased as it can be used to service utility-incurred debt or provide returns to utility shareholders.
If the Public Service Commission or the legislature resolves the difficulties facing utilities in the development of power plants, and leaves the same issues unresolved for non-utility developers it may exacerbate the problem of the influence of the distribution monopolists over the generation market, which the legislature sought to curtail in section 10(f) of the Customer Choice and Electric Reliability Act of 2000.

3. NON-UTILITY PLANT OWNERS CAN OFFER COMPARABLE OR SUPERIOR OPTIONS TO WHAT UTILITIES MAY OFFER.

The majority of utility-scale power plants constructed in the United States over the past 2 decades have been conceived, developed, permitted, financed, constructed, operated and owned by companies other than regulated utilities. On the other hand, neither of the large investor-owned utilities in Michigan has constructed a new baseload power plant since the 1980’s.

In response to requests for proposals to furnish new generating capacity in other states, non-utility developers have offered lower-cost, more reliable options than utilities. This has been possible because each potential new supply resource has different construction costs, site specific costs, and financing costs. In addition, non-utilities have provided unit efficiency and availability guarantees for their generating facilities, insulating ratepayers from performance risks associated the facility. It may be the case that the utility-proposed generating facility is best, or a that non-utility resource may prove to be superior. However, absent an evaluation to determine the lowest-cost, most reliable option, there is no way to credibly determine what option is best for the state’s ratepayers.

4. A PROSPECTIVE POWER PLANT DEVELOPER SHOULD BE ABLE TO OBTAIN A DETERMINATION OF A UTILITY'S NEED FOR CAPACITY AND THE FAIR COST OF POWER.

A process like that proposed in this forum as the Reliability Option can serve several needs, including the need to level the playing field for IPP participants. LS Power suggests that a contested case to determine (1) the capacity needs of a utility and (2) the fair cost to meet such needs should be within the ability of either the utility or a prospective capacity supplier to commence.

If the conclusion from a proceeding commenced by a supplier was that a need for capacity existed at the utility and that the price and terms for the supply of that capacity offered by the proponent were fair, the utility could then elect to enter into a contract for the provision of capacity and energy for substantially the life of the plant. If the utility did elect to contract for capacity on terms found fair by the Commission, recovery of payments made under that contract would thereafter be guaranteed to the utility more or less in the manner provided in Act 81, MCL 460.6(j)(13)(b), except that recovery of both capacity and energy charges would be guaranteed, and the supplying power plant need not be a qualifying facility under PURPA.

If, on the other hand, the utility declined to contract for the purchase of capacity and power on terms found fair by the Commission, it would not thereafter, for the expected life of the proposed plant, be permitted to recover any power cost in excess of that found to be fair but declined by the utility, in any PSCR case, because the decision not to contract for the power would be demonstrably imprudent.

Respectfully submitted,
LS Power Development Corporation

DTE's response, pages 114-118

Comments of The Detroit Edison Company
MPSC Staff's Proposed "Reliability Option"
Capacity Needs Forum
September 30, 2005

The Detroit Edison Company ("Detroit Edison" or "The Company") commends the Michigan Public Service Commission's Staff for its efforts in evaluating the need for new generation in the State of Michigan. <u>However, the State of Michigan must act immediately to assure future resource adequacy. At a minimum, the State of Michigan must implement policies that assign (1) clear responsibility for resource adequacy and (2) explicit cost recovery mechanisms together with regulatory certainty to encourage investments in new generating facilities.</u>

As noted in previous comments to the Capacity Needs Forum, Michigan's hybrid regulatory structure has significantly complicated the capacity addition process. The introduction of Electric Choice has fragmented the responsibility for generation supply between incumbent electric utilities and alternative electricity suppliers. Michigan's electric utilities no longer have sole responsibility for electric supply in their service territories. Without a certain and defined base of customers and the associated revenue certainty, both Michigan's electric utilities and independent power suppliers face substantial financial risk associated with the construction of new generating facilities.

1. Upfront regulatory commitment to new generating plant through formal case process

<u>Detroit Edison Comments:</u> As noted previously, any policy changes must be codified to insure the Michigan Public Service Commission possesses the unequivocal legal authority to implement such policies. In addition, a future Commission cannot be bound by a decision of the current Commission without modification to existing statutes. Given the tremendous investment required in new and existing generation infrastructure in Michigan, and the long-term financial assurances required by the capital markets, legislation is necessary to ensure that future Commissions could not alter the policies of the current Commission after the investments are made by the electric utilities. Therefore, an "upfront regulatory commitment" does not provide sufficient regulatory and revenue certainty – two key components to any reasonable capacity addition policy involving long lived, base load assets.

(a) recognition of need for plant and plant type

<u>Detroit Edison Comments:</u> The Company supports a legally binding Commission pre-approval process for the construction of new generating facilities. It is important to note that such pre-approval is a necessary, but not sufficient, condition for the construction of new generating facilities in Michigan. A pre-approval process would reduce, but not eliminate, the financial and regulatory risks associated with an after-the-fact review process with respect to capacity needs, fuel source and type of plant, construction cost estimates, and investment type (generation or transmission).

In its June 16, 2005 comments, ABATE offered its position that the Commission lacks the statutory and common law power to conduct a pre-construction review of either the need or the cost of a new generating plant. Further, ABATE believes there is no revenue certainty surrounding the pre-construction review of plant costs, and that recovery of such cost can only be authorized upon a finding that the completed facility is "used and useful." While Detroit Edison does not necessarily concur with the ABATE analysis, it illustrates the significant legal differences of opinion concerning the Commission's powers in this area. Therefore, legislative action will be needed to both clarify and institutionalize the Commission's powers over the construction of and payment for new generation plant in order to minimize legal challenges that will delay the addition of any such plant.

(b) enforceable commitment to capped price and schedule

Detroit Edison Comments: The Company agrees that the Commission should include a reasonable requirement for both the cost and schedule of construction of any new generating facility in its pre-approval process. However, the Commission should not limit recovery of prudently incurred expenses that may exceed the original estimate.

(c) demonstration that plant is the appropriate resource to meet need and analysis of public benefits, this needs to be demonstrated through a comprehensive planning assessment that evaluates risks and costs of traditional plant, renewable plant, energy efficiency, and load management

Detroit Edison Comments: The Company agrees that a process should include a reasonable analysis of the risks and costs of a traditional plant, renewable plant, energy efficiency, and load management. However, any programs adopted in conjunction with such analysis must be cost competitive with supply options.

(d) utility can request CWIP in rate base without an AFUDC offset

Detroit Edison Comments: The Company agrees with such a policy to allow Construction Work in Progress (CWIP) without the Allowance for Funds Used During Construction (AFUDC) offset as the new base load plant is being constructed. This would reduce the financial uncertainty and overall financing costs of the facility while supplementing cash flow during the construction period. Placing these CWIP rate adjustments into effect throughout the construction cycle has the added benefit of phasing-in the rate impact on customers.

(e) utility can request a reliability charge to be assessed to all distribution customers of the utility

Detroit Edison Comments: The Company generally supports the concept of a wires charge that would be assessed on all distribution customers of the utility for new capacity additions. New base load generating facilities in Michigan will not only increase overall system reliability, they will also likely reduce the market price of power and energy for all customers within Michigan. However, the MPSC must provide further details regarding the specific costs to be recovered by such a charge and the legal authority for the MPSC to impose such a charge on all distribution customers of the utility. In addition, such a charge should also be considered for existing generation that requires upgrades or environmental retrofits to maintain reliability (see further discussion on page 4). The wires charge must provide for sufficient revenue certainty for new generating facilities to be constructed in Michigan; it must also provide sufficient revenues to support the type of generating facility (i.e., base load, intermediate, peaking) required to meet load requirements in a least cost manner.

2. In exchange for paying the reliability charge associated with the plant, customers of an alternate electric supplier would receive a prorated share of the plants reliability value for satisfying any regional reliability standard. If customers of an alternate electric supplier pay the reliability charge, the alternate supplier would have a one time opportunity to make a pro-rata investment in the generating station

Detroit Edison Comments: While the Company generally does not object to the concept of allocating a pro-rated share of a generating facility's reliability value for satisfying any regional reliability standard to an alternative electric supplier, the details of such an allocation and the process by which such an allocation may occur must be clear and precise prior to the construction of any new facilities.

With respect to the concept of an alternate supplier having a one time opportunity to make a pro-rata investment in the generating station, Detroit Edison does not support such an arrangement. Public Act 141 introduced retail competition to the State of Michigan. To now require incumbent electric utilities to partner with their competitors in the construction, operation and maintenance of new generating facilities is not only inconsistent with Public Act 141, but runs counter to the structure of any reasonable competitive market.

With regard to the issue of "satisfying any regional reliability standard," it is important to note that load serving entities in Michigan operate under two very distinct reliability standards. Michigan utilities utilize an 11 to 15 percent planning reserve margin while alternative electric suppliers are only required to meet the North American Electric Reliability Council East Central Area Reliability Coordination Agreement's requirement of a four percent daily operating reserve pursuant to the Midwest Independent System Operator's tariffs. It is of the utmost importance that all load serving entities within the State of Michigan operate under the same reliability standards. The Commission's policy should address this inconsistency.

3. Competitive solicitation for new capacity is mandatory through a fair and transparent process. There would be a rebuttal (sic) presumption that a cost cap proposed by a utility in a reliability hearing is reasonable if the utility has undertaken a fair and open competitive solicitation

Detroit Edison Comments: The Company believes that the public interest will be fully protected if competitive bidding is limited to the Engineering, Procurement and Construction (EPC) aspects of generation development. Developing natural gas-fired peaking and combined-cycle plants is characterized by few permitting and sitting issues, standardized design specifications and short construction periods. Plant values are in the several hundred million dollar range and the development risks, other than market, are minimal.

On the other hand, coal-fired plants are far more difficult to permit and site, have complex design requirements and involve substantial more time to construct. Plant values are in the several billion dollar range and the development risks, beyond market, are large given the uncertain and evolving environmental compliance regulations and potential climate change requirements.

A turnkey fixed price guarantee for a major coal-fired power plant, which could take seven plus years to complete, would require a considerable risk premium to be included in any firm construction cost guarantee. Competitive bidding does not ensure the lowest possible all-in construction cost and introduces further uncertainty into an already complex permitting and construction process. Other recognized methods are available, such as benchmarking, to establish the reasonability of construction costs.

It is important to note that in any competitive capacity solicitation process, IPPs would likely seek a long-term Purchase Power Agreement (PPA) with the incumbent utility. A long-term PPA is required to provide project revenue certainty in order to finance the generation project. In order not to financially harm Michigan's electric utilities through a long-term PPA, the following two polices must be considered:

First, the current hybrid structure does not provide customer load requirement and regulated revenue certainty for Michigan's electric utilities. Consequently, a utility's long-term purchase commitment to an IPP would not be matched by a corresponding long-term purchase commitment from the utility's customers and the utility would be at risk to recover its PPA costs. Therefore, a regulatory out clause may be a necessary provision in any new PPA.

Second, rating agencies currently recognize PPAs as off-balance sheet debt and impute it into the capital structure. Additional equity capital would be required to maintain the same pre-PPA debt to equity ratio and credit rating. The incumbent utility must be able to earn a return on the additional equity capital required to maintain a balanced capital structure and which would also provide a financial incentive to contract rather than build.

4. **A utility proposal made under the reliability option would include an offer to other Michigan load serving entities to become partners in the generating plant.**

   Detroit Edison Comments: The Company supports such partnerships with traditional Michigan load serving entities – investor-owned, municipal and cooperative utilities -- in future generating facilities.

- **Issues Not Addressed in the MPSC Staff's Proposed "Reliability Option"**

Investments in Existing Generation

In Detroit Edison's original comments to the Capacity Needs Forum, the Company noted that as long as the current hybrid regulatory structure remains in Michigan, investments in base load generation, whether new or existing, are at risk. As new base-load capacity is added in Michigan, the market price for energy will likely decline. This decline in price will only serve to lower the market value of existing generation and increase the prospect of additional stranded cost.

Adopting new regulatory policies to provide revenue certainty to facilitate new generation investment creates substantial economic and financial risk distinctions between new and existing generation with existing generation clearly at risk. Such a policy distinction will likely lead to unintended consequences whereby low cost capacity expansions on existing generating units are forgone for investment in new generating facilities that may be of lower financial risk due to inconsistent regulatory treatment.

It should be noted that for all their shortcomings, RTO- managed capacity markets have not distinguished between new and existing generation when applying capacity charges. The reason is that all capacity is required to provide system reliability. If new generation that provides only a small portion of the total supply reliability is deemed to be a public good, then the same must certainly be true for existing generation.

Michigan electric utilities have and will be required to make massive investments in environmental retrofits at existing coal-fired generating plants. It is not good public policy to treat large generation investments in Michigan differently for regulatory cost recovery purposes simply because one occurs in a new plant and another in an existing plant to preserve its operation. Without preserving existing capacity, Michigan will require much greater investments in new capacity.

Market Power

In Detroit Edison's original comments to the Capacity Needs Forum, the Company noted that the market power provisions of Public Act 141 appear to conflict with the addition of new generating capacity in Michigan's hybrid regulatory structure. While the MPSC Staff notes this concern, the MPSC Staff's proposal does nothing to address the potential conflict.

This is another clear example of the legal ambiguity surrounding the development of new generating facilities in Michigan. Lower cost financing can only be achieved by reducing the regulatory uncertainty relative to future resource additions.

Conclusion

Detroit Edison appreciates the Commission Staff's efforts to determine the need for new generation and to recommend policies to ensure that needed generation infrastructure investments are made in Michigan. The results from the New Energy Associates modeling efforts clearly show that Michigan may need to install approximately 7,000 MW of new generating resources in the next ten years to provide reliable, least-cost power supply.

The Company believes that the current electric market structure in Michigan will not enable these investments to be made in the absence of significant policy changes. While the Commission Staff has proposed policy recommendations to address several significant investment impediments, these recommendations do not provide the revenue and regulatory certainty, and specificity, commensurate with multi-billion dollar investments in long-life base load generation assets.

Specifically, Michigan's current hybrid market structure fails to provide a stable customer base and hence creates uncertain customer supply obligation and corresponding regulated revenue stream. It is entirely possible that the customer base that existed at the time development commences for a new coal-fired plant, and created the need for the utility to build the plant in the first place, will not exist when the plant is placed into commercial operation. It is simply not possible to develop and finance long-life, capital intensive investments, or enter into long-term supply agreements (PPAs), in this hybrid market environment.

In addition, developing new power plants is inherently more risky today than it was 20 years ago when the last base load plants in Michigan were placed into commercial operation. This is due to fuel price uncertainty and volatility and uncertain and increasingly more stringent environmental control requirements. Consequently, it is essential to have regulatory and revenue certainty through a legally binding pre-approval process, a certain customer base, and a non-bypassable cost recovery revenue stream in order for any base load generation capacity additions to occur in Michigan.

Michigan's electric utilities must not be required to do what the wholesale markets have not done, namely develop new capital-intensive <u>merchant</u> base load generation. This is precisely what would occur if Michigan's electric utilities are required to develop, directly or indirectly through PPAs, new base load generation in the absence of the required policy changes to Michigan's existing hybrid electric market structure. Achieving these policy changes will be a major challenge, but they must be made if Michigan is to have a long-term, least-cost and environmentally responsible generation portfolio.

The Company looks forward to working with the Commission Staff, and other stakeholders, through the Capacity Need Forum to develop the policy recommendations that will ensure that the needed generation infrastructure investments are made in Michigan.

Lansing Board's response, pages 120-121

LANSING BOARD OF WATER&LIGHT

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September 16, 2005

Mr. George Stojic
Michigan Public Service Commission
6545 Mercantile Way
PO Box 30221
Lansing, Michigan 48909

Dear Mr. Stojic:

In response to your request, the Lansing Board of Water & Light (BWL) presents the following comments regarding Reliability Options, Competitive Bidding, Energy Efficiency, Construction Partnerships, and Market Power.

Reliability Options

The BWL supports the concept of retaining the traditional method of building a new generating plant and seeking fair and just rate compensation. With respect to the Reliability Option, our understanding is that the BWL's customers will not be subject to the proposed reliability charges nor the proposed credits so we have adopted a neutral position at this time. However, we do believe that the Commission's Reliability Option has merit for further consideration as the details of the reliability charges and credits are more fully finalized.

Competitive Bidding

The BWL supports competitive bidding for power plant construction.

Energy Efficiency

The BWL supports the concept of including an analysis of cost effective energy efficiency as a resource option. Energy efficiency is not necessarily always the primary driver of the best resource option but it should be a consideration. As an example, a lower cost peaking plant that is not as efficient as a more expensive peaking plant may be the best value for the industry if the peaking plant is to run only a few hundred hours per year.

Construction Partnerships

The BWL strongly supports the concept of construction partnerships for base load power plants. Smaller load serving entities, such as the BWL, should be allowed to become partners in a base load plant. This partnership should be required before the MPSC will even entertain rate treatment of the proposed base load plant. In addition, necessary transmission rights for the base plant output needs to be provided to all plant participants.

Market Power

The BWL strongly agrees that new base load plant construction should be open to all parties. The statement needs to go further to require contracts that allow access to plant and company information and do not discriminate or create adverse difference to minority partners.

As a municipal electric utility, the BWL puts the welfare of customers first. We feel our positions as discussed above will allow for a positive effect on our customers. Thank you for allowing us the opportunity to provide input and the BWL looks forward to working with the MPSC and others in the future for the betterment of the customers of electric utility businesses in Michigan.

Pete Schimpke

Pete Schimpke

Lansing Board of Water & Light
Manager, Resource & System Planning
730 E. Hazel
PO Box 13007
Lansing, Michigan 48901

CC- Bill Cook –BWL
Doug Wood- BWL

RESA's response, pages 123-124

RESA

Retail Energy Supply Association

Post Office Box 6089
Harrisburg, PA 17112

September 26, 2005

Ms. Mary Jo Kunkle
Executive Secretary
Michigan Public Service Commission
6545 Mercantile Way
P.O. Box 30221
Lansing, MI 48909

Re: Capacity Needs Forum, Docket No. U-14231
Comments of the Retail Energy Supply Association

Dear Ms. Kunkle:

The Retail Energy Supply Association[1] ("RESA") is a nonprofit organization and trade association that represents the interests of its members in regulatory proceedings and legislative matters in the Mid-Atlantic, New York, and New England regions. RESA is also beginning to participate in matters in the Mid-West that may impact the development of competitive retail electricity markets. Its members include providers of competitive retail energy supply. RESA appreciates the opportunity to submit these comments regarding the Commission Staff's proposal to maintain capacity adequacy being developed in the above referenced docket.

RESA opposes utility ownership of generation. Utility-owned generation undermines competitive markets. This is because utility ownership of generation increases the utility's incentive to retain customers on utility service in order to create or retain a large base to pay for the costs of the generation. Utilities that own generation are subject to pressure to create barriers to customers exercising choice in their retail supply. Thus, RESA opposes the Commission Staff's comments regarding the "Reliability Option". RESA's concerns are not allayed by the statement that this option should be pursued only "so long as a better alternative is not available". Rather, RESA is concerned by Staff's declaration that "electric reliability is not likely to be provided by a competitive market alone". Moreover, there is no evidence that supports Staff's position. Proposals supportive of utility ownership of generation are contrary to the public policies that supported the

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[1] RESA's members include Amerada Hess Corporation; Constellation NewEnergy, Inc.; Direct Energy Services, LLC; Reliant Energy Solutions; Select Energy, Inc.; Sempra Energy Solutions; Strategic Energy, LLC; SUEZ Energy Resources NA, Inc. and US Energy Savings Corp. The opinions expressed in this filing may not represent the view of all members of RESA.

implementation of competitive wholesale and retail electricity markets in Michigan and other markets.

The expansion of utility-owned generation and rate base recovery in Michigan will exacerbate the host of problems already created by the utilities' continuing ownership and operation of generation. Due to a market design that continues to permit heavy utility influence and activity in the competitive market, retail competition has been slow to emerge in Michigan. Creating additional utility-owned generation will hinder further development of the competitive marketplaces, both retail and wholesale. Utilities must exit the competitive segments of the market (i.e., wholesale and retail segments) in order for competition to develop and flourish. A properly functioning retail market requires that the utilities focus on and remain efficient in providing energy *distribution* services. Utility participation in generation markets will detract from this focus and will be deleterious to the emergence of a competitive retail electric market.

Equally troublesome, utility ownership of generation greatly enhances the potential for subsidies from the distribution business of the utility to its generation business. Such subsidies distort wholesale and retail electric markets. Moreover, these subsidies can cause irreparable damage to market development before they can be discovered, which is a difficult task in and of itself.

Finally, expanding utility ownership of generation carries with it an unacceptable possibility of creating stranded costs that may ultimately have to be passed through to Michigan consumers. The market is capable of producing capacity construction at the proper times in appropriate locations and with the greatest efficiency. Moreover, shareholders—not ratepayers—will bear the risk associated with new non-utility construction.

Fortunately, the Commission has numerous market-based options available to it to address future capacity needs. Staff can and should use market-based mechanisms to employ market forces to address capacity requirements. Staff correctly notes that regional reliability organizations take active roles in promoting reliability. While RTO/ISO markets continue to evolve, it is clear that they are *markets*, and that reliability concerns can be adequately addressed through these markets. Consequently, RESA recommends that the Commission avail itself of market-based alternatives.

RESA looks forward to working with Staff and other stakeholders to develop market-based mechanisms to ensure continuing reliability. If you have any questions regarding the foregoing, please contact the undersigned.

Very truly yours,

Ms. Tracy McCormick
Executive Director

cc: Hon. J. Peter Lark, Chairman
Hon. Monica Martinez, Commissioner
Hon. Laura Chappelle, Commissioner